Service Date: July 19, 1991

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA
* * * * *

IN THE MATTER OF The Application)	UTILITY DIVISION
by the MONTANA POWER COMPANY for)	DOCKET NO. 90.6.39
Authority to Increase Rates for)	ORDER NO. 5484k
Natural Gas and Electric Service.)	(REVENUE REQUIREMENT)

APPEARANCES

FOR THE APPLICANT:

Pamela K. Merrell, Esq., Montana Power Company, 40 East Broadway, Butte, Montana 59701

FOR THE MONTANA CONSUMER COUNSEL:
Robert A. Nelson, Esq., and Mary Wright, Esq., Montana Consumer Counsel, 34 West Sixth Avenue, Helena, Montana 59620

FOR THE INTERVENORS: .
Robert M. Pomeroy, Jr., Esq., Holland and Hart, Suite 1050, 4601 DTC Boulevard, Denver, Colorado 80237, appearing on behalf of the Large Customer Group

Donald W. Quander, Esq., Holland and Hart, Suite 1400, 175 N. 27th Street, Billings, Montana 59101, appearing on behalf of the Large Customer Group

Robert Rowe, Esq., Montana Legal Services, 127 East Main, No. 209, Missoula, Montana 59802, appearing on behalf of the District XI HRC

Lt. Col. Bruce J. Barnard, USAF, Chief Utility Litigation Team, HY USAF/ULT Stop 21, Tyndall AFB, Florida 32403-6001, appearing on behalf of the Federal Executive Agencies

John Doubek, Esq., Small, Hatch, Doubek and Pyfer, 39 Neill Avenue, Helena, Montana 59601, appearing on behalf of the Montana Irrigators, Inc.

James Robischon, Esq., Murphy, Robinson, Heckathorn and Phillips, P.C., 431 First Avenue West, Kalispell, Montana 59903, appearing on behalf of Rhone-Poulenc Basic Chemical Company

Donald D. MacIntyre, Chief Legal Counsel, Department of Natural Resources and Conservation, Lee Metcalf Building, 1520 E. Sixth Avenue, Helena, Montana 59601, appearing on behalf of the DNRC

C. Clark Leone, Esq., Bonneville Power Administration, P.O. Box 3621, Portland, Oregon 97208, appearing on behalf of the BPA

FOR THE COMMISSION:
Robin A. McHugh, Staff Attorney
Mark Lee, Rate Analyst, Revenue Requirements Bureau
Eric Eck, Rate Analyst, Revenue Requirements Bureau
Jasper Li, Economist, Rate Design Bureau
Dan Elliott, Administrator

2701 Prospect Avenue, Helena, Montana 59620 BEFORE:
HOWARD L. ELLIS, Chairman
DANNY OBERG, Vice Chairman
BOB ANDERSON, Commissioner
JOHN B. DRISCOLL, Commissioner
WALLACE W. "WALLY" MERGER, Commissioner

FINDINGS OF FACT

BACKGROUND

1. On June 27, 1990, the Montana Public Service Commission (Commission) received an application from the Montana Power Company (MPC or Company) for authority to increase electric and gas rates. At the time of the application MPC sought to raise electric rates to recover an additional $60,657,226 in annual revenues, and to raise natural gas rates to recover an additional $9,581,408 in annual revenues. The initial proposed increases represented a uniform percentage change in rates of 22.6 percent for electric retail customers and an overall change of 9.04 percent for natural gas customers. MPC's application did not contain allocated cost-of-service studies nor proposed adjustments to its electric and natural gas rate structures. MPC indicated that it expected to make separate cost-of-service/rate design filings by August 10, 1990, for gas and September 30, 1990, for electric and asked that ARM 38.5.176 and 38.5.177 be waived.

2. Concurrent with its general rate increase application MPC requested interim increases of $30,631,352 for the electric utility and $5,593,982 for the Montana" segment of the gas utility. Included in the request for an interim increase in electric rates, MPC requested that, effective July 1, 1990, it be allowed to accrue, for later reflection in rates, purchase power costs incurred under the WNP-1 Exchange Agreement, a contract among the Washington Public Power Supply System, BPA and MPC[1]. MPC stated in its request that on July 1, 1990, pursuant to the agreement, it would begin to incur additional purchase power costs that should be reflected in rates. Without prejudice to a later review of these costs, the Commission, in Interim Order No. 5484, authorized MPC to accrue unreflected WNP-1 power costs from July 2, 1990, (the effective date of Order No. 5484) to August 29, 1990, the anticipated date of the electric interim rate change. Accrued costs were to be recovered in interim rates.

3. On July 12, 1990, the Commission issued a Notice of Application and Intervention Deadline and scheduled a prehearing conference for July 26, 1990. On July 18, 1990, the Commission received from the Large Customer Group an objection to MPC's request to waive minimum filing requirements with respect to the electric rate increase application. On that same date the Commission also received from Stone Container Corporation an objection to MPC's request to waive minimum filing requirements with respect to the gas rate increase application. MPC responded to these objections on July 26, 1990.

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[1]MPC agreed that electric interim increases should not be effective until August 29, 1990, the date of an MPC rate change pursuant to the rate moderation plan approved in Order No. 5113b,Docket No. 84.11.71.

4. On July 31, 1990, in Order No. 5484a, Order on Objections and Procedural Order, the Commission sustained the objections of the Large Customer Group and Stone Container and established the procedures to be followed in this Docket. The Commission found that the filing would be complete upon receipt of information from MPC, for both electric and gas, as required by ARM 38.5.176 and ARM 38.5.177. For purposes of 69-3-302, MCA, the Commission found that the nine-month time period for issuing an order would begin upon receipt from MPC of all necessary information.[2] The Commission established a procedural schedule that contemplated February 18, 1991, as the opening day of hearing.

5. On August 27, 1990, the Commission staff granted intervention in this Docket to the following:

[2]The Commission received MPC's gas cost-of-service/rate design filing on August 10, 1990, and the electric cost-of service/rate design filing on October 1, 1990. Therefore, the nine-month period for issuing an order in this Docket ends July 1, 1991. Pursuant to a proposal by MPC, rates implementing this order will not take effect until August 29, 1991. Revenue from the date of this order to August 29, 1991, will be tracked and amortized over a one-year period. (See Tr. pp. 62-63)

Montana Consumer Counsel
District XI Human Resource Council Large Customer Group
Stone Container Corporation
Federal Executive Agencies, Malmstrom AFB Bonneville Power Administration
Department of Natural Resources and Conservation Great Falls Gas
Shelby Gas
Cut Bank Gas
Montana People's Action
Rhone-Poulenc Basic Chemical

The Commission granted late intervention in this Docket to Conoco Pipeline Company, Montana Department of Social and Rehabilitation Services and the Montana Irrigators. By Order No. 5484e the Commission denied intervention in this Docket to Montana-Dakota Utilities.

6. On August 28, 1990, by Interim Order No. 5484c, the Commission authorized MPC an interim increase in jurisdictional annual electric revenues of $30,483,417. On September 14, 1990, by Interim Order No. 5484d, the Commission authorized MPC an interim increase in annual natural gas revenues of $6,298,145.

7. On July 27, 1990, MPC requested that gas specific issues in Docket No. 90.6.39 be consolidated into Docket No. 90.1.1.[3] In Order No. 5484b, Order on Motion to Consolidate and Amended Procedural Order, the Commission granted MPC's request to consolidate and modified the procedural schedule accordingly. Specifically, the Commission ordered that the record established in Docket No. 90.1.1 would be consolidated with the record on gas only issues in Docket No. 90.6.39. The amended procedural schedule established in Order No. 5484b applied to Docket No. 90.6.39 and Docket No. 90.1.1 and

[3]Docket No. 90.1.1 is an application by MPC for authority to establish rates to implement a gas transportation plan.

contemplated February 25, 1991, as the opening day of hearing.

8. On October 22, 1990, the Commission issued Protective Order No. 5484f covering certain Western Energy Company materials and information as well as certain information requested by the Commission staff during its 1990 in-house audit. By Order Nos. 5484g, 5484i and 5484j the Commission subsequently amended Order No. 5484f to cover additional material and to remove certain material from protection.

9. On January 28, 1991, the Commission issued Order No. 5484h amending the procedural schedule to allow time for parties to respond to certain additional issues identified by the Commission staff and described in Order No. 5484h.[4] The revised procedural schedule contemplated April 16, 1991, as the opening day of hearing.

10. On December 17, 1990, the following parties prefiled direct testimony in Docket No. 90.6.39: Montana Consumer Counsel (MCC), District XI Human Resource Council, Large Customer Group, Federal Executive Agencies and Rhone-Poulenc Basic Chemical. The Montana Irrigators were permitted by Order No. 5484h to prefile direct testimony on March 18, 1991. On February 12, 1991, MPC filed rebuttal testimony in which it revised its request for additional annual electric revenues from $60,657,226 to $52,192,021. MPC's request for additional gas revenues did not change on rebuttal.

[4] In addition to these issues, MPC indicated to the Commission in late January, 1991, that its rebuttal testimony in Docket No. 90.1.1 would contain substantial changes to the initial proposal. Order No. 5484h also allowed time for parties to conduct discovery on these changes and to submit additional testimony.

11. On March 15, 1991, the Commission issued a Notice of Public Hearing in this Docket, to begin April 16, 1991, and to continue until completed. This notice contained a schedule of public satellite hearings to be held in Great Falls, Billings, Helena, Townsend and Missoula. A satellite hearing held in Shelby was noticed separately. The hearing in Docket No. 90.6.39 began on April 16, 1991, and, for electric issues, electric and gas common issues and gas revenue requirement issues, finished on April 30, 1991. By agreement of the parties, gas cost-of-service/rate design issues in Docket No. 90.6.39 were treated as part of the hearing in Docket No. 90.1.1, which began on April 30, 1991, and concluded on May 10, 1991.

12. The following persons testified on revenue requirement issues in this Docket:

For MPC: Robert P. Gannon
Thomas J. Matosich
Ernest J. Kindt
Jerrold P. Pederson
Robert A. Periman
Wilhelmus C. Verbael
Charles E. Olson
John S. Miller
Stuart G. McDaniel
William A. Pascoe
Robert M. Quinlan
R. John LeLand
Jeffrey T. LaFrance
Daniel R. Reardon
James H. Aikman
David A. Johnson
Ceil A. Orr

For MCC: Jacob Pous
John W. Wilson
Caroline M. Smith
Albert E. Clark
James H. Drzemiecki

For HRC: Thomas Michael Power

For LCG: Jan W. Michael

13. Simultaneous opening briefs on the revenue requirement portion of this Docket were filed on or around May 31, 1991. Reply briefs were filed on or around June 14, 1991.

14. This Order addresses the revenue requirement portion of Docket No. 90.6.39. Cost-of-service/rate design issues will be addressed in a subsequent order.

RESPONSE TO MPC'S OBJECTIONS
TO STAFF INTRODUCTION OF EVIDENCE

15. In this Docket (Tr. p. 22) MPC objected to the Commission staff's introduction into evidence of all responses to staff Data Requests. MPC argued that staff's introduction of evidence 1) was in violation of 69-2-102, MCA; 2) was made by a nonparty when only parties have a right to introduce evidence; and, 3) was improper because, as staff is not an advocate in these proceedings, MPC cannot know the purpose of the introduction of the data responses. The Commission took the objections under advisement and will address them here.

16. The Commission has addressed objections to its staff's introduction of evidence in previous orders. In Order No. 5399b, Docket No. 88.11.53, the Commission responded in detail to objections from Montana-Dakota Utilities that were very similar to the objections at issue here. The Commission hereby incorporates by reference paragraphs 8-23 of Order No. 5399b as a response to the objections in these Dockets.

17. Specifically, and in summary, the Commission found in Order No. 5399b, paragraphs 16-23, that 69-2-102, MCA, and ARM 38.2.601(n) and 38.2.3902(1) authorizes Commission staff introduction of evidence. The third sentence of 69-2-102, MCA, on which MPC relies to preclude staff introduction of evidence, must be read, according to standard rules of

statutory construction and in light of legislative history, as a prohibition on Commission introduction of evidence through an outside expert without first consulting with the parties. The Commission did not introduce evidence in these proceedings through an outside expert; consequently, the Commission is not in violation of 69-2-102, MCA.

18. MPC contends that the nonparty staff cannot introduce evidence because only parties have a right to introduce evidence. At paragraphs 9-13 of Order No. 5399b the Commission addressed this contention by noting 1) Commission rules specifically allow for the introduction of evidence by staff; and, 2) independent investigation by the decision-maker is one of the things that distinguishes administrative decision-making from judicial decision-making.

19. MPC also contends that staff introduction of evidence is improper because MPC does not know the purpose for which the evidence is being introduced. This contention has been discussed by the Commission at various places in Order No. 5399b, paragraphs 8-23, and also Docket No. 88.6.15, Order No. 5360e, paragraphs 7283. The purpose for staff introduction of evidence was stated succinctly by the Commission in Order No. 5399b, paragraph 14, when it said that, "The Commission has ... hired staff ... to make sure, through introduction of data responses or other evidence, or through cross-examination, that the record, to the extent possible, contains all the facts necessary to support a variety of reasoned decisions on the issues."

20. The Commission finds that MPC has provided no reason why a ruling on these objections should differ from previous rulings on similar objections. Therefore, MPC's objections to staff introduction of evidence are overruled and the

responses to staff Data Requests are admitted into the record.

MPC ELECTRIC
BOND RATINGS AND COMMISSION RANKINGS

21. Order No. 5484h in this Docket discussed the Commission's limited investigation which showed a weak relationship exists between Commission rankings and bond ratings. It also discussed the concept that utilities with higher bond ratings tend to have lower rates. The Order stated:

> The Commission is interested in developing an understanding of which significant regulatory practices in general, and this Commission's regulatory practices uniquely, have on MPC's cost of capital and the price of electricity charged to ratepayers. The Commission is also interested in attempting to determine the significance and scope of quantifiable measures of the other major issues of risk (business cycles, environmental/citing laws, management capabilities, general business climate of the state, etc.) faced by MPC's utility operations and the impacts of such other factors on the cost of capital and the price of electricity charged to ratepayers. Basically, this Commission would like parties to independently identify the most significant areas where improvement can be made to minimize capital costs to MPC and electricity prices charged to ratepayers while still maintaining a high quality of service. Results of the Commission's preliminary investigation are available, but they should not supplant the independent analysis requested of the parties. (Order No. 5484h, P. 13)

Testimony was received from MPC witness Charles Olson, MCC witness Dr. Smith and District XI Human Resource Council (HRC) witness Tom Power.

22. Dr. Olson testified that he is not optimistic that the impacts of various risk factors can be quantified. He stated that there have been numerous attempts to do so, but such studies have not proven very much. Dr. Olson believes there are so many risk factors affecting cost of

capital that it is hard to find very much individual impact.

23. Dr. Olson analyzed the relationship between Commission rankings and bond ratings in a manner similar to that used in the Commission's preliminary investigation. While the Commission's investigation looked only at Merrill Lynch Commission rankings vs. S&P bond ratings, Dr. Olson conducted regression analyses of several different Commission rankings and bond ratings. The results of his analyses were similar to those of the Commission in that only slight relationships between Commission rankings and bond ratings were found. Dr. Olson concluded the results indicate higher Commission rankings produce better bond ratings which result in lower electric rates. He recommended the Commission give strong consideration to MPC's coverage ratios to help improve MPC's bond ratings.

24. Dr. Smith agreed that measurement of the effect of individual risk factors on capital costs is difficult. She said that both Commission rankings and bond ratings depend on earnings performance which is a likely explanation for the relationship between the two. She concluded that Commissions with higher rankings are more generous than those with low rankings.

25. Concerning coverage ratios, Dr. Smith calculated a 2.8 times internal pre-tax coverage ratio for her return recommendation. This calculation assumes that investment, costs and revenues are those accepted by the Commission and not those claimed by the Company.

26. Dr. Power believes this is not a worthwhile area to pursue. He said the Commission would need utility specific

quantitative information on 1) the impact of particular regulatory policies on bond ratings; 2) the impact of bond ratings on the overall cost of capital; and 3) the impact of the cost of capital on utility rates. Dr. Power claimed the empirical evidence on these relationships is sketchy if not contradictory or inconclusive. He testified that the empirical evidence needed to support such an effort does not exist. Dr. Power explained his understanding of such a process:

> This approach to regulation is what I would call "financial regulation." It seeks to determine what it is about the way a commission regulates a utility that bothers investors and then tries to change those aspects of regulation so that investors will feel more positively about a utility. (Exh. HRC-5, p. 3)

Dr. Power explained the potential problems inherent in this type of process:

> First, it forces regulators into the hopeless "infinite regress" of trying to guess what it is the investment community expects while the investment community, in turn, focuses upon trying to guess what it is that the regulators are going to do. It turns regulators away from regulating toward figuring out what will keep the investment community happy.
>
> Second, this is an unprincipled approach to regulation with no guidelines except the extreme limits the courts may provide. Regulation under this approach is not really regulation at all in the sense of trying to guide or direct the utility's business - decisions in a way consistent with the public interest. (Exh. HRC-5, p. 4)

27. Dr. Power warned that a system that gives investors what they want could tend to destroy all business-like discipline and reward incompetence. He explained that if the Commission guides its

regulatory practices in ways designed to keep the investment community happy, customers rates would not be kept low. This is because the utility would be allowed the same financial rewards regardless of the soundness of management decisions. Dr. Power believes the long run consequences could be very severe.

28. In his supplemental rebuttal testimony, Dr. Olson opposed Dr. Smith's characterization regarding generosity of Commissions with higher rankings. He said it is not an issue of more generosity or less generosity, but an attempt to achieve lower rates in the long-run.

29. Regarding Dr. Smith's coverage calculation, Dr. Olson claimed that attrition alone would cause this calculation to be overstated.

30. Dr. Olson's main disagreement with Dr. Power is that Dr. Power's arguments against financial regulation ignore that financially constrained utilities cannot always make optimal decisions due to a potential lack of funds.

31. The Commission finds Dr. Olson's position is overly optimistic. First, he concluded that because a relationship (no matter how small) exists between Commission rankings and bond ratings, the Commission should "seek to assist MPC in improving its bond rating to a level of A/A2 or higher." (Exh. MPG-33, p. 37)
Second, he accepts without question the premise that higher bond ratings will result in lower long-term electricity prices. Dr. Power stated that the

empirical evidence on these relationships is sketchy if not contradictory or inconclusive. If Dr. Olson's conclusions were supported by clearly conclusive evidence, all regulatory commissions in the country would have realized it and manipulated their regulatory processes in a manner resulting in every utility being rated AAA. Dr. Olson's testimony clearly misses the point that this Commission is obligated to scrutinize all aspects of the Company's operations in order to ensure that the rates MPC charges are just and reasonable. One of the more important aspects of such scrutiny, as discussed by Dr. Power, is Commission judgment of the soundness of management decisions.

RATE OF RETURN

Capital Structure

32. MPC witness W. C Verbael, in his direct testimony, presented the Company's proposed electric and natural gas capital structures as of March 31, 1990. In his rebuttal testimony, Mr. Verbael updated the capital structures through September 30, 1990. In addition to a change in timing, Mr. Verbael's update reflected the Company's decision to not allocate debt to the Colstrip 4 division as it had originally proposed.

33. MPC proposed the following capital structure and associated costs:

ELECTRIC UTILITY:	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	50.49%	8.87%	4.48%
Preferred Stock	4.73	7.29	0.34
Common Equity	44.78	13.40	6.00
Total	100.00		10.82%

GAS UTILITY:	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	50.49%	9.21%	4.65%
Preferred Stock	4.73	7.29	0.34
Common Equity	44.78	13.40	6.00
Total 100.00 10.99%			

(Exh. MPG-29, WCV-3, pp. 1-2)

34. MCC witness Dr. Caroline Smith, in her direct testimony, presented MCC's proposed electric and gas capital structures as of March 31, 1990. At the hearing Dr. Smith updated those figures through September 30, 1990, the same period proposed by the Company. This was done so that timing differences would be eliminated, leaving only the methodology to be disputed. (Tr. P. 386)

35. MCC proposed the following capital structure and associated capital costs:

ELECTRIC UTILITY:	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	54.05%	8.91%	4.82%
Preferred Stock	4.73	7.29	0.35
Common Equity	41.22	11.40	4.70
Total	100.00		9.87%

GAS UTILITY:	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	54.05%	9.24%	4.99%
Preferred Stock	4.73	7.29	0.35
Common Equity	41.22	11.40	4.70
Total	100.00		10.04%

(Exh. MCC-2, Revised CMS-2, p. 1)

36. The differences between the two parties' capital structures relate to the treatment of debt and equity associated with the Company's Leveraged Employee Stock Ownership Plan (LESOP). During January 1990, MPC borrowed $40,000,000 from outside lenders which it subsequently loaned to its LESOP Trustee. With these funds the Trustee acquired in the open market $40,000,000 in outstanding common equity which will be

used to meet MPC's future matching obligations associated with the LESOP. Pursuant to generally accepted accounting principles this transaction was recorded on the Company's books by increasing long-term debt by $40,000,000 and reducing common equity by $40,000,000.

37. MPC believes the utility capitalization must be adjusted by adding back the common equity and subtracting the long-term debt. MCC believes the amounts reflected on the Company's books are appropriate for ratemaking purposes.

38. Mr. Verbael explained that the Trustee fully reimburses MPC for all interest and debt retirement payments. This is done with dividends and MPC matching payments received by the Trust. Therefore, Mr. Verbael concluded-it is proper to exclude the longterm debt component from the Company's capital structure.

39. Mr. Verbael explained that the common equity was purchased by the Trustee in the open market and remains outstanding by being held by the Trustee. He stated that LESOP common stock has not been redeemed or canceled but remains fully outstanding in the Trust for future distributions to the Company's employees over roughly a 15-year period. Mr. Verbael further contends that the Company is obligated to provide the same return on these shares as it provides to all other shares of common equity.

40. Mr. Verbael explained that the leveraging feature of the LESOP creates tax benefits due to dividends paid on the LESOP common shares. These tax benefits allow the Company to reduce its costs of the plan which lowers the revenue requirement. In the current filing, the revenue requirement reductions are $1,200,000 and $250,000 for the electric and natural gas utilities, respectively.

41. Dr. Smith testified that MPC's balance sheet shows that $40,000,000 of debt has been issued and is available to finance MPC's assets. She further stated that the balance sheet shows $40,000,000 of equity has

been purchased by the company and is not available to finance MPC's assets.

42. The Commission finds MPC's proposal is proper and accepts the Company's proposed capital structure. Clearly, the LESOP equity has not been canceled and MPC is required to pay dividends on these shares. The Commission agrees that such shares are entitled to the same return as other outstanding shares issued by the Company. Additionally, the Trustee fully reimburses all interest and debt retirement payments that are required of MPC resulting in no real debt costs to the Company.

Cost of Capital

Long-Term Debt

43. The differences in debt costs proposed by MPC and MCC are directly the result of differences in each party's proposed treatment of the LESOP debt. Pursuant to the Commission's decision to accept MPC's proposed treatment of LESOP debt as previously discussed, the Commission also accepts MPC's proposed debt cost rates of 8.87 percent for the electric utility and 9.21 percent for the gas utility.

Preferred Stock

44. The cost of preferred stock is not a contested issue in this proceeding as both MPC and MCC calculated a cost of 7.29 percent. This cost of preferred stock is accepted by the Commission.

Common Equity

MPC

45. In its rebuttal filing the Company requested an equity return of 13.4 percent, up from the originally requested 13.0 percent. Mr. Verbael explained that the increase in return is requested in order to

provide additional earnings to improve MPC's interest coverage ratios that were reduced when MPC agreed that the utilities would roughly retain $32,000,000 in debt that had been allocated to Colstrip 4 in the initial filing. He concluded that the higher return on equity is needed for MPC to achieve an "A" rating on its long-term debt. (Exh. MPG-29, p. 10) Mr. Verbael's requested equity return was based primarily on the testimony of Dr. Olson.

46. Dr. Olson performed Discounted Cash Flow (DCF) analyses on 25 electric utilities and 11 natural gas distribution utilities in recommending a 13.0 to 13.5 percent return on equity. The companies included in Dr. Olson's analyses were limited primarily to those that have little diversification outside the utility business and have A or AA rated debt.

47. The dividend yields in Dr. Olson's studies reflect the average of high and low stock prices from October 1989 through March 1990 for each company and the indicated dividend annualized at the end of that period. He then applied an adjustment factor to reflect the dividend yields in the coming year.

48. Dr. Olson's DCF growth rates were determined by reviewing historical growth rates in earnings, dividends and book value, as well as analysts' projected growth rates and retention growth rates. Finally, the entire amount is grossed up by 8 percent to reflect financing costs and potential market fluctuations. These results are shown below:

	Electric		Gas	
Yield	6.93%	6.93%	6.43%	6.43%
Yield Adjustment	0.17	0.19	0.18	0.19
Growth	5.00	5.50	5.50	6.00
Return	12.10%	12.62%	12.11%	12.62%
Adjusted Return	13.10%	13.60%	13.10%	13.60%

Based on such analyses, Dr. Olson recommended that MPC's electric and gas utilities be allowed to earn an equity return of 13.0 to 13.5 percent.

49. To check the reasonableness of his DCF results, Dr. Olson conducted an interest premium analysis. The result of Dr. Olson's interest premium analysis was significantly higher than his DCF results.

MCC

50. MCC's witness Dr. Smith also used DCF analysis in arriving at her return on equity recommendations. The result of Dr. Smith's analysis was a return on equity range of 10.9 to 11.9 percent with a recommended return of 11.4 percent. Dr. Smith's recommended return for MPC is determined in the context of a DCF analysis of 63 electric and combination electric and gas utility companies. Dr. Smith's companies represent most of the electric and combination utilities reported in the Value Line Investment Survey. Several of the Value Line companies were not included because of data problems or dividend omissions or reductions.

51. Dr. Smith's dividend yield of 7.9 percent was calculated by averaging high and low stock prices for the six months ending in September 1990, and dividing into the annualized end of period dividends.

52. To estimate-the growth component of her recommendation, Dr. Smith performed a statistical study of 10 years of compound historic growth rates in earnings, dividends and book value (30 growth rates) for her 63 companies. The statistical study measures the relationship between each of the historical growth rates and current pricing patterns to estimate investors' expected growth rates. The statistical study resulted in growth rates in the range of 2.8 to 3.3 percent. Dr. Smith reflected dividends to be received in the coming year by increasing the growth rate to 3.0 to 3.5 percent.

53. For the industry, Dr. Smith's study resulted in an equity return of 10.9 to 11.4 percent. In MPC Docket No. 88.6.15, Dr. Smith's study found MPC's required equity return requirement may have been 25 to 50 basis points higher than the industry. She took this into consideration in recommending a return of 10.9 to 11.9 percent. Dr. Smith then examined specific data for MPC to confirm her estimate. From this analysis, she concluded MPC's risk compared to the industry had declined somewhat from the previous docket.

54. Dr. Smith reported recent comparable earnings information for the utility industry and other sectors of the economy. She did not, however, advocate that MPC's return be set equal to such comparable earnings.

Commission Discussion

55. Dr. Smith and Dr. Olson disagreed over the need for a financing cost adjustment. The Commission agrees with Dr. Smith that such an adjustment should not be made unless the Company is planning to publicly issue shares in the near future. Dr. Olson's proposal would result in annual recovery of tuta1 issuance costs for all outstanding common equity, resulting in the Company recovering such costs many times over. Regarding protection from market conditions, the Commission agrees with Dr. Smith:

> First of all, Dr. Olson's proposal to protect MPC's shareholders from unfavorable market conditions is one step in the direction of providing a guaranteed return to MPC, a measure to which utilities are not entitled. Second, judgement in the timing of issuing securities is one of the roles of management. Under current registration procedures, MPC has considerable freedom as to specific offering dates if any shares were going to be issued at all. The job of pleasing shareholders by issuing at favorable market prices is a responsibility of MPC's

> management. There is no need for customers to pay rates sufficient to compensate MPC's shareholders in the event that management fails to meet that responsibility. (Exh. MCC-2, p. 63)

56. In his rebuttal testimony, Dr. Olson reported that Dr. Smith's statistical model is very sensitive to minor changes in input data. Due to such sensitivity, Dr. Olson concluded it is incorrect to use the model for the purpose of estimating the cost of equity capital. To demonstrate the model's sensitivity, he ran the model twice with slightly updated information each time resulting in growth rates that were different from those reported by Dr. Smith (i.e. 2-year dividend growth rate in one instance and 10-year earnings growth rate in an other compared to the 1-year dividend growth rate reported by Dr. Smith).

57. The Commission believes that updates in information would logically result in changes in the growth rates yielded by Dr. Smith's statistical model. Common sense suggests that as information changes, so will the pricing patterns of investors.
While Dr. Olson indicated that minor information updates resulted in different growth rates, he did not demonstrate that the magnitude of such changes was severe. To the contrary, he did not even report the actual growth rate figures that resulted from such updates. Therefore, the Commission finds little significance in Dr. Olson's conclusions relative to the sensitivity and usefulness of Dr. Smith's statistical model.

58. Dr. Smith testified that Dr. Olson's DCF study of gas distribution utilities yields questionable results because of poor historical data. She noted that these utilities have repeatedly restated their financial data over the past ten

years, and in some cases Moody's, Value Line and the individual company annual reports will contain different sets of historical data. She then noted that depending on which data source Dr. Olson used he would end up with different results. Dr. Smith also discussed the shortage of information about two of the companies, which effectively makes this small group even smaller.

59. While it may be true that the different data sources contain different financial data for some companies, Dr. Smith has not demonstrated that the DCF results would be significantly different based on such different data. In effect, she has not shown the magnitude of differences that would result from the varying sources of historical information. The Commission believes it is wrong to summarily reject this type of analysis without a reasonable showing of the differences which could result.

60. In his direct testimony, Dr. Olson reported that a recent Supreme Court decision (Duquesne Light Co. v. Barasch, 488 U.S ___,109 S.Ct. 609, 102 L.Ed.2d 646 (1989)) implies that in estimating the return on equity, risks created by the specific regulatory system must be considered. He then compared Montana regulatory practices with those of other states. After reviewing the type of test period used, the use of automatic adjustment clauses, the method of determining rate base, and the treatment of canceled or abandoned property, Dr. Olson concluded that the Montana regulatory system creates greater risks than most others in the country.

61. For the sake of discussion, the Commission will entertain Dr. Olson's conclusion about Montana's regulatory risks. Assuming Montana's risks are indeed higher, there has

been no quantitative showing of the impact on capital costs these supposedly higher regulatory risks are creating. Additionally, regulatory risks are only a minor subset of all risks faced by utility companies. Realistically, risk analysis in relationship to capital costs should include much more than a review of four regulatory practices faced by the utility; it should include a comprehensive analysis of all major risks (regulatory or otherwise) facing the utility.

62. Mr. Verbael presented several financial performance reviews showing the Company's financial ratios under various assumptions. Using 1991 budgeted expenditures, Mr. Verbael compared the results using MCC's proposed revenue requirement, currently approved interim revenue requirements and the Company's own proposed revenue requirements. He found that 1) the MCC proposed revenues would result in a "going out of business scenario"; 2) the interim revenues would support the low side of a BBB debt rating; and, 3) MPC's own proposed rates would probably not support an A debt rating. (Exh. MCC-29, pp. 15-17)

63. The Commission has traditionally been skeptical of budgeted information. In the budgeting process, multitudes of assumptions must be made in order to estimate the various components of expenditures, investments and revenues. These assumptions may or may not prove reasonable, but it is clear that they would not be known and measurable.

64. To truly assess the reasonableness of Mr. Verbael's financial reviews would essentially require that every budgeted cost, revenue, and investment component be scrutinized in full detail in a manner similar to the current ratemaking process. This additional level of

scrutiny would be costly, time consuming and redundant. Additionally, Mr. Verbael's budgeting process will invariably reflect costs and investments that this Commission traditionally has found to be improper and not recoverable through the ratemaking process.

Return on Equity Conclusion

65. The Commission's review of the record established in this proceeding does not result in a wholesale acceptance or rejection of either MCC's or MPC's proposals. The Commission gives credence to several of the DCF judgements and conclusions of both parties in attempting to estimate MPC's cost of equity capital. Based on the information presented in this proceeding, the Commission finds that 12.1 percent is a reasonable estimate of MPC's natural gas and electric utility cost of common equity capital. At 12.1 percent, MPC's allowed return on equity is slightly above the range proposed by MCC witness Dr. Smith (10.9 - 11.9 percent). It is also at the very bottom of the unadjusted ranges proposed by MPC witness Dr. Olson (12.10 - 12.62 percent and 12.11 - 12.62 percent).

Overall Rate of Return

66. Based on the findings for capital structure, cost of debt, preferred stock and common equity, the Commission finds MPC's gas and electric utility overall rates of return to be 10.24 and 10.41 percent as demonstrated below:

ELECTRIC UTILITY:	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	50.49%	8.87%	4.48%
Preferred Stock	4.73	7.29	0.34
Common Equity	44.78	12.10	5.42
Total	100.00		10.24%

Percent of Weighted

GAS UTILITY:	Total	Cost Rate	Cost
Long Term Debt	50.49%	9.21%	4.65%
Preferred Stock	4.73	7.29	0.34
Common Equity	44.78	12.10	5.42
Total	100.00		10.41%

RATE BASE

67. MPC witness Daniel Reardon presented testimony and exhibits supporting MPC's requested rate base. In its original filing, the Company requested a total electric utility rate base in the amount of $863,837,605. This represented a 13-month average rate base as of December 31, 1989, adjusted for known and measurable changes. In his rebuttal testimony, Mr. Reardon revised the Company's proposed rate base to $862,854,139.

68. MCC witness Albert Clark proposed four adjustments to the Company's originally requested rate base to arrive at MCC's proposed rate base of $853,402,797. All of these adjustments, except cash working capital, were basically agreed to by the parties and are discussed in the Uncontested Issues section of this Order.

69. There are several rate base adjustments that are discussed in greater detail in other sections of this Order. The following is a list of these adjustments and their impacts on the Company's originally proposed rate base:

CIS/FMS Stipulation	$ -386,105
Depreciation Rates	1,250,060
Prior Period	
Indirect Costs	-2,120,632
FOG Wire	-183,967

MPSC/FERC Plant Acquisition Adjustment

70. In his rebuttal testimony, MPC witness Ernest Kindt discussed the deductibility of the plant acquisition adjustment for income tax purposes. This issue involves the return to ratepayers of

certain previous years' tax benefits. He explained that Docket No. 88.6.15 established a two-year amortization of the 1978-1988 tax benefits based on the assumption of a 50 percent deductibility for the costs of the acquisition adjustments. The Company included in its original filing the effects of a 40 percent deductibility which it then thought would be allowed by the IRS. Subsequently, MPC was only allowed a 33 percent deduction.

71. By the time rates in this Docket become effective, ratepayers will have received benefits in excess of the tax savings received by the Company. The Commission finds it appropriate to true up the excess as proposed by Mr. Kindt. This adjustment increases rate base by $273,211. Adjusted Cost on Reacquired Debt

72. During the hearing Mr. Kindt offered a correction related to the loss on reacquired debt. He explained:
In the exhibits attached to the rebuttal testimony, there would be a change related to loss on reacquired debt. In the rebuttal testimony that was filed by the Company, there was a change in the capital structure to Colstrip Unit 4, and when we prepared our rebuttal exhibits for the taxes, we neglected to change the deduction for the loss to allocate 100 percent of it to the utility. (Tr. p. 129)

73. The Commission finds Mr. Kindt's explanation reasonable and believes it is proper to correct this oversight as proposed by O MPC. This adjustment results in a rate base decrease of $353,231. Cash Working Capita1

74. MPC witness Stuart McDaniel conducted a lead/lag study to determine MPC's cash working capital requirements. A lead/lag study measures the investment necessary to carry on the day-to-day cash transactions of the Company. The results of Mr.

McDaniel's study indicate negative cash working capital requirements of $2,610,000 and $1,610,000 for the electric and natural gas utilities respectively.

75. Mr. McDaniel recommended cash working capital be set at $0 because the study shows that investors have not supplied cash working capital. Mr. McDaniel believes that a negative working capital adjustment would act as a disincentive to efficiently manage the Company's cash transactions and result in a penalty being assessed to the Company for efficiently managing its cash transactions.

76. MCC witness Mr. Clark reviewed the Company's lead/lag study and concluded the study was completed in a reasonable manner and that the results should not be ignored for ratemaking purposes. Mr. Clark argues that MPC's proposal to use a $0 cash working capital requirement means rate base would include a level of non-investor supplied funds, which is inappropriate.

77. Mr. Clark proposed to adjust the lead/lag results to reflect the lags for long term debt interest and preferred stock dividends. Mr. Clark argued there should be no distinction in determining cash working capital between funds held to pay interest and preferred stock dividends and funds held to pay any other legal obligation. These adjustments would result in rate base reductions of $2,896,775 for the gas utility and $7,446,725 for the electric utility.

78. MPC witnesses John Miller and Mr. McDaniel filed rebuttal testimony opposing MCC's negative cash working capital adjustment. Mr. Miller argues that a negative cash working capital adjustment suggests that the Company can finance long term assets with the negative allowance; but the best the Company can actually do is offset short term borrowing or increase

earnings on short term investments. Both witnesses argue that long term debt interest and preferred dividends should not be considered because they do not represent operating expenses. It is the Company's position that since such costs are capital costs, they should belong to the investors when earned.

79. Regarding the lag associated with long term debt interest and preferred dividends, the Commission agrees with Mr. Clark's analysis:

The distinction between an operating expense and a capital expense is not the controlling factor for inclusion or exclusion in the lead/lag study. Rather, it is the cash nature of the item under examination and whether investors have had to contribute capital on which they are entitled to earn a utility rate of return, or whether the non-investor supplied nature of an item must be recognized in order to prevent such an opportunity. (Exh. MCC-4, p. 27)

Clearly, the ratemaking process reflects in rates the costs of long term debt interest and preferred dividends. To argue that such expenditures should not be considered in the determination of cash working capital requirements is irrational.

80. During the hearing, Mr. Miller and Mr. McDaniel testified that a working capital adjustment should be made if the lead/lag study had yielded a positive result. (Tr. pp. 463, 473) The Commission does not find persuasive the Company's arguments to make such an adjustment only when the working capital requirement is positive. To include working capital adjustments only when the results of the lead/lag study are positive would be totally inconsistent and unfair to MPC's ratepayers who have, on average, contributed significant cash working capital balances to the operations of the Company.

81. The idea behind a cash working capital adjustment is to provide a return on the average investment needed to carry out the day-to-day cash transactions of the utility. This investment is measured by the lead/lag study as adjusted to include the lag in cash payments for preferred dividends and long term debt interest. In the event the average investment is positive, stockholders have provided such investment and are entitled to a return on such investment by including the positive amount in rate base. In the event the average investment is negative, ratepayers have effectively provided such investment and rate base must be reduced by this amount.

82. The Commission disagrees with MPC's disincentive argument. There are clear incentives for the Company to efficiently manage its cash transactions when a negative cash working capital adjustment is included in rate base. This is because the potential shortfall from inefficient management would fall squarely on the shareholders during the period when rates are in effect.

83. The Commission disagrees with MPC's claim that a negative cash working capital adjustment would penalize the Company. Rather, to not reflect such an adjustment would clearly penalize ratepayers because it would ignore their contributions of a significant amount of capital over and above the amount required for day-to-day cash operations.

84. The Commission finds it proper to revise Mr. Clark's proposed adjustments to reflect the approved weighted costs of preferred stock and long term debt in the determination of this adjustment. Incorporating such changes results in an electric rate base reduction of $7,208,265 and a gas rate base reduction of $2,844,506.

Approved Rate Base

85. As a result of the decisions discussed above, the Commission finds MPC's approved electric rate base to be $855,108,676 on a total company basis. The resulting Montana jurisdictional approved rate base is $818,230,778 based on the results of the REC Jurisdictional Allocation Study.

CAPTIVE COAL

86. The Company's coal mining affiliate, Western Energy Company (Western Energy or WECo), supplies 100 percent of MPC's coal requirements for the Corette and the Colstrip units. MPC's coal costs in this filing approximate $34,000,000.

87. The reasonableness of utility transactions with affiliates must be closely scrutinized, especially when such transactions result in payments of this magnitude. The issue at hand is the reasonableness of the coal costs paid by MPC to WECo. To review affiliated coal transactions, the Commission has traditionally accepted a rate of return approach which examines the reasonableness of an affiliate's earned rate of return.

88. MPC witness Robert Quinlan presented an analysis of the 1989 coal segment earnings for seven large coal producing companies that mine coal predominantly west of the Mississippi River. Mr. Quinlan limited his analysis to companies with predominantly Powder River Basin and other western operations because he believes the operating characteristics are significantly different from coal mining operations east of the Mississippi River. He also reported that eastern mining companies were adversely effected by labor stoppages during 1989. For these reasons, Mr. Quinlan concluded that profit comparisons based on eastern coal operations would be unreasonable.

89. The 1989 arithmetic average return on equity for Mr. Quinlan's group of western coal operations was 24.3 to 27.4 percent. Weighted averages based on the coal companies' operating profit and tons sold were 26.3 to 26.8 percent and 23.9 to 24.7 percent respectively. Mr. Quinlan calculated a 17.1 percent return on equity for WECo's Montana coal operations and concluded such returns were in line with and slightly below the other operations which he examined. (Exh. MPG-37, pp. 13-14)

90. Dr. John Wilson testified on behalf of MCC that MPC's coal costs should be reduced by $3,619,000 to reflect an 11.5 percent return on equity. (Exh. MCC-8 p. 33) During the hearing, Dr. Wilson reduced his proposed adjustment to $2,679,000 to remove the effects of incorrectly reflecting Colstrip 4 volumes. (Tr. p. 713)

91. Dr. Wilson examined the coal segment earnings of 24 coal producing companies for the years 1987, 1988 and 1989. These companies were chosen from the companies listed as coal companies in the Energy Performance Review. Dr. Wilson excluded companies from his comparable earnings review if financial information on coal operations was unavailable or the coal company had transactions with an affiliated electric utility. Average equity returns for Dr. Wilson's coal companies were 8.28, 12.36 and 5.37 percent during 1987, 1988 and 1989. Excluding the high and low returns produced return on equity averages of 10.15, 12.72, and 6.69 percent.

92. Dr. Wilson also reported that companies in the fuel industry earned rates of return in the 11 to 12 percent range and that mining industry profits have been below 10 percent in every year since 1982.

93. Dr. Wilson discussed the relatively low risks associated with WECo's 100 percent equity capital structure compared to coal

companies with leveraged capital structures. He also mentioned the low risk nature of WECo's captive coal sales to MPC and its generating partners. Reflecting this information, the comparable earnings data, consideration of current money costs and MCC's estimate of MPC's own cost of equity, Dr. Wilson found an 11.5 percent rate of return on equity to be reasonable.

94. Dr. Wilson took exception to three of Mr. Quinlan's coal companies, MDU/Knife River, Black Hills/Wyodak Resources and PP&L/NERCO, all of which have substantial transactions with their electric utility affiliates. He reasoned that "Since the Commission's concern is the possibility of excessive profits on captive coal transactions, it is essential to examine this question from a data base that is not distorted by self-dealing affiliate transactions." (Exh. MCC-8, p. 21)

95. In his rebuttal testimony, Mr. Quinlan again argued that eastern coal operations should not be used for comparison purposes because eastern coal mine operating characteristics are different from western coal mining operations. He noted that many of Dr. Wilson's companies mine coal predominantly east of the Mississippi River.

96. Mr. Quinlan testified that, in-his opinion, companies with negative returns should not be used for comparison purposes because companies that lose money would eventually go out of business. He stated that several of Dr. Wilson's coal companies showed negative returns on equity.

97. Mr. Quinlan also noted that Dr. Wilson's 1987 and 1989 data contained statistical outliers. Removal of the outliers increased the average returns to 12.4 percent in 1987 and 8.11 percent in 1989.

98. Mr. Quinlan further examined Dr. Wilson's comparables by removing statistical outliers, negative returns and companies with no western coal mining operations. This analysis resulted in average equity returns in the 15.5 to 21.5 percent range. (Exh. MPG-38, p. 21)

99. Mr. Quinlan removed from his own comparables the three captive coal companies to which Dr. Wilson objected. Average returns on equity for the remaining four companies were in the mid to upper 20 percent range. (Exh. MPG-38, RMQ-6)

100. The basic question for the Commission to answer is whether MPC's affiliated coal transactions result in reasonable coal costs being charged to the Company's ratepayers. MPC and MCC have both analyzed the rate of return earned by WECo to judge the reasonableness of such transactions. Due to differing assumptions employed by the two parties (namely companies used in the comparable earnings analysis), MPC concluded the earned return was reasonable while MCC concluded it was not.

101. When asked why he chose not to restrict his comparable earnings analysis to companies with coal operations more similar to WECo's, Dr. Wilson stated:

> Why didn't I restrict it to companies that had coal operations that were physically similar to Western Energy or coal resources that had the same ash content, the same sulphur content, that were surface mining operations and so on, all of these physical characteristics that Mr. Quinlan set forth, and I think accurately, in his testimony? The reason I didn't do that is I felt that was not germane, was not fundamental to the question of what the cost-of-capital is any more than looking at the electric utility industry, that you would exclude all of those companies that generate electric power by

> burning gas and include only those electric power companies that burn bituminous (coal), or reject all those electric utilities that are east of the Mississippi River and look only at the financial data for electric utility companies that are western utilities.
>
> I thought that would result in an unnecessary and undesirable restriction of what was already a fairly limited database to a group that was not really representative of the industry. You can see from Mr. Quinlan's data, really, that if you proceed in a fashion which selects out only a limited number of companies, you will get a picture that is not only very different from the coal industry as a whole, but you will get results that happen to reflect historic circumstances that are not particularly good reflections of what the cost-of-capital is. (Tr. pp. 754-755)

Dr. Wilson's response clearly indicates that it is the cost of capital that is important in establishing a reasonable rate of return for MPC's affiliated coal transactions, and that returns earned by Mr. Quinlan's group of companies are not reflective of the cost of capital.

102. Mr. Quinlan testified that he looks at earned returns for companies he believes are comparable to WECo and that he does not focus on cost of capital. (Tr. p. 669) When asked whether a reasonable return on affiliate coal transactions should bear any relationship to the cost of capital, Mr. Quinlan stated:

> I think that is a point that the Commission has to decide, but in my view, it's not necessary. If you look at the rates of return on equity and look at other coal companies' rates of return on equity, I think that is an adequate estimate of what is reasonable in the coal industry. (Tr. p. 686)

103. The Commission agrees with Dr. Wilson that a reasonable return on equity should be based, to the greatest extent possible, on cost of capital.

104. The Commission is very concerned by the small number of companies reviewed by Mr. Quinlan. Clearly three of Mr. Quinlan's seven companies cannot be included because they are captive coal companies. The remaining four represent such-a small group that the Commission is unwilling to rely solely on the historic returns of these companies to determine a reasonable rate of return on the MPC/WECo affiliated coal transactions.

105. Dr. Wilson's group has some companies with predominantly eastern operations, as well as companies with predominantly western operations, including the four non-captive coal companies proposed by Mr. Quinlan. There is no dispute that the eastern companies in Dr. Wilson's group have different operating characteristics than WECo, but there has been no real showing that these companies face risks so different from WECo as to be un-comparable in a general industry sense.

106. Regarding the negative returns experienced by some of Dr. Wilson's companies, the Commission agrees that investors do not realistically invest in companies with the expectation of losing their money. However, common sense suggests it is also likely that investors do not realistically invest in companies with the expectation of earning in excess of 30 to 35 percent as has been achieved by several of these companies. Simple removal of negative returns with no adjustment to remove the very highest returns would bias the averages and not be reflective of actual circumstances. The median can be used as a central measure in instances where such extreme values exist that may skew the average value. The median returns for 1987 through 1989 are

11.08, 15.10 and 7.73 percent. The average of these median returns is 11.3 percent which is below Dr. Wilson's 11.5 percent recommendation. It is reasonable that Dr. Wilson's recommendation is higher than this average because 1989 was affected somewhat by union strike activity.

107. Mr. Quinlan testified that Dr. Wilson's 1987 and 1989 data contained statistical outliers and that removal of statistical outliers would increase the average returns for those years. Average returns for 1987 would be 12.4 percent while the 1989 average would be 8.1 percent. The 1988 average was 12.36 percent and contained no statistical outliers. The average of these figures is slightly less that 11 percent which is also below Dr. Wilson's 11.5 percent recommendation. Again, this is reasonable because 1989 was affected somewhat by union strike activities.

108. Regarding the risks faced by WECo on its affiliated transactions, the Commission agrees with Dr. Wilson's assessment:

> Western Energy is, of course, heavily dependent on its sales to Montana Power and Montana Power's Colstrip partners. But, those sales are not likely to be lost because of market uncertainties or cycles encountered by - the buyer. Indeed, in contrast to an independent coal company whose large contracts may imply greater risks and higher capital costs due to uncertain market conditions, Western Energy's large sales to its own utility affiliate and partners are about the lowest risk sales that one can imagine in the coal industry. (Exh. MCC-8, pp. 22-23)

109. Dr. Wilson also mentioned that WECo's capital structure is virtually 100 percent equity which reduces its risks even further compared to coal companies with leveraged capital structures. Indeed, review of Dr. Wilson's workpapers showing coal segment return calculations demonstrates that most of these companies are, in fact, quite leveraged. Also,

it must be noted that Dr. Wilson's 11.5 percent return recommendation is the total return for WECo whereas the leveraged firms generally have lower total rates of return due to the lower cost of non-equity financing which they employ.

110. Based on the information established in this Docket, the Commission accepts as a reasonable profit level the 11.5 percent rate of return on equity proposed by Dr. Wilson. Therefore, coal costs resulting in rates of return on equity in excess of 11.5 percent are found to be unreasonable and should be removed from the Company's filing. Dr. Wilson's recommendation to reduce test period coal costs by $2,679,000 is accepted.

LOADS AND RESOURCES

Purchased Power Expenses

WNP-1 Exchange Agreement:

111. MPC began buying 80 MW of capacity and 68 aMW of energy from BPA in July 1980. The contract continues through June of 1996. From the beginning of the contract through June 1990, WNP-1 contract power was priced according to the BPA priority firm rate. However, the contract stated that beginning in July 1990, the price would be based on the actual construction and operating costs of the WNP-1 nuclear project.

112. Since the WNP-1 project has been suspended indefinitely, the five Northwest utilities with WNP-1 contracts, MPC, PacifiCorp, Washington Water Power, Portland General Electric and Puget Sound Power & Light entered into negotiations with BPA and the Washington Public Power Supply System (WPPSS) in 1989 to establish the price for power

under the WNP-1 contracts. In October 1989 the five utilities with WNP-1 contracts filed suit against WPPSS alleging breach of contract and requested a ruling declaring the appropriate calculation of the price beginning July 1, 1990.

113. The lawsuit ultimately resulted in settlement agreements among all of the WNP-1 contract parties, which were signed in February of 1990. The settlement agreements establish the price for WNP-1 contract power at forty-three mills/kwh in July 1990, with increases of approximately one mill/kwh each July thereafter. In 1996, the last year of the contract, the price of WNP-1 power will be forty-eight mills/kwh. The annual increase in cost of purchased power under the WNP-1 contract as of July 1, 1990, is approximately $11,600,000. Costs associated with this contract have been allowed in prior MPC rate cases. No party in this Docket proposed that these costs should not be included for ratemaking.

114. In Order No. 5484, the Commission found that MPC would incur attrition as a result of the WNP-1 Exchange Agreement price increase for the time period of July 1, 1990, to August 29, 1990, the date Interim Order No. 5484c became effective. The Commission found it appropriate to mitigate this attrition incurred by MPC's agreement to the August 29, 1990, date. MPC was allowed to accrue the unreflected costs of WNP-1 power from July 2, 1990, to August 29, 1990. These accrued costs of approximately $1.9 million were to have been amortized over the period August 29, 1990, to August 29, 1991. This amortization will be completed and eliminated when rates change on August 29, 1991.

115. In Exh. MPG-18, Mr. Pascoe indicated that a change had

been made to the transmission losses associated with the WNP-1 contract. In May 1990, BPA informed MPC that the transmission loss reduction would be 4.6 percent. This figure was included in MPC's direct testimony in this Docket. However, since deliveries began on July 1, 1990, BPA has been reducing the energy amounts by only 1.6 percent to account for transmission losses. MPC reflected the increased energy as a result of this change in the rebuttal portion of its case.

Idaho Power Company Power Purchase:

116. In October 1989, MPC solicited offers from nineteen utilities throughout the western United States to sell firm power for a five year period beginning in 1991. Twelve proposals were received in response to M-PC's solicitation offer. The offer from Idaho Power fit MPC's needs for quantity, quality and price. Deliveries under this agreement began in December 1990 and will continue through March 1996. Under this agreement, MPC will receive 75 MW of capacity and energy during the months of October through March and 25 MW of capacity and energy from April through September. MPC will pay 24.5 mills/kwh from December 1990 through December 1992. The total annual cost of the Idaho purchase is $10,700,000.

117. In Exh. MPG-18, Mr. Pascoe noted that MPC had contracted with Washington Water Power (WWP) to sell approximately 315,000 MWH per year of firm energy in 1991, 1992 and 1993. In 1994 the sale will decrease to approximately 235,000 MWH of firm energy. Roughly eighty percent of this energy will be delivered during off-peak hours in the fall and winter, with the balance being delivered during on-peak hours in the fall. The price for

the duration of the contract is 22.25 mills/kwh. The contract was executed in December 1990. The sale to WWP begins on January 1, 1991, which is more than twelve months beyond the end of the test period, the normal period for making known and measurable changes. However, the WWP sale is closely related to MPC's new contract to purchase power from Idaho Power Company. The Commission finds that the Idaho Power contract is needed in the test year to serve peak loads. Mr. Clark also recommends that revenues from the energy sale to WWP be included in this Docket. The Commission agrees with the parties that the WWP revenues should be included in this Docket. Exh. MPG-18, (WAP-7) page 7 of 7, line 22, shows that total revenues of $7,112,213 associated with the WWP sale are included in the off system sales revenues in this Docket.

Hydro and Thermal Generation Capability

Background

118. In Docket No. 88.6.15, the generation capability of MPC's hydro and thermal resources was at issue. In Order Nos. 5360d and 5360e, the Commission required MPC to further address its thermal and hydro generation capability in a future proceeding. (FOF 17, Order No. 5360e) The Commission required the Company to develop its thermal resource capability based on statistical, engineering, and economic analysis of past performance, and present expectations of future performance. (FOF 335, Order No. 5360d) The Commission did not require MPC to develop its hydro resource capability based on statistical and econometric analysis. (FOF 342, Order No. 5360d)

119. In accordance with the Commission Order Nos. 5360d and 5360e, MPC examined the capabilities (energy and peak) of its hydro and thermal resources in this Docket. MPC chose to use econometrics to analyze its hydro energy capability. MPC also calculated a hydro peak capability, but based on the historical capability of its hydro resources.

MPC's Hydro/Thermal Capability Proposal

120. Compared to Commission decisions in Order No. 5360d, MPC's proposed capabilities reduce the combined hydro and thermal energy capability by 12.3 aMW (but, see -12.8 aMW in Table 1) and the January peaking capability by 33 MW. (Exh. MPG-20, p. 3) Table 1 below compares the proposed energy and peak capabilities from Docket No. 88.6.15, Order No. 5360d and the proposed energy and capacity in Docket No. 90.6.39. (Exh. MPG-20, pp. 20, 22)

Table 1

Hydro and Thermal Generation Capability

	Energy (aMW)			Capacity (MW)		
	MPC's Docket 88.6.15 Proposal	Order 5360d	MPC's Docket 90.6.39 Proposal	MPC's Docket 88.6.15 Proposal	Order 5360d	MPC's Docket 90.6.39 Proposal
Hydro	400	400	385	518	520	489
Corette	124.8	124.8	121.7	156	156	156
Colstrip 1	123.6	125.2	125.1	158.5	158.5	157
Colstrip 2	123.6	125.2	125.1	158.5	158.5	158
Colstrip 3	168.4	179.3	184.8	216	216	216
Total Thermal	540.4	554.5	556.7	689	689	687
Total (H+T)	940.4	954.5	941.7	1,207	1,209	1,176
Changes			-12.8			-33

Thermal Capabilitv

121. In Docket No. 88.6.15, Order No. 5360d, FOF 330, the Commission stated:

> ...MPC must provide analysis showing the peak capabilities of Corette, Colstrip 1, Colstrip 2, and Colstrip 3, using both daily and monthly peaks

> in its next general filing. The Company, of course, will be free to argue for whatever methodology it feels is appropriate.

In the current case, MPC studied the peak capability for each thermal unit. The study calculated the average of daily peaks and the average of monthly peaks. MPC recommends that thermal peaks be based on the average of daily peaks because use of daily peaks will provide a reliable peak value that is realistic and can be produced when needed.

122. Prior to 1985, MPC only recorded monthly peak data for Colstrip Units 1 and 2. As a result, MPC's recommended peak capabilities for these two units were derived on the average daily peak for the years from 1985 to 1989 adjusted for mechanical problems with the feedwater heaters. MPC's recommended peak capability for Colstrip 3 is based on the average daily peak for 1988 and 1989. For the Corette plant there was a permanent change in the coal supply in 1986. MPC's recommended peak capability for Corette is based on the average daily peak for 1987 through 1989.

123. The following table shows the peak capabilities that MPC recommends in this Docket based on the average of daily peaks:

	Peak Capability (MW)
Corette	156
Colstrip 1	157
Colstrip 2	158
Colstrip 3	216
Total	687

124. MCC witness Mr. Clark, in his testimony on this issue, states that the thermal plants should be able to produce at their nameplate rating. He describes the nameplate rating for Corette and Colstrip Units l, 2 and 3. However, Mr. Clark stopped short of recommending that peak capability be based upon those nameplate ratings. Mr. Clark recommends the following peak capabilities based upon the average of monthly peaks:

	Peak Capabilitv (MW)
Corette	160
Colstrip 1	159
Colstrip 2	159.5
Colstrip 3	218.1
Total	696.6

According to Mr. Clark, these proposed peak capabilities are attainable because they are the average of what has already been attained and they are reasonable because they do not overly penalize the ratepayers in Montana.

125. MPC witness John Leland provided rebuttal testimony which indicated that the Company favors using the average of daily peaks because it is a level of performance which is more likely to be achieved. Mr. Leland notes that another reason MPC supports the average of daily peaks is that MPC's thermal engineers and plant operators feel reasonably comfortable that the thermal units can achieve MPC's proposed peak capabilities when needed.

126. After reviewing the evidence provided by MPC and MCC on the issue of thermal plant capabilities, the Commission finds that thermal peak capability should be determined by taking the average of the monthly peaks. The Commission agrees with MPC that the use of the average daily peaks will produce a result which is easier to achieve; however, this does not convince the Commission that daily peaks should be used to determine peak capability. The fact that the monthly peaks have actually been achieved, as noted by Mr. Clark, indicates that use of monthly peaks is proper. As a result of accepting Mr. Clark's recommendation, the Commission finds that the thermal peak capability for Corette, and Colstrip Units 1, 2 and 3 is 696.6 MW.

MPC's Hydro Capability Studies

127. MPC's hydro capability study addressed the existing hydro system only, as the Company believes its hydro upgrade capabilities are developed correctly. MPC contends its hydro study developed energy and peak capabilities on a historical basis that is consistent with future hydro capabilities. The basis of MPC's study was to develop energy and peak capabilities that are compatible with actual generation and available water. That is, MPC utilized the historical water record and actual production to determine energy and peak capabilities. (Exh. MPG-20, p. 12)

128. The annual energy capability was developed from an econometric analysis of the Company's historical hydroelectric generation. A regression model that describes annual hydro energy production in terms of actual water conditions and a hydro/thermal index was estimated from a 1963 to 1989 data base. MPC argues to use this period because the existing hydro generating system became a "reality in 1958" when Cochrane went into service. The hydro/thermal index accounts for the transformation from a total hydro generating system to a combined hydro/thermal generating system. The result of this econometric analysis is a hydro energy capability of 385 annual average megawatts (aMW). (Exh. MPG-20, pp. 15-16)

129. The Company's annual peak capability was developed from a different analysis than the one used to calculate its energy capability. MPC used the noncoincident peak capability (the maximum one hour generation) for each hydroelectric facility regardless of the peak day hour of occurrence. MPC used a 1959 to 1989 data series and monthly median hydro peak capability data to develop its 489 MW peak capability proposal. In doing so, MPC sorted the monthly peak day noncoincident peaks in ascending order and found the median. The result of this study is the proposed January peak capability of 489 MW. (Exh. MPG-20, p. 18)

130. Next, the Company developed the monthly hydro energy capabilities by multiplying the expected annual energy capability by a monthly shape. (Exh. MPG-20, p. 17)

131. MPC's hydro energy capability study in this Docket was based on both average and critical water levels. The amount of electricity that can be generated under historical average water conditions is referred to as average water energy. The amount of electricity that can be generated under adverse water conditions is called critical water energy. The hydro energy capability in Docket No. 88.6.15 was based on the median (not average) water availability and an engineering estimate. The hydro energy capability in this Docket was based on the average water availability and actual historic generation. (Exh. MPG-20, p. 14)

132. In this Docket, the Company proposed to use the average water energy capability to define its customers' revenue requirement responsibility and the critical water energy capability to define the time when future energy resources need to be added. (Exh. MPG-20, p. 13)

133. MPC's proposed hydro capability study concludes that the historical values used for median water energy and peak generating capability have been overly optimistic when compared to actual production since 1959. (Exh. MPG-20, p. 15)

MCC's Hydro Capability Analysis

134. MCC disagreed with MPC's hydro energy capability study results. MCC notes two problems with the Company's statistical model. The first is that MPC's hydro energy capability study suffers from a high degree of multicollinearity between the independent variables. MCC pointed out that the two independent variables, natural flow and spill, had a correlation coefficient of 0.94721, which is the basis of the alleged high degree of

multicollinearity. The second problem involves the Company's selection of natural flows as the value for the independent variables. That is, the average value of natural flow for the period 1915 to 1989 was used as input by MPC. MCC believes that the Company should continue using the median value, which is a better indicator of future events than the average value. Based on these two problems, MCC concludes that the results of MPC's model cannot lead to any useful results. (Exh. MCC-6, pp. 16-17)

135. In correcting these two problems, MCC developed another two sets of regression equations, which are produced from a stepwise regression analysis. The result of MCC's analyses is an average energy production capability of 392 aMW. (Exh. MCC-6, p. 19)

MPC's Rebuttal --- Multicollinearity

136. MPC argues that some degree of multicollinearity is not a problem if the model is specified correctly and used for predicting the mean of the dependent variable (energy capability). MPC also states that in its particular study case, as in most time series data studies, multicollinearity is simply an integral part of the actual physical relationships being described by the regression. MPC argues that it is extremely difficult to avoid some degree of multicollinearity in most fully specified regression models. (Exh. MPG-21, p. 8)

137. MPC also testified that the relationship between natural water flows and spill is a physical reality even if multicollinearity exists between these two independent variables. That is, the amount of available generation is determined not only by the natural flows but also by the spill over the dams. MPC believes that the elimination of either one of these explanatory variables in the equation will create an inferior model.

Elimination of the spill variable implies that all of the water in the river (i.e., natural flow) is used to generate electric power. Thus, the elimination of the spill, as MCC recommended, results in an equation with biased coefficients and a biased prediction of the hydro energy capability. (Exh. MPG-21, p. 11)

138. MPC agrees that the presence of multicollinearity may result in one or more of the estimated coefficients of the model having large standard errors. MPC also acknowledges that the consequence of large standard errors of the estimated coefficients creates uncertainty about' the effects of specific independent variables. (Exh. MPG-21, p. 12) MPC further argues that multicollinearity is a problem only if the standard errors of the estimated coefficients are large. MPC believes there is no serious multicollinearity problem because the standard errors of the estimated coefficients are not large as evidenced by significant statistics. (Exh. MPG-36, p. 11) As verification, MPC performed the "principle components" tests to determine the degree of multicollinearity between the independent variables. The Company argues that there was at most a moderate degree of multicollinearity in the independent variables of its study. MPC concludes there is no multicollinearity problem in its hydro energy capability study since its regression model is used for prediction purpose and not to isolate the effect of each of these variables. (Exh. MPG-36, p. 12)

MPC's Rebuttal --- Median v.s. Average Water

139. MPC argues against MCC's proposal to use median hydro values in place of the Company's average values. The sample median water for the 75 year data period is 18,545 cubic feet per second (cfs) and the sample mean water for the same period is 18,686 cfs. (Exh. MPG-36, p. 19) MPC states that either median or average water measures can provide a good approximation of the expected

value because the 75 years of water flow data approximates a normal distribution. MPC states that it confirmed the normality of the natural water flow data by means of a Chi-squared test, and also by the fact that the average and the median are nearly equal. MPC indicates that the mean and the median of a variable will differ only if there is some asymmetry in the frequency distribution of natural flow. From the histogram for the natural flow data and the Chi-squared test, MPC believes that there is no evidence of such a skewed shape. (Exh. MPG-21, p. 19 and Exh. MPG-36, p. 18) 0

140. MPC further testified that its linear regression is estimated to predict the mean of the dependent variable, i.e., energy capability, given the values of the independent variable. Whatever values of independent variables are input for prediction purposes, the result is the mean of the dependent variable, conditional on the values for the independent variables. MPC testified that if the median value of 18,545 cfs were substituted into the regression model, the predicted hydro energy capability would be decreased by 1 aMW compared to MPC's recommended 385 aMW energy capability. (Exh. MPG-36, p. 18 and Exh. MPG-21, p. 19)

141. In explaining the issue of the relative precision obtained by using the mean versus the median water, MPC states that, for a normally distributed data sample, the distribution of the median has thicker tails than the distribution of the mean and thus will be less precise. In other words, there is a much higher risk that median water will give a poorer estimate of energy capability than mean water. MPC's conclusion is that use of median water produces an inferior estimate of the long-term average flow relative to the use of mean water. (Exh. MPG-36, p. 20)

MPC's Rebuttal --- Sample Period

142. MPC disagrees with MCC's proposal to use the 1959 through 1989 sample period in the hydro energy capability study. MPC explains that there were several structural shifts for the years 1938 through 1960; for example, the Quake Lake earthquake occurred in the summer of 1959. MPC believes that the period from 1963 to 1989 is more appropriate because it represents the period of time when all present MPC hydro facilities were in full operation. MPC asserts that if the effects of the structural shifts are ignored the predicted mean of energy capability will be biased. (Exh. MPC36, p. 5)

Commission's Decision

143. The Commission will address the hydro energy capability issue, which includes three parts: multicollinearity, median versus average water and the appropriate sample period. The Commission will then address the hydro peak capability issue.
Hydro Energy Capability – Multicollinearitv

144. The Commission accepts MPC's proposal to use 385 aMW as its hydro energy capability. The Commission finds that some degree Of multicollinearity is not a problem if the model is used for predicting the mean of the dependent variable and not to isolate the effect of each independent variable. The Commission agrees with MPC's statement that in most time series data studies, multicollinearity is simply an integral part of the actual physical relationships being described by the regression.

145. The Commission finds it is inappropriate to eliminate the spill variable as MCC recommended since it implies all of the water in the river is used to generate electric power. The Commission finds that the elimination of the spill variable results in an equation with biased coefficients and a biased prediction of the hydro capacity.

146. The Commission finds that the econometric model MPC proposed in this Docket should not be used to isolate the contribution of each independent variable to the mean of the dependent variable. This is because the multicollinearity between natural flow and spill exists for the same year.

Hydro Energy Capability -- Median v.s. Average Water

147. The Commission accepts MPC's proposal to use the values of average, instead of median water for the Company's hydro energy capability study. The Commission recognizes the predicted hydro energy capability would be decreased by 1 aMW if median water was employed in the model.

148. The Commission finds no evidence of asymmetry in the distribution of natural flow and thus the 75 years of water flow data approximates a normal distribution. The Commission notes that for normally distributed water data, the distribution of the median has thicker tails than the distribution of the mean. Thus, the use of the median water will yield less precise energy capability results. For this reason, the Commission concludes that median water provides an inferior estimate of the long-term water flow than does average water.

Hydro Energy Capability – Sample Period

149. The Commission finds merit in MPC's proposal to use the sample period for the years 1963 through 1989 to estimate the model parameters in MPC's study. The Commission finds the structural shifts in the hydroelectric system should be taken into consideration. The Commission also finds that if the effects of the structural shifts are ignored, the result of MPC's hydro energy capability study will be biased.

Hydro Peak Capability

150. For several reasons, the Commission denies MPC's proposed 489 MW of hydro peak capacity. As background, Order No. 5360d required that any future proposal to deviate from the installed capacity of 520 MW be accompanied by comprehensive studies, workpapers and testimony. (FOF 342, Order No. 5360d) MPC has changed the method used to determine hydro peak capability from the installed capacity used in Docket No. 88.6.15 to a simple median level production for the period 1959 to 1989. For the following reasons, the Commission believes that MPC's analyses is inadequate to change the Docket No. 88.6.15 method of computing hydro peak capability. First, the Commission finds inconsistent MPC's hydro energy and capacity studies. The 489 MW capacity is based on median values while MPC's 385 aMW energy capability is based on an average or mean value statistic. The Commission finds that either mean or median values should be used, but not a mix of the two concepts. The Commission also finds inconsistent MPC's use of two different time frames to determine its energy and peak capability. That is, the time period 1963 through 1989 was employed to determine MPC's energy capability while a data sample from the period 1959 through 1989 was used to determine the peak capacity. The Commission finds inappropriate MPC's use of one time period to set capacity, and another time period to set energy capability. In fact, two of MPC's own criticisms of MCC's hydro energy capability study appear applicable to MPC's hydro peak study. The Commission believes that 31 MW capacity decrease is a significant system resource change which has not been adequately addressed by other parties in this Docket. More importantly, the Commission is not satisfied that this change was thoroughly studied by MPC. For these reasons, the Commission denies MPC's proposal of 489 MW as its hydro peak capacity and requires that MPC use 520 MW of hydro capacity for purposes of rate making and resource planning.

Hydro Generation Adjustment

151. Mr. Pascoe introduced MPC's proposal to implement a Hydro Generation Adjustment Clause (HGAC), hereafter hydro tracker. MPC is proposing to track actual generation levels at their hydroelectric stations. The difference between actual and normalized hydro generation would be valued at spot market prices. Each year rates would be adjusted up or down to reflect 80 percent of the value of the previous year's difference between actual and normalized hydro generation. Mr. Pascoe gave four reasons why it is appropriate to track hydro generation: (1) hydro generation is primarily dependent on stream flows which are largely beyond MPC's ability to control; (2) hydro generation varies widely from year to year; (3) the variations in hydro generation cause a significant impact on MPC's power supply costs; and, (4) the variations in hydro generation are easily isolated and the impact on power supply costs can be easily measured.

152. In Exh. MPG-17, WAP-4, the Company shows hydro generation for the period 1980 through 1989. During that period, hydro generation varied from a low of 2,716,335 MWH in 1988 to a high of 3,740,557 MWH in 1983. Valuing the more than one million megawatt-hour difference between hydro generation for the years 1983 and 1988 at the normalized spot market prices in this filing (about 17 mills/kwh for spot sales or purchases) shows a variation of about $17 million in power supply costs due to variable hydro generation.

153. MPC recognized that some parties to this proceeding might be concerned that a tracking mechanism might remove the incentive to maximize hydro generation. Therefore, to assure those parties
is proposing to track actual generation levels at their hydroelectric stations. The difference between actual and normalized hydro generation would be valued at spot market prices. Each year rates would be adjusted up or down to reflect 80 percent

of the value of the previous year's difference between actual and normalized hydro generation. Mr. Pascoe gave four reasons why it is appropriate to track hydro generation: (1) hydro generation is primarily dependent on stream flows which are largely beyond MPC's ability to control; (2) hydro generation varies widely from year to year; (3) the variations in hydro generation cause a significant impact on MPC's power supply costs; and, (4) the variations in hydro generation are easily isolated and the impact on power supply costs can be easily measured.

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153. MPC recognized that some parties to this proceeding might be concerned that a tracking mechanism might remove the incentive to maximize hydro generation. Therefore, to assure those parties that an incentive will continue to exist, MPC proposed that only 80 percent of the total impact be included in the hydro tracker.

154. MCC points out that while it is probably true that hydro generation is primarily dependent on stream flows which are largely beyond MPC's ability to control, it is just as true for many other costs that MPC incurs. MCC witness Mr. Clark notes that Mr. Pascoe showed the last ten years of hydro generation and proceeded to compare the maximum generation to the minimum generation. MCC adjudged this comparison to be invalid because MPC's revenue requirement has traditionally been determined using

"normal" hydro generation. Therefore, the variability should only be measured against the normal, not over the entire range.

155. MCC reviewed the data on Exh. MPG-17, WAP-4, and found that the difference between actual hydro generation and normal hydro generation was only 50,109 MWH. Further, this variability was in MPC's favor. That is, MPC produced 50,109 MWH in excess of the normal generation over the entire ten year period. At 17 mills/kwh the total difference over ten years in only $852,000.

156. Mr. Clark does not see where MPC's incentive under the hydro tracker lies to produce the hydro generation above the "normal" level as compared to the present. Above the "normal" level MPC would only be able to retain 20 percent of the revenues from the spot market sales that are, in effect, imputed by the hydro tracker. Currently, all hydro generation above the "normal" level either produces additional revenues for the Company or reduces its costs from the level included in rates and in both cases MPC retains 100 percent of the net income effect. Mr. Clark believes that such retention is the ultimate incentive to maximize hydro generation. MCC recommends that the hydro tracker be rejected.

157. Jan Michael, the witness for the Large Customer Group (LCG), was concerned that the proposed hydro tracker might be unlawful in light of ARM 38.5.1702. If the hydro tracker is approved, Mr. Michael recommends that interested parties have an opportunity to formally comment on the annual filings and hearings should be held if substantive issues are raised.

158. In rebuttal testimony Mr. Pascoe stated that MPC proposed the hydro tracker to stabilize, not to enhance, earnings. The purpose of the hydro tracker is to reduce the volatility in earnings caused by the wide variations in hydro production from year to year. Mr. Pascoe agrees with Mr. Clark that if 385 aMW is normal

hydro generation, then hydro generation from 1980 to 1989 was nearly normal.

159. An important consideration in the discussion of the proposed hydro tracker is the appropriateness of shifting the risk of hydro generation from MPC to its customers. In the past this Commission has determined the revenue requirements for MPC based upon normalized hydro conditions. In this Docket MPC is asking that 80 percent of the variation between actual and normalized hydro generation be captured in a hydro tracker for reflection in rates. It is the view of this Commission that the risk of hydro generation belongs to MPC. Use of normalized hydro generation in the ratemaking formula (as has been the case for decades) results in the appropriate costs being included in the test year. The Commission does not agree with MPC that variation in hydro production is not a risk which should be faced by the Company. Many MPC customers face moisture related risk in their businesses (e.g., dry land wheat ranchers, ski resorts, hunting and fishing guides and marinas) without the benefit of a hydro tracker.

160. Establishment of a hydro tracker would eliminate 80 percent of the risk associated with variation in hydro generation. At the hearing staff asked Mr. Pascoe if it was correct that by reducing the volatility in earnings that a hydro tracker would result in a reduction of risk to the Company. He answered:

> I think you are outside of my area. I think it would be better if you put that question to one of the Company's financial witnesses. (Tr. p. 181)

At the same page in the transcript, Mr. Pascoe stated that he did not know if the Company had accounted for the reduction in risk in its computation of the cost of capital.

161. At the hearing staff asked MPC witness Dr. Olson several questions on the subject of reduced risk associated with the proposed hydro tracker:

> Q. Is it the case that if the hydro
>
> - tracker were implemented and thereby there was a reduction of the volatility of earnings, is it the case that this would reduce the risk to The Company?
>
> A. It would, but I decided in preparing my direct testimony in this case that I ought to be prepared for that, so when I picked my comparable companies, I excluded companies without fuel adjustment clauses, and I make reference to that at page 23 of Exh. MPG-31, lines 23 and 24, just so that would be an issue that you wouldn't have to deal with. That there aren't that many companies without these kinds of clauses, but I left them out so that a specific risk adjustment wouldn't be required. But as a general matter, you are correct. If the Company gets this tracker, it's going to have less risk than it would have currently in its situation without the tracker.
>
> Q. Do I understand your testimony, then, to be that your prefiled testimony on the Company's risks already accounts for the reduced risk that they would have if a hydro tracker were implemented?
>
> A. Yes. I knew this adjustment was going to be proposed and I had a discussion on this subject of several hours with Mr. Pascoe before I prepared my testimony for this case. (Tr. pp. 372-373)

162. There is a serious inconsistency between the testimonies of Mr. Pascoe and Dr. Olson. Mr. Pascoe testified that he did not know if the Company had accounted for the reduction in risk in its computation of the cost of capital, yet he apparently discussed this issue with Dr. Olson for several hours.

163. In Response to PSC Data Request No. 80, Dr. Olson stated that he did not believe that the benefits of a power cost adjustment or a future oriented test year can be precisely quantified. In the updated response to PSC Data Request No. 72, Dr. Olson stated that

MPC's fuel clause relates only to generation from its hydroelectric facilities. Therefore, the effect of the clause on the Company's cost of equity may not be the same as would be the case for another company with a fuel adjustment clause. According to Dr. Olson, since he attributes the average cost rate for a relatively large group of average risk companies, it is not necessary .to adjust his recommended return to reflect the fuel adjustment clause. The Commission finds that Dr. Olson has failed to accurately quantify the effect of granting a hydro tracker on MPC's cost of equity. Eliminating companies that do not have fuel adjustment clauses is a flawed comparison as acknowledged by Dr. Olson in his response to PSC Data Request No. 72.

164. Mr. Pascoe, in Exh. MPG-17, WAP-4, showed ten years of actual hydro production. However, included in that period was 1988, the driest year in some 100 years. It is wrong from a statistical standpoint to include 1988 in a sample size of less than 100 years.

165. Given the Commission's decision elsewhere in this Order to reduce hydro energy capability from 400 aMW to 385 aMW, there is even less justification for the hydro tracker. The hydro tracker proposed by MPC is denied.

MPC Test Year Sale and Loads Study

Background -- Docket No. 88.6.15

166. In Docket No. 88.6.15, MCC found that MPC proposed to use two different values for energy loads and for different purposes. On the one hand, the test-year energy loads of 881 aMW were used to determine the test-year revenue requirement. This implies that the energy sales associated with the 881 aMW of energy loads were used to determined the test-year revenue. On the other hand, the forecast energy loads of 893 aMW were employed for test-year load and resource planning. (FOF 137, Order No. 5360d)

167. MCC testified that the 12 aMW difference in these two values was caused by the different methodologies used to develop each set of values. The lower value of 881 aMW of energy loads was developed from actual 1987 test year loads and the higher value of 893 aMW energy loads was developed from the forecasting models. (FOF 138, Order No. 5360d)

168. MCC argued that MPC's forecast loads of 893 aMW were too high when compared to the actual test year loads of 881 aMW. MCC recommended the Commission adjust MPC's forecast loads downward by using the actual test year loads in Docket No 88.6.15. (FOF 321, Order No. 536Od)

169. In Order 5360d, the Commission disagreed with MCC's recommendation and found that it was not statistically valid to simply apply forecast test year loads to actual test year loads. (FOF 322, 323, Order No. 5360d)

170. The Commission received a motion for reconsideration on Order No. 5360d from MCC regarding the loads mismatch issue. MCC stated that to accept forecast loads that do not match test year loads would endanger a fundamental aspect of regulatory oversight, i.e., the need to match test-year revenue with test-year expenses. (FOF 21, Order No. 5360e) In Order No. 5360e the Commission found that MCC's argument might be valid in any future MPC filing where forecast loads affect test year revenue requirement. (FOF 24, Order No. 5360e)

171. Test year sales represent MPC's monthly sales metered at the customers' point of delivery. This data is taken directly from MPC's Customer Information System (CIS). In this Docket normalized test year sales are calendar year 1989 sales, adjusted for abnormal temperatures and other known changes. The normalized test

year loads represent MPC's required energy resources necessary to support the normalized sales plus line losses and unaccounted-for-losses. (Exh. MPG-20, pp. 4-5)

172. MPC testified that its normalized test year sales are used to develop test year revenue at current rates. The normalized test year loads are used for two purposes. First, they are used to calculate the test year operating expense which is a part of the test year revenue requirement. Second, the normalized test year loads are matched against MPC's energy capability, surplus energy will then be sold off-system. The revenue from off-system sales will then be included as part of the test year revenue. (Exh. MPC20, p. 5)

MCC's Test Year Sales and Loads Study

173. In this Docket MCC stated MPC used two different loads to determine its test year revenue and revenue requirement. MCC stated that MPC intends to use the energy loads of 916 aMW as its test year loads to determine the test year revenue and set rates while the energy loads of 936 aMW are used to justify additional resource need. (Exh. MCC-6, pp. 20-21) The 916 aMW is MPC's test year normalized loads while the 936 aMW is MPC's forecast operating year loads. (Exh. MPG-21, p. 21)

174. MCC believes that the difference between 916 aMW and 936 aMW energy loads is again caused by the different techniques used to develop each set of loads. The energy loads of 916 aMW are computed by adjusting actual test year (1989) sales for abnormal weather, billing cycle effects and other accounting adjustments plus line losses and unaccounted-for-losses. The energy loads of 936 aMW are produced from MPC's forecast econometric model. MCC points out that the result is that the higher energy loads from the forecast model are employed as justification for future

resource needs and the lower energy loads from the test year actual sales are used in the calculation of test year revenue. (Exh. MCC-6, pp. 6, 21)

175. MCC further stated that this is a fundamental mismatch. MCC recommended the Commission establish test-year rates based upon the same energy level (936 aMW) used by MPC to justify its resource purchases. (MCC recommended the Commission make a downward adjustment in Docket 88.6.15) (Exh. MCC-6, p. 20) MCC then repriced the 20 aMW energy, assuming it would be sold to system customers, rather than off-system customers. The price difference between the system average sales price and the off-system sales price, multiplied by the 20 aMW energy sale adjustment, would result in additional test year revenues of $4,035,769. (Exh. MCC-6, p. 22)

MPC's Rebuttal --- Loads Mismatch

176. MPC disagrees with the MCC's loads adjustment from 916 aMW to 936 aMW. MPC asserts that the 916 aMW energy loads cannot be compared with the 936 aMW energy loads. The 916 average energy represents the 1989 test year (January 1 - December 31) energy loads and the 936 average energy represents the 1989-1990 operating year (July 1 - June 30) energy loads. MPC asserts that MCC's use of these two numbers is an "apples and oranges" comparison. (Exh. MPG-21, p. 19)

177. MPC testified that there is another reason why the energy loads of 916 aMW are not comparable with that of 936 aMW. The Company points out that in addition to the time period difference, there is a loss difference between these two values. That is, losses associated with the test year off-system sales are not included into the energy loads of 916 aMW which is labeled "adjusted system load and loss absent net interchange after

generation transfers in average MW" in its direct testimony. (Exh. MPG-21, p. 20)

178. In order to clarify the above, MPC compared the loads used for rate making and the loads used for resource planning. MPC first set these two loads for the same test year period (1989) and then adjusted the test year loads with off-system sales losses. MPC asserts that the difference between the 1989 test year loads and the 1989 forecast loads is very small based on this comparison. MPC believes that the 1989 forecast energy load used for resource planning is only 8 aMW higher than the 1989 test year energy loads used for rate making, rather than the 20 aMW difference MCC claimed. MPC further states that some degree of difference between the forecast value and the test year value is unavoidable and the 8 aMW energy load difference is well within acceptable limits. (Exh. MPG-21, p. 22)

179. MPC further points out that if the Commission allowed loads to be adjusted prospectively through the known and measurable change period, it would create a very serious mismatch between revenues, expenses and rate base.- MPC also stated that the Commission has never permitted such adjustment. (Exh. MPG-21, p. 21)

180. MPC demonstrated the impact on the test-year revenue requirement by substituting actual test year energy loads of 920 aMW with the same period forecast energy loads of 928 aMW. MPC points out that the increased load would increase the test year operating expenses and thus cause a higher revenue requirement and eventually higher rates for its customers. (Exh. MPG-21, p. 23)
181. MPC then demonstrated the impact on customers' rates by substituting actual test year energy sale of 823 aMW with the same period forecast energy sales of 818 aMW. The Company holds that if the higher revenue requirements were collected over reduced test

year sales (823 aMW sale was reduced to 818 aMW sale), customers' rates must increase. (Exh. MPG-21, p. 23)

182. The following table shows the energy loads proposed by MCC and revised by MPC for the purpose of rate making and resource planning. The figure in parenthesis reflects the related energy sales. (Exh. MPG-21, RJL-11 and Exh. MCC-6, p. 20)

Table 2

Energy Load Proposal (aMW)

	Rate Making Purpose	Resource Planning Purpose
MCC Proposed	936 (test-year)	936 (operating-year)
MPC Revised	920 (test-year)	928 (test-year)
	(823)(test-year)	(818)(test-year)

183. Last, MPC testified that its resource need is justified by the need for capacity resources and not the need for energy resources. (Exh. MPG-21, p. 25)

Commission Decision

184. The Commission denies MCC's proposal to utilize an estimate of firm retail and whole sales of 936 aMW in setting rates in this Docket. (Exh. MCC-6, p. 20) Consequently, MCC's proposal of a 20 aMW adjustment and additional revenue adjustment of $4,035,769 (Exh. MCC-6, pp. 22-23) are also denied. The Commission makes this decision for the reasons described below.

185. First, the Commission finds that MCC misunderstood the concepts of loads and sales and then calculated the proposed revenue adjustment based on this misunderstanding. In his direct testimony, MCC witness Mr. Drzemiecki states: "I recommend that the Commission utilize an estimate of firm retail and whole sales of 936 MW in setting rates." (Exh. MCC-6, p. 20) The Commission finds that 936 aMW represents MPC's forecast energy loads, not sales. The Commission cannot accept MCC's proposal to calculate MPC's test year revenue on its forecast energy loads.

186. Second, the Commission finds that MCC's test-year sales

and revenue adjustments (Exh. MCC-6, p. 19, line 19) are not really based on the test year, but on two different time periods. The Commission finds that the 916 aMW loads represent MPC's 1989 test year (January 1, 1989 - December 31, 1989) normalized energy loads while the 936 aMW loads represent MPC's 1989-1990 operating year (July 1, 1989 - June 30, 1990) forecasted energy loads. (Exh. MPC21, RJL-12) The Commission agrees with MPC's assertion that the 916 aMW energy loads cannot be directly compared with the 936 aMW energy loads because of the difference in these two time periods.

187. The Commission also finds MPC's testimony correct that it is inappropriate to use forecast operating year energy loads (936 aMW) which extend 6 months beyond the test year for the purpose of test year historical energy loads (916 aMW). The Commission generally does not allow loads to be adjusted prospectively through the known and measurable change period. (Exh. MPG-20, p. 21) The Commission finds that if MPC is allowed to use forecast operating year loads which extend 6 months beyond the end of the test year, all of the rate base and expenses must also be adjusted based on a forecast through the same period in order to match test year costs and revenues. The Commission finds that MCC in effect proposes using forward-adjusted test year loads, or 6-month prospectively adjusted test year loads rather than the historical test year loads currently used in this Docket. The Commission believes that it is inappropriate to accept such a policy change without thorough study.

188. Third, the Commission finds that MPC's resource need in this filing is justified by the Company's peak loads, not the forecast energy loads. (Exh. MPG-21, p. 25) In other words, the Commission finds that the test year revenue requirement is impacted by MPC's capacity, not energy resource purchases. The Commission finds that forecasting energy loads of 936 aMW does not cause a higher test year revenue requirement in this Docket. The Commission finds that

whether or not the mismatch between the test year and the forecasted energy loads were adjusted or not, the test year expenses and revenue requirement would remain the same.

PacifiCorp Sale Repricing

189. Under a contract which began in January 1990, MPC is selling firm power to PacifiCorp. PacifiCorp is purchasing 15MW of firm capacity and energy in 1990, 1991 and 1992 and 10MW of firm capacity and energy in 1993, 1994 and 1995. In 1990 the contract price was 26.1 mills/kwh. Contract prices increase annually to a maximum of 53.31 mills/kwh in 1995.

190. This sale resulted from a settlement agreement between PacifiCorp and MPC signed in March 1988. Under the terms of this settlement, MPC agreed not to actively participate in the FERC proceedings on the Pacific Power & Light/Utah Power & Light merger. In return, PacifiCorp agreed to buy power from MPC under terms which were later embodied in the April 1989 contract.

191. Originally this sale was assigned to Colstrip 4 Lease Management Division (CS4LMD). However, CS4LMD contracted with Puget Sound Power and Light Company (Puget) to sell all of its remaining surplus power beginning in October 1989. As a result, CS4LMD no longer had resources available to serve the PacifiCorp sale. The MPC Utility Division chose to assume this sale.

192. MCC witness Mr. Clark does not agree that the combination of the Puget sale and the Los Angeles Department of Water and Power (LADWP) sale, that uses up the capacity of Colstrip #4, means that the utility should be reassigned the PacifiCorp sale. Mr. Clark goes on to state:

> The reassignment of this sale to the utility is a perfect example of MPC's attempt to maximize the

> CS4LMD's unregulated revenues at the expense of Montana ratepayers. This kind of manipulation should not be countenanced. Indeed, it is: my opinion that just the opposite -- i.e. the highest priced off-system sales should always be assigned to the utility to the extent the utility has the ability to serve the load -- is appropriate for setting
> rates. (Exh. MCC-4 pp. 42-43)

Mr. Clark proposed to reprice 131,400 MWH at the LADWP 1990 contract price of 34.16 mills per kwh. This adjustment increased the revenue from this sale by $1,059,084.

193. Mr. Pascoe provided rebuttal testimony on this issue for MPC. Mr. Pascoe argued that the two contracts are not comparable due to the difference in the length of the contracts. The sale to PacifiCorp is a six year sale, while the sale to LADWP is for 22 years. When CS4LMD approached MPC's Utility Division about the PacifiCorp sale, the Utility Division concluded that this sale would provide benefits for Montana ratepayers. In his rebuttal testimony Mr. Pascoe gives two alternatives which existed to the Utility Division assuming responsibility for the PacifiCorp sale: 1) approaching PacifiCorp about terminating the contract; 2) leaving the PacifiCorp contract with CS4LMD. If the second option had occurred, Mr. Pascoe states that:

CS4LMD could have obtained a supplemental supply for the length of the PacifiCorp contract and used any "gains" on the PacifiCorp sale to offset losses from the LADWP and Puget contracts. (Exh. MPG-18, p. 26)

The Commission finds this portion of Mr. Pascoe's rebuttal testimony to be extremely speculative and finds that it will not be relied upon in examining this issue. There is no evidence on this record which indicates the amount CS4LMD would have paid for supplemental power if it was available.

194. In rebuttal testimony the Company indicates that the 34.16 mills is not a "price" in the LADWP contract. It is-the average revenue per kwh expected in 1990. This average revenue figure is based upon specific fixed (capacity) and incremental (energy) charges and a specific market adjustment calculation called for in the contract. Additionally, this average revenue figure includes a substantial transmission component. These transmission payments are made by LADWP to CS4LMD which in turn passes these payments on to BPA and Washington Water Power. The 34.16 mills of average revenue is based upon an assumed load factor of 81.82 percent.

195. Exh. MPG-18, (WAP-8) consists of 4 pages which show various calculations of contract prices. Page 1 of 4 demonstrates how the 34.16 mills of average revenue were computed. Page 2 of 4 shows the imputation of the LADWP contract prices to the PacifiCorp sale with transmission expenses removed and the load factor adjusted to reflect the PacifiCorp load factor of 100 percent. This calculation shows that the average revenue from the LADWP sale is 23.12 mills per kwh. Page 3 of 4 represents the 1990 Puget sale average revenue of 30.00 mills per kwh based on a load factor of 75 percent. Page 4 of 4 reflects the Puget sale using a 100 percent load factor, producing average revenue of 22.14 mills per kwh. Mr. Pascoe concludes that Mr. Clark's adjustment which imputed LADWP contract prices to the PacifiCorp sale would actually disadvantage ratepayers if calculated properly.

196. In the initial brief of MCC, the proposed repricing of the PacifiCorp sale is modified to reflect the fact that the average price in the LADWP contract does include a charge for third party wheeling that would be paid to BPA and Washington Water Power. The MCC revised repricing is based on average revenue associated with the Puget sale of 30.00 mills per kwh. This

results in a revised adjustment to increase the electric utility's revenue by $512,460.

197. There is an error in the MCC brief dealing with the repricing of the PacifiCorp sale. At page 16, line 16, there is a sentence which reads:

> Since there are no third party wheeling charges in the 30.00 mills per kwh produced by the Puget contract (Exh. MPG-18, (WAP-8), page 3 of 4), the figure from the Puget sale is the highest per kwh of revenue and should be the basis of Mr. Clark's proposed adjustment.

A careful examination of Exh. MPC-18 (WAP-8), page 4 of 4, indicates that there are indeed third party wheeling charges in the 30.00 mills per kwh shown on page 3 of 4. The wheeling charges included on page 3 of 4 are 1.9 mills per kwh. As a result, the average revenue on page 3 of 4 goes down from 30.00 mills per kwh to 28.1 mills per kwh.

198. During the hearing Mr. Pascoe testified that if transmission expenses were removed from the LADWP contract, revenue would average 29.8 mills per kwh. However, this calculation is based on a load factor of 81.82 percent.

199. The Commission finds comparing the PacifiCorp sale to the LADWP sale not valid due to the difference in load factors in the two contracts. In order to make a valid comparison between the PacifiCorp and LADWP sales, the load factors used in each contract must be the same. This is because such contracts specify a fixed payment for capacity and a variable payment for energy which invalidates a comparison based on a simple average of revenues per kwh. If the load factors in either the LADWP or the Puget sale are set at 100 percent as the PacifiCorp sale is, the results of the calculations indicate that the adjustment recommended by Mr. Clark

would have a negative impact on ratepayers. The Commission finds that the repricing of the PacifiCorp sale by the MCC (which is overstated by 1.9 mills/kwh) is not based on comparable load factors and must be rejected.

Colstrip 3 and 4 "Off System" Sales Additional Issue

200. In Order No. 5484h in this Docket, the Commission requested that parties address certain additional issues. The second of these is as follows:

> In a 1985 order for Docket No. 84.11.74, the Commission approved the dedication to retail public utility service and the rate basing of Colstrip Unit 3. Such action was very significant, both in terms of its very large monetary impacts on MPC retail customers, and the implied dedication of this generating plant primarily to the service of MPC retail customers for its life cycle, absent extenuating or materially changed circumstances. MPC has recently signed contracts to sell power to the Los Angeles Department of Water and Power (LA) for the period July 17, 1989, through December 29, 2010, and to the Puget Sound Power and Light Company (PS) for the period October 1, 1989, through December 29, 2010. Such contracts appear to total 212.5 megawatts, which is measured at the Colstrip 3 and 4 busbar. Contract provisions also appear to equally implicate the physical power output of Colstrip Units 3 and 4, which are each nominally rated at 210 megawatts. Colstrip Unit 4 costs, which are significantly lower than those of Colstrip Unit 3 because Colstrip Unit 4 is leased, appear to provide the basis for pricing provisions contained in the contracts.
>
> At this juncture, the Commission has no opinion about the propriety of MPC's apparent contractual dedication of Colstrip Unit 3 output to LA and PS. However, the Commission is interested in the ramifications which the LA and PS sales have for Colstrip Unit 3 ratemaking, both from the perspective of whether physical delivery of power from Colstrip Unit 3 to retail

> customers will always be possible while the same power is obligated contractually to LA and PS, and from the perspective of whether the LA and PS contract provisions affect the implied dedication of Colstrip Unit 3 to MPC retail customers for its life cycle, absent extenuating or materially changed circumstances. The attendant rate basing of Colstrip 3, naturally, is implicated by such dedication. Because the ratemaking costs of Colstrip 3 are so significant, the Commission requests that very thorough analysis of these issues be presented.

201. In response, Mr. Pascoe explains that the Reciprocal Sharing Arrangement (RSA) is a power exchange in which the Utility Division exchanges 1/2 of its Colstrip 3 output for 1/2 of the CS4LMD's Colstrip 4 output. He claims the RSA reduces risk for both the Utility Division and the CS4LMD by diversifying the power supply mix of each. Mr. Pascoe claims operational conflicts among the Utility Division, the CS4LMD, and the other partners are minimized due to provisions of the RSA. He further contends that ratepayers benefit because the RSA tends to even out generation levels used to determine normalized test year resources. He believes the Commission should not be concerned about the rate based aspect of the Colstrip 3 resource exchanging power with the non-rate based Colstrip 4 resource because the concept is identical to the Utility's other power exchanges with Idaho Power and BPA. Rather, Mr. Pascoe contends the Commission should be concerned whether the RSA provides net benefits to Montana ratepayers. (Exhs. MPC-18 and 19, pp. 34-41)

202. MCC witness Mr. Clark raises the issue of the fairness of having to pay Colstrip 3 rates for Colstrip 4 power and claims that this may be unfair to Montana ratepayers because Colstrip 3 is more expensive than Colstrip 4. He questions Mr. Pascoe's claim about the RSA minimizing operational conflicts with other partners. He contends the RSA does not minimize operational conflicts with the other Colstrip partners because the other

partners own the same proportion of each unit. He contends that the CS4LMC receives greater diversification benefits because it has no other generating capabilities while the Utility Division has Colstrip 1 and 2, Corette and the hydro system. Mr. Clark claims the issue is far too complicated to resolve in this proceeding. He recommends the Commission institute a separate proceeding to resolve any relevant concerns with the RSA. (Exh. MCC-5, pp. 7-11)

203. The Commission finds that, in addition to obvious operational impacts, there are at least three ratemaking aspects to the RSA arrangement:

A. Test year generation for Colstrip 3 is normalized using the conventions set forth in the RSA, which allocates about 68,000 MWH to the electric utility at 7 mills/kwh. This energy is accounted for as displacement energy for spot market purchases costing about 16.S mills per kwh.

The result is a reduction in revenues required in the amount of about $650,000. (Exh. MPG-18, p. 40) Mr. Clark asserts, however, that over the life of the RSA, the above described effect on utility ratepayers will "even out." (Tr. pp. 500-501) This implies that revenues required in a future MPC electric case could actually increase, for example, by $650,000.

B. Both Mr. Pascoe and Mr. Clark argue that risks have been reduced because of the RSA. Mr. Clark states: "As to the first benefit, it obviously holds more potential for the CS4LMD. Without the Reciprocal Agreement, the CS4LMD has only one generating resource while the Utility Division still has Colstrip 1 and 2, Corette, and the hydro system, as well as Colstrip 3." (Exh. MCC-5, p. 8) Mr. Pascoe argues just the opposite, i.e., that the RSA holds less potential for the CS4LMD. (Tr. p. 188) When asked if he had quantified (in dollar terms) the reduction in risks for the electric utility, Mr. Pascoe said he had not, and that he may be unable to quantify them. (Tr. pp. 201-202)

C. Mr. Clark states another concern on Exh. MCC-5, p. 7:

> That is, Montana ratepayers are receiving 15% of the output from the project, but are paying for 30% of Colstrip 3. The Commission noted at p.6 of Order No. 5484h: "Colstrip 4 costs, which are significantly lower than those of Colstrip Unit 3 because Colstrip 4 is leased..." The pricing of the CS4LMD sales appears to be based solely on the costs of Colstrip 4. The pricing of the Utility Division sales for the energy from the project is definitely based solely on the costs of Colstrip 3. This arrangement may be unfair to Montana ratepayers.

Mr. Clark also notes that MPC failed to address this issue, which pertains mainly to the fixed costs of the two units.

204. The Commission is not persuaded by MPC's reasoning regarding the RSA. Before this proceeding, MPC had only praise for Colstrip Unit 3. It had never been identified as so risky that some of the risk needed to be mitigated through a power exchange. When the power exchange occurs with one of MPC's own nonutility businesses, MPC assumes a greater burden of persuading the Commission that increased risk exists and that the exchange is needed.

205. With respect to the first aspect of the RSA (point A - above), the Commission does not take comfort in the fact that revenues required in this case are reduced by $650,000. Even MPC witness Mr. Pascoe states that the RSA is a "two way street on which benefits will be transferred in both directions over the course of time." (Exh. MPG-18, p. 39) MPC's statements regarding the increased benefits and reduced risks to the electric utility (point B above) also do very little to ease the Commission's concerns. Reduced rising implies reduced costs or rate impacts. The $650,000 may actually translate into more revenues required in a future MPC filing, and Mr. Pascoe is unsure of whether or not MPC can quantify other risk reductions in dollar terms. The need to reduce the risk of Colstrip 3 seems simply to be a matter of

MPC judgment, which was not expressed by MPC when the Commission originally considered rate treatment for Colstrip 3. Finally, as Mr. Clark states in point C above, Montana ratepayers have been responsible for paying Colstrip 3 costs, which have been substantially higher than those of Colstrip 4, assuming life cycle calculations at year one of each plant's respective life. Mr. Clark correctly wonders if the RSA is really fair to Montana ratepayers.

206. The Commission finds that MPC has not met its burden of proof with respect to the RSA. The Commission does not know the ramifications which the RSA has on the operations of electric utility property that is dedicated to the service of Montana ratepayers, nor is it sure of the lifecycle ratemaking impacts. Accordingly, MPC is directed to file, on October 1, 1991, testimony and exhibits which quantify such impacts. At a minimum, the filing must quantify, from that day forward until the projected termination of the RSAs, all potential costs and benefits which will accrue to the Montana electric utility and the CS4LMD. MPC must also calculate the fully allocated life cycle costs of Colstrip 3 and Colstrip 4 (individually) for the same period. Additionally, MPC must also provide testimony on whether it explored a RSA for 50 percent of Colstrip 3 output with other, nonaffiliated entities. It must also demonstrate that the reduction in risk which it claims will accrue to the electric utility has no impact on its cost of capital. Subsequent to the MPC filing, the Commission will establish a procedural schedule for consideration of these matters. During the pendency of the proceeding, the $650,000 identified by MPC as a benefit of the RSA will be included in rates on an interim basis.

Intercompany Power Transactions and Business Relationships

207. On February 1, 1991, the Commission issued Order No. 5484h in this Docket, which included the following additional issue:

During the Public Service Commission's 1987 and 1988 investigations of Montana Power Company's operations, the Commission staff reviewed certain documents which described potential relationships between Montana Power Company (MPC), Idaho Power Company (IPC) and Washington Water Power Company (WWP). Specifically, an 82-page document from Reid and Priest, a New York law firm, described in detail potential forms of organization involving the three companies, including regulatory approvals needed and Public Utility Holding Company Act requirements under various scenarios. A Booz-Allen Hamilton report entitled "Positioning MPC for Success in the Utility Business" explained how MPC should develop new wholesale and retail markets, and establish new relationships with WWP and IPC.

One of the important reasons for the emphasis on WWP and IPC was the low variable costs of power production exhibited by them. In early 1988 McKinsey and Company made an oral presentation entitled "Assessing the Economic Benefits of Closer Coordination." This followed a presentation made to the three companies' Chief Executive Officers, which was entitled "Developing a Joint Operating Agreement." Subsequent to these presentations, a team of professionals from all three companies (WIM) was assembled to decide uniform forecasting methodology, update

WIM load and resource forecasts, develop an economic model of future WIM resources, analyze pooling savings under various scenarios, evaluate reserve margins and maintenance coordination, assess benefits of long term joint generation investment, determine resource blocks available for sale "off system" under pooled and individual generation scenarios, survey WIM marketing staffs to estimate price premiums and nonprice benefits of integrated "off system" sales, analyze economic benefits under current load and resource assumptions, assess Western Systems Coordinating Council (WSCC) supply and demand as it relates to integrated "off system" marketing, evaluate

> major transmission paths and constraints to integrated "off system" sales, assess the WIM competitive situation under multiple macroeconomic scenarios, and other relevant matters.
>
> Various conclusions were reached as a result of these studies. Staff interviews of MPC management during 1988 led to the conclusion that the investigation of WIM business relationships had been put on hold. However, prefiled testimony in Docket No. 90.6.39 suggests that there have been significant, recent power transactions among the WIM group.
>
> These include a substantial intermediate term power purchase by MPC from IPC, a substantial long term seasonal power exchange between IPC and MPC, a substantial intermediate term power sale from MPC to WWP and a MPC/WWP transmission agreement, which facilitated MPC's sale of power from Colstrip Unit 4. At this juncture the Commission has no opinion about the propriety of the transactions and relationships between MPC, IPC and WWP. It is of the opinion, however, that prefiled testimony should provide sufficient background information about the status of the WIM effort. If such effort continues to be pursued, either formally or informally, the Commission would appreciate a complete explanation of how it might relate to existing MPC power transactions, and how it will affect future MPC power transactions, both in a general and a specific sense. Because of the large dollar magnitude of such power transactions and their potential effect on ratepayers, the Commission expects the explanations and descriptions to be very complete.

208. Mr. Pascoe's testimony indicates that three companies, Washington Water Power, Idaho Power, and Montana Power (WIM), conducted studies in 1987 and 1988 to determine the economic benefits available from closer coordination of the bulk power activities of the three companies. The results of these studies were presented to the management of the three companies by

McKinsey & Company in early 1988. The consultants noted that the benefits of jointly dispatching the resources of the three companies would be insignificant because the benefits of economic dispatch were already being captured by participation of the three companies in the Intercompany Pool (ICP). McKinsey's presentation did note that potential benefits might be produced by joint resource planning, joint off-system marketing, and joint development of new generation ;~ and transmission projects to serve regional needs. The three companies elected not to pursue WIM because there were no immediate benefits.

209. There are five power transactions amongst the WIM group. The first transaction is a ten-year seasonal exchange between MPC and Idaho Power. Under this contract MPC receives 50 MW of power on all hours for a 90-day period from November 15 through February 12. Idaho Power receives 75 average MW of power for 60 consecutive days of its choosing between June 15 and September 12. MPC can shape the hourly deliveries of the 75 average MW to Idaho Power so that the deliveries do not exceed 50 MW on peak hours. The Idaho Exchange allows both companies to capture seasonal diversity benefits because MPC's peak loads occur in the winter while Idaho is a summer-peaking utility.

210. The second transaction is a firm purchase from Idaho Power beginning in December 1990 and concluding in March 1996. Under this contract MPC receives 75 MW of firm power on all hours from April through September.

211. The third transaction is a four year (1991-1994) firm energy sale to Washington Water Power (WWP). Under this contract, MPC will sell about 315,000 MWH to WWP in 1991, 1992 and 1993 and about 235,000 MWH in 1994. Roughly 80 percent of this energy will be delivered during off-peak hours in the fall and winter, with the balance to be delivered during on-peak hours in the fall.

MPC's system, which has a large base-load thermal component, produces surplus firm power during off-peak periods. WWP, on the other hand, is a hydro-based utility and can use this off-peak power.

212. The fourth transaction is a contract with WWP to provide firm transmission service for the CS4LMD sale to LADWP. This contract was required by LADWP's insistence that the sale be made on a firm transmission path and BPA's inability to provide a firm path through western Montana because of prior commitments to the Utility Division, the other Colstrip partners and Basin Electric.

213. The fifth transaction is a contract with WWP to provide nonfirm wheeling service for the CS4LMD sale to Puget. The Puget sale is being delivered on nonfirm transmission until a firm path becomes available. Originally, CS4LMD intended to purchase this nonfirm transmission service from BPA; however, WWP approached MPC expressing an interest in providing this service. Each of these transactions, according to MPC, would have been identified and completed if the WIM studies had never taken place. (Exh. MPG-18, pp. 41-46)

214. MCC witness Mr. Clark indicated that the seasonal exchange between MPC and Idaho Power has been included in MPC's loads and resources since 1988 and has never been challenged by any party. The new firm power purchase from Idaho that began in December 1990 is being actively scrutinized in this Docket by the MCC. The third transaction is the sale of firm energy by MPC to WWP. MPC has linked this sale of energy to the purchase of capacity (and the associated energy) from Idaho. The fourth and fifth transactions are related to the transmission of CS4LMD power. There is no indication in Mr. Pascoe's testimony as to why CS4LMD opted for WWP over BPA for the non-firm transmission path for the Puget sale. Mr. Clark asserts that so long as the prices

and terms are equivalent, as Mr. Pascoe has stated, and the service is needed, ratepayers should be neutral. Additionally, these transactions are not part of the electric utility. (Exh. MCC-5,
pp. 3-7)

215. Mr. Gannon's confidential testimony, Exh. MPC-7, provides further background on activities within the WIM group, some of which are very recent.

216. Although the Commission is curious about this matter, neither it, nor any of the parties (apparently), have the resources to investigate it further, at least for purposes of this Order. The Commission urges MPC, however, to carefully avoid any activities which would cause it to be in conflict with State or Federal antitrust or holding company law. Naturally, MPC is of the opinion that this is presently the case, and the Commission does not have reason to disagree. Because the Commission is responsible for regulatory oversight, and because of Mr. Clark's recommendation that the Commission should continue investigating in this area, the Commission directs MPC to immediately commence filing thorough quarterly reports which detail all WIM activities.

CONSERVATION AMORTIZATION

217. MPC is again recommending a ten-year amortization period for both electric and gas conservation expenditures. Mr. Pederson noted that the recommendation and the reasons for it are consistent with the MPC response to the PSC Notice of Inquiry, Docket No. 90.1.3.

218. At the hearing, staff asked MCC witness Mr. Clark if he agreed with Mr. Pederson's recommendation or if he favored the existing amortization period of 15 years:

My testimony in Docket No. 88.6.15 recommended that conservation expenditures be amortized over the estimated useful lives of those projects, which, at that time, the Company was estimating, if memory is correct, from 20 to 70 years, and that was my recommendation in that docket. I still support that testimony. The 15-year period that was ultimately ordered by the Commission in Docket No. 88.6.15, personally, I found as an acceptable compromise at that time, but if I had to seriously argue the issue, I would still argue for amortization over the life of the facilities. (Tr. pp. 490-491)

219. MPC made the suggestion that the comments from Docket No. 90.1.3 as they relate to the amortization period be incorporated into the record in this Docket. Both MCC and staff agreed to that proposal.

220. From an accounting perspective, the matching concept would provide for amortization of conservation expenditures over the useful life of those assets. The Commission is very interested in the proper development of conservation in the MPC service territory. As a result, the Commission finds that there is a sound policy reason to alter its previous position on the amortization of conservation expenditures. The Commission will accept the 10-year amortization period recommended by MPC. This change from the 15year amortization approved in Docket No. 88.6.15 is being made to encourage MPC to make the proper investments in cost effective conservation. The determination of whether conservation is cost effective should be made based on the expected payback of each conservation measure. Given that the amortization period is now being set at ten years, projects which have a payback of more than ten years will not be considered cost effective.

221. Although the Commission finds that the amortization period should be reduced from fifteen years to ten years, there is still

a need to closely monitor the investments which will be made in conservation measures. The Commission directs MPC to maintain detailed accounting records which show amounts invested, the dates placed in service, the estimated life of the assets, the amount of energy saved and the expected payback period. The Commission is well aware of the difficulty of collecting data on energy savings from conservation, but without such data it will be impossible to measure the success of MPC's conservation programs. Success in measuring the effects of conservation will ensure that future decisions on conservation are made based on sound evidence.

PRELIMINARY INVESTIGATION & SURVEY - CARTER FERRY & HAWSER

222. In Docket No. 88.6.15 MPC filed for recovery of preliminary investigation and survey expenses for Salem, Carter Ferry, Buffalo Rapids and Hauser. All of the above are hydro projects with the exception of Salem. In Order No. 5360d the Commission eliminated expenses in the following amounts:

Salem	$1,867,295
Carter Ferry	$225,627
Buffalo Rapids	$45,135
Hauser	$121,406

MPC filed a Motion for Reconsideration for Salem, Carter Ferry and Hauser. On November 27, 1989, the Commission issued Order No. 5360e, which was an order on the various Motions for Reconsideration. The Commission denied the Motion for Reconsideration on Salem, Carter Ferry and Hauser. However, the Commission did state with respect to Hauser that it was anxious to have MPC further explain its position. MPC was invited to again petition the Commission on this question.

223. In this Docket, MPC witnesses Robert Periman and John Leland presented testimony on Carter Ferry and Hauser. Mr. Periman described the costs incurred in the preliminary investigation and

survey of the potential Hauser hydroelectric upgrade and the Carter Ferry hydroelectric site. Mr. Leland explained why these costs were part of prudent resource planning and should be recoverable in rates. MPC is proposing to amortize the costs for Hauser and Carter Ferry over a period of five years. The amortization of the Hauser Capacity Study is $121,406, and the amortization for Carter Ferry is $203,885.

224. MCC recommends removing the amortization expenses related to the Hauser and Carter Ferry preliminary investigations and surveys. Mr. Clark notes that in the case of Carter Ferry he argued in Docket No. 88.6.15 that the plant had not yet been canceled and that it was premature to even consider the amortization of those costs. As to Hauser, MCC argued that since no used and useful facilities had been developed at the site, and none were going to be, ratepayers ought not be responsible for the return of this capital to the Company. Mr. Clark stated that the Commission has considered and rejected the argument advanced by John Leland that the inclusion of these costs in the revenue requirement is due to the need to develop a least cost resource plan.

225. The Company stated that its reading of Order No. 5360e was that the Commission invited the Company to revisit the question of whether it is appropriate to allow recovery of certain costs which are still in the nature of "feasibility study" costs, but which relate to specific resources as opposed to more general feasibility studies. Mr. Gannon feels it is appropriate to allow recovery of initial feasibility costs for specific sites, as it encourages "robust" resource planning.

226. MPC has filed again in this Docket for recovery of feasibility study costs related to the Carter Ferry project. The Commission denied the Company's request to amortize these costs in

Order Nos. 5360d and 5360e. After a review of the evidence in this Docket the Commission finds no reason to change those decisions. No new evidence presented by MPC in this Docket indicates that those costs should be paid for by MPC's customers.

227. With respect to the Hauser feasibility costs, the Commission finds that these costs relate to a project which was stopped due to environmental impacts which were judged to be unacceptable. The Commission finds that the costs associated with the Hauser upgrade study will be allowed to be amortized over the requested five-year period. This ruling is made in an attempt to recognize the nature of resource planning as it related to this project. Although the project was not completed and put into service, the feasibility studies represent an effort by MPC to examine the possibility of increasing the output of an existing hydro facility. As such, the Commission finds that this specific effort merits inclusion in rates.

228. However, the Commission wishes to be clearly understood on the overall issue of preliminary investigation and survey expenses. The Commission does not intend to allow recovery of all such expenses in the future in the name of "robust resource planning" as requested by MPC. This applies specifically to studies of hydro projects. While the Commission is making a decision to allow the amortization of the Hauser costs, the Company should be very careful with regard to future hydro studies. Environmental concerns are a serious matter and should from the start be factored into a decision on whether to begin feasibility studies on hydro projects. The Commission approves the five year amortization of the Hauser preliminary investigation and survey costs in the amount of $121,406.

REFUNDS AND SETTLEMENTS

229. In Docket No. 86.11.62 (9), the issue of BPA refunds and medical insurance refunds, each with a dollar value of approximately $2 million, was reserved for discussion in the next general rate case. In Docket No. 88.6.15, Mr. Pederson addressed this matter in his direct testimony and recommended that the Commission should not reflect the refunds in rates on the basis that they were not significant enough to be included. (Exh. MPC33, p. 20) He also said that if it is determined to be proper to include such items, then a policy should be established so that similar rate treatment was afforded refunds and payments in the future. (Exh. MPG-33, pp. 20-21)

230. The Commission found that those refunds, totalling about $4 million, should not be reflected in MPC's rates in Docket No. 88.6.15. However, the Commission indicated that the matter required further exploration to determine the proper ratemaking treatment of refunds. The Commission requested that MPC and MCC provide testimony giving observations and recommendations on refunds in the next MPC general rate case (FOF 478, Order No. 5360d). No testimony on the ratemaking treatment of refunds was initially filed by either MPC or MCC in this Docket.

231. In Docket No. 89.12.53 (an MPC Gas Tracker), Interim Order No. 5454, the Commission allowed the costs of two gas cost disagreement settlements. The first with the Blackfeet Indian Tribe was settled for $427,500 and the second with the Department of State Lands for $160,946. In that Interim Order the Commission indicated that it was committed to development of a policy for the proper ratemaking treatment of refunds and settlements in MPC's next general rate filing.

232. In Docket No. 90.12.84 (an MPC Gas Tracker), Interim Order No. 5528, the Commission allowed a gas cost disagreement settlement with Northern Montana Gas Company in the amount of

$710,438. Again, the Commission indicated that it was committed to development of a policy for the proper ratemaking treatment of refunds and settlements in MPC's next general rate filing.
233. On January 28, 1991, the Commission issued Order No. 5484h which asked all parties to file comments on a policy dealing with the proper ratemaking treatment of refunds and settlements. Comments were received from MPC and MCC.

234. Mr. Pederson indicated that MPC has instituted a procedure for tracking refunds and settlements that exceed $100,000. According to Mr. Pederson, gas cost refunds and settlements should receive different treatment than other refunds and settlements. He argues that these types of refunds and settlements are properly accounted for as gas costs. When there are significant items, MPC tries to point them out in the next gas tracker. Such payments or refunds are either included in the balance to be recovered from customers, paid to customers over the
ensuing year, or set aside separately and amortized over a longer period.

235. MPC indicated that the proper way to deal with this issue is either by establishing policy through use of a Notice of Inquiry or to initiate a rulemaking, preceded by an informal conference of interested parties. A clear definition of what constitutes a refund or settlement needs to be established. It will be necessary to define what amount is significant. Accounting guidance should be provided to utilities, and the mechanics of how and when a rate change would be put in place would have to be established.

236. Mr. Clark indicated in his supplemental testimony that it would be impossible to craft a rule that could determine what is "allowable" for ratemaking purposes in all instances. Instead, he noted that this question has to be dealt with on a case by case basis. Deferred accounting for these items should not be

permitted. For accounting purposes, when a refund or settlement occurs, the prescribed amortization should begin at that time. Finally, Mr. Clark recommends that the pass-through of settlements utilizing the gas tracker should cease.

237. The Commission agrees with the final recommendation of Mr. Clark. From this time forward, settlements of gas cost disagreements will no longer be allowed to flow-through the gas tracker. As to the proper treatment of refunds and settlements, both parties indicate that a Notice of Inquiry should be issued to take comments from the various companies and intervenors. The 1 ' Commission agrees that this is a sensible way to set policy concerning the proper ratemaking treatment of refunds and settlements. At the conclusion of this Docket, the Commission will consider the proper timing and structure of a Notice of Inquiry or other procedure to establish the correct policy with regard to refunds and settlements.

RESEARCH AND DEVELOPMENT

238. In Order No. 5484h, the Commission invited comments from parties on the appropriate level of research and development (R&D) expenses which should be allowed in rates. If the parties felt that additional R&D was needed, the order asked how much should-be allowed and what projects should be funded. The Commission also asked who would be responsible for selecting and monitoring the projects, what should the ceiling be in terms of expenditures, and should R&D funds be earmarked and used to reduce rates in the next year if not expended? Parties were asked if they foresaw MPC engaging in independent R&D, or joining in other existing programs. Finally, if ratepayer funded R&D results in significant commercial applications, should the profits flow to the ratepayers? Comments on R&D were received from MPC, MCC and HRC.

239. Mr. Gannon stated that MPC believes that its current policy of funding electric R&D through the electric utility industry's R&D arm, the Electric Power Research Institute (EPRI), is appropriate. On the gas side, MPC belongs to and supports the American Gas Association (AGA) which does gas R&D. According to

Mr. Gannon, the costs of conducting MPC's own effective R&D effort would likely be prohibitive. MPC indicated that the appropriate level of R&D expense for the Company is the amount of dues paid to EPRI plus those expense amounts required to continue to have MPC employees monitor that effort as well as other R&D, especially MHD research.

240. At the hearing, staff asked Mr. Gannon whether the Company had a position on whether or not expenses that were authorized for R&D should be earmarked for R&D; and if those expenses were not used for R&D, should they be returned to the ratepayers? Mr. Gannon answered:

> I don't have a problem from a policy standpoint that these should be earmarked or can be earmarked, or more particularly that they shouldn't be used for some other part of the business. (Tr. p. 67)

241. Western Energy is building a demonstration coal conversion plant at the Rosebud mine in Colstrip with the NRG group which is a nonregulated subsidiary of Northern States Power Company. Mr. Gannon indicated that this project would not constitute R&D for the utility since it will be developed by Western Energy.

242. Staff asked Mr. Gannon at the hearing how relatively successful R&D efforts that have been funded by ratepayers should be treated in the ratemaking process. Mr. Gannon indicated:

If it can be shown, and I'm not suggesting that it can't, that customer money was used and has come to fruition in some project, I'm sure that the customers should be given credit for whatever share of the investment that they made. There should be some mechanism in place that would recognize the customers' investment, if something comes to fruition. (Tr. p. 68)

243. Mr. Clark indicated that no cap on R&D expense should be put into place at this time. Earmarking funds for any expenditure provides a "tracking" provision for the expense and should not be implemented. Profits from the commercial application of R&D projects that were funded by ratepayers should flow to the ratepayers.

244. Dr. Power, the HRC witness, advocates that reasonable R&D efforts aimed at "proving up" or eliminating particular potential resources that do not immediately produce energy savings are not only acceptable but expected. It should be assured that those expenditures will be recoverable not upon a showing that they are cost effective, but upon a showing that they are yielding valuable information that is being productively incorporated into least cost planning.

245. The Commission finds that the current level of R&D expense is appropriate at the present time. MPC contributes to EPRI which does electric research and to the AGA which does gas research. Mr. Gannon stated clearly in his testimony that it would likely be prohibitive for MPC to fund its own research projects. The Commission finds no reason to change the level of R&D expense in this Docket. The comments by Dr. Power go to the support of a least cost planning effort. The Commission is involved in a least cost planning docket at the present time. Costs associated with least cost planning will be examined the same as other expense items in the ratemaking process.

FIBER OPTIC GROUND (FOG) WIRE

246. Commission Order No. 5484h identified agreements among MPC, AT&T and Telecommunications Resources Inc. (TRI) for the deployment of a fiber optic communications line from Thompson Falls to Billings across MPC's electric transmission system. TRI is an unregulated MPC affiliate. The Commission invited parties to comment on whether the agreements provide fair compensation and adequate safeguards for the use of utility property and employees. The Commission also invited testimony on the appropriate ratemaking treatment for associated revenues and expenses in the determination of revenue requirements in this proceeding.

247. The Commission received testimony from MPC and MCC on this issue. MPC witness Mr. Gannon explained that TRI owns the FOG Wire and leases it to AT&T. MPC received a $600,000 up-front payment (less costs to upgrade the transmission system) and free use of 48 microwave communication channels as compensation. The S600,000 compensation is based on double the pole attachment rates charged to cable TV companies. The 48 microwave channels allowed the Company to defer until 1995 an upgrade to its own microwave system. Finally, MPC will be reimbursed 20 percent of the normal maintenance costs for that part of the electric transmission system

248. Mr. Gannon stated that MPC's responsibility is to provide structures only and is not responsible for the FOG Wire operation and maintenance. Those risks and responsibilities are left to TRI. Mr. Gannon claimed it is doubtful the project would have occurred without TRI because the electric utility does not have the resources to seek out such projects.

249. It was pointed out during the hearing that 45 other utilities had engaged in similar FOG Wire projects. When asked if these

other utilities had subsidiaries similar to TRI engaged in these projects, Mr. Gannon indicated the possibility to be doubtful (Tr. pp. 60-61)

250. When asked if MPC had done an independent determination of the value of its rights-of-way, Mr. Gannon indicated the Company had not done so. (Tr. p. 75) During the hearing Mr. Gannon discussed MPC's rights-of-way along its transmission system:

> We had right-of-way easements of three types, as I said. One of them was very clear, granted a right to add telecommunications equipment. Another kind did not have any right whatsoever for telecommunications equipment. As a matter of fact, in these easements the telecommunications language was x'd out; and there was another type of easement that was in between. These easements said "telephone." There was a case from Kansas on the language that the Williams Bros. took up to their Supreme Court looking at right-of-way language to see how broadly it could be interpreted to allow FOG Wire applications, and it was a rather liberal decision.
> We, in the utility, weren't comfortable with the easement situation that I have just explained and said, AT&T, TRI, you get whatever additional rights-of-way you might need, and that was one of, what I thought, the very severe risks that they had, particularly along the Flathead Indian Reservation. So they went out and did whatever they had to do to get comfortable with the rights-of-way, and they then went and did that.
>
> We basically said, If we have the rights-of-way that authorizes what you want to do, then fine; but if we don't, then you better get it. And they convinced themselves that they had it. They paid a lot of money for it. (Tr. pp. 74-75)

251. Mr. Gannon's-explanation of the three different types of MPC-owned rights-of-way is informative, but does not excuse the Company from conducting some type of an independent analysis of the value of its rights-of-way to the project. Common sense suggests that the Company would need to have an idea of the value

of its property in order to negotiate reasonable compensation for use of such property.

252. MCC witness Mr. Clark testified that there is not enough information at this time to determine whether the utility has been fairly compensated. Mr. Clark stated that the utility should attempt to maximize its revenues from such transactions. Due to the fact that TRI received approximately $25,500,000, which is significantly more than the utility received, Mr. Clark believes the utility profit potential could have been captured by TRI. He explained that without the existing transmission system, it would have been necessary to acquire right-of-way and construct a system from the ground up, potentially rendering the project uneconomic. "What creates the opportunity is the utility facilities, not the corporate structure." (Exh. MCC-5, p. 20)

253. Mr. Clark recommends that the Commission initially reflect for ratemaking purposes the compensation actually received. Because there is not enough information to determine whether the Company was fairly compensated, he believes it should be explicitly reserved for future review.

254. Both MPC and MCC support reflecting the $600,000 FOG Wire revenues over either the 25-year life of the contract or alternatively over a shorter 5-year period, with the unreflected balance as rate base offset. The Commission finds a 5-year amortization to be appropriate resulting in increased revenues of $120,000 with an average rate base offset for the amortization period of $183,967.

255. Concerning the finality of this decision, the Commission agrees with Mr. Clark; there is insufficient information on the record to draw final conclusions about the reasonableness of MPC's compensation. This issue will again be visited in MPC's next

general electric rate case. At that time, the Company will be required to demonstrate that reasonable compensation was received.

COLSTRIP COMPUTER ALLOCATIONS

256. In Order No. 5484h, the Commission expressed concern over the magnitude of 1989 ($247,407) and 1990 ($503,035) decreases in computer costs charged to the Colstrip partners. Due to this concern, the Commission requested parties to address the reasonableness of MPC's computer cost allocation procedures and methods. Specifically, parties were asked to address the question of whether or not MPC's procedures achieve a fair balance of directly assigned and usage dependent factors.

257. MPC witness Mr. Miller testified that he believes the Company's current methods fairly allocate computer costs based totally on usage. Mr. Miller explained that-the utility usage increased significantly due to the new Customer Information System (CIS), and that the increase resulted in a lower rate per unit of use. Thus, total charges to the Colstrip partners decreased even though the~ir usage increased. He added that bringing up the CIS was an unusual occurrence which caused aberrations to occur in the charges to Colstrip partners, and that future charges to Colstrip for computer usage should be fairly constant.

258. MCC witness Mr. Clark believes that MPC's method could result in ratepayers bearing additional costs if outside usage drops. He did find the Company's explanation for decreased charges to be plausible. Mr. Clark testified that he is concerned with MPC's usage method when, in fact, almost all of these costs are fixed. He recommends MPC use a method that recognizes that most of the costs are fixed and that assigns a fixed amount of costs to all users. Mr. Clark generally described two possible methods to accomplish his recommendation.

259. Responding to Mr. Clark, Mr. Miller stated that the current method gives the Company flexibility to respond if, as has

occurred, amounts billed are inappropriate. Mr. Miller believes the current method has resulted in appropriate charges to the Colstrip partners. It has been audited and accepted by the other partners and any changes must be developed in a manner acceptable to the partners.

260. The Commission finds that it may be premature to require MPC to alter its current billing format. The Company has stated that future charges to the Colstrip partners should be fairly constant. If this is true, a revised method would provide no clear benefits to the Colstrip partners, MPC or its customers. The Commission does not wish to cause MPC to incur costs to revamp the computer billing methods if marginal or no benefits will occur.

261. However, MPC is on notice that the Commission remains concerned with this matter. The computer charges will be monitored periodically by the Commission staff to ensure that the Colstrip partners are paying a fairly constant amount for usage of MPC's computer facilities.

UNCONTESTED ISSUES

262. MPC and MCC agreed on a number of the revenue requirement issues in this Docket. In adopting these issues, the Commission will provide a brief description of the issue and its effect on revenues and expenses.

Coal Costs

263. In the Company's original filing the amount of coal expense was $33,528,290. Mr. Pascoe indicated that the original

filing contained estimated fuel costs which would be updated with actual costs later in this proceeding. In rebuttal testimony the Company provided an update to the amount of coal expense in the amount of $34,011,892. In the third update to MCC Data Request No. 140 (received by the Commission on April 11, 1991), the Company again updated the amount of coal expense. The amount in that response was $33,889,957. All of these amounts for coal expense exclude labor handling for the coal in the amount of $863,763. That amount must be included in each of the three numbers shown above to arrive at the total amount of coal expense in this Docket.

264. MCC witness Mr. Clark, in his prefiled testimony, recommended coal expense in the amount of $27,077,863, which 0 excludes labor handling for the coal. Mr. Clark used the first response to MCC Data Request No. 140 to prepare his adjustment to coal expenses. In this response there were accounting worksheets showing coal burned and coal expenses booked each month from January 1989 through August 1990 for each thermal plant.

265. In the Company's rebuttal testimony Mr. Pascoe noted that not all of the expenses associated with the coal burned in August were booked in that month. No royalty expenses were booked for Corette or Colstrip 3&4 in August. In addition, a credit was booked against Colstrip 1&2 expenses to reflect settlement of a contract dispute involving 1988 coal costs. In summation, MPC did not agree with this MCC coal expense adjustment because use of the August 1990, prices would result in coal costs which did not result in normal values. At the hearing Mr. Clark accepted the Company's position on this issue and agreed that the third update to MCC Data Request No. 140 should be used in this Docket. This agreement increases the amount of coal expense from Mr. Clark's original recommendation by X$6,812,094.

Corette Gas Expense

266. In its original filing MPC had projected a significant increase in the cost of gas at Corette (from $1.344 per Mcf to $2.00 per Mcf) because of the necessity to replace Heart Mountain gas with a more expensive supply. In its response to MCC Data Request No. 142, the Company stated:

> ...new expected gas cost for year end 1990 is likely to be very nearly the same as was the actual gas cost at the end of 1989...

MCC recommended that the gas at Corette be repriced at $1.34374 per Mcf. This reduced the cost of gas at Corette in the test year by $235,631. In his rebuttal testimony at page 5, Mr. Pascoe stated that actual experience showed that significant quantities of natural gas from sources other than Heart Mountain were not needed in 1990. As a result the Company agreed with Mr. Clark's proposed adjustment to reduce the cost of gas at Corette by $235,631.

Uncollectible Expenses

267. For both the natural gas and electric utilities, MPC calculated actual 1989 uncollectible expenses as a percent of residential class and commercial class revenues. This percentage applied to residential and commercial revenues and was used to determine the level of uncollectible expense in the test year.

268. MCC noted that 1989 actual data produced the highest level of uncollectible expense that MPC had experienced since at least 1985. Mr. Clark proposed to use a weighted average percentage based upon actual results from 1985 through 1989.

269. After reviewing information for recent years on uncollectible expense, MPC agreed that because the expense is up one year and down the next, an average of five years of data should be used. MPC did modify the five year period, choosing to use the period 1986-1990 instead of 1985-1989. At the hearing Mr. Clark stated:

> In its rebuttal case, the Company also used a five-year history but because they had an opportunity to include a more recent five-year period, they did so, and it's my view that that's acceptable for this case. (Tr. p. 491)

This adjustment results in a decrease for uncollectible expense for the gas utility of $82,822 and for the electric utility of $238,076.

FICA Tax

270. Mr. Clark noted that MPC had allocated FICA tax between the natural gas and electric utility based on an "administrative and general" split. This split resulted in an excess level of FICA tax expense assigned to the gas utility. Mr. Clark recommends that the gas utility's FICA tax expense be reduced by $56,173. The reallocation of FICA tax expense caused an increase in the electric utility's FICA tax expense of $55,328. MPC accepted the allocation between electric and natural gas that MCC recommended.

Federal Unemployment Tax

271. Mr. Clark originally proposed to reduce Federal unemployment tax expense to reflect tax rates provided in response to MCC Data Request 35(c). When it was discovered

that the tax rates provided were in error, Mr. Clark agreed that MPC's originally filed expense level was appropriate.

CIS/FMS Stipulation

272. In Order No. 5360d, the Commission disallowed all costs related to CIS (Customer Information System) and FMS (Financial Management System). In Order No. 5360e, the Commission reconsidered its action with regard to CIS and FMS and gave MPC the opportunity to present additional evidence on the appropriateness of including the costs of CIS and FMS in rates. On March 15, 1990, MPC prefiled the supplemental testimony of Jerrold P. Pederson and Wilhelmus C. Verbael on the issue of CIS and FMS. On July 25, 1990, MCC and MPC filed a stipulation which settled the CIS/FMS issues in Docket No. 88.6.15. On December 11, 1990, the Commission issued Order No. 5360f, which approved the CIS/FMS stipulation. The order was adopted by a vote of 4-1, with Commissioner Driscoll voting to dissent.

273. For the natural gas utility, including the stipulation decreases the depreciation expense from the original filing by $105,176 and decreases amortization expense by $44,429. Rate base for the natural gas utility is reduced by $59,275. For the electric utility the change to the rate base from the stipulation is a decrease of $386,105. In terms of expenses, the stipulation reduces the electric utility depreciation expenses by $333,059 and amortization expenses by $219,496.

Steam Plant Adjustment

274. After the initial filing in this Docket, MPC reviewed its methodology for calculating the variable steam plant O&M expenses which are considered in making dispatching

decisions. As a result of this review, the methodology was revised to include only those steam plant O&M expenses which vary with short-term changes in generation. This change in methodology resulted in a reduction to steam plant O&M expenses of $110,517. MCC witness Mr. Clark accepted this revision in his testimony.

Wheeling Revenues and Expenses

275. In Exh. MPG-17, pp. 40 and 41, MPC witness Mr. Pascoe discussed changes in wheeling revenues and expenses. Since January 1986 MPC had been wheeling up to 185 MW of power between its Crossover and Broadview substations on a firm basis under a contract with the Western Area Power Administration (WAPA). The sale from Basin Electric Power Cooperative to the Central Valley Project was expected to end in October 1990. As a result MPC reduced wheeling revenues by $1,387,902.

276. The termination of the Basin sale to the Central Valley Project also affected the Company's wheeling expenses. In order to provide a wheeling path for the Basin sale between the Broadview and Garrison substations, BPA and four of the five participants in the Colstrip 3&4 project (MPC, Puget Sound Power & Light, Portland General Electric, and Washington Water Power) agreed to an exchange of transmission rights. Under this arrangement BPA received 185 MW of transmission capacity on the transmission facilities owned by the Colstrip 3&4 partners between Broadview and Townsend. In exchange, the four Colstrip partners were relieved of the cost obligation for 185 MW of capacity in BPA's Montana Intertie from Townsend to Garrison. This relief was in the form of a credit on each participating utility's monthly bills for use of the

Montana Intertie. MPC's share of those credits was $903,432 in 1989. With the termination of the Basin sale, those credits were expected to be eliminated. To reflect this, MPC increased transmission expenses by $903,432.

277. MPC stated that with the termination of the Basin sale to the Central Valley Project, BPA would have adequate firm transmission capacity available to contract with CS4LMD to provide all of the transmission services required for CS4LMD's firm power sales to Puget Sound Power & Light and the City of Los Angeles. As a result, $908,802 of wheeling revenues from CS4LMD were removed from this Docket. Also, credits from Washington Water Power for wheeling power from CS4LMD to Washington Water Power were removed which increased wheeling expenses in the test year by $71,560.

278. In response to MCC Data Request No. 148, MPC indicated that these adjustments to wheeling revenues and expenses were not appropriate. Mr. Clark recommended that wheeling revenues be reduced by $372,490 instead of $2,296,704. MCC also recommended that wheeling expenses be reduced by $277,911 rather than increased by $974,992.

279. In its rebuttal testimony, MPC agreed with the adjustments made by Mr. Clark as a result of the response to MCC Data Request No. 148. On September 13, 1990, WAPA sent MPC a letter which indicated that Basin and the Central Valley Project had agreed to a one-year sale which would require 650,000 MWh to be wheeled from Crossover to Broadview. As a result of this update, MPC added $650,000 to the test year wheeling revenues. On October 1, 1990, BPA sent MPC a letter notifying MPC that because of ongoing discussions between BPA and Washington Water Power, BPA

would not be able to provide transmission capacity for any new firm wheeling contracts until March 1, 1991. No changes in Montana Intertie credits would occur before that date. Since that date is more than twelve months past the end of the test year, MPC added S903, 432 in Montana Intertie credits. MPC also increased wheeling revenues by $1,274,214 to reflect wheeling the CS4LMD sale to LADWP on an annualized basis. Finally, MPC included $277,911 in wheeling credits from WWP to reflect the impact of wheeling the CS4LMD sale to Puget on an annualized basis.

Prior Period Indirect Costs

280. In Interim Order Nos. 5484c and 5484d, the Commission determined that in order to comply with the Commission's findings in Docket No. 88.6.15, only the 1987 prior period adjustment should be allowed in the present case. When the Company was ordered to institute prospective rates in Docket No. 88.6.15, MPC included, as a part of the revenue requirement, the capitalization of these indirect costs as was ordered by the Commission. However, during 1988 the rates that were in place reflected the Company's capitalization policies. Therefore, if MPC is allowed to prospectively recoup the 1988 indirect costs through capitalization, the costs would be recovered twice from the 4' ratepayers. Mr. Clark proposed to make the interim treatment of prior period indirect costs permanent. This adjustment caused a reduction in the natural gas rate base of $578,585. The effect on natural gas depreciation expense is a decrease of $26,120. For the electric utility the rate base reduction is $2,120,632. The outcome of this adjustment on electric depreciation expense is a decrease of $124,050. The rate base decreases noted above are the change from MPC's original filing to MPC's rebuttal filing.

281. MPC witness Mr. Kindt, in his rebuttal testimony, stated that deferred income taxes related to the capitalized indirect costs should be added back to rate base as negative customer contributed capital and amortized over the life of the tax basis plant. The capitalized indirect costs were removed from rate base in the interim orders. With the removal of indirect costs from rate base, the ratepayer has no tax basis in assets to be depreciated. According to Mr. Kindt, the ratepayer is not entitled to the benefits of tax depreciation for assets in which he or she has no basis. The deferred income tax recognizes that this deduction results from a timing difference. The ratepayer has already received the benefit of the deduction for indirect costs as an operating expense in 1988 even though MPC was required to capitalize the cost for tax purposes. This change has been incorporated into the numbers shown above.

282. Staff asked Mr. Clark if he agreed with the comments of Mr. Kindt on the deferred tax issue related to prior period indirect costs. He answered:

> I think I do, yes. It's a matching problem. I guess I'm a little unclear as to why the adjustment is incomplete in the Interim Order. It's my understanding that the number was provided by the Company in the first place, but regardless, I think the deferred income tax treatment has to be consistent. (Tr. p. 492)

Electric and Common Plant Depreciation

283. MPC filed in Docket No. 90.3.17 a request to increase rates to reflect, among other things, proposed changes in

electric utility depreciation rates. MCC is a party to that proceeding. On January 22, 1991, the Commission approved a stipulation between MPC and MCC regarding depreciation rates for electric and common utility plant. (Docket No. 90.3.17, Order No. 5465c)

284. The Company's rebuttal filing in the instant proceeding included adjustments to properly reflect the approved electric and common utility depreciation rates. Those adjustments result in a decrease in depreciation expenses of $2,333,367 and an increase in rate base of $1,250,060.

INTEREST SYNCHRONIZATION

285. Mr. Clark of MCC calculated interest synchronization using the same procedure approved by the Commission in past decisions. He states that the interest deduction included in the income tax calculation should be the interest component of the return on rate base plus the interest used to finance construction work in progress plus the interest on customer deposits. Mr. Clark's proposed adjustment stems from his proposed rate base and MCC witness Dr. Smith's changes to the capital structure.

286. The Commission continues to approve the use of the interest synchronization adjustment to give recognition in current rates of the deduction of interest on construction borrowings. Since there are regular additions to rate base from construction, there is no reason to ignore interest which is currently deductible. Therefore, based on the approved level of rate base and cost of weighted debt capital in this proceeding, the Commission finds a

reduction in Federal Income Taxes in the amount of $905,189 and a reduction in Montana Corporation License Tax in the amount of $203,086 to reflect interest synchronization to be proper in this proceeding.

REVENUE REQUIREMENT

287. Based on the above Findings of Fact, the following table shows that an increase in MPC's annual electric revenues in the amount of $39,789,239 on a total company basis is necessary in order to provide the opportunity to earn an overall rate of return of 10.24 percent:

THE MONTANA POWER COMPANY - DOCKET 90.6.39
FINAL REVENUE REQUIREMENTS CHART - ELECTRIC
TO PRODUCE 10.24% RATE PF RETURN
TEST YEAR! DECEMBER 31, 1989

		(A) MPC Pro FORMA	(B) TOTAL ACCEPTED ADJUSTMENTS	(C) PSC APPROVED PRO FORMA	(D) INCREASE FOR 10.24% RETURN	(E) APPROVED TOTAL	
1							1
2	OPERATING REVENUE	$323,562,093	$8,374,105	$331,936,198	$39,789,239	$371,725,437	2
3							3
4							4
5	OPERATING REVENUE Deductions						5
6	TOTAL OPERATION & MAINTENANCE EXPENSES	195,093,123	- 404,865	194,688,258		194,688,258	6
7	DEPRECIATION EXPENSES	32,006,312	-2,457,417	29,548,895		29,548,895	7
8	AMORTIZATION OF COMPUTER SOFTWARE COSTS	196,173	4,896	201,069		201,069	8
9	AMORTIZATION OF COMPUTER SOFTWARE COSTS CIS & FMS			675,911	- 337,956	337,955	
10	AMORTIZATION OF KERR LICENSE COST	25,194	0	25,194		25,194	10

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AMORTIZATION OF KERR

	WILDLIFE STUDY	16,195	0	16,195		16,195	11
12	AMORTIZATION OF PLANT ACO, ADJ MILWAUKEE LINE	94,914	0	94,914		94,914	12
13	AMORTIZATION OF MPSC/FERC PLANT DIFFERENCE	1,458,187	0	-1,458,187		1,458,187	13
14	AMORTIZATION OF INVESTMENT TAX CREDIT-NET	-1,813,136	0	-1,813,136		-1,813,136	14
15	DEFERRED FEDERAL INCOME TAXES	-7,749,270	968,937	-6,780,333		-6,780,333	15
16	TAXES OTHER THAN INCOME TAXES	30,102,805	803,888	30,906,693	99,473	31,006,166	16
17	CORPORATE ENVIRONMENTAL TAX	55,535	5,153	60,688	44,256	104,944	17
18	FEDERAL INCOME TAXES - CURRENT	14,825,763	1,460,339	16,286,102	12,424,116	28,810,218	18
19	MONTANA CORPORATION LICENSE TAX	3,326,268	327,640	3,653,908	2,809,876	6,463,784	19
20		-----------	----------	------------	------------	-----------	
21	TOTAL OPERATING REVENUE DEDUCTIONS	$268,313,974	$ 370,615	$268,684,589	$15,477,721	$284,162,310	21
22							22
23							23
24	NET OPERATING INCOME	$ 55,248,119	$8,003,490	$63,251,609	$24,311,518	$87,563,127	24
25		==========	==========	===========	===========	==========	25
26							26
27	AVERAGE RATE BASE	$863,837,605	-$8,728,929	855,108,676		855,108,676	27
28		===========	===========	===========	===========	=========	28
29							29
30	RATE RETURN	6.40%		7.40%		10.24%	30
31		=====		=====		=====	31

THE MONTANA POWER COMPANY
COST OF SERVICE
REC SEPARATION STUDY
DOCKET 90.6.39 - ORDER CALCULATION
SCHEDULE 1 - COMPUTATION OF REQUIRED REVENUE INCREASE/DECREASE

		TOTAL ELECTRIC	REC WHOLESALE	MPSC JURISDICTION
1				
2	RATEBASE	855,108,675	36,877,897	818,230,778
3				
4	TOTAL WEIGHTED COST OF CAPITAL	10.24%	10.24%	10.24%
5				
6	RETURN ON RATE BASE	87,563,128	3,776,297	83,786,832
7				
8	NET OPERATING INCOME	83,251,604	3,807,127	59,444,477
9				
10	REQUIRED INCREMENTAL INCREASE/ DECREASE	24,311,524	(30,830)	24,342,355
11				
12	ADD:			
13	CORPORATE ENVIRONMENTAL TAX	44,256	(56)	44,312
14	MPSC TAX	63,663	(81)	63,744
15	CONSUMER COUNSEL TAX	35,810	(45)	35,856
16	ADDITIONAL FEDERAL INCOME TAX	12,524,119	(15,882)	12,540,001
17	ADDITIONAL STATE INCOME TAX	2,809,876	(3,563)	2,813,439
18				
19	TOTAL REVENUE INCREASE/DECREASE	39,789,284	50,458	39,839,707
20				

289. Many of the revenue requirement issues for the natural gas utility are common with those discussed in the electric utility section of this order. For example, uncollectible expenses, FICA taxes, Federal Unemployment taxes, interest synchronization, CIS/FMS and the lead/lag study philosophies are all common between the electric and gas utilities. There remains a handful of contested issues that relate only to the gas utility. These, along with the natural gas rate base, income statement and revenue change will be shown in this section of the Order.

Depreciation Adjustments

290. MPC proposes to adjust depreciation expenses for its natural gas utility properties. The adjustments are based on studies done by MPC witness Mr. James H. Aikman of Management Resources International (MRI), and are based on plant account values which existed at December 31, 1987. MPC witness Daniel Reardon also testified to certain of MPC's depreciation proposals.

291. Mr. Aikman's studies explain some of the background which underpins depreciation accruals and studies:

The development of appropriate book depreciation accrual rates is a subjective process; the primary consideration is life estimation. Some think that life analysis is the primary point. Certainly one should collect property history and analyze it to collect whatever "evidence" can be gleaned therefrom, but life estimation is not life - analysis.

One must recognize weaknesses and peculiarities in the life analysis employed, he must be generally aware of the equipment in the group analyzed; he must be aware of what the rest of the industry estimates for like equipment; and he must make every effort to get qualitative, first-hand input relative to the particular company and equipment under study.

The remaining life technique of computing depreciation accruals is a function of four variables; the plant investment, the book reserve, estimated net salvage, and the average remaining life of the group of assets. The average remaining life is a function of the age distribution of the assets, the average service life of the assets, and the survivor curve.

To help assure appropriate capital recovery involves periodic depreciation rate studies, such as this. The reason is utility property is not as static as one might think. The equipment, technology, life expectations, mortality patterns, salvage and removal costs, demands of the public all change. Periodic studies are made to detect such changes and to adjust the depreciation rates accordingly.

For some categories of property, particularly mass properties, statistical mortality studies of past retirement experience provide historical indications of the dispersion of retirements and of average service life, if there has been sufficient retirement activity over a reasonable period of time. Such indications can provide a guide as to what to expect in the future, but it should not be taken for granted that the future will mirror the past, especially when present policies, plans, or external circumstances which are different dictate otherwise. In such instances, as well as when reliable retirement experience is lacking, reliance must be placed upon informed judgment in the establishment of expected average service lives and accrual rates.

292. According to Mr. Aikman, the proposed depreciation rates and methods result in a reduction in annual depreciation accruals of approximately $530,000 when compared to the depreciation rates and methods which would exist if the 1982 depreciation rates were used. (Exhs. MPG-51, p. S-2, and MPG-52, p. S-2)

293. In response to MPC's natural gas depreciation proposals, Mr. Jacob Pous of Diversified Utility Consultants, Inc., filed testimony on behalf of MCC. Mr. Pous, on page 57 of Exh. MCC-9, states: "The adoption of all my various recommendations would result in a $1,018,806 reduction from the Company's requested level of $6,314,322 to my recommended level of $5,295,516 based on the year ended December 31, 1987."

294. Of the $1,018,806, it appears that $1,018,482 continues to be at issue after Mr. Aikman filed rebuttal Exh. MPG-39, as follows:

	Account	Description		MCC Adjustment	Explanation
Gas Storage Plant	2351.4	Other Structures		($1,240)	Life Adjustment
	2355.1	Meas. & Regulating Station Equip.		($3,160)	Life Adjustment
	2353.1	Field Lines		($8,009)	Salvage Adjustment
	2354.0	Compressor Station Equip.		($9,841)	Life Adjustment
Transm. Plant	2367.1	Mains		($269,076)	Life Adjustment
	2368.1	Compressor Station Equip.	**($318,444)**	($46,776)	Life Adjustment
	2368.2	Dehydration Equip.		(2,592)	Life Adjustment
Dist. Plant	2376.3	Mains, Plastic Pipe		($22.708)	Life/Salvage adjustment
	2381.0	Meters 8 Regulators		($28,035)	Life/Salvage Adjustment
General	2390.8	Structures, Multiple Uses		($4,625)	Life/Salvage Adjustment
Production Plant	2327-2329 2332-2337	Various		($151,963)	Salvage Adjustment Life Adjustment
Production Wells	2325 2330-2331	Various	($622,420)	($438,765)	Depreciation Method/Life Adjustment
Products	2340-2347	Various		($31,692)	Life Adjustment

Extraction Plant	
TOTAL	($1,018,482)

The Commission finds, for any account value not listed above and upon which Mr. Pous and Mr. Aikman disagree, that 50 percent of the difference be awarded to MPC, regardless of whether the difference is a positive or negative value.

295. Mr. Aikman performed studies on all of the corporate entities which comprise MPC's natural gas utilities. Mr. Pous presented testimony which pertains only to the Montana operations. The Commission approves Mr. Aikman's studies as they pertain to corporate entities for which Mr. Pous did not file testimony.

Account 2351.4 - Gas Storage Plant. Other Structures

296. MPC uses an average service life of 28 years and a mortality dispersion Iowa Curve of R1.0. MCC uses 32 years and R1.5.

297. Mr. Pous states: "The problem is that the Company's adjustment from the current twenty-five (25) year average service life to a twenty-eight (28) year average service life, given the fact that its own actuarial analysis indicated thirty-six (36) years as the shortest indicated average service life, does not seem to be adequate." (Exh. MCC-9, p. 26)

298. Mr. Aikman claims that Mr. Pous did not do an actuarial analysis on this account as he had claimed, but rather relied solely on Aikman evaluation notes. He claims that Mr. Pous does not have an adequate basis for his proposed 32 year life. (Exh. MPG-39, pp. 13-14)

Commission Discussion

299. The Commission finds that the MCC position stated above is a more credible compromise between the status quo (25 years) and

the shortest average service life indicated in the MPC analysis (36 years). It, therefore, adopts 32 years and R1.5 for this account.

Account 2355.1 - Gas Storage Plant. Measuring and Regulating Station Equipment

300. MPC uses an average service life of 22 years and a mortality dispersion Iowa Curve of S1.0. MCC uses 25 years and S1.0.

301. Mr. Pous performed actuarial analysis to support 25 years. Additionally, he states that the Company's mathematical curve-fitting approach shows 29 years, and its manual curve fitting approach shows 25 years. He states that MPC chose to ignore these findings because the presently used 22 years is close enough. (Exh. MCC-9, pp. 27-28)

302. Mr. Aikman suggests that his standard mode of operation (M.O.) is to make gradual movements from existing lives to lives indicated by new analysis. He suggests, as an example, that a movement of 10 percent of the difference may be appropriate. Therefore, in this case, where the difference is 3 years, or 25 years less 22 years, he suggests that .3 years is "too close to call," and proposes no adjustment upward. (Exh. MPG-39, p. 14)

Commission Discussion

303. The Commission finds that the MCC position is a more credible compromise between the status quo (22 years) and MPC's 25
or 29 year analysis. The Pous analysis reflects a 25-year life. Additionally, the Commission is not persuaded by Mr. Aikman's 10 percent M.O. On cross-examination by MCC Mr. Aikman stated:

Q. Mr. Aikman, you've performed depreciation studies for the Montana Power Company since at least 1977; is that right?

A. Yes;

Q. Page 14 of your testimony at line 19, you state that you have a standard mode of operation, or MO, in which you make moderate adjustments to average life estimates as time goes on and evidence indicates; is that correct?

A. Yes.

Q. In fact, you indicate that your MO is to adjust estimated average life by approximately 10 percent at a time; is that correct?

A. That's correct.

Q. Do you believe that this 10 percent limitation factor on modifying prior estimates is appropriate if there are specific facts and circumstances which have changed from the time that prior estimates were performed?

A. It is not an absolute. Yes, I would agree. (Tr. p. 836)

For these reasons, the Commission adopts the MCC position.

Account 2353.1 - Gas Storage Plant Field Lines

304. MPC proposes a 5 percent net negative salvage value, while MCC proposes 0 percent net salvage.

305. Mr. Pous suggests that historical retirement data do not exist on which an accurate estimate of future salvage values can be computed. He states: "...given the fact that these lines are small and there should not be any effort to remove them for scrap value or reuse would indicate that there should be relatively little cost involved in retiring these particular lines as they sit in the ground." (Exh. MCC-9, pp. 50-51)

306. Mr. Aikman specified that Mr. Pous did not do any independent salvage value analysis, and relies only on opinion. Mr. Aikman does not disagree with Mr. Pous' assertion that there is a lack of retirement data. He does opine, however, that MPC will incur some costs when it retires these facilities in place, such as line cutting, purging them of gas and securely capping them. (Exh. MPG-39, pp. 11-12)

Commission Discussion

307. The Commission finds Mr. Aikman's arguments to be persuasive: Abandonment of these lines will very likely require measures such as line cutting, purging them of gas, and capping the lines. Accordingly, the Commission adopts MPC's recommended negative salvage value.

Account 2354.0 - Gas Storage Plant. Compressor Station Equipment

308. MPC uses an average service life of 30 years and a mortality dispersion Iowa Curve of R2.0. The MCC uses 35 years and R2.5.

309. Mr. Pous states that MPC's service life for this account is based on judgment and a life analysis. Mr. Pous states that his study yielded a short survivor curve, but an average service life of about 40 years. This corresponds with MPC's proposed life for "gas rights" and "gas storage rights," which Mr. Aikman specifies as a proper gauge for this account. Mr. Pous thinks 35 years is conservative. (Exh. MCC-9, pp. 26-27)

310. MPC's Aikman states that MPC tried to obtain information from Mr. Pous about the 40 year life in his study, but received nothing. (Exh. MPG-39, p. 14)

Commission Discussion

311. It appears the parties misunderstood each other during the information exchange phase of the Docket with regard to information on this account. The Commission, however, did not receive an objection that MCC was unresponsive. Regardless of the misunderstanding, it appears that even some of Mr. Aikman's study for this account could plausibly be interpreted to support a life of longer than 30 years. This, coupled with Mr. Pous' study which concludes that this property has a 40-year life, suggests that a 35-year life and R2.5 Iowa curve is reasonable. The Commission, therefore, adopts the MCC recommendations.

Account 2367.1 - Transmission Plant. Mains

312. MPC uses an average service life of 50 years and a mortality dispersion Iowa Curve of R4.0. MCC uses 63 years and R4.0.

313. Mr. Pous relied on MPC's analysis and evaluation notes, evaluation notes from the 1982 study, his own analysis of historical data and future expectations. He states that MPC should have lengthened the life in 1982 to longer than 45 years, but it did not because it thought that gas fields would deplete relatively quickly. They (apparently) did not deplete as quickly as thought, and Mr. Pous thinks this nondepletion (in relative terms) trend will continue. He suggests that the 63 year proposed life is conservative, "but it appropriately represents what appears to be more than an emerging pattern of a longer service for this subaccount." (Exh. MCC-9, pp. 31-32)

314. Mr. Aikman, relying mainly on his previously explained M.O., thinks the increase in service life from 45 to 50 years is conservative and, therefore, justified. He also states that with the R4 dispersion pattern, some plant added in 1989 would not be retired until 2084 under Mr. Pous' recommendations, and 2064 with his own recommendations. (Exh. MPG-39, p. 15)

Commission Discussion

315. The following cross-examination of Mr. Aikman by the MCC appears to support Mr. Aikman's proposed life:

> Q. Why do you believe that your MO is appropriate for limiting the change to approximately 10 percent for this account when you didn't apply the same calculation in the last proceeding and specific facts and circumstances associated with the exhaustion of the gas reserves that you based your initial estimate on is no longer valid?

A. First, there are a lot of things that could be said in response to that. First of all, I don't think that my 50-year proposal at this point in- time is significantly different than that which was proposed in '82. If one were to look at the same parameter mentioned in the '82 and '76 notes, that of the gas reserves, I would think that we would find my 50-year projection not to be far off relative to that. Equally important and relative to the dissertation that you have just gone through, the survivors of this 1932 vintage, the fact that they are, say, 85 percent of the original placement, which apparently doesn't follow an R4 curve, doesn't disturb me, doesn't surprise me in the slightest. Frankly, it's a function of the fact that in the real world, you seldom find a curve, one curve and one life that will accurately fit every single vintage. (Tr. pp. 852-853)

On the other hand, cross-examination recorded on p. 843 of the transcript reflects the results of Mr. Aikman's actuarial analysis, which suggests a longer average life: 64 years, 69 years, and 93 years. If the middle of these values, i.e., 69 years, were concluded to be reasonable, it would indicate a life adjustment (from the existing 45 years) of 24 years. A conservative life adjustment would be one-half of 24, or 12 years plus 45 years. A 57-year average life is also at the middle point between the Pous and Aikman recommendations.

316. The Commission notes the fact that the 20-inch pipeline, which was the subject of much cross-examination pertaining to this account, was placed into service in 1932. (Tr. p. 873) It also notes that compressors for the 16-inch replacement are reflected in MPC's filing as providing service on and after September 1989, which

effectively completes the 16-inch replacement of the 20-inch line. These factors suggest that the 20-inch pipeline provided primary service for 57 years. The Commission is also aware, through its enforcement of pipeline safety statutes, that cathodic protection of the old 20-inch line was difficult and its outer coatings were inadequate. (see Exh. MPG-23, p. 3) Adequate coatings materially deter corrosion of newer pipelines. The Commission believes, therefore, that MPC's studies, which reflect lives significantly longer than 57 years, are probably quite accurate. It is only in the interests of moderation for this very material account ($74,213,863 at 12/31/87) that the Commission finds 57 years to be reasonable.

Account 2368.1 - Transmission Plant. Compressor Station Equipment

317. MPC uses an average service life of 33 and a mortality dispersion Iowa Curve of R3.0. MCC uses 42 years and R2.5.

318. Mr. Pous states that the 1982 study showed, by actuarial analysis, that 40-60 year lives were exhibited. Following its M.O., MPC chose to embody 10 percent of the difference between 30 and 33 years. The 1982 evaluation notes state that "...establishment of trend in the next study might call for further revisions." The present study evaluation notes specify that good fits were obtained from actuarial analysis which resulted in 60-80 year average lives. Mr. Aikman stated that his own results were not reasonable, and decided, based on judgment, that the existing 33 years is reasonable. Mr. Pous finds this to be improper, and suggests a 42 year average life. He also suggests an R2.5 curve, because it has a better fit than MPC's 3.0 curve. He states that 42 years is conservative, compared to other gas utilities. (Exh. MCC-9, pp. 33-35)

319. Mr. Aikman does not agree that the 42 year R2.5 fit is better, and specifies that a good visual fit could conceivably come with a 77 year L0.5 computer generated fit. He also states that the other gas utilities to which Mr. Pous refers have an average life of 31.6 years for this account, and a median of 30.4 years. He also states that 18 of the 26 companies referred to by Mr. Pous have a shorter average life than 33 years. (Exh. MPG-39, pp. 1516) An American Gas

Association (AGA) publication (Survey of Depreciation Statistics) also reflects only 4 of 17 companies with lives of 42 years or more. (Tr. pp. 883, 885)

Commission Discussion

320. Both Mr. Pous and Mr. Aikman have valid positions with regard to this account. Mr. Pous' recognition that MPC specific analysis reflects probable lives of much longer than 33 years is certainly valid. On the other hand, Mr. Aikman and MPC produced evidence which indicates that many other firms in the industry have lives of about 33 years. Accordingly, the Commission finds that a compromise between the two positions is proper. It finds the average service life to be 38 years, with a survivor curve of R2.5. Account 2368.2 - Transmission Plant. Dehydration Equipment

321. MPC uses an average service life of 30 years, and a mortality dispersion Iowa Curve of R3.0. The MCC uses 35 years and R3.0.

322. Mr. Pous states that MPC did not perform actuarial analysis for this account in the 1987, 1982, or 1976 studies, but rather relied upon judgment. Mr. Aikman's notes correlate this account with storage dehydration equipment, and Account 369.1 equipment, which show lives of 29-35 years. Mr. Pous supports his recommendations by using these factors and by reviewing limited actuarial data and industry averages. (Exh. MCC-9, pp. 35-36)

323. Mr. Aikman indicates that he studied the accounts to arrive at his recommendations, but did not perform actuarial analysis. He also specifies that physical inspections were done, which Mr. Pous did not perform. Mr. Aikman states that such inspections are required in Missouri and Massachusetts. (Exh. MPC39, pp. 16-17)

Commission Discussion

324. Given the relatively small dollar magnitude of this account, it appears that neither party spent much time developing a convincing analysis. Mr. Pous' adjustment differs from Mr. Aikman's by only $2,592. A compromise between the parties at

a 32-year average service life appears well within industry averages, and the Commission, therefore, adopts it. When MPC files its next depreciation update, the Commission suggests that it provide more substantial testimony on the physical inspection requirements of Missouri and Massachusetts.

Account 2376.3 - Distribution Plant. Plastic Mains

325. Life: MPC uses an average service life of 60 years and a mortality dispersion Iowa Curve of R3.0. The MCC uses 70 years and R3.0.

326. Mr. Pous states that MPC did not perform statistical analysis on historical data, but relied on industry expectations for steel pipe. He states that his 70 year recommendation is conservative, based on industry tests for plastic pipe, which show lives of more than 100 years. (Exh. MCC-9, pp. 39-40)

327. Mr. Aikman states that retirements are not just caused by deterioration, but that other factors, such as inadequate capacity, are the cause of earlier retirements. He specifies that experience with plastic dates to 1960, and is not long enough to allow a change from reliance on data for steel mains. (Exh. MPG-39, p. 18)

328. Salvage: MPC uses a 10 percent negative net salvage value, and the MCC uses negative 5 percent.

329. Mr. Pous relies on the net salvage exhibited from 19841987. He specifically excludes 1983, which includes about 90 percent of the 1983-1987 cost of removal, because he opines that it is not reasonable. He also says that the pipe will be retired in place, which will minimize costs of removal. (Exh. MCC-9, p. 53)

330. Mr. Aikman states that the negative net salvage for 19831987 was 235.3 percent. He says that at times Mr. Pous bases his salvage estimates upon actual experience (for example, Account 2381), but not at other times. Mr. Aikman states that Account 2376.10 (steel

mains) is the most indicative for 2376.30 due to the fact' that steel and plastic main salvage will be very similar (i.e., material sales for both would be zero) and because the experience for steel is longer. He says that Account 2376.10 salvage has been negative 19 percent to 29 percent. (Exh. MPG-39, pp. 12-13)

Commission Discussion

331. With respect to life, the Commission finds Mr. Pous' arguments to be reasonable, convincing, and conservative. While it is true that steel main experience must be considered, industry studies for plastic pipe must also be taken into account. An adjustment to steel main experience of 10 years (out of a possible adjustment of more than 40 years) nearly fits Mr. Aikman's very conservative M.O. The Commission, therefore, finds an average 70year service life to be reasonable.

332. With respect to salvage, the Commission finds Mr. Aikman's arguments to be slightly more convincing, but only because of the dramatically high negative salvage experience of the past several years. Although the experience of 1983 is definitely an outlier, most of which is properly excluded by Mr. Pous, it can't be discounted entirely. The Commission finds that Mr. Aikman has accorded a proper weighting to the 1983 experience, and, therefore, adopts his recommendation.

Account 2381.0 - Distribution Plant. Meters and Regulators

333. Life: MPC uses an average service life of 4S years and a mortality dispersion of R5.0. The MCC uses 50 years and R5.0.

334. Mr. Pous noted that MPC did a SPR (simulated plant record) analysis but tempered its results with information pertaining to a replacement program for nontemperature compensating meters, which is presently underway at MPC. The SPR resulted in a 48-79 year life, up from the existing 40. Mr. Pous says 50 years is warranted because the replacement program is being undertaken for technological reasons, including improved ability to measure gas sales. He also

says the replacement program is nearly at an end, and therefore the SPR results should not be adjusted downward. (Exh. MCC-9, pp. 40-42)

335. Mr. Aikman specifies that technological advances in meters will continue in such areas as automatic meter reading and electronic meters. He says that these factors will tend to shorten meter lives, which will be offset by the expanded capabilities of electronic meters. (Exh. MPG-39, p. 19)

336. Salvage: MPC uses a proposed net salvage value of 2 percent, and the MCC uses 5 percent.

337. Mr. Pous says that higher salvage is warranted because MPC is nearing the end of its non-temperature compensating meter replacement program, and therefore, the temperature compensating meters which will be removed will have a higher salvage value. (Exh. MCC-9, p. 54)

338. Mr. Aikman states that as the old tin meter numbers decline and the price of tin drops, the salvage value will decline. The new hard case meters have almost no salvage value. Likewise, he states that gas regulators have almost no scrap salvage value, and no reuse salvage because they are cradle-to-grave in their application. (Exh. MPG-39, p. 13)

Commission Discussion

339. With respect to average life, the Commission finds some of the arguments of Mr. Pous to be more convincing than those of Mr. Aikman. However, the Commission is interested in Mr. Aikman's statement that MPC may deploy more advanced meters (which may allow for substantial expense savings in items such as meter reading expense). Therefore, the Commission finds Mr. Aikman's life for this account appropriate, but it also finds that MPC must present to the Commission, on or before July 1, 1992, a comprehensive meter plan which is consistent with Mr. Aikman's arguments.

340. With respect to salvage values for meters and regulators, the Commission finds the logic of Mr. Aikman's position with respect to the price of tin to be persuasive. Any nonferrous metal, which newer hard case meters do not contain, has substantial value. Since the older meter retirement program is nearing its end, it stands to reason that salvage values will decline. The Commission, therefore, adopts Mr. Aikman's recommendation.

Account 2390.8 - General Plant. Multiple Use Structures

341. Life: MPC uses an average service life of 45 years and a mortality dispersion Iowa Curve of S0.0. The MCC uses 55 years and L1.0.

342. Mr. Pous states that both his and MPC's actuarial analysis shows that for 90 percent of the dollar-weighted amounts, the results indicate a lengthening of service life. Also, industry data support 55 years or greater. Both analyses suggest a low model "L" type curve. (Exh. MCC-9, pp. 45-46)

343. Mr. Aikman relies mainly on industry statistics to rebut Mr. Pous. He states that the FERC publication "Electric Utility Depreciation Practices," presented as JHA-8, shows the median life to be 45 years, and only 29 of 83 companies use 50 years or more. Also, of 213 average life estimates, only 27 are 50 years or more. (Exh. MPG-39, pp. 20-21)

344. Salvage: MPC uses a proposed net salvage value of 5 percent, and the MCC uses 25 percent.

345. Mr. Pous states that MPC data show an 85 percent salvage rate. He says that the proposed rate of 5 percent tends to ignore the value of structures and improvements at sites, as opposed to the site itself, which, in his opinion, is unacceptable. Hence, his estimate of 25 percent salvage. (Exh. MCC-9, pp. 54-55) ~;

346. Mr. Aikman states that MPC would likely be out of step with the industry if it continued to record high salvage, as it did during 1968-1987. He also states that many Account 390 items actually result in negative salvage. (Exh. MPG-39, pp. 19-20)

Commission Discussion

347. The Commission adopts Mr. Pous' recommendations for both life and salvage as being both credible and conservative. Both the Pous and Aikman MPC specific analysis reflect a lengthening of lives for this account. Mr. Aikman, however, actually reduced the average life, based on select values he found for the industry. Mr. Pous, on the other hand, properly suggests a conservative lengthening of the average service life. In like fashion, Mr. Pous is conservative in that he does not recommend a salvage rate which mirrors the 85 percent historical salvage rate. Instead, he suggests a 25 percent salvage value which gives proper conservative weight to historical salvage values.

Accounts 2327. 2328. 2329.2. 2332.1. 2334.1. 2336.1. Production Plant Salvage

348. MPC uses 0 percent or 5 percent salvage for these accounts, and MCC uses 10 percent, except for 2336.1, for which it uses 5 percent.

349. Mr. Pous states that Mr. Aikman's depreciation study notes reflect:

> ... a consistent pattern of discounting the actual historic experience of the Company as being illogical or difficult to believe given that they exhibited positive values, and that this was contrary to MRI's understanding of the facilities contained within the plant accounts. This holds true for all six accounts noted, with the exception of Account 2336.1 - Other Dehydration Equipment. For Account 2336.1, the only statement reflected in MRI's evaluation notes is that the estimated net salvage level of zero should be utilized again in spite of the fact that a high positive net salvage is shown for all - periods analyzed. (Exh. MCC-9, p. 15)

Additionally, Mr. Pous states that the materiality of the historic retirements is sufficient to be representative for future depreciation purposes. He does not propose increasing salvage values to those indicated by account history, but does propose some increases. He states, however, that:

> In the next analysis the Company should be directed to specifically investigate this particular area to determine the appropriateness of increasing the positive level of net salvage to historical levels or to fully explain why such levels should be reduced." (Exh. MCC-9, pp. 14-18)

350. Mr. Aikman states that the structures (for which these accounts contain depreciation expense) do not appear, after his physical inspection, to be able to command the kind of salvage which can be deduced through historical account analysis. He also states that these accounts show retirements year to year back to 1968, but salvage history is spotty, and not adequate or sufficient to rely upon for future depreciation purposes. (Exh. MPG-39, pp. 9-11)

351. During cross-examination of Mr. Pous, the following points were made regarding Mr. Pous' workpapers, which were provided in response to Data Request MPC 1-35:

A. For Account 327, a review of ten years of information shows three years with salvage values;

B. For Account 328, a review of ten years' information shows four years with salvage values;

C. For Account 329.1, a review of ten years' information shows two years with salvage;

D. For Account 329.1, one of the two years taken from MPC's data base reflects a $50 negative retirement, which is, according to Mr. Pous, a "theoretically impossible result." (Tr. pp. 887-888)

Also, MPC cross-examined Mr. Pous about companies reflected in AGA's Survey of Depreciation Statistics, which have experienced, for the most part, zero or negative salvage for these accounts. Mr. Pous discounted the value of this inquiry when he stated: "For the area you were questioning me, we have but a handful of companies, and so it's not the greatest information of a comparative nature." (Tr. p. 882)

Commission Discussion

352. As with Account 2390.8, which was discussed previously, the Commission finds Mr. Pous' recommendations, including his

recommendation which pertains to MPC's next depreciation analysis, to be more credible and convincing than that of MPC. Even if retirements are not a yearly routine in these accounts, and even if some values seem to be out of line, the Pous recommendations embody a conservative reflection of the retirements which have occurred. Mr. Aikman's recommendation appears nearly to ignore or to discount substantially such retirements. Mr. Pous also opines that idiosyncrasies in MPC's -accounting system may contribute to retirement amounts reflected in these accounts. Regardless of this, the Commission agrees with the following statement in Mr. Pous' testimony, and adopts his recommendations:

> Q. Have you increased the positive levels of salvage to those exhibited by the plant accounts on a historic basis?
>
> A. No, I have not. While I have ~> increased the level of net salvage from that ~} proposed by MRI, I have not increased them to the levels exhibited on the historical basis. In the next analysis the Company should be directed to specifically investigate this particular area to determine the appropriateness of increasing the positive level of net salvage to historical levels or to fully explain why such levels should be reduced. However, at this point there must be some further recognition of the high positive level of salvage that continues to occur for this Company in these accounts. (Exh. MCC-9, p. 18)

Accounts 2325. 2330. 2331. Production Wells - Depreciation Method

353. MPC uses the Units of Production (UOP) method, and MCC uses the Forecast method of depreciation.

354. Mr. Pous states that MPC's depreciation method for these three accounts (Leaseholds and Right-of-Way, Gas Wells - Wells Construction, and Gas Wells - Well Equipment) is different from the forecast method used by MPC for production plant and products extraction plant. He also states that NARUC's publication Public Utility Depreciation Practices specifies UOP only "in instances where (production of units) predominantly affects the service life of the property." Mr. Pous states that just because 10 percent of the reserves in a particular location are removed in a given year does not mean that the value of the equipment declines by 10 percent; hence, the production of gas does not "predominantly affect the service life of the property." Additionally, he asserts that if the Commission were to use UOP, MPC's calculation of UOP expense is incorrect. He relies upon data from 1987, 1988 and 1989 to establish the fact that MPC overestimates estimated MCF production, which overstates depreciation expense by $438,134. Mr. Pous' preferred depreciation method is the "forecast" method because MPC uses it for other production plant accounts, MPC uses it for its electric

utility, and it is used by the utility industry in general. (Exh. MCC-9, pp. 6-9)

355. Mr. Aikman specifies that UOP more closely matches costs with expenses for these accounts because matching production costs with revenues is more completely achieved. Additionally, he states that three regulated utilities use UOP, as well as gas production and pipeline companies. He says that Engineering Valuation and Depreciation by Marston, Winfrey and Hempstead supports UOP if it properly allocates production expense over the period of productive service of the property. He states that service life does not decline in equal increments, even when Mr. Pous' service life method is used. (Exh. MPG-39, pp. 4-7) MPC's Reardon states that MPC did not err in any material way when it calculated UOP expense. For an example, he states that MPC estimated 7,374,948 Mcfs for 1988 production, and actually produced 7,271,667 Mcfs. This amounts to an error of about 1 1/2 percent. (Exh. MPG-12, pp. 4-7)

356. MCC cross-examined Mr. Reardon and Mr. Aikman to establish that:

> A. Approval of the UOP method implies a change in the depletion rate each year, without PSC approval. This is inconsistent with depreciation expense used for other
> - accounts, even though property is added and retired from them in much the same way as reserve additions, depletions, and rates of gas production change (after a final order) for the three accounts in question. (Tr. pp. 798-802)
>
> B. Of the 20 or so gas companies for which MPC's Aikman performs depreciation (two of which produce gas), none use the UOP method. (Tr. pp. 822, 823, 873)
>
> C. Mr. Aikman thinks that UOP is appropriate for electric production plant (just as he does for gas production plant), but regulatory agencies have always denied such proposals. (Tr. pp. 829-830)

Commission Discussion

357. It may be that both the UOP and forecast methods of depreciation could yield credible natural gas depreciation, all things being equal. It may be true that the UOP method could also be a credible method for electric production properties, but regulatory agencies have rejected the method. This Commission has never approved UOP for electric plant, nor has it approved UOP for most natural gas properties. It approved UOP for the three accounts in question during the late 1970s, but from a record which contained only UOP recommendations (for new and some existing gas properties in these accounts). It appears that both Mr. Pous and Mr. Aikman

would agree that not many regulated utilities use the UOP method of depreciation.

358. An important reason for discontinuing Commission approval of UOP is that the UOP method implies the ability to change depreciation expense each year without Commission approval by, in effect, changing the unit depreciation rate. If this same concept were extended to other utility property, all the depreciable lives and depreciation percentages approved by the Commission in this order could be changed any time without Commission approval. The Commission does not find such flexibility to be warranted for MPC's monopoly businesses. It is no surprise that Mr. Pous' preferred depreciation method is the forecast method. For these reasons, plus the fact that the forecast method is used for all other MPC – electric and natural gas accounts and by the utility industry in general, the Commission adopts the forecast method of depreciation for these three accounts.

Accounts 2325-2337 Production Plant and Accounts 2340-2347. Products Extraction Plant - Depreciable Lives and Interim Retirements

359. Depreciable Lives: MPC uses 2007 A.D. for a retirement date, and MCC uses 2010-A.D.

360. Mr. Pous relies upon MPC's statement that: "This date t2007) reflects the quantity of natural gas reserves and the anticipated rate of consumption of the reserves." He states that MPC's figures in this regard reflect too much production, based on the most recent three years of experience, and assume no reserve additions over time. Because of this, he says that MPC, in effect, is proposing accelerated depreciation. He states that his retirement date of 2010 is a conservative estimate of remaining life. (Exh. MCC-9, pp. 9-12)

361. Mr. Aikman states that Mr. Pous' use of more recent data for his life calculations is inappropriate, and that nothing

significant has happened since 1988 (when the studies were done) to indicate that the 2007 date is wrong. Additionally, he and Mr. Reardon specify that Mr. Pous' 2010 date is based on the erroneous assumption that reserve lives are those shown in the financial statements, which show lower than actual amounts due to SEC reporting requirements. (Exh. MPG-12, pp. 6-7 and Exh. MPG-39, pp. 7-8)

362. In cross-examination of MPC witnesses (by MCC) the following points are expressed:

A. Based on the change in reserves of Montana gas during 1989, the Montana reserves would last until 2015-2016. (Tr. pp. 793-795)

B. Mr. Aikman states that if a depreciation study has been performed recently: "...you shouldn't really look at one piece without looking at everything. This piece might go down, that piece might go up." (Tr. pp. 832-834)

C. Mr. Aikman states that one years' reserves and production rates may not be normal or reflective of the future, and a normal year should be used for ratemaking. He adds, however, that numbers upon which he based his life analysis were provided by MPC, and he does not know whether or not they reflect normal conditions. (Tr. pp. 835-836)

363. Interim Retirements: Mr. Pous uses a direct weighting method to account for interim retirements because he feels it is more accurate. He also states that the California PUC uses this method. (Exh. MCC-9, p. 13)

364. Mr. Aikman specifies that Mr. Pous' method assumes that all future interim retirements will occur at the midpoint of the remaining life. He states that his method, the whole life or instantaneous harmonic weighting method, gives more weight to short-lived interim retirements, and thus, charges each generation of customers the proper depreciation expense. (Exh. MPG-39, pp. 8-9)

365. During cross-examination by MPC, Mr. Pous specified that Mr. Aikman's firm has given two conflicting answers as to what the harmonic weighing method is: Formerly, they stated it was similar to

equal life group depreciation (ELG) but in this case they stated that it was not like ELG. (Tr. pp. 885-886)

Commission Discussion

366. With respect to computing the appropriate depreciable life for these accounts, it appears to the Commission that the main issue is whether or not the single year used by MPC is representative of what "normal" production and reserve levels will be. (Tr. pp. 835-836) The best evidence on which the Commission may rely is that which was elicited in cross-examination of Mr. Reardon, which reflects reserve lives extending past 2015 A.D., based on reserves at 12/31/88 and at 12/31/89. Additionally, these reserve levels conservatively reflect very low levels of reserve additions. On the other hand, the Commission understands Mr. Aikman's reluctance to look past 12/31/87 for one item which is included in a depreciation study. Within reason, the Commission finds Mr. Aikman's reluctance proper. The Commission, for example, would be unwilling to choose 2015 A.D. or 2020 A.D. as the end point of depreciable lives for these accounts based on the post1987 data. Reason suggests, however, that the Commission use the evidence on the record, i.e., the 2015-2016 A.D. date, to test the accuracy of MPC's estimate, which is based on a single year.

367. In arriving at 2015-2016, MCC and Mr. Reardon (during cross-examination) computed the years of reserve life using 1989 as the start date, rather than 1987. If 1987 were used, the end point would be 2013-2014. The Commission finds that Mr. Pous'

- recommended end point of 2010 A.D. represents a conservative compromise between MPC's 2007 and 2013-2014. It also accords proper weight to the evidence which suggests that a life of longer than 2007 A.D. is reasonable, and it gives proper weight to Mr. Aikman's concern about adjusting single items outside the context of the 1987 depreciation study. Additionally, it is conservative in MPC's favor, because 2010 is less than halfway toward the 2013-2014 date, and much less than halfway toward the 2015-2016 date. Accordingly, the Commission finds Mr. Pous' recommendations to be proper.

368. With respect to the interim retirements issue, the Commission finds the concept proposed by Mr. Aikman, which tends to reshape a bell-shaped curve of interim retirements, to be interesting. The proposal, which weights interim retirements by dollar magnitude and life, may be more accurate than assuming that retirements will occur at a consistent ratio to the present plant balance, as do both Mr. Pous and the California Public Utilities Commission. Unfortunately, Mr. Aikman's proposal was not explained well enough on the record for all of the ramifications of its adoption to be known. Accordingly, the Commission adopts Mr. Pous' direct weighting method, which is both credible and conservative. The Commission, however, directs MPC to fully address the ramifications of its instantaneous harmonic weighting method in the next depreciation analysis case. The record reflects some confusion over what Mr. Aikman means by instantaneous harmonic weighting (Tr. pp. 885-886); this point should also be clarified in the next depreciation case.

Rate Base Addition - Compressors

369. The interim order in this Docket disallowed from rate base the annualization of new compressors as being a selective application of the year-end rate base concept. The compressors were included in the rate base for the months during which they actually provided service.

370. MCC witness Mr. Clark continued this adjustment in his testimony, which resulted in a net reduction in MPC's gas rate base of $3,497,795. Mr. Clark asserts that selective application of the year end rate base concept is improper. He states that such selective application results in a mismatch between revenues/expenses and the investment that was used to generate associated revenues/expenses. He also states that the higher operating expenses associated with the old 20" pipeline were not, in like fashion, adjusted. He does not think this plant addition is significant enough to warrant special consideration, as has been allowed for large, central station generating facilities. (Exh. MCC-4, pp. 19-20)

371. In rebuttal, MPC witness Mr. Reardon disagrees with Mr. Clark. He states that the compressors have been providing service, and are an integral part of the new 16" pipeline project. He says that the large size of the compressors addition suggests that annualization should be allowed, even though retirements, which are of smaller magnitude, were not annualized by MPC. The compressors equal about 3 percent of gas plant, which was in service for four months of 1989. He states that the largest electric addition, which was not annualized, was about .5 percent of plant in service. He states that there is not a mismatch between rate base and revenues/ expenses because the compressors are replacing existing plant in service. Finally, he states that the compressors, in his opinion, constitute a major plant addition threshold, and therefore, annualization should be allowed. (Exh. MPG-12, pp. 1-4)

372. During cross-examination of Mr. Reardon, MCC established that the smallest single property for which annualization has been allowed was the south half of the 16" pipeline, which was about 8 percent of plant in service. (Tr. p. 99) MCC also established that the north half of the pipeline, the Cut Bank liquids plant and the Cobb storage loop line, were all considered together when annualization was allowed for them, the total value of which was substantially more than 8 percent. (Tr. pp. 121-122)

373. On pp. 4-5 of Exh. 23, MPC witness Mr. David Johnson explains the status of the 16-inch pipeline project:

> Q. Please summarize the current status of the overall 16-inch pipeline construction project.
> A. This project, begun in 1983, was designed to replace the Gas Utility's aging, main 20-inch trunk line running from Cut Bank, MT to Morel Junction near Warm Springs, MT. The most significant parts of the project are, for the most part, complete and in operation today. The first phase of the project, the 16-inch pipeline itself, was completed and incorporated into rate base as the south and north halves in Docket Nos. 86.11.62 and 88.6.15, respectively. There are regulator station and farm tap heater

> installations remaining to be made as we complete the severing of ties to the old 20-inch, tentatively over the next 18 months. We also plan to complete the monitoring program mandated by the PSC on the south half of the 16-inch line.
>
> The second major phase of the project was installation of additional compression at mainline station number one (ML#1) at Cut Bank to bring the 16-inch line closer to its design capability. The new compressor units were installed in 1988 and 1989 and costs associated with that construction, approximately $6.5 million as of December 1989, represent the major reason for the change to our rate base proposed in this filing. Additional work to decommission and clean up mainline station number two (ML#2) and upgrade the compression at mainline station number three (ML#3) is planned for 1991.

He also states the following at p. 10 of Exh. 23:

> The balance of the new system from Helena to Morel Junction is still being operated in parallel with the 20-inch and will continue as ' such until the upgrade at ML#3 is completed in 1991. This operating plan has allowed us to phase into operation of the 16-inch, testing and gaining experience with its operating characteristics, while the 20-inch is temporarily available as backup. (Emphasis added)

Commission Discussion

374. The Commission, as a general proposition, agrees with Mr. Clark in this matter. Selective application of the year-end rate base concept is improper. He is also right to assert that higher operating expenses of the old 20" line were not adjusted to reflect, for ratemaking purposes at least, that the old 20-inch line is providing, at best, backup service. MPC's assertion that tangible savings would be difficult, if not impossible, to quantify is untenable. (see Exh. MPG-23, p-. 6) Unless MPC is very different from other businesses, capital improvements are made when the present value total of capital costs plus maintenance, taxes, principal repayment (depreciation) and other operating costs of the new project are less than those of the old plant and equipment. Included in operating costs are insurance premiums, which would result in reimbursement in the event of loss. MPC is correct only to

the extent that the utility obligation to serve implies extra reliability because monopoly customers do not have quickly available alternatives to monopoly service. The Commission notes that MPC had the opportunity to make the above calculations for the 16-inch pipeline project, but failed to do so. The Commission will require such calculations for future long-lived projects.

375. The Commission finds that the circumstances of the phase in of the new pipeline, as described by Mr. Johnson, allow for special consideration of annualization. By itself, addition of the compressors is not material enough to allow the mismatch which occurs between expenses, revenues, and plant when annualization is allowed. Additionally, the fact that the 16-inch is a replacement for the 20-inch is not persuasive, particularly when few, if any, of the 20-inch expense reductions or salvage have been used to offset the costs of the 16-inch line. Also, arguments that the construction of the 16-inch did not create additional revenues is not persuasive: The matching concept is "important in the aggregate picture of ratemaking." (Tr. p. 98) However, the argument for annualization in this case is that which also supported annualization of the Cut Bank liquids plant and Cobb storage loop line in Order No. 5360d, Docket No. 88.6.15: The compressors are an integral part of the 16-inch pipeline project. (see FOF 489) The fact that the 16-inch pipeline project has been gradually added to rates over the course of several rate cases does not diminish its substantial cost, which, if totaled, equals more than 26 percent of gas plant in service (FOF 489, Order No. 5360d). Although such reasoning is not directly advocated on the record in this proceeding, the Commission finds that this total percentage for the 16-inch pipeline project is similar to percentages for other property which has been annualized. The Commission, therefore, approves this annualization.

376. The Commission notes that MPC is continuing its search for uses of the 20-inch pipeline easement:

> Another option may be to use the easements either for a conventional buried fiber optic route or as a starting point in negotiations to obtain new easements.

> A significant problem exists, however, and that is finding anyone interested in building a fiber optic communication system on or near the route of the old 20-inch line. Telecommunication Resources, Inc. (TRI), an Entech subsidiary, has several feelers out at our request to see if any of the major communication companies might have any interest. Nothing has surfaced at this point but we have several months to continue the search before we must deal with the decision to proceed with further salvage efforts in 1991. (Exh. MPG-23, pp. 17-18)

The Commission encourages MPC to do all it possibly can to preserve these easements, not just for a fiber optic pathway, but also, if possible, for a high voltage underground transmission line. The Commission directs MPC to report on the status of this easement in its next general filing.

377. Finally, Mr. Johnson, on pp. 14-15 of Exh. MPG-23, explains the slow, deliberate salvage process which MPC envisions for the 20-inch line. The net salvage revenues, which may be substantial, could and should be used to offset the large costs of the new 16-inch line as soon as possible. Accordingly, the Commission directs MPC to credit these net revenues to ratepayers in a gas tracker or a general rate case, whichever occurs first.

Additional Issue - Gas Plant Accounting

378. The PSC's additional issues list requested that parties address MPC's gas plant accounting processes and whether or not they provide adequate assurance that gas rate base is accurately recorded. (see Order No. 5484h, pp. 13-14)

379. MPC witness John Miller states that internal controls are sufficient to assure the integrity of gas rate base additions. He states that controls for retirements are also adequate, but that "...the need for accuracy in retirements is not as great as for the other areas." (They reduce both plant and accumulated depreciation equally, which are offsetting accounts.) He asserts that starting on January 1, 1992, MPC will keep gas plant records at the same level of detail as electric records. This will be on a prospective basis and will not affect plant and equipment acquired prior to 1992. He states that keeping gas records at a level of detail which would allow physical inventories to be taken is not necessary because gas plant is not easily converted to cash. Additionally, he states that notations in MPC internal auditor workpapers, which expressed concern over the lack of detailed gas plant records and the lack of physical inventory practices, were not reflected in a final internal audit report and are, therefore, not relevant. (Exh. MPG-24, pp. 7-14)

380. MCC witness Mr. Clark says that his testimony is purely in response to MPC's testimony and implies that he has not independently investigated this area. He says that inaccurately recorded retirements may result in excessive depreciation expenses. He specifies that his involvement in a case in Maryland has resulted in depreciation calculations being made for net plant, rather than gross plant, because the utility does not have a fixed asset system in place and does not record

retirements according to generally accepted accounting principles. He states that improperly recording (or not recording) retirements may also lead to improperly not recording salvage and removal costs. He states that he is not aware of any process which would correct errors which have been built into accounts, absent a full review of gas property records from day one. (Exh. MCC-5, pp. 25-28)

381. In rebuttal, Mr. Miller states that Mr. Clark has not demonstrated that errors exist. He also states that salvage and removal costs would definitely be recorded, even if the proper account were not used, because of double entry accounting:

> Some of the possible wrong accounts could still result in an appropriate rate base (e.g. removal charged to additions) while others might affect cost of service. In either event, I believe the associated removal costs and salvage would be considered in rates. (Exh. MPG-25, pp. 1-4)

Commission Discussion

382. The Commission finds the record in this case to be incomplete. It is interested in Mr. Clark's assertion, however, that inaccurately recorded retirements may result in excessive depreciation expenses, particularly in view of Mr. Pous' statement
with respect to salvage values in accounts 2327.0, 2328.0, 2329.2, 2332.1, 2334.1 and 2336.1:

> In the event that atypical occurrences may transpire, one would not anticipate they would

> transpire over extended periods of time such as over the 20-year time period reviewed by MRI. However, in each of the time periods analyzed by MRI, the high levels of positive net salvage occur on a relatively consistent basis. Thus, if the results are truly illogical, as reported by MRI, they are more a function of the Company's accounting system rather than the assumption that such transactions are abnormalities and are not anticipated to reoccur. (Exh. MCC-9, p. 17) (Emphasis added)

The Commission notes that elsewhere in this Order it has directed MPC to investigate this matter. Additionally, Mr. Miller states that MPC will change its gas plant accounting procedures beginning January 1, 1992, so that they are consistent with electric accounting processes established by FERC. The change, however, will only affect amounts recorded after 1991. The Commission thinks that the credibility of MPC's pre-1992 gas accounts would be enhanced if it were to employ an independent expert to attest to their integrity. It is likely that they have never been comprehensively scrutinized.

MPC's Rebuttal Testimony Revenue Requirement Revision

Amortizations

383. MPC witness Ceil Orr includes a revision in her rebuttal testimony at p. 2, which is explained as follows:

> The normalized revenues at current design rates presented in this Docket included two amortizations which were in their final year

> Of amortization. These two amortizations were the A&S and Energy Oils Settlements, approved for amortization in Docket No. 85.12.52, and the Bond-Fogelson Settlement, approved for amortization in Docket No. 86.12.68. The normalization process should have eliminated these amortizations from revenues, since the expenses associated with them were eliminated. However, these unit amortizations were inadvertently included in the current design rates, and the normalized revenues at current design rates in the initial filing were overstated.

MCC agrees with including the affect of the change. The Commission finds the agreement of the parties to be acceptable.

Canadian Dividend Tax Treatment

384. MPC's U.S. operations received a large dividend from MPC's regulated Canadian subsidiaries during 1990, which caused a tax liability of $468,448. MPC amortized this amount over two years. MCC's Clark amortized the amount over five years, because MPC has received dividends on a five-year cycle, e.g., in 1980, 1985 and 1990. In rebuttal, MPC witness Ernest Kindt accepts five years, but suggests that the unamortized balance be included in rate base. Mr. Clark agrees with Mr. Kindt's rate base suggestion. The Commission finds the agreement of the parties to be acceptable.

RATE BASE, REVENUES, EXPENSES, AND REVENUE REQUIREMENT

385. The Commission finds the following schedule of adjustments, which are based on Commission analysis and findings heretofore presented, to be reasonable and proper:

REQUIRED
REVENUE

	ADJUSTMENT	RATE BASE	Increase @ 10.41%	FILING REFERENCE
1	REVENUE ADJUSTMENT	$0	-$1,039,559	COL A-D EXH. TJM-1 ORIGINAL FILING P.5
2	GAS SUPPLY ADJUSTMENT	174,387	-4,450,519	COL E-H EXH. TJM-1 ORIGINAL FILING P.5
3	A & G MISCELLANEOUS ADJUSTMENT	780,870	-138,403	COL I-K EXH. TJM-1 ORIGINAL FILING P.5
4	AMORITIZATION ADJUSTMENT	-1,168,568	-1,818,582	COL L EXH. TJM-1 ORIGINAL FILING P.7
5	LABOR ADJUSTMENT	0	901,444	COL M-O EXH. TJM-1 ORIGINAL FILING P.7
6	DEPRECIATION ADJUSTMENT	3,552,974	953,505	COL P-R EXH. TJM-1 ORIGINAL FILING P.7
7	PRIOR PERIOD CONSERVATION PROGRAM ADJ.	0	131,004	COL S EXH. TJM-1 ORIGINAL FILING P.7
8	PROPERTY TAX SETTLEMENT	1,956,270	1,613,984	COL T EXH. TJM-1 ORIGINAL FILING P.7
9	TAXES OTHER THAN INCOME PROPERTY & MISC	0	1,617,486	COL U EXH. TJM-1 ORIGINAL FILING P.7
10	CIS/FMS ADJUSTMENT	115,198	58,814	COL V EXH. TJM-1 ORIGINAL FILING P.9
11	TAX ADJUSTMENTS	-117,829	1,463,545	COL W EXH. TJM-1 ORIGINAL FILING P.9
12	CHANGE IN MT. CORP.LIC.TAX RATE	0	70,906	COL X EXH. TJM-1 ORIGINAL FILING P.9
13	EXCHANGE AND TAX ADJUSTMENT	0	227,241	COL Y-Z EXH. TJM-1 ORIGINAL FILING P.9
14	INTEREST SYNCHRONIZATION	-1,347,859	423,834	COL AA EXH. TJM-1 ORIGINAL FILING P.9
15	REMOVAL OF CIS/FMS ADJ IN ORIG. FILING	-111,863	-59,509	COL F EXH. TJM-5 REBUTTAL FILING P.3
16	INCLUSION OF CIS/FMS STIPULATION	52,588	-96,516	COL G EXH. TJM-5 REBUTTAL FILING P.3
17	FICA TAX ADJUSTMENT	0	-56,312	COL H EXH. TJM-5 REBUTTAL FILING P.3
18	CANADIAN WITHOLDING AX ADJUSTMENT	421,600	-157,555	COL I EXH. TJM-5 REBUTTAL FILING P.3
19	REMOVAL OF 1988 RATE BASE IMPACT IND. COSTS	-578,585	-119,818	COL J EXH. TJM-5 REBUTTAL FILING P.3
20	REVENUE ADJUSTMENT	0	1,658,766	COL K EXH. TJM-5 REBUTTAL FILING P.3
21	UNCOLLECTIBLE EXPENSE ADJUSTMENT	0	-83,029	COL L EXH. TJM-5 REBUTTAL FILING P.5
22	PROPERTY TAX UPDATE	0	-105,510	COL M EXH. TJM-5 REBUTTAL FILING P.5
23	INJURIES & DAMAGES ACCRUAL ADJUSTMENT	0	-120,302	COL N EXH. TJM-5 REBUTTAL FILING P.5
24	RATE BASE ADJUSTMENT (DEFERRED TAX)	-179,691	-30,496	COL O EXH. TJM-5 REBUTTAL FILING P.5
25	MONTANA UNITARY TAX METHOD	0	-29,484	COL P EXH. TJM-5 REBUTTAL FILING P.5
26	INTEREST SYNCHRONIZATION	0	-482,741	COL Q EXH. TJM-5 REBUTTAL FILING P.5
27	DEPRECIATION ADJUSTMENT	-116,704	-1,289,132	FINAL ORDER ADJUSTMENT
28	WORKING CAPITAL	-2,844,506	-402,741	FINAL ORDER ADJUSTMENT
29	CANADIAN WITHHOLDING TAX ADJUSTMENT	-187,376	-31,800	FINAL ORDER ADJUSTMENT
30	ADJUST COST OF REACQUIRED DEBT	-115,592	-18,812	FINAL ORDER ADJUSTMENT
31	INTEREST SYNCHRONIZATION	0	95,204	FINAL ORDER ADJUSTMENT
32	CHANGE IN RATE OF RETURN & ORDER	0	7,546,722	FINAL ORDER ADJUSTMENT

33		---------	---------
34		$205,314	$6,166,028
35			
36	ORIGINAL FILING AMOUNT	$220,361,538	
37		------------	
38			
39	APPROVED IN THIS ORDER	$220,646,852	$6,166,028
40		=============	===========

386. The Commission finds that an increase in MPC’s annual natural gas revenues of $6,166,028 is needed to allow the company the opportunity to earn 10.41 percent on its rate base, as follows:

THE MONTANA POWER COMPANY - DOCKET 90.6.39
FINAL REVENUE REQUIREMENTS CHART - GAS
TO PRODUCE 10.41% RATE OF RETURN
TEST YEAR DECEMBER 31, 1989

		(1)	(B)	(C)	(D)	(E)	
		MPC PRO FORMA	ACCEPTED ADJUSTMENTS	APPROVED PRO FORMA	TOTAL FOR 10.4% RETURN / INCREASE	PSC APPROVED TOTAL	
1		---------	-----------	---------	---------	---------	1
2	OPERATING REVENUE	100,441,855	- 1,658,758	106,783,097	6,166,028	112,949,12	2
3							3
4							4
5	OPERATING REVENUE Deductions						5
6	TOTAL OPERATION & MAINTENANCE EXPENSES	65,962,682	- 247,251	65,715,431		65,715,431	6
7	DEPRECIATION EXPENSES	8,102,886	- 855,691	7,247,195		7,247,195	7
8	AMORTIZATION OF COMPUTER SOFTWARE COSTS	61,949	1,547	63,496		63,496	8
9	AMORTIZATION OF COMPUTER SOFTWARE COSTS CIS & FMS			213,445	- 106,723	106,722	
	106,722						9
10	2 YR AMORTIZATION CANADIAN WITHHOLDING TAX	234,222	- 104,533	93,689		93,689	10
11	AMORTIZATION OF INVESTMENT TAX CREDIT NET	-310,432	0	- 310,432		-310,432	11
12	DEFERRED FEDERAL INCOME TAXES	1,119,645	194,953	1,314,598		1,314,598	12
13	TAXES OTHER THAN INCOME TAXES	10,451,429	- 165,561	10,285,868	15,415	10,301,283	13
14	CORPORATE ENVIRONMENTAL TAX	12,497	- 2,312	10,185	6,855	17,070	14
15	FEDERAL INCOME TAXES - CURRENT	3,117,969	- 655,573	2,462,396	1,948,424	4,410,820	15
16	MONTANA CORPORATION LICENSE TAX	745,829	- 138,982	606,847	413,069	1,019,916	16
	17	-----------	----------	------------	------------	----------	
17							
18	TOTAL OPERATING REVENUE DEDUCTIONS	89,712,121	- 2,116,126	87,595,995	2,383,793	89,979,788	18
19							19
20							20
21	NET OPERATING INCOME	18,729,734	457,368	19,187,102	3,782,235	22,969,337	21
22		==========	==========	===========	===========	==========	22
23							23
24	AVERAGE RATE BASE	224,306,981	- 3,660,129	220,646,852		220,646,852	24
26		===========	===========	===========	===========	=========	25
26							26
27	RATE OF RETURN	8.35%		8.70%		10.41%	17
28		=====		====		======	

CONCLUSIONS OF LAW

1. All Findings of Fact are hereby incorporated as Conclusions of Law.

2. The Applicant, Montana Power Company, furnishes electric and gas service for consumers in the State of Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. Section 69-3-101, MCA.

3. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company's rates and operations. Section 69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

4. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Sections 69-3-303, 69-3-104, MCA, and Title 2, Chapter 4, MCA.

5. The rate level approved herein is just, reasonable, and not unjustly discriminatory. Sections 69-3-330 and 69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

1. Applicant, Montana Power Company, is hereby authorized to accrue for implementation in rates an increase in annual Montana jurisdictional electric revenues of $39,839,707. Such accrual, beginning on the effective date of this Order, will be reflected in rates beginning August 29, 1991, and amortized over a one-year period.

2. Applicant, Montana Power Company, is hereby authorized to implement increased rates, beginning August 29, 1991, designed to increase annual jurisdictional electric revenues by $39,839,707. Such implementation will be subject to the cost-of-service/rate design order in this Docket to be issued at a later date.

3. Applicant, Montana Power Company, is hereby authorized an increase in annual natural gas revenues of $6,166,028.

4. Applicant, Montana Power Company, is hereby ordered to accrue for implementation in rates a decrease in annual natural gas revenues from the interim level of $132,117. Such accrual, beginning on the effective date of this Order, will be reflected in rates and amortized over a one-month period.

5. Applicant, Montana Power Company, is hereby ordered to decrease natural gas rates from the interim level, such rates to be implemented on a date to be established in a future Commission order on gas cost-of-service/rate design and the Company's proposed gas transportation plan.

6. The electric and natural gas revenue changes ordered by the Commission are in lieu of and not in addition to the interim changes authorized by previous Commission orders in this Docket.

7. Applicant, Montana Power Company, is hereby ordered to comply with any and all directives of the Commission as described in the body of this Order.

8. The effective date of this Order is July 12, 1991.

DONE AND DATED this 12th day of July, 1991, by a 4 - 1 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Chairman

WALLACE W. "WALLY" MERGER, Commissioner

JOHN B. DRISCOLL, Commissioner
Voting to Dissent-Written Dissent Attached

BOB ANDERSON, Commissioner

ATTEST:

Ann Peck
Commission Secretary

(SEAL)

NOTE: Any interested party may request that the Commission reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

July 12, 1981

Dissenting Opinion: 90.6.39
MPC Electric Revenue Requirement

I disagree with many revenue related findings in this Order. I'm concerned with indications of self dealing between the company. I'm disappointed by the lack of certain consumer Counsel Oversight Committee activity. We have no effective role for the Public, particularly at the Policy level. The process for regulating utilities in Montana is in disrepair.

We need to get this company's undivided attention. Instead of deferring remedies until the next Docket, we should be making hard nosed decisions from information available in this record. This Order, from which I now dissent, does not even come close.

Questionable Decisions

1. Why agree that the risk of generating from hydro sources should not be shifted to the ratepayer (FOF 158), that using 385 aMW shifts or eliminates that risk (FOF 164), and then "accept MPC's proposal to use 385 aMW as its hydro capability" (instead of MCC's 392 aMW)? The risk is not only shifted, MPC gets to keep all of the income earned from higher levels of hydro generation, and can yet justify more thermal resources. Impact: $1,168,375 (annually).

2. Why refrain from using 936 aMW as the number for both justifying resources, and computing revenue requirement (FOF 183)? By allowing MPC to use a lower "sales" number of 916 to compute revenue requirement, either we force ratepayers to pay aMW more in rate base than they actually need. True the operating year for loads ends six months past the end of the test year for sales (FOF 185 & 186). But, by the end of the test year, the hydro based system managers know loads within the load following capability of water budget and storage system.

The justification that capacity, not energy, is driving cost increases (FOF 187) is irrelevant. The decision is about which energy figure to use for the basis of rates.

Most importantly, the determination that loads are not sales (FOF 184) is like saying "weight is not pounds", or "length is not inches". Worse, this declaration as justification for decision in such a minor matter, lays even more obstacles for the Commission when it tries to decouple sales revenues and load growth from profitability. This "decoupling" is a threshold issue before we can really motivate a utility toward conservation and energy efficiency. Load growth no longer has to be seen as the key to company success. We can set a sales/load figure. Then, after a year of operations, make the company whole if sales drop below predictions due to conservation and efficiency. If they exceed the established figure, return the difference to ratepayers. Impact: $2,712,397 (annually, after removing losses of passing off system sales).

3. Why are we allowing the utility to charge CS4LMD less ($1,274,214 revenue + $277,911 WWP credits = $1,552,125) than what was charged for-the Basin sale ($1,387,902 revenues +

$903,432 consortia credits = $2,291,334) for the use of its Colstrip to Garrison transmission facilities and entitlements (FOF 273 -277)? The LA and Puget sales are 27 MW more than the 185 MW Basin sale, they use more transmission facilities (add the Colstrip to Crossover segment), and either contract requires a firm path for a longer period of time. Under any pricing strategy I've seen, CS4LMD should be charged more for amount, length, and a greater portion of the replacement cost ~}
of the transmission facility because of longer use. Impact:
$739,109 (annually).

4. Why violate the used and useful statute, simply because a facility failed to be used and useful because of environmental reasons (FOF 226)? Either we have the used and useful statute to enforce or not. If it needs to be changed to make exceptions for environmental hang ups in a project then let the Legislature make that change. Impact: $121,406 (amortized over five years).

5. Why delay a policy on refunds and settlements enjoyed by the utility (FOF 227-235), if its been delayed for a study once already (FOF 228)? With the last delay a large portion of $4 million that should have been passed to the customer was left for the utility to keep, pending a study. This is not appropriate. Note that with much smaller amounts (i.e. $121,406 for the Hauser upgrade) MPC uses every effort to get additional money.
A simple policy in this Order would stop this nonsense: All refunds and settlements must flow to the ratepayer. Those above $2 million should be amortized over two years, and percentage wise reduce first block rates of all classes. Amounts under $2 million should go to a refund account. When there is sufficient in that account ($200 to $300 thousand) reduce all customer charges in one month equally; indicate the
refund on each bill. Redistributional inequities pale compared
inequities of the present n study" policy that leaves the money in the utility's pocket. Impact: Forgone $4 million (amortized over two years).

6. Why haggle over repricing the Pacificorp sale (FOF 188-198) to this market's best price of a 100% load factor sale after transmission cost (FOF 198; 26.1 @ mills?), when we should be imputing a price floor equal to MPC's 100% load factor purchase (FOF 112; WNP-1 @ 43 mills)? A single plant like Colstrip #4 may sell to a load like this as long as the price is above its operating cost, and some contribution is being made to fixed costs. For an integrated utility, the situation is much different. It makes no sense to bring in 68 MW at 100% load factor for 43 mills (include delivery cost), only to turn around and sell 15 MW at 100% load factor for 26 mills. Both the resource and the load are non varying entities in the stacks manipulated by the system dispatcher. Approximate Impact: $2.2 million (annually).

7. Why accept Montana Power's assertion that its subsidiary, TRI, really did deserve to keep $24.9 million of the $25.5 million paid to Montana Power for installation of Fiber Optic Cable (FOF 253)? The idea of installing fiber optic cable in utility right of way is outstanding. Even though, 45 other utilities have sold similar access without dealing through subsidiaries, I have no problem with a fledgling telecommunications affiliate profiting. However, flowing to the utility only $600,000 of a $25.5 million AT&T payment is suspect. MPC's right of way across Montana may be the real hidden asset in this deal, and we have solid legal precedent for using asset liquidation proceeds to offset rates.
At a minimum, in this Order we should be treating one half of the total amount as utility income, until MPC overcomes a rebuttable presumption that the utility right o~ way was worth far more than $600,000 in this deal. Impact: $12.7 million (this Order).

8. Why has the Commission settled for the $650,000 identified by MPC as the benefit of the Reciprocal Sharing Arrangement (RSA), pending further inquiry (FOF 206)? From this record its

clear (See Leland p 606) that the RSA demanded by LA hands the responsibility for force outage reserves back to MPC's utility resources.
Note from the record:
Driscoll: "So there is no requirement to provide a firm delivery to Los Angeles?"
Leland: "It's a unit contingent and backing off because of the utility need is not a unit contingent criteria. That is, if the unit is performing, deliveries will be made. In fact, in the sharing agreement, the reciprocal, agreement, its a contingent on the unit's performance, and its not contingent on a load situation. n
Driscoll: "So it is strictly associated with Colstrip 4 and none of the other plants?"
Leland: n The performance of Colstrip 3 and 4, through the reciprocal agreement."
Driscoll: "So 3 is involved. So 3 might have picked up the load?"
Leland: "It would have--3 and 4 share their output..."
This means that in a pinch, when both the ratepayer and LA need Colstrip 3, LA gets it. The only time the utility is off the hook, is if both CS #3 and #4 are down simultaneously. Now, MPC is carrying 32 MW more of forced outage reserves than it expected. Externally, MPC says it needs only 182 MW of reserve (including the 32 MW increase) to suit the Intercompany pool, because "LA is providing its own reserve." Internally, MPC has to worry about outage of two Colstrip #3 sized plants. MPC gains no reserve advantage from CS #4 as a result of the RSA, because it can't call on the output equivalent to CS #4, to offset the increased outage risk. In effect the increased reserve requirement to MPC is that of another CS #3 (31 MOO). Combine this increased reserve requirement with the 35 to 40 MW allowable as standard error in MPC's capacity requirement forecast (Leland p 583), and we are very close to justifying the need for a 75 MW Idaho Power Purchase. There is also the reserve requirement associated with the 15 MW Pacificorp sale inherited from CS4LMD . I don't know how Puget is to provide its own forced outage reserve, but that, too, causes more wonder about an indirect connection between these loads and the Idaho Power capacity purchase.
It should be up to Montana Power to dispel concern that utility ratepayers are providing the reserve for CS4LMD's sales. Until that presumption is rebutted, the cost of the Idaho Purchase, as well as any income from resales, should be left out of rates. Impact: $10.7 million, - $7.1 million, = $3.6 million (This Order).

9. Why did the Commission rush to raise MPC's rates by $30.5 million annually on an interim basis? As I indicated in my dissent ll months ago:
We failed to use consistent standards as required by Montana Law;
All of the Minimum Filing Standards for the permanent filing were not satisfied by the time we approved the Interim;
There was never asked, nor demonstrated, a clear showing that deferring rate relief "will result in irreparable financial harm to the petitioning utility"; and
We failed to disallow, in the Interim, items being contested in the main case.
I'd have no problem at all if the Commission were to now reduce rates from pre Interim levels by $30.5 million, for the same 10 months MPC has had the use of the money. A return to ratepayers of about $3 million would have about the same effect. Impact: $3 million (amortized over two years).

10. Why is the Commission making the absence of intervenor testimony on an issue equivalent to the applicant's proving its case (i.e. FOF 112 & 113)? Just because the Consumer Counsel failed to contest over $28 million of this requested increase, we do not have reason enough to concede that MPC
carried its "burden of proof".

This Commission generally avoids Show Cause Orders and Investigations. We have concluded that our Staff is too small to carry the burden of proof required of initiatives. Instead, we've adopted a generally passive role. When the regulated utility requests more money, it has the burden to prove its case. With our conditioning power we try to put a little public policy guidance into utility activities, if supported by the record. This passive regulation by excessively tiny steps, is characterized by utility attorneys constantly criticizing the

Commission, or its Staff, for an "advocacy" role (FOF 14-19). The criticism keeps the Commission defensive, by advancing an unstated and unquestioned presumption that our pressure on behalf of monopoly regulation is wrong.

The single tiny advantage for our being passive has now been eliminated. In this case we equate "proven" with "uncontested". In my mind there is a huge difference. If the Consumer Counsel fails to contest $28 million of the requested rate increase, the applicant still has not proven that $28 million in new funds is needed. If the Consumer Counsel, itself, had presented an application for a $28 million increase for Montana Power, it too should be expected to carry the burden of proof. Instead, we've taken the lack of
4l opposition to $28 million of the requested rate hike as a floor, above which were added further increments requested by the utility.

The nine month statute colors the atmospherics of a rate case. Requested rate levels go into effect automatically, absent final Commission action. Mentally, we now start from the requested level and work downwards, subtracting what is countered by intervenor testimony. In~ other words, we have allowed the nine month statute to remove from the applicant its burden of proof, and given ourselves, through intervenors, the burden of disproof. Impact: $28 million.

Possible Corporate Self Dealing

Years ago, I agreed to the holding company settlement with MPC, because the utility, not a holding company, would still control deployment of capital internally. We retained access to affiliates' books, and I perceived Entech start ups as a good way to incubate mid-sized corporations for the Montana economy. I am worried, now, that we are allowing enormous ratepayer subsidies to MPC's corporate affiliates.
Consider the following:

-Even allowing for construction costs and the compensating use of 48 microwave channels, MPC's utility right of way across Montana likely was the most valuable asset in the TRI transaction. Yet, the regulated utility received only $650,000 out of a $25.5 million payment from AT&T, and --~ possibly was not fully compensated.

-CS4LMD is not earning income in the same relation to its debt costs (ratio = less than 1) that MPC management asks us to have the utility earn (ratio = greater than 2.8). The "hell or high water" provisions of the lease back of CS #4 are "debt" from the investors perspective in the overall capital structure of MPC. Its instructive that MPC moved debt formerly allocated to CS4LMD over to the utility, and then argued for higher equity rate of return to improve interest coverage ratios (FOF 44). Are the affiliates finances dragging down the entire corporations bond rating? Is the effect forcing the utility to cajole offsetting revenues -from the ratepayer by any artifice this Commission will accept?

-The combination of CS4LMD shifting its Pacificorp 15 MW sales obligation to the utility (at a losing price), and CS4LMD satisfying LA's demand for a RSA (CS #3 tied to CS #4), seems to cause a costly reserve obligation for the utility. The effects of the Puget sale are unclear. Its highly likely that the regulated utility is subsidizing the so called "independent" affiliate.

-If Western Energy is enjoying lesser risk than a truly independent coal company, because of its sales to MPC (FOF 107). it seems the same sort of reduced risk is being passed to CS4LMD. The RSA means CS4LMD has divided one large load (LA) into two (LA & MPC). In return the utility has to shoulder the new reserve exposure, and an expensive new load (l/2 the LA sale).

-MPC management has shifted the utility's entitlement to sell power to Pacificorp to CS #4. A little later, when the Pacificorp sale was using so much of CS #4's output, the "independent" couldn't land the larger, more lucrative, LA contract, the smaller sale was shifted to the regulated utility. The Commission must be able to see the contradiction. Either utility management shifted something economically desirable to CS #4, or they shifted something economically undesirable from CS #4 to the ratepayer. Its actually possible that they did both. The floor price represented by the WNP-1 contract was at one time lower. By the time the CS4LMD gave back what it took from MPC, the new WNP-1 settlement made the Pacificorp sale a losing proposition for the utility. It seems that self dealing by affiliates could mean having it both ways, regardless of consumer impact.

-The argument MPC used to justify the "reciprocal agreement" gives even greater cause for alarm. That CS #4 was working more often than CS #3 only suggests a similar bias on the by the utility toward its affiliate on an hourly basis. It is in MPC's financial interest to run CS #4 full tilt all the time, except for maintenance intervals. As long as revenue covers operating costs, particularly with the artificially high transfer price of coal from Western Energy fully allowed, MPC gains. If MPC access to transmission is limited, or if the market itself is saturated barely above CS #3 & #4 operating costs, the corporation's priority self interest has to be in favor of selling from the n independent" plant. The ratepayer under present regulatory laxity can be counted upon to cover the losses at CS #3, one way or the other.

-Piggybacking Colstrip #4 onto MPC's institutional access to the bulk electricity market is another ratepayer subsidy. All independents should be in that market equally, instead of being favored if they happen to be affiliates of a generating utility. Eventually, anti-trust protections in the evolving competitive market will force affiliates to clean up their act. We are letting MPC management position themselves behind our regulatory shield. This must stop. We should make Colstrip #4's market access equal to any QF or IPP on the system. Further, we need to clarify that any damage claims against MPC arising from anti-trust action by Colstrip #4's truly independent competitors will not be compensated by the ratepayer.

-The back and forth jockying of CS4LMD for "firm" transmission status on MPC's facilities (FOF 273-277) is alarming. I've already mentioned the price bias. The policy implications are even more important. Would a truly independent power plant be able to build 212 MW of transmission facilities across Montana for private profit from export? It seems to me that a Certificate of Need would be rather difficult to get under the Major Facilities Siting Act. Would a private independent power plant for export be able to condemn private property in Montana under the Eminent Domain statutes? I think not. This facile transfer of the major transmission capacity to an affiliate must at least stand a test of "equal access", in the public interest. All independents must have the same access, or we are overseeing the misuse of a public use facility. It may also be that, by our failure to correct this self dealing situation, we are impeding interstate commerce. ~ ~

In this Order this Commission looks toward a more detailed inquiry into Colstrip #4. The mildness of approach is inexcusable. We gave fair warning to the utility when we approved the sale lease back of Colstrip #4, that their would be no ratepayer subsidies. Its time, now to enforce that caution. Based upon the record in this docket, every benefit of the doubt should now be in favor of the beleaguered ratepayer, not still again in favor of a financially healthy utility.

Management chiding to the contrary, ratepayers are keeping the utility healthy, in spite of the weight of subsidized affiliates, particularly Colstrip #4.

Instead of constantly rehashing the captive coal issue (FOF 85-109), we should routinely expect to make the adjustment, and just as routinely apply the same principle to other affiliate relationships. We have not begun to regularly police self dealing among MPC's many companies. The self dealing inquiry should cover the entire range of MPC affiliates. In addition to stopping the subsidies, our inquiry
might establish an affiliate start up and tracking system that ,--is straightforward, public and enforceable. I'd like to see us continue MPC as a mid sized corporation incubator, but the temptation to abuse ratepayer revenue flows has to be controlled.

If we cannot conclude with an acceptable system for reviewing start up costs, and controlling subsidies, then MPC will have to divest its affiliates. If Entech and its subsidiaries are so hot, as management is prone to intimate, then those companies will do just fine, ...floating on their own bottoms. The gain or loss from the sale of these assets should flow to offset rates, as with any asset liquidation. Our most important goal should be to place clean trustworthy operational lines around the regulated utility, and have the customer pay only for reasonable costs of reasonable service.

Consumer Counsel Oversight Committee

Montana's utility regulation is neutralized, if the "regulated" utility succeeds in capturing the Consumer Counsel Oversight Committee. The majority of even a consumer oriented, well staffed, Oversight Committee can be captured if it fails to:

-Take public testimony on new policy initiatives to place in front of the Public Service Commission;

-Fund expert testimony in areas the regulated utility would rather see avoided, rather than just respond to issues highlighted by the utility;

-Demand of the Commission that the applying utility meet a burden of proof, even when the Consumer Counsel chooses not to contest a given issue area;

-Hold well publicized and open public meetings when giving direction to Consumer Counsel Staff concerning the
choice of experts, and their focus.

With this case, I'm convinced the Consumer Counsel Oversight Committee is not diligently keeping our regulatory system from capture. I no longer will abide by this institutional failure. When the hard working staff and experts of that agency are applied to all the issues there is a balance of analysis. When the issues are selected only for being sure things, then the balance disappears.

The Commission is left trying to preserve the appearance of fairness (FOF 64 & "questionable decisions"), by turning down Consumer Counsel positions that are air tight, and the Commission has no alternatives to consider over an enormous range of issues. : .~- I am appalled that the Consumer Counsel left $28 million
of a $52 million rate increase request uncontested. Our system depends on Consumer Counsel experts being deployed on the full range and full depth of issues in a rate case. We would also expect the Consumer Counsel position to reflect the testimony we hear at public hearings; lately the likeliness has become

more remote.

Until the Consumer Counsel applies itself as it should, I will consider its narrow positions as the first screen of obvious problems in a major rate case. The revenue requirement recommended by the Consumer Counsel will for me be the ceiling, below which I will be examining other rate increase and policy issues. The reach of vision and the range of policy options presented by the Consumer Counsel has become far too conservative. That agency seems intent on doing what it perceives the Commission's job to be, which is rather redundant. It should do its own job: represent the consumer.

The Public's Role

This Commission should give Citizen a larger role than it does. As Aristotle advises, the best judge of a home's design is he who lives in it, not the designer; the best judge of a soup is he who eats it, not the chef. For similar reason, this Commission should incorporate the Public's views into its deliberations, along with expert testimony.

The Public's interest, and the narrow band of rate paying consumer interests are different. Public testimony allows us see what we do for the poor, what we do to the poor, and what we enable the poor to do for themselves, as recommended by the U.S. Catholic bishops in their letter on a just economy.

Involving the Public is our worst suit. We have evolved a system that complicates rather than simplifies, obfuscates rather than clarifies, lulls rather than forewarns, confuses rather than explains, diffuses and discourages, rather than encourages and harnesses. ,

None of the following indicate that we are supportive of true public involvement:

-We accept a company's new rate request while other rate requests are still pending, with interims overlapping interims.

-We expedite interim rate awards to coincide with scheduled rate reductions.

-We approve agreed upon stipulations, then wrap these done deals into the larger case.

-We accept enormous numbers of petitions from citizens as though they will make a difference to our deliberations, and then pay them little heed.

-We encourage Montana's self appointed energy information elite to work on policy matters privately, by responding to their back channel communications, and enabling their committees to remain private and low profile.

-We fail to include in our order a set of conclusions from the Public's testimony, and our explanations why and how those conclusions are being applied or discarded.

Actual Public involvement, not its image, results in optimal, rigorous, healthy, and far sighted decision making. Our procedures for major rate cases must, a least, have the following:

-Simplicity;

-Straightforward advance public warning;
-Maximum one annual utility application;
-Only proposed stipulations in given issue areas;
-Burden of proof clearly identified;
-Rolling summary of Commission tasks to the utility, still unsatisfied;
-Relevant policy questions currently under discussion;
-Commission conclusions from Public testimony;
-Commission disposition of those conclusions; and
-Commission public explanation of its Order, not interpretations of Commission decisions by the utility.

These simple procedures will draw us closer to public attitudes' and expertise as a resource, thereby rebuilding
public confidence in our efforts. Most importantly they will help us responsively set sound utility and energy policy.
This Commission and the people of Montana are supposed to do
that, not n the experts".

Policy

Why is it taking this regulatory system so long to do the obvious? We act as though we really don't consider our policy initiatives as important as garden variety rate cases. We have a major Integrated Least Cost Planning and Competitive Resource Procurement docket in progress. We should not be considering any rate increases connected with resource additions, until the results of that proceeding are complete. It is just that simple! Only when we place our agenda, in front of the regulated utility's agenda can we say that the utility is under our control.

Our administration of the nine month statute clearly needs a closer look. Its reasonable for us to allow only one properly filed rate case each year, from each utility. Our limited resources have to be spread equitably to all the - companies we regulate. The annual case should be the trimmest possible at the start, not bloated prior to the interim award, then mysteriously reduced afterwards. We should ask for expert
and public testimony on all relevant policy issues outstanding before the Commission. As the utility gets timely attention to its wants, the Commission will be getting just as timely treatment of its concerns. In this case, for example, we could be at least positioning MPC for Demand Side

Management by decoupling its profits from its energy sales. By dealing concurrently with what is of interest to us, the nine month statute places equal expeditiousness on the side of Commission policy development.

Conclusion

I have shown why I disagree with this Order. I've explained why I am troubled by both the Consumer Counsel Oversight Committee's inactivity and certain management policies of the Montana Power Company. This dissent is not just to highlight a difference of opinion, it is to suggest areas where I believe our regulation is too timid. Our system is in need of serious improvements, which only the handful of people who will ever read this dissent can make.

Respectfully,

John B. Driscoll
Commissioner