Service Date: October 17, 1991

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

* * * * *

IN THE MATTER OF The Application by the MONTANA POWER COMPANY for Authority to Increase Rates for Natural Gas and Electric Service. CLASS COST OF SERVICE RATE DESIGN ELECTRIC	)	UTILITY DIVISION DOCKET NO. 90.6.39 ORDER NO. 5484n

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BEFORE:

HOWARD L. ELLIS, Chairman
DANNY OBERG, Vice Chairman
BOB ANDERSON, Commissioner
JOHN B. DRISCOLL, Commissioner
WALLACE W. "WALLY" MERCER, Commissioner

FINDINGS OF FACT

BACKGROUND

1. On July 19, 1991, the Montana Public Service Commission (Commission) issued Order No. 5484k, addressing the revenue requirement portion of this Docket. Paragraphs 1 through 11 of that order described the background to this Docket, and those paragraphs are hereby incorporated by reference. In addition, the Commission's response to the Montana Power Company's (MPC) objections to the staff introduction of evidence, described at paragraphs 15-20 of Order No. 5484k, is also incorporated into this Order.

2. The following persons testified on cost-of-service/rate design (COS/RD) issues in this Docket:

For MPC:
Phillip E. Maxwell
Thomas E. Wilde
Patrick R. Corcoran

For Montana Consumer Counsel (MCC):
James H. Drzemiecki
John W. Wilson

For Human Resource Council, District XI (HRC):
Thomas Michael Power

For Large Customer Group (LCG):
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For Rhone-Poulenc Basic Chemical (RPC):
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For Federal Executive Agencies (FEA):
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For Department of Social and Rehabilitation Services (SRS):
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For Montana Irrigators (MII):
Anthony J. Yankel

3. Simultaneous opening briefs on the COS/RD portion of this Docket were filed on or around June 28, 1991. Reply briefs were filed on or around July 12, 1991.

INTRODUCTION AND ORGANIZATION

4. This Order is divided into three parts. Part I addresses cost of service (COS). Included in this part is a summary of the parties' positions, followed by the Commission's decisions on COS matters. A summary of the parties' reconciliation and moderation testimony and the Commission's decisions follow. In Part II the parties' rate design testimony is summarized followed by the Commission's decisions. Finally, Part III provides the Commission's decisions regarding policy directives.

Part I

COST OF SERVICE

Introduction

5. This part summarizes the parties' COS proposals. MPC's COS proposals are summarized first, followed by a summary of the COS proposals made by the Montana Consumer Counsel (MCC), the Montana Irrigators, Inc. (MII), the Large Customer Group (LCG), the United States Federal Executive Agencies (FEA), Rhone-Poulenc Basic Chemicals Co. (RPC), and District XI Human Resources Council (HRC). Each party's COS proposals are summarized using the COS/RD model contained in Table 1.

MPC COST OF SERVICE

6. Philip E. Maxwell (hereafter MPC) presented electric COS testimony on MPC's behalf (Exh. Nos. MPC-40, 41, and 42, respectively). An overview of MPC's costing method is provided, followed by a review of the methods MPC has changed in this Docket relative to Docket No. 87.4.21 and revisions MPC made to its study in Rebuttal Testimony.

Overview

7. Table 1 illustrates the steps in MPC's Allocated COS study and rate design testimony (Exh. No. MPC-40, p. 4). A discussion of the specific methods MPC uses to compute and allocate costs follow.

Table 1. MPC Cost of Service/Rate Design Model

Cost of Service				Rate Design/
Function	Classified	Allocated	Reconciled	Pricing
Generation Transmission Substation Distribution	Energy, Capacity, Reactive Power, Customer (Access)	Seasons, Peak Days, Customer Classes	Equal percent	c/kWh $/kW $/KVAR $/Customer

8. In this Docket, MPC once again functionalizes costs as generation, transmission, substation, and distribution. Generation costs are classified as energy and capacity, and measured in c/kWh and $/kW. Transmission, substation, and distribution costs are classified as energy and capacity (demand) and measured in c/kWh and $/kW, respectively. Distribution costs are also classified as customer and measured in $/customer. Distribution costs are broken down into primary and secondary voltage levels. All costs are expressed in beginning-of-year 1992 dollars (Exh. Nos. MPC-40, p. 13, MPC-46, and MPC RDR PSC-280).

9. MPC proposed to separately price service at each of the transmission, substation, primary, and secondary voltage levels since the costs differ at each level. MPC computed and allocated voltage-level energy and capacity loss costs and maintains loss

related costs should be born by the cost causers (Exh. Nos. MPC-40, p. 10 and MPC-41, p. 7). MPC maintains customers served at the transmission and primary levels should not be charged for down-stream costs (Exh. No. MPC-46, p. 13).

Changes in MPC's COS Approach

10. MPC's proposed COS study changed relative to its COS study proposed in Docket No. 87.4.21. These changes include the following:

a. MPC proposes real levelized energy and capacity generation costs based on 10 years of data obtained from its July 1990 avoided cost compliance filing. Capacity cost data were supplemented with four years of Bonneville Power Administration (BPA) New Resource (NR) cost data (Exh. No. 40, pp 13-15). In Docket No. 87.4.21, MPC measured these costs using 25 years of real levelized PROMOD and BPA NR data (Order No. 5340, FOF 22-23).

b. MPC computed separate transmission and substation costs and included Montana Resources, Inc. (MRI) at the substation function for cost allocation purposes (Exh. No. MPC-40, PEM-10). Transmission and substation costs were not separately computed in Docket No. 87.4.21.

c. MPC made two changes to its distribution cost method proposed in Docket No. 87.4.21. First, MPC based distribution costs solely on capacity and energy losses (Exh. No. MPC-40, p. 18). In Docket No. 87.4.21 distribution costs included plant investments, A&G and O&M costs (Order No. 5340, FOF 27). Second, in Docket No. 87.4.21 MPC proposed to allocate distribution costs by season based on class non-coincident peak (NCP) data (Id. FOF 37). In this Docket, MPC proposes non-seasonally allocated distribution costs using the annual twelve-month average of NCPs (Exh. No. MPC-41, p. 7).

d. MPC reduced the winter season from five to four months. The winter season would be November 1 through February 28/29 (Exh. No. MPC-40, p. 6). In Docket No. 87.4.21 MPC expanded its winter season from four to five months (FOF 35, Order No. 5340).

e. Whereas MPC treats transmission plant as capacity related (Exh. No. MPC-40, p. 16), in Docket No. 87.4.21 transmission costs were classified as capacity related, new load and energy related reliability investments (Order No. 5340, FOF 24). Also, in this Docket MPC allocates transmission costs on an annual basis (Exh. No. MPC-40, p. 12). In Docket No. 87.4.21, MPC allocated transmission costs seasonally (Order No. 5340, FOF 37).

f. In this Docket MPC allocated only meter reading O&M expenses by customer size. In Docket No. 87.4.21 MPC allocated one half of all O&M expenses by customer size (MPC RDR PSC-301).

g. In Docket No. 87.4.21 MPC allocated energy and capacity losses at the generation level seasonally. Energy losses were allocated based on class usage and capacity losses were allocated by the seasonally normalized system peak and by voltage level. In this Docket MPC computes average monthly energy and seasonally-adjusted average monthly capacity loss costs and allocates these costs at each voltage level. MPC allocates energy loss costs based on normalized usage. Capacity loss costs are allocated at the transmission and substation levels by the average monthly coincident peaks (CPs) and by the average monthly NCP at the distribution level (Exh. No. MPC-40, pp. 9-10 and 12 and MPC-41, pp. 7-8, and FOF 37-39, Order No. 5340).

11. Rebuttal In either data responses or rebuttal testimony (Exh. No. MPC-41), MPC revised its proposed cost study as follows:

a. In direct testimony, MPC proposed winter and summer marginal generation energy costs of $.01930/kWh and $.01938/kWh, respectively, and asserted energy charges should not vary by season (Exh. No. MPC-40, p. 14). In rebuttal testimony MPC corrected these costs to equal $.02369/kWh (winter) and $.01717/kWh (summer), respectively (Exh. No. MPC-41, p. 4). (MPC RDR FEA-17 and Exh. No. MPC-41, p. 2).

b. MPC revised its annual marginal generation capacity costs from $102.22/kW (Exh. No. MPC-40, p. 14) to $101.86/kW (Exh. No. MPC-41, PEM-15) and revised its winter and summer capacity costs from $58.47 and $43.75 to $58.26 and $43.60, respectively. This change also affected marginal distribution costs (Exh. No. MPC-41, p. 1-4).

c. MPC revised the implicit price deflator used to levelize transmission plant costs (Exh. No. MPC-41, p. 1-4, PEM-16), and updated the 1986 system peak value from 1,299 MW to 1,259 MW (Id.) which reduced marginal transmission plant costs from $47.73/kW to $47.09/kW (Id. and Exh. No. 40, PEM-4). MPC also transferred Substation O&M expenses from transmission to Substation costs (Id.) which reduced marginal transmission O&M costs from $33.42/kW to $24.94 (Id.).

d. MPC revised the implicit price deflator used to levelize its estimated substation construction costs, which reduced marginal substation plant costs from $7.72/kW to $7.61/kW. MPC also added O&M expenses to its substation costs valued at $.33/kW (Exh. No. MPC-41, pp 1-4 and PEM-17).

e. MPC changed its distribution capacity cost allocation method from using the sum of each class' monthly NCPs to using each class' annual average monthly NCPs. This revision and MPC's revised generation capacity costs resulted in reduced distribution costs by $47.1 million (Exh. No. MPC-41, pp. 2, 5, and 7-8).

f. MPC recomputed the annual transmission customer costs and computed demand and non-demand metered customer costs for secondary irrigation. Also, MPC revised the implicit price deflator it used to levelize customer plant costs, which decreased customer plant costs by about $164,000 (Exh. No. MPC-41, pp. 3 and 5 and Exh. No. MPC-40, p. 4 and PEM-7).

g. MPC recomputed its capacity loss factors by correcting the seasonal adjustment which increased the transmission capacity loss factor from 9.45 percent to 9.46 percent and reduced the substation loss factor from 1.3 percent to 1.2976 percent (Exh. No. MPC-41, pp. 2 and 4).

h. MPC revised its Street Lighting O&M costs, which increased the class customer costs by about $40,000 (Exh. No. MPC-41, p. 5).

12. The net (negative) effect of MPC's changes was about $55 million. This included roughly a $.9 million increase in energy costs, and decreases in total capacity and customer costs of about $55.9 million and about $.1 million, respectively (Id., p. 3).

Functionalized and Classified Costs

13. The following describes MPC's method of computing generation, transmission, substation, distribution, and customer costs. MPC's reactive power costs are also summarized in this subsection.

14. Generation. MPC computed annual marginal generation energy costs of $.01935/kWh using a ten-year stream of annual energy costs from its July 1990 avoided cost compliance filing (Exh. No. MPC-40, p. 13-14). On a seasonal basis the winter and summer marginal generation energy costs equal $.02369/kWh and $.01717/kWh, respectively (Exh. No. MPC-41, pp.1-4 and MPC RDR FEA-17).

15. MPC computed marginal capacity costs of $101.86/kW using

a combination of 6 years of data from its July 1990 avoided cost compliance filing (1996 through 2001) and the cost of purchased BPA NR capacity (1992 through 1995) (Exh. No. MPC-41, pp. 1-4 and PEM-15 and MPC RDR FEA-6), maintaining it needs capacity not reflected in the avoided cost data (Exh. No. MPC-40, p. 15).

16. MPC allocates annual generation capacity costs seasonally using loss of load hours (LOLHs). Winter and summer costs thus equal $58.26/kW and $43.60/kW, respectively (Exh. No. MPC-40, p. 14 and PEM-3 and MPC RDR FEA-6).

17. Transmission. MPC proposed transmission costs composed of incremental capacity plant investments, O&M expenses, and losses. Plant investment costs include new load and reliability investments, both of which MPC classified as capacity related. MPC escalated 1985 through 1989 incremental annual plant investments to 1992 dollars to compute plant costs. The sum of these incremental costs, divided by the change in peaks (1989 and 1986) results in a $47.09/kW marginal transmission plant cost. O&M Expenses ($24.94/kW) were computed by escalating incremental expense data from 1985 through 1989 and then dividing this increment by the same year's incremental peak. O&M expenses were not levelized (Exh. Nos. MPC-40, pp. 15-17 and PEM-4 and MPC-41, PEM-16 and MPC RDR PSC-511).

18. MPC derived transmission level loss costs of $9.64/kW (capacity) and $.0001734/kWh (energy) by applying transmission loss factors to annual generation costs. Transmission capacity costs consist of plant, O&M and capacity loss costs. Energy related transmission costs consist of loss costs (Exh. No. MPC-41, PEM-16).

19. Substation. MPC's marginal substation costs consist of the cost to construct a generic substation, O&M costs, and loss costs incurred at the substation level. MPC estimated substation construction costs of $43.00/KVA which, when levelized result in a $7.61/kW cost (note 1 KVA equals 1 KW, MPC RDR 298 and Exh. Nos. MPC-40, pp. 17-18). O&M expenses were computed using a method similar to that used to compute transmission O&M expenses; however,

the resulting substation O&M expense values differ. MPC substation O&M costs equal $.33/kW (Exh. Nos. MPC-40, pp. 17-18, MPC-41, pp. 1-4 and PEM-17 and MPC RDR PSC-511).

20. MPC's substation level loss costs ($1.33/kW (capacity) and $.000217/kWh (energy)) result from applying substation level loss factors to annual generation costs. Substation capacity costs consist of plant, O&M and capacity loss costs. Energy related substation costs consist of loss costs (Exh. No. MPC-41. PEM-17).

21. Distribution. MPC's distribution costs consist of energy and capacity losses incurred at the primary and secondary voltage levels of service and exclude plant investment or additional expenses (Exh. No. MPC-40, p. 18 and MPC RDR LCG-129). MPC asserts plant costs "should be handled through ... a line extension policy" (TR 962).

22. MPC's primary ($1.35/kW and $.000219/kWh) and secondary ($4.49/kW and $.000722/kWh) loss costs are derived by applying voltage level loss factors to annual marginal generation energy and capacity costs (Exh. No. MPC-41, PEM-18).

23. Customer. MPC's customer costs consist of the service drop (MPC RDR PSC-520), meter, and customer O&M expenses, the latter of which are divided into meter and non-meter reading expenses. Except for non-metering O&M, MPC computes lighting customer costs separately (Id., pp. 19-20).

24. Non-lighting Customer Costs. MPC computes customer plant investment (service drop and meter) costs using a "minimum size method" (Exh. No. MPC-40, p. 19). Application of this method results in "the plant costs of providing service to customers of minimum demand" (Id.). Thus, MPC includes the costs of connecting a customer to its system and metering usage. MPC compares its customer cost method to a replacement cost method (MPC RDR PSC-301).

25. MPC computes class specific customer plant investment

costs based on the total average cost required to connect a customer to its system, and levelizes the sum of these costs for all classes (Exh. No. MPC-41, PEM-19 and MPC RDR PSC-511).

26. MPC computes customer O&M expenses based on a five-year average of expenses. These expenses are divided into meter and non-meter reading expenses. Non-meter reading O&M includes customer accounting, service, and information and sales expenses.

27. MPC computed annual customer costs by summing the plant and O&M costs allocated to each customer class and dividing by the number of customers in each class.

28. Lighting Customer Costs. Lighting customer costs consist of investment costs and customer expenses. Customer investment costs are based on the annual replacement costs of poles, lamps, and hardware and include a return on investment and O&M expenses. Return on investment costs are computed as a proxy of the annual costs of installed plant (TR 1035). This cost is based on MPC's marginal cost of capital (11.46 percent), which is applied to the installed cost of plant for each lamp and pole type, wattage, and distribution facility. Investment related O&M expenses consist of changing lamps, cleaning refractors, etc. Customer expense costs include customer accounting, customer services and information and sales expenses (Exh. No. MPC-40, p. 21).

29. Reactive Power. MPC performed two reactive power cost analyses. First, MPC computed and proposed a reactive power adjustment charge of $2.23/kVAR/year. This charge is based on feeder capacitor costs of typical 300 to 600 kVAR size and computed in 1992 dollars. Based on 1987 to 1989 budgeted material and labor expenses, MPC computed the real-levelized annual fixed charge associated with the average installed cost feeder capacity costs. MPC computed the above costs as part of rate design and did not allocate these costs in its COS study.

30. Second, MPC examined, but did not propose, the costs to meter reactive power. MPC maintains reactive power metering and

billing would be roughly $2,000 per site and $40 per customer per month, respectively, if reactive demand and energy data were collected. If, however, only reactive energy information is needed, these costs would be about $550 per site and $7.75 per customer per month (Exh. No. MPC-46, TEW-12 and MPC RDR PSC-250).

Allocation of Classified Costs

31. This section summarizes MPC's cost allocation methods. MPC's loss factors, seasonal determination and allocation, time-of-day analysis and discount development, and allocation of costs are discussed, in turn. MPC's lighting unit and total cost allocations are also summarized.

32. Energy and Capacity Losses. MPC computes energy and capacity loss factors (henceforth loss factors) using the same approach used in its previous filing (MPC RDR LCG-113). MPC's loss factors and costs are presented in Table 2.

Table 2. MPC's proposed Voltage Level Line Losses and Costs

Voltage Level	Percent Line Loss		Line Loss cost	
	Capacity (%)	Energy (%)	Capacity ($/kW)	Energy ($/kWh)
Transmission	9.46	8.96	9.64	.001734
Substation	1.2976	1.12	1.33	.000217
Primary Dist.	1.33	1.13	1.35	.000219
Secondary Dist.	4.41	3.73	4.49	.000722

Source: Exh. No. MPC-41, PEM-16, 17, and 18.

33. MPC computed average monthly energy loss factors based on monthly loss factors using loss relationships at each of the substation and primary and secondary distribution levels of service (MPC RDR MCC-244 and MPC RDR LCG-112). MPC applied these relationships, in turn, to total monthly system distribution energy volumetric losses and substation, primary, and secondary level sales to computed primary, substation, and secondary level loss factors (Exh. No. MPC-40, pp. 10-11, and MPC RDR LCG-112). MPC

computed transmission level loss factors based on transmission and distribution level volumetric losses and sales (kWh).

34. MPC computed seasonally adjusted, average monthly capacity loss factors using its monthly energy loss factors, class coincidence and load factors, and total monthly system peaks at generation (Exh. Nos. MPC-40, p. 11 and PEM-10 and MPC-41, PEM-21 and MPC RDR LCG-112). MPC computes monthly capacity loss factors by voltage level of service. MPC's proposed factors are those which, when summed and applied to the normalized monthly CPs at each voltage level, equal monthly system generation peaks.

35. Seasonality. MPC reduced the current winter season, comprised of November through March, by removing March from its definition. Summer would be defined as March through October. MPC maintains its winter season displays similar LOLHs, marginal energy costs, and load shapes (Exh. No. MPC-40, p. 6). MPC asserts it costs more to supply energy and capacity during the winter season (Id.).

36. Seasonal Determination. MPC determined seasons by analyzing the variance (ANOVA) of prospective (1991 through 1993) monthly marginal energy cost (system lambda) and LOLH data. MPC also compared monthly load shapes from PROMOD using historical, 1986 through 1989 data (Exh. No. MPC-40, p. 7 and MPC RDR LCG-111).

37. The following describes the data and analysis MPC used to define seasons. MPC used the same energy cost data to determine seasons and to seasonally allocate its marginal energy costs. These data differ, however, from those used to compute annual marginal energy costs (MPC RDR PSC-270). A LOLH measures the "hours during which there is a relative need for capacity" (MPC RDR PSC-237), or the expectation that capacity will not be sufficient to serve load in a given hour (Exh. No. MPC-46, p. 23 and MPC RDR PSC-237). MPC used these data in its ANOVA.

38. MPC's monthly load shapes consist of hourly load factors plotted against the hours of a typical week in a month and are

based on average historical monthly loads 1986 to 1989 (Exh. No. MPC-40, p. 8 and PEM-9). All of MPC's data come from the same PROMOD run (MPC RDR PSC-267). By visually comparing load shapes, MPC asserts that "the month of January is similar to February, November, and December" (Exh. No. MPC-40, p. 8). MPC also maintains its load shapes "show how the months of March and October are not similar to January" (Id.).

39. In its ANOVA, MPC analyzed six winter season scenarios but limited its winter definition to include no more than the months in the current winter season (Exh. No. MPC-40, PEM-9). MPC maintains its analysis of LOLHs revealed a winter season of January and December.

40. MPC determined its seasons using the results of the above analysis and its current seasons to recommend the four-month winter season it proposed rather than the highest ranked LOLH ANOVA scenario which consists of January and December. MPC, however, also appears to have accounted for adverse effects of customer reactions to changes in seasonal rates as part of its selection criteria (Id., p. 8, MPC RDR PSC-268, and TR 1041).

41. Seasonal Allocation. The following describes MPC's seasonal allocation of marginal generation costs. MPC computed its winter/summer (W/S) marginal generation energy costs using PROMOD generated data. MPC averaged its energy costs by season and computed ratios of these costs to annual average costs from the same data set (Exh. No. MPC-41, PEM-14, p. 2 and MPC RDR FEA-17). MPC used these ratios to compute winter and summer marginal energy costs of $.02369/kWh and $.01717/kWh, respectively (Exh. No. MPC-41, p. 4).

42. MPC used LOLH data to compute a W/S marginal generation capacity cost ratio of 57/43. MPC computed this ratio by separating monthly LOLHs for 1991 through 1993 into its proposed winter and summer seasons. MPC then summed these LOLHs by season and divided each seasonal total by aggregate annual LOLHs for the combined three years (MPC RDR FEA-6). MPC applied the results to

its annual marginal generation capacity costs which resulted in winter and summer generation capacity costs of $58.26 and $43.60 (Exh. No. MPC-40, p. 14 and PEM-3 and MPC RDR FEA-6 and Exh. No. MPC-41, p. 2).

43. Time-of-Day Analysis. MPC also analyzed six time-of-day (TOD) peak and off-peak periods using the same LOLH data it used to determine seasons (Exh. No. MPC-40, p. 9 and PEM-11 and MPC RDR PSC-272, and RDR HRC-26). MPC used this analysis to develop its Off-Peak Discount Rate, which would apply to hours other than 7:00 am through 8:59 pm, Monday through Friday, excluding holidays (Exh. No. MPC-46, p. 28 and proposed Schedule Nos. GS-1 and GS-2, Appendix B, filed October 1, 1990). MPC currently defines the off-peak period as all week day hours beginning at 8:00 PM through 7:00 AM (MPC GS-1 and GS-2 Montana Tariffs).

44. MPC proposed discounted prices for off-peak loads, but not based on a TOD cost study (MPC RDR PSC-248). MPC computed seasonal off-peak discounts by voltage level based on peak and off-peak LOLH ratios (Exh. No. MPC-46, p. 27 and TEW-22). MPC also included peak and off-peak billing demand and seasonal marginal demand charges in its formulation of the discount (Id., TEW-22). MPC holds its proposed discount would "reflect appropriate off-peak demand charges" (Id., p. 27).

45. Based on the above analysis, MPC proposed the following seasonal off-peak demand discount rates:

Table 3. MPC's Proposed Off-Peak Demand Discount Rates

Customer Class	Winter	Summer
Primary	45%	44%
Substation	46%	48%
Transmission	27%	36%

Source: Exh. No. MPC-47, TEW-22.

46. MPC's current off-peak demand discount is fifty percent

of current monthly demand prices. This discount applies to demand exceeding the customer's highest on-peak demand for each of the GS-1 and GS-2 classes (MPC Montana electric tariff, Schedules GS-1 and GS-2). MPC's off-peak discounts would apply to MPC's proposed monthly seasonal demand prices for each of the above listed classes for excess off-peak demand (Amendment to Application, Appendix B, revised October 11, 1991, Schedules GS-1 and GS-2). MPC proposed to retain its current 1,000 kW minimum average annual demand eligibility threshold. MPC's current off-peak discounts are experimental, but it proposed the above discounts as a permanent option. MPC will continue to limit the number of customers served through the discount (Exh. No. MPC-47, p. 27).

47. Allocation to Classes. As the forgoing summarized MPC's losses, seasons, TOD analysis and discount development, the following reviews MPC's allocation of costs. MPC reduced the residential employees' contribution to each of the allocation volumes by 40 percent (TR 1037). Also, all of the energy and capacity allocators MPC used at each of the generation and voltage-levels were measured at the meter (MPC RDR FEA-10-15). The parties' generation and voltage-level allocation methods are summarized in the following tables.

TABLE 4
The Parties' Proposed Allocation Methods: Generation

	Energy			Capacity		
Party	Winter	Summer	Annual	Winter	Summer	Annual
MPC	Sales	Sales	N/A	1CP	1CP	N/A
MCC	Sales	Sales	N/A	N/A	N/A	12CP
MII	--	--	N/A	1CP	8CP	N/A
LCG	--	--	N/A	1CP	1CP	N/A
RPC*	Sales	Sales	N/A	1CP	1CP	N/A

Sources: Exh. No. MPC-40, p. 12-13
Exh. No. MCC-6, JD-6, p. 5
Exh. No. MII-2, p. 17-24, AJY-5
Exh. No. LCG-6, pp. 7-12, JWM-5

Exh. No. RPC-2, p. 9-10, RPC RDR PSC-583 and PSC-618

*Allocation computed at generation.

Definitions: 1CP - Single month coincident peak
12CP - Average of twelve monthly coincident peaks
12NCP - Average of twelve monthly non-coincident peaks
SumNCP - Sum of the non-coincident peaks

TABLE 5
Parties' Proposed Allocation Methods: Losses

		Energy			Capacity		
Party	Function	Winter	Summer	Annual	Winter	Summer	Annual
MPC	Generation	N/A	N/A	N/A	N/A	N/A	N/A
	Transmission	N/A	N/A	Sales	N/A	N/A	12CP
	Substation	N/A	N/A	Sales	N/A	N/A	12CP
	Distribution	N/A	N/A	Sales	N/A	N/A	12NCP
MCC	Generation	N/A	N/A	N/A	N/A	N/A	N/A
	Transmission	N/A	N/A	Sales	N/A	N/A	12CP
	Substation	N/A	N/A	Sales	N/A	N/A	12CP
	Distribution	N/A	N/A	Sales	N/A	N/A	12NCP
LCG	Generation	Sales	Sales	N/A	1CP	1CP	N/A
	Transmission	N/A	N/A	Sales	N/A	N/A	12CP
	Substation	N/A	N/A	Sales	N/A	N/A	12CP
	Distribution	N/A	N/A	Sales	N/A	N/A	SumNCP
RPC*	Generation	Sales	Sales	N/A	1CP	1CP	N/A
	Transmission	N/A	N/A	N/A	N/A	N/A	12CP
	Substation	N/A	N/A	N/A	N/A	N/A	12CP
	Distribution	N/A	N/A	N/A	N/A	N/A	11/12 SumNCP

Sources: Exh. No. MPC-40, pp. 12-13, MPC-41, pp. 7-8
Exh. No. MCC-6, pp. 61-62, JD-7 and JD-8 (Revised per MCC RDR MPC-107 and at hearing, Tr pp. 1324-1325)
Exh. No. LCG-6, pp. 7-12, JWM-5
Exh. No. RPC-2, pp. 9-10, RPC RDR PSC-583 and PSC-618

*Allocation computed at generation.

Definitions: 1CP - Single month coincident peak
12CP - Average of twelve monthly coincident peaks
12NCP - Average of twelve monthly non-coincident peaks
SumNCP - Sum of the non-coincident peaks

48. Generation. Seasonal generation energy costs are allocated to all customer classes based on each class' contribution to normalized, seasonal kWh sales (MPC RDR FEA-10). Seasonal

generation capacity costs are allocated to all customer classes based on each class' contribution to winter and summer normalized CPs (Exh. No. MPC-40, p. 12). MPC based its winter and summer CP months on monthly system peaks at the generation level (Exh. No. MPC-41, p. 6).

49. Transmission and Substation. MPC allocated transmission energy costs based on each class' contribution to normalized annual kWh sales at the transmission level. Capacity related costs are allocated based on each class' contribution to the normalized average monthly CP (Exh. Nos. MPC-40, p. 12 and MPC-41, PEM-13, and MPC RDR PSC-511). MPC applied the same methods it used to allocate transmission costs to allocated substation energy and capacity costs, but used substation level data (Id.).

50. Distribution. MPC allocated primary and secondary distribution energy costs according to each class' contribution to normalized annual kWh sales at each level. MPC allocated primary and secondary distribution capacity costs according to each class' average monthly NCP (Exh. No. MPC-41, pp. 7-8).

51. Customer. MPC allocated non-lighting customer plant investment costs and meter reading O&M expenses to non-lighting customer classes based on customer size. Non-meter reading O&M expenses were allocated to all customer classes, including lighting, based on number of customers (Exh. No. MPC-40, pp. 19-20 and PEM-7, and Exh. No. MPC-41, PEM-19, and MPC RDR PSC-303 and PSC-511).

52. Lighting. MPC allocated costs to lighting classes to arrive at unit costs by lamp and pole type, wattage, distribution facility (overhead or underground), and facility ownership (company or customer) (MPC RDR PSC-304). As a result, generation, transmission, substation, and distribution energy and capacity costs were allocated by lamp type based on their total annual consumption and bill wattage units, respectively (Exh. No. MPC-40, pp. 20-21).

53. Return on customer investment costs are allocated to company owned lights by lamp and pole type, and distribution facility. Investment related O&M expenses are allocated to all Lighting classes excluding customer owned and miscellaneous street lights. Customer expense costs are spread to the number of lights per customer for all lighting classes (MPC RDR PSC-602).

MCC COST OF SERVICE

54. The MCC employed James H. Drzemiecki (hereafter MCC) of J. W. Wilson & Associates, Inc., to testify on its behalf. An overview of MCC's COS approach, the changes MCC has made relative to Docket No. 87.4.21, and a detailed discussion of MCC's methods follow (Exh. No. MCC-6).

Overview

55. The manner in which MCC organizes its costs and computes electric costs of service differs from that used by MPC. MCC functionalizes total plant costs into bulk power supply and other functional costs. Bulk power supply costs consist of generation and high voltage transmission. Other functional costs include distribution and customer related costs (Exh. No. MCC-6, p. 36). Although MCC organizes its costs differently than does MPC, MCC includes the same cost functions as MPC does. MCC supports this costing approach by noting that bulk power supply costs represent three-fourths of the total cost of electricity supply and vary most by time of use (Exh. No. MCC-6, p.35). Table 7 Illustrates MCC's COS/RD model.

Table 7. MCC Cost of Service/Rate Design Model

Function	Cost of Service Classified	Cost of Service Allocated	Reconciled	Rate Design/ Pricing
Bulk Power	Energy	Seasons	Bulk Power	c/kWh
Distribution	Capacity &	and	Adjustment	$/kW
	Customer	Customer		$/Customer
	(Access)	Classes		

56. MCC used marginal cost to compute bulk power supply costs and embedded cost to compute distribution and customer costs. MCC reasons that it is more important to focus marginal cost applications on bulk power supply costs since the objective of efficiency, conservation, and equity are best achieved at the bulk power level. MCC maintains these reasons do not apply to distribution and customer cost (Exh. No. MCC-6, pp. 36-39). MCC asserts embedded distribution and customer costs approximate long-run marginal costs (Id., p. 56).

57. MCC conducted two marginal cost studies, one each for its and MPC's revenue requirements. Based on MCC's cost theory, the level of accounting revenue requirements impacts marginal costs. MCC recommends using its COS study which, in turn, adopts Mr. Clark's proposed revenues (Exh. No. MCC-6, p. 5).

Differences in MCC's COS Approach From Docket No. 87.4.21

58. The following summarizes the differences between the COS study filed in this Docket and that filed by MCC in Docket No. 87.4.21:

a. Whereas in Docket No. 87.4.21, MCC computed annualized long-run marginal transmission capacity costs using a nominal carrying charge (Order No. 5340, FOF 43), in this docket MCC used a real carrying charge (Exh. No. MCC-6, p. 53 and MCC RDR MPC-108).

b. Whereas in Docket No. 87.4.21, MCC allocated bulk power capacity costs seasonally using the normalized system peak for each of the winter and summer seasons (Order No. 5340, FOF 48), MCC now allocates these costs using the annual average of monthly CPs (Exh. No. MCC-6, p. 61).

c. Whereas in Docket No. 87.4.21, MCC allocated bulk power energy costs seasonally, adjusted for losses at each of the transmission and distribution voltage levels, by normalized kWh sales (Order No. 5340, FOF 49), MCC now proposes to allocate the same type of costs by season based on each class' contribution to annual normalized energy sales. MCC allocates energy costs, including losses at the generation level (Exh. No. MCC-6, p. 61). MCC also states that "the losses were applied by cost function in the same manner as was developed by MPC." (MCC RDR PSC-334).

d. In Docket No. 87.4.21, MCC allocated distribution costs based on each class' NCP demand (Order No. 5340, FOF 45). In this Docket MCC proposes to use the monthly average of normalized NCPs (TR 1325-1326).

59. The balance of this section summarizes MCC's proposed functionalized and classified cost methods. During the course of this proceeding, MCC made several COS study changes.

Functionalized and Classified Costs

60. Bulk Power Supply. As noted, bulk power supply consists of generation and high voltage transmission costs. Generation costs are classified as capacity and energy. Transmission costs are classified as capacity. MCC maintains that a utility incurs capacity costs to provide system peak demand. Energy costs are incurred to "drive" capacity. MCC maintains that energy costs consist of the cost of fuel and O&M costs. Further, MCC maintains that:

> The marginal cost of meeting peak demand is the annual carrying cost of additional capacity that must be added only for the purposes of meeting that additional demand. The cost of meeting additional peak demand will, therefore, never exceed the carrying cost of that generating unit with the lowest fixed cost per Kw of capacity. (Exh. No. MCC-6, p.42.)

61. MCC includes transmission costs in its definition of bulk power costs since bulk power must be available at all times and in the various quantities demanded (Exh. No. MCC-6, p. 40). MCC argues "the marginal cost of transmission is the cost associated with connecting additional bulk power loads during peak periods" (Id., p. 44), which consists of the least capital-intensive generating plant costs to meet peak load (Id., p. 45).

62. In practice, MCC defines generation energy as bulk power energy costs and generation and transmission capacity costs as bulk power capacity costs. The following describes how MCC actually

computed generation and transmission costs and how MCC develops its bulk power energy and capacity costs.

63. Generation. MCC computes annual and seasonal marginal generation energy and annual marginal generation capacity costs using twenty-five years of data from MPC's July 1990 avoided cost compliance filing. MCC's capacity cost data were amended, like MPC's, to include the cost of BPA NR capacity during 1992 through 1995 (Exh. No. MCC-6, pp. 43, 52-54, and JD-5 as revised in MCC RDR MPC-107). MCC holds that generation energy and capacity costs computed using twenty-five years of data, as opposed to MPC's ten years of data, better approximates the long-term trends in energy and capacity costs and would be consistent with prior Commission orders. MCC maintains MPC has, by limiting the period over which it computes marginal energy and capacity generation costs, "selected a period which maximized the value of capacity and minimized energy costs" (Exh. No. MCC-6, p. 7 and p. 43).

64. MCC computed annual generation energy costs of $.02237/kWh. MCC allocated this cost to seasons as discussed below. MCC computed an annual generation capacity cost of $95.86/kW-year (revised to $95.64/kW-year, MCC RDR MPC-107) (Exh. No. MCC-6, pp. 43, and 52-53 and JD-5, revised in MCC RDR MPC-107).

65. Transmission. MCC computed transmission capacity costs using data Montana-Dakota Utilities provided MCC in Docket No. 86.5.28, but escalated to 1992 dollars (MCC RDR MPC-108). MCC computes the installed cost of transmission capacity to connect a combustion turbine (CT) at $42.11/kW, which MCC annualizes using a 10.34 percent carrying charge. MCC adjusts this cost for fixed O&M and a 15 percent reserve requirement. This results in transmission costs of $5.31/kW (Exh. No. MCC-6, p. 53 and MCC RDR MPC-108). MCC recommends the Commission reject MPC's estimated transmission costs because, MCC contends, MPC's use of historical plant additions overstates transmission capacity costs (Exh. No. MCC-6, p. 8). Also, MCC appears to compute transmission costs to include energy losses in addition to capacity. As noted above, MCC applied losses by cost function (MCC RDR PSC-334).

66. Bulk Power Energy and Capacity Costs. As noted, MCC defines generation energy as bulk power energy costs and computes this cost as described above. MCC adds its generation and transmission capacity costs, $95.64/kWh-year and $5.31/kW, respectively, and defines the sum, $100.95/kW/year (revised from $101.17/kW/year in MCC RDR MPC-107), as bulk power capacity costs (Exh. No. MCC-6, p. 53 and JD-6). MCC retains these definitions for its allocation and reconciliation process. MCC expresses all marginal bulk power costs in beginning-of-year 1992 dollars (MCC RDR PSC-316). As noted below, MCC reconciled these costs with its embedded revenue requirement prior to allocating costs to classes. MCC's embedded revenue requirements are computed with a 1989 test-year (MCC RDR MPC-140).

67. Distribution and Customer. As noted above, MCC used embedded costs as a proxy for marginal customer costs. MCC gives three reasons in support of this proxy approach. First, the margin related to these functions is conceptually difficult to define. Second, marginal customer and distribution costs are difficult to measure. Finally, MCC maintains there is less reason to be concerned with marginal and time variation costs for the distribution and customer functions than for bulk power supply (Exh. No. MCC-6, p. 56).

68. MCC classified distribution costs as energy and capacity and used MPC's jurisdictional separation study as a basis for its distribution cost study. MCC classified total investment in distribution plant (accounts 360 through 368) as demand-related and maintained the primary and secondary division of the distribution system to compute these costs (Exh. No. MCC-6, p. 55). MCC computed energy and capacity loss costs for each of the primary and secondary distribution levels using MPC's loss factors and MCC's generation costs (Exh. No. MCC-6, p. 8 and MCC RDR MPC 1-113).

69. MCC disagrees with MPC's distribution cost approach and maintains it is a short-run method, which can only be considered as long-run if there is excess capacity on its system. MCC argues

that if there is excess distribution capacity, "the Commission should require the Company to prove in its next rate case why the excessive portion of distribution capacity costs should not be excluded from future rates" (Exh. No. MCC-6, p. 57)

70. MCC holds customer costs are those related to connecting a customer to the system, maintaining the connection, and billing and metering costs (Exh. No. MCC-6, p. 38).

Allocation of Classified Costs

71. This section discusses MCC's allocation of costs to seasons and classes.

72. Seasonality. MCC maintains MPC's capacity and energy costs should not be seasonally allocated. MCC makes this determination based on its analysis of winter and summer peaks on MPC's system. MCC also maintains MPC's marginal energy cost analysis shows little seasonal difference (Exh. No. MCC-6, p. 7).

73. MCC's seasonal analysis seeks to determine time periods within which costs are similar and between which they differ (Exh. No. MCC-6, p.45). MCC based its analysis on the load data MPC used to compute marginal energy and capacity costs and five-year, historical seasonal peaks. By examining the average monthly peaks for each of the winter (November through February) and summer seasons for 1985 through 1989 and the test year, MCC contends the summer peak load is experiencing a greater growth rate than is that of the winter. MCC maintains that capacity costs over time appear to be experiencing less seasonal differences than in the past. Based on its analysis, MCC concludes MPC's system load patterns do not significantly vary by seasons and existing seasonal rate differentials should gradually be narrowed (Exh. No. MCC-6, pp. 47-48).

74. Allocation to Classes. Unlike MPC, MCC first reconciles its total marginal (bulk power) costs to its revenue requirement and then allocates each of its costs, marginal and embedded, to

classes. MCC's application of this process to each of its cost functions is summarized below.

75. Bulk Power Energy. MCC reconciled and allocated its bulk power energy costs as follows. First, MCC seasonally allocated its annual unit marginal energy cost ($.02237/kWh) using the same seasonal energy cost ratios MPC used (MCC RDR MPC-107) which resulted in winter and summer energy costs of $.02231/kWh and $.02240/kWh (revised to $.02739/kWh and $.01985/kwh, MCC RDR MPC-107), respectively (Id., p. 53-54 and JD-5 and 6). MCC then computed class annual usage costs based on normalized seasonal energy usage. Next, MCC computed its class energy cost allocation factors based on each class' contribution to total annual energy costs. MCC reconciled its total marginal energy costs and its total marginal capacity costs to its embedded energy and capacity costs and, in turn, allocated these costs to classes using the above described allocation factors. MCC maintains it adjusted seasonal energy costs for line losses at the generation level. MCC also states, as noted above, it applied losses by cost function (Exh. No. MCC-6, p. 61, JD-6, p. 5 and JD-7, p. 1 and MCC RDR PSC-334).

76. Bulk Power Capacity. MCC allocated bulk power capacity costs based on "the average of the twelve monthly CPs of each class" (Exh. No. MCC-6, p. 61) as follows. MCC computed total generation and transmission capacity costs by applying each function's unit cost to MPC's jurisdictional peak (1,028,157 kW). MCC then reconciled the total of these costs and its energy costs to its embedded capacity and energy costs and allocated its total reconciled capacity cost based on each class' portion of MPC's average of the twelve monthly CPs (Exh. No. MCC-6, p. 61, JD-7, and JD-8).

77. Distribution. MCC allocated distribution costs to classes using the sum of the monthly NCPs contained in MPC's study (Exh. No. MCC-6, p. 62). At the hearing, MCC reallocated some of the primary distribution costs, initially allocated as substation costs, to distribution. MCC also revised its distribution cost

allocation to use the average monthly normalized NCPs (TR 1324-1325).

78. Customer. MCC appears to have allocated its customer costs to classes based on each class' portion of MPC's total customer costs (Exh. No. MCC-6, JD-8, p. 1 and Exh. No. MPC-40, PEM-1, p. 1). MCC does not appear to have computed unit customer costs. Since MPC's total customer charge revenues were less than MCC's total customer costs for all classes, MCC used MPC's customer charges to design rates (Exh. No. MCC-6, pp. 63-64).

Rebuttal

79. Each of MPC, LCG, and RPC rebutted MCC's COS testimony. MPC rebutted MCC's bulk power supply costs, including the number of years of data MCC used to compute generation costs, MCC's transmission cost method, MCC's use of embedded costs to compute distribution and customer costs, and its seasonal analysis.

80. LCG rebutted several issues, including the number of years of data MCC used to compute generation costs, its choice of the winter peak month, and its allocation of both marginal capacity losses and generation capacity costs.

81. LCG argues that MCC's COS study is flawed due to several errors and omissions, some of which result from using invalid MPC data. LCG also challenges MCC's COS study for distorting the marginal cost of energy and capacity. LCG contends that distortions arise due to incorrect computations, classifications, and allocations of marginal costs. LCG recommends the Commission give more weight to MPC's COS study, as corrected in its direct testimony, than to MCC's COS proposals (Exh. No. LCG-7, pp. 1-2).

82. RPC also challenges MCC's allocation of generation costs to seasons and classes and MCC's loss costs.

Functionalized and Classified Costs

83. Bulk Power Supply: Generation. Both MPC and LCG rebutted

MCC's used of twenty-five years of data versus MPC's ten years to compute generation costs as follows.

84. MPC maintains that MCC's criticism of MPC's use of ten years of marginal energy and capacity cost data is invalid. MPC argues the marginal cost objective is to provide a proper price signal and that customers should be able to make intelligent decisions based on ten-years of costs. MPC contends that MCC's cost approach, which MCC asserts remains consistent with previous Commission orders, benefits the Residential class by reducing capacity costs and increasing energy costs. MPC maintains MCC's twenty-five year period maximizes energy and minimizes capacity costs (Exh. No. MPC-41, p. 10-11).

85. LCG recommends that if the Commission continues to rely on marginal costs to set class revenue requirements and rates, it base these costs on the ten years of data MPC used to compute marginal generation energy and capacity costs. LCG argues this period would be sufficient to establish long-run marginal cost based prices, yet short enough to avoid estimation error.

86. Also, LCG contends the appropriate price signal for rates out of this Docket should first recognize the need for peak, followed with a need for energy resources, as argued by MPC. LCG plotted real capacity costs per MCC's Exhibit No. JD-5 and maintains the resulting graph shows "capacity needs have priority until well into the next century" (Exh. No. LCG-7, p. 4). LCG also maintains that at this time (apparently in year 2004) capacity costs fall and remain relatively stable through 2016. LCG maintains MCC's twenty-five year analysis melds capacity and energy priorities, resulting in distorted price signals (Exh. No. LCG-7, pp. 4-5 and JWM-9, p. 1).

87. Further, LCG maintains prices should be based on long-run marginal costs that exhibit a clear future pattern. LCG argues MCC's marginal capacity costs contain conflicting price signals over several long-run cycles and, because of the cyclical nature of MCC's costs, the price signals understate marginal capacity costs.

LCG also maintains that MCC's marginal capacity cost analysis illustrates that including such diverse costs, even though they occur in later years, reduces real levelized capacity costs. LCG also notes that this is the case even though less weight is given those costs occurring in later years through levelization (Exh. No. LCG-7, pp. 2-6).

88. Bulk Power Supply: Transmission. MPC rebuts MCC's transmission capacity cost method noting it has been rejected by previous orders. Further, MPC maintains MCC's transmission capacity cost method conflicts with MCC's assumption that the present system exists.

> ...Mr. Drzemiecki, in his testimony states that a marginal cost analysis recognizes that the present system exists and that it is the addition to this existing system that determines the marginal cost (see page 28 of Mr. Drzemiecki's testimony). However, his analysis assumes something very different. His assumption that the Company would or could place a combustion turbine near a load center does not take into account the limitations, both physical and political, that the Company faces. He does not account for the cost of the combustion turbine, the cost of fuel (including securing a fuel source), nor the cost of siting the combustion turbine near a load. He assumes apparently, that these costs are not capacity related or do not exist and conveniently ignores them. Those assumptions are, obviously, simply incorrect.

(Exh. No. MPC-41, p. 11-12).

MPC states that "at this time [it] may not add combustion turbines to its existing system because the total cost, which includes generation and transmission related cost, may not be economic when compared to adding transmission capacity" (Id., p. 12). MPC holds that it considers political and environmental concerns when it chooses a transmission cost method. MPC, however, agrees that transmission marginal cost methods need further study (Id., pp. 11-13).

89. Distribution and Customer Costs. MPC rebuts MCC's use of embedded distribution and customer costs to approximate long-run marginal costs. MPC maintains that historic depreciated plant costs are not incremental. Also, MPC maintains that equating marginal and embedded costs is incorrect for COS purposes. MPC argues that MCC's reasoning that distribution costs are difficult to define and measure is invalid. MPC notes it has measured and computed these costs and maintains that these costs should be used for consumption decisions (Id., p. 13).

90. As an aside, MPC notes that, although MCC criticized MPC's distribution and customer cost analyses, MCC used the results of these studies to allocate its revenue requirement to customer classes (Id., p. 13-14).

Allocation of Classified Costs

91. Loss Costs. Both LCG and RPC rebut MCC's allocation of loss costs. LCG maintains MCC uses MPC's approach to allocate capacity loss costs. LCG reiterates that MPC's treatment of capacity loss costs wrongly allocates costs to customer classes. LCG contends that MCC's methods also wrongly allocate these costs (Exh. No. LCG-7, p. 7).

92. RPC maintains MCC's use of sales level energy and demand volumes to compute functional marginal cost revenue requirements improperly functionalizes losses; RPC discusses this topic in its direct testimony (Exh. No. RPC-3, p. 4 and RPC RDR PSC-583).

93. Further, RPC maintains MCC improperly allocates energy loss costs to customer classes by using sales level volumes. RPC notes MCC holds, at page 61 of his direct testimony, that generation level energy should be used to allocate marginal energy costs, but allocates these costs using the same sales level volumes used by MPC. RPC also maintains generation capacity costs should be allocated on the same basis in which MCC computed these costs -- using system peak month demand (Exh. No. RPC-3, pp. 4-5).

94. Seasonality. MPC maintains MCC's seasonal analysis is incorrect because MCC only examines monthly peaks rather than LOLHs and marginal costs. Further, MPC argues that MCC's argument in which MCC links peak similarity with cost similarity is incorrect since peak similarity does not mean that the costs of serving these peaks are the same. MPC maintains the peaks MCC examined are not similar (Exh. No. MPC-41, p. 9).

95. MPC maintains that the average monthly seasonal peaks used by MCC incorrectly depict the trends in MPC's peak loads. MPC maintains the trend in seasonal peak loads should be determined by examining the actual one-hour peak load for a season, which by definition is the seasonal peak. MPC also maintains MCC's use of seasonal-monthly averaged peak data "moves the analysis away from examining the trend in the one hour seasonal peaks to examining something between seasonal peak and seasonal energy" (Exh. No. MPC-21, p. 26).

96. Using bivariate regression analysis on actual winter and summer peak load data, MPC shows that seasonal peaks have diverged not converged. In this analysis, MPC regressed actual peak loads on a trend variable for each of the winter and summer seasons (Exh. No. MPC-21, p. 26, RJL-13, MPC RDR HRC-130, and MPC RDR PSC-10, Late-Filed Exhibit).

97. Seasonal Allocation. Both MPC and RPC rebut MCC's failure to revise its COS to incorporate MPC's revised system lambdas used to seasonally allocate energy costs. In this regard MPC rebuts the accuracy of MCC's study by asserting that use of system lambdas other than those provided in response to DR No. FEA-17 appears as an attempt to minimize the winter/summer differential (Exh. No. MPC-41, p. 8-9).

98. RPC maintains that MCC has not reflected MPC's revised seasonal marginal energy costs per MPC's RDR FEA-17, even though RPC recognizes MCC's acknowledgement of its oversight (Exh. No. RPC-3, p. 5). RPC maintains that by correcting MCC's energy costs,

the interruptible class' revenue requirement, per Exhibit No. MCC-6, JD-7, would be $12,808,998 compared to $13,291,000. Although it used MCC's unit marginal costs and revenue requirement to recompute the interruptible revenue requirement, RPC does not intend to suggest the data are valid (RPC RDR PSC-584 and Exh. No. RPC-3, p. 4).

99. Generation Capacity. LCG rebuts MCC's choice of February as the 1989 test year peak and MCC's allocation of bulk power generation capacity costs as follows.

100. LCG's rebuttal maintains MCC incorrectly used MPC's February measure of the 1989 test year peak rather than the system peak month of January. LCG maintains that the jurisdictional peak value should be 1,088,991 kW, not the 1,028,157 kW value MCC used (Exh. No. LCG-7, p. 6).

101. LCG argues that MCC's allocation of bulk power generation capacity costs should not be adopted. LCG maintains MCC uses MPC's transmission cost allocation approach, which consists of the annual average of the twelve monthly peaks, to allocate these costs (Id., p. 10). Further, LCG maintains MCC abandoned the method it proposed and the Commission approved in Docket No. 87.4.21. LCG notes that in Docket No. 87.4.21 MCC allocated marginal capacity costs seasonally based on each season's single largest peak. Also, LCG notes that MCC has not provided in this docket any support for changing its method. LCG asserts that MCC's proposed method distorts relative customer class capacity and energy use (Id., p. 11).

MII COST OF SERVICE

102. Montana Irrigators, Inc. (MII) employed Anthony J. Yankel of Yankel and Associates, Inc. to file testimony on behalf of MII. Mr. Yankel (hereafter MII) filed direct testimony regarding COS issues in this case (Exh. No. MII-2). MII compares MPC's current and proposed residential and irrigation electric prices with those charged by other northwest utilities. MII also addressed certain

aspects of MPC's cost allocation proposals. Based on these concerns, MII provides a recommendation regarding the irrigation class revenue responsibility which is summarized under reconciliation.

Functionalized and Classified Costs: Regional Price Comparisons

103. MII addresses the reasonableness of MPC's irrigation rates by a comparison to regional rates. MII testified that rates should be consistent on an interclass COS basis. MII also maintains that such comparisons are important for irrigators since their products compete in regional and local markets. The following summarizes MII's Residential and Irrigation rate comparison, followed by a review of MII's conclusions.

104. Residential Rates. MII compared regional Residential rates on an average price per kWh basis which includes customer and energy prices and rate riders, if applicable (Exh. No. MII-2, p. 7 and MII RDR PSC-587). MII compared MPC's current Residential rates with those of Idaho Power, UP&L (3 states) and PP&L (4 states). Additionally MII made comparisons for usage intervals between 250 and 2,000 kWh. MII maintains that MPC's current winter rates are near the median of the nine sources examined. Yet MPC's proposed winter rates would lower the price for low usage and maintain the price for higher usage customers around the median for the sources examined.

105. MII maintains MPC's current summer rates are second among the nine sources. MII suggests this difference may indicate the need for a rate increase and that more of MPC's costs are incurred in the winter. MII maintains that MPC's proposed increase would result in summer rates that are third lowest for low usage customers and in maintaining the price for higher usage customers are around the median for the jurisdictions examined.

106. Irrigation Rates. MII compared irrigation rates on a basis similar to that used to compare Residential rates (MII RDR PSC-590). With irrigation, however, MII examined usage ranges from

9,500 kWh to 109,500 kWh. MII included UP&L irrigation rate option C, offered in Utah and Wyoming, in its analysis. Customer loads on this rate are subject to interruptions for up to 12 hours per week, although no customer has been interrupted in several years (Exh. No. MII-2, p. 9).

107. MII asserts MPC's current irrigation rates are lower than all other jurisdictions examined and second lowest for larger customers. MII maintains MPC's proposed immediate 29 percent increase to the irrigation class would result in raising small and large usage irrigation customers up to about the median inter-jurisdictional rate. MII also holds that "given the fact that the average demand for Montana irrigation customers is approximately 30 kW and given the fact that these customers are proposed to take the largest relative shift in rates, this means that the weight of this proposed change is greater than that experienced by the residential class" (Exh. No. MII-2, p. 9).

108. MII concludes MPC's proposals would disadvantage its irrigation customers relative to irrigation and residential customers in other jurisdictions. MII further maintains that even though its analysis is not scientific or cost-based, MPC's proposed 44.6 percent increase for the irrigation class is not appropriate. MII maintains its observations indicate that "it is imperative that any cost-of-service study utilized to develop the Company's proposed rate spread between customer classes be thoroughly reviewed in order to ensure that all data and methodologies employed are accurate reflections of the cost of service for the irrigation class" (Exh. No. MII-2, p. 10). MII also maintains that, given the relative size of the irrigation class' contribution to MPC's overall revenues (1.3 percent), strict allocation of cost causation may not be appropriate for this class (Exh. No. MII-2, pp. 10-11).

Allocation of Classified Costs

109. Other than the errors already identified and corrected in this proceeding, MII argues there are three problems with MPC's COS

study. These problems relate to the load research data and the method MPC used to allocate summer marginal generation capacity costs.

110. MPC Load Research Data. MII contends MPC's load research data for the irrigation class' NCPs is flawed. MII compares irrigation class CP data for each of November, October, September, 1989 from MPC's COS study (Exh. No. MPC-40, PEM-10, p. 10) and individual meter demands for July, 1989, from MPC's rate design exhibits (Exh. No. MPC-46, TEW-24, p. 1, MII RDR PSC-593). MII notes the November 1989 Irrigation class CP (105,556 kW) is nearly double the class peaks listed for the summer months and greater than the individual meter demands for July 1989. MII asserts that since there was little irrigation load during November 1989 the 105,556/kW is incorrect. MII also asserts the October 1989 Irrigation class peak is mistaken since it is greater than the September 1989 Irrigation class peak. Based on its comparison of Irrigation class peaks, September Irrigation energy consumption, and its assertion that data problems are not isolated to one month, the MII finds the problem generic rather than mathematical in nature (Exh. No. MII-2, pp. 12-13).

111. MII recommends the Commission use load research data for the irrigation class from Docket No. 87.4.21 to recompute irrigation class NCPs to correct this problem. MII computed these values based on monthly NCP load factors from Docket No. 87.4.21 and normalized monthly energy sales from this Docket (Exh. No. MII-2, AJY-4). MII asserts its recomputed NCPs "produce a pattern of class peak loads which fit the expected pattern of irrigation usage" (Exh. No. MII-2, p. 14). MII also compares the impact of its recommended NCPs with those of MPC's and maintains that its NCPs reduce total average class peak demand by about one-third and reduce distribution costs allocated to the irrigation class by about $50,000 (Id., pp. 13-14).

112. MII also asserts that since there are problems with the irrigation class peak data there may also be problems with the Company's system CP data. Based on MPC's response to DR MII-1, MII

maintains that system peak values may be in error by more than 15 percent for the irrigation class. Based on these results, MII maintains it would not be fitting to disproportionately increase irrigators' revenues.

113. At hearing, MII accepted the changes MPC made to the data it used to compute system CP and class NCP values for the Irrigation Class in Exh. No. 42, PEM-24 (see the following summary of MPC's rebuttal). MII also notes that use of MPC's changes in its COS study reduces the irrigation class' revenue requirement further than MII proposed in Exh. No. MII-2, AJY-5 (TR 1105-1106).

114. Allocation: Marginal Generation Capacity Costs. MII maintains MPC's use of the single-peak summer month to allocate marginal generation capacity costs is inappropriate and contrary to past Commission orders. MII recommends allocating summer marginal generation capacity costs based on each class' contribution to the average of summer peaks.

115. First, MII contends the Commission allocated summer marginal generation capacity costs to classes using the average of summer peaks in Docket Nos. 83.9.67 and 87.4.21. MII notes the Commission's rationale in Docket No. 87.4.21 for allocating summer generation capacity costs using an average of the summer peaks was based on the winter peaking nature of MPC's loads. MII also notes the Commission would reevaluate the use of this method if the summer peak were to approach or exceed the winter peak. As an aside, MII's testimony does not acknowledge the Commission's order on motions (Docket 87.4.21) did not retain use of an average of summer peaks. MII also maintains MPC has not presented any analysis of the appropriate method to allocate summer generation capacity costs, as directed by the Commission. Since MPC testified that use of the average of summer peaks was correct in the last Docket, MII concludes MPC's use of a single summer month to allocate generation capacity costs in this Docket was an oversight on MPC's part (Exh. No. MII-2, pp. 17-20).

116. MII maintains the Commission's finding regarding MPC's

winter peaking nature is even more appropriate in this case. MII notes that in Docket No. 87.4.21, the Commission found MPC's summer CP was within 12 percent of the winter peak. In this case MII maintains that the winter peak is more than 16 percent greater than the summer peak at generation which makes using the average of summer peaks to allocate marginal generation capacity costs even more appropriate (Id., p. 20). In this regard, MII cites MPC's rebuttal testimony (Exh. No. MPC-21, p. 26) and asserts winter and summer peaks are expected to diverge in the future. MII also asserts that such a trend mitigates the need to review alternative methods of allocating marginal generation capacity costs (Id., p. 21).

117. Second, MII argues that summer marginal generation capacity costs are not related to peak capacity as are winter capacity costs. MII also asserts that summer generation capacity costs are more related to general or average use of the system than to defining the system peak. MII then argues to allocate summer generation capacity costs using an average demand since capacity is designed for a broad spectrum of usage. MII maintains that the average of summer peaks represents a middle-ground allocator between allocating demand (energy) to every hour of the season and the single hour of the season (Id., p. 22).

118. Finally, MII contends it would be consistent to allocate marginal generation capacity costs to classes using a form of average usage, since the data used to allocate these costs to seasons are based on average usage (Exh. No. MII-2, p. 24). MII maintains MPC's use of LOLH data, which consist of "typical weekly hourly data" (Id., p. 23), to allocate generation capacity costs to seasons reflect average demand over the time frame. MII further maintains it is inappropriate to use such data to spread summer marginal generation capacity costs based on a single peak, since such costs are not incurred to serve the annual system peak, but an overall seasonal requirement.

Rebuttal

119. MPC rebutted MII's COS testimony as follows.

Functionalized and Classified Costs

120. Regional Price Comparisons. MPC contends that MII's interregional rate comparison is invalid because several variables would cause costs to differ between utilities. MPC identifies resource mix, O&M expenses, variations in customer mix, and whether the utilities are summer or winter peakers as some of these variables. Further, MPC refutes MII's apparent assumption that similar customer classes pay their total service cost or some equal percentage thereof by noting that total cost responsibility for a given class may vary across utilities (Exh. No. MPC-42, pp. 4-5).

121. MPC also maintains that MII's regional rate comparison is inconsistent. MPC refutes rate development based on regional averages by stating that class revenues should be COS based and rates designed with costs as a guide. Other utility rates would need to be adjusted for factors such as COS, loads and resources, class load characteristics, and price/cost differences before rates could be compared across utilities. In summary, MPC maintains MII's regional rate comparison is incomplete and should be disregarded because it lacks scientific rigidity, is not cost based, and is not exhaustive (Exh. No. MPC-48, pp. 17-19)

Allocation of Classified Costs

122. MPC Load Research Data. MPC concedes MII's assertion that there is a problem with the irrigation class peak it used to allocate distribution costs. MPC holds that the error raised by MII was due to an oversight. When MPC implemented its 1989 irrigation class load research data it failed to shift cyclical monthly (actual billed) energy usage to calendar monthly usage. MPC then proposed corrected monthly energy sales and class and system CP values based on load and coincident factors from its 1989 load research analysis (Exh. No. MPC-42, p. 5 and PEM-24). MPC maintains these corrected data exhibit usage patterns expected for the Irrigation class (Id., pp. 5-6).

123. MPC also rebuts MII's proposal to use load research data from Docket No. 87.4.21 and its computed irrigation class peak data. MPC holds that since MII's proposal (as computed Exh. No. MII-2, AJY-4) is based on energy usage data from its initial filing, MII's computations would suffer the same problems as did MPC's initially filed data. MPC maintains the irrigation class demand data contained in Exh. No. MPC-42, PEM-24 are of sufficient quality for use in this proceeding. Also, it asserts the data exceed PURPA standards for customer classes using sample metering such as the Irrigation class (Exh. No. MPC-42, p. 7).

124. Generation Capacity Costs. In response to MII's assertion that the average of the summer peaks should be used to allocate summer demand costs, MPC cites Finding No. 84 of Order No. 5340 in which MII maintains the Commission ordered MPC to allocate summer demand costs using the average of summer peaks. Further, MII states "[t]he company did not follow the order in the compliance filing for Docket No. 87.4.21, this was an oversight by the company and Commission (see response to PSC 6-261)" (Exh. No. MPC-42, p. 8). MPC also notes it has previously argued for allocating using the average of summer peaks, but notes there is merit in using either a peak month or "average of the summer months" (Id.).

LCG COST OF SERVICE

125. The LCG employed Jan W. Michael, President of Applied Economics Group, Inc., who filed a revision to MPC's COS study and testimony regarding rate design issues. Mr. Michael (hereafter LCG) filed Direct, Rebuttal, and Answer Testimony (Exh. Nos. LCG-6, 7, and 8, respectively).

126. LCG's direct testimony addressed mathematical errors in MPC's initial COS study and its proposed reactive power charge. LCG also addressed MPC's method of allocating energy and capacity losses, and of allocating generation capacity costs. LCG argues MPC's proposal to separate the GS-2 Transmission/Substation class by voltage level should be denied.

127. In its answer testimony, LCG addressed MPC's revised distribution cost allocation method.

LCG Direct Testimony

128. Mathematical Errors. LCG maintains there are several mathematical errors affecting MPC's computed generation and loss costs. LCG maintains that even though MPC has identified these errors, it has not updated its COS study. LCG lists the following errors in MPC's COS study.

129. First, LCG corrected MPC's winter and summer generation energy costs per MPC's response to DR No. FEA-17. Second, LCG corrected MPC's winter and summer generation capacity costs using MPC's own revised data (MPC RDR FEA-6). LCG maintains this change affects transmission, substation, and distribution capacity costs and corrects the same. LCG also corrected the winter and summer GS-2 Substation class normalized energy usage. LCG updated MPC's COS study by correcting these errors (Exh. No. LCG-6, pp. 4-6 and JWM-2 & 3).

130. Reactive Power. LCG argues that since improved large industrial customer power factors benefit all ratepayers, MPC's reactive power charge should be changed to remove its punitive aspect. LCG recommends a reactive power factor tariff to foster a cooperative effort between MPC and large industrial customers. In lieu of MPC's proposal, LCG proposed that a power factor improvement program be implemented as a demand side management program. LCG suggests this program include "financial incentives available to large industrial customers that correct and maintain good power factors" (Exh. No. LCG-6, p. 19). LCG maintains the most appropriate forum for determining such financial incentives would be in Docket No. 90.8.49 (LCG RDR PSC-388). LCG considers 85 percent or greater a good power factor (Id.).

131. Allocation of Loss costs. LCG argues that by changing its method to allocate loss costs from that approved in Docket No.

87.4.21, MPC does not correctly allocate these costs. LCG asserts losses are a generation cost and by allocating these costs to the transmission, substation, and distribution voltage levels MPC is mixing functional and generation cost recovery. LCG also asserts MPC's method does not allocate losses to seasons, which a proper loss allocation method should recognize (Exh. No. LCG-6, pp. 8-11).

132. Further, LCG maintains that MPC's method of allocating loss costs does not quantify generation capacity loss costs the same as the previously approved method. The LCG argues MPC's proposed method overstates annual generation capacity loss costs by about $46.7 million, or about 40 percent. LCG computes these figures by comparing total generation capacity costs, adjusted for losses, using the previously approved method and MPC's proposed total generation capacity costs adjusted for losses. LCG asserts total generation capacity costs, adjusted for losses, using each of these methods are about $118 and $164.7 million, respectively. LCG computes the $118 million figure based on MPC's initial seasonal generation capacity costs, adjusted for losses by voltage level, and normalized seasonal CPs. LCG computed the $164.7 million figure by summing MPC's total generation capacity costs and its total voltage level capacity loss costs. MPC's total generation capacity costs are computed using MPC's seasonal generation capacity costs and normalized seasonal CPs. MPC's total voltage-level capacity loss costs are computed using MPC's voltage level capacity loss factors, its annual generation capacity cost, and normalized average monthly CPs at each of the transmission and substation levels and the sum of monthly NCPs at each of the primary and secondary distribution levels (Exh. No. LCG-6, pp. 10-11 and JWM-4 and Exh. No. MPC-40, PEM-1, 4, 5, and 6).

133. LCG asserts the prior approved Commission method applied the appropriate loss factors to unit marginal costs, a method LCG maintains properly recognizes the marginal cost to serve customers at lower voltage levels. LCG recommends the Commission recognize generation losses as it did in Docket No. 87.4.21 (Exh. No. LCG-6, pp. 8-12 and JWM-4 & 5).

134. Allocation of Generation Capacity Costs. LCG maintains MPC erred in its designation of the single largest winter CP month. In this regard, LCG maintains MPC has not complied with the Commission's requirement in Docket No. 87.4.21. MPC used February, which LCG argues is the third highest winter coincident peaking month, with peak demand of 1,031,537 kW, to allocate generation capacity costs. LCG maintains January, which had a peak demand of 1,092,826 kW, is the appropriate peaking month upon which generation capacity costs should be allocated. In this regard, LCG recommends MPC's COS study be corrected using January's winter peak (Exh. No. LCG-6, p. 7 and JWM-3).

135. LCG provided a cost study which encompassed all of above summarized corrections to MPC's study. In addition to adjusting generation energy and capacity costs for losses, LCG adjusts transmission, substation, and apparently distribution capacity costs for losses (Id., p. 12 and JWM-5).

136. GS-2 Transmission/Substation Class Split. Based on its update of MPC's COS study, LCG recommends the Commission retain the current GS-2 Transmission/Substation rate class. LCG's analysis consists of comparing MPC's proposed prices and costs as corrected by LCG.

137. On the pricing side, LCG holds MPC's transmission demand and energy prices would be about 31.5 percent and 9 percent lower than the substation demand and energy prices, respectively. LCG maintains that once MPC's costs are corrected, transmission capacity costs would be about 5 percent, rather than 31.5 percent, lower than the substation capacity costs. Also, transmission energy costs would be about 1 percent, rather than 9 percent, lower than the substation energy costs. LCG's 5 and 1 percent figures are based on LCG's computed full marginal costs (Exh. No. LCG-6, JWM-6). LCG maintains the cost difference between these two classes is minimal and separate transmission and substation rates are not needed (Exh. No. LCG-6, pp. 16-18).

138. In recognition of the cost difference between

transmission and substation delivery levels, LCG proposed a monthly transmission level credit to the GS-2 Transmission/Substation rates of 5.17 percent for demand and 1.02 percent for energy. These credits are based on LCG's analysis of the full marginal cost differences between the substation and transmission delivery levels (Id., pp. 18-19, JWM-6 and 7 and LCG RDR MPC-158). LCG also proposed a GS-2 Transmission/Substation, combined-class rate design based on its corrections to MPC's COS (Exh. No. LCG-6, JWM-7 and LCG RDR PSC-379).

Rebuttal to LCG Direct Testimony

139. MPC and FEA rebutted LCG's direct testimony. FEA commented on the mathematical errors LCG identified in MPC's COS study. MPC rebutted LCG's proposal, its loss cost allocation method, and its determination of the winter peak month used to allocate generation capacity costs. FEA supported LCG on this issue, unless MPC could show good reason to use February. Both MPC and FEA rebutted LCG's opposition to MPC's proposal to separately price Transmission and Substation levels of service.

140. Mathematical Errors. Although FEA recognized LCG identified errors in MPC's COS study and a means of correcting them, FEA maintains that not all errors in MPC's study are presented in either its or LCG's testimony. FEA asserts that the errors recognized by it (see summary of FEA direct, below) and LCG have minor impacts on MPC's COS. FEA maintains that the errors LCG identified regarding MPC's winter and summer generation capacity costs and the other two errors regarding the GS-2 Substation class' normalized energy usage, should be reflected in the final COS study (Exh. No. FEA-3, pp. 3-4).

141. Reactive Power. MPC rebuts LCG's reactive power tariff proposal. MPC maintains its reactive power charge should be approved to provide information to its transmission and substation customers to examine the economics of improving their power factors. MPC maintains its proposal would allow 120 days for customers to improve their power factors. MPC would be willing to

work with its large customer groups to improve power factors and would be willing to extend the grace period before a reactive power charge is imposed providing a customer agreed to correct its power factor in a timely manner (Exh. No. MPC-47, p. 20).

142. Allocation of Loss costs. MPC contends it used the same method to allocate loss costs in this filing as it did in Docket No. 87.4.21, but moved these costs to the transmission, substation, and distribution functions. MPC concedes, however, that LCG correctly argues that the previously accepted method of determining losses does not correspond with the method it used to allocate capacity losses in this case. MPC admits that it incorrectly applied the sum of NCPs to allocate distribution capacity costs. To correct this problem, MPC revised its proposed distribution cost allocation method to use the average of the sum of the NCPs. MPC made this revision by dividing the sum of NCPs it used by 12. MPC contends a comparison of the total capacity loss costs using its previous and proposed methods are similar. The dollar and percentage differences between MPC's previous and proposed methods with the above revisions are $0.38 million and 0.32 percent (Id., pp. 7-8 and PEM-22).

143. FEA opposed LCG's treatment of losses as generation costs which, if allocated at the generation level, would reduce distribution costs to zero (Exh. No. FEA-3, p. 4). At hearing, FEA indicated that LCG was not proposing distribution costs equal to zero (TR 913).

144. Allocation: Generation Capacity Costs. MPC maintains it complied with the method established by the Commission to allocate winter and summer capacity costs. MPC maintains it determined the proper months for allocating these costs from monthly coincident system peaks at generation from Exhibit No. MPC-40, PEM-10, p. 12/13, line 61. MPC holds LCG used monthly CPs at the meter (MPC references Exh. No. MPC-40, PEM-10, p. 12/13, line 30) to select winter and summer peaks which would result in allocating lower marginal capacity costs to the LCG customers (Exh. No. MPC-41, pp. 6-7).

145. FEA supports LCG's proposed modification of MPC's COS study regarding generation capacity cost allocation using January as the peak month, unless MPC can support using February (Exh. No. FEA-3, p. 4).

146. GS-2 Transmission/Substation Class Split. MPC maintains the cost differences between the transmission and substation classes should be reflected in rates. MPC agrees with LCG's comparison of the cost differences between the transmission and substation levels of service based on LCG's cost comparison in Exh. No. LCG-6, JWM-6 (MPC RDR LCG-204). MPC argues, however, that LCG's analysis fails to account for differences in load characteristics, which are reflected in rates as well as costs. MPC asserts that even if capacity costs are the same for two classes, their billing demand may differ, causing billing demand charges to differ. MPC maintains that combining two classes with different load characteristics could result in distorted prices (Exh. No. 47, pp. 19-20). MPC also maintains that a cost-based rate discount for transmission customers would be an alternative to separately pricing transmission and substation service, but the discount would need to account for cost and load differences (Id., p. 20).

147. FEA maintains LCG incorrectly asserts the COS between the transmission and substation classes differs. FEA argues LCG's comparisons of total marginal energy and capacity costs with energy and demand charges for these classes are incorrect. FEA argues the demand charges LCG compares with demand costs are measured in billing demand terms, whereas demand costs are measured in a combination of annual CP demand (generation capacity) and average monthly CPs (transmission and substation capacity) (Exh. No. FEA-3, p. 5 and FEA RDR PSC-568). Further, FEA maintains that if LCG's comparison had not mixed demand units, the comparison would have reflected additional facilities used by the substation customers.

148. FEA maintains that since capacity costs are recovered through billing demand a more important comparison would be the

cost per kW of billing demand. FEA asserts that "if the revenue produced from demand charges is to be approximately equal to the total demand costs, then the charge per kW of billing demand should be approximately equal to cost per kW of billing demand" (Exh. No. FEA-3, p. 6, emphasis in original). Using LCG's costs, FEA maintains the moderated marginal costs per billing demand kW are $6.86 and $10.86 for each of transmission and substation customers, respectively, which FEA maintains is a substantial difference in the costs to serve these classes. FEA also maintains LCG's combined-class rates, would overcharge transmission customers by $517,787, an amount that would subsidize substation customers (Id., pp. 5-7).

149. FEA maintains transmission and substation class costs differ due to differences in load patterns. FEA argues that since transmission customer's load patterns contribute less to class CPs and monthly average peaks than those of substation customers, transmission customers contribute less to costs. FEA uses coincidence factors as a measure of the differences in load patterns for these classes. FEA notes that the annual average coincidence factors for each of the transmission and substation classes are 60 and 96 percent, respectively. FEA also argues that customer classes with high coincidence factors drive the system peak (Id., pp. 7-8).

LCG Answer Testimony: Allocated Distribution Costs

150. LCG maintains MPC has, in its rebuttal testimony, improperly shifted distribution cost responsibility to classes not using distribution facilities. The LCG maintains that by shifting distribution costs, revenue requirement responsibilities to those not using these facilities would, if accepted, send distorted price signals to distribution level customers. LCG also maintains MPC's shift is contrary to principles of cost causation (Exh. No. LCG-8, p. 2).

151. LCG asserts MPC implicitly allocates marginal distribution capacity costs to the GS-2 Substation class, even

though MPC does not explicitly recognize this class as a distribution level class. LCG asserts MPC shifts $7.2 million of marginal distribution capacity costs to the GS-2 Substation class. Further, LCG maintains MPC reduces its initially proposed distribution costs of $51.4 million by $47.1 million to $4.3 million in its rebuttal testimony by removing all but generation related capacity costs from the distribution function (Exh. No. LCG-8, p. 3).

152. LCG maintains MPC's reduction of distribution costs imposes no cost change to the GS-2 Substation class. However, LCG asserts that MPC's increased reconciliation factor, from about 78 percent to about 88 percent, proposed in rebuttal testimony, results in shifting distribution costs to the Interruptible, Transmission, Substation, Primary, and Lighting classes (Id., p. 3 and LCG RDR PSC-610). LCG expands its explanation of this cost shift in response to DR No. PSC-610 as follows.

153. LCG maintains the above distribution cost shift to the above listed classes is the net effect of MPC's changed distribution cost allocation method (from sum of NCPs to average monthly NCPs) and its changed reconciliation factor. To show this, LCG computes the effect of MPC's changed distribution cost allocation method in terms of its initially proposed reconciliation factor. To this, LCG adds the effect MPC's changed reconciliation factor has on the portion of all of MPC's changes to its COS made in rebuttal testimony related to distribution costs adjusted for the change in MPC's reconciliation factor (LCG RDR PSC-610).

154. LCG recommends MPC's shift of distribution costs be rejected. To avoid this shift, LCG recommends the Commission, in the interim, reaffirm the marginal distribution cost methods it found acceptable in Docket No. 87.4.21 (Exh. No. LCG-8, p. 4). LCG maintains its preliminary analysis using this method for the test period in this Docket shows the costs roughly compare to MPC's originally proposed distribution capacity costs (Id., p. 4). LCG provided this analysis in a completed form in response to DR No. PSC-611 and, at hearing, recommended the Commission use this cost

study (TR 1255-1256). LCG maintains distribution costs should be based on incremental plant investments (TR 1263). LCG also explained how these results could be incorporated into MPC's COS study (TR 1255-1257).

155. To avoid such cost shifts in the future, LCG suggests the Commission require distribution costs be unbundled in order to isolated transmission and substation classes such that distribution costs are allocated only to the classes causing these costs (Exh. No. LCG-8, p. 5 and TR 1265). LCG suggests this be accomplished by revising the reconciliation procedure (Id., p. 5).

Rebuttal to LCG Answer Testimony

156. MPC rebutted LCG's testimony that marginal distribution costs were not allocated to the GS-2 Substation customer class. MPC argues that Exhibit Nos. MPC-41, PEM-13 and MPC-42, PEM-23 show that marginal distribution costs are not allocated to the substation customer class. MPC also maintains marginal costs were not shifted among classes. Further, MPC maintains the GS-2 Substation class' reconciled revenue requirement increased in its rebuttal testimony because total marginal costs, including distribution costs, decreased and MPC used an equal percentage reconciliation factor. MPC also notes that even though total marginal costs for the substation class fell, this class' share of the revenue requirement increased by 10 percent due to an increase in the reconciliation factor of the same magnitude.

157. MPC contends that, because the results of using the distribution cost method from Docket No. 87.4.21 are comparable to the costs computed in previous cost studies, that does not make the methods superior. Regarding LCG's proposal to isolate transmission and substation classes from distribution cost shifts, MPC suggests the moderation procedure should be examined in future proceedings, but LCG's proposed isolation would not be needed (Exh. No. MPC-42, pp. 1-4).

FEA COST OF SERVICE

158. The FEA employed Charles E. Johnson of Exeter Associates, Inc. to testify on its behalf. In Direct Testimony (Exh. No. FEA-2) Dr. Johnson (hereafter FEA) provided his analysis of MPC's COS and RD proposals. FEA also rebutted certain issues proposed by MCC, LCG and HRC (Exh. No. FEA-3).

159. FEA addressed two general areas: MPC's COS computations and General Service rate design. FEA's rate design testimony is largely related to the measurement and application of marginal generation energy costs. As such, this segment of its testimony is summarized below, while its GS-2 Transmission class price proposals are summarized under electric rate design.

160. At the outset, FEA notes that even though it uses MPC's requested revenue levels to present its proposals, it takes no position on MPC's jurisdictional revenue levels; it limits its testimony to "revenue distribution" and rate design issues (Exh. No. FEA-2, pp. 3 and 6).

Mathematical Errors

161. The FEA cites four errors in MPC's COS study cited in data responses. These errors pertain to 1) MPC's marginal energy costs (MPC RDR FEA-17); 2) MPC's incorrect value of the 1986 peak used to compute transmission plant and O&M costs (MPC RDR FEA-21); 3) MPC's capacity losses (MPC RDR PSC-274); and, 4) MPC's omission of O&M costs in its substation plant costs (MPC RDR PSC-268). The FEA also asserts MPC incorrectly transferred marginal secondary distribution costs between two of its exhibits and, as a result, computed transmission-level customer costs as $2,988 but used $2,458 in a subsequent computation for transmission, substation, and interruptible customer costs (Exh. No. FEA-2, pp. 4-5).

162. By duplicating MPC's COS study and intraclass revenue responsibility model, FEA estimated the impact of correcting these errors on MPC's proposed class revenues. FEA maintains, however, that MPC provided insufficient information for the fourth error,

and therefore argues its estimate of the impacts of these errors will not provide exact class revenue requirements (Id., p. 5-6).

163. FEA maintains that total marginal costs for all classes are lower than those computed by MPC, with the largest change occurring for the GS-1 Secondary class (about $2.2 million lower than MPC's results) (FEA RDR PSC-370). FEA maintains that if the Commission grants a revenue level other than that proposed by MPC, its Schedule 3 would require adjustment (Id. p. 6). FEA also notes an error that MPC concedes involving price deflators used to compute substation costs (Exh. No. FEA-2, p. 6).

Functionalized Costs: Generation

164. FEA recommends modifying MPC's computed General Service (GS) energy prices to only recover short-run marginal energy costs (Exh. No. FEA-2, p. 4). FEA finds MPC's proposed GS class rates unacceptable and maintains MPC did not base its energy prices on the marginal costs it developed to determine class revenues. The FEA contends that energy prices are commonly set at full short-run marginal costs (Exh. No. FEA-2, p. 8 and FEA RDR PSC-371). Furthermore, FEA suggests the methods used to set class revenue levels and pricing of each rate schedule can be separated. FEA maintains that for "...setting the price of energy, short-run or relatively near-term intermediate-run marginal costs are the most relevant" (Exh. No. FEA-2, p. 8). The FEA maintains these concepts measure the costs of production, using existing plant, and are the costs imposed on the utility, on average, that it should recover.

165. The FEA asserts that "[d]uring the test year ending December 1989, hourly system lambdas averaged 9.84 mills per kWh." (Exh. No. FEA-2, p. 8). FEA explains that MPC computed average system lambdas for monthly typical weeks over a three-year period (1991-1993) and averaged these values to arrive at a three-year average system lambda of 11.37 mills per kWh. FEA maintains these values are less than MPC's proposed GS energy price of $.020561 per kWh. FEA concludes the method MPC used to compute its Secondary, Primary, and Substation rates result in an energy charge which is

greater than its marginal cost.

166. Further, the FEA notes the difference between its short-run marginal energy cost (11.37 mills/kWh) and the Company's long-run marginal energy cost (19.35 mills/kWh) and cites two possible reasons for this difference. First, FEA notes that MPC's July 1990 avoided cost analysis resulted in a 1992 $17.76/MWh cost which is higher than the revised average system lambda for the year of $11.37/MWh (based on MPC's RDR FEA-17). This cost is derived from the same system lambda data MPC used to allocate energy costs seasonally. Compare Exh. No. FEA-2, pp. 11-12 and CEJ-1, Schedule 4 and Exh. No. MPC-41, p. 2) (Exh. No. FEA-2, p. 9). FEA maintains the method MPC used to compute its long-run marginal cost should result in a cost close to the average system lambda and suggests the size of the increment (10 MW) MPC used to compute its cost may be the reason for the difference (Id., pp. 9-10).

167. Secondly, FEA maintains that MPC's use of ten-year levelized costs (1992 through 2001) is attributable to the difference in the short-run and long-run marginal energy costs. FEA argues this as follows.

> This calculation is highly dependent on the forecast price of energy in the last three year's of the period, i. e., in the years 1999-2001. In particular, a projected 23.5 percent increase in the cost of energy in 1999 has an immense impact on the result.

(Exh. No. FEA-2, p. 10)

FEA maintains it is more reasonable to set prices based on near-term marginal energy costs, since sales revenues per kWh will reimburse costs on average. FEA also contends that setting prices this way is more rational than setting prices beginning with demand charges based on 70 percent of moderated marginal demand costs, which is the method MPC uses (Id., pp. 10-11).

Rebuttal

168. MPC and RPC rebutted FEA.

169. Mathematical Errors. RPC supports FEA's request that the Commission require MPC to correct the errors in its original exhibits (Exh. No. RPC-3, p. 1).

170. Generation Energy Costs. MPC rebutted FEA's proposal to base energy prices on short-run marginal cost. MPC maintains there are two factors affecting the choice between short-run and long-run costs that should be reflected in prices. These factors are the consumers' purchasing decision criteria and MPC's intended price signal. MPC argues that if consumers' purchasing decisions are short-term, then short-run may be correct. However, MPC contends that consumers make long-term purchasing decisions, such as entering long-term contracts or investing in equipment, which require future cost information. Further, MPC maintains that future prices, which are changing, are important to it. MPC thereby concludes that long-run costs are appropriate (Exh. No. 41, pp. 5-6).

171. MPC maintains the system lambda FEA uses as a short-run energy cost is incorrect. MPC maintains the short-run cost ($17.76 mills/kWh, MPC's nominal annual energy cost) is the price it would pay in 1992 for energy (Id., p. 6 and MPC RDR LCG-160).

Allocation of Classified Costs

172. RPC notes the FEA failed to address the use of sales level energy and demand volumes to determine allocated class revenue requirements.

RPC COST OF SERVICE

173. Frank R. Lanou (hereafter RPC) filed Direct and Rebuttal testimony on behalf of Rhone-Poulenc Basic Chemicals Co. (Exh. Nos. RPC-2 and 3). RPC's direct testimony addresses a mathematical error in MPC's COS study regarding seasonal marginal generation

energy costs. RPC also addresses MPC's cost allocation methods. Each issue is summarized below.

Mathematical Errors

174. RPC refers to MPC's response to DR FEA-17 in which MPC corrected its winter/summer division of marginal generation energy costs. RPC requests the Commission direct MPC to revise its cost and rate design exhibits to reflect the changes to Exh. No. MPC-40, PEM-2.

Allocation of Classified Costs

175. RPC maintains that MPC's cost allocation method, in which it multiplied energy and demand volumes by marginal costs, is a proxy for allocating costs using separately developed allocation factors. RPC argues that the same unit marginal costs should not be allocated using different volumes for each different function (Exh. No. RPC-2, p. 9-10). To correct this problem, RPC maintains MPC should allocate costs to all classes based on a common system level of energy and demand volumes (Exh. No. RPC-2, pp. 9-10 and RPC RDR PSC-361 (c)). RPC defines its "common system level" as allocation volumes determined at the generation level which account for system losses in marginal costs (RPC RDR PSC-583 and 618 and TR 1278-1279). RPC contends that all of the necessary information is contained in Exhibit No. MPC-40, PEM-10. RPC maintains that by using this method and the data it cites, the Industrial Interruptible class revenues would be reduced by roughly $179,000 (Id., p. 11 and RPC RDR MCC-260).

HRC COST OF SERVICE

176. Thomas M. Power filed Direct and Response Testimony (Exh. Nos. HRC-3 and 4, respectively) on COS and RD issues in this proceeding on behalf of District XI Human Resources Council (HRC). The following summarizes Dr. Power's (hereafter HRC) electric COS testimony.

Functionalized and Classified Costs

177. Generation. HRC recommends the Commission place the highest priority on accurately reflecting energy costs in rates. Further, it speculates that energy costs will most likely be driving prices upward during this decade (Exh. No. HRC-3, p. 74). HRC's arguments follow.

178. HRC maintains that MPC's marginal generation cost analysis, which places an emphasis on demand charges, does not accurately characterize relative energy and capacity costs (Id., p. 70); HRC maintains that MPC's approach defines energy costs as just variable operating costs with capacity costs the residual (Id., p. 72). HRC speculates MPC will add base-load plants before the costs of purchased power or peaking facilities rise, assuring low avoidable operating costs. HRC maintains these low operating costs will result from higher investments in base-load generation and transmission plant located remote from load centers. HRC maintains MPC would classify these fixed costs as capacity, although they are fuel-cost minimizing investments. Further, HRC maintains that barring any change in generation technology, energy costs will be driving changes in utility costs. HRC speculates that additional base-load generation investment may begin in the next ten years (Id., pp. 71-74).

179. Further, HRC maintains that MPC is integrated in the northwest regional electric market. HRC also maintains that, since this market has a large hydroelectric base, it is energy constrained and this is why the Northwest Power Planning Council focuses its planning on energy considerations. HRC also states: "Given MPC's ready access to a regional mix of resources, it is hard to believe that its situation is fundamentally different from that of other regional utilities." (Id., p. 71).

180. In order to determine the long-run incremental cost of energy, HRC recommends the Commission direct MPC to analyze incremental electric costs so that marginal energy costs are not limited to short-run operating costs. HRC contends that short-run

marginal cost pricing is not applicable in a tightening energy market (Id., pp. 74-75).

181. Transmission. HRC maintains MPC's transmission capacity cost analysis is not a marginal cost analysis and "can't be used as the basis for any significant shift in revenue responsibility among customers or any significant change in rate design" (Exh. No. HRC-3, pp. 66-67). In this regard HRC presents arguments regarding peak-related transmission costs, the analysis period used by MPC, and cost causality. These arguments are summarized below.

182. First, HRC questions the relationship between MPC's transmission and generation capacity costs and concludes the former is 17 percent lower than the latter. HRC argues that since MPC does not locate its generation facilities near load centers nor use CTs to meet peak loads, "the transmission system was built to provide services other than the delivery of peaking capacity" (Id., p. 59). HRC argues MPC does not examine other transmission services in its marginal transmission capacity cost analysis, but asserts that changes in transmission expenditures are all peak related which, in HRC's opinion, is inconsistent with marginal cost analysis. Further, HRC maintains the EPRI study MPC references (MPC RDR HRC-43) does not support its conclusions. HRC maintains this study discusses the need to identify the services for which transmission investments are made and then to remove non-peak related costs.

183. Second, HRC maintains the period over which MPC has chosen data to compute transmission costs is too short, causing unstable cost results. HRC agrees with the EPRI study which recommends the use of ten to fifteen years of data to compute transmission costs. HRC also argues that since transmission investments and O&M expenditures are made to serve future loads, fluctuations in peak loads and the lumpy nature of transmission investments will cause unreliable cost estimates. Further, HRC argues that MPC mismatches the years in which investments are made and peaks occur (Exh. No. HRC-3, pp. 62-66). HRC maintains transmission investments are made in advance of expected peak loads

and that it is "not appropriate to use simultaneous transmission investments and peak load data" (Id., p. 65).

184. Third, HRC argues MPC's transmission cost analysis is unrelated to cost causality of increased peak loads since transmission costs are designed to meet local loads upon occurrence, not annual CP loads. HRC maintains the wrong measure of peak load is used to compute marginal transmission capacity costs (Id., p. 66).

185. HRC also maintains that if MPC's transmission costs were marginal costs, such information could not be accurately conveyed to most MPC customers. HRC contends this is due to the equal-percentage method MPC uses to reconcile its costs with its revenue requirement. HRC argues that this method shifts revenues away from high-use transmission customers, but also notes that the method produces a marginal cost signal. HRC also maintains there is little relationship between measured and billing demand. It states that customers billed for demand are billed on the basis of monthly peak usage, whereas transmission capacity costs are measured per the CP load (Id., pp. 67-68).

186. HRC notes, however, that accurate assessment of the marginal transmission costs of segments of the system are needed to assess the rationale of transmission charges. HRC maintains that the information on transmission costs in this case is not accurate and, if it were, it should not be mechanically applied to set revenue responsibilities and prices (Id., p. 68).

187. Customer. HRC argues MPC's proposed customer costs are the results of a fully distributed cost approach. HRC holds that customer O&M expenses regarding sales, customer service, and information expenses should be eliminated from the study since they do not vary directly with the number of customers and are not directly related to customer behavior. HRC also suggests uncollectables be considered as sales or revenue related (Exh. No. HRC-3, pp. 75-76).

188. Further, HRC contends the cost of a new service and meter should be excluded from customer costs since these costs are sunk. Including these costs serves little purpose because they provide little cost information to customers currently taking service. HRC maintains line extension policies provide sufficient information to the small portion of customers seeking new service.

189. HRC holds marginal customer costs include meter reading, customer records, and customer installations which result in a $2.75 per customer per month cost (Id., p. 77).

Allocation

190. Seasonality. HRC maintains its LOLH analysis suggests an eight month peak season and recommends the Commission reject seasonal rates and replace them with an inverted-block price structure. HRC argues that winter is not the peak season, seasonal rates have been confusing, and that an inverted block rate design will accomplish the same purpose as seasonal rates, namely the design would reflect peak-period pricing and seasonality (Exh. No. HRC-3, pp. 81-82). A summary of HRC's seasonal analysis follows.

191. HRC maintains MPC's analysis supports reducing the current season from five to four months, but does not identify the actual peak season. HRC says that MPC's initially filed energy cost data, used to seasonally allocate energy costs (Exh. No. MPC-40, PEM-2), suggests a late summer season. HRC argues that the data MPC averaged to revise its seasonal allocation of energy costs show peaks in two winter and three summer months (Exh. No. HRC-3, pp. 77-79).

192. HRC argues that identification of a winter peak season should rely on LOLH analysis. HRC maintains LOLH data from Docket No. 87.4.21 (1987-1992) show an eight-month (August through March) peak season (Id., pp. 79-81). In response testimony, HRC contends that those data show an off-peak period during the spring run-off months and summer LOLHs as high as in some winter months. Using data from the this Docket, HRC maintains there is either a two-

month winter season (December and January) or a three-month off-peak season (April through June). Further, HRC maintains that while "there is more 'peaking' in February" (Exh. No. HRC-4, 29), LOLHs during most of August are greater than those of February. HRC's analysis appears to be based on visual observations of graphed data (Exh. No. HRC-4, pp. 26-27 and Schedules C through E).

193. HRC makes two additional points. First, it concurs with MCC that, based on MPC's initial monthly system lambda estimates, MPC's generation costs do not vary seasonally (HRC notes MCC bases its conclusion on PEM-2, p. 2 (Exh. No. HRC-4, p. 27)). HRC also notes that MCC's position remains the same even though MPC revised its average monthly system lambda estimates which show a 3 mill/kWh seasonal difference. HRC maintains this 3 mill/kWh difference doesn't support the current 18.3 mill/kWh Residential rates or MPC's proposed 8.7 mill/kWh seasonal differential (Exh. No. HRC-4, pp. 26-27).

194. Second, HRC questions the reliability of MPC's revised system lambda estimates provided in MPC's response to DR FEA-17. HRC argues that monthly system lambda values should be greater, rather then less, than incremental energy costs, since incremental generation would include units with lower operating costs. HRC also argues that MPC's initial system lambdas support MCC's conclusion that seasonal differences in short-run marginal energy costs are nonexistent. It maintains these costs show high runoff months (May and June) as having significantly lower incremental energy costs (Exh. No. HRC-4, pp. 27-28 and Schedule G).

Rebuttal

195. The following is a summary of MPC's and FEA's rebuttal of HRC's testimony regarding generation, transmission, and generation.

196. Generation Costs. MPC rebutted HRC's argument "...that MPC's allocation should reflect regional energy needs and not MPC's capacity needs..." (Exh. No. MPC-21, p. 32). MPC argues that its planning should not be tied to a regional market and that

consistency with the Northwest Power Planning Council's resource plan will be achieved through individual utility plans. MPC further argues that by tying itself to a regional market, it would not make sound business decisions, since the region and MPC are not in the same resource position. Further, MPC rebuts HRC's point that it will construct base-load coal plants in the future. MPC maintains it is capacity deficient but is seeking acquisitions of both energy and capacity resources. Also, MPC argues that if additional capacity can be avoided through rate design, its total long-run costs will be lowered (Exh. No. MPC-21, pp. 32-35).

197. MPC also challenges HRC's comparison of marginal energy costs to operating costs. MPC argues its marginal energy costs reflect estimates of short-term energy markets as well as displaced energy costs and an interaction with MPC's loads and resources (Id., pp. 35-36).

198. Finally, MPC rebuts HRC's assertion that since the Northwest regional market has a large hydroelectric base, it is energy constrained. MPC argues that due to environmental concerns, regional hydroelectric operation may be altered, resulting in capacity and energy constraints (Id., pp. 35-36).

199. FEA rebuts HRC's argument that MPC's marginal energy costs are understated and maintains these costs may be overstated. FEA maintains MPC forecasts an $11.37/MWh system lambda (provided in MPC RDR FEA-17) in 1992 but uses a value fifty percent greater ($17.76/MWh, from Exh. No. MPC-40, PEM-2, p. 2 (FEA RDR PSC-572)) for short-run marginal energy costs. FEA also reiterates its argument from its direct testimony that MPC's levelization process depends as much on forecast costs in the tenth year as the second, resulting in a cost used for revenue responsibility nearly twice the expected short-run marginal energy cost (Exh. No. FEA-3, pp. 11-12).

200. The FEA notes, however, that HRC may be correct in asserting that marginal demand costs are overestimated in MPC's study. FEA maintains, "(t)he marginal cost of demand should not

exceed the cost at which generating capacity can be obtained" (Id., p. 12). The FEA compares the forecast cost stream of BPA capacity costs with the capacity cost MPC used beyond 1995 (Id., CEJ-2, Schedule 1) and claims MPC's capacity costs are twice the cost of BPA capacity. FEA maintains that "[i]f MPC can purchase generating capacity from BPA for less than $75/kW, the marginal cost of demand cannot be higher than $75 per kW and may be lower." (Id., p. 13)

201. Transmission Costs. MPC rebutted HRC's argument that locating a CT at a load center would be more economical and would remove "the need for any transmission peak power" (Exh. No. MPC-41, p. 14) in two ways. First, MPC maintains HRC has not provided analysis showing such is the case. Second, MPC contends HRC's argument is flawed since it does not account for energy costs.

202. MPC rebuts HRC's argument that transmission is built to serve energy rather than capacity needs. MPC maintains the transmission system is designed to serve load at the time the system peak occurs, which includes new and reliability-related loads. MPC cites similar texts from the EPRI study HRC cited, but adds a section which qualifies the list of reasons for transmission investment (Id., pp. 15-16).

203. MPC also maintains HRC's position that the transmission system is designed to meet the sum of NCPs rather than the CP is not supported by evidence or reasoning (Id., pp. 14-17).

204. FEA rebuts HRC's contentions that MPC's marginal transmission costs are flawed and its estimated costs are too high by noting that HRC has offered no alternative estimate.

205. FEA also rebuts HRC's argument that MPC's use of an equal-percentage reconciliation method shifts cost responsibility away from high-use transmission customers. The FEA maintains that reducing MPC's marginal transmission costs would result in reducing the cost responsibility for high-use transmission system customers. FEA maintains that a reduction of marginal transmission costs to four customer classes (General Service Primary, Substation,

Transmission, and Industrial Interruptible), whose transmission costs are greater than the average, would result in shifting cost responsibility from these classes to the remaining classes (Exh. No. FEA-3, pp. 13-14 and CEJ-1 and 2).

206. Customer Costs. MPC reiterates that marginal customer cost is the annualized cost of providing service and maintaining minimum service investments. It restates that minimum service includes the service drop, meter, and customer accounting and service expenses. MPC also notes a customer may not base his decision to take service on customer costs and if an existing customer were to discontinue service the costs avoided would be small. However, MPC maintains its customer costs are marginal since there is a marginal cost of adding a new customer to the system. Also MPC maintains it finances the connection investment that a customer would otherwise finance through a mortgage and maintains monthly charges are the payments. Further, MPC contends that its system is "constantly being replaced and repaired and the customer is responsible for the cost of providing the service averaged across all customers. Therefore, the existing customer also must pay for the marginal resources used to provide service." (Exh. No. 41, pp. 17-18).

207. FEA maintains HRC understates marginal customer costs by eliminating capital costs. FEA maintains meter costs are not sunk and should be included in marginal customer costs. The FEA argues that meters have economic value due to their fungibility. FEA notes, however, that customer charges need not necessarily include meter costs since other policy objectives may cause customer charges to differ from costs (Exh. No. FEA-3, pp. 10-11).

RECONCILIATION AND MODERATION

Introduction

208. This part summarizes the reconciliation and revenue moderation proposals made by each of MPC, MCC, MII, LCG, and FEA. HRC also testified on the reconciliation process with respect to

transmission costs.

MPC RECONCILIATION AND MODERATION

Reconciliation

209. MPC proposed an equal-percentage reconciliation (EPR) of its total marginal costs with its proposed revenue requirement, adjusted for its proposed Industrial Interruptible credit. MPC's reconciliation factor of about 88.44 percent (roughly 78.54 percent, in direct testimony) resulted in class revenue changes, absent any moderation, ranging from -0.88 percent to 70.81 percent (Exh. Nos. MPC-40, PEM-1 and MPC-41, PEM-13 and MPC-44, PRC-4).

Moderation: MPC's Rate Implementation Plan

210. MPC does not propose to fully implement the revenue requirements that result from its EPR, but will phase it in over several years based on its Rate Implementation Plan. MPC proposes to restrict each class' revenue recovery increase in the first year to 29.18 percent (revised from 32.5 percent in direct testimony) (Exh. No. MPC-44 & 45). MPC computes its caps by adding 10 percent to its overall revenue requirement request. This limits revenue recovery for each of the Substation, Irrigation, and Post-Top and Yard Lighting classes to a 29.18 percent increase (revised from Mr. Corcoran's Supplemental Direct Testimony to include the Substation class, Exh. No. MPC-44). MPC's reasons for proposing its rate increase cap are: 1) without application of its allocated costs, MPC would have increased rates uniformly by 22.5 percent (per MPC's October 1, 1990, filing, Exh. No. MPC-45, p. 5); 2) MPC's additional 10 percent adder to its proposed overall revenue requirement would move class revenue requirements toward MPC's target; and, 3) it reduces billing impacts to the classes whose increases are capped (Exh. No. MPC-45, pp. 4-5). MPC proposes to recover the aggregate of revenues not recovered from each of the classes whose revenue increases are capped by proportionally spreading these revenues to the remaining classes and holding the

Transmission class at its current revenue level (Id., pp. 5-6 and PRC-4).

211. In rebuttal testimony, MPC made an additional adjustment to the redistribution of revenues to account for its proposed LIEAP discount. Using the Residential rate design it proposed (Exh. No. MPC-47) and LIEAP customer billing determinants (Exh. No. MPC-44, PRC-8), MPC computed preliminary LIEAP class revenues. MPC then proportionately spread ten percent of these revenues to all remaining classes, including the Residential class (Id., PRC-4).

212. Over the three years (1992-1994) following the year in which rates are established (1991), MPC proposes to recover its allocated COS study justified revenues from each of the above listed classes. MPC argues that the revenue differences exhibited for these classes have been proposed in the past to be recovered by future filings. Because this process can be slow, MPC proposed to move class revenues to their cost-justified revenue levels through its Rate Implementation Plan. MPC proposes to implement the plan on August 29 of 1992, 1993, and 1994. Assuming no other filings will affect rates and revenues, the test period information in this Docket would serve as a basis for the rate adjustments (Exh. No. MPC-45. pp. 6-7).

213. MPC's rate implementation plan would result in annual class revenue changes as illustrated in Table 8.

Table 8. MPC's Rate Implementation Plan

Rate Classes:	Initial Percentage Change 1991	Rate Implementation Plan: Annual Percentage Change To Preceding Year's Change 1992	1993	1994
Residential	15.83%	-0.31%	-0.31%	-0.32%
General Service 1				
Secondary	15.68%	-0.31%	-0.31%	-0.32%
Primary	21.34%	-0.31%	-0.31%	-0.32%
General Service 2				
Substation	29.34%	0.50%	0.50%	0.50%
Transmission	1.12%	-0.31%	-0.31%	-0.32%

Interruptible	20.26%	-0.31%	-0.31%	-0.32%
Irrigation	29.34%	3.92%	3.77%	3.63%
Street Lighting	8.64%	-0.31%	-0.31%	-0.32%
Post-Top Lighting	29.34%	10.69%	9.66%	8.81%
Yard Lighting	29.34%	3.16%	3.06%	2.97%
Total	19.18%			

Source: Exh. No. MPC-44, PRC-4

MCC RECONCILIATION AND MODERATION

Reconciliation

214. MCC presents the results of its embedded cost analysis for the bulk power supply, distribution and customer cost functions for each of its and MPC's proposed revenue requirements. MCC holds that by substituting the bulk power supply costs it computes for these embedded costs, MPC would over-collect revenues. MCC proposes to reconcile total marginal bulk power supply costs to its embedded revenue requirement by reducing these costs proportionately. MCC thus proposes to reduce marginal energy and capacity bulk power supply costs by applying factors of .837366 and .971536 for each of its and MPC's proposed revenue requirements, respectively (as revised in MCC RDR MPC-107).

215. Table 9 illustrates MCC's cost reconciliation method. Since MCC only adjusted bulk power supply costs, distribution and customer costs are aggregated for the purpose of this illustration. Also, MCC's proposed revenue requirement is used.

Table 9. MCC's Proposed Method of Reconciliation
(Millions of Dollars)

		Bulk Power		
	Total Montana	Capacity	Energy	Distribution
Functionalized Embedded Revenue Requirement	$290.3	$143.6	$69.4	$77.3
Marginal Cost of Service	$331.6	$103.8	$150.6	$77.3
Reconciliation				

Factor		.837366	.837366	
Reconciled Marginal Cost of Service	$290.3	$86.9	$126.1	$77.3

Source: Exh. No. MCC-6, JD-7 (as revised TR 1324-1325)

Moderation

216. MCC maintains its reconciliation methods would result in rate reductions for the GS-2 transmission class, rate increases below the system average to the Residential and GS-1 Secondary classes, and rate increases above the system average to the remaining classes. MCC proposed to moderate the rate increases to the Residential and Transmission classes to 75 percent of the overall increase of 7.79 percent (MCC RDR MPC-107) or 5.83 percent. Further, MCC proposed to moderate rate increases to the Interruptible Industrial, Irrigation, and Lighting classes to 150 percent of the overall increase at 11.67 percent. Further, MCC proposed to increase the Primary class' revenues by 9.65 percent and spread the remaining revenues to the remaining classes (Exh. No. MCC-6, pp. 62-63).

217. MCC recommends the Commission deny MPC's Rate Implementation Plan. MCC describes MPC's plan as one in which subsidies to certain classes resulting from MPC's proposed class revenues would be eliminated. MCC argues the approach is problematic since future loads and cost patterns will change revenue and cost relationships for all classes. MCC recommends MPC correct future cost discrepancies in future rate cases (Exh. No. MCC-6, p. 66).

Rebuttal

218. LCG and FEA rebutted MCC's reconciliation method. FEA and RPC rebutted MCC's moderation proposals. A summary of these rebuttals follow.

219. Reconciliation. LCG maintains that MCC's method

reclassifies generation capacity costs to energy costs and that these capacity costs are then allocated using MCC's energy allocation factor (Exh. No. LCG-7, p. 7-8).

220. LCG also rebuts MCC's justification to reclassify marginal generation capacity costs as energy costs. LCG notes that MCC's proposed reconciliation method is not new in this proceeding and has been unsuccessfully proposed in past dockets, including Docket No. 87.4.21. LCG cites Order No. 5340 in which the Commission found invalid MCC's argument to reassign marginal capacity costs to marginal energy costs. LCG adds that MCC has not provided any new reasons for the Commission to change its policy regarding this type of reconciliation. LCG thus recommends the Commission reject MCC's reconciliation method (Id., pp. 8-9).

221. The FEA describes MCC's COS study as "an allocated, embedded cost-of-service study that incorporates some aspects of marginal costing" (Exh. No. FEA-3, p. 8). FEA maintains the only difference between MCC's functionalized embedded and reconciled marginal costs is that $56,224,000 of bulk power costs have been reclassified from generation capacity to energy.

222. FEA contends, however, the same objection does not apply to MPC's cost study. Since MPC's costs are based on costs caused by each customer's incremental usage, costs must be reconciled with revenues. Further, each class' revenue requirement is 78 percent of its full cost. Conversely, FEA maintains that functionalized costs computed in an embedded study are allocated to classes based on analyst-selected allocation factors. As an example, FEA notes that MCC computes total generation capacity costs using the jurisdictional peak (1,028,157 kW) and allocates these costs using the average of the twelve monthly CPs (939,268 kW). FEA maintains that the residential class caused 38.85 percent of these costs and MCC allocated 29.99 percent of these costs to this class. FEA recommends the Commission totally reject MCC's cost study on this basis (Exh. No. FEA-3, pp. 8-9).

223. Moderation FEA maintains that MCC uses its COS study to

set class revenue increases for all classes but the Transmission class. FEA maintains that MCC proposes Residential, Primary, Secondary, and Substation revenues which exceed costs by 2 percent or less and Industrial, Irrigation, and Lighting revenues which are less than costs. FEA also maintains that MCC treats the Transmission class differently by proposing revenues for this class which exceed costs by 29 percent. Based on this observation, the FEA recommends MCC's class revenue level proposals be rejected (Exh. No. FEA-3, p. 10).

224. RPC rebutted MCC's moderation proposals. First, RPC maintains MCC did not use its class revenue requirements to develop rates. Although MCC proposes that the interruptible class (referenced as "industrial" by MCC) receive an 11.67 percent increase, RPC maintains MCC used incorrect percentages to compare current class revenues to its computed class revenues. MCC's error results from comparing interruptible class revenues with and without an interruptible credit. RPC would correct this error by applying the credit procedures described in both its and MPC's direct testimonies. RPC holds the revised interruptible class revenue requirement is $9,152,000. RPC maintains this would result in a 5.83 percent increase for the industrial class (Exh. No. RPC-3, p. 6 and RPC RDR PSC-584).

225. RPC supports MPC's EPR and Rate Implementation Plan since these measures will result in most customer class revenues reflecting their marginal costs. RPC maintains MCC's design revenues, from which MCC designed rates, do not equal marginal costs due to MCC's revenue adjustments (Id., p. 7).

MII RECONCILIATION AND MODERATION

226. MII maintains that by implementing its proposed changes to MPC's cost study, namely allocating distribution demand costs based on data from Docket No. 87.4.21 and use of average summer peaks to allocate marginal generation capacity costs, the irrigation class' revenue requirement would be $3.8 million, an increase of 12.4 percent over current rate levels. MII also

maintains these changes have less an impact on other customer classes relative to the impact on the irrigation class (Exh. No. MII-2, pp.25-26, AJY-5 & 6).

227. If the Commission allocates summer marginal generation capacity costs using a method other than MII's proposed method, MII would continue to recommend limiting the increase to the irrigation class to 12.4 percent. MII notes that the irrigation class currently makes up 1.3 percent of MPC's total revenues (MII RDR PSC-598) and its recommendation would not "substantially impact" other class' revenue requirements. Finally, MII maintains that "by keeping the revenue level limited to the increase for the irrigators in this case limited to the increase that would be received under the average of the summer coincident peaks method, the irrigators and other parties would be given time to more fully review costs and allocation theories so that alternatives may be presented in the next case" (Id., p. 28, emphasis in original). MII makes this recommendation only if the Commission allocates summer demand costs differently than it has in the past.

Rebuttal

228. MPC characterizes MII's position regarding who would be responsible for revenues in the event the irrigation class' revenues are set below costs as implying that a lower revenue increase is justified for the irrigation class since irrigation and some industrial customers compete on a regional and local basis. MPC maintains that if a cost study indicates a revenue increase for the irrigation class is needed but delayed, the difference between current and marginal cost revenues will increase (Exh. No. MPC-48, pp. 19-20).

LCG RECONCILIATION AND MODERATION

229. In answer testimony LCG recommended the Commission require distribution costs be unbundled in the future to avoid shifting such costs to the substation and transmission levels. The LCG suggested this be accomplished by revising the moderation

procedure (Exh. No. LCG-8, p. 5 and TR 1265). MPC rebutted LCG by maintaining that distribution costs were not shifted to the substation level, as LCG claims. MPC stated, however, that the moderation procedure should be examined in the future (Exh. No. MPC-42, pp. 1-4).

FEA RECONCILIATION AND MODERATION

230. FEA finds reasonable and supports MPC's proposal to cap class revenue increases at 32.5 percent in any year (Exh. No. FEA-2, p. 7).

231. RPC Rebuttal to FEA RPC rebutted FEA's adjustment to the interruptible class revenue requirement (Exh. No. FEA-2, CEJ-1, Schedule 3). RPC maintains the FEA used a different method than MPC to spread class revenues in excess of the 32.5 percent cap with the result FEA over computed the design revenues by $2.9 million greater than MPC's class revenue requirement. RPC maintains the FEA failed to apply the entire $2.9 million interruptible participation credit to its corrected design revenues for the interruptible class. RPC computed the $2.9 million figure by applying FEA's reconciliation factor to the interruptible credit computed by MPC.

COMMISSION DECISION: COST OF SERVICE

INTRODUCTION

232. The Commission's decisions in this section are organized as follows. After an opening policy statement, the Commission will state and explain its findings on costing issues raised by the parties in this Docket. This section contains technical and policy decisions required to resolve contested cost of service issues. After addressing cost of service issues the Commission will address reconciliation and moderation of marginal costs, followed by pricing issues. A final section of this Order contains policy directions to MPC.

Policy Overview

233. This policy overview provides the Commission's reasoning that underpins later COS and pricing decisions. To resolve contested issues in this Docket the Commission must weigh and balance the concerns raised by numerous and diverse interests. These interests include the intervenors, MPC, and the public. Combined, these interests represent the public interest. Thus, the Commission's decisions will not rest on the position of a single party (interest) or on a single point of view, but will reflect a reasoned balance of many and diverse interests.

234. The prices the Commission sets in this Docket affect hundreds of thousands of residential, business, agricultural and industrial consumers. The prices set must also allow MPC an opportunity to earn its allowed rate of return. As past experience reveals, customers' reluctance to absorb any costs arguably not their own responsibility, the Commission will seek to achieve a fair allocation of revenue requirements taking into account the impact such prices have on customer classes.

235. Although costing is not the only basis for decisions on class revenue requirements and prices, cost of service testimony is one important Commission consideration. As a result, costing decisions must be well reasoned. The Commission concurs with MCC that relevant rate design criteria are found in Professor James Bonbright's often-cited text Principles of Public Utility Rates. MCC relates Bonbright's criteria to the three rate-design-related objectives of encouraging conservation, efficiency and equity. MCC concludes that marginal cost pricing meets these objectives. Most parties appear to agree on the import and merit of using marginal cost based prices. The Commission concurs with the above objectives, notably pricing's impact on incentives to conserve and use resources efficiently.

Year's Dollars

236. As part of its costing decisions, the Commission finds

merit in and approves MPC's expression of costs in beginning-of-year 1992 dollar terms. Ideally, however, the year's dollars would reflect the mid-point of time period during which the resulting prices will be tariffed. Absent this knowledge January 1992 dollars will suffice.

Generation

237. For several reasons, generation ranks as the most important cost function. Among the resources included in the major cost functions, the Commission holds that generation resources are those that can be most efficiently conserved by pricing decisions.

238. Second, in terms of the relative magnitude of total marginal costs, generation surpasses any other cost function. Based on MPC's testimony generation comprises about 72 percent of the total marginal costs, excluding reactive power costs ($264 out of $369 million). This percentage varies with each party's testimony.

239. Third, in a competitive sense, generation is also different. Generation resources can be obtained from non-MPC sources and MPC's own resources have alternative uses. MPC buys and sells power in the marketplace, which includes the Pacific Northwest and may extend to the Southwest. Thus, generation costs are not limited to MPC's cost of operating existing resources or building and operating new resources. As a result, generation costing involves the source, time horizon, and classification of costs. Each is discussed in turn.

240. Source of Costs. The source of generation costs the Commission approves in this docket is MPC's proposed July 1990 avoided cost compliance filing, as amended. This source was used by MPC and MCC in their respective cost studies. Costs included in MPC's filing include operating and new construction costs, purchase power costs, and off-system opportunity (sales) costs. In this Docket, MPC amended its July 1990 source of costs to include BPA capacity costs in the early years (1992 through 1996). MCC adopts

MPC's amendments.

241. The Commission finds little merit in MII's proposal to base certain MPC customer class prices and costs on the prices tariffed by some other regional utility. MPC appropriately rebutted this proposal.

242. Time Horizon for Costs. The Commission adopts MCC's 25 years of costs. Testimony on the relevant time horizon spanned the short to the long run. The Commission denies the short-run costs proposed by the FEA. For comparison purposes, on an annual average basis, MPC's 10- and MCC's 25-year generation marginal energy (capacity) costs, respectively, equal \$0.01935/kwh (\$101.86/kw) and \$0.02237/kwh (\$95.64/kw).

243. The long run proposals of MCC and MPC are not well-reasoned. Regarding energy, Mr. Maxwell simply states "...the long-run... is appropriate" (Exh. No. MPC-41, p. 6). For being such a critical variable, the Commission is puzzled that it received so little analysis. The Commission finds a 25-year time horizon valid for this Docket. This time horizon could increase or decrease in MPC's next COS docket depending on the arguments made at that time.

244. In the absence of significant analysis from the parties on a proper time horizon, the Commission's reasons for using a 25-year time horizon are as follows. First, MPC has an obligation to serve loads over the long term and customers depend on MPC for long term commitments. Resource planning decisions involving hydro upgrades, Colstrip 4, conservation, and financial cost-of-equity estimates all require long term forecasts and unavoidably involve errors. Second, twenty-five years is not the longest term one could justify. MPC voluntarily commits to longer-term resources, e.g., Colstrip 3. Third, parties who argue forecast error is a valid reason to not use a long-term time horizon raise a weak argument. Most resource planning decisions require forecasts. Forecasts have been, and will continue to be, used for resource planning and ratemaking decisions; forecasts are not unique to

costing and pricing. Fourth, and importantly, power sold to native load customers has a long-term firm opportunity cost value that most likely exceeds the short-term non-firm value MPC currently imputes in its generation costs in this Docket.

245. Classification of Costs. The Commission rejects MPC's method of classifying generation costs contained in its July 1990 compliance filing. This July 1990 method treats capacity as a residual after valuing energy. The Commission recently rejected the same method in Order No. 5506a, Docket No. 90.8.51. MPC did not file a motion to reconsider the Commission's decision in that Docket. Thus, the Commission finds merit in and adopts the classification method MPC proposed in its BGI rate calculations (Docket No. 90.8.51) and which the Commission ordered MPC to use in its revised July 1990 avoided cost compliance filing (Order No. 5506a, January 9, 1991).

246. Additional background is needed in advance of stating the Commission's reasons for rejecting MPC's classification method. MPC's July 1990 compliance filing states in part:

> The Montana Power Company (MPC) is submitting compliance default avoided cost tariffs that reflect an improved methodology from that previously submitted. The method was scrutinized by all parties involved in 88.6.15...and the Commission expressed its findings on these issues in order 5360d. This method adds one PROMOD/CER run to the existing two runs... (emphasis added)

247. Because MPC cites Docket No. 88.6.15, the Commission reviewed MPC's direct testimony in that Docket. The Commission does not find in Mr. Leland's prefiled direct testimony in Docket No. 88.6.15 a proposal to change the avoided cost classification method for any avoided cost calculation suggested in the above quote.

248. Finally, if Order No. 5360d (Docket No. 88.6.15) approved

the classification method described in the July 1990 filing, as the above quote suggests, MPC should have reflected the same in its Order No. 5360d compliance filings. MPC did not propose to change the classification method until July 1990. This suggests either that MPC's Order No. 5360d avoided cost compliance filings were incomplete, or MPC's July 1990 compliance filing was actually the first occasion on which MPC proposed the changed classification method on which it states the Commission already expressed its approval in Order No. 5360d.

249. Several parties criticized MPC's capacity cost sources and the method of classifying generation costs by which MPC computes capacity costs. First, the FEA's rebuttal testimony criticized MPC for overestimating marginal capacity costs. FEA's economic rationale for incurring generation capacity costs states:

> The marginal cost of demand should not exceed the cost at which generating capacity can be obtained. ... In subsequent years of the study, MPC used an approach that resulted in estimates of marginal demand costs that are twice the cost of BPA capacity. (Exh. No. FEA-3, p. 12-13.)

250. Thus, FEA concludes that MPC's marginal demand costs may be overestimated. That is, MPC's July 1990 classification method values capacity in some years at over twice that which MPC would have to pay BPA. MPC never rebutted FEA's criticism.

251. Second, MCC echoed FEA's economic rationale. MCC stated:

> The marginal cost of meeting peak demand is the annual carrying cost of additional capacity that must be added only for the purposes of meeting that additional demand. The cost of meeting additional peak demand will, therefore, never exceed the carrying cost of that generating unit with the lowest fixed cost per kw of capacity." (Exh. No. MCC-6, p. 42)

252. Third, HRC, while expressing more general concerns, also objects to MPC's generation costing and classification method (Exh. No. HRC-3, pp. 70-74).

Transmission

253. The Commission finds merit in and approves MPC's proposed transmission energy and MCC's proposed transmission capacity costs. The Commission approves MPC's energy line and capacity loss computation method and recognizes that the loss factors used will change according to changes in the seasonal definition and by reallocating the Malmstrom load to the transmission class. The capacity costs that are approved are MCC's capital and O&M cost estimates, which amount to $5.31/kW. The reader is referred to MCC's capacity cost.

254. The Commission's reasons for approving MCC's transmission capacity costs stem from their logical appeal combined with problems with MPC's estimate. Parties' testimony on which this decision is based follow. MCC's estimate of the cost of connecting the least cost source of generation capacity is the maximum MPC ought to pay for transmission capacity. This argument is tantamount to FEA's point that the cost of generation capacity ought not to exceed the cost at which it can be obtained. That is, the Commission's reasons for adopting MCC's transmission costs also relate to the earlier findings on what is wrong with how MPC classified generation costs.

255. In addition, the Commission is persuaded to accept MCC's proposal in light of HRC's testimony. The Commission concurs with HRC's testimony that MPC's cost estimates are unstable in relation to variations in the time horizon. Also, the change in demand which MPC divides into the change in costs is not well grounded, again for the reasons HRC noted. Last, the Commission finds merit in HRC's argument that transmission capital costs are not simply capacity related. That is, there is an energy function to marginal transmission costs not established in this Docket.

Substation

256. The Commission finds merit in and approves MPC's proposed substation energy and capacity costs. The Commission approves MPC's energy and capacity loss computational method and recognizes that the loss factors used will change according to changes in the seasonal definitions and by reallocating the Malmstrom loads and usage to the transmission class. The Commission also approves MPC's substation plant and O&M costs of $7.61/kW and $.33/kW. The Commission approves MPC's substation costs for the following reasons.

257. Both MPC and MCC proposed substation costs. The Commission approves MPC's substation costs because MCC uses embedded costs as a proxy for long-run marginal costs. The Commission's reasoning is similar to that described below regarding MCC's use of embedded costs to proxy long-run marginal distribution costs. The Commission favors a marginal cost method over an embedded cost method, and finds that historical, embedded costs cannot serve as a proxy for future costs and technological change. The Commission also finds merit in and approves MPC's substation O&M costs in this case.

Distribution

258. The Commission finds merit in and approves MPC's distribution cost estimates for energy and capacity. The Commission recognizes these cost estimates will change according to changes in the seasonal definitions and by reallocating Malmstrom's load to the transmission class. No party contested MPC's estimate and use of energy costs. Certain parties contested MPC's exclusion of specific distribution capacity costs. MPC's generation capacity loss cost proposal is a separate issue which the Commission will address along with other allocation factors.

259. The Commission received testimony on three different methods to compute marginal distribution capacity costs. The Commission finds merit in MPC's proposal to include only

distribution costs related to losses. The reasons for this decision follow and relate to the alternative proposals before the Commission. The Commission notes that, whereas it finds relative merit in MPC's testimony, there remain issues that need addressing in MPC's next COS study as discussed in the final section of this Order. Chief among these issues is whether to reflect the cost of distribution in line extension policies or in recurring cost studies, or both. How this issue gets resolved will depend on the treatment of common costs (e.g., primary distribution) and customer specific costs (e.g., drop lines).

260. The parties' testimony raised two distribution cost issues: 1) whether to use embedded costs or marginal costs; and, 2) if marginal costs are used, whether to use short- or long-run costs. In contrast to MPC's short-run marginal costs, MCC proposed using embedded costs as a proxy for long-run marginal costs (LRMC). LCG proposed using a method that tends toward a long-run cost estimate. LCG's proposal references analysis contained in a data response (RDR PSC 611).

261. The Commission favors a marginal cost method over the use of embedded costs as a proxy for LRMCs. Before MCC's argument could be adopted two explanations would be required. First, how do MPC's current line extension policies account for incremental costs contained in MCC's embedded cost proxy? Second, how does use of the past 30 or more years of embedded costs serve as a proxy for future costs and technological change?

262. The Commission does not favor LCG's proposed use of the analysis contained in data response PSC-611. The primary reason relates to the criticism HRC leveled against MPC's transmission cost analysis. The Commission finds merit in applying HRC's criticisms of MPC's transmission costs to LCG's proposed distribution costs. Other reasons include the lack of any explanation of the source and type of costs included in LCG's analysis, whether they exclude line extension contributions and whether the resulting avoided costs are only capacity related.

Customer

263. The Commission's findings on what customer costs to include in this Docket reflect the testimony of several parties. This decision involves a discussion of fixed and variable, long- and short-run, and opportunity costs. In this section the Commission will address both non-lighting and lighting customer costs.

264. Non-Lighting. First, differences between MPC's and HRC's testimony can be illustrated in terms of fixed and variable costs. HRC includes variable metering and billing costs that MPC incurs on a recurring basis. MPC agrees with HRC on this count but would add the fixed costs of the meter and drop line. The Commission notes that, based on a narrow definition of marginal costs, neither HRC's variable nor MPC's fixed and variable costs can be avoided unless a customer ceases service. However, such a narrow view excludes the contributions an opportunity cost analysis would provide.

265. As a result, the Commission's starting point for defining relevant marginal customer costs is to initially include the fixed costs in MPC's study and the variable costs agreed on by HRC and MPC. However, the Commission finds relevant a consideration of opportunity costs. Clearly the variable costs of metering and billing are avoidable based on an opportunity cost screening; if MPC did not meter and bill a customer, the labor and computer resources involved could be used for other purposes, or avoided.

266. The same opportunity cost screen can be applied to the meter and drop line. Whereas the Commission finds a meter to have an opportunity cost value, the drop line does not. The reason is that MPC could recycle or salvage and sell a meter with a positive net value but probably could not do so with a drop line. Thus, the decision to include the meter but exclude the drop line (underground and overhead) on an opportunity cost basis likely overstates the value of the meter and understates the value of the drop line. Until such time as refinements are made to account for salvage costs, this decision, which is similar to Commission

decisions in previous dockets, will have to suffice.

267. The Commission notes that MCC's transmission cost uses as a proxy the cost to connect a peaking capacity unit. MPC similarly used a proxy for the capital costs of its substation class. In other words, both MPC and MCC have proposed using proxy cost measures elsewhere in their respective cost studies. Consistent with the Commission's adoption of MPC's and MCC's testimony on these counts, the Commission finds valid the inclusion of meter costs in the customer cost function.

268. Lighting. The Commission's decisions on lighting customer costs address O&M and plant costs. First, consistent with its decisions regarding non-lighting customer costs, the Commission excludes from MPC's customer lighting costs all non-investment related O&M. In terms of non-lighting customer costs these costs would include costs that MPC and HRC do not agree on, including their customer costs. As a result, excluded costs include customer accounting, customer service, information expenses, and sales expenses.

269. Second, consistent with the decision to exclude service drops from customer costs, the Commission directs MPC to exclude the drop line (underground and overhead) and installed investment costs for underground facilities from lighting customer costs. MPC testified that investment in underground facilities is considered a sunk cost (TR 1034-1035). Therefore, the Commission directs MPC to exclude these costs from its lighting customer costs since they are not fungible. With respect to annualizing plant investment costs, MPC testified that the return on investment it uses to compute plant costs is used as a proxy for the annual costs of installed plant (TR 1035). This cost is based on MPC's marginal cost of capital (11.46 percent). To remain consistent with the use of real levelization in this Docket, the Commission directs MPC to adjust its marginal cost of capital for inflation. The Commission questions this means of annualizing plant costs and directs MPC to address levelizing these costs in its next cost study.

Allocation of Classified Costs

270. The Commission's findings regarding the determination of seasons, allocations of classified costs to classes, MPC's computation of losses, and mathematical and data corrections are addressed below.

Seasonality

271. MPC, MCC, and HRC addressed seasonality in this Docket. MPC proposed to reduce the winter season by one month, to which MCC concurred with respect to its use of MPC's seasons to allocate energy costs. HRC performed its own visual analysis of graphed data using LOLHs and energy costs and concludes the Commission should abandon seasonal rates and replace them with inverted block rates.

272. With respect to the proper methods MPC uses to determine seasons, the Commission finds that neither the use of LOLHs or load shapes are cost-based methods. As such, MPC mixes cost and non-cost related data to determine seasons. Also, the Commission finds that MPC's use of three years of prospective marginal system lambdas to determine seasons, while using 10 year's prospective data to compute generation energy and capacity costs is inconsistent. The Commission finds MPC's seasonal analysis unacceptable with regard to these issues. MPC is therefore directed to examine appropriate seasons for capacity and energy costs using cost-based methods and to address the inconsistency between the costs used to define seasons and to compute costs. The Commission also finds merit in HRC's observation that MPC's analysis supports reducing the current season but fails to examine other possible seasons. Therefore, MPC is directed to broaden the scope of its seasonal analysis.

273. In Docket No. 87.4.21, the Commission granted MPC's proposal to increase its winter season by one month by adding March to the definition. Yet, MPC proposes removing March from the winter season definition in this case. The Commission is concerned

that the next time it considers this issue the definition of the winter and summer seasons may once again change. Therefore, the Commission finds merit in maintaining the current winter/summer seasonal definitions until such time as the issues of the proper methods used to determine seasons are resolved. The Commission also makes this decision in light of the uncertainty involved in the arguments presented by MPC and HRC. The Commission finds the winter season to be November 1 through March 31 and the summer season to be April 1 through October 31.

Allocation to Classes

274. This section addresses cost allocations to seasons and classes. The Commission's findings are presented for the energy, capacity and customer cost classifications. Further, allocation of classified costs to the unit cost level are also addressed per these classifications for the lighting classes. The Commission's decision on MPC's proposal to price service to GS-2 Transmission and GS-2 Substation and GS-1 Primary and GS-1 Secondary levels of service (GS-2 and GS-1 class splits) separately and MPC's proposed Off-Peak Demand Rate are also discussed.

275. Energy. MPC and MCC allocated generation energy costs to classes seasonally based on each class' contribution to kWh sales. The Commission finds this approach acceptable and approves this method. However, MPC must revise its seasonal energy cost allocation method to reflect the Commission's decision to maintain the current seasonal definition. The Commission finds MPC's use of three year's prospective system lambda data to allocate energy costs to seasons and 10 year's prospective data to compute energy costs inconsistent. Given the limited record on this issue, the Commission accepts this method in this case.

276. MPC and MCC allocated generation energy losses by voltage level. RPC and LCG allocated energy losses at the generation level. RPC allocated energy losses on a volumetric basis rather than by adjusting costs for losses (RPC RDR PSC-618 and MCC-260). LCG allocated energy losses by applying MPC's loss factors to

energy costs. The Commission finds it appropriate to compute energy losses by adjusting energy costs for losses as was done by MPC, MCC, and LCG. The Commission also finds that allocating energy losses at the generation level or at the voltage level produces nearly the same results (MPC RDR PSC-267). Consistent with its decision regarding distribution costs, the Commission approves MPC's allocation of energy loss costs at the transmission, substation, and distribution voltage levels. The Commission accepts MPC's method to allocate energy costs within each of its lighting classes.

277. Capacity. This section addresses capacity cost allocations at each voltage level. Although the Commission finds MPC's use of LOLH data to determine seasons questionable, the Commission accepts MPC's use of LOLH's to allocate generation capacity costs to seasons in this Docket and intends to revisit the method in MPC's next general rate case. However, MPC must address the use of cost versus non-cost (LOLH) based methods to determine seasons and to allocate capacity costs to seasons in its next case. MPC must revise its seasonal capacity cost allocation method to reflect the Commission's decision to maintain the current seasonal definition.

278. MPC, LCG, and RPC agree that seasonal generation capacity costs should be allocated to classes based on each class' contribution to winter and summer normalized CPs. MCC proposes to allocate these costs based on each class' contribution to the annual average CP. MII proposes to seasonally allocate capacity costs based on each class' contribution to the winter CP and to each class' contribution to the average of the summer monthly peaks. FEA and HRC did not express an opinion on this matter. The Commission finds merit in and approves MPC's seasonal allocation of generation capacity costs based on each class' contribution to winter and summer normalized CPs. The Commission rejects LCG's determination of the winter coincident peak as January and accepts MPC's determination of this peak as February. The Commission finds that determining the winter and summer peaks using volumes at the meter, as LCG has done, fails to account for generation capacity

losses as generation capacity costs. Since generation capacity losses are generation costs, seasonal CP capacity volumes must be determined using generation level kW volumes.

279. The Commission also finds reasonable, and consistent with its decision regarding distribution costs, the decision to allocate generation capacity loss costs at the transmission, substation, and distribution voltage levels. Also, consistent with its finding that generation capacity loss costs are generation costs, the Commission finds merit in and directs MPC to allocate these costs at each voltage level based on each class' contribution to the annual normalized CP. The Commission finds it reasonable to compute generation capacity loss costs by applying MPC's loss percentage factors to its unit generation capacity costs.

280. Since all customer classes rely on the transmission system, as they do on generation, to provide power, the Commission finds merit in allocating transmission plant and O&M costs to classes according to each class' contribution to the normalized annual CP. Additionally, the Commission finds merit in allocating substation plant and O&M costs using the same method. The Commission's reason for this allocation is that substation costs are more like transmission costs in that the bulk of MPC's peak loads are served through the substation. Furthermore, MPC does not appear to have computed substation costs based on the average of monthly CPs.

281. The Commission accepts MPC's method to allocate capacity costs within its lighting classes as described elsewhere in this Order.

282. Customer. The Commission approves MPC's method to allocate meter plant costs and meter reading related O&M costs. The Commission approves MPC's method to allocate lighting customer costs, but must include only those costs not excluded by the Commission. These costs would be limited to non-service drop related costs.

283. GS-1 and GS-2 Class Separations. The Commission grants MPC's proposal to price service to its GS-2 Transmission and GS-2 Substation and GS-1 Primary and GS-1 Secondary classes separately. The Commission recognizes that Malmstrom Air Force Base, a customer not included in the test-year transmission class allocation data (TR 1067-1068), has switched service to the transmission voltage level (TR 917) and will be charged for service as a transmission level customer when rates become effective November 1, 1991 (TR 1127). Accordingly, MPC must recompute the energy, capacity, and customer volumes used to allocate such costs to its transmission class to exclude Malmstrom Air Force Base from the class under which it was served according to the data used to compute costs in MPC's direct and rebuttal COS testimonies (Exh. Nos. MPC-40 and MPC-41) and include that customer in its transmission class.

284. Off-Peak Demand Rates and Time-Of-Day (TOD) discount. This section addresses MPC's proposed TOD discounts for its Off-Peak Demand Discount Rates. MPC's proposed rates will be addressed in the rate design section of this Order.

285. Consistent with its decision on the use of LOLH's to determine seasons and to allocate capacity costs seasonally, the Commission denies MPC's proposal to revise its time-of-day definition for its Off-Peak Demand Discount Rate. Further, the Commission directs MPC to examine peak and off-peak periods using a cost-based approach in its next COS study. As with seasonality, the Commission is concerned that MPC's peak and off-peak periods may change when analyzed using a cost-based approach. Hence, the Commission finds it reasonable for MPC to maintain its current peak and off-peak definitions.

Losses

286. The Commission finds MPC's computation of energy and capacity loss percentage factors deficient in two areas. First, the Commission has concerns that the energy costs in MPC's July 1990 Avoided Cost Compliance Filing may result in double counting transmission line losses (DR No. FEA-18 and MPC RDR PSC-521). MPC

maintains the data it used to compute generation energy costs exclude the loss factor ordered in Order No. 5091c (MPC RDR PSC-276). The Commission directs MPC to remove any transmission line loss adjustments it made to the energy cost data it used from its July 1990 Avoided Cost Compliance Filing to compute generation energy costs.

287. Secondly, the Commission questions MPC's logic regarding its determination of capacity losses. Although MPC's analysis is limited to including capacity losses associated with generation, the Commission questions why capacity losses associated with transmission, substation, and distribution are not also computed. The Commission finds it illogical for there to be capacity loss costs associated with generation but not for transmission, substation, and distribution levels. In other words, if generation capacity is sized to meet the capacity required to serve the customers on the system and account for losses, why wouldn't the transmission systems, substations, and distribution facilities also be sized similarly? MPC is required in its next case to address this issue.

288. The Commission finds reasonable and approves the method MPC used to compute energy and capacity loss percentage factors. MPC must compute losses using load (mW) and usage (kWh) data adjusted for the Malmstrom load in the transmission class. Additionally, the Commission directs MPC to compute its energy and capacity loss percentage factors according to the Commission's decisions regarding seasons. That is, MPC must use a winter season of November through March; all other months will comprise the summer season.

Mathematical and Data Corrections

289. The Commission approves MPC's revised data for the irrigation class as presented in Mr. Maxwell's supplemental rebuttal testimony (Exh. No. MPC-42, PEM-24). The Commission directs MPC to include these data in its computation of energy and capacity cost allocations for the irrigation class.

290. With the exception of one error identified by LCG and supported by FEA regarding MPC's energy allocation sales volumes, it appears MPC has corrected all the errors in its study that were identified by other parties. It appears, however, that MPC has not corrected the substation energy values listed on page 6 of Exh. No. LCG-6 regarding the substation class' winter and summer energy usage. The Commission directs MPC to make these corrections in conjunction with the changes MPC must make for seasonal volumes per the Commission's decision on seasons. Also, the Commission finds the annual substation energy usage volumes need correction for the transmission and substation voltage levels. This value should be 1,992,340,500 (MPC RDR LCG-119).

Reactive Power Costs

291. In Order No. 5051f (Docket No. 83.9.67), the Commission directed MPC to address the issue of reactive power. In that Order the Commission directed MPC to address the marginal cost of reactive power demand and measures of billing determinants. In Order No. 5340 (Docket No. 87.4.21) the Commission again directed MPC to address the issue of the marginal cost of reactive power.

292. Although MPC has addressed the marginal cost of reactive power in this Docket, the Commission finds its treatment deficient. MPC's reactive power costs appear related only to O&M costs and not the costs associated with reactive power demand resulting from serving the GS-2 classes, namely generation, transmission and substation. Therefore, MPC is directed to further examine the marginal costs of reactive power in its next COS study as they relate to these functional costs. For the purposes of this case, the Commission accepts MPC's reactive power costs. The Commission's decisions regarding implementation of MPC's reactive power charge will be addressed in the Rate Design section of this Order.

Reconciliation

293. To summarize, the Commission finds merit in continuing its use of the equal percentage method to reconcile costs. The Commission has used this method for years and in many different dockets. The Commission has always moderated the results of the equal percentage reconciliation (EPR) method and will do so again in this Docket.

294. As a result of adopting the EPR method, MPC must, as usual, compute the total marginal costs of providing electric service to each class. For this purpose, all classes MPC proposed in this docket must be included. The total marginal costs must be reconciled to the $310,403,998 discussed below. This would include revenues approved in this Docket and those approved on an interim basis in Docket No. 91.6.24.

295. The Commission finds merit in and approves MPC's method of computing the interruptible credit for its Industrial Interruptible class (II-1 tariff), as described in the rate design section of this Order. This credit must be applied to the II-1 class' total marginal costs before MPC reconciles costs to the base rate revenues as described below. As noted in the rate design section of this Order, the Commission denies RPC's proposal to apply a performance incentive credit to the II-1 class' total marginal cost.

Moderation

296. The following discusses the Commission's moderation decisions, final total base rate revenues, and how the revenues MPC has been authorized to collect in other dockets are to be implemented into rates.

297. Class Revenue Moderation. Although the Commission's costing decisions are largely based on proposals in this case, the Commission is not entirely convinced that any single party's proposals would result in costs which accurately depict MPC's cost of service. One of the Commission's goals in this case is to provide as accurate a price signal as possible of the costs to

provide service.

298. The Commission believes that prices will be used by residential, business, agricultural, and industrial customers to make investment and/or production decisions. While the Commission has opted to moderate class revenues in this case, it will address moderation of class revenue requirements in future cases, as needed.

299. In keeping with the earlier-stated reasons for using marginal costs, the Commission also embraces Professor Bonbright's principle of moderation of rate impacts. Thus, the Commission finds merit in moderating class revenue responsibilities using MPC's proposed capping method. Since the Commission approved a system average revenue increase of about 14.79 percent over base rates (Paragraph No. 1, Order section, Order No. 5484k, p. 165), MPC's capping method results in a 24.79 percent maximum increase in any class revenue requirement. Thus, revenue increases to the GS-2 Substation, Interruptible, and Post-top Lighting class' are capped at about 24.79 percent. Absent the 24.79 percent cap, these class' revenues would have increased by about 34.08, 26.19, and 43.58 percent, respectively. Uncollected revenues resulting from capping are to be spread equally to all other classes. This may take two or more iterations.

300. The following table provides illustrative class revenues resulting from the Commission's moderation decision. The Commission notes that the pre-interim and final class revenues do not include the PSC tax since this tax is subject to change. A further explanation of the components included in the revenues listed in this table is provided below.

Table 10
Pre-Interim and Final (Illustrative) Class Revenues
($ 000)

Customer Class	Pre-Interim Base Rate Revenues	Moderated Base Rate Revenues	Percent Change
Residential	$ 91,406	$ 101,128	10.64%

(includes employee)			
General Service - 1			
Secondary	81,260	90,974	11.96%
Primary	13,016	15,577	19.68%
General Service - 2			
Substation	59,382	74,103	24.79%
Transmission	3,324	3,909	17.61%
Interruptible	9,343	11,659	24.79%
Irrigation	3,405	4,061	19.27%
Street Lighting	4,663	5,183	11.14%
Post-Top Lighting	528	658	24.79%
Yard Lighting	2,570	3,151	22.59%
Total	268,897	310,404	14.79%

Sources: Pre-Interim Base Rate Revenues: Exh. No. MPC-44, PRC-4, without the PSC tax (.16%)
The final revenues reported in this table exclude adjustments for the PSC tax.

301. The Commission denies MPC's proposed Rate Implementation Plan (RIP) for the following reasons. First, the Commission finds that by phasing in revenue increases to those classes whose revenues are capped would result in confusing the price signals resulting from this proceeding. Second, the Commission finds that in the event future rate cases were completed before the plan runs its full course, changes in class revenues resulting from numerous sources (e.g., changed costing philosophies), may result in inconsistent price signals. Such results would run contrary to the Commission's goal of providing accurate cost information through prices. Third, the Commission finds merit in MCC's argument that future class loads and costs will change which, in turn, will change revenue and cost relationships among classes. Also, since the majority (72 percent) of the revenue increase is reflected in current prices (since August 29, 1990) there remains a small additional final increase. Further, the Commission finds merit in

MCC's recommendation that class cost/revenue differences should be handled in future cases and not through a RIP.

302. MCC, MII, and RPC also proposed to moderate class revenues. The Commission denies MCC's moderation proposal due to its inapplicability to class revenues other than those developed in its COS study. The Commission also denies MII's proposal to cap irrigation rates at 12.5 percent and RPC's proposal to apply the total system increase, 14.7923 percent in this instance, to the II-1 class' revenue increase. In this regard, the Commission finds more merit in reflecting accurate cost information, as best as possible, to these classes as well as all other classes. The Commission finds this is best achieved through its reconciliation and moderation decisions described above.

303. Base Rate Revenues. The following describes the base rate revenues MPC shall use as a basis for prices in this Docket. First, MPC's pre-interim base rate revenues reflected the PSC tax effective August 29, 1990, through August 28, 1991, of 0.16 percent (0.0016). In Interim Order No. 5565, Docket No. 91.8.28, the rate for this tax was revised. In that Order the Commission permitted all affected regulated utilities to reflect the new rate (0.24 percent (0.0024)) in their revenue requirements beginning August 29, 1991 (FOF 3, Order No. 5565). Since Order No. 5566 (Docket No. 91.8.31) includes the revised PSC tax as part of the several changes MPC is entitled to make to its annual revenues on November 1, 1991, MPC must compute the class jurisdictional base rate revenues it uses to compute prices in this case without including the PSC tax.

304. Second, in Order No. 5561 (Docket No. 91.6.24), the Commission approved MPC's interim request for additional revenues ($1,730,643) for QF expenses (see Order Nos. 5561 and 5561a, Docket No. 91.6.24) which are added to its jurisdictional base rate revenues. Since this is an adjustment to jurisdictional base rate revenues, the Commission includes these revenues in its computation of prices in this Docket (90.6.39). The Commission notes, however, that a final decision has not been made in Docket No. 91.6.24. As

such, the Commission emphasizes that inclusion of these revenues as part of the base rate revenues used to compute prices in Docket No. 90.6.39 in no way indicates final approval of the issues in Docket No. 91.6.24. The Commission estimates MPC's base rate revenue requirement to equal $310,403,998.

305. Implementation of Revenues from Other Dockets. The following describes the procedures MPC is to follow to implement the revenues it has been authorized to collect in Docket No. 91.8.31 (Order No. 5566a), beginning November 1, 1991. In compliance with this Order MPC must file rates reflecting the Commission's decisions using class revenues computed as described above for the final revenues in this Docket and the interim approved revenues in Docket No. 91.6.24. MPC must then recompute rates, on an equal-percentage basis, based on the remaining amortization and accounting adjustments listed in Order No. 5566a.

Direction

306. For the purpose of documenting compliance tariffs that will be implemented on November 1, 1991, the Commission directs MPC to provide the following information to the Commission and all parties. First, MPC is directed to compute total allocated marginal costs by class according to the Commission's decisions described above. Second, as noted, MPC must reconcile and moderate the above discussed $310,403,998 total revenue requirement. MPC's moderated revenue requirements for each class must account for the discounted low income tariff. MPC must appropriately account for the 40 percent employee discount.

307. Third, MPC is directed to provide full unit marginal costs for each of the Commission approved rate designs in this Docket. These unit costs must be computed according to the Commission's costing decisions in this Order. Unit costs for energy and capacity must be provided with and without losses for each voltage level.

308. Fourth, MPC must provide its marginal capacity costs for

its generic interruptible credit and its QF standby charge per the Commission's costing decisions.

309. MPC must provide supporting work papers for the unit costs requested above. MPC must also provide complete cost of service work papers supporting the Commission's cost of service, reconciliation, and moderation decisions.

310. In the process of finalizing an order in this Docket, the Commission directed its staff to request COS workpapers from MPC that reflected the Commission's COS decisions. MPC complied with this request, the results of which were used to reconcile and moderate revenue impacts and design rates.

311. The Commission requests MPC to document its development and classification of generation costs. As noted in this Order MPC must apply the classification method MPC itself used to classify avoided costs for BGI, which the Commission approved in Docket No. 90.8.51. MPC must apply this BGI classification to MCC's 25 years of generation costs. Because MPC's expert witness in the BGI docket testified that the method of classification does not change the total generation avoided costs (BGI Docket No. 90.8.51, TR 82-83), any changes in total generation avoided costs must be fully explained.

Part II

RATE DESIGN

INTRODUCTION

312. This part of the Order addresses MPC's, MCC's, LCG's, FEA's, and HRC's rate design proposals. The proposals will be summarized and the Commission's rate design decisions will follow.

MPC RATE DESIGN

313. Thomas E. Wilde (hereafter MPC) sponsored rate design

testimony on MPC's behalf (Exh. Nos. MPC-46, 47, and 48). Patrick R. Corcoran (hereafter MPC) also addressed rate design issues on MPC's behalf (Exh. Nos. 43, 44, and 45). A summary of MPC's rate design objectives, priorities, and general process is provided below, followed by its class rate design proposals. MPC's proposed prices and class billing impacts are summarized per its revisions made in rebuttal testimony.

Rate Design Objectives, Priorities, and Methods

314. MPC maintains its pricing proposals are an attempt to achieve understandable and predictable prices and to move prices toward marginal costs to achieve efficient use of resources. MPC also maintains its proposals account for billing impacts. Further, MPC claims that its proposed optional rates and modifications to existing rates to moderate billing impacts address customer wants and needs. Finally, MPC maintains its prices generate total class revenue responsibilities (Exh. No. MPC-46, pp. 3-4).

315. MPC proposed rates which reflect generation capacity as the highest priority, followed, in turn, by energy, other demand-related costs, and customer costs. MPC contends its resource planning studies show the need for capacity over energy resources. MPC asserts that it emphasizes demand side management, interruptibility, and off-peak prices (Exh. No. MPC-46, pp. 4-5).

316. To compute prices MPC first computed each of its marginal demand and energy charges. Next, marginal transmission, substation, and distribution charges were computed, followed by marginal customer charges. MPC defines a "marginal charge" as marginal revenues divided by the "appropriate billing statistics" (Exh. No. MPC-46, p. 5). MPC computed marginal revenues by applying its marginal costs to its allocation volumes (see e.g., Exh. No. MPC-41, PEM-13, pp. 2-7). Marginal charges were then adjusted to each class' revenue requirement. MPC further adjusts its prices to address billing impacts.

317. In direct testimony MPC translated its marginal costs

into rates as follows. First, MPC proposed rates that reflect its reduced winter seasonal definition. Second, MPC spread its transmission, substation, and distribution costs throughout the year since these costs were not seasonally allocated. Finally, since MPC determined that its winter and summer energy costs showed little difference, it priced energy on a non-seasonal basis (Exh. No. MPC-46, pp. 5-6).

318. In addition, MPC proposed to separately price service to its Secondary, Primary, Substation, and Transmission level customers. MPC proposed separate prices for demand and non-demand metered service to its secondary and primary general service and irrigation customers. The balance of this section summarizes MPC's specific pricing proposals by class.

Residential

319. MPC proposed seasonally blocked energy prices featuring a basic usage block (hereafter initial block) for consumption of 0-600 kWh and a second, higher priced, seasonally differentiated, non-basic usage block (hereafter tail block) for consumption above 600 kWh. MPC's initial and tail-block prices are based on: 1) its average moderated marginal non-generation and non-customer charges; and, 2) moderated marginal seasonal capacity and energy charges (Exh. No. MPC-46, pp. 7-9 and TEW-2).

320. MPC's objectives for its residential rate were to reflect costs, retain seasonality, and to "smooth the billing impact of seasonal rates" (Exh. No. MPC-46, p. 7). MPC maintains the last of these goals addresses a customer concern. Based on its customer survey, MPC believes residential customers prefer non-seasonal prices and that they continue to misunderstand higher winter prices. MPC maintains its initial block flattens winter and summer prices for basic use, which it contends consists of average summer usage or usage associated with operating lights and appliances. MPC states that since this level of usage is non-seasonal and inelastic, "it ... makes little sense to apply price signals to such basic usage since there are few opportunities for the customer

to respond to such a price signal" (Exh. No. MPC-46, p. 8). Further, MPC asserts that consumption in the tail block would consist of water and space heating. MPC also asserts that other advantages of blocked rates include conservation and an approximate reflection of marginal cost in the tail block price.

321. MPC contrasts its blocked-rate structure with inverted-block or lifeline rates, which MPC maintains raise questions of subsidized rates. MPC contends its blocked rate structure represents "an informational approach to pricing" (Exh. No. MPC-46, p. 9) and emphasizes that its initial-block price is average cost based.

322. MPC argues several other points regarding its residential rate. First, MPC argues there is a continued need for seasonality in its blocked rate to reflect costs. Second, MPC maintains the winter billing impact of its rates on large users would be about the same if an equal-percentage increase were applied to its current prices. Third, MPC contends that its budget billing program, through which a customer is billed the same amount each month, does not nullify the need for seasonal rates. MPC suggests its customers use budget billing to pay for service over time. Fourth, MPC avers its blocked rates will yield monthly billing stability for its customers, including those with lower incomes. Finally, even though MPC claims its rates would benefit most low-income customers, some of those customers may not benefit if their consumption is high (Exh. No. MPC-46, pp. 10-11).

323. In rebuttal testimony, MPC proposed blocked winter and flat summer energy prices. MPC retained its 0-600 kWh initial block for the winter season which it priced at $.052493/kWh. MPC proposed a winter tail block price of $.064985/kWh and a customer charge of $3.31/month. The initial block price is based on average marginal costs which include annual energy and non-generation capacity costs. The tail block price is based on seasonal marginal generation capacity costs. MPC set its customer charge at one-half its marginal customer cost. MPC's computed prices were then uniformly reduced to attain class revenues.

324. MPC maintains that its revised rate design discourages seasonal consumption and its summer prices do not reflect "promotional pricing," which is why it priced its summer block at average marginal cost (Exh. No. MPC-47, p. 4). Other features of this design follow.

325. MPC priced its winter tail block 24 percent higher than its winter initial block and its summer flat rate. This results in a winter/summer ratio of 1.24, one half the current ratio of 1.48. Also, MPC claims its winter tail block is priced at 91 percent of MPC's marginal cost (about $.07/kWh). Compared to current base rates, MPC's revised rate design results in about a 15.8 percent billing impact for the average customer (Exh. No. MPC-47, pp. 3-4).

326. MPC, MCC, HRC, and SRS stipulated to several aspects of the residential and low income rate designs. With respect to residential rates, the parties agreed that MPC's proposed residential rate design, including its customer charge and 0-600 kWh initial block is "an acceptable way of introducing an inverted residential rate design" (Exh. No. MPC-1, p. 2). The parties did not stipulate to any specific residential rates.

RESIDENTIAL AND LOW-INCOME ELECTRIC RATE DESIGN

327. A stipulation was entered into by MPC, HRC, MCC and SRS on the contested issues related to the establishment of a low-income residential electric rate design. The positions and recommendations of each party will be described, then the terms of the stipulation will be summarized, followed by the Commission's decision.

HRC ENERGY ASSURANCE PROGRAM

328. Mr. Roger Colton, of the National Consumer Law Center, testified on behalf of HRC. Mr. Colton proposed a low income rate design called the Energy Assurance Program (EAP). The EAP involves establishing a low-income class of ratepayers. This class would

make payments for utility service based on a percentage of income. In particular, Mr. Colton suggests that participants be required to pay seven percent of their income toward heating service and three percent of their income toward nonheating service (HRC Exh. 2, p. 24). The customer's total utility bill will not exceed 10 percent of household income.

329. Participation in EAP is contingent on three criteria. First, household income must not exceed 150 percent of the federal poverty level. Second, the household's current heating bill must be greater than seven percent of household income. Third, the household will be required to apply for state LIEAP assistance. The LIEAP application process determines the household's income level which, in turn, is used to determine the household's utility bill as described above.

330. Mr. Colton's testimony also addressed how Montana Power can take advantage of the "leveraged resources" provisions of the Federal Government's Low Income Household Energy Assistance Program (LIHEAP) reauthorization statute enacted in 1990. The testimony provides the definition of "leveraged resources," as found in the federal reauthorization statute (HRC Exh. 2 p. 39). According to the statute, leveraged resources are resources that:

> (1) represent a net addition to the total energy resources available to State and federally qualified households in excess of the amount of such resources that could be acquired by such households through the purchase of energy at commonly available households rates; and
>
> (2)(a) result from the acquisition or development by the State program of quantifiable benefits that are obtained from energy vendors through negotiation, regulation... (HRC Exh. 2 p 39; emphasis in original)

331. Any action by MPC that meets these requirements can be reported to the federal LIHEAP program. This results in the state LIEAP program receiving additional federal funds. Examples of

leveraged resources include rate discounts, utility sponsored weatherization programs or other utility actions that assist state LIEAP customers in acquiring and paying for utility services. One of Mr. Colton's particular proposals was that the customer charge be waived for the LIEAP sub-class. MPC would recover the amount associated with the waiver from all other ratepayers and would also report this amount as leveraged resources.

MPC REBUTTAL OF HRC

332. Mr. Patrick Corcoran testified on MPC's behalf and responded to Mr. Colton's testimony (MPC Exh. 44). MPC rejected most of Mr. Colton's proposals. Mr. Corcoran indicates that the Company is not convinced that an EAP in Montana is totally cost justified. There is no evidence for Montana that the program will save more than it costs. MPC is also concerned with the administrative aspects of such a program, particularly whether it is appropriate for the utility to handle such administration. MPC feels that many of the proposals made by Mr. Colton "reach beyond the nature and scope of the utility business" (MPC Exh. 44). In response to Mr. Colton's proposal to designate the dollar difference from payments made under his EAP proposal and the otherwise applicable rate, Mr. Corcoran stated that MPC will report the dollars associated with its own low-income rate proposal as leveraged resources. Finally, the Company disagrees with Mr. Colton's proposal to waive the customer charge (MPC Exh. 44, p. PRC-23).

SRS LOW-INCOME RATE DESIGN PROPOSAL

333. Mr. Thomas J. Schneider submitted Testimony on behalf of SRS. SRS's testimony calls attention to the worsening living conditions of LIEAP customers. According to Mr. Schneider, recent trends indicate that LIEAP customers are experiencing rising utility bills, declining LIEAP benefits and static income levels; hence, LIEAP customers have become increasingly worse off.

334. Because of the recognized poverty circumstances which

characterize LIEAP customers, SRS believes these customers constitute a homogeneous group entitled to individual treatment in the rate design process.

335. SRS makes three low-income rate design proposals. First, MPC should create a sub-class within the residential class. This sub-class would be composed of the LIEAP primary electric heat customers. The revenue requirement for this sub-class would be derived, in part, by discounting the sub-class' revenue requirement at regular residential rates by 10 percent. This 10 percent discount would be recovered by contributions from all other customer classes just as MPC recovers revenues associated with its employee discounts. Second, SRS proposes that the current benefit matrix method of distributing LIEAP funds to households be abandoned. Instead he suggests the total SRS LIEAP fund available to the primary electric heating customers be credited toward the total revenue requirement of the LIEAP electric heating customer sub-class. Mr. Schneider states that this proposal ensures that the LIEAP benefits are distributed based on consumption and reduces the administrative costs to SRS, HRC and MPC. Mr. Schneider recommends integrating these two proposals in designing the low-income rates for electric service. Third, SRS proposes that the low-income weatherization program be significantly accelerated.

336. SRS proposed two alternative rate designs. The first one involves a uniform percentage discount to both the monthly Customer Charge and the commodity price blocks. The second alternative involves recovering the class' revenue requirement through a commodity price only rate structure (i.e., no customer charge). Mr. Schneider recommended the second alternative in part because the commodity price would be higher and would therefore provide a better conservation price signal.

TESTIMONY OF DR. THOMAS M. POWER (HRC XI)

337. Dr. Thomas M. Power testified on behalf of HRC. Dr. Power suggests combining Mr. Schneider's and Mr. Colton's proposals and he makes several recommendations which address this

possibility. First, Dr. Power recommends that SRS's ten percent rate reduction to the LIEAP class be provided primarily through the elimination of the fixed monthly customer charge. Dr. Power's reasoning behind this recommendation is that "the fixed monthly charge is the part of the rate that is least capable of carrying an effective price signal and influencing economic activity in a rational way" (HRC Exh 4 p 6).

338. According to Dr. Power, Mr. Colton's proposal can be addressed by comparing the LIEAP household's remaining bill (the bill that remains after LIEAP benefit credit and 10% discount through elimination of the customer charge) to the household's income. The part of the remaining bill that is in excess of seven percent (for example) of household income would then be dropped, thereby maintaining the household's utility bill at that percentage of income.

339. Dr. Power stated at the hearing (TR 1306) that HRC supports the low-income rate design stipulated to by the parties in this proceeding. This stipulation specifies an inverted-block residential rate structure with 600 kWh/month being the breakpoint between the initial and tail block. However, during cross-examination Dr. Power pointed out that there are disadvantages to an initial block of this size. HRC believes a significant number of customers will carry out all their consumption within the 600 kWh initial block; thus, their decisions concerning the use of additional electricity will be based on the lower price associated with that initial block and they will base consumption decisions on a wrong marginal cost price signal. HRC recommends an initial block size of 400 kWh/month (HRC Exhibit 3, p. 97) in order to provide a stronger conservation price signal. HRC noted that a 600 kWh/month initial block reduces the differential between summer and winter bills. HRC also states that a 600 kWh initial block is a reasonable place to start because there is agreement that it represents basic customer usage -- what MPC customers will use at a minimum (TR 1306).

MPC LOW-INCOME RATE DESIGN

340. In MPC's rebuttal testimony, Mr. Corcoran describes MPC's low-income rate design proposals. MPC agrees with SRS's proposal to categorize the LIEAP primary electric heating customers as a sub-class of the residential class and to provide this sub-class with a 10 percent rate discount. However, MPC does not agree to credit the total LIEAP benefit fund to the LIEAP class revenue requirement as SRS proposed. The Company feels the current method of distributing these funds through the use of the benefit matrix more appropriately considers the customer's "need." MPC also stated, as was previously mentioned, that it disagrees with the proposal to eliminate the customer charge. MPC's proposed rate design for the LIEAP class involves simply discounting all components of the residential electric rates, including the customer charge, by 10 percent. The Company proposes to recover the discount by uniformly spreading the revenue effects to all other classes based on each class' proportion of total revenue. The low-income electric rate discount will require the recovery of $371,055 according to MPC.

RESIDENTIAL AND LOW-INCOME ELECTRIC RATE DESIGN STIPULATION

341. MPC, HRC, SRS and MCC stipulated that MPC's across-the-board ten percent discount is the appropriate low-income rate proposal for the purposes of this proceeding. As described above and in MPC Exhibit 44, this proposal involves discounting by 10 percent all components of the residential electric rates approved by the Commission in this proceeding.

342. These parties also agree that the Company's proposed residential rate structure, which includes a monthly customer charge and a two step inverted block commodity charge, is acceptable. The initial block will be 600 kwh per month. MPC has also agreed to cooperate with SRS in obtaining Federal funds through the process of leveraging as proposed by HRC.

343. Finally, these parties agree to collaborate with other interested persons in further examining low-income issues. Among

the issues these parties agree to consider are: 1) whether the 600 kwh/month initial commodity block in the residential and low income rate structure is the most appropriate size; 2) alternatives and additions to the Company's ten percent low-income discount such as HRC's EAP proposal, the elimination or reduction of the customer service charge and incorporating LIEAP benefit funds directly into rates; and, 3) low-income weatherization programs, especially for all electric homes.

General Service

344. This section summarizes MPC's proposed General Service (GS) rate design. MPC's proposed GS-1 and GS-2 service, Off-Peak Demand Rate, Reactive Power Charge, and Electric Rate Stability Option prices follow and include the direct and rebuttal methods MPC used to compute GS-1 and GS-2 prices for secondary and primary service.

345. GS-1 and GS-2 Levels of Service. As noted above, MPC proposed to price service to its Secondary, Primary, Substation, and Transmission level customers separately. Currently, Secondary and Primary customers are served as one class through MPC's GS-1 tariff. MPC defines Secondary service as Primary service with additional transformation and losses. Primary service is provided between the substation and customers delivery point over a high-voltage line (2.4 to 34.5 kV) (Exh. No. MPC-46, pp. 12-13).

346. Substation and Transmission customers are currently served as one class through the GS-2 tariff. MPC would provide Substation level of service to a customer who uses an MPC-owned substation to transform power from the transmission voltage level to the customer's delivery voltage. Transmission service would be provided and measured at voltage levels of at least 50 kV from the transmission system through a customer-owned substation or transmission line (Id., pp. 13-14).

347. Demand Charges. MPC bases its demand charges on marginal capacity charges which, in turn, are based on total class capacity

costs. MPC maintains that even though it computes demand costs using various forms of CP data, it does not, nor is it practical to, measure and bill for demand coincident with the system peak. As such, MPC claims that demand costs "must be expressed in terms of available data, e.g., billing demand" (Exh. No. MPC-46, p. 14).

348. In response to a Commission concern in Docket No. 87.4.21 regarding the efficiency of using billing demand to compute demand prices, MPC compared its method of determining demand charges with the seasonal marginal capacity charges it computed for each of its GS-1 and GS-2 classes to a method suggested by the National Economic Research Associates (NERA). This method uses LOLHs, class load shapes, and monthly seasonal capacity costs to determine hourly demand charges (Exh. No. MPC-46, p. 14 and TEW-3). MPC summed these charges over a typical peak day for each of the winter and summer seasons. MPC maintains the resulting demand charges are similar in magnitude to the demand charges it uses for pricing.

349. Demand Metering. MPC proposed a cost/benefit analysis to support demand metering secondary and primary classes if their monthly consumption exceeds 2,500 kWh for 12 successive monthly billing periods, or if maximum demand or kWh usage are estimated to exceed 10 kW or 2,500 kWh, respectively. MPC compared the cost of a demand meter and the additional demand related revenues it would generate from demand metering (Exh. No. MPC-46, pp. 15-17 and TEW-4).

350. GS-1 Secondary and Primary. Currently, MPC's GS-1 Secondary and Primary service tariff features a common monthly customer charge for demand and non-demand metered customers. The tariff also features declining-block seasonal energy prices with a break point at 2,500 kWh. According to MPC, the current initial block energy price includes energy and demand costs associated with 10 kW of demand and the tail block collects energy costs (Exh. No. MPC-46, p. 17). Demand is seasonally priced for demand exceeding 10 kW. (MPC Electric Tariff, Schedule No. GS-1, 4th Revised Sheet No. 20.1, effective 8/29/90). MPC proposed to eliminate its declining block energy prices since a customer consuming more than

2,500 kWh of energy is only contributing to energy costs, while a demand metered customer would be paying for demand and energy costs.

351. MPC proposed a two-part tariff for secondary and primary non-demand metered customers consisting of seasonal energy prices and monthly customer charges. MPC computed energy prices for its secondary non-demand metered class based on its secondary class demand prices, an annual weighted average class load factor, and the energy price proposed for demand metered customers with the asserted result that energy prices collect energy and demand costs (Exh. No. MPC-46, p. 18 and TEW-5). MPC set its primary non-demand metered service customer charge equal to its secondary service non-demand metered customer charge. MPC used the same load factor it used to compute secondary non-demand metered seasonal energy prices to compute seasonal energy prices for its non-demand metered primary service class in conjunction with the demand and energy prices computed for primary demand metered service (Exh. Nos. MPC-46, TEW-6 and MPC-47, TEW-17).

352. MPC proposed a three-part tariff consisting of an annual energy price, seasonal demand prices, and a monthly customer charge for its demand-metered secondary and primary classes. MPC computed seasonal demand prices based on seasonal marginal capacity charges and annual non-generation marginal capacity charges. MPC then moderated these charges using the same factor it used to reconcile total marginal costs to its proposed revenue requirement. Demand charges were again moderated to 70 percent of unit marginal charges. The annual energy price was computed by dividing total class revenues, less demand and customer charge revenues, by annual energy usage. Customer charges for demand and non-demand customers were computed based on secondary service customer costs which were not differentiated for demand and non-demand meters (Exh. No. MPC-46, TEW-5 and MPC RDR PSC-205).

353. In rebuttal testimony, MPC revised the method used to compute demand, energy, and customer charges for each of its secondary and primary demand and non-demand metered rates. First,

demand prices were computed to reflect generation capacity costs plus losses. MPC justified recovering non-generation capacity costs in demand and energy prices by noting that total demand costs changed. Further, MPC argues that balancing these costs between energy and demand prices addresses its billing impact objectives, rate stability, and its rate design priorities. Second, MPC set demand prices half way between marginal capacity charges and current demand prices. Third, MPC computed energy prices based on annual energy costs plus losses. MPC explains that it did not price energy seasonally as it did demand since demand reflects MPC's highest rate design priority. MPC also contends that non-seasonal energy prices mitigate seasonal billing impacts to GS customers. Third, customer charges were set at 50 percent of customer costs. MPC proposed demand and non-demand metered customer charges for its secondary and primary classes based on revised costs (Exh. No. MPC-47, pp. 5-8).

354. MPC's proposed Secondary and Primary demand and non-demand metered service prices and billing impacts are summarized in Table 11 below.

355. GS-2 Substation and Transmission. MPC computed demand, energy, and customer charges for its Substation and Transmission classes using the same methods its used to compute secondary and primary demand metered prices. However, transmission level demand charges were not moderated to 70 percent of marginal capacity charges (Exh. No. MPC-46, TEW-5 through 8 and MPC-47, pp. 5-6). In rebuttal testimony, MPC revised its methods used to compute substation and transmission level prices to use the same methods its used to compute prices for secondary and primary demand metered service. MPC's proposed Substation and Transmission service prices and billing impacts per its rebuttal testimony are summarized in Table 11 below.

Table 11.
MPC's Proposed General Service Prices

Demand Metered					Average
	Demand				Billing
	Winter	Summer	Energy	Customer	Impact*

	$/kW	$/kW	$/kWh	$/Mo.	%
Secondary	$ 8.897791	$ 5.179125	$.026392	$ 6.50	14%
Primary	$10.869810	$ 5.778348	$.026450	$19.31	21%
Substation	$12.445073	$ 5.017843	$.025820	$27.19	30%
Transmission	$ 7.006428	$ 3.005524	$.023685	$29.17	1.2%

Non-Demand Metered	Energy			Average Billing
	Winter $/kWh	Summer $/kWh	Customer $/Mo.	Impact* %
Secondary	$.067514	$.050324	$4.20	21%
Primary	$.075841	$.052569	$4.35	21%

Source: Exh. Nos. MPC-44, PRC-7 and MPC-47, TEW-16 through 19
* MPC maintains actual billing impact depends on each customer's consumption patterns.

356. Off-Peak Demand Discount Rate. MPC proposed to revise the hours during which its Off-Peak Demand Discount Rate would apply and to make this rate permanent. MPC also revised the applicable discounts for each of its primary, substation, and transmission customers. MPC maintains that during 1989 the difference between peak and off-peak usage was about 30 MWs of billed demand.

357. Reactive Power Charge. MPC proposed a reactive power adjustment charge of $2.23/kvar/year. MPC applies this charge to GS-2 customers with billing demand greater than 1 MW and power factors less than 90 percent. MPC proposed to examine the loads of all GS-2 customers with billing demand greater than 1 MW to determine which have power factors less than 90 percent. MPC would notify these customers, provide them an estimate of the potential annual penalty, and give the customer 120 days to enter a mutually agreed upon correction program. MPC proposed that the customer install corrective facilities to raise its power factor to at least 90 percent, at which time the power factor clause will become effective for billing (Amended Appendix B, Schedule No. GS-2 and Exh. No. MPC-46, p. 30). MPC also proposed to install a meter for

a customer with whom an agreement is not made and bill the customer for reactive power (Exh. No. MPC-46, TEW-12 and MPC RDR PSC-250).

358. Electric Rate Stability Option. MPC proposed an Electric Rate Stability Option (ERSO) for its GS-2 classes to provide customers in this class a "steady stream of electric energy costs" (Exh. No. MPC-46, p. 38). MPC's ERSO would be available to new and expanding loads of at least 1 MW for up to 5 years and available for an aggregate load of 10MW. The customer's current rate components would be escalated using the Consumer Price Index.

359. MPC asserts that its ERSO is not a promotional, discount, or load-building rate, but rather is intended to afford customers price stability. Regarding cost recovery, MPC proposed that it would "retain the authority to make this service available, based on its determination of the effect of such service on the Utility's cost of service, in the near and long term" (Exh. No. MPC-46, pp. 38-39).

Irrigation

360. Currently, MPC's irrigation service tariff features a seasoned customer charge for demand and non-demand metered customers. The tariff also features a declining-block energy price with a break point at 3,800 kWh. MPC states that the current initial block energy price includes energy and demand costs associated with the first 15 kW of demand and the tail block collects energy costs (Exh. No. MPC-46, p. 36). Demand is priced for demand exceeding 15 kW. (MPC Electric Tariff, Schedule No. IS-1, 4th Revised Sheet No. 30.1, effective 8/29/90). In this Docket MPC proposed to eliminate its declining block energy prices because a customer consuming more than 3,800 kWh of energy is only contributing to energy costs, while a demand metered customer would pay for demand and energy costs. MPC maintains that separate demand and non-demand metered prices for irrigation customers is "an improvement in the rate design for non-demand metered customer(s)" (Exh. No. MPC-46, p. 36).

361. MPC proposed a two-part tariff for non-demand metered irrigation customers consisting of an energy price and per season customer charge. MPC computed the energy price using the method it used to compute secondary non-demand metered energy prices. Hence, energy prices would collect energy and demand costs (Exh. No. MPC-46, pp. 36-37 and TEW-14).

362. MPC proposed a three-part tariff consisting of annual energy and demand prices, and a per season customer charge for its demand-metered irrigation class. Demand and energy prices were computed using the same methods used to compute these prices for the secondary and primary demand metered classes, except demand charges were not moderated to 70 percent of unit marginal charges. Demand and non-demand metered customer charges were set at 6 times the demand and non-demand metered customer charges for secondary service (Exh. No. MPC-46, TEW-14 and TEW-6).

363. MPC applied the same revisions it proposed in rebuttal testimony to compute secondary and primary service prices to compute irrigation prices. Also, MPC's revised customer charges reflect the costs it computed for demand and non-demand metered service (Exh. No. MPC-47, pp. 5-8 and TEW-24).

364. Table 12 summarizes MPC's proposed irrigation class prices and billing impacts.

Table 12
MPC's Proposed Irrigation Service Prices

Demand Metered	Demand $/kW	Energy $/kWh	Customer $/Season	Average Billing Impact* %
Irrigation	$ 6.834644	$.022930	$75.73	28%

Non-Demand Metered	Energy $/kWh	Customer $/Season	Average Billing Impact* %
Irrigation	$.046629	$48.59	28%

Source: Exh. Nos. MPC-44, PRC-7 and MPC-47, TEW-24
* MPC maintains actual billing impact depends on each customer's consumption patterns.

QF Standby Rate

365. MPC proposed a standby capacity price and consumption demand and energy prices for Qualifying Facilities (QFs). MPC would supply energy and capacity to a QF contracting for such service when it required replacement energy or capacity otherwise generated by its own facilities during unscheduled outages. MPC's QF standby service would be applicable at the substation level.

366. MPC proposed an annual standby capacity price based on service at the GS-2 Substation level which includes generation and transmission capacity costs. These costs are distributed to billing kilowatts using the substation level coincidence factor, and are adjusted for an assumed "probability that any standby customer will require capacity" (Exh. No. MPC-46, p. 34). MPC assumes a QF would be available 85 percent of the time, on average (MPC RDR PSC-252). MPC further reduced these costs using its total marginal/revenue requirement reconciliation factor. This resulted in a standby capacity price of $1.93/kW/mo. (Exh. No. MPC-47, TEW-23). MPC also proposed consumption energy and demand prices would be those applicable in the GS-2 Substation tariff.

367. MPC would offer standby service for a minimum demand of 1MW. The customer would be required to pay all substation and metering costs on an individual case basis (MPC RDR PSC-253). MPC proposed to determine consumption, frequency of use, and length of service terms for each delivery point at its own discretion. Additionally, MPC would determine the length of prior notice it would require a customer to provide MPC before consumption. The notice period would depend on load size and duration (Exh. No. MPC-46, pp. 35-36 and MPC RDR PSC-254).

Lighting

368. MPC computed lighting prices by adjusting unit costs

using its total marginal cost/revenue requirement reconciliation factor. Prices were further adjusted to attain class revenue responsibilities per MPC's proposal to cap certain class' revenue responsibilities and to account for the low-income residential rate discount (Exh. No. MPC-44, PRC-5 and MPC RDR PSC-608).

Electric Economic Incentive (EEI)

369. MPC proposed to cancel its EEI tariff since it no longer has the resources to provide this service. Montana Resources, Inc. (MRI), is currently taking service as a GS-2 Substation level customer (Exh. No. MPC-45, pp. 10-11). Given MPC's rate design proposals, MRI would have the generic interruptible credit and Off-peak Discount as alternative rate options. MRI has previously expressed interest in an interruptible rate (MPC RDR PSC-184).

Electric Industrial Retention Interruptible (EIRI)

370. MPC proposed to cancel its EIRI tariff and serve RPC (formerly Stauffer Chemical) under its proposed Interruptible Industrial tariff (Id.).

Interruptibility

371. This section summarizes MPC's proposed generic and customer-specific interruptible rates. MPC's generic interruptibility rate would be available to GS-2 Substation and Transmission customers. Its customer specific rate would be available through a separate Interruptible Industrial tariff (II-1).

372. MPC proposed several conditions which would generally apply to interruptible service. However, in rebuttal testimony, MPC revised some of these conditions for its II-1 tariff. These conditions are summarized, followed by a summary of MPC's generic and customer specific interruptible service. MPC also proposed energy and customer charges for its II-1 tariff, through which RPC would be served. These charges are also summarized in this

section.

373. MPC proposed to offer its interruptible service in the form of a credit to a customer's seasonal demand charge (Amended Appendix B, Schedule No. GS-2). MPC computes this credit based on adjustments to its 10-year levelized marginal capacity cost. MPC also proposed a 10-year contract term for interruptibility. To qualify for service, a customer must have an interruptible load of at least 10 MW. To ensure deliverabiltiy of contracted interruptible power, MPC proposed a penalty charge of 10 times the customer's firm power rate for interruptible power not curtailed. This rate appears to be based on the customers average price per kWh (Exh. No. MPC-46, pp. 21-22 and MPC RDR PSC-230). In rebuttal testimony, MPC reduced this penalty to 5 times the otherwise applicable firm rate for its customer specific II-1 tariff (Exh. No. MPC-44, p. 9). Through its interruptible service, MPC intends to enhance its operating efficiency and address its capacity needs.

374. MPC proposed emergency and non-emergency types of interruptions. MPC defines an emergency interruption as

> a curtailment of service to the customer's interruptible loads in order to maintain service to firm customers. (Exh. No. MPC-46, p. 22)

MPC defines non-emergency interruptible service as

> a curtailment of service to the customer's interruptible loads in order a) to avoid purchasing power at prices higher than the customer's firm energy rate, or b) to make off-system sales at prices higher than the customer's firm energy rate. (Id.)

375. A customer may continue to take service in non-emergency situations. However, for two hours after the unanticipated loss of a generating unit MPC may curtail service at its discretion. MPC proposed a replacement power option if service is continued during a non-emergency interruption. Under this option, MPC would charge

the greater of the customer's firm energy price plus 20 percent or the wholesale market price plus 20 percent (Exh. No. MPC-46, pp. 22).

376. Generic Interruptible Rate. MPC proposed a generic seasonal (winter and summer) interruptible credit algorithm, as a means for customers to determine the value of interruptibility. The method of valuing seasonal interruptible credits is based on adjustments to seasonal marginal demand charges. These adjustments would include a notice correction, the expected availability of capacity, and an interruptibility index. The notice correction measures curtailment savings lost during the notice period or the period of time between notification and actual curtailment. The interruptibility index is the ratio of the LOLHs in the requested interruption period to annual LOLHs. Since MPC proposes to apply these adjustments to the capacity cost portion of its marginal demand charges, it revised its method to compute credits by removing the expected availability adjustment in rebuttal testimony (Exh. Nos. MPC-46, pp. 23-24 and MPC-47, pp. 8-9).

377. An interruptible customer would have the option to be interrupted for 5, 10, or 20 week days of interruption per month; 4, 8, or 14 hours of interruption per day; and would have a choice between a ten minute or one hour notification period. The capacity credits computed from the above method would be fixed for the duration of the interruptible contract term (Exh. No. MPC-46, pp. 23-24 and MPC RDR PSC-235, PSC-236, and PSC-524).

378. Customer Specific Interruptible Rate (Interruptible Industrial (II-1)). MPC also proposed a customer specific interruptible rate for which RPC would qualify. This rate schedule would be available for larger customers and feature its own energy and customer charges. MPC's initial and rebuttal proposed methods to value interruptibility under this rate schedule follow.

379. MPC initially required certain information and conditions which included the ability to interrupt service for non-emergency purposes. In rebuttal testimony, MPC revised these conditions by

removing its ability to interrupt RPC for non-emergency purposes, increasing the number of hours RPC would be available for interruptions, and reducing the penalty for continuing service during interruptions from 10 to 5 times the otherwise applicable firm service rate (Exh. Nos. MPC-47, p. 21 and MPC-44, p. 9). With these revisions, MPC required the following information and conditions to determine the value of interruptible service to RPC:

1) A 10 minute emergency notice period.

2) The total number of interruptible hours per 12 month period.

3) The ability to curtail service during the 12 month contract year for emergency purposes.

4) At least an 8 hour duration for emergency interruptions.

5) A contracted interruption cycle which consist of a schedule of the duration of interruptions and time between interruptions (Exh. No. MPC-46, pp. 24-25).

380. MPC valued RPC's interruptible load in terms of an annual credit. MPC based its valuation on the total marginal generation capacity costs allocated to RPC in its COS study, adjusted for losses and the portion of MPC's total required hours of interruptibility (1,268 LOLHs) RPC would be available to meet (800 hours). Costs were also adjusted for a 10 minute notice period (Exh. No. MPC-46, pp. 24-26).

381. MPC revised its valuation method in rebuttal testimony by adjusting the total marginal generation capacity costs allocated to RPC plus losses for the portion of MPC's required hours of interruption (1,200 hours) RPC could meet (1,200 hours). With this revision MPC proposed an interruptible credit for RPC of $5.7 million, resulting in a class revenue responsibility increase of about 20 percent (Exh. No. MPC-47, p. 21).

382. MPC proposed energy and customer charges for service to RPC, but excluded a demand from the II-1 rate structure to simplify operations for MPC's off-system sales. MPC proposed to set the energy price at the substation level energy cost ($.01935/kWh) plus losses and recover the remaining revenues through the customer

charge. This resulted in energy and customer prices of $.021671/kWh and $228,801/month, respectively (Exh. No. MPC-47, p. 21 and TEW-21).

383. MPC also proposed a performance incentive credit for RPC which is summarized below under MPC's rebuttal to RPC.

MCC RATE DESIGN

384. MCC based its rate designs on the class revenues it computed and MPC's Operating Revenue Workpapers (MCC RDR LCG-144), and revised these rates in response to DR MPC-107. For each of the rates summarized below, MCC proposed to reduce the seasonal differences proposed by MPC by one half. MCC supports this approach based on the findings in its COS study. Additionally, MCC adopted MPC's proposed customer charges for each rate design (Exh. No. MCC-6, p. 64).

Residential

385. MCC proposed seasonally inverted blocked energy prices. MCC used a 0-600 kWh initial block priced at $.04689/kWh with the winter and summer tail blocks priced at $.05627/kWh and $.05234/kWh, respectively. MCC adopted MPC's monthly customer charge. MCC maintains it priced energy at its marginal cost. Also MCC maintains "generation capacity costs reflect marginal costs" (Exh. No. MCC-6. pp. 64-65 and JD-9).

General Service

386. MCC proposed rates for each of MPC's secondary, primary, substation, and transmission customer classes based on MPC's proposed rate structures. Table 13 summarizes MCC's proposed general service prices.

Table 13.
MCC's Proposed General Service Prices

Demand Metered

Demand

	Winter $/kW	Summer $/kW	Energy $/kWh	Customer $/Mo.
GS-1 Secondary	$6.69765	$5.77384	$.02405	$ 9.62
GS-1 Primary	$8.27719	$6.67524	$.02292	$27.09
GS-2 Substation	$8.36811	$6.29181	$.02038	$35.06
GS-2 Transmission	$6.5568	$5.16284	$.02165	$32.03

Non-Demand Metered

	Energy		
	Winter $/kWh	Summer $/kWh	Customer $/Mo.
GS-1 Secondary	$.05485	$.05067	$5.21
GS-1 Primary	$.06076	$.05358	$5.21

Source: Exh. No. MCC-6, JD-10, revised (MCC RDR MPC-107)

Irrigation

387. MCC proposed irrigation rates using MPC's rate structure. For demand metered customers, MCC proposed a customer charge of $57.72/month, a demand charge of $5.29977/kW, and an energy price of $.02246/kWh. For non-demand metered customers, MCC proposed a customer charge of $31.26/month and priced energy at $.04063/kWh (Exh. No. MPC-6, JD-12 as revised in MCC RDR MPC-107).

Interruptibility

388. MCC witness Dr. Wilson indicated that MPC's generic interruptible service appears to be "an extremely good deal for large industrial customers" (Exh. No. MCC-8, p. 35). MCC reached this conclusion based on the following.

389. MCC contends that MPC may not curtail service for emergency purposes often or for long periods due to MPC's available generation resources. Further, MCC maintains that a customer could override non-emergency interruptions, except when MPC chooses to curtail service for 2 hours following the unanticipated loss of a generating unit, "by paying a fee for the interruption period equal to 20 percent of the greater of the current wholesale market price

or the firm rate" (Exh. No. MCC-8, p. 36). MCC maintains this fee would be less than the customer's monthly interruptible credit. To illustrate this point, MCC states that a customer opting for interruptible service for 280 hours per month with a 10 minute notice period would receive winter and summer credits of $8.79/kW and $3.54/kW, respectively. MCC also maintains that if MPC interrupted 100 percent of these hours for non-emergency purposes, the customer could override such interruptions at a monthly cost of about $1.50/kW. MCC assumes Substation and Transmission class energy prices of $.02056/kWh and $.02298/kWh, respectively and short-term wholesale energy prices of 20 to 30 mills to which MCC applies MPC's 20 percent surcharge to compute the $1.50/kW fee (Exh. No. MCC-8, pp. 36-37).

390. Although MCC could not determine the cost/benefit relation of MPC's proposed credits based on its available information, MCC suggested MPC's interruptible rates could be a way of attracting additional loads. MCC asserted new loads may be attracted by "offering large customers promotional rates below the fully distributed cost of service" (Exh. No. MCC-8, pp. 37-38). MCC noted, however, that no evidence exists in MPC's filing or testimony to suggest this would be the case.

391. MCC also states that even though emergency interruptions may occur, they may not be significant. MCC notes the monthly amortized cost of new peaking capacity would roughly compare to MPC's interruptible credits.

392. MCC does not appear to oppose MPC's proposed interruptible service. Even though MCC does not find any evidence suggesting MPC's proposed interruptible credits would be subsidized, it asserts these credits could potentially be subsidized in the future. MCC maintains it may be incorrect to transfer costs currently allocated to large industrial loads, which would become interruptible, to other loads. MCC recommends that if MPC's interruptible service is approved, MPC should provide certain cost/benefit information regarding interruptions (Exh. No. MCC-8, pp. 34-40).

Interruptible Industrial

393. MCC proposed a $261,471.25/month customer charge and priced energy at $.01865/kWh for the Interruptible Industrial class (Exh. No. MCC-6, JD-11).

Rebuttal

394. MPC's and LCG's rebuttal testimonies are summarized, followed by MPC's and RPC's rebuttal on interruptibility.

395. MCC's Rate Designs. MPC maintains MCC's proposals are based on its own cost studies and MPC's rate designs. Further, MPC asserts MCC "arbitrarily reduces the Company's proposed seasonal differences by one-half" (Exh. No. MPC-47, p. 13). MPC also holds MCC's rates do not reflect its own costs. MPC recommends MCC's rate designs be "disregarded" (Id.).

396. LCG rebutted MCC's seasonal demand prices for the GS-2 Substation class, MCC's adoption of MPC's GS-2 rate design, and MCC's marginal energy costs as a basis for energy prices. LCG's testimony regarding each of these issues is summarized in turn.

397. LCG maintains MCC used the ratio of MPC's GS-2 Substation seasonal demand prices to compute its seasonal demand prices, rather than its own COS study. LCG maintains that since MCC allocated capacity costs using a 12 CP method, a non-seasonal approach, MCC computed seasonal demand prices based on MPC's demand prices and not on its own COS study. LCG also claims MCC did not "validate" the use of such data from another COS study. LCG recommends demand prices be computed using the method presented in Exh. No. LCG-6, JWM-7 (Exh. No. LCG-7, pp. 12-13 and 15-16).

398. Additionally, LCG disagrees with MCC's proposed separate substation and transmission rate designs. LCG notes that by using MPC's initially proposed prices, MCC includes in its prices the errors in MPC's COS study. LCG maintains this causes MCC's

"marginal cost analysis to distort the delivery service cost differential between transmission and substation classes in a fashion consistent with Montana Power Company's" (Id., pp. 15-16). LCG also reiterates its position that substation and transmission services should not be separately priced.

399. LCG argues that even though MPC concluded in its initially proposed rate designs that energy should not be seasonally priced, MPC's corrected energy costs suggest energy should be seasonally priced. LCG noted that MPC's corrected seasonal energy costs results in a 38 percent difference between the winter and summer costs. LCG also claims MCC's revised Exh. No. MCC-6, JD-6 shows a 38 percent winter/summer energy cost difference which is similar to the 33 percent difference in Docket No. 87.4.21. Due to the difference between winter and summer energy costs, LCG recommends energy prices be seasonally differentiated (Id., pp. 13-15).

400. Interruptibility. MPC and RPC rebutted MCC regarding interruptibility. MPC rebutted MCC's position that an interrupted customer could purchase replacement power at a price less than the customer's firm service price. MPC maintains MCC's computation of the override fee of $1.50/kW, the price an interrupted customer could purchase replacement power, is incorrect. MPC reiterates that a replacement power price would include a 20 percent surcharge added to the market price for energy. MPC cites MCC's response to DR MPC-99 in which MCC notes the customer would still have to pay for services rendered (MCC RDR MPC-99).

401. MPC asserts MCC finds the level of the interruptible credits correct based on MCC's comparison of the cost of peaking capacity and the proposed credits. MPC rebuts MCC's claim that MPC's interruptible credits are a means of attracting loads by reiterating its position that the interruptible credits it proposes are a way for customers to value their interruptible loads (Exh. No. MPC-47, pp. 11-12).

402. MPC also rebuts MCC's apparent suggestion that MPC's

interruptible rates may not be cost-based and may result in subsidies. MPC maintains its interruptible rates are cost based and the rates reflect the cost savings associated with interruptions (Exh. No. MPC-44, pp. 10-11).

403. RPC first notes MCC's analysis, regarding MPC's interruptible rates, is limited to the substation class and notes this class has no operating history. Also, in response to MCC's statement that emergency interruptions would not be significant now or in the future, RPC notes MPC curtailed service for more than 500 hours in 1989. Finally, with regard to MCC's claim that the monthly amortized cost of new peaking capacity would roughly compare to MPC's interruptible credits, RPC maintains interruptible credits are intended to represent this cost (Exh. No. RPC-3, pp. 2-3).

LCG RATE DESIGN

404. LCG filed direct and answer rate design testimony regarding MPC's Primary and Substation class rate designs. The following summarizes this testimony. MPC's rebuttal to each of LCG's direct and answer testimonies are also summarized below.

LCG Direct Testimony

405. GS-1 Primary and GS-2 Substation Rates. LCG maintains MPC's proposed rate design for the Primary and Secondary classes "would shift a significant amount of revenue requirements from the demand charge to the energy charge" (Exh. No. LCG-6, p. 12). LCG contrasts MPC's rate designs for these classes with the approach used to set demand charges in Docket No. 87.4.21. LCG maintains that setting the demand charge at about 70 percent of moderated marginal costs rather than 100 percent reduces the "relative spread between the demand and energy charges, also known as flattening the 'tilt'" (Id.). LCG argues this causes higher unit costs for high load factor customers.

406. In lieu of setting the rate tilt to achieve a class average billing impact, which LCG asserts MPC may have done, LCG

contends it is more important that prices reflect costs. Further, LCG asserts that if cost based prices result in different intra-class billing impacts, then the composition of the class may need to be reevaluated.

407. Further, LCG maintains MPC's rate designs do not promote rate moderation. LCG notes the Commission's decision to apply this principle by setting demand charges at 70 percent, rather than 85 percent of full marginal costs in Docket No. 87.4.21. LCG argues this same principle should also be applied to a reduction of current demand prices to 52 percent of full marginal costs. (LCG computes this figure by multiplying MPC's total marginal cost/revenue requirement reconciliation factor (74%) with its moderation factor applied to marginal demand charges (70%).) (Id., pp. 14-15)

408. LCG also declares that MPC's proposed rate tilt does not promote rate continuity which LCG holds would be accomplished by not drastically changing the rate design between cases. LCG says that MPC's proposed prices give customers an incentive to lower their load factors. Further, LCG claims MPC's energy and demand prices are not cost based, but rather are set to achieve "a predetermined rate increase to the 'average' customer" (Id., p. 15). LCG argues that MPC's flattening of the rate tilt does not provide a price signal consistent with its rate design priority. LCG states that cost-based prices would achieve MPC's goal to signal to its customers that capacity costs are its highest rate design priority.

409. In summary, LCG recommends that the rate tilt approved in Docket No. 87.4.21 should be retained.

410. LCG proposed to retain one tariff for Substation and Transmission voltage level customers and discount energy and demand prices for transmission level service. These prices are summarized in Table 14 below. LCG based its GS-2 prices on its revisions to MPC's marginal cost study and billing units from MPC's rate designs. LCG computed seasonal demand prices by first computing

seasonal marginal demand charges based on total seasonal reconciled generation capacity costs for the substation and transmission voltage levels. LCG added marginal demand charges for substation and transmission capacity to these values to arrive at demand prices. LCG computed customer charges dividing total reconciled transmission and substation customer costs by annual bills. LCG computed its energy price by dividing reconciled total revenues, less demand and customer revenues, by annual substation and transmission usage (LCG RDR PSC-379).

Table 14.
LCG's Proposed General Service-2 Prices

	Demand Winter $/kW	Demand Summer $/kW	Energy $/kWh	Customer $/Mo.
General Service-2	$14.627751	$8.781219	$.015931	$32.93

Source: Exh. No. LCG-6, JWM-7

Rebuttal

411. MPC rebutted LCG's substation class energy price, its arguments regarding the rate tilt, and methods to determine demand prices, as follows.

412. GS-1 Primary and GS-2 Substation Rate Design. MPC asserts that because LCG based the GS-2 energy price on system lambda plus losses, energy prices are below avoided energy costs. MPC criticizes such a price since system lambda, unlike avoided energy costs, does not reflect the market value of energy. MPC revised its rebuttal by noting that since LCG's energy price was less than the energy cost reported in Exh. No. LCG-6, JWM-4, it assumed the energy price equaled system lambda plus losses. MPC further noted that the energy price may equal the moderated energy price. On the other hand, MPC maintains that energy and demand prices "should not simply be based on moderated charges" (MPC RDR LCG-193 and Exh. No. MPC-47, p. 15).

413. MPC rebutted LCG's proposed rate tilt. MPC maintains

that LCG, which consists largely of high load factor customers (12 substation customers with an annual average load factor of about 86 percent versus an 80 percent annual average load factor for the entire substation class) would benefit from high demand prices relative to energy prices. MPC claims that if class revenues are fixed and a customer has a load factor greater than the class average, then a high demand price, relative to the energy price, would result in a per/kWh unit cost which is lower for that customer than for the class. MPC further holds that LCG's rate design would result in higher costs for lower load factor customers. MPC also says its rate design results in an appropriate rate tilt. Finally, MPC argues that its proposed substation prices benefit high load factor customers and result in billing impacts for the balance of the substation class close to the class average increase (Exh. No. MPC-47, pp. 15-18).

414. MPC asserts that LCG's proposal to set demand prices at 100 percent of moderated marginal costs does not account for current demand price or billing impacts. MPC claims its rate design recognizes these considerations along with marginal capacity charge levels. Further, MPC maintains its demand prices are set 58 percent higher than those set in Docket No. 87.4.21. Finally, MPC asserts its substation rate design results in a lower billing impact to customers with above average load factors (Id., pp. 18-19).

LCG Answer Testimony

415. LCG responded to MPC's rebuttal GS-2 Substation rate designs by comparing the methods MPC used in direct and rebuttal testimonies with the method used in Docket No. 87.4.21 with regard to its computation of energy and demand prices. LCG identifies the following substantive changes MPC makes to its computations of demand and energy prices. First, LCG notes MPC's direct and rebuttal methods used to set energy prices. LCG also notes that in Docket No. 87.4.21 energy prices were set after demand prices were set at 100 percent of moderated marginal charges. Second, LCG asserts that MPC did not price energy seasonally even though the

data it used in its COS study showed a greater seasonal cost differential than those found in Docket No. 87.4.21. Third, LCG maintains MPC's energy and customer prices are overstated since MPC uniformly spreads $14.7 million of demand related costs to its demand, energy, and customer prices. Thus, LCG holds energy and customer prices are overstated and demand prices are understated (Exh. No. LCG-8, p. 6).

416. Fourth, LCG declares that MPC included $14.7 million in demand costs in its energy price and that MPC's moderated marginal demand costs were $40.6 million and it's demand prices were set to recover $25.9 million, the remaining $14.7 million of demand costs being recovered in the energy price (Exh. No. LCG-8, p. 10 and JWM-13). LCG compares demand and energy prices based on MPC's rebuttal method and the method adopted in Docket No. 87.4.21. LCG claims that MPC understates winter and summer demand prices by about 24 and 48 percent, respectively. LCG also claims that winter and summer energy prices are overstated by roughly 51 and 26 percent, respectively (Id., p. 10 and JWM-14).

417. LCG asserts MPC's proposed demand prices are inconsistent with the high relative priority MPC claims they should have. LCG cites MPC's response to DR LCG-189 in this regard, in which MPC maintains that the demand price signals are stronger in its rebuttal rate than in Docket No. 87.4.21 since both the costs and prices in the present Docket are both higher than those in Docket No. 87.4.21. LCG contends that the demand cost shift, summarized above, would result in distorted price signals and a subsidy from high load factor customers to low load factor customers. LCG concludes that this would result in an inefficient use of resources (Id., p. 11).

418. Fifth, LCG asserts that MPC's method of determining its demand price, in which it averages its marginal capacity charges in this case with current demand prices, further separates such prices from costs. LCG declares that this method distorts future demand prices and such cost/price differences could continue in the future if capacity costs increased, and the same method were used to set

demand prices. LCG also illuminates MPC's intent to not use its averaging method in the future, that MPC used this method to produce a desired billing impact and that MPC concedes it may change its method if costs were to change in this case (Id., pp. 5 and 11-14).

419. LCG concludes that MPC's rebuttal rate designs should not be adopted as MPC made these changes to reduce billing impacts for low load factor customers at the expense of higher load factor customers. LCG added that MPC's rebuttal rate designs are not cost based and MPC's billing impact concerns conflict with generally accepted ratemaking objectives and standards. In this regard LCG cites MPC's response to DR LCG-178 and LCG-197, which states prices should account for costs, rate design priorities, billing impacts, and other objectives. LCG says that "[i]t is generally accepted that cost-based rates are the standard for evaluating the many competing objectives of rate design" (Id., p. 8).

420. LCG recommends the Commission use the rate design method it adopted in Docket No. 87.4.21. If the Commission does not adopt seasonal energy prices, LCG recommends the Commission set demand prices at 100 percent of moderated marginal charges (Id., pp. 11 and 14).

Rebuttal

421. MPC rebutted LCG's assertion that MPC departs from the rate design principles adopted in Docket No. 87.4.21. MPC contends that rate design principles and methods change as costs, cost methods, customer loads, and billing characteristics change. In further defense, MPC asserts that costs as well as billing impacts should be considered in pricing and that its rate design priorities are used to develop prices.

422. With regard to LCG's COS/RD comparisons (Exh. No. LCG-8, pp. 10-11), MPC asserts the proper comparison between its current and rebuttal proposed prices is required to determine if an "incremental improvement in pricing" has been achieved (Exh. No.

MPC-48, p. 4). MPC compared its current and proposed prices and the prices it maintains LCG proposed in Exh. No. LCG-8, JWM-14, p. 2, Cols. C and D (see Exh. No. MPC-48, TEW-27) and concludes that its prices "represent an incremental movement towards cost" (Id., p. 7). MPC asserts LCG's prices are "too extreme and appear to be results driven" (Id.).

423. MPC contrasts its rate design method, in which it examines costs, rate design priorities, and billing impacts, with the method it attributes to LCG in which prices are computed as a function of costs and adjusted to achieve class revenue responsibilities. MPC maintains that if the magnitude of costs change as a result of this case, so too could demand prices (Id., pp. 7-8).

424. MPC rebutted LCG's argument that MPC's rate design shifts demand costs to the energy price. MPC compares class functionalized costs to the revenues it proposes be collected in its rate design and includes its demand price collects about 86 percent of marginal capacity costs and 100 percent of marginal energy costs in its energy price (Id., 8-10).

425. MPC rebutted LCG's claim that its substation rate design is targeted toward low load factor customers. First, MPC explains that there is a certain degree of cost and rate averaging within a customer class when a class is composed of customers with similar characteristics. Further, MPC notes that the substation class consists of customers with diverse load factors. MPC argues that if a class' revenue responsibility increases 29 percent, then this should be the increase faced by the average customer in that class. MPC points out that if rates are tilted to benefit a high load factor customer revenues would be shifted to a low load factor customer.

426. Second, in further defense, MPC states that since it used the same methods to set prices for all of its GS classes and the irrigation class, LCG's assertion that prices based on this method would be "unduly discriminatory" or result in "preferential rate"

is not justified. MPC also asserts that if LCG's pricing method were used to compute GS-1 demand prices, energy prices for GS-1 non-demand metered customers would increase greater than they would under MPC's method (Exh. No. MPC-48, pp.10-12).

427. MPC rebutted LCG's assertion that MPC's rate design would encourage low load factor customers to consume electricity less efficiently. MPC maintains its rebuttal substation rate design results in higher annual billing increases for its low load factor customers than for its high load factor customers. Further, MPC argues that there is not a significant difference between LCG's and its rebuttal rate designs for high load factor customers. MPC calculates that the per kWh unit prices between its and LCG's substation prices differ by about 1 percent for a customer with an 85 percent load factor. MPC also notes that LCG's proposed method could result in billing differences with lower load factor customers (Id., pp. 14 and 17).

428. MPC adds that its proposed prices encourage demand-side management investments. Second, LCG has not accounted for MPC's interruptible service and Off Peak Demand Discount proposals in its testimony which would be options available to the LCG. Third, MPC's non-seasonal energy prices would encourage a high load factor customer to limit winter consumption. MPC notes that its prices reflect a 26 percent seasonal differential for a high load factor customer with consistent usage through out the year. Yet, if prices were set without accounting for rate design priorities and billing impacts, the seasonal difference could be about 76 percent. MPC claims a high load factor customer would not be affected negatively by non-seasonal energy prices (Id., pp. 14-16).

FEA RATE DESIGN

General Service: Transmission

429. FEA proposed the energy price for the GS-2 Transmission class be determined based on the energy costs provided by MPC in response to DR FEA-17 of $0.012604. FEA also proposed a monthly

customer price of $27.09, with the remaining revenues recovered in winter and summer demand prices of about $10.34/kW and $6.56/kW, respectively, based on MPC's September 1990 filing. FEA also provided billing impacts for this design which ranged from 1 percent to 23 percent (Exh. No. FEA-2, pp. 11-12 and CEJ-1 (revised), Schedules 4 and 5).

430. In addition to its arguments that energy prices should be based on short or relatively near-term, intermediate-run marginal costs, FEA asserts that "[p]ricing energy at marginal cost is more rational because the quantity being billed (kilowatt hours) is exactly the same as the quantity for which the marginal cost was measured" (Exh. No. FEA-2, p. 11). In contrast, FEA contends that billing demand does not correspond with the quantity used to measure marginal capacity costs, namely, CP demand, which then results in a lost price signal. The FEA contends that even though all customers may respond to a price signal that demand is expensive by reducing peak demand, such responses may not alter the system CP and thereby have no cost impact on MPC (Exh. No. FEA-2, p. 11).

Rebuttal

431. MPC concludes that FEA's energy price is set below the avoided energy cost and that remaining revenues are collected through demand prices which are higher than MPC's. Further, MPC stresses that energy prices should be based on energy costs determined from the allocated cost of service study. MPC also notes FEA's rate design would be about 10 percent less than the design initially proposed by MPC for service to FEA's client. Finally, MPC rebuts FEA's position "that setting energy prices at marginal cost for GS rates first is more rational than MPC's approach" (Exh. No. MPC-47, p. 24). MPC states that it sets demand charges first and argues that this is consistent with its rate design priorities.

RPC RATE DESIGN

432. RPC addressed MPC's proposed customer specific interruptible rate and its II-1 tariff as they relate to the current contract between it and MPC (hereafter MPC/RPC Contract) and the EIRI tariff. RPC also proposed a performance incentive credit. Each topic is summarized below.

EIRI and Industrial Interruptible Tariffs

433. RPC compares the current EIRI tariff, MPC's proposed II-1 tariff, and the MPC/RPC Contract. RPC indicates that both the EIRI and II-1 tariffs reference RPC as the customer served and the MPC/RPC Contract. RPC's remaining comparisons follow.

434. RPC maintains the rate change provision in the MPC/RPC Contract and the EIRI tariff, which states that rate changes would reflect the overall system average percentage change is not present in the II-1 tariff (Exh. No. RPC-2, pp. 3, 5, and 6). RPC illuminated MPC's proposed system average rate increase of 22.5 percent and its increase to RPC's rates of 28.2 percent and then notes that both the MPC/RPC Contract and the EIRI tariff state that if RPC fails to curtail service when requested, it would be billed at 5 times the equivalent firm power rate. RPC points out that this penalty is 10 times the equivalent firm power rate in the II-1 schedule (Id., pp. 3, 5, and 7). Also, RPC notes the provisions for the number of hours MPC can interrupt RPC is up to 800 hours during each 12-month period in the MPC/RPC Contract and the EIRI and II-1 tariffs (Id., pp. 3-4, 5, and 7). Finally, RPC claims that MPC's non-emergency interruption provisions relate to apparent economic benefits to MPC. RPC also notes the II-1 tariff does not contain language stating MPC can interrupt for reasons other than meeting firm loads (Id., pp. 7-8).

Performance Incentive Credit

435. RPC proposed an energy related performance incentive credit to be added to MPC's proposed interruptible credit. RPC maintains the value of this credit equals the savings due to the difference in energy costs over the revenues MPC would earn absent

interruption. RPC computed its proposed credit as follows.

436. RPC assumes an avoided energy cost equal to BPA's NR energy price, adjusted for line losses between BPA's and MPC's system. From this RPC subtracts MPC's proposed II-1 energy price adjusted for substation energy losses and applies the result to the total kWhs it computes from MPC's July 1990 Avoided Cost Compliance Filing based on 3 aMW for the 1989/1990 year, which results in a credit of $339,616. RPC maintains this credit would increase to $661,658 if MPC interrupted RPC 800 hours per year assuming a 64 MW interruptible load. RPC recommends this credit be applied to its class revenue responsibility. Further, RPC concludes that since the credit is not based on marginal cost it need not be reconciled (Exh. No. RPC-2, pp. 11-14).

Rebuttal

437. MPC rebutted RPC's testimony on the comparison of the MPC/RPC Contract and its proposed II-1 rate. MPC also commented on RPC's proposed performance incentive credit.

438. MPC rebuts RPC's claim that the current MPC/RPC Contract does not permit MPC to make its proposed changes to the interruptible rate. Even though MPC states the rate provisions of the MPC/RPC Contract are subject to the Authority of the Commission, MPC modified two aspects of the proposed terms for service to RPC. MPC reduced the penalty charge for failure to interrupt from 10 to 5 times the firm rate (Exh. Nos. MPC-44, p. 9). MPC also removed its ability to interrupt service to RPC for "economic reasons" (Id.). MPC retained its proposed rate revisions since they reflect the cost to provide RPC interruptible service. MPC asserts its proposed rates for RPC reflect costs. MPC contends that a change in RPC's rates equal to the system average would result in rates set below cost.

439. MPC agrees with RPC's proposed performance credit with the following modifications. MPC wants the performance incentive credit to apply only if the energy costs avoided are greater than

the price of RPC's interrupted energy. MPC proposed to credit RPC the difference between the market cost for power and the cost of RPC interruptible energy if the market cost of energy exceeds the cost of the interruptible energy. Further, MPC does not want to pay RPC a performance credit when RPC purchases replacement power during an interruption (Exh. No. MPC-47, pp. 22-23).

HRC RATE DESIGN

Residential

440. HRC supports MPC's residential rate design, with several modifications which follow a summary of HRC's concerns regarding inverted-blocked rates.

441. HRC argues inverted rates allow marginal cost signals to be preserved in the price structure. HRC argues that by setting the rate element to which purchasing decisions are most sensitive (the tail block rate) close to marginal cost, and allowing the rate elements to which purchasing decisions are least sensitive (the initial block and customer charge) to deviate from marginal cost, accomplishes this goal. HRC maintains that it is important to send an accurate price signal at the level at which customers make purchasing decisions (Exh. No. HRC-3, pp. 83-85).

442. HRC maintains the nature of an inverted-block structure reflects seasonal pricing by charging a higher price for non-basic consumption. Based on MPC-provided data and Dr. Power's prior review of similar data in the Pacific Northwest, HRC contends that large usage customers impose a greater cost on MPC. Further, HRC maintains the overall billing impact resulting from inverted rates is mitigated relative to seasonal rates since seasonal rates have an adverse effect on customer budgeting. HRC concludes that since the price signal is in the tail block, basic usage is protected. HRC concludes that such a rate structure "should reduce customer resistance to rates reflecting the higher costs associated with peak periods" (Id., p. 87).

443. HRC argues that inverted rates will reduce billing impacts on low-income customers since there electric consumption is less than average. In this regard, HRC asserts that low-income customers consume less electricity than those with high incomes. HRC also quotes portions of an MPC witness' testimony from Docket No. 80.4.2 in support of its position that inverted rates would benefit low income customers. HRC notes that even though an inverted block rate design would bring higher bills to between 5 and 15 percent of the low income customers, the remaining 85 to 95 percent of this group would benefit (Id., pp. 87-90).

444. HRC rebuts what it characterizes as MPC's mechanistic approach to designing inverted-block rates, particularly with respect to MPC's computation of its initial-block price. HRC maintains that since pricing will deviate from marginal costs due to the reconciliation process, judgement in designing rates should be used by ratemakers to attain their goals. In order to preserve the price signal in the rate design and to attain efficiency goals, HRC contends some elements of the design may not be tied to cost (Id., pp. 90-92).

445. HRC asserts that the impact prices have on low and fixed income households are legitimate concerns for the Commission. HRC maintains that inverted rates and the energy assurance program it proposes are means by which the Commission can address both costs and social objectives (Id., pp. 93-95).

446. HRC rebuts MPC's inverted rate design since it does not reflect marginal cost in the tail block. HRC maintains MPC's winter and summer tail-block prices are set roughly 20 percent below full marginal cost. HRC argues that the customer charge does not need to be linked with costs as MPC has done. HRC also avers that residential tail block rates do not need to be differentiated seasonally. Further, HRC rebutted MPC's "all electric" household billing impact concerns by asserting that if an "appropriate" price signal is not conveyed, efficiency goals or possible energy source switching may not be accomplished (Id., pp. 95-97).

447. Although HRC did not propose specific prices, it proposed the following method to compute a residential rate design. First, HRC would set the tail-block price at average marginal cost less marginal customer costs. HRC would then keep the customer charge at its current level and compute the initial block price to recover the remaining residential revenue responsibility (Id., p. 97).

448. Although HRC would accept a 0-600 kWh initial block, it presented two arguments for different sized blocks and concludes a 0-400 kWh block is more appropriate. First, HRC contends that most customers' consumption should exceed or at least reach the limits of the initial block. HRC maintains that the price signal conveyed to customers whose consumption is increased within, but does not exceed, the initial block may not be correct. Second, HRC urges that the billing impact on larger users should also be considered. HRC asserts that a design with a small, lower priced initial block and a higher priced tail block may result in adverse winter billing impacts relative to summer billing impacts for larger users. HRC posits that differences in winter and summer bills and preservation of the price signal are two areas MPC's rate design is attempting to address. HRC maintains that since these concerns "cannot be solved in an ideal way simultaneously" (Id., p. 100), they may need to be addressed in this case and again future cases (Id., pp. 97-100).

449. For illustrative purposes, HRC computed residential rates using its proposed method and compares its prices with those proposed by MPC in direct testimony. HRC compares its tail block price with MPC's summer tail block price and concludes this price is appropriate for the winter price. In support of its conclusion, HRC reiterates its findings regarding seasonality. To address the difference in MPC's winter and HRC's non-seasonal tail block prices, HRC says there is an apparent error in MPC's computation of residential rates. HRC's illustrative rate designs (0-600 kWh and 0-400 kWh initial block) and MPC's initially proposed rate designs are summarized in Table 15 below (Id., 100-102).

Table 15.

HRC's Illustrative and MPC's Initially Proposed
Residential Rate Designs

0-600 kWh Initial Block

Block	HRC Proposal $/kWh	MPC Proposal Winter $/kWh	MPC Proposal Summer $/kWh
0-600 kWh	$ .05223	$.05458	$.05458
600 + kWh	$ .06948	$.07014	$.06143
Customer	$2.72	$3.32	

HRC's Alternative 0-400 kWh Initial Block Rate

Block	HRC Proposal $/kWh
0-400 kWh	$ .04605
400 + kWh	$ .06948
Customer	$2.72

Source: Exh. No. HRC-3, p. 100

Rebuttal

450. MPC rebutted HRC's residential rate design. MPC maintains these rates should reflect seasonal capacity costs, the initial block should be cost based, and reconciled revenues should be applied to all parts of the rate design. MPC also appears to argue that using reconciled revenues to compute only the basic usage price may result in a low priced, non-cost based basic block. MPC also rebutted HRC's recommended initial block price for 0-400

kWh. MPC contends that while HRC's method for setting the level of the initial block would subject more customers to the tail block price, the trade off would be a lower initial block price. MPC concludes that as a starting point for blocked residential rates, a 0-600 kWh initial block, representing average summer or basic usage, should be used.

451. MPC agrees with HRC that concerns regarding billing impacts and price signals should be addressed in this and future cases. MPC cautions that when changes in rate structures could affect rate continuity and revenue stability. Further, MPC maintains its proposed structure addresses seasonal billing problems, improves price signals, and provides relief to low-usage customers, including some low-income customers (Exh. No. MPC-47, pp. 14-15).

COMMISSION DECISION ON RATE DESIGN

Overview

452. After a brief review of the parties' and its own rate design priorities, the Commission will explain the approach used to compute prices for each class.

Rate Design Priorities

453. A brief review of MPC's, MCC's, LCG's, and HRC's rate design priorities follow. MPC proposed that generation capacity costs be the highest priority followed by generation energy, other capacity costs, and customer costs (Exh. No. MPC-46, p. 4). Other parties expressed the following opinions regarding rate design priorities. MCC maintained energy costs should be the highest priority in designing rates and energy prices should be set as close as possible to marginal costs (MCC RDR PSC-308). LCG argued that each price element should reflect unit costs as closely as possible (LCG RDR PSC-380). HRC argued that energy costs should be the primary concern in rate design as summarized in the COS section of this order.

454. In this Docket the Commission will attempt to reflect energy costs as its highest priority followed, in turn, by capacity and customer costs. The following provides the Commission's reasons for these priorities.

455. First, the Commission finds merit in LCG's criticism of how MPC computes demand prices in accordance with MPC's rate design priorities. LCG argued that by transferring demand costs to its energy price in its computation of its Substation demand prices, MPC dilutes the emphasis placed on demand (capacity) costs (Exh. No. LCG-8, pp. 9-11). The Commission agrees with LCG that MPC's pricing methods concentrate less on generation capacity costs than MPC's rate design priorities would suggest.

456. Energy costs are the easiest unit costs to define. Energy costs per kWh don't change between COS and RD. MPC's capacity costs, however, are more difficult to consistently define between COS and RD. For instance, MPC allocated seasonal generation capacity costs using a 1CP approach. However, MPC converts these costs to unit costs by dividing a class' total capacity costs by seasonal billing demand, thereby changing the estimation of costs for purposes of cost recovery and rate design. The Commission intends to explore the relevant basis of marginal-cost based capacity prices in MPC's next docket.

457. Second, a comparison of MPC's proposed marginal generation energy and demand costs raises a question as to why MPC ranks demand costs higher than energy costs. In rebuttal testimony, MPC's aggregate generation energy and capacity costs (excluding losses) amount to about 56 and 44 percent of its total generation costs, respectively (Exh. No. MPC-42, PEM-13).

458. Third, the Commission finds it logical to reason that, on average, the demand for energy would be more elastic than the demand for capacity. Once a demand metered customer reaches his peak for a given billing period, energy will become the customer's avoidable cost. MPC measures demand based on the "average kW

supplied during the 15-minute period of maximum use during the month" (Amended Appendix B, Schedule No. GS-1).

459. Fourth, and related to the first reason above, over a 25-year time period a utility goes through periods of generation energy and capacity balances, taking into account actual resource additions. Absent resource additions and based on an ex ante view, a utility with load growth surely becomes deficient in both generation energy and capacity over 25 years. In fact, this is precisely MPC's own expectation. Given the June 1990 Addendum to its Projection of Electric Loads and Resources (1982-2012), chronic deficiencies in generation energy begin in 1996. MPC's initial July 1990 Avoided Cost Compliance Filing showed the same looming energy deficiencies.

460. Last, the area of prioritization is one in which MPC's testimony was clearly deficient. It wasn't so long ago that MPC's own witness Mr. Lacapra (Docket No. 83.9.67) testified to a different prioritization than that in this Docket. A much more serious analysis is needed. The Commission fully supports MCC's and HRC's energy prioritization testimony in this Docket.

Rate Design Methodology

461. This section describes how the Commission computed prices in this Order and how MPC is to compute prices in compliance with this Order. The Commission will note the sources of various cost and revenue data used to compute the numerous prices for each class. The prices computed are illustrative, as has been the Commission's practice in prior rate cases. Although illustrative, the Commission has attempted to estimate those prices MPC will compute in compliance with this Order. Some simplifying assumptions were made by the Commission. These assumptions are detailed so that MPC can calculate all necessary prices precisely. MPC must follow the methods set forth in the findings below when computing final prices.

462. Due to the Commission's decision to coordinate rate

changes in Docket No. 90.6.39 with extra-Docket revenue impacts (e.g., the Colstrip 3 Rate Moderation Plan and accounting amortizations), the Commission has two revenue requirement choices in designing rates. One choice would be to design rates that only reflect Docket No. 90.6.39 revenue requirement increases of roughly $39 million plus the interim approved revenues in Docket No. 91.6.24. However, the aforementioned extra-Docket revenue impacts on November 1, 1991, are not trivial and amount to about an 8.94 percent increase over and above the final Docket No. 90.6.39 and interim Docket No. 91.6.24 revenue requirements of roughly $310 million.

463. Since the Commission's rate design decisions attempt to moderate impacts in addition to reflecting costs, the Commission had its staff compute prices assuming the total revenue requirements that MPC has the opportunity to generate on November 1, 1991. Thus, the Commission initially considered rate design decisions taking into account all revenue impacts effective November 1, 1991. These rates and the philosophy upon which they are based can be adjusted to reflect Docket Nos. 90.6.39 and 91.6.24 revenue requirements only by backing out the extra-Docket revenue impacts on a uniform percentage basis. This, in fact, is the method the Commission would use to compute rates if it were to only assume a Docket No. 90.6.39 and 91.6.24 revenue requirement. The Commission will explain this process for the residential class with the understanding that the same process may be applied to all other classes. This process will also have an impact on the off-peak demand discount rate.

464. Illustrative Unit Marginal Costs. The following describes the data sources and methods the Commission used to compute illustrative unit costs for each voltage level of service. MPC is directed to compute the marginal costs it uses to determine each class' prices, off-peak demand rate discounts, and generic interruptible credits using these methods.

465. Upon completion of its costing decisions the Commission directed MPC, through its preliminary COS decisions, to provide

work papers reflecting those COS decisions. MPC initially provided draft compliance COS work papers in mid-September and later revised the generation costs (on October 7 and 8) to reflect changed generation cost estimates. The total generation costs in the first and second revisions were about $246 million and $241 million, respectively. For purposes of estimates, the Commission based its rate design decisions, in part, on the costs provided in MPC's first revision to its draft compliance COS work papers.

466. First, the Commission used unit energy costs from MPC's first revision (October 7) to its draft COS compliance filing, using the method MPC described at the hearing (TR 1042-1043).

467. Second, with the exception of the residential class, the unit capacity costs reflect MPC's method to determine demand charges (total class capacity costs by function divided by class seasonal billing demand). Residential unit capacity costs were computed by dividing total class annual and seasonal capacity costs by annual and seasonal consumption. Unit capacity costs for each customer class reflect seasonal generation capacity costs and voltage level unit costs.

468. Except for the Irrigation and Industrial Interruptible class, the Commission used the monthly customer costs computed by MPC in its September 13, 1991, draft compliance filing (p. 31). For the irrigation class, the Commission used annual customer costs from the same source.

469. MPC also provided updates to its rate designs and unit costs reflecting the Commission's draft COS decisions. For the most part, the Commission used billing determinants from work papers MPC provided.

Residential Rate Design

470. The Commission's residential rate design assumes a revenue requirement of approximately $110,000,000, which reflects estimates of Docket Nos. 90.6.39 and 91.6.24, and all extra-Docket

accounting adjustments. Among the Commission's simplifying assumptions, this revenue requirement excludes any adjustment for MPC's employee discount and the low-income residential tariff. MPC must, of course, make these adjustments.

471. The Commission's rate design decisions follow. First, the Commission approves the low-income tariff stipulation, which includes MPC's proposed rate design structure. Thus, the residential tariff features a seasonal commodity rate differential with an inverted-block winter structure. Further, the flat summer rate will be the same as the initial-block winter rate, up to 600 kwh per month. Second, the Commission adopts a Customer Charge of $3.60 per month. Any customer charge must be rounded to the nearest nickel. Third, the Commission finds merit in freezing the currently tariffed winter commodity rate at $.070007/kWh. As a result of these decisions, the initial-block rate in the winter and the summer rate shall serve as a residual ensuring the tariff produces the allocated revenue responsibility.

472. For an estimate of what the Commission's Docket Nos. 90.6.39 and 91.6.24 prices would have been, the above illustrative rates must be reduced by the uniform percentage increase of approximately 8.94 percent to remove the extra-Docket revenue impacts.

473. The Commission's reasons for adopting the above prices include the following. First, the winter tail-block price is frozen at its current winter level to mitigate the impacts of reducing the price, especially given the uncertainty associated with how MPC's demand costs are converted into a cents per kWh commodity rate. Second, the Commission set the customer charge at $3.60/month so as to minimize moving the winter tail-block commodity rate further away from marginal cost. The resulting summer commodity price exceeds marginal cost while the winter marginal cost exceeds the initial-block price, a necessary result of the stipulation's rate design (Exh. No. MPC-1).

COMMISSION DECISION - RESIDENTIAL LOW-INCOME TARIFF

474. The Commission finds that the low-income rate design stipulated by MPC, MCC, HRC, and SRS provides an appropriate introduction of discounted rates for low-income ratepayers. The Commission therefore approves the stipulation as submitted. The Commission understands that MPC will collaborate with interested parties to further study other low-income rate design proposals, such as reducing or eliminating the customer charge, a different size initial kWh block, including the LIEAP fund in rates and other proposals made in this proceeding. The Commission directs MPC to keep the Commission informed of its findings.

475. The Commission is concerned that less than half of MPC's LIEAP-eligible ratepayers are currently participating in the program. The 10 percent discount adopted by this Order for LIEAP participants will provide a strong incentive for increased enrollment. However, any ratepayers who qualify for LIEAP but who do not participate will actually be less well off than they would be if no discount were in effect because the burden of the revenue requirement imposed by the discount will be shared by all ratepayers. Therefore, it is important that LIEAP participation be as high as possible.

476. MPC is directed to take affirmative action to maximize LIEAP participation. In collaboration with SRS and the HRCs, MPC shall develop a program aimed at recruiting LIEAP participation. MPC shall monitor the program and its effectiveness and report its results to the Commission on a quarterly basis.

477. One of the primary Commission goals is to ensure that customers are provided the proper marginal cost price signals while at the same time balancing equity objectives. The Commission would like to address two of the low-income rate proposals made in this proceeding. While recognizing the absence of LIEAP specific cost information, the Commission finds that the low-income rate design stipulation could distort marginal cost price signals.

478. First, the stipulation discounts each rate component by

10 percent, i.e., the commodity charge and the customer charge are discounted equally. Based on relative demand elasticities, the Commission concurs with HRC and SRS that the customer charge provides a less effective price signal than the commodity charge. Hence, in order to maintain proper price signals to low-income customers it may be more efficient to provide rate discounts primarily through adjusting the customer charge component of the rate, assuming the commodity prices are cost based.

479. Second, the stipulation specifies a 600 kWh initial commodity block. But MPC presented LIEAP specific consumption data (MPC Exh. 44) which reveals a significant number of low-income customers whose consumption never reaches 600 kWh per month. Under an inverted-block pricing scheme with the tail block set at marginal cost this means that low-income customers are not provided the proper marginal cost price signal. The Commission agrees with Dr. Power that the size of the initial block may need to be reduced for low-income customers. However, because of the uncertainty as to how low-income consumption may change as a result of the discount and because MPC's data were not weather normalized, the Commission accepts the stipulation's 600 kWh initial block.

General Service (GS) Rate Designs

480. This section discusses the Commission's decisions regarding general service. Included in this section are the Commission's decisions regarding demand metering, GS-1 and GS-2 rate designs, MPC's Off-Peak Demand Discount Rates, Reactive Power Charges, and MPC's proposed Electric Rate Stability Option (ERSO).

481. Demand Metering. For the purposes of this case, the Commission finds MPC's proposal to meter and bill demand for its Primary and Secondary customer classes reasonable. MPC proposed to meter and bill a Secondary or Primary customer for demand if the customer's monthly energy sales exceeds 2,500 kWh for 12 successive monthly billing periods or if maximum demand or sales is estimated to exceed 10 kW or 2,500 kWh, respectively. However, the Commission finds that the data MPC used to support its proposal is

inconclusive to make a final determination on this issue. The Commission questions how the sales data MPC used in its cost/benefit analysis for metering demand (0-1,600 kWh and 1,600-6,000 kWh) support its proposed minimum monthly sales level of 2,500 kWh. The Commission questions why there would not be merit in examining the revenues and costs associated with billing for demand at sales strata around 2,500 kWh in addition to the two strata used by MPC in this case. For instance, at what sales level do the costs out-weigh the benefits associated with metering and billing for demand?

482. GS-1 and GS-2 Rate Designs. The Commission finds merit in MPC's proposal to price service to its Secondary, Primary, Substation, and Transmission customers separately. The Commission's decision is based on the differences in unit energy and capacity costs to provide service to these customers. Table 16 summarizes the illustrative unit costs the Commission computed for each of these classes.

Table 16

The Commission's Illustrative Unit Marginal Costs

For General Service

Energy

$/kWh

Class	Winter	Summer
Secondary	.033245	.026795
Primary	.032286	.025836
Substation	.031994	.025544
Transmission	.031707	.025257

Capacity

$/kW

Class	Winter	Summer

Secondary	5.57010	3.733635
Primary	6.889752	4.402156
Substation	8.862207	4.197486
Transmission	6.788699	3.104605

Sources:
Costs: MPC's Draft Cost of Service Compliance Filing, First Revision, October 7, 1991, pp. 2-7.
Billing Determinants to compute capacity costs: MPC's September 13, 1991, facsimile containing unit rates.

483. Two other areas require attention before reviewing the Commission's general service rate design decisions. First, the Commission denies MPC's proposal to price energy for its GS-1 and GS-2 customer classes annually. LCG observed that even though the energy costs MPC provided in rebuttal testimony showed a seasonal difference, MPC continued to price energy in a non-seasonal fashion (Exh. No. LCG-8, p. 6). LCG also asserts that MPC's rebuttal energy costs showed "that stronger seasonality of costs" exist (Id.). MPC's rebuttal COS study showed a winter/summer cost ratio of about 1.38. MPC's first revised draft compliance COS work papers showed winter and summer energy costs of about $.02941/kWh and $.02296/kWh, respectively, a winter/summer ratio of about 1.28. Based on this information, the Commission finds merit in retaining seasonal energy prices for the Substation class. The Commission also finds it reasonable to price energy for the remaining general service classes (Transmission, Primary, and Secondary) seasonally in order to maintain a consistent rate design across these classes. The Commission finds that seasonally priced energy would more accurately reflect marginal energy costs and thereby result in more efficient prices than would non-seasonal energy prices. Further, the Commission finds seasonal energy prices would promote conservation.

484. Second, in its deliberations to set prices for each of the general service classes, the Commission sought to accomplish the following. The Commission attempted to retain the general

interclass cost differentials between each of the general service classes. The Commission's pricing decisions focus on the energy prices for these classes to the greatest extent possible. Also, the Commission considered billing impacts and attempted to determine prices which closely approximated the percentage change in each class' total revenue requirement between the revenues generated by the currently effective prices (effective as of August 29, 1991) and those the Commission anticipates will be in place on November 1, 1991.

485. GS-1 Primary and Secondary. The Commission finds merit in and approves MPC's proposal to price service to its demand and non-demand metered Primary and Secondary customers separately. The Commission approves MPC's method to compute energy prices for non-demand metered customers based on the demand and energy prices computed for demand metered customers (see, e.g., Exh. No. MPC-47, TEW-16 and 17). The methods used by the Commission to compute prices for each of the Secondary and Primary classes are summarized below. Although MPC computed non-seasonal energy prices for its Primary and Secondary non-demand metered classes using an annual load factor, the Commission finds merit in and will use the same load factor to compute seasonal energy prices for non-demand metered service. This load factor is about 29.64 percent. Table 17 below summarizes the illustrative prices computed by the Commission for the GS-1 Primary and Secondary classes.

Table 17

The Commission's Illustrative GS-1 prices

Demand Metered

	Demand		Energy		Customer
	Winter $/kW	Summer $/kW	Winter $/kWh	Summer $/kWh	$/Mo.
A. Secondary	$6.489528	$4.653063	$.033245	$.026795	$5.00
Billing					

Determinants (millions)	2.3014	3.2989	815.4	1,084.8	.145
B. Primary	$9.379961	$6.892365	$.032286	$.025836	$16.50
Billing Determinants (millions)	.344	.459	158.5	209.7	.00148

Non-Demand Metered

	Energy Winter $/kWh	Energy Summer $/kWh	Customer $/mo.
A. Secondary	$.063237	$.048300	$5.00
Billing Determinants (millions)	87.521	99.644	.314
B. Primary	$.075637	$.057690	$5.00
Billing Determinants	30,544	145,241	118

486. The Commission computed the above prices based on estimated $99.105 million and $16.969 million class revenue requirements on November 1, 1991, for the Secondary and Primary voltage level classes, respectively. The Commission computed these prices using MPC's billing determinants provided in various workpapers and MPC's Operating Revenue Work Papers (p. 4/45, filed February 13, 1991). As with every other class MPC's workpapers in compliance with this Order must precisely document the revenue requirements, billing determinants, unit marginal costs and prices. The following describes the Commission's methods and rationale for computing the above illustrative prices. MPC is to follow these approaches when computing tariffed prices.

487. The Commission computed the Secondary voltage level class' prices by holding monthly customer charges for the demand and non-demand metered classes at the currently tariffed price (MPC's Montana Electric Service Tariff, Schedule No. GS-1, 4th Revised Sheet No. 20.1, effective August 29, 1990). Seasonal energy and demand prices for demand metered customers were set at their full marginal cost. The projected November 1, 1991, class revenue requirements were then calculated by adjusting the demand prices using demand billing determinants. The Commission finds these prices reasonable since the energy prices reflect their costs. The Commission then computed the energy price for non-demand metered customers using MPC's method to do the same.

488. The Commission computed the Primary voltage level class' prices by setting the demand metered customer charge at one-half its monthly cost and the non-demand metered customer charge at the currently tariffed price (MPC's Montana Electric Service Tariff, Schedule No. GS-1, 4th Revised Sheet No. 20.1, effective August 29, 1990). Seasonal demand and energy prices were set at marginal cost. The projected November 1, 1991, class revenue requirements were computed by then adjusting the demand price. The Commission then computed the energy price for non-demand metered customers using MPC's method to do the same.

489. The Commission finds the methods it used to compute Secondary and Primary prices reasonable, since the energy prices reflect cost. Also, the Commission finds that use of MPC's method results in energy prices too far above cost for the Primary class and below cost for the Secondary class. The Commission found that using the above methods versus MPC's results in mitigating the impact of the energy price increase.

490. The Commission finds the Primary class prices it computed reasonable since the energy prices reflect the cost differences relative to those at the Substation level of service. Also the demand prices are consistent with the relative costs for demand at the Secondary level. The Commission recognizes, however, that the

summer demand prices for the Primary and Substation classes do not appear to reflect the relative cost differences between these two classes. This may be caused by the way in which unit demand costs are computed and by capping the Substation class revenue requirement.

491. GS-2 Substation and Transmission Table 18 summarizes the illustrative prices the Commission computed for the Substation and Transmission classes.

Table 18.
The Commission's illustrative Substation and Transmission Prices

	Demand		Energy		
	Winter $/kW	Summer $/kW	Winter $/kWh	Summer $/kWh	Customer* $/Mo.
A. Substation	$9.493578	$5.548857	$.031994	$.025544	$24.01
Billing determinants (millions)	1.411	2.006	822.7	1,168.9	
B. Transmission	$8.99617	$5.312083	$.031707	$.025257	$28.71
Billing determinants (millions)	.104	.126	42.366	51.756	

* The customer billing determinants for the Substation and Transmission classes amount to 682 and 48, respectively.

492. The Commission computed the prices listed in Table 18 based on projected November 1, 1991, revenue requirements of $80.726 and $4.259 million, respectively, for the Substation and Transmission classes.

493. The Commission computed illustrative prices for the Substation class by setting the customer charge at one-half its monthly cost and setting energy and demand prices at marginal cost. The Commission then adjusted the demand price using demand billing determinants to attain the revenues it anticipates would be in place November 1, 1991. The Commission finds these prices reasonable since they reflect the relative energy cost differences between the Transmission, Substation, and Primary levels of service. MPC must follow the same approach in its compliance filings.

494. The annual average billing impacts associated with these prices range from about 9 to 15 percent for high and low load factor customers, respectively. Also, the average annual billing impact for the average Substation and average electric contract customers appears to be about equal to the Commission's estimated revenue increase for the Substation class between the revenues associated with the currently-tariffed prices and those anticipated to be in effect on November 1, 1991. The Commission considers these billing impacts reasonable given the revenue increase that would have otherwise affected the Substation class absent an application of the 24.79 percent revenue increase cap. The Commission recognizes that each customer's billing impacts for this and for any other class will differ from the class average due to individual consumption.

495. The Commission computed illustrative Transmission level prices using the same method it used to compute Substation prices. Demand prices were adjusted using demand billing determinants to attain the anticipated November 1, 1991, revenues. The Commission used this approach in order to mitigate an increase in the energy price. The method used by the Commission resulted in energy prices that appear to reflect the relative energy cost differences between the Substation and Transmission classes. The Commission would also note that its computed demand prices do not appear to reflect the relative capacity cost differences between the Transmission and Substation classes. This may be caused by the method the Commission used to compute unit capacity costs, as well as the

Commission's capping the substation revenue requirement. MPC must follow the above approach in its compliance filings to compute prices for its transmission class.

496. The Commission denies FEA's proposal to set the Transmission energy price at short-run marginal cost. The Commission finds merit in MPC's argument that energy prices should be based on long-run marginal costs since customers make long-term rather than short-term purchasing decisions (Exh. No. MPC-42, p. 6). The Commission also finds merit in MPC's argument that setting the energy price based on system lambda would not reflect the market value of energy as would a price based on avoided energy costs (Exh. No. MPC-47, p. 15). Further, short-run marginal energy costs would not appear to reflect the variable costs associated with changes in MPC's load and resource plans as reflected in long-run marginal costs. Therefore, by pricing energy based on short-run marginal costs and demand based on long-run marginal costs would result in a mixed bag of price signals.

497. Off-Peak Demand Discount Rate. The Commission finds merit in and approves MPC's proposal to make its Off-Peak Demand Discount Rate a permanent option for its Primary, Substation and Transmission classes. The Commission finds it reasonable and approves MPC's method to compute these discounts as shown in Exh. No. MPC-47, TEW-22 with the following changes. These changes would maintain consistency between the methods the Commission used to compute demand prices for the above listed classes. First, MPC must use the methods used by the Commission to compute seasonal unit marginal capacity costs as cost inputs to develop its off-peak discounts. These costs would be used in place of the marginal billing capacity charges to compute the discounts for the Primary, Substation, and Transmission classes. The Commission used these methods to compute the illustrative off-peak discounts listed in Table 19.

498. Second, MPC must compute its discounts using the prices it develops for the Primary, Substation, and Transmission classes, pursuant to the Commission's rate design decisions. Since demand

prices appear to be a variable in MPC's model, the Commission anticipates these discounts will change commensurate with future changes in demand prices. The discounts listed in Table 19 were computed using the illustrative prices computed by the Commission for each of the listed classes. The Commission computed these discounts using MPC's proposed TOD on- and off-peak hours. Since the Commission denied MPC's proposal to change the currently tariffed on- and off-peak hours, it anticipates these discount rates will differ from those MPC is directed to compute. MPC must compute its off-peak demand discount rates using the currently tariffed on- and off-peak periods.

Table 19.
The Commission's Illustrative Off-Peak Demand Discount Rates

Class	Winter	Summer
Primary	43%	46%
Substation	37%	39%
Transmission	45%	63%

499. Reactive Power Charge The Commission finds merit in and approves MPC's proposed implementation of its reactive power charge of $2.23/Kvar/year. The Commission also finds MPC's proposed terms and conditions of its tariffs regarding reactive power acceptable. The Commission also finds merit in LCG's proposal to examine reactive power charges through a demand-side management program just as MPC would examine kW and kWh charges. The Commission urges MPC to review such an option in its integrated resource planning efforts.

500. Electric Rate Stability Option The Commission denies MPC's proposed ERSO for the following reasons. First, the Commission finds no reason why any of MPC's customers should

receive service at rates which are exempt from changes subject to the outcomes of future rate cases. Second, MPC has not proven that its general service prices would track with a consumer price index (TR 1213). The Commission finds merit in MCC's response to DR PSC-344 which states that the arguments regarding MPC's Rate Implementation Plan are also applicable to the ERSO. The Commission questions whether the costs associated with the new or expanding loads which would qualify for the ERSO would continue to be reflected in the customer's prices.

501. The Commission is not unsympathetic to the desires of both customers and utilities for stable prices. While there are many benefits from a planning and economic development perspective associated with MPC's proposed ERSO, the Commission finds such a development premature at this time. Given the uncertainties the Commission has with costs in this case, it would be contrary to the interests of all other customers to potentially exempt substantial loads from proper cost allocations in the future. Such an option might also be counter-productive to rate stability for all customers as it may actually make it easier for MPC to file a rate revision if the load most sensitive to price changes would be exempt from the effects of such a filing. Additionally MPC's proposal runs contrary to the cost based principles adopted by this commission. This finding, however, is made without prejudice to similar proposals in the future.

Irrigation

502. The Commission finds merit in and approves MPC's proposal to price service to its demand and non-demand metered Irrigation customers separately. The Commission also finds MPC's method to compute non-demand energy prices based on the load factor MPC developed for this class reasonable and approves this method. Table 20 summarizes the Irrigation prices the Commission computed for the Irrigation class.

Table 20

The Commission's illustrative Irrigation Class Prices

	Demand Metered			Non-demand Metered	
	Demand $/kW	Energy $/kWh	Customer $/Seas.	Energy $/kWh	Customer $/Seas.
Irrigation	$5.604838	$.028407	$92.76	$.047840	$38.88
Billing Determinants	317,867	81,483,806	885	3,248,384	2,321

503. The Commission computed the above illustrative prices for the Irrigation class as follows. Consistent with MPC's proposed method to compute demand and non-demand metered prices for this class, the Commission first determined the energy and demand prices for demand metered customers and customer charges for the demand and non-demand metered customers. Customer charges were set at annual marginal costs. Energy was set equal to the summer unit marginal energy costs for the secondary level and demand was set at the currently tariffed (MPC's Montana Electric Service Tariff, Schedule No. IS-1, 4th Revised Sheet No. 30.1) demand price. The Commission then adjusted the energy price associated with demand metered service to attain class revenues. The Commission then determined the non-demand metered energy price using MPC's method and proposed load factor of 39.51 percent. The Commission computed these prices based on an estimated November 1, 1991, revenue requirement of $4.424 million. MPC is to follow this approach when computing tariffed prices.

504. The Commission's rationale for setting these prices is based foremost on its adopted rate design priorities. The Commission found it reasonable to use a method which resulted in energy prices which reflect cost. The Commission also considered it important to set the energy price within the proximity of the summer energy price it computed for the GS-1 Secondary class. The Commission also finds reasonable to moderate the Irrigation demand price. In so doing, the Commission also finds it reasonable to set the customer charges for demand and non-demand metered service at

their annual marginal cost.

Lighting

505. The Commission finds reasonable and approves MPC's proposed method to compute prices for each of its lighting classes. Prices for these classes must be computed based on the unit costs which result from the Commission's COS decisions using the method portrayed in Exh. No. MPC-41, PEM-20.

Generic Interruptibility

506. The Commission finds merit in and approves MPC's proposed generic interruptible rate with the following changes. First, the Commission is concerned whether the seasonal interruptible credits, based on a negotiated ten-year interruptible contract, accurately reflect avoided capacity costs throughout the life of the contract. Although the Commission approves MPC's proposed method to compute these credits, the Commission intends to reexamine the level of the credits in future cases. One concern the Commission has is whether the level of the credit would accurately reflect the value of interruptible power in the future.

507. Second, the Commission finds merit in MPC's proposed penalty for failure to curtail consumption during emergency interruptions. However, the Commission finds the sizes of MPC's penalties proposed for emergency and non-emergency interruptions inconsistent. The Commission finds that invoking a rate 10 times the customer's firm power rate in emergency interruptions reasonable. However, the Commission considers this level to be set unnecessarily high for failures to curtail consumption during non-emergency interruptions. The Commission finds a penalty of 5 times the customer's otherwise applicable firm power rate reasonable for failures to curtail consumption during non-emergency interruptions.

508. Third, the Commission is concerned with how MPC would administer and determine the replacement power prices proposed for non-emergency interruptions. The Commission directs MPC to propose

a means by which interruptible, or potentially interruptible, customers would have ready access to long and short-term wholesale markets and power. Additionally, the Commission is not convinced that the 20 percent surcharge MPC proposes for replacement power is properly set. The Commission questions whether this adder accurately reflects the transactions cost associated with finding and providing replacement power or any other costs associated with providing such service. Furthermore, does the adder correctly reflect these costs during all potential situations that MPC would seek either to avoid purchasing off-system power or to resell the interruptible customer's power? Therefore, the Commission directs MPC to justify the level of its proposed 20 percent surcharge associated with providing replacement power during non-emergency interruptions in its next COS/RD filing.

509. Fourth, the Commission finds merit in MCC's caution regarding potential future subsidies brought about by MPC's interruptible rates. MCC suggests that if a portion of a customer's load becomes interruptible, and the costs associated with that load shift away from this customer's class, then a subsidy may appear. The Commission requires MPC to report the following information:

1. When a customer commences interruptible service, MPC must provide a copy of the contract between it and the customer pertaining to interruptible service. If not part of the contract, MPC must provide the specific combination of the days per month the customer will yield to interruption, the duration of each interruption, and the applicable notice period. This information must be provided for each of the winter and summer seasons and each time any of these variables are changed.

2. For each of its interruptible customers MPC must provide the size of the load each agrees to make available for interruptions. This information must be provided when the contract between MPC and the customer becomes effective or whenever the interruptible load size is

changed.

3. MPC is directed to file the following information with its annual report for each of its interruptible customers. This information must be provided for each month spanning the year of its annual report.

   a. MPC must provide the total number of hours it interrupted each customer for emergency and non-emergency purposes.

   b. For emergency interruptions, MPC must indicate the source of alternative power MPC would have relied on if the interruptible power would not have been available and the price of this alternative source.

   c. For non-emergency interruptions, MPC must provide the average monthly price at which MPC sold the interrupted power off-system. If a customer purchased replacement power during non-emergency interruptions, MPC must indicate the price MPC charged the customer for such service in the same terms the customer's interruptible credit is computed.

510. The Commission considers this information beneficial for monitoring the potential revenues MPC may generate by selling interruptible power off-system.

511. Finally, The Commission finds merit in and approves MPC's proposed method of computing its generic interruptible credits. MPC appears to compute its seasonal marginal capacity costs, which are one input into the model used to compute credits, by dividing total seasonal class generation capacity costs plus losses by seasonal billing demand (TR 1199 and Exh. No. MPC-47, TEW-18). Since MPC has been directed in this Order to reexamine the method it uses to compute unit capacity costs, the Commission also directs MPC to reexamine the method it uses to compute its marginal

capacity costs for use in determining its generic interruptible credits. The Commission is also concerned with the way in which MPC computes its marginal capacity costs for its interruptible credit. That is, MPC computes the marginal capacity cost based on: 1) the average of the GS-2 base rate demand price prior to the interim revenue increase in this case; and, 2) the unit capacity costs it computed for the Substation class. While this method may have merit in computing demand prices, the Commission fails to see how it would result in properly crediting an interruptible customer for the capacity it is willing to provide to MPC during curtailments.

512. The Commission is concerned that a consistent price signal be relayed through the demand prices it computed for the Substation class and the interruptible credits MPC proposed in this case. Therefore, the Commission finds it reasonable for MPC to compute its marginal capacity costs for use in determining its generic interruptible credits based on unit marginal generation capacity costs plus losses at the Transmission and Substation levels per the methods described above to compute unit marginal capacity costs. For illustrative purposes, the Commission computed these costs as $8.208158/kW and $3.838227/kW for the winter and summer seasons, respectively. MPC is to follow this approach when computing the marginal capacity cost inputs for its generic interruptible credits.

QF Standby Rate

513. The Commission finds MPC's QF standby rate reasonable and approves MPC's proposal with the following changes. First, MPC's proposed GS-2 tariff, through which MPC proposes to provide this service, does not specifically state that its proposed rates apply to GS-2 Substation level of service. However, MPC's testimony on this matter clearly indicates that MPC views a QF standby customer as one who would take service at the Substation level (Exh. No. MPC-46, pp. 33-35). MPC's proposed tariff language, however, reads that service for a QF standby customer would "...be billed at the rates set forth above under RATES,..." (Amended Appendix B,

Schedule No. GS-2) but does not specifically state whether it would be Substation or Transmission. Based on MPC's testimony, the Commission finds MPC must revise its tariff language to state that service for a QF Standby customer would be charged at the Substation rate.

514. Second, the Commission has a concern that even though MPC would charge a QF standby customer at the Substation rates, it computes its monthly standby charge based on generation and transmission capacity costs. This appears inconsistent. Therefore, to more accurately reflect the costs associated with standby service, the Commission finds that MPC must include substation level capacity costs in its QF Standby price. With this change the Commission finds MPC's QF Standby demand price would be approximately $1.23/kW/year, based on MPC's first revision to its draft compliance COS work papers dated October 7, 1991.

515. For other aspects of MPC's QF Standby rate, the Commission is not convinced that MPC's assumed probability that a standby customer will require capacity will reflect actual experience. Therefore, the Commission requires MPC to reexamine the probability it assumes as it gains experience with its QF Standby rate or as better industry data becomes available.

Electric Economic Incentive and Electric Industrial Retention Interruptible

516. The Commission approves MPC's request to cancel its Electric Economic Incentive and Electric Industrial Retention Interruptible tariffs.

Interruptible Industrial (II-1) Rate Design

517. The following addresses MPC's proposed customer specific II-1 tariff with respect to its interruptible credit, performance incentive credit, and the energy price and customer charge MPC proposed for this tariff.

518. The Commission finds merit in and approves MPC's proposed method to compute the customer specific interruptible credit as portrayed in MPC's rebuttal testimony (Exh. No. MPC-47, TEW-21). For illustrative purposes the Commission computed the II-1 interruptible credit to be $4,086,366 based on MPC's first revised compliance COS filing (dated October 7, 1991).

519. The Commission finds merit in and approves MPC's proposed performance incentive credit for the II-1 tariff. The Commission finds that RPC would only be eligible for a performance incentive credit if the market value of energy MPC avoids purchasing by interrupting RPC exceeds the energy price the Commission approves for the II-1 tariff. The Commission denies RPC's proposed credit. Since it is not known with certainty what the short-term wholesale market price will be at any given hour in which MPC would require RPC to curtail service, the Commission denies RPC's proposal to credit the revenue requirement for the II-1 class RPC for a performance incentive prior to actual interruptions.

520. It appears that with a performance incentive credit in place, MPC would be indifferent to the choice of interrupting RPC and purchasing power in the wholesale market, assuming the wholesale market price for energy was greater than or equal to the II-1 energy price. The Commission is also concerned with the means by which MPC intends to award performance incentive credits to RPC. MPC is required to file annual reports listing the following information:

1. A list of the hours MPC interrupts RPC each month;

2. The duration and reason for each interruption;

3. Whether RPC sought replacement power during each interruption or if MPC paid RPC a performance incentive credit;

4. The wholesale market price of energy during each interruption during which RPC received a performance

credit; and

5. The value of the performance incentive credit paid to RPC during each interruption.

521. Finally, the Commission finds reasonable and approves MPC's proposed rate structure for the II-1 tariff and the method MPC used to compute prices for this tariff (Exh. No. MPC-47, TEW-21). Based on its COS decisions, the Commission estimates the II-1 tariff energy price to be $.028224/kWh, which equals annual unit marginal generation energy costs plus losses at the Transmission and Substation levels. The Commission computed a $136,277 per month customer charge based on the balance of the II-1 revenue requirement estimate as of November 1, 1991. The Commission estimates this amount to be $12.7 million.

Part III

COMMISSION DECISION: POLICY DIRECTIVES

522. In this section, the Commission will discuss certain policies related to cost of service and rate design.

Cost of Service Policy Issues

523. Generation Costs. The Commission questions whether the current method for developing total generation incremental costs best reflects the value of generation. MPC's current method, which the Commission adopted in this Docket, includes incremental generation costs and off-system opportunity sales and purchases, albeit only short-term non-firm opportunity sales values.

524. The policy question is whether a long-term firm regional opportunity sales value is relevant to the development of generation resource costs. The implementation question then turns on what is the long-term firm opportunity cost value of generation. Answers to these questions involve operational considerations. These issues are raised now to alert MPC that the Commission

expects analysis and testimony on this matter in the Company's next cost of service filing.

525. Transmission Costs The Commission has two transmission cost policy concerns. One involves cost-effective investments and the second cost development and classification. First, the Commission is aware of new transmission technologies such as flexible AC transmission systems (FACTS). EPRI estimates substantial avoided generation and transmission costs with FACTS technology. The question which MPC must address in its next cost of service testimony is whether it has begun implementing this and other technological advances. MPC must provide testimony at that time on the cost of available alternative transmission technologies and whether these technologies can be implemented to reduce costs.

526. The second concern involves the development and classification of transmission costs in class cost of service studies. Although the same issues have been raised in prior dockets, HRC aptly questioned whether MPC's cost study contains all relevant transmission costs and how MPC classifies such costs. The classification issue involves whether transmission costs are energy or capacity related. The role of reliability related investments and whether such costs are energy or capacity related must be addressed in MPC's next COS filing.

527. Distribution and Customer Costs. MPC testified in this Docket that its recommended distribution costs are appropriate, given its existing line extension tariff. Although the Commission approved MPC's proposal, it continues to question how optimal line extension policies should relate to distribution and customer (D & C) marginal costs. Should line-extension policies assess the cost causer all costs and if so is such a policy vintage pricing? In other words, should an average of D & C costs be included in a cost study and unusual costs collected via a line extension charge? Does it matter whether average or unusual costs are common or associated with one customer (e.g., the meter)?

528. Second, what is a valid cost perspective for computing D

& C marginal costs, aside from the costs collected in a line extension charge? Options range from MPC's short-run to the long-run. With a long-term perspective, some options include a mortgage estimate, the market value of the D & C system if it were sold, and the cost of incremental capacity expansion. MPC must address the merit of each of these two broad issues in its next cost of service filing.

529. Demand Costing and Pricing. The Commission finds that the issue of how demand costs should be reflected in demand prices remains at issue in this Docket. An example is illustrative. If two different classes are similar in all respects except that the billed demand differed, MPC's costing philosophy in this Docket generates different cost-based unit demand prices. That is, dividing the same total demand costs by different amounts changes the cost-based unit demand cost. Although this method was not debated in this Docket, the Commission remains concerned that the results may be inefficient. Although they surfaced in gas dockets, alternatives to MPC's method exist and include Dr. Dodd's approach in Docket No. 90.1.1 and Mr. Ambrose's in Docket No. 91.3.20. Thus, the Commission finds that MPC must and other parties may revisit how demand costs should be reflected in efficient prices.

530. Meter Reading Technological Changes. The Commission has, for some time, had interest in the operational and COS value of state of the art demand metering technologies. Several concerns will be discussed. First, it is not at all evident to the Commission whether MPC uses the best available metering technology to minimize the costs of measuring consumption (kWh, kW and/or Kvar). Second, it is not clear that utilities have studied collaborative measures to minimize the individual costs of meter reading and billing. Could, for example, utilities share resources used to measure consumption of different regulated services in order to minimize costs? Third, is there merit in rate design changes such as increased demand (kW) metering based on technological improvements in metering?

531. Reactive Power Costs. Since MPC has not proposed

reactive power charges for customers served at levels other than the transmission and substation levels the Commission finds that MPC must determine reactive power costs and charges for such customers in its next cost of service filing. At a minimum MPC must address reactive power costs for its industrial and irrigation customer classes.

532. The Commission is also concerned that the impact reactive power has on capacity costs has not been fully reflected in costs. The Commission finds merit in and directs MPC to examine the possible incentives that could be directed to MPC and its customers to reduce reactive power costs.

533. Incentives To Invest In Cost Effective Technology. The Commission seeks suggestions on incentive mechanisms that encourage cost-effective technological investments. Incentives may have different targets including the utility, other power suppliers and consumers. While not limiting MPC's analysis, this finding is only concerned with utility investments. Are incentives needed for MPC to make investments in cost effective technological advances including, but not limited to, transmission (FACTs) and distribution (automated meter reading)? If yes, what incentives are needed? In evaluating the cost effectiveness of technological investments, MPC must, for consistency, include the avoided costs discussed in the next two findings of fact.

534. Consistent Programmatic Conservation Resource Investments. The Commission's principal concern is for consistent cost treatment between cost of service and programmatic conservation resource investments (PCRIs). Although the source of the generation avoided costs MPC will use is known, the Commission does not know MPC's intent with respect to other cost functions. Thus, the findings below establish the Commission's policies on which MPC must base its cost-effectiveness analysis of PCRIs.

535. The Commission finds that MPC must use this Order's findings on functional and classified costs when analyzing the cost effectiveness of PCRIs. Although the Commission assumes MPC has

included each function's costs in its avoided cost analysis, there occurred some changes in MPC's cost of service study which were approved, but which the Commission wishes to affirm are not excluded by MPC when analyzing PCRIs. For transmission, substation and distribution, MPC must include the costs approved in this Order. The Commission draws attention to MPC's loss cost proposals which this Order approves. MPC must factor the same costs, as avoidable, into its PCRIs made after the issuance of this Order.

Rate Design Policy Issues

The Commission's rate design policy decisions follow.

536. Street Lighting. Street lighting tariffs are no less a point of customer concern than any other tariff. In the past several years, the Commission has received several complaints on lighting rates. The Commission attempts to resolve lighting tariff issues as follows.

537. First, the Commission requests MPC to either file two new street lighting tariffs or make revisions to the existing Company- and Customer-owned tariffs to accommodate the following concern. The Commission finds merit in MPC's offering an optional customer-owned Street Light metering tariff that provides the customer the opportunity to manage the amount of street lighting. A customer can then directly control the annual hours of use and, in turn, the avoidable power costs in MPC's tariff. MPC has 90 days from the date new rates take effect out of this Docket to file a compliance tariff. The customer will be responsible for the cost of converting any lights over to this metered option.

538. Second, although uncertain of the economic benefits, the Commission also requests MPC to analyze and testify on the merits of selling its company-owned street lighting plant to customers (e.g., cities) at original cost less depreciation. This option would allow customers the opportunity to replace worn out plant, bulbs and other routine maintenance instead of having MPC perform the same. It is unclear to the Commission whether customers would

find this option economical given the fact the same customers buying out the plant will have to pay for the recent high pressure sodium vapor conversion costs. So long as the choice is optional the customer can perform its own cost-benefit analysis. At this time MPC need not file a tariff allowing for this option, but its next COS testimony must address the merits of this option.

539. Peak Shaving Time of Day and Interruptible Rates. The Commission commends MPC on its effort to structure optional time of day tariffs. MPC's efforts, however, can be characterized as cautious due to uncertain customer responses and the resulting shifts in revenue requirements. The Commission finds merit in making this topic a central issue in MPC's next COS filing based on the following principles and objectives.

540. As with all other customer classes the design of optional TOD tariffs should be, to the maximum extent, cost-based. In revisiting TOD rates in its next cost filing, MPC must address certain issues, including the following. First, lowering the 1000 kW minimum load to as low as 500 kW must be analyzed. Analysis must include the potential for existing customers to shift tariffs as well as for new customers to take off-peak service. The associated cost savings and shifts in net revenue responsibility must be analyzed. Candidates would likely include larger customers, at least initially, but must eventually include all customers.

541. Second, the Commission finds that MPC must analyze the variation in costs between weekdays and weekends. This analysis must include avoidable energy and capacity costs and distinguish between any seasonal variations in costs. The ultimate purpose of this analysis is to analyze the merit of optional weekday weekend tariffs. As a result, MPC must survey existing customer loads that could cost-effectively shift between the two time periods. The results of these analyses must be included in MPC's next cost of service filing testimony.

542. Third, MPC must also analyze and incorporate

interruptible resources into its cost of service filing. The Commission assumes MPC's 1991 RFP sought sufficient detail on the quality spectrum of the interruptible resources in terms of duration (length of interruption), resource provided (kW and/or kWh), size of resource, timing of interruption (e.g., seasonal) and the reserve requirement benefits, to provide adequate supply curves in the next cost of service filing.

543. Irrigation. On April 18, 1990, the Commission Chairman wrote MPC expressing many diverse irrigation rate design concerns. Although many of these issues overlap with policy concerns contained in this Order, the Commission finds merit in formalizing its concerns by this Order. MPC is directed to, at a minimum, respond to these concerns in its testimony:

1) Time-of-Day Pricing. Would it be rational and efficient to offer an optional time-of-day irrigation tariff?

2) Conservation. Does the irrigation class have a place in MPC's conservation programs?

3) Low Income Irrigators. Is there any merit in treating individual irrigation customers as "low income" for purposes of targeting these customers for conservation investments?

4) Rate Moderation. Is there any merit in moderating the rate impact to any individual customer (e.g., set rate increase limits for specific customers)?

5) Elasticity. What is the ranking of the elasticity of demand for the various irrigation rate design components, e.g., demand versus energy versus the connection charge component?

6) Demand Charges. Is there any merit in continuing demand charges for the irrigation class, i.e., going back to a per kWh commodity charge only?

7) Retention Rates. Is there any merit in irrigation retention rates tied to agricultural commodity rates? For example, the irrigation rate could be tied to the price of hay and/or wheat, much like the EEI rate which was tied to the price of copper in the case of Montana Resources, Inc (MRI).

CONCLUSIONS OF LAW

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

2. The Applicant, Montana Power Company, furnishes electric 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 cost-of-service and rate design approved herein are just, reasonable, and not unjustly discriminatory. Sections 69-3-330 and 69-3-201, MCA.

ORDER

1. Montana Power Company shall provide a detailed cost-of-service study reflecting all of the Commission's cost-of-service decisions included in this Order.

2. Montana Power Company shall compute total and unit

marginal costs for this Docket pursuant to and reflective of the Commission's cost-of-service and rate design decisions and directions contained herein. Also included shall be the specific information requested in Finding Nos. 306-311, as well as other parts of this Order. Montana Power Company must file complete workpapers supporting the above-required information.

3. Montana Power Company must compute class revenue responsibilities for each class pursuant to the Commission's cost-of-service, reconciliation, and moderation decisions as set forth in this Order, as indicated in but not limited to Findings of Fact Nos. 293 through 305.

4. Montana Power Company must also compute prices based on the final base rate revenues approved in this Docket and those approved on an interim basis in Docket No. 91.6.24. Montana Power Company shall also follow the directives provided herein to convert the prices computed based on estimated November 1, 1991, revenues to the revenue level which includes the final revenue requirement in this Docket and interim Docket No. 91.6.24. Montana Power Company shall file workpapers supporting this conversion.

5. Montana Power Company shall compute and file prices computed according to the Commission's methods and direction contained herein. Montana Power Company shall provide detailed workpapers supporting the prices it computes in compliance with this Order. These workpapers should include billing determinants, anticipated revenues generated by each price, and total anticipated revenues generated for each class.

6. Montana Power Company shall submit all reports and studies as directed in this Order.

7. Montana Power Company must file testimony in its next cost-of-service and rate design filing on the various issues for which testimony is required as directed in this Order.

8. Montana Power Company shall provide copies of all

workpapers and tariffs it has been directed to file in compliance with this Order to the Commission and all of the intervenors in this Docket, postmarked October 23, 1991.

9. All other motions or objections made in the course of these proceedings which are consistent with the findings, conclusions, and decision made herein are Granted, those inconsistent are Denied.

DONE AND DATED at Helena, Montana, this 16th day of October, 1991, by a 4 to 0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Chairman

DANNY OBERG, Vice Chairman

WALLACE W. "WALLY" MERCER, Commissioner

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 normally be filed within ten (10) days. See 38.2.4806, ARM. However, due to the length and complexity of this Order, the Commission hereby waives ARM 38.2.4806 and will allow twenty (20) days from the service date of this Order for motions to reconsider. The Commission will also allow 10 days for any replies to the motions.