Service Date: January 31, 1992

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.	))))	UTILITY DIVISION DOCKET NO. 90.6.39 ORDER NO. 5484r (Class Cost of Service)

ORDER ON MOTIONS FOR RECONSIDERATION

TABLE OF CONTENTS

Page

FINDINGS OF FACT

BACKGROUND

On October 17, 1991 the Montana Public Service Commission (Commission) issued Order No. 5484n, the Final Order on electric class cost of service/rate design (COS/RD) in this Docket. In Order No. 5484o (Docket No. 90.6.39, November 5, 1991) the Commission stayed implementation of Order No. 5484n pending reconsideration. On or around November 6, 1991 the Commission received motions for reconsideration (and accompanying briefs) of Order No. 5484n from the Montana Power Company (MPC), the Large Customer Group (LCG), and Rhone-Poulenc Basic Chemical Company (RP). On or around November 25, 1991 the Commission received reply briefs from District XI Human Resource Council (HRC), the Montana Consumer Counsel (MCC), and MPC. On December 4, 1991 LCG filed a motion to strike a portion of HRC's reply brief. HRC filed a response to that motion on December 11, 1991. This Order disposes of motions on class cost of service. For the reasons described below, motions on rate design issues will be addressed in a subsequent order.

Motion to Strike

LCG moved to strike parts B, C and D, pp. 14-19, of HRC's reply brief, contending that this part of the brief contains new evidence, argument and theories to support MPC's position on marginal distribution capacity costs. HRC responded that a motion to strike is inappropriate, that its reply brief consists of argument based on the record, and that its reply brief is not part of the evidentiary record.

With one exception noted below the Commission agrees with HRC that the part of its brief in question consists of arguments from the record and in response to LCG's initial brief. HRC is free to argue for the conclusions it thinks the Commission should reach from the record, as it did in a post-hearing brief. HRC is also free to disagree with LCG, both over conclusions that can be supported by the record and over conclusions that should be drawn from the record, as it did in its reply brief on reconsideration. HRC's reply brief contains legitimate argument. The Commission will strike HRC's references to "HRC 4, pages 13-26" at page 18, line 5 of its reply brief because those pages were made part of the record in Docket No. 90.1.1 (see HRC 1 and TR 1284). Other than this, LCG's motion to strike is denied.

Use of A Preliminary COS Study.

Summary of The Issue, Motion, and Reply. MPC holds that, due to the changes in the COS study contained in its compliance filing versus the costs used by the Commission to design illustrative rates, the Commission should "... evaluate its rate designs in light of the final cost study contained in the compliance filing" (MPC Motion for Reconsideration (MFR), p. 14). MPC also notes that if further changes in costs result from MFRs, prices must be reconsidered.

HRC suggests that staff represents the public interest during the order writing process, a time in which cost studies are exchanged between staff and the company. HRC requests, however, that the Commission make those data available to other parties (HRC Reply, pp. 7-8).

Commission Decision. MPC appears to be requesting that the Commission reconsider its rate designs pursuant to MPC's COS and RD compliance filing to Order No. 5484n. This is impractical given the Commission's reconsideration of Order No. 5484n. Instead, the Commission will use the following procedure to process the motions for reconsideration of Order No. 5484n.

As it did in its deliberation of the issues in the Final Order, the Commission will rely on MPC's computation of costs reflecting the Commission's COS decisions in this Order to examine reconciliation, moderation, and rate design (see Order No. 5484n, FOF 310). However, to alleviate possible inconsistencies between rates based on a draft COS study and a final compliance study, the Commission has chosen to bifurcate the COS and RD portions into two orders on reconsideration. This Order will address only COS issues and a later order will address reconciliation and RD motions. The Commission considers it appropriate to first review the results of its COS decisions prior to finalizing its reconciliation/moderation and RD decisions. MPC is directed to make a compliance filing pursuant to this Order and Order No. 5484n within seven days of the service of this Order. MPC shall provide this compliance filing to MCC, HRC, LCG, FEA, RPC and MII. These parties should direct any comments on the filing to the staff as soon as possible thereafter, but no later than seven days following receipt of the filing from MPC.

Classified Generation Costs

Summary of the Issue. At Findings of Fact (FOF) Nos. 245-252, Order No. 5484n, the Commission rejected MPC's proposed method of classifying generation costs between energy and capacity. Instead, the Commission adopted a classification method previously adopted in Order No. 5506a, Docket No. 90.8.51. The Commission based its decision on Order No. 5506a and on the testimony of three witnesses: Drzemiecki (MCC), Johnson (FEA), and Power (HRC) (see Order No. 5484n, FOFs 249-252). The Commission directed MPC to apply the method the Commission adopted in Order No. 5506a (henceforth the BGI method) to the data used to compute costs in the instant Docket (Id., FOF 240).

Motions and Replies. The following summarizes MPC's and LCG's objections to the Commission's decision and MCC's and HRC's responses. MCC and HRC supported the Commission's decision in their replies to MPC's and LCG's MFRs.

Use of Extra-Record Evidence. MPC and LCG argue the Commission cannot base its decision on extra-record evidence such as that used in Docket No. 90.8.51. MPC notes that several parties objected to making the compliance filing made pursuant to Order No. 5506a, Docket No. 90.8.51, part of the record. MPC notes the filing was never made part of the record (MPC MFR, pp. 1-2). LCG contends the use of the evidence from the BGI case deprived the parties of their due process rights (LCG MFR, pp. 21-23). LCG also argues that the classification method was uncontested, was not addressed as an issue, and that the BGI case did not pertain to class COS allocation issues (Id., p. 20).

MCC argues the record contains sufficient evidence which the Commission recognized in support of its decision. MCC summarized this evidence as follows. First, the Commission rejected MPC's proposed classification method based on FEA's position that capacity costs may be over-estimated, a position MPC did not rebut. Second, the Commission cited MCC's argument that marginal capacity costs should never exceed the cost of the generating unit with the lowest per kW fixed cost of capacity. Third, the Commission recognized HRC's objection to MPC's method. Thus, MCC notes that the Commission's decision was based on reasoning MPC and LCG have omitted from their motions. MCC argues the Commission is entitled to accept these positions.

MCC also asserts the Commission's decision results in a logical link to the method it approved for computing transmission costs (MCC Reply, pp. 2-4. See also Order No. 5484n, FOF 253-255). MCC also suggests that, since intervenors criticized MPC's classification method which produced a specific rate design and the Commission agreed with these criticisms, MPC has failed to meet its burden of proof that rates are just and reasonable (MCC Reply, p. 3).

Notice of the 90.8.51 Decision. MPC and LCG argue that parties were not given adequate notice of the Commission's plans to use its decision out of Docket No. 90.8.51. MPC maintains the parties did not have adequate notice that the Commission's staff was planning to introduce the BGI compliance filing into the record or that the Commission might use the filing in its decision (MPC MFR, p. 3). MPC also argues that if the changes ordered in the BGI case were used in this Docket, the result would be higher energy and lower capacity costs relative to those proposed by MPC (Id.). MPC notes that HRC and LCG opposed including the BGI compliance filing data in the record. Further, MPC maintains that if new data, such as those included in the BGI compliance filing, are to be used, parties must be afforded the opportunity to scrutinize or rebut the use of those data (Id., p. 4). MPC asserts this violates due process. LCG echoes MPC's concern (LCG MFR, p. 23).

Both MCC and HRC responded to these arguments. MCC notes the Commission required MPC to use the data contained in the record in this proceeding (MCC Reply, p. 5). HRC concurs that the Commission did not adopt the "facts and figures" from the 90.8.51 Docket, but adopted the method MPC proposed to compute the BGI avoided cost rates (HRC Reply, p. 2). HRC also asserts the Commission can adopt policy in a variety of ways, such as through orders and based on its expertise.

In response to LCG's contention that the Commission would be required to provide judicial notice of its decision in Docket No. 90.8.51 in order to use that decision in this case (LCG MFR, pp. 24-25), MCC responds that it has not been previously necessary to notice all orders the Commission may rely upon in its decisions (MCC Reply, p. 4).

MFR to Order No. 5506a (Docket No. 90.8.51). MPC and LCG argue that the Commission's reference to the fact that MPC did not file a MFR in the BGI case is irrelevant to the Commission's adoption of the BGI method. MPC holds it is "... free to present a cost of service analysis using any methodology which it believes is appropriate" (MPC MFR, p. 5). MPC claims that the method it used in this case conformed with a previously approved Commission method, disagrees with the BGI method, and believes the method it used in this case is correct. MPC contends it is not bound to the BGI method and the Commission did not intend to make the BGI method permanent.

MCC responds that all of the Commission's orders are subject to future review. MCC also argues that none of the parties proved there is a classification method superior to the BGI method previously approved (MCC Reply, pp. 3-4). MCC notes that prior dockets set precedent and that departure from such precedent must be supported (MCC Reply, p. 4).

LCG reminds that neither it nor most other parties to this Docket were parties to Docket No. 90.8.51. As such, the Commission's use of the fact that MPC did not file a MFR of Order No. 5506a as support for its decision in this case is irrelevant

(LCG MFR, pp. 25-26). LCG also argues that the Commission can use its specialized knowledge to evaluate evidence but not as evidence (LCG MFR, p. 26).

HRC Observations. HRC identifies two advantages of the Commission's decision, although HRC "... does not maintain the BGI approach is perfect" (HRC, Reply, p. 3). First, the Commission's adopted classification method results in a higher energy and lower capacity cost using data in this Docket. Second, the method reduces the difference between the avoided cost treatment and generation cost treatment in allocated COS rate cases, an issue raised in the past.

Commission Decision. The Commission denies MPC's and LCG's motions to reconsider its generation classification cost decision in Order No. 5484n. The Commission's reasons for denying these motions, along with certain other responses and replies to the motions are set forth below.

First, and most importantly, neither a "whole new set of data," nor any other extra-record evidence of the sort proscribed by the ample authority cited by MPC and LCG, was used by the Commission in Order No. 5484n. The load and resource data used are from MPC's July, 1990 avoided cost compliance filing as incorporated into this Docket by MPC (FOF 240). Obviously, all parties were on notice of these data. The Commission did reject MPC's July, 1990 method to classify generation costs between energy and capacity, in favor of a method the Commission had approved in Order No. 5506a. This decision was proper.

The objection that the Commission cannot refer to its previous orders seems to be a serious misunderstanding of the decision-making process. Consider the following analogy. Suppose a judge, sitting as both trier of fact and law, presides at a trial where evidence is introduced to establish a record from which the judge can determine the facts. At the close of the trial an issue of law is raised that the judge allows the parties to argue and brief. The judge considers the arguments, does some independent research, and decides the issue of law based on a case that was not cited by any party. The Commission posits that it would be incorrect to argue that the judge's decision cannot stand because it relies on evidence (the case cited by the judge) not in the record. Yet, this is the argument made by MPC and LCG.

The Commission, as agency decision-maker is, for purposes of this discussion, in the same position as a judge. The proper classification of generation costs between energy and capacity is a policy decision for the Commission. It is not a matter of determining adjudicative facts on the record (the who, what, when and where of utility rate cases), as the Commission did in Order No. 5484n when it accepted the generation cost data from MPC's July, 1990 avoided cost filing, data that were not challenged by any party. In fact, as indicated in Order No. 5484n, as further discussed in this Order, and as pointed out by MCC, there is discussion in the record on this issue from which the Commission can and did draw in making its decision. Howev er, even absent such discussion, the Commission would be free to reject the policy proposal of MPC based on its own reasoning (which may be reflected in its prior decisions) or the reasoning of others as reflected in decisions from other jurisdictions or in ratemaking literature.

MPC contends it is "free to present a cost of service analysis using any methodology which it believes is appropriate." The Commission agrees. Similarly, intervenors are free to criticize that methodology. Also, the Commission is free to reject the methodology presented by MPC in favor of a methodology which the Commission deems more appropriate; in doing so the Commission is free to refer to one of its prior orders. Previous Commission orders are not evidence, any more than case law is evidence when referred to by a court. A court does not have to give notice to parties of the case law it will use to support a decision. Similarly, the Commission is not required to notify all parties of other relevant Commission decisions and afford an opportunity on the record to respond to all conclusions that might be supported by those decisions.

The Commission finds that in the course of reaching a decision on an issue it is not only permitted to refer to previous decisions, it is in most cases well-advised to refer to previous decisions. There are many issues that are common to nearly all rate cases, and there are many issues that are similar from one rate case to another such that an appropriate analogy may be made from one issue to another. Reasoned decision-making requires that the Commission make the necessary connections between its decisions in current cases and its decisions in past cases. In this case MPC proposed a method for classifying generation costs. Several parties criticized that method. The Commission took note of those criticisms, as well as its own discussion of that method from a previous order, and decided not to approve MPC's proposed method. The Commission finds that this decision-making procedure was appropriate and did not violate due process, case law, or statutory authority.

The ample authority cited by MPC and LCG may support the proposition that for the most part decision-makers may not rely on extra-record evidence without notice and opportunity to the affected parties to be heard. That authority, however, is not relevant to this proceeding, because the Commission relied on no such evidence contemplated by the case law cited or the Montana Administrative Procedure Act. For authority supporting the Commission's ability to refer to its previous decisions, the parties are referred to Illinois Central Railroad Company v. Thomas Alabama Kaolin Company, 275 Ala. 236, 153 S.2d 794, 796 (1963) ("The |Alabama Public Service¬ Commission is, of course, permitted to take cognizance of its own orders.") and Capital Packing Company v. United State of America, Interstate Commerce Commission, 167 F.Supp. 420, 424 ("The |Interstate Commerce¬ Commission is an expert body within its field. Part of that experience comes from its experience in previous cases. Certainly, in our opinion, the Commission has the right to refer to ex perience in other cases as a guide for the application of its expert knowledge in a particular case." Citing Ward Transport v. United States, 125 F.Supp. 363, 368). For a detailed general discussion of this area of the law see McCormick on Evidence (2d Ed. 1972) <<335 and 357; also 2 Davis, Administrative Law Treatise, ch. 15 (1958); and 3 Davis, Administrative Law Treatise, ch. 15 (1980).

The foregoing addressed the fundamental legal objection to the Commission's decision classifying generation costs. The parties made several other comments on objections to the Commission's decision on this issue that will be discussed below.

First, LCG maintains classified generation costs were not an issue in the Docket. It should be clearly evident that both FEA's and HRC's criticisms of MPC's method, as cited in the Commission's decision (Order No. 5484n, FOF 249 and 252), gave rise to the issue in this case. As noted in Order No. 5484n (FOF 250), MPC did not rebut FEA's criticisms. Further, MCC's argument, as summarized at FOF 251, Order No. 5484n, addresses the same issue.

Second, LCG maintains the BGI case did not pertain to class COS allocation issues (Id., p. 20). As HRC points out in its reply brief, this issue is not new to this case (HRC Reply, p. 3). The Commission addressed the same issue in Docket No. 87.4.21. In that case the Commission found that MPC had used its 1986 loads and resources plan (1986 plan) to develop generation costs for its retail rate COS study and its 1987 plan to develop avoided cost payments to qualifying facilities (QFs). In that case the Commission also agreed with Dr. Power's testimony that there should be no disparities between the relative price movement between capacity paid to QFs and that charged to retail customers. Hence, the Commission ordered MPC to recompute its generation costs based on its 1987 plan (see FOFs 66-67, Order No. 5340).

Although the issue in Docket No. 87.4.21 involved the use of different loads and resources plans, the Commission finds the general issue regarding differences between avoided generation costs used for resource procurement and marginal generation costs used for retail rate making remains the same. As pointed out by MPC witness Maxwell, use of the changes ordered in the BGI case would result in increasing the energy cost and decreasing the capacity costs relative to the same costs proposed by MPC in the instant Docket (TR 1056-1057). These results confirm Dr. Power's testimony in Docket No. 87.4.21. In that Docket Dr. Power maintained the Commission "... should not be simultaneously lowering capacity payment to QFs while raising capacity charges to retail customers" (quoted at FOF 67, Order No. 5340). In Docket No. 90.8.51 the Commission found that the method MPC used to compute

BGI's rates is consistent with the guidelines of Order No. 5091c (Order No. 5506a, FOF 50). In the same Docket the Commission directed MPC to revise its July, 1990 avoided cost compliance filing, pursuant to Order No. 5091c, using the BGI method (Id., FOF 56). Thus, by using the July, 1990 avoided cost classification method for retail rates and the BGI method for avoided cost rates, there would remain a disparity between prices paid for resource procurement and the costs used to compute retail rates. It was to avoid this disparity that the Commission decided to apply the BGI method to the load and resource data from the July, 1990 avoided cost compliance filing to classify generation costs.

Third, MCC asserts that the decision on classifying generation costs logically relates to the Commission's decision to compute transmission costs based on the cost to connect a peaking unit to MPC's system (MCC Reply, pp. 2-4). The Commission finds this reasoning unsound. To presume the Commission's approved generation classification method is based on its decision on transmission capacity costs would be incorrect. In this Docket the Commission's COS decisions for each of the general cost functions (e.g., generation and transmission) are independent of one another with one exception. In Order No. 5484n the Commission found it reasonable to use the single coincident peak (1 CP) to allocate voltage level capacity costs which included generation capacity loss costs (Order No. 5484n, FOF 279-280). The Commission also found it reasonable to adopt MPC's proposed short-run marginal distribution cost approach which consisted of marginal generation loss costs only (Id., FOF 258-259 and 279). Further, the Commission reasoned that, since marginal distribution capacity costs are generation-related, placed at the distribution level these costs should be allocated using a 1 CP (Id., FOF 279). An extension of MCC's logic would be that, since distribution costs are short-run, then so too should generation costs. This is not the case.

Fourth, at FOF 245 of Order No. 5484n the Commission does appear to conclude that its decision to adopt the BGI method is related to MPC's decision not to file for reconsideration of Order No. 5506a. MPC correctly points out that, for purposes of a Commission decision in this Docket, it is irrelevant whether MPC asked for reconsideration of a previous order. Therefore, the Commission hereby deletes the fourth sentence of FOF 245. This deletion does not affect the Commission's decision expressed at FOF 245.

Finally, the Commission will revisit MPC's capacity cost amendment as follows. This issue relates to the Commission's direction in Finding No. 311, Order No. 5484n. There the Commission directed MPC to document any changes in total generation avoided costs. The Commission noted that such costs would not change if different classification methods were used. The background to that direction follows.

MPC proposed that marginal generation capacity costs be computed using a combination of purchased capacity from BPA at its NR-89 rate (MPC RDR FEA-6) and the nominal annual capacity costs from its July, 1990, avoided cost filing. The first four years of the ten-year cost stream were comprised of the BPA rate and the last six were taken from the July filing. MPC justified using the BPA NR-89 rate, which comprises the above noted amendment, due to its expected capacity deficiency not shown in the July, 1990 avoided cost filing (Exh. No. MPC-40, pp. 14-15). Although it computed marginal generation costs over a 25 year period, MCC adopted MPC's amendment and used the July, 1990, avoided cost data for the remaining 21 years.

MPC amended the results of its determination of annual nominal marginal capacity and energy costs from its July, 1990 avoided cost filing (cf Exh. No. MPC-40, PEM-3 and MPC RDR FEA-19). Consistent with this method the Commission directs MPC to compute generation costs in a manner that will mirror this approach using the BGI classification method. To do this MPC must use the following approach. The July, 1990 avoided generation costs would be recomputed using the BGI method. Using this approach the Commission finds it logical to assign a zero value to capacity costs during years in which the loads and resources forecast shows excess or sufficient capacity. For instance, using 25 year's of avoided costs as the basis for marginal generation costs, the base-case peak forecast included in MPC's July, 1990, avoided cost filing shows excess capacity during the contract years 1990-1991 through 1995-1996 (see MPC RDR PSC-521 a and b, work papers, p. 45). Thus, annual nominal capacity costs would be zero from 1992 through 1995 and valued at the BPA NR-89 rate for the remaining 21 years.

To eliminate the possibility of double counting transmission line losses, as noted in Order No. 5484n, FOF 286, the

Commission directs MPC to remove any transmission line loss adjustments made to energy costs to the extent these adjustments are incorporated in the base-case and/or change-case generation costs. The resulting 25 year stream of capacity costs would be supplemented with the capacity cost amendment as proposed by MPC and adopted by MCC. MPC must continue to adhere to Finding No. 311, Order No. 5484n. However, total generation costs may not precisely equal MCC's 25 years of generation costs, since MCC's allocation of generation capacity costs differ from the method approved by the Commission.

As a result of adopting MPC's amended marginal capacity costs, the Commission finds that real levelized marginal generation capacity costs used for rate making would exceed real levelized avoided generation capacity costs used for QF pricing for an equivalent number of year's costs. Thus, there would continue to be a difference between the capacity costs used for avoided cost QF pricing and marginal cost-based retail rates. This difference appears to be the result of applying MPC's proposed amendment which, in turn, appears to stem from MPC's suggested capacity deficiency based on the loads and resources forecast used by Mr. Leland (Exh. No. MPC-20, pp. 25-27 and RJL-6 and 7; MPC RDR MCC-119, Attachment, Exh. E). This forecast appears to differ from that used as a partial basis for MPC's marginal generation capacity costs (1996-2001) (Cf. id. and MPC RDR PSC-521). The Commission intends to address such differences in future dockets.

Programmatic Conservation Programs

Summary of the Issue. Out of a concern for consistency of cost treatments between retail COS and programmatic conservation resource investments (PCRIs), the Commission directed MPC to use the COS study approved in this Docket to evaluate the cost-effectiveness of PCRIs (FOFs 534-535, Order No. 5484n). MPC objected and HRC supported the Commission's decision. The parties' positions are summarized in turn.

Motions and Responses/Replies. MPC maintains the COS study in this Docket was not indented to be used to evaluate the cost effectiveness of PCRIs. MPC holds this Docket is an inappropriate forum in which to decide the analytical basis for the cost effectiveness of conservation resource acquisitions. MPC asserts the appropriate forum is a proceeding in which the issue can be debated by all interested persons. MPC further argues that this issue was not raised in this proceeding and is irrelevant to the issues in this Docket. MPC asserts it would be inappropriate to require MPC to make cost-effectiveness decisions based on the Commission's COS decisions in this Docket, decisions on which MPC disagrees (MPC MFR, p. 10).

Although HRC asserts that more guidance and further discussion will be required, the Commission's decision provides information about the standard by which conservation resources will be evaluated. HRC maintains that the Commission's policy regarding consistency between programmatic conservation and other resources is important. HRC supports the Commission's findings (HRC Reply, p. 6).

Commission Decision. The Commission finds this issue closely related to classified generation costs with respect to resource acquisitions and retail rate making. The Commission reaffirms its decision in Order No. 5484n on this issue as sound policy, and thereby denies MPC's motion. The use of the COS decisions out of this Docket to assess the cost effectiveness of PCRIs and the decision to use the BGI method to classify generation costs would result in narrowing the gap between resource acquisition costs and costs used as a basis for retail rates.

Further, the Commission questions the consistency of MPC's argument on this matter and its position in the least cost planning Docket. In Docket No. 90.8.49, one of MPC's opening comments indicated that integrated least cost resource planning (ILCRP) could be used for, among other things, programmatic conservation acquisitions and rate design (Opening comments presented by John Leland, Docket No. 90.8.49 Conference, October 1 and 2, 1991, p. 7). Although MPC objects to the use of COS decisions and results out of this Docket to assess the cost effectiveness of PCRIs, the Commission wonders whether MPC would resist using the same costs developed for all resource acquisitions and retail rate making. Most prominent among these concerns is the use of different generation cost classification methods, or studies in general including load and resource data as was the case in Docket No. 87.4.21, to acquire resources and to design retail rates. Yet, in the least cost planning Docket, MPC stated an ILCRP could be used for programmatic conservation acquisitions and rate design. MPC's positions in this Docket and Docket No. 90.8.49 appear contradictory.

Finally, at Finding No. 535, Order No. 5484n, the Commission directed MPC to include the transmission, substation, and distribution costs approved in that Order to analyze the cost effectiveness of PCRIs. The Commission directs MPC to use the costs for these functions that result from both this Order, to the extent that the Commission's COS decisions in this Order affect those costs, and from Order No. 5484n.

Distribution Costs

Summary of the Issue. MPC proposed marginal distribution costs consist of losses only (henceforth the MPC method); MCC proposed embedded costs as a proxy for long-run incremental costs; and LCG proposed the Commission adopt the method it approved in Docket No. 87.4.21 (henceforth the 87.4.21 method). The Commission adopted MPC's proposal (FOFs 258-262, Order No. 5484n) and LCG filed a motion for reconsideration of the Commission's decision. HRC supported the Commission's decision.

Motions and Responses/Replies. The following summarizes LCG's motion and HRC's reply regarding marginal distribution costs. LCG's arguments pertain to the theoretical and factual support for MPC's proposal, the use of a speculative line extension policy to recover plant costs, the rejection of MPC's proposal by non-MPC witnesses, the cost-shifting nature of MPC's proposal, and the evidentiary support for the 87.4.21 method. Although the fourth issue is related to reconciliation, it will be addressed in this section to preserve the cohesiveness of the over-all issue. Each of the above arguments is summarized in turn (in an order different from that in which they appear in LCG's MFR).

Theoretical Basis For The MPC Method. LCG argues MPC's proposal was supported by a single witness (Mr. Maxwell) whose opinion was not factually or theoretically based. LCG maintains the record shows no meaningful support for MPC's proposal and the discussion of the proposal is limited. LCG maintains MPC's proposal is unprecedented and a "radical departure" from the 87.4.21 method (LCG MFR, p. 5). LCG also maintains that neither MPC nor any other utility ever used the MPC method before. Further, LCG claims the MPC method has not been approved by this Commission or any other state commission nor is the method based on any study, technical literature, authority, or generally accepted marginal distribution cost method found in the technical literature (Id., pp. 6-8).

HRC maintains the record supports the Commission's decision and the MPC method has a "firm and familiar basis" (HRC Reply, p. 14). HRC maintains MPC's method is supported by substantial and credible evidence and that other parties' positions regarding the MPC method were motivated by "fairness and policy implications of applying it in this case" (Id.). Further, HRC alleges MPC "... measured marginal distribution capacity costs exactly the way LCG would suggest the Commission measure marginal energy costs" (Id.). HRC asserts that MPC concluded the marginal distribution cost for an existing customer is increased capacity losses due to the redundant nature of the design of the distribution system "for reliability and economy of scale purposes" (HRC Reply, p. 14). HRC also asserts MPC's method would be considered a long-run marginal cost approach if the system is designed to be redundant for its economic life in order to meet peak demand (Id., pp. 16-17).

LCG's Argument Regarding Line Extensions. LCG argues that MPC's suggestion that any changes in plant costs should be recovered through a line extension policy constitutes speculation on a policy not in place. LCG maintains such a speculative policy cannot serve as a basis for the Commission's decision. LCG asserts such a policy does not have a factual basis in the record or in MPC's operating history.

LCG also maintains MPC's method does not recognize its expenditures on its distribution system in 1987 through 1989. LCG claims MPC continues to expend funds on its distribution system. Additionally, by citing Finding No. 527, Order No. 5484n, LCG alleges the Commission continues to doubt the relationship between marginal distribution costs and future line extension policies. Further, LCG asserts MPC's line extension policy argument is inappropriate since such policies relate to pricing and cost recovery and not marginal cost (LCG MFR, pp. 10-13).

HRC asserts Dr. Power's analysis (provided at TR 1291-1292) suggests MPC's distribution investments could not correctly be designated as only capacity costs, since most distribution costs are incurred not only to meet expanding loads for existing customers, but to extend service to new customers. HRC suggests this is one of the major reasons the costs are incurred. HRC maintains this is the reason MPC recommended reenforcing its line extension policy to better reflect costs. HRC concludes the reasoning is logical, not speculative (HRC Reply, pp. 14-15).

LCG's Appeal to the Testimony of Non-MPC Witnesses. LCG asserts that each of the non-MPC witnesses addressing MPC's method rejected it as improper. LCG maintains HRC witness Power "... testified that MPC's ongoing investment in the distribution system must be included in its marginal costs, and was in fact not included in Mr. Maxwell's short-run analysis" (LCG MFR, p. 15). LCG asserts HRC also rejected a short-run analysis such as MPC's and supported a long-run approach. Next, LCG maintains RPC witness Lanou held that the method approved in Docket No. 87.4.21 was more appropriate than MPC's since some marginal costs needed to be recognized for distribution. Further, LCG recites FEA's testimony which states MPC's method of computing marginal distribution costs is improper and is not used in any oth er jurisdiction. LCG asserts HRC's, RPC's, and FEA's views are consistent with the views of its own witness (Mr. Michael) on this issue (LCG MFR, p. 17).

HRC argues LCG misinterpreted and misused Dr. Power's testimony to support its case. HRC maintains Dr. Power does not support the method LCG proposes, but opposes it as "... unworkable, illogical, couterfactual, and the source of unstable results" (HRC Reply, p. 18). HRC notes that even though part of Dr. Power's testimony addressed transmission costs, the analysis also applies to distribution costs. Further, Dr. Power did not state MPC's method lacked capacity costs. HRC maintains Dr. Power's point was that capacity costs should not serve as the residual of non-energy or customer costs. For the marginal cost analysis to be complete, costs such as marginal reliability, quality-of-service, and access costs would also need to be computed. Additionally, HRC contends that Dr. Power's testimony cannot be used to "selectively attack one marginal distribution cost method and support another" (HRC Reply, p. 19).

LCG's Cost Shifting Argument. LCG alleges the MPC method ignores $50 million of marginal distribution costs. LCG asserts these costs are shifted to all customer classes through the reconciliation process, $7 million of which are shifted to the Substation class. LCG notes the substation class is not served by the distribution system (LCG MFR, pp. 5-6).

HRC characterizes LCG's objections as a combination of embedded and marginal cost concepts as well as short and long- run marginal cost considerations. HRC supports its characterization as follows.

HRC characterizes LCG's concern that the MPC method understates distribution costs, even though such costs are incurred, as an embedded cost approach. HRC argues that many accounting costs are not marginal costs. For instance, HRC argues that the costs not associated with a particular service should not be combined with the marginal costs of that service (HRC Reply, p. 16). Regarding LCG's disagreement with MPC's distribution cost method as a short-run marginal cost (SRMC) or variable cost approach, HRC asserts LCG supports using a variable cost approach for computing marginal energy costs (Id.).

HRC also argues that while LCG criticizes MPC's use of the equal-percentage reconciliation method, LCG uses the method. HRC notes that use of this method results in arbitrarily shifting embedded costs among classes (HRC Reply, p. 16).

HRC argues LCG's objection to the MPC method is embedded cost based. HRC claims LCG's primary argument pertains to marginal distribution cost methods due to the impact different methods would have on their class revenue requirement through equal-percentage reconciliation. HRC argues LCG is not interested in whether marginal costs are correctly computed, but objects to the reconciliation process. HRC contends LCG is objecting to the use of marginal costs. HRC notes that marginal costs have been accepted in the Montana courts and LCG's objection should be dismissed. HRC holds the Commission has a firm ground for its use of marginal costs (Id., p. 17).

Factual and Theoretical Basis For The 87.4.21 Method. LCG maintains the 87.4.21 method is supported by substantial record evidence. LCG maintains it computed and presented an unchallenged replica of the 87.4.21 method. LCG holds this method has a theoretical basis in the literature and cites two publications in this regard (LCG MFR, pp. 17-20).

LCG maintains the logic underlying the Commission's application of HRC's transmission cost criticisms to LCG's distribution costs is "strained" when applied to the 87.4.21 method. LCG also asserts that HRC "... disagreed with both Mr. Maxwell's proposal and the prior Commission-approved method ..." (LCG MFR, pp. 18-19, emphasis in original). LCG asserts that the deficiencies in its proposed study, as listed in FOF 262, Order No. 5484n, should have been addressed at the hearing. LCG suggests the Commission direct MPC to use the method approved in Docket No. 87.4.21 to resolve these concerns. LCG maintains such uncertainties cannot be used to support the MPC method.

Commission Decision. The Commission reaffirms its decision to adopt MPC's proposed distribution cost method and thereby denies LCG's motion on this issue. The following discussion addresses LCG's legal objection, expands on the Commission's discussion of this issue in Order No. 5484n, summarizes the theoretical basis upon which the Commission's decision rests and addresses each of LCG's arguments and HRC's responses summa rized above. The application of the economic theory is discussed as it applies to each of the first three arguments described above. LCG's cost-shifting argument will be addressed, followed by a discussion of LCG's marginal distribution cost computations. The Commission will also summarize the areas in which MPC is to further examine the appropriate methods used to measure and compute marginal distribution costs and will also address some remaining uncertainties with the MPC method not addressed in the Final Order.

The Legal Issue. The LCG argues that there is not substantial credible evidence in the record to support the Commission's decision on marginal distribution capacity costs. The Commission disagrees.

Numerous times the Montana Supreme Court has described the standard that the Commission must adhere to when making decisions: Commission decisions must be reasonable and supported by sufficient evidence that is capable of being believed. Montana Power Company v. Department of Public Service Regulation, 204 Mont. 224, 229-230 (1983); Commission decisions must be supported by substantial credible evidence, Public Service Commission v. Montana Irrigators, 209 Mont. 375, 381 (1984); Commission decisions must not be "clearly erroneous in view of the reliable, probative and substantial evidence on the whole record;" and if the record contains support for a decision then "the courts may not weigh the evidence." Montana-Dakota Utilities Company v. Public Service Commission, 223 Mont. 191 (1986).

With this issue the Commission had to decide what costs are appropriately included as marginal distribution capacity costs. MPC's marginal cost of service study indicated that "The marginal cost of supplying an additional unit on the distribution system, either capacity or energy, is losses only" (Exh. No. MPC-40, p. 18). Implicit in this conclusion, an implication not challenged by any party, is that MPC's distribution system is designed to serve the foreseeable load of existing customers. MPC's position was not fully supported by any party. As will be discussed below, however, the underlying theory behind MPC's position was supported by HRC witness Power and is further supported by the Commission and economic literature. MPC's position on this issue is credible and capable of being believed. Furthermore, the following discussion will demonstrate that the Commission's decision was reasonable given the options proposed by other parties.

LCG's cross-examination on this issue, as described in its motion, demonstrated that MPC witness Maxwell was not well prepared to defend the Company's position on this issue. (Mr. Maxwell is not alone in his relative neglect of the appropriate measure of marginal distribution costs. Since its inception, marginal cost analysis in ratemaking has focussed primarily on generation costs.) There is a distinct difference, however, between undermining a witness and undermining the position he is espousing. MPC may not have adequately explained and defended its own position; however, the Commission can buttress that posi tion by referring to other evidence on the record and by using its own expertise. As will be discussed below, the Commission does not find that MPC's method is perfect; but it is credible and preferable to the alternatives.

Theoretical Basis For The MPC Method. First, the Commission finds LCG's claim that neither MPC nor any other utility has used a method similar to MPC's proposed method is not accurate. The Commission finds that similar methods (line losses only) were proposed in Docket Nos. 90.3.20 (Great Falls Gas Co.) and 90.1.1 (MPC). In Docket No. 90.3.20, GFGC witness Bruce Ambrose favored the use of SRMC. He divided the distribution system into high and low-pressure segments which are synonymous to the primary and secondary electric distribution segments. For the high-pressure segment, GFGC proposed that the marginal costs are nearly zero since GFGC lacks any need for additional capacity. (See GFGC Exh-4, Docket No. 90.3.20.)

In Docket No. 90.1.1 MPC witness Falvey abandoned his initial marginal distribution cost method as a result of testimony by Department of Natural Resources and Conservation (DNRC) witness John Tubbs. Mr. Tubbs maintained that capacity charges should be excluded from marginal distribution costs and doubted that capacity was a constraint on the distribution system (Order No. 5474c, FOF 289, Exh. No. MPC-27, pp. 7-8, and Exh. No. DNRC-1, p. 23). Although Dr. Falvey proposed a method which excludes all capacity costs, he maintained the method was not perfect. Dr. Falvey believed that MPC's distribution system could "... accommodate additional load without additional investment" (Order No. 5474c, FOF 287). MPC used this approach throughout Docket Nos. 90.1.1 and 90.6.39.

Daniel Dodds, another DNRC witness, estimated that, since MPC stated there is excess capacity on its gas distribution system, the marginal cost of providing additional peak capacity is zero (Exh. No. DNRC-3, p. 15, Docket No. 90.1.1). The Commission based its Order on a stipulation among several of the active intervening parties in Docket No. 90.1.1 (see Id., FOF 11-12). However, the Commission's Order did not express any support or acceptance of any particular marginal cost analysis, cost classification, or allocation method (see generally Order No. 5474c, FOF 313-315).

Second, although Mr. Maxwell could not cite any "... authority or technical literature that specifically supports or endorses ..." his distribution cost approach (TR 1001), the Commission finds there is substantial evidence on the record and in economic literature supporting MPC's method.

Generally, long-run marginal costs (LRMC) are those costs that would vary during a time period sufficiently long enough to vary all inputs. Conversely, the short-run is a time period during which some inputs are fixed and, thus the costs associated with those inputs would not vary with changes in production. The "marginal cost" aspect of long or short-run marginal costs pertains to costs that would be incurred to provide the next unit of service (1 kW of capacity in this instance) or the costs that would be avoided if one less kw of capacity were demanded.

MPC claimed its marginal distribution costs are long-run (TR 1012). MCC asserted that MPC's distribution costs would be considered long-run if the system possessed excess capacity (Exh. No. MCC-6, p. 57). Also, HRC asserted the MPC method may be considered a "relatively long run" approach if the distribution system were redundant over its economic life such that increased demand for peak capacity would not cause system upgrades (HRC Reply, pp. 16-17). Although each of these positions may have merit, for the purposes of this issue in this case, the Commission will proceed as if the MPC method, which excludes capacity investment costs, is a short-run approach. Further, the Commission will identify the 87.4.21 method, which treats all distribution investments as marginal capacity costs, as tending toward a long-run approach.

The Commission finds that the issue of whether the MPC or the 87.4.21 method should serve as the basis for marginal distribution capacity costs rests on the theoretical basis for each method and whether the record in this case supports one method over the other. The Commission also considers the distinction between the capacity costs associated with serving new and existing customers a central issue. This issue was addressed by each of MPC and HRC as follows.

An underlying assumption of MPC's claim that its marginal distribution costs are long-run is that MPC's current line extension policy will recover all changes in plant and O&M (operations and maintenance) costs (TR 1012). HRC witness Power testified that marginal distribution capacity costs may be zero plus losses for an existing customer if redundancy is built into the electric distribution system (TR 1290-1291). As noted, HRC asserts that MPC concluded the marginal distribution cost for an existing customer is increased capacity losses due to the redundant design of the distribution system "for reliability and economy of scale purposes" (HRC Reply, p. 14). Such conditions could result from adding capacity in large increments to accommodate all anticipated peak loads. It is due to the economies of scale associated with adding large increments of capacity that a utility would have the incentive to construct a distribution system to accommodate anticipated peak loads. Economies of scale exist when the nature of the production process results in declining costs per unit of output as larger increments of capacity are installed. If a utility did not construct its distribution system in large increments, it would face periodic capacity additions to meet increases in existing customers' peak loads.

If MPC's distribution system were designed to accommodate all anticipated demand, capacity would not be an avoidable cost and SRMC would be the appropriate measure. If, however, MPC's distribution system is designed such that capacity only temporarily exceeds demand, in which case the utility would periodically need to add capacity, then LRMC would be the appropriate measure. In other words, capacity cost would be an avoid able cost. As noted above, economies of scale in the distribution system would provide an incentive for MPC to design its distribution system to accommodate anticipated peak loads. As such, there is a theoretical basis for the method MPC proposed as discussed by HRC. Moreover, the MPC method exhibits greater theoretical economic merit as the basis for the design of its distribution system for service to existing customers than does the 87.4.21 method. The MPC method assumes the distribution system has excess capacity throughout the foreseeable future. The 87.4.21 method merely includes all distribution investments, which may be related to service other than capacity and may include line extension costs which may be related to service to new customers. Some economic literature suggests that SRMC would be the appropriate cost measure if demand were never expected to cause an increased need for capacity.[1]

As noted, the Commission finds MPC's distribution cost method reasonable and reaffirms its approval of that method. However, the Commission is not convinced that the marginal distribution capacity costs consist of capacity loss costs only. As
such, the Commission directs MPC to further address and provide

---

1 See generally, e.g., Kahn, Alfred E., The Economics of Regulation: Principles and Institutions, Cambridge, MIT Press, 1988, pp. 63-158. Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, Principles of Public Utility Rates, 2nd Ed., Arlington, Public Utility Reports, Inc. 1988, pp. 410-477. Both of these works discuss the economic merits of applying short and long-run marginal cost pricing in situations of excess capacity.

empirical evidence supporting the method it proposed in this Docket in its next COS/RD filing. This would include, but not be limited to, information regarding MPC's distribution system engineering/design policies and objectives with respect to capacity-related investments for existing customers. MPC should also describe the size of expected peak loads and when they would occur for each of the investments it has made over the recent past and anticipates in the future. MPC should also indicate the portion of these investments that should be considered marginal dis-tribution capacity costs for existing customers. The Commission also reaffirms its direction in Finding Nos. 527-528 in Order No. 5484n.

Use of SRMC as a basis for pricing can provide an incentive for customers to increase use of excess capacity. As such, a reduction in price due to reduced distribution costs between dockets may result in increased consumption by distribution level customers. Price elasticities (measures of sensitivity to price changes) for service to these classes would provide information useful in determining whether such reduced prices would result in consumption that would cause an increased need for capacity above the level in place. Thus, the Commission directs MPC to provide such information in its next COS/RD filing for each of the rate elements for each distribution level customer class affected by a change in marginal distribution capacity costs.

LCG's Argument Regarding Line Extensions. The foregoing analysis addresses the appropriate cost for existing customers. SRMC may not, however, be the appropriate measurement for service to new customers for at least two reasons. First, MPC may not have accounted for unanticipated peak demands in its distribution system design resulting from unanticipated new customers or load growth. Thus, service to new customers may require additional capacity. Second, service to a new customer may also require MPC to incur access-related plant additions. HRC classified service extensions to new customers as access costs and stated such costs represent a large share of distribution costs and could not be considered marginal capacity costs. While it does not appear that MPC recommended reenforcing its line extension policy to recover capacity costs (HRC Reply, p. 15), there may be merit in recovering marginal capacity and access costs caused by new customers through a line extension policy. However, the degree to which these costs should be recovered through a line extension policy is not yet known. Thus, the Commission's continues its direction to MPC to address its line extension policy (see FOF 527-528, Order No. 5484n).

LCG argues that a line extension policy which would recover changes in plant costs is based on a speculative policy and should not serve as a basis for the Commission's decision. LCG also alleges the Commission doubts the relationship between marginal distribution costs and future line extension policies. At Finding Nos. 258-262, particularly 259, the Commission found relative merit in MPC's method versus MCC's and LCG's methods. The Commission's emphasis in its distribution cost decision largely pertains to the theoretical basis of the MPC and 87.4.21 methods and the mechanics of the latter method. Additionally, the Commission questions the source and types of costs LCG used to compute costs using the 87.4.21

method (see Order No. 5484n, FOF 262). The Commission does not find MPC's method perfect. Pending further investigation of MPC's line extension policy, the Commission is unable to address the role MPC's line extension policy plays relative to its marginal distribution costs. Thus, the Commission has sought to address marginal distribution costs for existing customers and intends to address such costs for new customers in future dockets.

LCG's argument that line extension policies are only cost recovery mechanisms may be incorrect (LCG MFR, p. 10). The entire COS/RD process is geared toward computing accurate marginal costs and reflecting those costs in prices. However, as noted in Finding Nos. 527-528 in Order No. 5484n, the Commission seeks further consideration of the costs most appropriately recovered in a line extension policy. As such, the Commission finds indeterminable at this time whether LCG's argument in this regard is correct.

As a final comment regarding LCG's line extension argument, the values listed on page 12 of its MFR overstate MPC's expenditures on its distribution system relative to those costs MPC used in its 87.4.21 method. It appears LCG has taken these data from the same source it used to compute marginal distribution costs (LCG response to data request (RDR) PSC-611c). For instance, LCG holds MPC spent $15.3 million on distribution additions in its electrical system in 1987. However, using the accounts LCG used to compute marginal distribution costs, total additions to plant would be $15.3 million only if additions in services, meters, and street lighting and signal systems were included. Expenditures in these accounts amount to $4.3 million

(LCG RDR PSC-611). The 87.4.21 method excludes costs from these accounts. The Commission notes, however, that the expenditures LCG lists on page 12 of its MFR are irrelevant to the MPC method in this case.

LCG's Appeal to the Testimony of Non-MPC Witnesses. LCG maintains the testimonies of RPC, FEA, and HRC are consistent with that of its own witness, Jan Michael (LCG MFR, p. 17). Based on an examination of each witness' testimony that LCG lists and HRC's reply brief, the Commission finds this aspect of LCG's argument incorrect.

A review of the parties' testimonies listed by LCG appears to reveal the following. RPC witness Lanou testified that the 87.4.21 method was more appropriate because it recognized "some marginal cost of distribution" (TR 1280). Although FEA witness Johnson maintains the MPC method is improper since its has a zero marginal cost, he would not verify the approach Mr. Michael used. Dr. Johnson noted this is a commonly used ap proach, but it could not be mechanically applied (TR 913-914). HRC witness Power addressed the economic merits of MPC's method and the application of his criticism of MPC transmission cost analysis to the 87.4.21 marginal distribution cost method (TR 1290-1292, 1294-1295, and 1297).

LCG witness Michael, however, concentrates his arguments on the impacts the MPC method would have on shifting distribution costs to customers not using the distribution system (Exh. No. LCG-8, pp. 1-5 and LCG RDR PSC-611). This analysis includes the effects of reconciling marginal costs with the revenue requirement (see e.g., Exh. No. LCG-8, pp. 3 and 5). Even though Mr. Michael testified that marginal costs should be used to allocate costs to customer classes causing certain costs, he does not argue the merits of using short-run versus long-run marginal costs, as defined above. As an interim solution to avoid shifting distribution costs to customers not served by the distribution system, Mr. Michael proposed that the Commission "... reaffirm the marginal distribution cost methodology found acceptable in Docket No. 87.4.21" (Exh. No. LCG-8, p. 4). Further, he provides citations to technical literature describing the method he proposed as a basis for his proposed method (LCG RDR 612 d).

RPC and FEA appear to discard the MPC approach since it does not include the costs they think should be included, but do not weigh the economic merits. HRC, however, seeks to weigh the economic merits of the different methods proposed. In contrast to each of these witness' testimonies (save Dr. Power's analysis of Mr. Michael's criticisms of the equal-percentage reconciliation process) LCG focuses on the results of using the MPC method. Therefore, it does not appear that LCG can argue RPC, FEA, and HRC support its position which appears only related to cost shifting.

LCG's Cost Shifting Argument. As previously noted LCG's cost shifting arguments relate to the results of using the MPC versus the 87.4.21 methods. HRC correctly notes in its reply brief that these arguments are embedded cost based (HRC Reply p. 17). Therefore, the Commission find's LCG's arguments inapplicable to marginal distribution cost analysis.

There are essentially two facets to LCG's cost shifting argument. First, LCG implies marginal distribution costs are composed of incremental plant and O&M

costs. This assertion stems from LCG's proposal to use its replication of the 87.4.21 method (Exh. No. LCG-8, p. 4). In his answer testimony (following MPC's rebuttal testimony), Mr. Michael argued that MPC shifted the distribution costs it initially computed to other classes by, in part, reducing its distribution costs (Id., p. 3). Second, LCG argues that the equal-percentage reconciliation method shifts incremental investment costs to customers not served by the distribution system (Id.). These arguments are addressed below.

First, HRC correctly argues that many accounting costs are not marginal costs (HRC Reply, p. 16). In an embedded (accounting) cost study, the analyst seeks to fully distribute or allocate a utility's total costs to customer classes. Direct costs, those costs directly related to the provision of a service, are first determined and assigned to customer classes. The remaining costs are allocated to classes based on their function and classification. Also, the costs used in an embedded cost study are historical and, therefore, lack the impacts prospective technological change would have on the cost of service.

In a marginal cost study, the analyst seeks to determine the costs a utility would incur (avoid) by providing one more (one less) unit of a particular service. This is done for functionalized and classified costs. A key difference between a marginal and an embedded approach is that marginal cost analysis includes only avoidable costs: not all embedded costs are avoidable. In an embedded cost study, however, total costs are allocated to classes, whereas in a marginal cost study only avoidable costs are allocated to classes.[2]

In the above analysis, which discusses the theoretical basis for the MPC method, the Commission addressed why MPC's incremental distribution investments would not be considered marginal costs. If, however, one were to allocate distribution costs using an embedded approach, one would probably allocate to tal historical distribution investments to those classes served

---

[2] Peak and off-peak marginal cost allocations are omitted to simplify this analysis.

by the distribution system regardless of their avoidability. Thus, embedded costs may not recognize the theoretical basis for determining that distribution costs are short-run as discussed above.

Second, HRC characterizes the equal-percentage reconciliation method as an arbitrary distribution of embedded costs to customer classes. This characterization is correct <u>only if the concern is the allocation of embedded costs</u> (<u>see</u> HRC Reply, p. 16 and TR 1287-1290). Dr. Power contends that by using an equal-percentage reconciliation method, embedded costs would be randomly miss-allocated among classes. This argument does not apply to marginal cost analysis.

As noted, marginal costs consist of those costs incurred or avoided at marginal levels of consumption. These costs are then allocated to classes using methods intended to reflect the demand for the commodities or services for which classified functionalized sources of costs are incurred, which in turn reflects system design. If certain accounting costs, such as incremental distribution plant investments, are not considered avoidable, then those costs would not be included in a marginal cost study.

It follows then that those costs would not be included in each class' total marginal costs (the sum of allocated classified costs). Moreover, those costs would not be shifted among classes not using a certain cost function or to other classified cost functions through an equal-percentage reconciliation method. As Dr. Power notes, the equal-percentage reconcili ation method is used to preserve the marginal cost information for each class (TR 1289). This is done by equally rescaling all classes' total marginal costs to the total revenue requirement. If the same were done to allocate embedded costs among classes the allocation would be random. However, equal-percentage reconciliation is not designed to allocate costs, marginal or embedded; it is designed to preserve marginal cost price signals.

HRC's characterization of LCG's concern for the way in which marginal costs are measured due to the impact such measurement has on large industrial customers' revenue requirements through the reconciliation process appears correct. As discussed above, LCG's primary concern is that distribution costs are shifted to customers not served at the distribution level. LCG recommends using the 87.4.21 distribution cost method "in the interim" to avoid shifting distribution costs to classes not using the distribution system (Exh. No. LCG-8, p. 4). However, LCG does not address the economic merits of the method nor does it address whether the costs it computes are the correct marginal capacity costs to be used in this case. LCG, by recommending the 87.4.21 method, implies that the costs resulting from the 87.4.21 method are marginal distribution capacity costs (Exh. No. LCG-8, pp. 1-5). But, as HRC points out, LCG appears to be concentrating on the results each of MPC's and the 87.4.21 distribution cost methods would have on class revenues through reconciliation.

Factual and Theoretical Basis For The 87.4.21 Method. As an aside, the Commission questions LCG's replication of the 87.4.21 method, both with respect to the data required to replicate the method and the methodological considerations related to the method. The Commission makes these observations with respect to the magnitude of the distribution costs LCG computes and its argument regarding the application of HRC's criticism of the 87.4.21 method. As noted, however, the Commission finds more economic merit in MPC's proposed method than the methods proposed by MCC and LCG (the 87.4.21 method) and approves MPC's method on theoretical grounds.

87.4.21 Method Data Requirements. Among the reasons to question LCG's replication of the 87.4.21 method stated in Order No. 5484n, the Commission questions the "source and type of costs" used and "whether the resulting avoided costs are only capacity related" (FOF 262, Order No. 5484n). The following supplements these reasons.

Other than the year's data used to compute costs, there are five general differences between the marginal distribution cost study accepted in Docket No. 87.4.21 and the replication proposed by LCG.

First, LCG computed annual incremental plant costs for 1986-1989 by subtracting each year's year-ending total plant investments from the following year's year-ending plant investments. In Docket No. 87.4.21, however, MPC determined annual marginal plant costs subtracting plant retirements and transfers (estimates of replacement costs), escalated to current costs, from annual additional investments (FOF 28, Order No 5340, and LCG RDR PSC-611 c; see also Statement L, Docket No. 87.4.21). The data required to escalate plant retirements to current costs do not appear to be on the record. Failure to escalate retirements and transfer costs would overstate incremental costs.

Second, unlike MPC, LCG did not extract transmission-related costs from account nos. 362 (station equipment plant) and 592 (station equipment O&M). The Commission is uncertain whether this adjustment would be relevant and/or correct for any or all of the years included in LCG's replication.

Third, in Docket No. 87.4.21, MPC computed unit marginal costs ($/kW) using non-coincident peak (NCP) data (FOF 28, Order No. 5340). LCG, on the other hand, used system coincident peak (CP) data to perform this step (LCG RDR PSC-611 c, Attachment C). The NCP data required for this step do not appear to be in the record in this case. Thus, the Commission is unable to determine the impact using CP versus NCP data.

Fourth, the Commission questions LCG's use of MPC's price indices from MPC's transmission cost study in this Docket to express annual incremental distribution plant investments O&M costs in 1992 dollars. The price indices MPC used to compute transmission O&M and distribution plant and O&M costs in Docket No. 87.4.21 differ (cf pp. 9 and 12, Statement L, Docket No. 87.4.21). The Commission is uncertain if these indices are available in the record in this Docket.

Fifth, while both MPC, in Docket No. 87.4.21, and LCG, in this Docket, levelized distribution plant costs, it appears LCG did not adjust these costs for general and common plant, administrative and general expenses, and distribution plant-related working capital (Statement L, p. 10 and Exh. No. MPC-5, Docket No. 87.4.21). The data required to make these adjustments do not appear to be on the record.

LCG recommends that if the Commission continues to have uncertainties regarding its replication of the 87.4.21 method, the Commission should direct MPC to use the method approved in Docket No. 87.4.21. The Commission could do this; however, it will not because it finds the 87.4.21 method inferior to the MPC method. LCG maintains the uncertainties the Commission has with LCG's replication of the 87.4.21 method cannot be used to support MPC's method. However, the above discrepancies along with the below methodological problems constitute sufficient reason to question LCG's study. As noted, the above listed data do not appear to be available on the record in this case. Thus, the Commission questions the magnitude of LCG's proposed total marginal distribution costs.

Methodological Concerns. Methodologically, LCG claims the Commission's application of HRC's transmission cost criticisms to LCG's distribution costs is "strained" when applied to the 87.4.21 method (LCG MFR, pp. 18-19). An excerpt from a technical journal provided by LCG (LCG RDR PSC-612, Attachment D), titled Rate Design: Traditional and Innovative Ap proaches (EPRI CU-6886, Project 2343-4, Final Report, July, 1990, pp. 11-26 through 11-28) suggests three considerations applicable to computing demand-related distribution costs regarding the method used by LCG.

First, the EPRI publication suggests costs be computed over historical and projected time spans. LCG estimated historic costs only. Second, EPRI suggests computing unit costs using a method which recognizes different load characteristics between the primary and secondary voltage levels. That is, the peaking nature between these levels are most likely non-coincident. LCG uses system coincident peak data to perform this step. Third, EPRI suggests using planned load growth data to unitize costs. In contrast, LCG uses historical load growth data to unitize costs. HRC addressed the first and third of these considerations with respect to transmission costs (see generally Exh. No. HRC-3, pp. 57-69).

HRC witness Power points out that his criticism of the numerical analysis of transmission costs applies to the distribution costs computed by LCG (TR 1294-1295). Therefore, LCG's statement that use of HRC's criticisms of the method to compute transmission costs as proposed by MPC is "strained" is not correct. The Commission finds HRC's criticism applicable.

Allocation of Classified Costs

Seasonality: Summary of the Issue. MPC, MCC, and HRC addressed seasonality. Based on statistical analysis of prospective monthly marginal energy costs (system lambda) and loss-of-load-hour (LOLH) data and an examination of historical load shapes, MPC proposed its winter season be reduced from the current November 1 to March 31 period to a four month period by removing March from the winter season (Order No. 5484n, FOF 35-42). Although MCC proposed that energy and capacity costs should not be seasonally allocated (Exh. No. MCC-6, p. 7), MCC allocated marginal generation energy costs seasonally using the same seasons proposed by MPC (cf Exh. No. MCC-6, JD-6, p. 5, Revised and Exh. No. MPC-40, PEM-1, p. 2). MCC argued that MPC's system load patterns do not vary significantly by season and that current seasonal rate differentials should be narrowed (Order No. 5484n, FOF 72-73).

HRC maintained that its LOLH analysis shows an eight-month peak season (August through March) and MPC's system lambda data show peaks in two winter months and three summer months. HRC also doubted the reliability of MPC's revised monthly system lambda estimates. HRC proposed replacing seasonal prices with inverted-block prices (Order No. 5484n, FOF 190-194 and Exh. No. HRC-4, pp. 26-29).

The Commission found MPC's seasonal analysis unacceptable since it mixed cost- (system lambda) and non-cost- (LOLH and load shapes) based analysis to determine seasons. The Commission also expressed concern regarding the mismatch between the year's cost data used to determine seasons and to compute costs. The Commission directed MPC to examine seasonality using cost-based methods. The Commission found the current winter and summer seasons appropriate (see, Order No. 5484n, FOF 271-273).

Both MPC and HRC opposed the Commission's decision. The following summarizes MPC's motion and HRC's reply regarding seasonality.

Motions and Responses/Replies. MPC maintains the Commission's decision on seasonality "ignores all of the evidence in this case" (MPC MFR, p. 7). MPC maintains the Commission's reasoning, which was not subject to reply by the parties, "... is arbitrary, capricious and an abuse of the discretion" (Id., p. 8). Further, MPC maintains that since the Commission does not support its conclusion that the LOLH data and load shapes are not cost-based data, its decision is arbitrary. MPC questions the Commission's direction to examine seasons using cost-based methods. MPC maintains LOLH and load shapes are cost-based methods and asks the Commission to explain why these methods are not cost based and what cost-based methods it would suggest MPC use to perform seasonal analysis.

HRC maintains that, based on the Commission's findings, retention of seasonal rates does not make sense. HRC holds that, if accurate cost information were reflected in seasonal prices, customers would not be able to act on such information. HRC notes its refutation of winter/summer seasons and suggests a peak and off-peak period consisting of July-February and March-June, respectively. If the

Commission should choose not to abandon seasonal pricing, HRC would support MPC's proposed four-month winter season.

Further, HRC supports the Commission's direction that MPC broaden the scope of its seasonal analysis. HRC agrees that LOLH and load shapes are not cost-based methods, but are measures of physical demand. HRC refers to these measures as non-economic. HRC agrees with MPC that guidance regarding the methods to use would have merit (HRC Reply, pp. 4-5).

Commission Decision. The Commission grants MPC's motion regarding seasonality and approves MPC's proposed four month winter season (November 1 through February 28/29) and an eight month summer season. Although the Commission finds MPC's seasonal analysis reasonable in this case, it continues to question its mixture of cost and non-cost based analyses.

The following provides support for the Commission's findings regarding the non-cost basis of the LOLH and load shape analysis performed by MPC. The Commission will also explain why it doubts the validity of the system lambda data MPC used and what types of cost-based analysis might be used in future dockets.

Although HRC witness Power maintained that seasonal analysis should be performed using LOLH data, HRC agreed with the Commission's order that LOLH and load shapes are non-cost based data/methods (Exh. No. HRC-3, p. 80 and HRC Reply,p. 4). HRC also noted these data/methods measure "physical demands on the system" (Id., p. 4). MPC stated that a LOLH is a "... re source planning measure of the hours during which there is a relative need for capacity" (MPC RDR PSC-237 b).

Further, the way in which LOLH is computed appears to suggest that it is based on the probability the utility would not be able to accommodate demand (cf Id., Exh. No. MPC-46, p. 23, and Order No. 5340, FOF 33). Thus, as HRC suggests, a LOLH appears to be a physical measure of demand on the system.

The load shapes MPC used are graphical plots of typical hourly load factors against the hours of a typical week in the month observed. MPC used load factors based on hourly demand for a typical week in the month observed and annual peak (Exh. No. MPC-40, p. 8 and PEM-9). (Load factors are typically the ratio of kWh consumption over a given time period to the product of the peak demand (kW) and the number of hours in the period). These data measure consumption and demand, not cost. It might be noted that the quantity of energy or capacity demanded are affected by prices and ultimately costs, but the above measures are not cost or economic measures.

As noted, MPC used prospective monthly marginal energy costs (system lambda) to determine seasons and to allocate marginal energy costs to seasons (MPC RDR PSC-270). HRC questioned the reliability of these data. HRC observed that the data MPC initially used to allocate energy costs to seasons were average incremental costs. In rebuttal testimony MPC revised the data it used to allocate energy costs to seasons (Exh. No. MPC-41, p. 2). These revised data consisted of hourly system lambdas or the hourly costs associated with the most expensive generating unit (Exh. No. HRC-3, p. 79). HRC observed that the monthly system lambda values are less than, rather than greater than, the incremental energy costs MPC initially used. HRC suggests that incremental generation costs would include units with lower operating costs and should therefore be less than the system lambda values (Exh. No. HRC-4, pp. 27-28). The Commission finds HRC's analysis correct and, therefore, questions, as did HRC, the validity of the energy cost data MPC used to determine seasons and allocate energy costs to seasons.

The Commission reemphasizes the importance of using a cost-based seasonal analysis throughout MPC's generation cost planning horizon. The Commission is most particularly concerned with using cost-based analysis as regards MPC's potential to shift between capacity and/or energy surpluses and deficits and the market value of power. As stated in Finding No. 239 (Order No. 5484n), MPC can sell or purchase generation resources in the market place. Thus, generation resources have alternative uses. As such, measuring both the avoided costs and regional value of generation are relevant to the value of power. To exclude such valuation from an analysis of seasonal generation costs could result in inefficient pricing. That is, seasonal prices could be less likely to fulfill the task of efficiently allocating scarce resources in local and regional markets since the full values of seasonal power would not be considered. None of the data used by MPC, MCC, or HRC appear to account for the market value of power.

The Commission reiterates by reference its concerns about MPC's seasonal analysis as noted in Finding Nos. 272 and 273, except as modified in this Order.

Several other comments are noteworthy. First, the Commission clarifies the sixth sentence of Finding No. 272 in Order No. 5484n. HRC apparently uses this portion of Order No. 5484n to argue that the Commission recognized the merit of HRC's position "that the |winter¬ season should be reduced or eliminated. FOF 272" (HRC Reply, p. 4). The thrust of this statement is that MPC's analysis is limited to the months in the current winter season only and does not consider all reasonable possibilities of peak, off-peak or "shoulder" seasons (see, Order No. 5484n, FOF 39 and Exh. No. HRC-3, pp. 77-78).

Finally, in this Docket MPC used LOLH data to seasonally allocate capacity costs. Consistent with its concern that MPC's seasonal analysis mixes cost- and non-cost-based methods, the Commission directs MPC to address the use of this method relative to using cost-based methods to determine the seasonality of capacity costs in its next COS filing. For the purposes of this case, however, the Commission finds MPC's proposed method to allocate capacity costs to seasons acceptable. The Commission also finds MPC's seasonal allocation of energy costs acceptable.

Non-generation Voltage Level Capacity Costs: Summary of the Issue. MPC proposed 1) that transmission and substation capacity costs be allocated according to each class' contribution to the average of normalized monthly coincident peaks (CPs) (12 CP), and 2) that distribution capacity costs be allocated according to each class' average monthly normalized NCPs (12 NCP). MCC, LCG, FEA, and RPC adopted MPC's methods for these costs. However, RPC used generation versus sales level data. HRC proposed allocating transmission capacity costs using a NCP approach.

MPC objected to the Commission's decision to allocate the above listed costs using a 1 CP approach (see FOF 279-280, Order No. 54784n and MPC MFR, pp. 9-10). HRC supports MPC's objection (HRC, Reply, p. 5).

Motions and Responses/Replies. The following summarizes in turn MPC's MFR and HRC's reply regarding this issue. MPC maintains the 1 CP method used by the Commission was not proposed by any party and the decision is not supported by any evidence. MPC notes that only it and HRC proposed different methods to allocate voltage level capacity costs. MPC holds that by using the 1 CP method no cost responsibility would be placed on customers who make little or no use of the transmission, substation and distribution systems during the time of the annual peak, but use each segment regularly during other times of the year. MPC cites the irrigation class as one example (MPC MFR, pp. 9-10).

HRC supports MPC's motion regarding this issue and holds MPC's method is "... preferable to the method ordered by the Commission" (HRC Reply, p. 5). HRC maintains that MPC's system is designed to meet local rather than system peaks.

Commission Decision. The Commission grants MPC's motion regarding voltage level capacity cost allocations. However, the Commission directs MPC to address these issues in its next COS/RD filing. The following provides a background of the transmission, substation, and distribution capacity cost allocation methods accepted in MPC's last two electric COS filings. The Commission's reasoning behind its decision also follows.

In Docket No. 83.9.67, the Commission approved MPC's proposal to allocate generation and transmission capacity costs to classes seasonally using a 1 CP method for the winter, and an average of monthly CPs (8 CP) for the summer seasons (FOF 130 and 135, Order No. 5051d). In Docket No. 87.4.21, the Commission approved MCC's proposal to allocate generation and transmission costs to classes seasonally using a 1 CP method in each season (Order No. 5340a, FOF 18), even though MPC proposed an allocation method similar to that approved in Docket No. 83.9.67 (Id., FOF 37). Generation and transmission capacity costs were treated the same in each case. Additionally, it appears substation capacity costs were included with transmission capacity costs and, therefore, treated the same as transmission and generation in Docket No. 87.4.21 (the GS-2 Rate applied to transmission and substation levels of service). Due to the seasonal allocation of transmission and substation costs in the above-listed dockets, those classes whose usage largely occurs in the summer months were allocated costs.

The Commission, therefore, questions why generation, transmission, and substation capacity costs should be allocated differently in this Docket than the above listed dockets with respect to both seasonality and coincident peaks. Further, even though MPC proposed transmission and substation costs be allocated using a 12 CP method, Mr. Maxwell testified that "... a utility designs a transmission system to be able to serve the load at the time of the system peak" (Exh. Nos. MPC-40, p.12 and MPC-41, p. 15). Thus, there is some confusion whether transmission capacity costs should be allocated using a 1 CP or 12 CP method.

In this Docket HRC testified that transmission and distribution costs are incurred to satisfy local load growth (TR 1295-1296). MPC testified that the transmission system is designed to meet system peak load and the distribution system designed to meet non-coincident peaks (TR 961-962). Also, MPC appears to suggest that if rural or customer-specific loads occur during times other than the winter peak the transmission system would be designed to meet those peak loads when and, possibly, where they occur (Id.).

Turning to distribution, in Docket No. 83.9.67 the Commission opted to allocate distribution capacity costs using a NCP approach (Order No. 5051d, FOF 137-140). In Docket No. 87.4.21, MPC proposed distribution costs be allocated to classes seasonally using a NCP approach (Order No. 5340, FOF 37). In this Docket there does not appear to be any reasoning provided by MPC supporting its 12 NCP method. However, MPC states that by using the sum of NCPs total marginal capacity (loss) costs would be overstated by a factor of 12. By using a 12 NCP, total generation capacity loss costs would be similar in magnitude regardless of whether they were placed at generation or the non-generation voltage levels (Exh. No. MPC-41, p. 8).

The means by which costs are allocated to classes should reflect marginal cost causation: when and how costs are incurred (or avoided) for each classified cost function. Such cost occurrence would, in turn, appear to reflect the design (e.g., sizing) of the segment of the system underlying each cost function. Based on its examination of the changes in cost allocation methods proposed and the related testimony in this Docket the Commission questions whether the methods proposed most accurately depict cost causation and correctly convey accurate cost information. Based on the Commission's decisions from past dockets it appears the 1 CP method would be most applicable for the transmission and substation levels since these levels have traditionally not been treated differently from generation. Moreover, all customer classes make use of the transmission system and those using the substation contribute to 98.7 percent of the coincident peak at generation (MPC COS/RD Compliance Filing, October, 24, 1991, Section 3, p. 56/119. This includes the reallocation of Malmstrom loads to transmission). However, in past dockets these costs were also allocated seasonally. If transmission, substation, and distribution capacity costs were allocated seasonally, customers, such as irrigation customers, whose usage occurs primarily during times other than the annual system peak, would be allocated costs.

In the interest of stability and consistency in rates for all customer classes, the Commission finds it reasonable to allocate marginal transmission and substation capacity costs to classes using MPC's proposed 12 CP method. The Commission also finds it reasonable to approve MPC's proposed 12 NCP method to allocate marginal distribution capacity costs to classes. However, the Commission continues to question the allocation of generation capacity costs at the non-generation voltage levels using a method different then that used for generation capacity costs. The Commission directs MPC to examine the appropriate methods to allocate transmission and substation capacity costs in light of its own system designs and how and when peaks occur on MPC's system. This should be done in MPC's next COS/RD filing.

Non-Generation Voltage Level Loss Costs

Although not addressed in any of the COS/RD motions, the Commission directs MPC to compute and include voltage-level capacity loss costs as stated in Finding No. 287, Order No. 5484n. The data required to compute these costs are on the record. LCG appears to have made similar adjustments to the transmission, substation, and distribution level marginal capacity costs (Exh. No. LCG-6, JWM-5, p. 1).

LCG proposed generation loss costs be allocated at the generation level and recomputed MPC's COS using this approach (Id. and Order No. 5484n, FOF 131). LCG also applied MPC's initially-proposed generation capacity loss factors (computed by voltage level) to MPC's proposed transmission, substation, and distribution marginal capacity costs to arrive at unit marginal capacity costs at each voltage level. For instance, LCG computed its unit marginal transmission capacity costs for the GS-1 Primary class by applying MPC's proposed cumulative primary level loss factor (12.0778%) to MPC's initially-proposed marginal plant and O&M transmission costs ($81.15/kW).

The Commission finds LCG's method may overstate the loss costs at each non-generation voltage level per the adjustment described in Finding No. 287, Order No. 5484n. LCG uses loss factors reflecting the percentage loss occurring between the generator and a particular voltage level (cf Exh. No. MPC-40, PEM-10, p. 13, MPC RDR LCG-112). However, to capture the losses occurring at a particular voltage level for service to downstream voltage levels, the loss factor associated with moving power through that level should be removed. MPC maintains its proposed capacity loss factors represent the losses that occur at each voltage level (MPC RDR PSC-278 and Table 2, Order No. 5484n). Using the loss factors listed in the second column of Table 2 in Order No. 5484n, Table 1 (below) lists loss fac tors illustrative of those the Commission finds reasonable to adjust each of the transmission and substation marginal capacity costs to account for losses associated with service to downstream voltage levels.

Consistent with the placement of generation loss costs at the non-generation voltage levels, the Commission finds it reasonable to place non-generation voltage costs at each voltage level where they occur. For instance, using the illustrative loss factors in Table 1, secondary distribution costs would include the 7.0379 percent adjustment to transmission capacity costs and the 5.74 percent adjustment to substation capacity costs.

TABLE 1
Illustrative Non-Generation Voltage Level Capacity Loss Factors

Downstream Voltage Level	Cost Function Transmission	Substation
Substation	1.2976%	----
Primary	2.6276%	1.33%

Secondary	7.0376%	5.74%

Source: Table 2, Order No. 5484n and Exh. No. MPC-41, PEM-16, 17 and 18.

Since SRMCs serve as the basis for marginal distribution capacity costs in this case, primary distribution capacity loss costs for service to secondary level classes would not be applicable. Generation-related capacity loss costs would, however, continue to serve as the basis for marginal distribution capacity costs at each of the primary and secondary distribution levels. The Commission notes that these loss factors would be subject to change due to shifting the Malmstrom load to the transmission level and its reconsideration on seasonality. The Commission continues to direct MPC to address the inclusion of such capacity loss adjustments in its next COS filing.

While the Commission finds it reasonable to make the above adjustment to capacity loss costs in this case, it is also interested in examining a similar adjustment for energy losses at voltage levels other than generation. Thus, MPC is directed to address energy loss costs at voltage levels other than generation in its next COS/RD filing.

Additional Findings Requested BY LCG

At pages 14-15 (LCG MFR), the LCG requests explicit findings "with respect to all issues on which it presented testimony or argument, including but not limited to both marginal distribution costs and the classification method for generation costs ...." This Order contains extensive additional findings on marginal distribution costs and the classification method for generation costs. Section 2-4-704(2)(b), MCA, reads, "findings of fact, upon issues essential to the decision, were not made although requested." A vague request to make findings with re spect to all issues presented in testimony or argument is not, in the Commission's view, a request in compliance with < 2-4-704(2)(b), MCA. The Commission finds that this Order and Order No. 5484n contain adequate findings on all issues essential to the decision. LCG's request for further unspecified findings is denied.

Direction

The Commission finds that its decisions in this order will result in costs and seasonal billing determinants that will be used as a basis to reconcile total marginal costs to the revenue requirement and compute rates different than those resulting from Order No. 5484n. The Commission therefore directs MPC to provide the following information to the Commission and all of the parties in compliance to this order. This information must comply with this Order and Order No. 5484n to the extent COS issues other than those addressed herein remain unchanged in Order No. 5484n.

First, the Commission directs MPC to compute total allocated marginal costs by class according to the Commission's COS decisions in Order No. 5484n with revisions thereto as stated in this Order. Second, MPC must reconcile and moderate the total revenue requirement discussed in Finding Nos. 303 through 304, Order No. 5484n per the Commission's decisions affecting reconciliation and moderation in Order No. 5484n and the COS decisions in Order No. 5484n with the revisions thereto as stated in this Order. This reconciliation must comport with the rate design decisions in Order No. 5484n regarding service to RPC through the Industrial Interruptible (II-1) tariff. Further, MPC must follow the Commission's decisions on reconciliation and moderation in Finding Nos. 293 through 302, Order No. 5484n. Third, MPC must provide full unit marginal costs as described in Finding Nos. 307 and 308, Order No. 5484n. MPC must also provide documentation discussed in Finding No. 311, Order No. 5484n.

Fourth, MPC must provide billing determinants for all customer classes reflective of the Commission decisions in Order No. 5484n with revisions made thereto in this Order. This would include seasonal energy and demand billing determinants for all customer classes. MPC must reconcile these billing determinants with those it proposed in rebuttal testimony including the shift of the Malmstrom load between the primary and substation levels of service.

Fifth, MPC must provide updates to Exh. No. MPC-46, TEW-3 and TEW-4 reflecting the Commission's decisions in Order No. 5484n with revisions made thereto in this Order. This information must be provided within four days of the date MPC makes its compliance filing regarding COS, reconciliation, and moderation. This information must be provided to the parties listed in Finding No. 7. Finally, MPC must file complete and detailed work papers supporting its computations in compliance with the COS, reconciliation, and moderation decisions in Order No. 5484n with revisions thereto in this Order.

CONCLUSIONS OF LAW

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

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

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.

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.

The cost of service approved herein is just, reasonable, and not unjustly discriminatory. Sections 69-3-330 and 69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

All Motions for Reconsideration of cost of service issues in Order No. 5484n are disposed of as described above.

The Large Customer Group's Motion to Strike a portion of the reply brief filed by District XI Human Resource Council is disposed of as described at FOF paragraph 3 above.

All other Motions for Reconsideration of Order No. 5484n will be addressed in a subsequent order.

The stay of Order No. 5484n, invoked by the Commission in Order No. 5484o, remains in effect pending a subsequent order.

Montana Power Company shall comply with each requirement of this Order as described above.

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

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.

Montana Power Company shall provide a detailed cost-of-service study reflecting all of the Commission's cost-of-service decisions included in Order No. 5484n with revisions thereto as stated in this Order.

Montana Power Company shall compute total and unit marginal costs pursuant to and reflective of the Commission's cost-of-service decisions in Order No. 5484n with revisions thereto as stated in this Order.

Montana Power Company must compute class revenue responsibilities for each class pursuant to the Commission's cost-of-service decisions in Order No. 5484n with revisions thereto as stated in this Order, and the Commission's reconciliation and moderation decisions in Order No. 5484n.

Montana Power Company must file complete and detailed work papers supporting the above-required information.

DONE AND DATED this 29th day of January, 1992, by a vote of 5 - 0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Chairman

DANNY OBERG, Vice Chairman

BOB ANDERSON, Commissioner

JOHN B. DRISCOLL, Commissioner

WALLACE W. "WALLY" MERCER, Commissioner

ATTEST:

Ann Peck
Commission Secretary

(SEAL)

NOTE: You may be entitled to judicial review in this matter. Judicial review may be obtained by filing a petition for review within thirty (30) days of the service of this order. Section 2-4-702, MCA.