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

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IN THE MATTER Of Montana-Dakota	)	UTILITY DIVISION
Utilities Co., Application for Authority	)	
To Establish Increased Rates for Electric	)	DOCKET NO. D2007.7.79
Service.	)	

Direct Testimony
of
John W. Wilson
on Behalf
of
The Montana Consumer Counsel

October 22, 2007

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia, 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J.W. Wilson & Associates, Inc., a Washington, D.C. corporation.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified as an expert witness in court proceedings dealing with competition in the electric power industry and on regulatory matters before more than 50 Federal and State regulatory bodies throughout the United States and Canada. I have also appeared on numerous occasions as an expert witness at the invitation of U.S. Senate and Congressional Committees dealing with antitrust and regulatory legislation. In addition, I have been retained as an expert on regulatory matters by more then 25 State and Federal regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA’s Antitrust, Insurance and Regulatory Law Sections.

II. OVERVIEW OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am presenting testimony in this proceeding on behalf of the Montana Consumer Counsel (MCC).

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. While MDU's rate increase filing in this case reflects numerous changes since the utility's last electric rate case some twenty years ago, the single biggest change triggering this filing is the expiration of the power purchase contract that MDU had with Basin Electric Power Cooperative (Basin) from 1985 until October 31, 2006. Since then and prospectively, MDU is replacing purchases from Basin with higher cost short term energy purchases from the Midwest Independent Transmission System Operator (MISO) market and capacity purchases from Northern States Power (NSP). This is the primary cause of the requested rate increase.

In addition to prompting the rate increase request that is being sought at this time, the expiration of the Basin contract is the underlying cause of two other important and related aspects of MDU's rate filing: (1) the Company's request for the implementation of a fuel and purchased power cost tracking mechanism (tracker) and (2) a related margin sharing incentive proposal that would allow the company to retain, as additional profit, a portion of the system cost compensation that may be realized from offsystem sales. Without margin sharing, the cost-offsetting benefit of offsystem sales revenues could, like increased fuel or purchased power costs, be fully passed through to ratepayers under the tracker mechanism, or it could be estimated as a system cost offset on a test year basis (as it has been previously) with any variation from the estimate being an incremental profit (or loss) to MDU.

While the Basin contract was in place, MDU's power supply costs were relatively stable (and low) in contrast to what may realistically be expected with replacement energy purchases from the short term MISO market. In addition, the Basin contract frequently provided MDU with low cost surplus power generation that it was able to sell at a profit. That opportunity too is gone. As a consequence, variations in purchased power costs and power sales revenues between rate cases are now as likely to result in profit reductions as in the profit increments that occurred in the past. This has motivated MDU to seek the implementation of a fuel and purchased power tracker at this time, together with a margin sharing provision for offsystem sales revenues.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE REQUESTED IMPLEMENTATION OF A TRACKER AND

MARGIN SHARING?

A. From MDU's perspective, the request for a tracker is understandable and reasonable. Because of the replacement of the Antelope Valley contract (the Basin contract) with short term energy purchases from MISO, MDU's electric energy costs are likely to be considerably less stable than in the past. This will warrant more frequent electric rate adjustments, which a tracker is designed to accommodate. MDU has had a gas cost tracker for its jurisdictional gas utility rates in Montana for many years, and Montana's other major electric utility, NorthWestern Energy, has had an electric cost tracker since 2002. Both of these considerations (increased need and uniform regulatory treatment) support approval of a tracker mechanism for MDU's electric service, although the uniform regulatory treatment rationale is qualified by the fact that NorthWestern was a default supply provider subject to Montana's restructuring law which did not apply to MDU, which is a vertically integrated supplier with its own generation resources.[1]

While there is also a rational basis for implementing an incentive-based margin sharing mechanism, the proposed 60%/40% split, as recommended by the Company, is not appropriate. There is also the question of whether it is reasonable to implement a margin sharing incentive mechanism for only one component of energy supply costs rather than a more comprehensive

[1] Also, recovery of NorthWestern's electricity supply costs are mandated by statute (MCA 69-8-210 (4)(a)) whereas MDU's are not.

mechanism that applies equally to all fuel and power cost elements, reflecting both market sales and purchases. As I will discuss below, the MCC suggests that if such a cost incentive mechanism is to be implemented, a more appropriate split between consumers and the utility would be 90%/10%, and that the split should apply equally to both offsystem electricity sales revenues and to tracker adjustments for changes in fuel and purchased power costs. If the Commission were to determine that margin sharing is not an appropriate incentive to be implemented at this time for MDU's fuel and purchased power cost tracker, then MCC would oppose this incentive only for off system sales revenues. In that case, it would be more even-handed and equitable (and a greater profit incentive) to retain the current method for recognizing off system sales revenues, which is to include them on a reasonably estimated basis in the determination of test year costs and rates.

Q. ARE THERE OTHER ISSUES THAT YOU ADDRESS IN THIS TESTIMONY?

A. Yes. In addition to MDU's changed supply cost circumstances, the request for a fuel and purchased power cost tracker and the Company's margin sharing proposal, I will also testify on matters pertaining to proposed cost allocations between customer classes and resulting rate structures, and on the Company's requested rate of return. As I will explain below, the

Company's proposed cost allocation tilts revenue recovery excessively to residential and small business ratepayers, and its proposed rate design produces conflicting price signals. Also, the requested equity return, while derived from a traditional and generally credible analytical approach, appears to be at least somewhat excessive because of computational adjustments that are unwarranted.

III. INCREASED POWER SUPPLY COSTS

Q. PLEASE ELABORATE ON MDU's INCREASED POWER SUPPLY COSTS.

A. MDU, unlike Montana's other major electric utility, NorthWestern Corporation, did not "restructure" and sell off its generating plants. Thus, in important respects, MDU remains much the same vertically integrated electric utility that it has been for many years, relying largely on the same company-owned electric generating resources as it had two decades ago. Over the same period of time, the utility's parent corporation, MDU Resources Group, has changed substantially, achieving substantial growth in its unregulated non-utility businesses -- most notably construction services, construction materials and aggregate mining operations which produce and supply sand, gravel, concrete, asphalt and related products in markets throughout large areas of the central and western United States.

While the Company's utility operations have remained relatively stable over the past twenty years, the parent corporation, including non-utility subsidiaries, has experienced revenue growth from about $300 million twenty years ago to about $4 billion today. Electric and gas utility operations, which accounted for a predominant share of MDU's revenues twenty years ago, accounted for less than 15 percent last year.[2] Most recently, MDU Resources acquired Cascade Natural Gas, a gas distribution utility in Washington and Oregon for $300 million and sold its unregulated electric generating company, Centennial Energy Resources, for about $600 million. Centennial owns, among other properties, the recently constructed 107 Mw coal-fired Hardin Generating Plant in Hardin, Montana.

For the most part, MDU continues to rely on the same generation sources that it did twenty years ago, the Heskett, Lewis & Clark, Big Stone and Coyote coal plants and the Miles City and Glendive gas turbines, serving 119,000 customers in 177 communities in 2006 as compared to a reported 110,000 customers in 174 communities in 1987. Over this period, the only significant generation resource change was the loss of the twenty-year Antelope Valley II purchase contract (66.4MW) with Basin Electric in

[2] In 1987, in addition to its gas and electric utility businesses (which were its largest business segments), MDU's other significant enterprises were the Williston Basin pipeline system whose regulation had been transferred from this Commission to the FERC in 1985, Knife River Coal which produced coal for MDU's generating plants (at regulated profit levels for electricity rates in Montana) and for sales to others, and some oil and gas production. Today, Williston remains a FERC-regulated interstate gas pipeline and storage system, Knife River has sold off its coal operations (to Westmoreland in 2001) and expanded significantly into gravel and other construction materials, and oil and gas production and other business segments (most notably construction services) have continued to grow.

December 2006. This, in turn, has resulted in MDU purchasing significantly more short term electric energy supply in 2007 than it did previously. In addition, the company has entered into limited term capacity (without energy) purchases with Northern States Power (NSP) to bridge the gap until new owned capacity is expected to come on line in 2012.

Q. DID MDU ATTEMPT TO REPLACE THE ANTELOPE VALLEY CONTRACT WITH BASE LOAD SUPPLY RATHER THAN TURNING TO THE HIGHER COST MISO SHORT TERM MARKET?

A. MDU says that it did. The Company testifies that it first attempted to renew the Antelope Valley contract with Basin, but was unsuccessful. MDU subsequently entered into a purchase agreement with the Nebraska Public Power District (NPPD), but says that it was unable to arrange for suitable transmission service, and that deal was therefore cancelled. The Company also issued an RFP for a replacement contract, but received no bids that matched its needs.[3] According to the Company's testimony, while other acquisition efforts were also made, they were unsuccessful.

Q. YOU NOTED EARLIER THAT MDU'S SUBSIDIARY,

[3] The Company did receive a bid from Black Hills Power & Light for about 30% of the capacity and energy that it was seeking at a proposed price of $18/Mwh plus $17.50/Kw month. This partial replacement, which appears to be less costly than replacement MISO purchases, was not purchased, apparently in the hope that something better would become available before it was needed. Unfortunately, that did not happen.

CENTENNIAL, WHICH WAS RECENTLY SOLD, WAS THE OWNER OF A NEW GENERATING PLANT IN HARDIN, MONTANA WHICH WAS COMPLETED IN 2006. DID MDU CONSIDER ACQUIRING THE HARDIN PLANT GENERATION AS A UTILITY RESOURCE?

A. I attempted to look into this question in some detail during the discovery phase of this case. In doing so, I concluded that while the Company did apparently consider the possibility of adding Hardin to its system, it declined to do so. The Hardin plant is located in the NorthWestern Energy control area and is not within the MDU transmission network nor on the MISO system that provides transmission to MDU. Because the NorthWestern system is on the Western interconnection and MISO (and MDU) is on the Eastern interconnection, significant transmission investment would have been required to add Hardin as an MDU system resource. MDU’s preliminary estimates of what this would have cost ranged from less than $30 million to more than $100 million. (See response to MCC-061).

At the upper end of this range, transmission investment costs may have been prohibitive because of the Hardin plant’s relatively small size (107Mw). However, at the lower end of the range, the cost would have been well under 1¢/Kwh (and even less had capacity at Hardin been expanded) as compared to more than 6¢/Kwh for MISO purchases as projected by MDU. While Hardin generation costs would also have been a consideration, MDU's transmission cost studies do not suggest that transmission costs would have been an insurmountable barrier. Yet, despite the transmission cost studies that MDU completed and despite MDU's acknowledgment that it did consider Hardin as a base load capacity resource replacement, MDU says there is no written communication or analysis of any kind (other than the transmission cost studies in response to data request MCC-061) documenting a basis for rejecting the Hardin option to high cost replacement purchases from NSP and MISO. (See response to data requests MCC-244 and MCC-245).

Q. WERE THERE OTHER BASE LOAD SUPPLY OPTIONS THAT MDU TURNED DOWN AS REPLACEMENTS FOR THE BASIN CONTRACT?

A. Yes. As noted above, MDU did receive a bid from Black Hills Power & Light for about 30% of the capacity and energy it was seeking to replace the Basin contract. The Black Hills bid was 1.8¢/Kwh plus $17.50/Kw month for unit contingent capacity and energy, with a minimum capacity factor of 80%, from the Black Hills Ben French Coal Facility (see attachment A to data response MCC-065). At an 80 percent capacity factor, the total cost of this purchase would have been 4.8¢/Kwh - - again, well below the MDU's alternative projected cost of MISO purchases. When asked to explain why this Black Hills offer was rejected, MDU stated:

> The Black Hills proposal, received in response to Montana-Dakota's RFP seeking 70-100 MW of capacity, was for only 23 MW of capacity from the Ben French Coal facility, which is located in the western interconnection. The power would have had to be moved through a DC tie, to which Montana-Dakota has no rights, to the eastern interconnection, and was considerably less than the requested minimum 70 MW. Montana-Dakota did not analyze this proposal as an alternative to MISO energy purchases.

The explanation that the Ben French facility was on the western interconnection and would have to be moved to the eastern interconnection, while true, seemed mistaken because the Black Hills offer included Black Hills moving the capacity and energy to the eastern grid, and Black Hills represented that the facility was accredited in the Mid Continent Power Pool. Also, while this offer was for less than 100% of the required Basin replacement, it would still appear that partial replacement at the lower Black Hills price (as compared to higher cost MISO purchases) may have been a prudent choice. When the MCC called these concerns to the attention of MDU, the Company changed its answer as to why it did not make the Black Hills purchase, indicating that the real reason was not the location of the plant on the Western grid or any lack of access to the required D.C. tie, but their assessment that the cost was above then-current short term purchase costs. (See response to MCC 270 updated 10/11/07)

Unfortunately, no lower cost replacement purchase was acquired, and ratepayers are now apparently stuck with higher cost MISO replacement purchases rather than the Black Hills offer or whatever lower cost alternative MDU may have anticipated in its place.

IV. FUEL AND PURCHASED POWER TRACKER

Q. PLEASE DESCRIBE MDU'S PROPOSED FUEL AND PURCHASED POWER COST TRACKER.

A. The Company's proposed electric fuel and purchased power cost tracker is set forth in its proposed Rate 58 tariff. It reflects what is known as a comprehensive fuel and purchased power cost rate adjustment approach in which periodic rate adjustments are made to correspond to the full amount of changes in total fuel and purchased power costs per unit (kwh) of electricity sales. It is a full fuel and purchased power cost pass-through to ratepayers with annual true ups (including compensation for the time value of money), similar to the comprehensive power cost tracker that was previously implemented for NorthWestern Energy pursuant to MCA 69-8-210(4)(a).

Q. SHOULD THE COMMISSION IMPLEMENT THE SAME TYPE OF ELECTRIC TRACKER FOR MDU THAT IT HAS IMPLEMENTED FOR NORTHWESTERN?

A. Not necessarily. Because MDU was never subject to Montana's restructuring law, which specified the terms of NWE's tracker, the same type of tracker is not required. More substantively, as is reflected in MDU's own proposal for a Margin Sharing Adjustment (MSA), there are important incentive issues in optimizing a utility's performance in power (and fuel) markets that are not always well-served by this type of tracker.

A. PURPOSE AND OPERATION OF A TRACKER

Q. HOW DOES A TRACKER FIT INTO THE OVERALL PROCESS OF ELECTRIC UTILITY RATE REGULATION?

A. Throughout the nation and in Montana, the retail prices charged for electricity by rate regulated utilities like MDU must be approved by state commissions. When an electric utility wants to change its prices, it must file a set of rate schedules, showing the new prices that it proposes to charge, with its state regulatory commission. These rate schedules are price lists, showing the rates and charges for electric service, and also explaining any other terms and conditions under which electricity service is furnished by the utility.

Before approving a utility's request for a rate increase, the regulator, as here, generally institutes an investigation and hearing into the need for the higher rates. This process of investigation and hearing is called a general rate case. It involves, as here, the presentation of testimony and other evidence by the utility company, arguing its need for the higher rates, as well as testimony by intervenors, such as the MCC, large customers or other consumer groups, addressing the utility's request.

After all the parties to the rate case have been heard, the commission examines the complete record of its investigation and renders its decision. It may accept the proposed rates as filed; reject them entirely, thus continuing the old rates in effect; or, most typically, permit the utility to increase its rates by some part of the total amount originally requested.

Each general rate investigation is a major undertaking for a public utility commission, and it generally extends over a period of many months. The effort and time required for a general rate investigation are needed in part to satisfy the procedural requirement that the interested parties, including the company, all have adequate opportunity to prepare their cases and be heard. In addition to procedural requirements are the scope and complexity of the issues that may be considered in a general rate case investigation.

Because of the great length of a complete rate investigation, the rate decision that results from it must necessarily be based only on the factual situation as it was seen at the time of the rate case. However, newly approved rates are almost certain to remain in effect for at least a year or more, before they can be superseded by rates that may result from the next succeeding rate investigation.

In an effort to reduce the time and resource requirements of complete rate investigations, partial cost adjustment procedures, such as fuel and purchased power cost trackers, are sometimes used for changing electric utility rates between complete general rate investigations. The purpose of these adjustment procedures is to permit prompt changes in electric utility rate levels, to reflect changes in some of the utility's larger and more volatile cost elements, without the necessity of a complete rate investigation.

The specification of which cost elements may properly be the subject of rate adjustments between general rate proceedings is an important and difficult substantive issue. For example, in NorthWestern's case, the Commission has determined that it is appropriate to make rate adjustments between general rate cases reflecting Demand Side Management (DSM) costs and for revenue reductions attributable to DSM programs.

There is often not ready agreement about which cost elements require rate adjustment between general rate cases and which do not. Utility companies are likely to want rate adjustments for those factors most responsible for increasing total costs such as inflation in the prices of the inputs they purchase; whereas consumer groups are likely to want consideration of those offsetting factors that tend to reduce costs or inflation, such as improvements in productivity. To make the adjustment process work effectively, a regulatory commission must establish and enforce a firm policy defining the cost factors that may be considered in this process.

When a policy for rate adjustments is established, it must also specify the events that will trigger the adjustment process. This trigger may be simply the passage of time (as MDU proposes here), as with a monthly review of fuel and purchased power costs; or it may be a specific cost event. When the triggering event occurs, the next step is to calculate the changes in the costs for which interim adjustment is allowed. This process is facilitated if the commission, at the time it establishes its rate adjustment policy, is able to prescribe a precise method of calculating the amount of the required rate change. This is largely accomplished in MDU's proposed Rate 58 tariff.

As in proposed Rate 58, a uniform price change per kilowatt-hour is typically deemed the appropriate way to reflect fuel and purchased power cost changes in rates, although this can become more complex if time-varying rates are adopted.

Q. DO FUEL AND PURCHASED POWER COST ADJUSTMENTS PROCEDURES HAVE A LONG HISTORY?

A. Yes. Fuel cost adjustment procedures between general rate cases date back to World War I, and they remained in effect in many jurisdictions for many years without creating substantial controversy. This situation changed when fuel prices began rising extremely rapidly in the mid 1970's, largely as a result of the oil embargo in 1973-74 and periods of rapid inflation that followed. Electric utility rates increased by billions of dollars through the operation of automatic fuel adjustment clauses in response to these fuel cost increases. These rapid rate increases attracted national attention and automatic fuel adjustment clauses were abolished in several states, either by legislation or by action of regulatory commissions. In some states, the entire notion of rate adjustments reflecting fuel cost changes between general rate cases was done away with; but in other states, procedural changes were made only to the automatic nature of the fuel adjustment process.

Experience over the past 30 years has shown that fuel and purchased power cost adjustment procedures are workable within the overall regulatory process. It is now generally agreed that fuel and purchased power costs are a good candidate for partial cost adjustment procedures, because they are a large fraction of the total cost of electric service and also because they may be more volatile and less controllable than other utility service cost components.

Q. WHAT ARE THE ADVANTAGES OF FUEL AND PURCHASED POWER COST TRACKERS?

A. Fuel and purchased power cost trackers offer only one advantage: because they focus on only some of the many elements in the total cost of service for an electric utility, and because they typically do not involve any consideration of rate structure, they permit prompt and more frequent adjustment of electric utility rate levels, in response to changes in the costs on which they are focused, than is possible in complete rate investigations. This advantage is an important one, with the following consequences:

- If the costs subject to the tracker are moving in the same direction as the total costs of the utility, then the rate adjustment process helps keep the overall rate level in touch with the total cost level of the utility, and therefore it reduces the needed frequency of complete rate investigations. If the costs subject to the tracker are not moving in the same direction as total costs, the tracker process will result in a greater separation of rates and costs and thus make matter worse.

- The tracker process also permits regulatory resources to be concentrated on those cost elements that are large, highly volatile, or otherwise important. It conserves resources that would otherwise be used for repeated study, in complete rate investigations of other cost elements not requiring such frequent regulatory attention.

- Trackers also permit a prompt rate adjustment at times when extremely large changes in one cost of service element make an adjustment in the rate level most essential.

Q. ARE THERE ALSO DISADVANTAGES ASSOCIATED WITH FUEL AND PURCHASED POWER COST TRACKERS?

A. Yes. Trackers also involve a number of disadvantages.

1. Since tracker rate adjustments are based upon consideration of some, but not all, of the costs of an electric utility, it is possible for the rate adjustments to go in one direction while the utility's total costs are moving in the other direction. This result is obviously worse than no tracker at all.

2. Even when not perverse, as in (1), partial cost adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering the offsetting factors, such as productivity improvements, that reduce total cost increases. (In principle, the opposite bias could also be found, but in fact it has not appeared to be a problem.)

3. Trackers may also tend to weaken or distort incentives, and they can be subject to abuse.

Q. WHAT ARE THE POTENTIAL INCENTIVE PROBLEMS OF A COST TRACKER?

A. Trackers may tend to weaken the incentives for a utility to supply electricity at minimum cost. If the rate level is fixed, then it is the shareholders who stand to gain or lose the full amount of any cost savings or increases, at least until the next rate case, when the rate level is reset to the then prevailing cost level. If, instead, there are cost tracker procedures to change the rate level quickly in response to cost changes, then these gains and losses are shifted very quickly to the ratepayers, and management has less incentive to minimize costs than when the benefits or costs go to the shareholders.

Utilities seeking the implementation of cost trackers are sometimes reluctant to acknowledge that such cost-pass-throughs tend to undermine efficiency incentives. For example, in this case MDU was asked:

> “Would the Company’s incentive to minimize fuel and purchased power costs be reduced if its proposed fuel and purchased power cost tracker were adopted?” (See EAC 3.6 part b).

While the undeniable straightforward answer to this question would have been "yes", MDU instead replied:

> "No. Montana-Dakota runs its system on an economic dispatch basis utilizing the most economical units first and the more costly units as needed. A fuel and purchased power tracker will not change the way Montana-Dakota operates its system. (See response to EAC 3.6 part b).

While the question clearly asked about incentives to minimize fuel and purchased power costs, MDU chose to avoid the obvious answer by responding as if the question had asked about incentives for the economic dispatch of the Company's generating units. In reality, MDU is clearly aware of the incentive issue they were asked about, as evidenced by their proposal in this case for offsystem sales revenue sharing. These are obviously parallel issues with parallel incentives, and there is, therefore, a parallel regulatory tool to mitigate the efficiency disincentive inherent in MDU's proposed fuel and purchased power cost pass-through. This will be discussed further below.

In addition to weakening the incentive for a utility to minimize the outlay on items subject to rate adjustment, the existence of a tracker may distort the incentive for a utility to select the most efficient and least costly combination of inputs for supplying electricity. When all costs are rising, the utility may have an incentive to use relatively more of the inputs for which tracker adjustments are possible, and less of the inputs for which there is the greatest regulatory lag in recovering cost increases through higher rates. For example, fuel and purchased power cost trackers may provide an incentive for utilities to build less capital-intensive generating plants that use more or more costly fuel, or to spend relatively less on maintenance or on expenditures to reduce line losses or to achieve optimal resource mix. Among the factors that affect the generation mix, and through it the average fuel cost per kilowatt-hour, one that is extremely important is outages for scheduled and unscheduled maintenance of efficient base load steam generating units.

Since fuel costs per kilowatt-hour are different at different plants, a utility can reduce its total fuel cost by obtaining more electricity from plants with lower fuel costs per kilowatt-hour, and less electricity from plants with higher fuel costs per kilowatt-hour. In this way, the generation mix can have an important effect on total fuel costs. This is essentially the economic dispatch issue that MDU referred to in its misfocussed answer to the question above about fuel and purchased power cost efficiency incentives.

Q. YOU MENTIONED ABUSE OF TRACKER PROCEDURES BY THE UTILITIES TO WHICH THEY APPLY. IS THIS A RISK IN

MONTANA?

A. While abuse is always a potential problem, it is limited in Montana by the oversight afforded in annual tracker proceedings. Without this type of oversight, utilities have sometimes manipulated the transactions to which rate adjustments apply, or simply misstated key facts, taking advantage of the absence of detailed scrutiny by the regulatory authority. The solution to this problem is increased vigilance by the regulatory authority, which is largely achieved in Montana by virtue of the Commission's annual tracker proceedings.

B. <u>TYPES OF TRACKERS</u>

Q. ARE THERE DIFFERENT TYPES OF FUEL AND PURCHASED POWER COST ADJUSTMENT PROCEDURES?

A. Yes. There are two major types of fuel and purchased power cost adjustment procedures that have gained acceptance:

- fuel <u>price</u> adjustments, in which rate adjustments are made to correspond only to the impact of fuel price changes on total fuel costs, disregarding the impact of other elements (such as generation mix); and

- comprehensive fuel and purchased power <u>cost</u> adjustments, in

> which rate adjustments are made to correspond to the full amount of the change in total fuel and purchased power cost per kilowatt-hour of electricity sales, whatever the cause of the fuel and purchased power cost change may be.

In a typical fuel and purchased power cost tracker, such as MDU is seeking in this case, the size of the rate adjustment is simply the difference in total fuel and purchase power cost per kilowatt-hour of sales between the current cost and the amount embodied in the base rates.

As noted above, the principal disadvantage of comprehensive fuel and purchased power cost trackers is that they reduce the incentives for a utility to minimize the costs that it incurs for fuel and purchased power. When markets for fuel and purchased power are unsettled, there may be considerable scope for aggressive action by utilities to seek lower priced supplies. But if fuel and purchased power cost trackers permit utilities to pass on fuel and purchased power price increases to ratepayers, and also require utilities to pass on any fuel cost and purchased power cost savings, then the incentives for management aggressiveness in this regard are reduced.

With a complete fuel and purchased power cost pass-through a utility has no direct financial incentive to economize on its use of fuel and purchased power, especially if these savings depend upon the expenditure of other resources, because the cost of additional fuel and purchased power can be passed on immediately to the ratepayers, whereas the costs of other resources cannot.

Consider, for example, a change in generation mix due to unscheduled plant outages. If these outages are completely beyond the control of the utility's management, and if they have a substantial effect on the utility's fuel cost, then it can be argued that the cost effects should be passed on to ratepayers. However, it is unlikely that plant outages are completely beyond management influence and control. In the competitive sectors of the American economy, each business bears the costs of its own operational difficulties, because it cannot include in its prices the cost of production problems more severe than those experienced by its competitors. This discipline of competition is one of the most important stimulants to productive efficiency, and there is no reason why it should not also be applied to public utilities to the maximum extent possible. If changes in the generation mix are not reflected in rates, then a utility with unusually severe operational problems must bear the costs of these problems, at least until the next rate case, when it can attempt to convince its regulatory commission that these operational difficulties are a proper part of its cost and therefore its rate level. Conversely, a utility with an unusually good operations record will be able to earn greater profits than it would otherwise. These arrangements are the best incentives for good operational performance. Their disadvantage is that they may cause financial difficulties for a utility experiencing unusual problems; and they deny to consumers, at least temporarily, the savings that result from unusually high operating efficiencies.

The key disadvantage of a comprehensive fuel and purchased power cost tracker, then, is that it both weakens and distorts the incentives for cost minimization. With this type of rate adjustment procedure in effect, a utility has no direct financial incentive to either seek out the lowest cost resources or to economize on the use of fuel, when to do so would require the expenditure of money on any other resource that is not subject to a tracker.

Q. ARE THERE ALTERNATIVE TRACKER APPROACHES THAT MAY ELIMINATE OR REDUCE THE INCENTIVE PROBLEM YOU HAVE IDENTIFIED WITH COMPREHENSIVE COST ADJUSTMENT?

A. Yes. If a utility is allowed to include only a substantial part (say 90%) of its calculated fuel and purchased power cost change in its rates, then most of the benefits that result from a fuel and purchased power cost tracker are still being realized; while, at the same time, the incentives that depend upon fixed rates are also present, because a portion of the costs or cost savings that result from changes in fuel and purchased power expenditures accrue to the utility. For this reason the allowance of a rate level adjustment equal only to a percentage of the calculated change in fuel and purchased power costs is an incentive factor. This, of course, is the basic logic of the Margin Sharing Adjustment that MDU proposes for the cost impact of off system sales, but which can be even more important and beneficial if applied to fuel and purchased power cost adjustments as well. The cost and profit percentage split between ratepayers and the utility is an important area for the exercise of regulatory judgment. What is clear is that a 100 percent pass-through of the calculated fuel and purchased power cost change fails to provide the economic incentive that would be inherent in a partial pass-through.

Q. WHAT ARE THE POTENTIAL MERITS OF AN INCENTIVE FACTOR?

A. The argument favoring an incentive factor is based primarily on the proposition that public utility regulation has been and is likely to remain an art, rather than an exact science. Public utilities and the markets in which they operate are far too complex for regulatory agencies to maintain rates at levels exactly equal to what costs currently are, and it is even more difficult for regulatory agencies to ensure continuously that costs are what they should be. Since rates can only be established within a zone of reasonableness, it is mistaken to argue that monthly rate changes must be made exactly equal to monthly changes in fuel and purchased power costs. A tracker cost pass-through, of, say, ninety percent will provide nearly all of the benefits of a full cost tracker, namely extension of the time during which the divergence between rates and costs is kept within a zone of reasonableness, and it would add an important incentive element to rate design. Stronger incentives (i.e., lower percentage factors) may also be desirable; but once there is at least a significant incentive factor, it remains for the judgment of the regulatory agency to determine whether the benefits of stronger incentives are or are not outweighed by the possibility that revenues will fail to keep pace with costs in a time of unsettled fuel and purchased power prices.

V. MARGIN SHARING

Q. PLEASE SUMMARIZE MDU'S MARGIN SHARING ADJUSTMENT (MSA) PROPOSAL IN THIS CASE.

A. MDU's Margin Sharing Adjustment proposal is contained in its proposed Rate 57 tariff. It is a simple formula for splitting profits ("net margins") from power sales that the Company may make in wholesale energy markets between retail ratepayers and the Company. MDU proposes to credit retail ratepayers with 60% of the net margins and to retain 40% for itself. This proposal is in contrast to historic practice in which it was estimated, based on test year concepts, what the Company's net wholesale sales revenues were expected to be, with the full amount (100%) credited against retail revenue requirements. Under that procedure the Company faced an even more compelling profit incentive structure than would exist under the proposed 60/40 splitting arrangement. That is so because a full 100% of any increment or decrement from the test year target would flow through (positively or negatively) to the Company's profit. The proposed 60/40 split significantly reduces performance incentives not only because the potential reward is 40% rather than 100%, but also because it applies only to positive margins, with no risks borne by MDU (other than failure to realize the full potential gain) for sub-par performance.

Q. SHOULD THE COMMISSION APPROVE MDU'S PROPOSED MSA?

A. No; not as proposed. First, the proposed 60/40 split has no valid basis. While the rationale for incentives in a purchased power and fuel cost adjustment mechanism applies equally to a margin sharing adjustment for wholesale sales revenues, there is no sound basis for crediting the Company with 40 percent of realized net proceeds and customers with only 60 percent. Second, it would not make sense to set up a profit incentive mechanism (as opposed to full flowthrough) for only the wholesale sales part of power supply but not for the much larger and for more potentially beneficial fuel and purchased power component of supply.

Q. HAS MDU ATTEMPTED TO JUSTIFY THEIR PROPOSED 60/40 SPLIT?

A. Only insofar as offering their opinion that it is "equitable" and will provide an incentive. Repeated efforts to attempt to get MDU to better support its proposal were unsuccessful. In response to data request MCC-062:

> Please provide all studies and other evidence pertaining to the choice of a 60/40 margin sharing ratio as opposed to alternative ratios.

MDU responded:

> No such studies exist. The 60/40 margin sharing ratio was determined to be an appropriate economic incentive for the Company to maximize the wholesale sales margin while providing a return of the benefits realized directly to the customers.

Following up, in data request MCC-214 MDU was asked:

> A. Please fully explain all rationale that went into the determination.
>
> B. Please explain why this ratio provides a more appropriate incentive than an alternative ratio (e.g., 80/20).
>
> C. Please provide, in detail, all support for the selection of this ratio.

And their only reply was:

> A. The underlying rationale was to determine a margin sharing

ratio that provides an appropriate economic incentive for the Company to maximize wholesale sales margins while providing a return of the benefits realized directly to the customers.

B. A 60/40 ratio provides more incentive for the Company to maximize wholesale margins than would the referenced 80/20 ratio. The Company believes that the 60/40 ratio is appropriate.

C. The 60/40 ratio was subjectively determined by the Company.

In view of the fact that this proposal would substantially redistribute the benefits of offsystem sales revenues in favor of the Company, with a one-way profit increment over and above the "allowed" rate of return, and reduce the cost offset allocated to ratepayers, a far better rationale is required.

Q. CAN ANY PROFIT SHARING SPLIT FOR WHOLESALE NET MARGINS BE JUSTIFIED IN THIS CASE?

A. Yes. First, the historic procedure of adopting a test year offsystem sales amount that is fully credited to ratepayers on a fixed basis provides a rational incentive split. Under that approach, ratepayers would get credit for 100% of the test year target and the Company would get/pay 100% of the actually realized deviation from the target. This historic approach is equitable and provides a strong market incentive.

Second, if as suggested in the previous section, the Commission implements a fuel and purchased power cost tracker with an incentive feature, such as passing through 90 percent of fuel and purchased power cost changes, it would be comprehensive to include wholesale sales offsets in that procedure.

VI. COST ALLOCATION AND RATE DESIGN PRINCIPLES

A. SUMMARY

Q. WHAT IS YOUR OPINION REGARDING MDU'S PROPOSED METHODS FOR COST ALLOCATION AND RATE DESIGN IN THIS PROCEEDING?

A. MDUs cost allocation and rate design procedures follow a traditional framework that is, for the most part, consistent with economic and regulatory principles. However, the Commission should consider modifications to both the Company's cost of service allocations and rate design in several important respects as I explain below. Where my recommendations differ from the Company's, an explanation is provided regarding the considerations that are required in evaluating the alternatives as well as the end-result impacts that are at issue. The substantive cost allocation and rate design issues that I believe merit particular consideration by the Commission in this proceeding include:

- MDU's assignment of all generating plant and transmission facility investments to demand and none to energy; and the related use of non coincident demand as a major generation and transmission capacity cost allocator

- MDU's assumption of "minimum system" and "zero intercept" values to assign distribution system costs to the "customer" classification;
- Assignment of no distribution system costs to energy;
- The potential to give greater attention to marginal energy cost considerations in MDU's rate design proposals; and
- The extent to which rate design improvements may better relate prices to cost causation, including cost-justification for substantially different price signals to customers in different rate classes.

Q. IS THERE ONLY ONE CORRECT WAY FOR MDU TO ALLOCATE COSTS AND DESIGN RATES?

A. No. regulators have considerable latitude in resolving cost allocation and rate design issues in cases like this. Public policy considerations and other factors requiring the exercise of discretionary regulatory judgment typically play a significant role in resolving questions about "fairness" and "equity" that are central to these subjects. Even determinations involving cost causation require subjective judgments to deal with alternative perspectives.

B. PRINCIPLES, CONCEPTS AND ISSUES

Q. WHAT ARE THE OBJECTIVES OF COST ALLOCATION AND RATE STRUCTURE?

A. The objectives of utility rate structure have been recognized for many years. Professor James C. Bonbright provided a useful and comprehensive enumeration of these objectives in his well-known 1961 text, Principles of Public Utility Rates. Bonbright identified the three primary criteria of a desirable rate structure as follows:

1. Providing the required revenues;
2. The "fair-cost-apportionment objective"; and
3. The optimum-use or "consumer rationing objective."

The fair cost apportionment objective (as well as the total revenue requirement objective) is mandated under law in many regulatory jurisdictions.

In addition, Bonbright identified several other criteria that are not necessarily subsumed by the three primary criteria. They are:

1. “The related ‘practical’ attributes of simplicity, understandability, public acceptability, and feasibility of application.”

2. “Freedom from controversies as to proper interpretation”.

3. “Revenue stability from year-to-year.”

4. “Stability in the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.”

These additional criteria, although important, are generally assigned less weight in evaluating a rate structure than the “three primary criteria.”

Q. HAVE THESE CRITERIA OR OBJECTIVES CHANGED IN RECENT DECADES?

A. The substance of these objectives has not changed over the ensuing four decades, although the emphasis placed on the primary objectives has increased significantly. Most notably, beginning in the late 1970s with the passage of the Public Utilities Regulatory Policies Act (PURPA), the complementary goals of <u>conservation</u>, <u>efficiency</u> and <u>equity</u> emerged as the hallmark of modern electric utility rate design. An economically sound cost-of-service study is a critical precondition to the achievement of these goals.

Q. HOW ARE ELECTRIC UTILITY RATES GENERALLY ESTABLISHED?

A. The traditional process for establishing a set of electric utility rates involves five steps:

1. Establishing the total revenue requirement, or rate level, required by the utility;
2. Grouping of customers into classes upon which different rates will be imposed;
3. Dividing the total revenue requirement into the revenue responsibilities for each rate class. This is usually done by functionalizing, classifying and allocating the utility's rate base and operating costs;
4. Designing the general rate form to be used to collect the appropriate revenue from each class; and
5. Specifying the detailed elements of each rate, in accord with the overall rate design, class revenue responsibilities, and test year quantities of service to be furnished by the utility.

Q. LOOKING AT EACH OF THESE FIVE STEPS INDIVIDUALLY, WHAT ROLE DOES ESTABLISHING A TOTAL REVENUE

REQUIREMENT FOR AN ELECTRIC UTILITY PLAY IN TERMS OF STRUCTURING RATES?

A. Although the revenue requirement (or rate level) is often the issue that is most hotly contested in electric utility rate proceedings, it has little or no direct bearing upon most rate structure issues. It is the assignment of the total revenue requirement to customers based on cost allocation and rate design that results in rates charged to each type of customer.

The utility and its management are always concerned with the allowed revenue requirement, because it is a primary determinant of the Company's profitability, but they have often been less urgently concerned with how the responsibility for this revenue is divided among the customer classes. In large part, this has been attributable to the fact that utilities have had sufficient monopoly power to succeed in collecting their allowed rates, no matter how total revenue requirements are divided among customer classes.

Customers have an equally obvious interest in the disallowance of excess revenues, and their interest in rate structure has often been limited by their view of rate design as essentially a zero-sum game, once the total system revenue requirement has been determined. Each class may seek to have its own share of the total revenue requirement reduced, at the expense of other classes; but these maneuvers do not directly change the total burden of the rates upon all the customers together.

In more recent years, as various forms of competition have forced their way into electric utility markets, utilities have become increasingly concerned about cost allocation and rate design and have often attempted to use these tools in conjunction with competitive objectives. In some cases this has resulted in attempts to allocate costs and design rates to gain advantage in potentially competitive markets (e.g., markets for industrial loads with alternative fuels, wheeling or locational alternatives) at the expense of more monopolized market segments.

Q. THE SECOND CRITERION FOR SETTING ELECTRIC RATES IS GROUPING CUSTOMERS INTO CLASSES. WHY IS THIS DONE?

A. Customers are grouped into different classes so that they may be charged different rates. These rate differences are intended to reflect differences in the character of the service provided or in the cost of furnishing service. Differences in the former (even where the character of the service is not related to cost) have often been as important as differences in the latter.

In practice, the grouping of customers into rate classes has often been done largely by tradition, with the only test ordinarily imposed being that of continuity. The traditional customer classes are often so well accepted that their continuation is not even perceived as an issue in many rate proceedings.

Q. ONCE CUSTOMERS ARE GROUPED INTO RATE CLASSES, HOW IS THE THIRD CRITERION, THE ESTABLISHMENT OF REVENUE RESPONSIBILITIES OF EACH CLASS, DETERMINED?

A. With the customer classes fixed, the task of apportioning the total revenue requirement among them is performed using a class cost of service study. In its most advanced form, a traditional class cost of service study allocates the total cost of service (which is all of the costs comprised by the revenue requirement) among the various rate classes. Alternatively, allocations may be made to customer categories that are broader than individual rate classes (e.g., residential, commercial, industrial), with further cost attribution to individual rate classes in term of less precise discretionary procedures. In class cost of service studies, the Company's test year costs are grouped into functions, such as generation and distribution, and then are classified and allocated among the classes in proportion to the perceived use made by each class of each functional cost element. For example, fuel costs are generally allocated among the classes in proportion to each class's energy use (kilowatt-hours); while capacity costs are generally allocated in proportion to class demands (kilowatts) as well as capacity usage (kilowatt-hours). An important characteristic of the traditional class cost of service study is that it is based upon total or average embedded costs, as they are recorded and used in the ratemaking process for establishing the revenue requirement, rather than upon other possible measures of economic cost, such as marginal cost.

Q. PLEASE EXPLAIN WHAT IS DONE IN THE FOURTH STEP OF DESIGNING THE GENERAL RATE FORM TO BE USED TO COLLECT THE APPROPRIATE REVENUE FROM EACH CLASS?

A. Rate design is the establishment of the general principles according to which a specific rate is constructed. For example, the choice between a one-part rate, which has only an energy (kilowatt-hour) charge, and a two-part rate, which is both demand (kilowatt) and energy charges, is an issue in rate design. So is the choice between a declining block rate and a flat rate, and so forth. Rate design questions are sometimes addressed with specific reference to the cost structure as developed in the class cost of service study, but the judgment, experience and objectives of the rate analysts are also important ingredients. In most cases, the existing rate design is simply carried forward with only minor modifications. When rate increases are large and rate design changes little, it is sometimes perceived as a less important issue. When rate design can have a large impact on competition, its relative importance is elevated.

Q. WHAT IS THE FIFTH AND FINAL STEP IN ESTABLISHING ELECTRIC RATES?

A. The last step in the development of a rate structure is the selection of the numerical values for the specific rate elements. These elements must be chosen in such a way that the rates recover the authorized total revenue requirement or, if class revenue responsibilities have been determined, the authorized responsibilities for each class. This is accomplished by reference to the billing determinants for the test year. The billing determinants are the quantities for each kind of service provided and billed by the utility, such as kilowatt-hours of usage in each rate block, kilowatts of demand, and number of customers. The test year is the twelve-month period to which the revenue requirement determination is applicable, and the billing determinants for the test year are the quantities of service from which the authorized revenue is to be recovered. The new rates must therefore be calculated so that, when applied to the test year billing determinants, they provide precisely the authorized revenue for that test year. Selection of the specific rate elements that meet this requirement, and that are constructed in accord with the accepted rate design principles, completes the process of constructing authorized rates.

Q. ARE THERE INCENTIVES FOR UTILITIES LIKE MDU TO EMPLOY COST ALLOCATION TECHNIQUES THAT TEND TO FAVOR CERTAIN TYPES OR CLASSES OF CUSTOMERS?

A. Theoretically, it can be expected that, under certain conditions, a firm operating in two or more distinguishable market sectors with different degrees of competition may attempt to strengthen its posture in competitive markets by reducing rates there and making up the difference with higher rates in less competitive markets. That tendency is greatest where, as here, the firm's total rate of return is constrained by regulation.

From a regulatory policy perspective, permitting this practice would be undesirable. Rate regulation, after all, was established for the primary purpose of protecting customers in monopolized markets from overcharges and monopolistic abuse. Clearly, MDU's residential and small commercial ratepayers who purchase electric power and energy in a market that is, as a practical matter, monopolized by MDU, are the ones most in need of the regulatory protections that this Commission was established to provide. Customers who purchase goods and services in competitive markets do not require the same degree of protection since their interests are guarded, at least in part, by competitive market forces. Thus, especially where, as here, a great deal of discretion must be exercised in the allocation of shared costs between customers in more competitive and less competitive market segments, considerable regulatory attention is required to assure that cost allocation is not tilted against those customers with the least viable competitive options. They are the customers most in need of regulatory protection.

It would be ironic if the regulatory system was used to create relative benefits (i.e., lower rates in relation to costs) for those customers with the greatest competitive market options at the expense of those customers with the least.

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY?

A. The most important use of a cost-of-service study is to determine the cost responsibility of each customer class, which can then be used as a guide to determine the revenue responsibilities and rates for each class.

Q. WHAT ARE THE MOST COMMON CONTROVERSIES IN ALLOCATING COSTS?

A. The most common controversies surrounding the proper classification and allocation of costs concern the classification of (1) production and transmission costs between demand- and energy-related components, and (2) distribution facilities costs between customer, energy, and demand related components. Cost classification procedures that assign more costs to "demand" and less to "energy" favor high load factor customers (e.g., industrials) and result in higher charges to low load factor customers (e.g., residential and small commercials). Likewise, cost classification procedures that assign more costs to energy and less to demand favor low load factor customers and result in higher rates for high load factor customers. This outcome follows from the fact that high load factor industrial customers buy a relatively large amount of energy (kwh) in relation to their capacity demands (kw), whereas low load factor residential and small commercial customers require more capacity in relation to their energy needs. Similarly, classification methods that attribute more costs to "customer" and less to "demand" or "energy" result in lower bills for big customers and higher bills for small customers. Not surprisingly, perceptions of cost allocation equity typically differ between customer groups in concert with these predictable end results. That is why large industrial customers almost always argue for allocation methods that attribute as much of total cost as possible to demand and as little as possible to energy. Utilities concerned about the greater competitive options that are available to large industrial than to small commercial and residential customers will often have the same bias.

Q. ONCE COSTS HAVE BEEN ALLOCATED TO CUSTOMER GROUPS, HOW DOES RATE DESIGN PROCEED?

A. Customers are grouped into different rate classes so that they may be charged different rates. These rate differences are generally intended to reflect differences in the cost of furnishing service, but sometimes they reflect end use differences that are not correlated with cost differences. In general, after customers are grouped into several classes, each class purchases its electricity service from a different rate schedule. Each electric rate schedule, or tariff, is a price list for electricity service. Rates for each class of customers are set at levels that are intended to recover that portion of the utility company's costs that is apportioned or allocated to the class.

Rates must be calculated so that, when applied to the test year billing determinants, they provide the authorized revenue for that test year. Selection of the specific rate elements that meet this requirement, and that are constructed in accord with the accepted rate design principles, completes the process of constructing authorized rates.

Q. IS MDU'S PROPOSED RATE DESIGN IN GENERAL CONFORMANCE WITH THESE PRINCIPLES?

A. Yes, both MDU's proposed cost of service study and rate design follow these general principles. Within this general framework, however, there are modifications that I would urge the Commission to consider.

VII. MDU'S COST OF SERVICE STUDY

Q. HAVE YOUR REVIEWED MDU'S COST OF SERVICE STUDY IN THIS CASE?

A. Yes, I have.

Q. WHAT ISSUES HAVE YOU IDENTIFIED WITH RESPECT TO MDU'S COST OF SERVICE STUDY?

A. As stated above, while MDU's cost of service study conforms to general cost of service principles, there are several key issues in the Company's application of cost classification and allocation that the Commission should consider.

First, MDU has chosen to attribute all of its generation and transmission plant costs to demand and none to energy. This choice results in an allocation of generation and transmission costs that falls well short of conforming to the principles of cost causality. The end result of MDU's approach is to attribute more generation and transmission costs to low load factor customers (i.e., residential and small commercial) and fewer costs to high load factor customers (i.e., industrial) than would result from an allocation based on both demand and energy.

Complicating this problem MDU has allocated 67% of generation plant costs and 80% of transmission plant costs on the basis of non-coincident demand - - that is, on the basis of each customer's own peak demand whether it occurs at a system offpeak or at an onpeak time. While a non-coincident demand allocator is often used to allocate local distribution plant costs, I have never before seen an electric utility allocate generation and transmission costs in this manner. (MDU has informed me that the North Dakota Commission has adopted rates derived from the Company's NCP allocation procedure, even though the Commission did not comment on or acknowledge the procedure it its order. See response to data request MCC-366). To the extent that generation and transmission plant investment levels are caused by peak demand, it is usually recognized that they are caused by coincident peak demand - - not non-coincident peak demand. It is also often recognized that generation and transmission plant investment is not all caused by coincident peak demand, but also by the amount of energy produced and delivered. MDU, however, has allocated no generation plant costs on the basis of energy.

A non-coincident peak demand allocation method assigns demand-related costs to customer classes in proportion to each class' share of the sum of all class non-coincident peaks ("NCP"). Thus, in contrast to the coincident peak method, this procedure distributes the interclass diversity benefits so that classes that have peaks coincident with the system (such as high load factor industrials) are assigned a smaller share of total NCP demand-related costs, and classes with high diversity (such as the residential class) are assigned a larger portion of these costs.

The Company's choice to allocate generation and transmission capacity on the basis of non-coincident peak demands is particularly harmful to residential and small commercial ratepayers whose non-coincident peaks are quite diverse and it is beneficial to large industrials whose non-coincident peak totals are more similar to coincident peaks because of their high load factors and lack of diversity. The table below shows the percentage of costs allocated to each major class using MDU's coincident demand, non-coincident demand and energy. Again, MDU allocates 67 percent of generation plant and 80 percent of transmission plant using non-coincident demand while allocating none of these costs based on energy.

Class	Non-Coincident Demand	Coincident Demand	Energy
Residential	35.28%	28.25%	23.99%
Small Commercial	22.86%	25.89%	16.48%
Large Commercial	39.25%	44.10%	56.91%

MDU has also assigned a large percentage (about 80%) of its distribution plant costs to the customer category and none of these costs to energy. The Company's large assignment of distribution costs to the customer category is the result of using a so called "minimum system" method that incorrectly uses actually used equipment as a proxy for minimum system design. As in the case of attributing all generation and transmission plant to demand, assigning most distribution system costs on a flat per customer basis results in greater cost responsibility for small customers. In this case residential customers get 55.4 percent of the distribution plant cost allocation even though they account for only 37.3 percent of distribution voltage energy deliveries. This end result is the obvious outcome since small customers account for a much larger percentage of total customers than they do for total demand or energy.

As shown below, if MDU's plant costs are reallocated to more properly reflect (1) energy responsibility for plant investment and, (2) a smaller attribution of distribution system costs to the customer category, the calculated rates of return for customer classes change substantially. Under this alternative approach, the end result indicates that residential customer rates produce returns close to the system average.

Indicated Rates of Return (Before adjustments)

Rate Class	MDU Study (JWW-1)	Corrected Study (JWW-3)
Total Company	4.024%	4.024%
Residential	-2.207%	3.281%
Small General	-3.386%	-0.756%
Large General Primary	9.004%	8.533%
Large General Secondary	11.035%	2.740%
TOD Primary	13.899%	11.748%
Contract	25.685%	9.300%
Mun. Pumping	-1.101%	-3.540%
Priv. Lighting	30.203%	23.694%
Street Lighting	15.344%	6.881%

A. GENERATION COSTS

Q. HOW SHOULD GENERATION PLANT COSTS BE ALLOCATED?

A. A portion of generation plant costs are driven by the system maximum peak (CP). It is therefore logical to allocate these CP related costs in proportion to each customer or rate class contribution to the single system coincident peak. MDU reasonably allocates one-third of its generation plant costs on the basis of CP.

It is also generally recognized that hours other than the peak hour are critical from a system planning perspective, and regulators and utilities have moved toward multiple peak allocation methods as well as the division (classification) of generation plant costs between energy and demand responsibility. The FERC's application of the 12-CP method in its allocation of generation costs between jurisdictions based on the combination of the twelve monthly system coincident peaks rather than on the basis of contribution to the single highest hourly demand during the year is an attempt to at least capture relevant cost-causative attributes of the loads that the utility must serve. That is, although the monthly peaks in, say, the spring and fall months may be significantly below the winter and summer peaks, the probability of losing load and capacity needs may be similar in all seasons because most scheduled maintenance occurs during the spring and fall months. Thus, under FERC's jurisdictional allocation method, which MDU has used for jurisdictional (but not class) cost allocation in this case, it is argued that there is little or no seasonal or monthly variation in demand responsibility, and so an average of all twelve monthly peaks is used as the measure of peak demand. This implies that generation and transmission capacity is not installed to meet only coincident peak demand, but rather to maintain system reliability during all months of the year. Note that while this approach may justify the allocation of generation and transmission plant costs that are properly classified as demand-related on the basis of 12-CP, they do not warrant the allocation of energy-related capacity costs in proportion to CP demand.

Q. WHAT OTHER METHODS ARE USED TO ALLOCATE GENERATION PLANT COSTS?

A. It is now generally recognized that energy loads are a major determinant of generation plant costs. Consequently, a number of methods have been developed to incorporate energy weighting into the allocation of production plant costs. Typically, this is done by classifying part of the utility's production plant costs as energy-related and allocating those costs to rate classes based on energy consumption. Two methods that follow this approach are: "Average and Peak" and "Equivalent Peaker."

Q. PLEASE EXPLAIN THESE METHODS.

A. Under the Average and Peak method, each class' average demand (load factor times CP) is combined with its peak demand to develop the class allocator. The end result is that the system load factor determines the percentage of plant costs to be allocated as energy-related, and the remainder (1-load factor) is allocated in proportion to each class's CP demand.

Alternatively, the "Equivalent Peaker" method reflects generation expansion planning objectives as they relate to both peak loads and energy loads in determining the most cost-effective type of generation capacity to be added. The premise of the peaker method is that increases in peak demand require the addition of peaking capacity and that utilities incur costs for more expensive intermediate and base load units because of the energy loads they must serve. That is, in the system planning process, utilities first determine their need for additional capacity and then choose among the available generation options. These options may include low-cost combustion turbines ("CTs"), more expensive combined cycle units and even more expensive base load coal or nuclear units. The choice of unit depends on the duration of the load to be served. A peak load of brief duration would be most economically served by a CT, whereas a continuous load would be served most economically by a base load unit. Thus, the cost of a peaker is determined by peak demand, but the additional cost of a base load unit is determined by energy needs. In other words, the ratio of the cost of peaking capacity per unit of load (kW) to the utility's total capacity cost per unit of load determines the percentage of generation plant cost to be classified as demand, with the remainder being classified as energy.

Q. WHAT METHOD DO YOU RECOMMEND IN THIS CASE?

A. Because it is clear that a large portion of MDU's base load generation plant investment is driven by energy requirements and not just by demands at coincident peaks, I would recommend that the Commission give consideration to allocation methods that incorporate significant energy weighting into the allocation of production plant. In this case, for example, MDU's cost allocation would have been more reasonable if it had used energy (kwh) rather than NCP to allocate the portion of generation and transmission plant that was not allocated based on coincident peak. Below, I will present these alternative cost of service results to illustrate how the choice of methodology will alter conclusions about the return levels that are attributable to each rate class. Ironically, although MDU appears to acknowledge that capacity costs are incurred for purposes other than meeting peak demand, they use NCP to allocate the non-CP portion of their generation and transmission plant costs – which results in even less acknowledgement of energy load as a determinant of plant investment costs. They also mistakenly cite texts that advocate a more equitable and broadly based allocation of plant costs as justifying their NCP approach. (See response to data request MCC 312)

Q. WHY SHOULD A PORTION OF THE COMPANY'S GENERATION PLANT COSTS BE ASSIGNED IN PROPORTION TO ENERGY CONSUMPTION INSTEAD OF ASSIGNING ALL OF THESE COSTS TO CP AND NCP DEMAND?

A. Virtually all utilities, including MDU, install and maintain various types of generating units. Some plants are used to deliver energy practically around-the-clock. Consequently, these investments are made with an aim to reducing energy costs, in addition to meeting peak demand. If a utility's goal for power plants were simply to meet peak demand rather than building expensive base load capacity, it would install only low capital cost peaking plants with much lower generation and transmission network capital requirements. Peakers and their associated transmission facilities have much lower capacity costs but are more expensive to run. But, if they only run during peak times, the higher running costs are justified in order to save on capital costs. Much more costly, but operationally efficient (i.e., low operating costs), base load generating plants and associated transmission grids are installed, if they can be run long enough to generate enough fuel savings that more than offset their higher capital expenditures. Hence, these higher capital costs are incurred to serve year-round energy requirements at lower total costs. When a plant serves both base load and peak needs (as most base load plants and transmission systems do), its cost classification should reflect both functions.

Q. ARE THESE SAME CONSIDERATIONS RELEVANT TO TRANSMISSION PLANT INVESTMENTS?

A. Yes. As discussed below, these same principles are true for capital intensive, high voltage transmission grids that deliver power from generating plants and tie their output together in an integrated network. Base load plants and their associated transmission grids are used to produce, coordinate and deliver energy around-the-clock, and a significant portion of their relatively high capital costs are justified by long hours of use (i.e., an energy consideration) and not predominately by a limited peak hour demand.

B. TRANSMISSION COSTS

Q. HOW SHOULD TRANSMISSION COSTS BE CLASSIFIED AND ALLOCATED?

A. Utilities typically use transmission for three purposes: to reduce generating costs, to increase energy delivery reliability and to mitigate the need to add generating resources. Transmission facilities reduce the cost of kWh output by permitting the development of efficient base load generating units and integrating generation resources. A cost-minimizing utility maintains a mix of generating resources in order to meet the varying demands placed on its system. This mix allows the utility to reduce overall production costs, thereby lowering the cost of energy. In order to be successful at this, the utility uses its transmission grid to achieve optimal dispatch. Hence, a capital-intensive transmission grid reduces energy costs, and this should be recognized in the classification of transmission costs. Also in this way, the large energy consumers who benefit from the lower cost energy that these investments make possible will pay a fair share of the costs that reduce their energy charges. This cost-causality is not recognized in MDU's classification of transmission costs, which attributes all transmission grid costs to CP and NCP demand.

Q. PLEASE EXPLAIN HOW TRANSMISSION INVESTMENT REDUCES ENERGY COSTS.

A. When utilities make capital intensive transmission (and generation) investments, they typically make their choice based on a variety of engineering considerations related to system loads and resources. Many of these considerations are energy related—such as decisions to build base load plants, even though they are more capital intensive, because they are more economical to run for long periods of time. Likewise, the location of such plants at sites remote from load centers—because those remote sites are close to fuel supplies and/or because they minimize environmental or public safety impacts—is likely to involve more capital investment in transmission. But this does not mean that the actual cost of this transmission plant is the best (or even a good) measure of peak related transmission capacity costs. The reason is that a substantial portion of the actual plant investment resulted from energy considerations and should not, therefore, be counted as a demand-related cost of transmission capacity. If an efficient utility were solely interested in adding capacity, and energy was not an issue, it would add the least costly plant to build and the cost of connecting this plant to the distribution grid would be the transmission cost caused by peak demand. Large transmission networks for load and resource integration and energy transport from remote base load plants would not be required or justified.

The transmission system function of tying the generation plants together in an integrated network for system reliability is quite different from the movement of additional peak capacity. Transmission capacity that permits interconnection for system reliability, or that is in lieu of constructing more generation capacity reserves, involves costs independent of the movement of additional capacity at peak times. Transmission costs incurred for such reasons are not primarily a cost of providing additional peak capacity. The same is also true for large transmission level substations. These are typically needed on integrated systems that efficiently tie remote base load plants to network load centers, but their costs are not primarily attributable to the cost of peak demand.

Q. ARE THERE OTHER WAYS TO RECOGNIZE THE IMPORTANCE OF ENERGY REQUIREMENTS AS A DETERMINANT OF TRANSMISSION PLANT COSTS?

A. Yes. Some utilities and regulators have attempted to recognize that transmission investment is undertaken for energy as well as demand purposes by categorizing each planned facility as related to growth in demand or as related to “non-demand” usage. There are some problems with such an approach, however. First, it is not economically possible to neatly pigeon-hole all facilities as demand versus non-demand because in the real world they actually serve a dual function. Second, the approach has the potential for costly and unproductive litigation over the appropriate designation of facilities. Third, a designation approach also provides an opportunity to inappropriately affect rates by biasing determinations of demand versus non-demand investments. For example, it may be profit-maximizing for a utility to shift costs away from those who are more able to turn to economical energy alternatives, like alternative fuels, self-generation or off-system suppliers.

If a generation plant is located near the source of fuel rather than near the load center, the cost of fuel is reduced but transmission costs are increased. Likewise, if a base load plant is sited at a remote location for water, environmental, fuel or safety reasons, the power generated there must be transmitted over high-voltage transmission to load centers and integrated on a transmission network with power production from other locations. The result is a savings on energy-related generating costs at the expense of greater transmission costs. Those who benefit from low cost energy consumption should be allocated an energy share of these costs. In MDU’s case, substantial transmission investment and expense is clearly related to both the transport and network integration of less costly energy from base load plants rather than to simply meet peak demand. The important network integration aspect of these facilities would be better recognized as in the case of generation plant, by assigning a significant portion of all transmission plant to energy.

C. <u>DISTRIBUTION COSTS</u>

Q. DO YOU AGREE WITH THE WAY THAT MDU HAS ALLOCATED ITS DISTRIBUTION SYSTEM COSTS?

A. No. While I will recommend several alternatives to MDU's allocation methods for distribution system costs, the largest fault that I find with the Company's procedure is that it allocates nearly all of its distribution system cost (about 80%) on a flat per customer basis. Only a small part of distribution system costs are allocated in proportion to demand and none are allocated in proportion to energy deliveries. Electricity delivery systems and the facilities that comprise them (poles, wires, transformers, etc.) are designed by their manufacturers and installed by utilities to meet demand and load requirements and should not be allocated so predominantly on a flat per customer basis. MDU's allocation method for distribution system costs results in a very large portion of these costs being allocated to residential customers because they account for 77 percent of MDU's Montana customers.

Q. IS THERE ALWAYS GENERAL AGREEMENT AMONG RATE ANALYSTS AS TO HOW CUSTOMER-RELATED COSTS SHOULD BE CLASSIFIED?

A. No. Most rate analysts do agree that a portion of total distribution facility costs should be classified on a customer-related basis. For example, billing and accounting costs, meters and service line drops are reasonably considered to be customer-related. However, the customer component of distribution facilities can be exaggerated and that results in smaller customers being allocated a much greater portion of costs than their share of overall consumption. Such a cost-shift is often based on a motivation to recover more costs from those market sectors with the less competitive alternatives in order to bolster the prospect for economic success in more competitive market segments. To the extent that rate design follows cost allocation, this cost allocation also provides a stable (fixed charge) revenue stream that is unaffected by ups and downs in sales volume.

Q. IS MDU'S CHOICE OF AN NCP ALLOCATOR, RATHER THAN CP, FOR DISTRIBUTION PLANT THAT IS PROPERLY ALLOCATED TO DEMAND A REASONABLE CHOICE?

A. Yes. The coincident peak method basically allocates all costs classified as demand-related to customer classes in proportion to each class's contribution to the system coincident peak or peaks. The rationale for this approach is that the required capacity is determined by the maximum annual or monthly coincident demands to be placed on the system. However, this rationale does not hold where the cost level is not determined by system coincident peak demands. In the case of local distribution networks, it is local loads, which often vary from the system coincident peak, that determine plant requirements. Therefore, a noncoincident demand allocator for distribution capacity is generally thought to be more reasonable for cost allocation.

Since each class may experience its own peak at a different time than when the system peak occurs, the sum of the non-coincident class peaks typically will exceed the system coincident peak by a significant margin. This inter-class diversity benefits the system in the sense that the utility need only install sufficient generation capacity to meet the diversified (i.e., coincident) peaks of the several classes.

Q. PLEASE SUMMARIZE MDU'S ALLOCATION OF DISTRIBUTION SYSTEM COSTS.

A. MDU has employed a version of what is sometimes referred to as a "minimum distribution system" or "minimum-size" methodology in an effort to assign distribution plant and associated distribution costs on a flat per customer basis rather than in proportion to power demand or energy consumption. The Company then uses this methodology to allocate most of its distribution system costs among customer classes on the basis of the number of customers in each rate class. Because the residential class has, by far, the largest number of customers, and, on average, residential customers typically use much less electricity than large commercial and industrial customers, the Company's minimum-system methodology assigns a very high percentage of distribution plant costs to the residential rate classes.

Q. PLEASE DESCRIBE THE MINIMUM DISTRIBUTION SYSTEM METHODOLOGY.

A. The minimum distribution system methodology generally involves the estimation of costs associated with a <u>theoretical minimum plant</u> that would be required to serve a minimum (i.e., near zero) load. In contrast, the methodology employed by MDU in this case apparently involves the Company's estimated cost of constructing a normal system under normal industry circumstances but with relatively small sized (but high cost) facilities that are capable of carrying normal small loads. Because MDU has used actual, contemporary standard equipment and conventional system construction (such as triplex wire, pad-mounted transformers and underground conduit) designed to meet today's actual and anticipated loads in costing out its estimate of a minimum size system, the end result includes substantial costs that are clearly load related, and is not "minimum system" at all. Rather than a theoretical construct, the Company's approach reflects the cost of the smaller, but still highly costly, load carrying facilities that are actually installed and operating on its system. As such, the costs of this system reflect its demand and energy carrying capability rather than representing only fixed costs that would be incurred independent of demand and load levels. Consequently, the use of MDU's methodology to determine a fixed customer cost component for rates severely tilts distribution cost allocation in a way that is costly to small customers with relatively small loads.

Q. WHAT EVIDENCE SHOWS THAT MDU'S MINIMUM SYSTEM COST ESTIMATE IMPROPERLY REFLECTS THE COSTS OF ACTUAL LOAD SERVING FACILITIES RATHER THAN THE THEORETICAL COST OF A NEAR-ZERO LOAD SYSTEM?

A. The Company has used nothing other than actual load-serving facilities costs to develop its minimum system cost estimated. Moreover when asked the costs of smallest known units of equipment, the Company did not even know (see response to datea request MCC-278):

> (b) For each of the above types of equipment [poles, overhead conductor, underground conduits, underground conductors,

underground devices, meters] please state the smallest size unit known to be available and the unit cost thereof

Response:

(b) Information is not available as requested.

Further, even though the Company has nearly 500 single phase transformers in Montana ranging in size from 3KVA to 7.5KVA (see response to data request MCC-246, attachment C) the smallest size transformer that MDU used to estimate minimum system costs was 10KVA. Also, although most single phase line transformers are overhead (pole mounted) equipment, MDU used only much more expensive pad mounted transformer equipment to estimate minimum distribution system costs.

Q. WHAT IS THE BASIC PREMISE WITH RESPECT TO THE CUSTOMER COMPONENT OF DISTRIBUTION SYSTEM COSTS?

A. The basic premise is that these costs do not vary with demand levels or energy usage. Therefore, it is not proper to allocate or charge for these costs on the basis for demand or energy. Rather than allocating or charging these costs on the basis of system usage or in proportion to the amount of service that is provided through these facilities, the premise is that they should be recovered through fixed monthly customer charges. It should be noted that in this case, while MDU has allocated a large portion of distribution system costs based on number of customers, it has not fully reflected these costs in customer charges, but has included a substantial portion of them in energy charges within the residential and small business classes.

Q. ARE DISTRIBUTION SYSTEM COSTS UNRELATED TO LOAD OR ENERGY REQUIREMENTS?

A. No. During the past century the cost of electric utility distribution facilities has increased by a multiple of more than 30 times, and the cost of some distribution system components (e.g., poles and fixtures) has increased by far more than this. Over the same period, overall price levels in the economy (as measured by the CPI) have increased by only about 20 times. But, this is not to say that the rate of inflation for electric distribution equipment has been double or triple the overall rate of inflation.

Over the years the standard quality and capability of electric distribution equipment has been significantly enhanced. Fifty years ago average distribution line transformers in the industry were about one-third the size (measured in KVA capacity) of today's average transformer and, yet, they served an average of 7-8 meters as compared with today's average of about 3-4 meters.

In short, distribution system equipment has been substantially redesigned and upgraded to meet load requirements as they have grown over time. For this reason, it would be a great pricing distortion to assume that the cost of today's actual distribution equipment and its installation is a reasonable basis for computing the cost of a minimum theoretical system designed to serve a near zero load.

Q. WHAT IS YOUR ESTIMATE OF THE COST OF A MINIMUM THEORETICAL SYSTEM DESIGNED TO SERVE A NEAR ZERO LOAD?

A. I would estimate that the cost of such a theoretical system would be no more than 10 to 25 percent of the actual distribution system costs. MDU has estimated that the minimum system is about 80 percent of actual costs, but that estimate reflects the actual cost of state-of-the-art facilities designed, sized and installed to handle today's actual loads. In contrast, we know that (1) today's actual distribution equipment has been substantially enhanced over time to meet increased load requirements, (2) more equipment per meter served has been required as load has grown, (3) about half of today's equipment cost level is attributable to load related upgrades that have occurred over time rather than to price inflation and (4) even the starting points for these comparisons were actual systems and equipment rather than a theoretically minimum system designed to meet a near zero load level. It follows that the theoretical minimum cost would be in the range of 10 to 25 percent of MDU's actual cost rather than 80 percent as the Company proposes.

Q. ARE THERE ADDITIONAL REASONS FOR REJECTING THE ALLOCATION OF DISTRIBUTION NETWORK COSTS ON A PER CUSTOMER BASIS?

A. Yes. Allocating these costs on a per customer basis ignores the basic fact that the costs associated with investments in distribution lines and related equipment are part of an integrated power delivery network; they are not customer-specific facilities that are causally attributable on the basis of customer counts.

Q. WHY IS THAT?

A. MDU's distribution facilities have been sized by manufacturers and installed to meet the expected loads placed upon them, and not to meet a specific number of customers to be served. It therefore makes little sense to allocate these distribution plant costs on the basis of the number of customers being served in each rate class. The fact that an electric utility's distribution lines are sized and installed to meet customer loads and not customer counts is demonstrated by the following hypothetical example: An area of a specific size may contain 20 individual commercial customers, each with a 50 KW peak load, or 4 office buildings, each with a 250 KW peak load, or 5 apartment buildings, each with 40 individually metered apartments having a 5 KW peak load. While the number and type of service connections and meters will vary directly with the number of customers and there are likely to be some differences in transformer configuration, the local distribution facilities must be structured to handle a 1,000 KW peak load in each case, regardless of whether there are 4 or 20 or 200 customers. Thus, as Bonbright *et al.* have observed:

> The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system - a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-size distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

> What this last-named cost computation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis (in Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the cost of a minimum-size distribution system.
>
> (James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Public Utility Reports, Inc., Arlington, Virginia, 1988)

Q. ARE THERE FURTHER REASONS FOR QUESTIONING THE ALLOCATION OF MINIMUM DISTRIBUTION SYSTEM COSTS ON A PER CUSTOMER BASIS?

A. Yes. That approach overallocates distribution costs to smaller customers whenever the minimum system is not a purely zero load system. That is clearly the case here. Consider the following hypothetical: assume that there are 100 small customers with a combined peak load of 1,000 and 10 large customers with a combined peak load of 3,000. Further, assume that 50% of distribution costs are asserted to be minimum system costs to be allocated on a per customer basis and only the remaining 50% of these costs are allocated in proportion to demand. In this event, the small customers would be allocated 57.95% of the distribution costs and the large customers would be allocated only 42.05% of the costs:

$$\text{Small Customers} = \frac{100}{110} \times .50 + \frac{1{,}000}{4{,}000} \times .50 = .5795$$

$$\text{Large Customers} = \frac{10}{110} \times .50 + \frac{3{,}000}{4{,}000} \times .50 = .4205$$

But if the so-called minimum system could actually handle loads, then an adjustment is necessary to reflect a credit for demand costs that are, in effect, actually covered by minimum system charges. For example, if the so-called minimum system could actually handle, say, 50 percent of demand, and distribution system costs were a linear function of demand, an adjusted result would be as follows:

$$\text{Small Customers} = \frac{100}{110} \times .25 + \frac{1{,}000}{4{,}000} \times .75 = .4148$$

$$\text{Large Customers} = \frac{10}{110} \times .25 + \frac{3{,}000}{4{,}000} \times .75 = .5852$$

If the minimum system could actually handle 80 percent of demand, an adjusted result would be:

$$\text{Small Customers} = \frac{100}{110} \times .10 + \frac{1{,}000}{4{,}000} \times .90 = .3159$$

$$\text{Large Customers} = \frac{10}{110} \times .10 + \frac{3{,}000}{4{,}000} \times .90 = .6841$$

Quite obviously, using the costs of actual load bearing facilities as a proxy for minimum system costs that are allocable on a per customer basis can severely overcharge small customers in relation to their true cost responsibility.

Q. IS IT REASONABLE TO CLASSIFY NON-CUSTOMER-RELATED DISTRIBUTION FACILITIES AS BOTH DEMAND AND ENERGY RELATED?

A. Yes. Because these facilities are designed to meet both local peaks and energy requirements over time, non-customer-related distribution facilities are appropriately classified as both demand and energy related. These facilities may therefore be classified using a demand-energy split. The allocation of the energy-related portion should be done in accordance with each class' contribution to total energy consumption and the demand-related portion should be allocated in accordance with each class' share of non-coincident peak demands.

D. <u>ALTERNATIVE COST OF SERVICE STUDIES</u>

Q. HAVE YOU PREPARED ALTERNATIVE COST OF SERVICE STUDIES BASED ON MDU'S FILING IN THIS CASE THAT INCORPORATE THE RECOMMENDATIONS THAT YOU HAVE MADE?

A. Yes.

Q. PLEASE DESCRIBE THE COST OF SERVICE STUDIES THAT HAVE BEEN PREPARED.

A. The alternative cost of service studies that I have prepared are summarized in Exhibits___ (JWW-1) through (JWW-3). These studies follow the same format as presented in MDU's rate filing and, with the exception of the changes noted, are based on the same cost of service data and allocation procedures presented in the Company's filing. Exhibits___ (JWW-1) and (JWW-2) contain printouts of only the summary pages for each cost of service study, while Exhibit___(JWW-3) contains the printout of all pages. Each exhibit contains results for major customer classes.

Q. PLEASE DESCRIBE EXHIBIT___(JWW-1).

A. Exhibit___(JWW-1) is simply a replication of the cost of service study filed by MDU. It is included here as a convenience for comparison purposes and also as a check that any alternative results start from the same place as the Company's filing.

Q. PLEASE DESCRIBE EXHIBIT___(JWW-2).

A. Exhibit___(JWW-2) addresses the concerns that have been raised in my testimony regarding MDU's allocation of all generation and transmission plant costs in relation to coincident and noncoincident peak demand measures. Whereas MDU's filed cost of service study (replicated in Exhibit___(JWW-1)) used a combination of CP and NCP to allocate all generation and transmission plant costs, Exhibit___(JWW-2) allocates generation and transmission plant in relation to CP and energy. I have retained MDU's CP allocation for these plant components, but have replaced NCP with energy as described above. Under this approach, two thirds of MDU's generation and 80% of its transmission plant is allocated in proportion to class energy loads and the remainder is allocated in proportion to the same CP allocator used by the Company.

Q. PLEASE DESCRIBE EXHIBIT___(JWW-3)

A. Exhibit___(JWW-3) combines the adjustments in Exhibit___(JWW-2) with corrections that I have discussed for distribution costs. Specifically, in Exhibit___(JWW-3) I have divided distribution network costs (poles, towers, fixtures, conduit and transformers) 80/20 between usage and customer. I then added the customer component of distribution network costs to customer premises equipment costs (meters and service lines) and allocated that total on a flat per customer basis. I also split the usage component of distribution network costs half and half between demand and energy and allocated those cost components in proportion to Kwh and NCP, respectively. As is shown on page 2 of Exhibit___(JWW-3) when these corrections are made to MDU's cost of service study, it no longer appears that residential customers are carrying less than their fair share of total system cost.

VIII. MDU'S RATE DESIGN

Q. PLEASE SUMMARIZE MDU'S RATE DESIGN.

A. As stated above, MDU's rates are structured to recover a specific portion of the Company's total revenue requirement from each rate class. As a general proposition the Company acknowledges that the revenue requirement for each rate class should equal that portion of MDU's total cost of service that is incurred to provide the electric service requirements of the rate class. If a cost of service study has correctly attributed the proper portion of total costs to each rate class, an appropriate rate structure would result in equal rates of return for each class.

As demonstrated above, the Company's cost of service study does not reasonably reflect rate class cost responsibility. If, as has been suggested, the Commission determines that MDU has underallocated costs to high load factor customers and overallocated costs to smaller, lower load factor customers, rate adjustments to achieve appropriate rate class parity would be quite different than MDU's cost of service study suggests.

Q. IN ADDITION TO PROVIDING THE REQUIRED REVENUES AND ACHIEVING FAIR COST APPORTIONMENT, DOES THE COMPANY'S RATE STRUCTURE ACHIEVE THE OPTIMUM USE OR CONSUMER RATIONING OBJECTIVE?

A. It appears likely that substantial improvements can be made in this regard. One area for improvement would be to correct inconsistent price signals between various tariffs. For example, large general service customers (Rate 30) are being told that summer capacity is much more costly than winter capacity (i.e., $8.50 vs. $4.50 for primary service and $9.00 vs. $5.00 for secondary service), but small general service customers (Rate 20) are being told that the differential is much less ($10.00 vs. $8.00 for primary and $10.25 vs. $8.25 for secondary). Likewise, while large general service (primary) customers (Rate 30) who now pay $4.99/Kw for winter demand would have their rate cut to $4.50/Kw, contract service customers (Rate 35) who also now pay $4.99/Kw for winter demand would have their rate raised to $7.00/Kw.

Customers are also receiving highly inconsistent price signals for incremental energy consumption. For example, while residential customers are being told that the incremental cost or cost savings associated with one kilowatt-hour more or less in the summer is 8.439¢, large contract service customers are being told that it is less than half that amount - - 3.785¢. Likewise, while residential summer incremental energy rates will be 36% higher than winter incremental energy rates and small general service summer incremental energy rates will be 52% higher than corresponding winter rates, there will be no summer/winter incremental energy rate differential at all for large general service or contract rates. Also, while small general service primary customers will receive a 60% increase in summer incremental energy rates, (from 4.089¢ to 6.540¢ per kwh) the corresponding increase for large general service contract customers will be 11% (from 3.414¢ to 3.785¢ per kwh). While the summer incremental energy rate is now 0.675¢/kwh higher (about 20% higher) for small general service primary customers than for large general service contract customers, it will become 2.755¢/kwh higher (about 73% higher). In fact, at the Company's marginal generating plants (i.e., the plants being dispatched to match total generation with load), at any particular time the incremental cost or cost savings of one kilowatt hour more or less ("system lambda") is exactly the same regardless of which customer's load is varying.

Q. WHAT DO YOU RECOMMEND REGARDING MDU'S RATE DESIGN?

A. MDU has designed rates which largely equalize the total requested revenue increase from most major customer classes. The proposed overall increase is 20.2% for the residential (Rate 10), large general service (Rate 30) and contract service (Rate 35) classes, but 32.9% for the small general service (Rate 20) class. Given the substantial misallocation of class cost responsibility identified in the class cost of service study, MDU has not presented a credible case for revamping overall class revenue responsibilities. But rather than merely equalizing total class revenue increases, it would be desirable to at least restructure incremental energy charges and rationalize interclass rate comparisons in each season so as to better reflect short-run incremental energy costs. Incremental energy costs (primarily the fuel cost associated with one kilowatt-hour more or less at any time) are perhaps the least difficult and least controversial costs to quantify with reasonable accuracy. Marginal energy rates are also the strongest energy conservation tool available to utilities and the most important price signal to get right because customers can respond to marginal energy costs much more readily than they can to estimates of any other functional marginal cost. For example, what response can be expected (or would be desired) from increasing the customer cost “price signal” from $3.00 to $6.00 per month as MDU proposes for residential customers in this case?

Q. WHY IS IT IMPORTANT FOR PRICES TO REFLECT INCREMENTAL ENERGY COSTS?

A. In a market economy, it is the price system that allocates resources, encourages producer and consumer efficiency, rations limited supplies of goods and services and, in general, serves as a disciplinary force in determining what is produced, in what volume, and how it is distributed.

The prices of various goods and services in a market economy constitute a ranking of incentives affecting both producers and consumers. Through their willingness to pay various prices for various goods, consumers signal their preferences to producers. By their willingness to sell various goods at various prices, the producers, in turn, signal costs to consumers. When certain conditions are present, especially those associated with the ideal of perfect competition, the price system forces each individual producer and consumer, while working purely in his or her own interest, to contribute to the welfare of society as a whole. Under these conditions, available resources are used in the most efficient way to produce the largest possible quantity of the most wanted goods and services, and these are distributed so as to maximize aggregate economic satisfaction. But this requires the price for incremental consumption to reflect the cost of incremental production.

In an efficient market producers will supply additional units as long as prices exceed the cost of producing additional units. At the same time consumers will demand and purchase additional units as long as prices are below the benefit of consuming additional units. The producer's cost of incremental production defines supply, and the consumer's benefit from incremental consumption defines demand. Efficiency is achieved in markets when cost and benefit of incremental production and consumption are equal. Prices that reflect the cost of incremental production are the key to achieving this efficiency.

In competitive markets prices also tend to reach an equilibrium at a level that covers the total costs of production (including a return to capital investment). Prices above such a level cannot prevail over long periods as that would attract competitive entry and expand production to capture the excess of price over costs, and at the same time, such a high price would discourage consumption to a level below what would have prevailed with cost-based rates. Conversely, prices below cost would encourage consumption and discourage production, as no firm can exist for long when price fails to cover the costs of production. Thus, in a competitive market, consumers cannot expect to buy goods at prices below the cost of production, and they cannot be forced to pay prices above that level

Q. DO THESE PRINCIPLES APPLY EQUALLY TO PRICES REFLECTING MARGINAL ENERGY COSTS, MARGINAL CUSTOMER COSTS AND MARGINAL DEMAND COSTS?

A. No. They are, by far, much more important for marginal energy costs. Customers can respond directly to price signals telling them the incremental (fuel or purchased power) cost of an increase or decrease in kwh consumption. In contrast, they have little or no ability to alter demand in response to changes in per customer rates. In a similar sense, capacity costs (whether generation, transmission or distribution) are more or less fixed in the short run and it is therefore far more difficult to design and implement efficiency inducing price signals for these cost components. In short, efficient (i.e., cost-reflective) electricity pricing should start with energy rates reflecting marginal energy costs for all classes. In this case it is clear that while energy rates for residential customers generally exceed marginal energy costs at most if not all times, a large portion of the Company's large commercial energy sales (most notably sales to large general service contract customers) are proposed to be at rates well below marginal energy costs. While I am not here recommending large shifts in class revenue responsibility to fix this problem, rate designs within classes should be revised to deal with it.

IX. RATE OF RETURN

Q. WHAT IS RATE OF RETURN?

A. Rate of return is often described as the profit, expressed as a percentage of the utility's invested capital (measured as rate base), that the utility is allowed to include in its rates. From an economist's perspective it is not quite right to call this allowed "profit" because it includes both the cost of debt capital (interest expense) as well as the allowed return on equity investment. If a utility has $100 million invested in rate base and this is funded with $50 million of debt, with an average interest of 6%, and $50 million of equity, which the Commission has determined requires a return of 10% (cost of equity or "ROE"), the allowed rate of return would be 8% or $8 million annually. This amount along with all expenses and taxes would be the revenue requirement reflected in the utility's rates.

Q. IS THE DETERMINATION OF A UTILITY'S RATE OF RETURN ALLOWANCE A CONTROVERSIAL ASPECT IN MOST RATE CASES?

A. Yes. Rate of return accounts for a substantial portion of a utility's rates. While the debt component of rate of return is usually a straightforward reflection of the Company's actual interest costs as reflected on its books, the equity return component is largely a matter of judgment and is typically hotly contested.

In this case the Commission is relatively fortunate to have a comparatively clear and traditional equity return (ROE) presentation as reflected in the testimony and exhibits of MDU witness Gaske, and not a highly unusual or unconventional presentation that strays far from traditional regulatory practice. While I will suggest a number of criticisms and alternatives to Dr. Gaske's calculations and conclusions, his presentation is an instructive illustration of conventional rate of return evidence that is typically seen in utility rate cases. Also, while I take exception to certain “adjustments” that he makes, his ultimate conclusion (i.e., his recommendation of an 11% ROE allowance) is at the high end of what I would consider to be a reasonable ROE range. I will attempt to more completely define that range, which includes somewhat lower return allowance values, for the Commission’s consideration.

Ultimately, I would candidly stress that the ROE determination in this (and any) rate case is very largely a matter of informed judgment. While Dr. Gaske and I may be able to offer the Commission facts, analyses and insights that will help to inform a reasonable range within which that essential judgment can be exercised, it is ultimately a determination that must depend on the Commission’s priorities, objectives and exercise of discretion, which no model, set of “expert” calculations, or sworn opinions can replace.

A. THE DCF MODEL

Q. DO YOU DISAGREE WITH THE DESCRIPTION OF THE DISCOUNTED CASH FLOW (DCF) MODEL THAT DR. GASKE HAS PRESENTED IN HIS DIRECT TESTIMONY?

A. No.[4] Discounted cash flow (or DCF) models are frequently used as a method for measuring the cost or required return of a firm's common equity capital. The DCF model is based upon two fundamental principles. First, it is based on the principle that rational investors evaluate the risks and expected returns of securities in capital markets and establish a price for a particular security which adequately compensates them for the risks they perceive. Second, the model is based on the proposition that the total return received by shareholders consists of dividends and capital gains, and these are measured in terms of the current dividend yield plus the expected rate of dividend growth. The DCF model, which combines yield and growth information to produce the total return expected by investors, is the following:

$$\begin{matrix} \text{Total Return} \\ \text{to Investor} \end{matrix} = \begin{matrix} \text{Current} \\ \text{Dividend Yield} \end{matrix} + \begin{matrix} \text{Expected Dividend} \\ \text{Growth Rate} \end{matrix}$$

The model makes no separate provision for capital gains because they are fully accounted for in the growth component. That is, capital gains are a consequence of price appreciation which, in turn, is a consequence of rising dividends and expected dividend growth.

Since an individual investor cannot control either the current dividend rate

[4] My agreement is with Dr. Gaske’s basic description of the model. As explained below, I do not agree with his .625g adjustment to the dividend yield or with his flotation cost adjustment, I will also explain that his “second-stage retention growth analysis” is a partially mistaken application of what is more generally known as “fundamental” DCF model.

or the dividend growth rate, his decision about the adequacy of returns is reflected by his buy, sell, and hold decisions. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will fall below book value. If investor expectations and requirements are the same, the stock will trade at a price equal to book value.

In other words, the DCF procedure for estimating the cost of equity capital reflects the fact that the maximum price a logical investor will pay for a security is an amount equal to the present value of the dividends that he or she expects to receive over the years during which the security is held plus its resale price, including capital gains, when the security is sold. Algebraically, this observation can be represented by the following equation:

$$Po = \frac{D_1}{1 + R} + \frac{D_2}{(1+R)^2} + \ldots + \frac{D_t}{(1+R)^t} + \frac{P_t}{(1+R)^t}$$

where Po is the price of a company's common stock today; D1, D2 ... Dt are expected dividends in subsequent periods; Pt is the expected resale price of the stock at some time in the future; and R is the discount rate or required return (sometimes referred to as the opportunity cost of capital). This algebraic statement, becomes an infinite geometric progression (because P_t and all subsequent resale values depend on expected dividends and resale prices at that point in the future, and dividends are assumed to grow at a constant annual rate) which reduces algebraically to the familiar DCF formula:

$$R = D/P + g$$

where g is the expected annual rate of dividend growth.

The market price is the present value of all cash flows expected in the future, discounted at a rate equal to the rate of return investors require on the investment. Present value is the current worth of expected future returns – that is, what an investor would be willing to pay today in order to obtain the expected cash flows in the future. Today's price is the present value of these expected cash flows, discounted at a rate that reflects the cost of capital, including the risk perceived by investors that their expectations will not be met.

The most controversial aspect of DCF analysis is usually estimating of the growth component of the model, rather than the underlying model or theory, itself.

Q. WHAT EXPECTATIONS ARE IMPORTANT IN DCF ANALYSIS?

A. Investors collective expectations are central to the discounted cash flow approach and are the key to establishing the cost of common equity capital. While analysts may opine on what they think investor expectations may be, the only way in which investors reveal their collective expectations is in the market prices that they establish for common stock. Investors establish prices for common stocks on the basis of their collective expectations of future income streams (dividends and capital gains) relative to their return requirements for the level of perceived risk. It is the consensus of investor expectations that establishes the price of common equities, and those expectations are ultimately concerned with investors' expected future income stream (i.e, dividends). This means that it is the expected future growth in dividends, which is most important.

Although dividend yields are easy to estimate with published data, the expected growth component is not as easy. Although analysts often publish their expectations, which, overall, tend to be somewhat bullish, there is no published consensus value for the expectations investors hold. That analysts' forecasts are somewhat more bullish than investors' actual expectations is evident from a number of observations, including stock market prices which are typically somewhat lower than analysts price forecasts. Really valuable analysts are those who know something that the market does not already know. In seeking an equity cost rate one must determine, on the basis of factual information, what the most reasonable estimate of growth expectations held by investors is at any point in time.

In this regard, it is important to emphasize that the task of the rate of return analyst is to determine what growth rate investors are expecting, and not to forecast the actual growth rate the analyst expects. Nor does it matter whether investors' expectations turn out to be right or wrong. Today's common stock prices, which enter the DCF calculation through the dividend yield term, depend upon today's expectations for future growth. Of course, expectations and requirements may be different at different times, and therefore the cost of common equity is likely to change over time. For example, when interest rates are very high, it is likely that required equity returns are higher than when interest rates are low. Similarly, when expected long-term inflation rates are high, it is likely that the cost of common equity will be higher than when long-term inflation expectations are low. A cost of common equity established at one point in time may be quite different from that established previously, or that found to be true in the future. Also, while tomorrow's hindsight may prove that today's expectations were wrong, that does not and cannot possibly affect today's cost of capital. That is why it is necessary only for the rate of return analyst to estimate, as accurately as possible, what present investor expectations actually are, and not whether they are correct.

Q. DO YOU AGREE WITH DR. GASKE'S DCF CALCULATIONS?

A. I have some disagreements with his specific calculations.

Q. PLEASE EXPLAIN THOSE DISAGREEMENTS.

A. First, I disagree with his .625g adjustment to the dividend yield component of the model. This adjustment, as explained by Dr. Gaske at JSG-1, page 11, is based on the premise that the dividend in the yield component of the model is a dividend payment that investors expect to start growing on a quarterly basis during the first year reflected in the DCF calculation. While it may be reasonable to expect some dividend growth during this first year reflected in the calculation if the dividend value used in the calculation is the actual historic dividend paid in the prior year, it is not reasonable if the dividend value used is the current "declared" dividend that is expected to be paid during the current year. In this case, the dividend that Dr. Gaske uses in his DCF calculation is the declared dividend in the spring of 2007 (Dr. Gaske refers to this as the "indicated" dividend) and he relates that declared dividend to the stock's average historic price for a prior period (here, November 2006-April 2007) (see JSG-2, schedule 2, page 3). Thus, Dr. Gaske's DCF calculation relates the dividend declared for payment in the future to a past historic price, and the dividend in relation to price is therefore already forward looking so that the first year's growth is already reflected in the dividend yield calculation. Consequently, the dividend payment component of the model (the declared dividend) is already more than sufficiently forward looking in relation to the stock price (an historic price beginning in November of the prior year) used in the yield calculation, and Dr. Gaske's .625g adjustment therefore overstates the reasonably expected dividend yield in the first year of his DCF calculation.

Q. ARE THERE OTHER ASPECTS OF DR. GASKE'S CALCULATION WITH WHICH YOU DISAGREE?

A. Yes. I also disagree with his flotation cost adjustment. That is, while actual flotation costs are part of the cost of capital, assuming a flotation cost of 3.5% for all of MDU's common equity capital, as Dr. Gaske does, greatly overstates actual issuance costs.

In the case of debt, actual issuance or flotation costs are incorporated into the capital cost computation by relating the actual proceeds from debt issuances (e.g., the face amount of bonds less actual issuance costs) to interest payment obligations. Thus, if a company issues $100 million of debt at a 6% interest rate and has actual proceeds of $99 million (i.e., issuance costs are $1 million) the embedded cost of debt is 6.06% (6/99) and not 6.00% (6/100).

In the case of common equity, the great preponderance of equity growth for electric utilities (including MDU) is retained earnings - - not new public issuances. Retained earnings (and other forms of raising equity capital such as dividend reinvestment plans and parent company equity infusions out of parent retained earnings) do not have the issuance costs that Dr. Gaske assumes.

Especially in the case of MDU’s Montana operations, which have generated substantial retained earnings but have grown little at all during the past twenty years (and for which there are small growth expectations), there is no realistic basis for the flotation cost adjustment that Dr. Gaske proposes.

Q. DO YOU HAVE ANY OTHER DISAGREEMENTS?

A. Yes. While I agree that a retention growth forecast (generally known as “fundamental” growth) is a rational way to estimate expected growth, I disagree with Dr. Gaske’s “second stage” use of retention growth and with his weighting of this growth measure by only 33%. (see Exhibit No.___(JSG-2), Schedule 2, page 5).

Q. WHAT IS THE DCF RESULT WHEN CORRECTIONS ARE MADE FOR THESE CALCULATION ERRORS?

A. Had Dr. Gaske properly used retention growth in his calculations and had he refrained from his .625g adjustment to dividend yield and his 3.5% equity flotation cost adjustment, his indicated average primary market cost of equity capital would have been 7.8% rather than 10.3%. Likewise, as regards his “basic” DCF model, had Dr. Gaske omitted his improper .625g adjustment and his 3.5% flotation cost adjustment, his average primary market DCF cost of equity result would have been 10.77% rather than 11.32%.

Q. PLEASE DESCRIBE YOUR OWN DCF COST OF EQUITY ESTIMATES.

A. DCF cost of equity indications are presented in Exhibits___(JWW-4) and (JWW-5). In both cases the reported dividend yields are Value Line’s most recently reported declared dividend yield for each company. These reflect the dividends currently declared to be paid in the future divided by each company’s recent market price of common stock.

Q. PLEASE SUMMARIZE EXHIBIT ___(JWW-4).

A. Exhibit___(JWW-4) provides DCF model results for all major electric utility companies covered by Value Line using dividend yield values as described above plus the average of Value Line and Zacks growth forecasts (similar to the Zacks forecasts used by Dr. Gaske). The average indicated ROE estimates are in the 9% to 11% range. The major difference between this exhibit and Dr. Gaske's analysis, in addition to the calculation corrections discussed above, is that it reflects results for all electric utility companies, whereas Dr. Gaske presents results for only a sample or a sub-set of the whole. While it is not necessarily wrong to select and focus only on a sub-set of the whole group, that always raises questions about "cherry picking" to achieve a desired end result. In this case the end result is not substantially different using the whole population of electric utilities rather than only Dr. Gaske's sub-set. Nevertheless, I felt that it would be more informative and less subject to questions about manipulation to provide the Commission with a full picture, which, of course, allows the Commission to pick and focus on sub-sets if it believes that is appropriate.

Q. HAVE YOU PERFORMED ANY ADDITIONAL DCF CALCULATIONS?

A. Yes. I have also performed a "fundamental" DCF calculation as an alternative means of estimating MDU's common equity costs.

Q. WHAT IS A FUNDAMENTAL DCF CALCULATION?

A. A fundamental DCF calculation uses retained earnings as the measure of expected growth. Because retained earnings provides for growth in equity and growth in equity provides for business growth, the rate of earnings plow-back (i.e., those earnings not paid out in dividends) serves as a basis for estimating future dividend growth. If the funds that are retained and reinvested earn the allowed return and the allowed return is equal to the cost of capital, retained earnings provide a good estimate of future growth.

For example, if a company with a stock price and book value of $50 per share earns $5.00 (10%) and pays out a dividend of $2.50, its dividend yield is 5% (i.e., 2.50/50). Expected growth will also be 5% because, if the 10% earnings rate is maintained, the $2.50 that is retained will permit earnings to increase by that amount (i.e., $2.50 x 10% = $0.25 which is 5% of $5.00). Likewise, the retention of $2.50 of earnings within the corporation will cause the book value of its stock to increase by 5% (i.e., $2.50 is 5% of $50.00). In this case, the dividend yield of 5% plus expected growth of 5% equals 10%, which is the cost of capital.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR FUNDAMENTAL DCF CALCULATION.

A. The results of my fundamental DCF calculations are presented in Exhibit___(JWW-5). I have again used the full Value Line population of electric utilities in compiling this exhibit. Both the divided yield and retained earnings percentages reflect Value Line's projections for the future. As in Exhibit ___(JWW-4), the results are similar to Dr. Gaske's retained earnings growth calculations, except that I have not included his .625g adjustment nor his flotation cost adjustment, and I have given this calculation a full 100% weight rather than the limited 33% weight allowed by Dr. Gaske. The Commission may, of course, give whatever weight it deems appropriate to the "basic" DCF results shown in Exhibit__(JWW-4) and the fundamental results shown in Exhibit ___(JWW-5), as they both lie within a reasonable range. The average indication in this case is 9.1 percent. Standing alone, the indication for MDU is 9.4%, which is the sum of the Company's projected dividend yield and the fundamental growth rate associated with its projected retained earnings.

B. <u>CAPITAL ASSET PRICING MODEL</u>

Q. HAVE YOU ALSO PERFORMED CAPITAL ASSET PRICING MODEL CALCULATIONS TO ESTIMATE THE COST OF EQUITY CAPITAL?

A. Yes, I have.

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is, like the DCF model, one of the most widely used techniques to estimate the cost of equity capital. The fundamental principle underlying the CAPM is that investors require compensation for risk when making an investment – that is, a higher return than is required for a riskless investment. In other words, while the DCF model estimates the cost of equity capital directly by examining expected dividend flows and market prices, the CAPM estimates required returns by evaluating the relative risk of alternative investments.

In comparison with the expected return on a risk-free investment, a risky investment must provide investors with a risk premium – an expected return higher than the riskless rate. The most commonly used measure of a risk-free asset is a short term (e.g., 90 day) U.S. Treasury security, which has little or no default or inflation price risk. It should be emphasized that only very short term Treasury debt can be assumed to be risk-free. Long term treasury debt, which locks investors into U.S. dollar denominated assets for years, can be very risky as inflation or international currency fluctuations can significantly impair investment value.

Investors who locked their investments into long term treasuries in 2000 have seen the purchasing value of their investment plummet by more than one-third in terms of buying power in relation to Canadian, European and other world currencies. Only very short term treasury debt is substantially free of this and the risk of inflation, which can also cause the real asset value of long term Treasury bonds to plummet as they did in the early 1980s.

CAPM separates the total risk of an investment into two parts: systematic and unsystematic risk. Systematic risk is unavoidable; it affects all assets to a greater or lesser degree. For example, a sharp rise in inflation would affect all stocks to a greater or lesser degree. The size of the risk premium for each stock is determined in a proportion to the stock's co-movement with the market for all stocks. A stock that is twice as volatile as the average requires a risk premium that is double the average risk premium. A stock that is half as volatile as the average requires a risk premium that is half the average, etc. All systematic risk is rewarded with a risk premium, above the risk free rate of return that varies in direct proportion to the stock's relative volatility. The relative risk of each stock is measured by a value known as beta ("B"), which is a measure of the stock's relative volatility in comparison with the volatility of the entire market.

In contrast, unsystematic risk is that portion of total risk that can be avoided by diversifying. Unsystematic risk is not rewarded with a risk premium.

The CAPM defines the cost of equity for each company's stock as equaling the riskless rate plus an increment equal to the amount of systematic risk that goes with the investment:

$$K_n = R_f + B_n (R_m - R_f)$$

where,

K_n = the cost of equity for company n

R_f = the riskless rate of return

B_n = the beta for the stock of company n

$R_m - R_f$ = the expected market risk premium

(i.e., the average difference between the expected returns on the diversified market portfolio and the riskless return).

Q. WHAT ARE THE APPROPRIATE VALUES FOR THESE VARIABLES IN THIS CASE?

A. At the present time, riskless treasury bills are yielding approximately 4%, and the high for the year has been about 5%. Thus, R_f = 4.0 to 5.0%. With regard to risk premium, surveys and academic analyses indicate that the expected market risk premium R_m is in the range of 3% to 7%. For example, according to Dinson, March and Staunton ("Risks and Returns in the 20th and 21st Centuries," Business Strategy Review, 2000, Volume 11, Issue 2):

"It has become clear that the current level of the equity risk premium is unlikely to be as high as was considered reasonable in the mid-

> 1990s. The arithmetic mean of 8½% recommended by Ross, Westerfield and Jaffe (1993), the 8-9% suggested (with caveats) by Bealey and Myers (2000), and the 7½% recommended by Wetson, Chung and Sui (1997), and a similar figure inferred from the Copeland, Koller and Murrin (1995) geometric mean of 5-6%, all look excessive. The market is almost certainly building lower risk premia than this into stock prices….The cost of capital has thus fallen substantially in recent years."

Also, according to Eugene F. Fama of the University of Chicago and Kenneth R. French of Massachusetts Institute of Technology, the risk premium over the past half-century was about 4%. Their calculation is based on going back to the past and analyzing what kinds of returns investors had a reasonable right to expect for the future, given companies' dividend yields and expected growth rates. Risk premiums exceeding 4% were, they say, the result of a series of surprises, such as the end of the Cold War and the development of the computer – windfalls that investors do not count on to repeat themselves. Fama and French expect stocks to outperform risk-free securities by only 3% to 3.5% a year in the long term. (See E.F. Fama and K.R. French, "Dividend Yields and Expected Stock Returns," Journal of Financial Economics, 22 (1), 3-25 and "Business Conditions and Expected Returns on Stocks and Bonds," Journal of Financial Economics, 25 (1), 23-49.)

Among the people who have studied the equity premium closely, most think it is probably in the range of 3 to 5 percentage points above treasury bills. On the other hand, rank-and-file finance professors have often continued to peg the long-term premium at about 6 to 7%, according to a comprehensive survey published by Ivo Welch of Yale University. Welch, himself, agrees with the 3-5 percent range. According to his analysis, a 3% geometric equity premium estimate and a 5% arithmetic estimate are more accurate than the 6% to 7% consensus of the profession. (See Ivo Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies" (University of California, Los Angeles and Yale University, 2001)).

As shown in Exhibit___(JWW-8), average beta values for comparable electric utilities are 0.96 (and 1.00 for MDU). Using 0.96 as the beta estimate and 5 percent as the market risk premium, the CAPM cost of equity estimate is:

$$K = 5.0\% + 0.96\ (5.0\%) = 9.8\%$$

CAPM equity return calculations are summarized in Exhibit___(JWW-6).

C. <u>COMPARABLE EARNINGS</u>

Q. HAVE YOU ALSO EXAMINED COMPARABLE EARNINGS FOR INVESTORS IN COMPARABLE UTILITIES?

A. Yes. I have examined the rates of return that are expected to be earned on common equity capital by comparable electric utilities as well as returns that are expected to be earned in relation to the market prices of those equity securities. This latter and most relevant comparison is essentially the return on book value divided by the market/book ratio.

Q. WHAT IS A MARKET/BOOK RATIO AND WHY IS IT RELEVANT IN DETERMINING A FAIR COMMON EQUITY RETURN ALLOWANCE?

A. A market/book ratio is the relationship that exists at any time between the value that investors place on a firm's common stock and the stock's book value.

If regulators allow firms to earn rates of return that equal the cost of obtaining capital in the marketplace, then market forces will tend to drive the prices of stocks toward their book values. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will tend to fall below book value. If investor expectations and requirements are the same, the stock will tend to trade at a price equal to book value.

Q. IS THIS AN IMPORTANT CONSIDERATION IN RATE REGULATION?

A. Yes. It is an important consideration in rate regulation. If the market price of common stock rises to and remains at a level that is substantially in excess of book value, that is a clear signal that investors' earnings expectations as a percentage of book value exceed the cost of capital, and that investors have capitalized these expected excess earnings by bidding up the price of common stock to a level greater than the stock's book value.

Thus, for example, if an investor purchases common shares at a market price equal to 1.5 times the stock's book value and the company earns a 15 percent rate of return on book value, the investor actually realizes a smaller return (i.e., 10 percent) on the market value of his or her investment. Since 15 percent exceeds the return that is required in the marketplace (we know that because, in this example, with a 15 percent return investors bid the stock price up to 150 percent of its book value), the 15 percent return on book value is capitalized (i.e., built into the discounted present value of the security) by investors, thus inflating the market price of stock. While this may result in gains for original stockholders who paid book value for their holdings, the excess return is an unnecessary expense for ratepayers if it is reflected in allowed rates. Since it is both excessive and unnecessary, this condition should typically be avoided under effective rate regulation. Of course, temporary fluctuations and short-term cycles affect prices, and a stock price varies from its trend over time. This means that, if common equity costs remain about the same over time, and if investors expect future returns equal to the market cost of equity, the price of stock will fluctuate within a reasonably narrow range of book value.

Q. IS THERE EVIDENCE AS TO WHAT RETURN ON EQUITY CAPITAL IS EXPECTED TO PRODUCE A MARKET-TO-BOOK RATIO OF 1.0 IN THE ELECTRIC UTILITY INDUSTRY IN THE FUTURE?

A. Yes. The Value Line Investment Survey, which is an excellent source of reported historical financial data, has published projected market-to-book ratios for companies for the period 2010-2012 in recent issues. These are summarized for MDU and comparable companies in Exhibit___(JWW-7). As shown in this Exhibit, it is projected that an average 11.6 percent return on the book value for comparable electric companies will produce a market-to-book ratio of 1.69. This, in turn, implies a cost of equity capital for these companies of about 7%. The corresponding result for MDU is also close to this value.

A market price equal to book value indicates that investors expect future earnings rates equal to their required return or cost of capital. To the extent that investors expect that the rate of return earned on book assets will exceed the required return or cost of capital, there will be a tendency to bid up the market value of stocks to the level at which the expected return in relation to market value equals the required return or cost of capital. Thus, if the required return or cost of capital is 8 percent, but investors expect that a 12 percent return will be earned on book value, market prices will be bid up to 1.5 times book value so that the realized return equals the cost of capital (i.e., 8%). The implication in this case is that an equity return of 6.9 percent would be sufficient to sustain the stock price at book value,

$$\text{i.e., } 11.7/1.68 = 6.9$$

Q. WHY HAVE YOU EXAMINED THESE EXPECTED COMPARABLE EARNINGS RATES?

A. Comparable rates of return from alternative investment opportunities determine the return level that investors can expect to obtain in competitive capital markets at any time. Moreover, comparable returns are generally considered by regulatory commissions and courts in determining "fair earnings" rates in rate proceedings. Indeed, regulatory standards demand that Commissions make an effort to allow similar profit rates to firms in similar circumstances. In examining comparable earnings data, it is, of course, important to remember that rates of return earned by other regulated companies are determined in some measure by previous regulatory decisions, and they may be either excessive or inadequate for certain firms at certain times. Therefore, while comparable earnings data do provide an essential reference point for any cost of capital decision (indeed, comparable earnings opportunities are the foundation on which investors make their capital commitment determinations and they are therefore the foundation of DCF and other cost of capital models) a simple mathematical extrapolation is not always sufficient.

Q. SHOULD MDU'S RATES INCLUDE A COMMON EQUITY RATE OF RETURN ALLOWANCE EQUAL TO THAT EARNED IN RECENT YEARS BY THESE COMPARABLE COMPANIES?

A. Not necessarily. Experienced returns may be an approximate benchmark for return authorizations, but there are several reasons why caution should be exercised in simply applying those average rates of return here. First, there is an obvious element of circularity in allowing a rate of return for a given regulated enterprise equivalent to the rate of return which other regulated enterprises have been allowed to earn.

Second, earned returns are not always the same as required returns. When market to book ratios exceed unity, it means that book return expectations are higher than current equity market return requirements.

D. CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE DOES MDU RECOMMEND FOR RATEMAKING PURPOSES IN THIS CASE?

A. MDU recommends establishing a rate of return allowance based on its computed average utility capital structure for 2007, using beginning and end of year values (and average monthly short term debt) to compute the average. The result, as shown on page 1 of Rule 38.5.146, Statement F, is 50.67% common equity and 49.33% debt and preferred stock. This compares with 49.13% common equity and 50.87% debt and preferred stock at 12/31/06.[5]

Q. IS THAT A REASONABLE CAPITAL STRUCTURE FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes, however a 50% common equity ratio is at the high end of a reasonable range for electric utility ratemaking.

Q. WHAT IS THE COST OF MAINTAINING A HIGH COMMON EQUITY RATIO?

A. The cost of maintaining a high common equity ratio is the resulting higher overall return requirement (including actual or imputed income tax costs) attributable to the higher percentage of common equity in the overall capital structure.

Q. IS THERE ANY BENEFIT TO MAINTAINING A HIGH COMMON EQUITY RATIO?

[5] The 12/31/06 percentages assume the same amount of short term debt as the monthly average for 2007.

A. The benefit derived from maintaining a high common equity ratio is the savings in capital costs at the margin (if any), which are attributable to low debt leverage. To the extent that the costs of common equity, new debt and preferred stock are reduced as a consequence of a high common equity ratio, the annual savings are the benefits of maintaining high common equity ratios.

It may also be true that, when financial markets are especially risk-averse, companies with high common equity ratios may have greater access to new debt and equity capital. However, above the BBB bond rating category this advantage may not produce a net benefit to ratepayers as the cost of maintaining a thick equity ratio is not likely to exceed debt cost savings.

Q. DO THE BENEFITS OF HIGH COMMON EQUITY RATIOS GENERALLY OFFSET THE COSTS?

A. Not necessarily, and almost certainly, not above the level needed to attain a BBB+ to A bond rating. Although it is true that low common equity ratios imply greater risk and higher capital costs, the degree to which a high common equity ratio contributes to reductions in risk and capital costs, in comparison with an adequate common equity ratio, is most likely to be minimal. The reason for this is that investors do not reduce their return requirements by enough as a result of the high common equity ratio to offset the higher cost of an equity rich capital structure.

A second reason that the benefits to ratepayers do not generally offset the costs of high common equity ratios is that the additional costs of new debt and preferred stock issues (when ratings are lower and issue yields are incrementally higher) are generally small in comparison to the large additional overall pre-tax return requirement resulting from a higher common equity ratio. Very high common equity ratios are also not cost beneficial because the income tax allowance charged to ratepayers on the extra common equity capital would typically more than cancel out any cost savings that might be realized on new debt issues.

Q. IS THERE EMPIRICAL EVIDENCE DEMONSTRATING THAT REGULATED ELECTRIC UTILITIES ARE LESS RISKY BUSINESSES THAN COMPETITIVE UNREGULATED ENTERPRISES?

A. Yes. Analyses of stock market indices reflect the comparatively stable and low-risk nature of common stock investments in regulated electric utilities.

Q. WHAT STOCK MARKET INDICES HAVE YOU REVIEWED?

A. In addition to the beta coefficients that I have used above in the CAPM cost of equity analyses, Value Line also publishes indices of safety, price stability and earnings predictability for a wide variety of firms in all sectors of the economy. As shown in Exhibit___(JWW-8), the comparable companies have an average safety index of 2.32 on a scale from 1 to 5, where 1 is the highest safety rating. Also, price stability ranks toward the upper end of the scale from 5 to 100 where 100 is the highest stability rating. The average earnings predictability index for these companies is 57.5 on a scale from 5 to 100. By all of these measures, electric utilities are indicated to be somewhat below average risk for large publicly owned firms in the U.S. economy.

E. COMMISSION ALLOWED RETURNS

Q. HAVE YOU ALSO REVIEWED THE EQUITY RETURN ALLOWANCES (ROE) AUTHORIZED FOR ELECTRIC UTILITIES BY OTHER STATE REGULATORY COMMISSIONS IN THE PAST TWO YEARS?

A. Yes. ROE allowances as reported by Public Utility Fortnightly and by Value Line for 2006 and 2007 are shown in Exhibit___(JWW-9). As shown there, out of 27 reported state regulatory commission ROE decisions, 20 were in the 10.0% to 11.0% range, 5 were between 11.1% and 11.5%, 1 was above 12% and 1 was below 10%. While these are interesting reference points, I again note the circularity that would be inherent in simply allowing returns equivalent to what other commissions have allowed.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION CONCERNING THE RATE OF RETURN ON COMMON EQUITY CAPITAL AND THE OVERALL RATE OF RETURN APPROPRIATE FOR MDU IN THIS CASE.

A. As summarized in Exhibit___(JWW-10), there is a substantial range of ROE measurements. While the averages for DCF and CAPM indications are in the 9-10 percent range, comparable expected market returns are lower (about 7%) and ROEs authorized by other state commissions during 2006 and 2007 have been higher, averaging about 10.6%.

Q. IS IT SURPRISING THAT STATE COMMISSION ALLOWANCES HAVE BEEN SOMEWHAT HIGHER THAN THE COMPUTED ROE INDICATORS?

A. No. State regulatory commissions, in exercising their informed judgment regarding ROE allowances, often allow for some margin of error and do not always hold allowed ROEs at the bottom of what they believe to be a reasonable range. Where within the range of reasonableness regulators establish allowed returns will be influenced by how well they believe the utility has performed. Where utility performance is judged to be superior an allowed return in the upper part of the reasonable range may be seen as a reward for such performance. Where performance is judged to have been disappointing, a return allowance toward the lower end of the range may serve as an incentive for future improvement. While utilities often attempt to turn this logic around (i.e., "give me a high return and I will improve upon my poor past performance"), the sensible approach is for rewards to follow performance. Utilities with disappointing performance records should know that their return allowance reflects that performance and that there is the potential for improved returns, with improved performance results. This is especially important where utilities with undeserved rewards in base rates may sustain those rewards and poor performance for years without filing new rate cases.

Q. WHAT IS YOUR SPECIFIC RECOMMENDATION IN THIS CASE?

A. As I said at the outset, within a zone of reasonableness, the determination of an appropriate ROE allowance is a matter of the Commission exercising its discretion in balancing the public interest objectives of consumer protection and incentives for adequate service and capital attraction. The empirical evidence and calculations that I (and Dr. Gaske) have provided define an ROE zone of reasonableness within a range from about 9 percent to 11 percent. Within this zone of reasonableness, I use the mid point (10 percent) to calculate a recommended return on rate base. An ROE allowance of this amount acknowledges that MDU has provided and is expected to continue to provide adequate service to its Montana customers, even though it is disappointing that the Company did not replace its expiring contract (Antelope Valley) for base load resources with another economical base load supply. It also recognizes MDU's comparatively modest level of business risk for electric utility service and the Company's comparatively high common equity ratio. Based on a 10% ROE allowance, the Company's allowed return on its electric utility rate base would be 8.45 percent:

	Ratio	Cost	Allowed Return
Long Term Debt	38.170%	7.217%	2.755%
Short Term Debt	7.565%	6.107%	0.462%
Preferred Stock	3.586%	4.605%	0.165%
Common Equity	50.670%	10.000%	5.067%
	Overall Return		8.449%

X. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. My testimony has addressed MDU's:

- Generation Supply Resources

- Proposed Fuel and Purchased Power Cost Tracker
- Margin Sharing
- Cost Allocation
- Rate Design; and
- Rate of Return

GENERATION SUPPLY RESOURCES

The Company's generation supply resources are very much the same as they were twenty years ago. The only significant change is the expiration of the base resource supply contract with Basin Electric for unit purchases from Basin's Antelope Valley Plant. Because MDU was unsuccessful in arranging for an economic base load supply replacement of the Basin purchase, that resource is being replaced with capacity (no energy) purchases from Northern States Power and higher cost energy purchases from the short term MISO market. This purchased power cost increase is the primary underlying cause of the rate increase being requested in this case.

MDU should be required to better justify its failure to replace the Basin contract with an economical base load resource than it has in its rate filing. To some extent, this matter can be addressed within the context of subsequent fuel and purchased power cost tracker rate proceedings if the

Commission decides to implement a fuel and purchased power cost tracker for MDU. In this case, discovery has revealed that MDU did contemplate the addition of the Hardin Montana coal plant as a supply resource before it elected, instead, to sell it off this year with the rest of affiliate Centennial's assets. In fact, MDU prepared studies of the costs that would be incurred to connect Hardin (which is now on NorthWestern's transmission network) directly to MDU's own transmission grid. When further discovery was attempted on this matter, MDU insisted that it had no further documentation, evaluation, communications or writings of any kind on the matter.

Discovery has also revealed that MDU received a proposal from Black Hills Power & Light for the sale of capacity and energy from the Ben French coal plant at a price that appears to be significantly less than MDU projects for the MISO purchases that it selected instead. While the Black Hills offer was for a smaller quantity than MDU was seeking at that time, it could have been taken as a partial replacement. MDU has now changed its explanation for turning down the Black Hills offer and no longer contends that it was not practical because of the plant's location on the western grid. Instead, MDU now says that it turned down the Black Hills offer because the price was higher than contemporaneous short term purchase prices in MAPP. While that may be interesting, MDU did not make any alternative replacement purchase at a lower price and now proposes to charge consumers for higher cost MISO purchases.

FUEL AND PURCHASED POWER COST TRACKER AND MARGIN SHARING

Because the new short term MISO energy purchases are likely to have less stable and predictable costs than the prior long term Basin purchase, and because the loss of the Basin purchase eliminates a primary part of MDU's opportunity to make profitable offsystem sales, the Company is seeking the implementation of a fuel and purchased power cost tracker to replace the fixed electric rate regime under which it has operated until now. MDU's proposed fuel and purchased power cost tracker is a comprehensive rate adjustment mechanism that would pass through all future changes in fuel and purchased power costs to consumers on a projected basis with annual cost/revenue true-ups.

Also because of the loss of the Basin contract and the changes that brings to the Company's related opportunity to make profitable off system sales, MDU is now proposing a Margin Sharing mechanism under which it would retain 40% of offsystem sales profits and pass 60% of such profits on to ratepayers. In the past and currently, MDU's offsystem sales profits were estimated on a test year basis, with 100% of the estimated benefit built into rates on a fixed basis. In that way MDU realizes 100% of the deviation from the test year estimate as incremental profit (or loss). In recent years the combination of economical Basin purchases and higher electric energy market prices provided a profit opportunity that is now substantially reduced.

While the requested margin sharing percentages (60%/40%) are plainly unwarranted and unjustified, if (and only if) offsystem sales margin sharing were to be coupled with fuel and purchased power cost margin sharing, a margin sharing ratio of 90%/10% may be acceptable.

Given its changed supply circumstances, the Company is now proposing to move from its current fuel and purchased power cost sharing percentage of 100% for the company and 0% for ratepayers to the complete opposite - - 100% for ratepayers and 0% for the Company. While the old (current) split (a zero pass-through) provided a very strong incentive for success, a 100% pass-through provides very little. Witness the default supply procurement success that others have achieved with a 100% cost pass-through. By allowing nearly all of the shift that the Company is proposing (i.e., 90%), but requiring the Company to bear 10% of the risk of poor success and allowing it to profit by 10% of good success, the risk-reducing protection that MDU seeks can be largely achieved and an incentive for successful performance can be retained.

If (and only if) the Commission elects to implement this 90/10 margin sharing for fuel and purchased power costs, then it is reasonable also to allow the same margin sharing for offsystem sales. In contrast, the Company's offsystem sales Margin Sharing proposal would unreasonably shift all risks to ratepayers while retaining an unreasonably large profit margin for MDU. Under the present method (which should be retained unless margin sharing is also extended to fuel and purchased power costs), MDU bears 100% of the risk of falling short of the test year offsystem revenue amount and it stands to gain 100% of any surplus over that amount. Under the Company's new Margin Sharing proposal, MDU would bear none of the risk and still enjoy 40% of any gain - - a far less equitable and incenting arrangement.

COST ALLOCATION

The Company has prepared and presented a comprehensive cost allocation study as part of its filing. This study allocates all of the Company's test year costs between rate classes. While there are many variations that may be applied to allocate costs in such studies, MDU has selected allocation methods that attribute an unreasonably large portion of its costs to residential customers. Among the techniques that MDU uses in this regard are the allocation of all generation and transmission plant costs in proportion to coincident and noncoincident peak demand and none of these costs in proportion to energy. Because residential ratepayers (due to their relatively low load factors) account for 35.3% of noncoincident peak demand (which MDU uses for 67% of generation plant and 80% of transmission plant) but only 24% of energy, and because large commercial customers account for 57% of energy but only 39% of noncoincident demand, the choice to allocate all of these plant costs to demand and none to energy substantially over-attributes cost responsibility to the residential customer class. Small business customers are similarly disadvantaged.

In addition, MDU allocates approximately 80% of its distribution plant costs on a flat per customer basis and the remainder on the basis of noncoincident demand. Again, none of these costs are allocated in proportion to energy consumption. Because the residential customer count is the great preponderance of the Company's total number of customers, a corresponding preponderance of distribution system costs are directed to residential customers.

While it is clear that the Company's cost allocation is extremely unfair to residential customers and greatly understates large commercial customer cost responsibility, MDU does not propose to redistribute customer cost responsibility accordingly. And, it should not. The bottom line is that the Company's cost of service study does not reasonably reflect cost responsibility and it should not serve as a basis for attributing system costs to rate classes or for setting rates.

RATE DESIGN

MDU also presents the results of what it characterizes as a "marginal cost study", but this too does not appear to be a major factor in designing proposed rates. Instead, the Company's proposed rate design sends extremely diverse price signals to customers in different classes. For example, proposed marginal energy rates for residential customers are more than double those proposed for large commercial contract customers, and even within the large commercial class, while proposed peak season rates for some customers receive proposed increases, others are reduced. At best there is limited consistency or cost reflectiveness in the Company's proposed rate design. While retaining most of the features of its previous (current) rate design, the Company's proposed tariffs do not make a significant contribution to improved price signals.

If the Commission desires improved rate design, a new filing based on improved principles is required. In order for that to be successful, however, it is very likely that the Commission will have to provide hands-on or very detailed advance guidance, as the Company's own inclinations are well revealed in the present filing. At a minimum, the Company must be directed to allocate substantial plant costs to energy and to refrain from loading distribution system costs into a flat per customer cost allocator. It must also be directed to develop energy rates that reflect energy marginal costs and that bear rational relationships between customer classes. Not only is this a fairness consideration, it is also absolutely needed as a reasonable energy conservation and DSM incentive measure.

RATE OF RETURN

MDU's proposed rate of return is premised on a high common equity ratio (over 50%) for electric utility ratemaking and a return on equity allowance (11%) that is at the top end of the reasonable rate of return range. This 11% proposed equity return allowance incorporates a substantial increment for equity issuance costs which MDU has not actually incurred and is unlikely to incur, as well as other adjustments that are not reflective of actual costs.

MDU does not warrant a return allowance at the very top end of the reasonable range. Its business risks in the stable Montana market that it serves are not great. Especially if a fuel and purchased power cost tracker is implemented, future risks will be even further reduced. Because the Company's equity ratio is very thick, it already imposes significant costs on ratepayers (not only because equity is more costly than debt but also because of the income tax loading attributable to equity capital returns). And, although there is no evidence that MDU has rendered inadequate service in Montana, the Company did fail to replace its expiring base load supply contract on a timely basis. In view of these considerations, it would be reasonable to establish MDU's allowed equity return at 10% -- approximately the mid point of the reasonable rate of return range.

Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY AT THIS TIME?

A. Yes; it does.