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

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service in the State of Montana	)))))	REGULATORY DIVISION DOCKET NO. D2015.6.51

CROSS-INTERVENOR RESPONSE TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

MONTANA LARGE CUSTOMER GROUP

January 14, 2016

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc., 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS CASE?

A. Yes, I filed direct testimony on behalf of the Montana Large Customer Group ("LCG").

Q. WHAT IS THE PURPOSE OF YOUR CROSS-INTERVENOR RESPONSE TESTIMONY?

A. I respond to the direct testimony of Montana Consumer Council ("MCC") witness Dr. John Wilson on class cost of service, the apportionment of the rate increase to rate classes ("rate spread"), and rate design.

Specifically, with regard to class cost of service issues, I will respond to Dr. Wilson's recommendation to use a production/transmission demand allocator based on a peak and average methodology comprised of a 50% energy weighting and a 50% 12 coincident peak ("12 CP") weighting. I will explain why this recommendation is not reasonable and relies on a faulty methodology. I will also respond to Dr. Wilson's proposal to allocate distribution costs (plant investment, expenses) on a 50% energy/50% demand basis, and will explain why his approach is not consistent with any reasonable measure of cost causation associated with distribution plant and expenses.

Based on his cost of service study, Dr. Wilson recommends that the residential class increase be limited to no more than the average retail percentage increase. As I discussed in my direct testimony, residential rates are significantly below cost of service and should

receive an increase to full cost of service, subject to a mitigation mechanism that would limit the increase to any rate class to 1.5 times the retail average increase.

Finally, on rate design, I will respond to Dr. Wilson's recommendation to apply 100% of any revenue increase to non-residential rate classes to the energy charges of these rates. This proposal, which is not based on cost of service and is arbitrary, should be rejected. If approved, Dr. Wilson's non-residential rate design recommendation would result in unreasonable and unwarranted penalties to business customers with high load factors.

Q. WOULD YOU SUMMARIZE YOUR RESPONSE TO DR. WILSON'S TESTIMONY?

A. Dr. Wilson is recommending class cost of service methodologies in this case that are not based on cost and therefore bear little or no relationship to cost causation in the allocation process. While I believe that a 12 CP production/transmission demand allocator is reasonable and appropriate in this case, Dr. Wilson arbitrarily weights this 12 CP demand allocator with a 100% energy allocator (average demand) using a 50/50 weighting scheme. He provides no substantive evidence to support this 12 CP/energy weighting. Rather, he relies on conclusory statements to support his proposal. His recommendations are not based on cost causation principles.

MDU plans its capacity resources consistent with the Midcontinent Independent System Operator ("MISO") summer peak criterion. As such, a summer peak allocator would be appropriate for both production and transmission demand cost allocation. I have recommended a 12 CP (12 monthly peaks) allocator as a transition measure to a full summer peak allocator, and because this is the same methodology MDU uses to allocate

production and integrated transmission fixed costs to its Montana jurisdiction. There is no support for an allocation method, like Dr. Wilson's 50/50 12 CP/energy weighting method, that allocates costs to rate classes on the basis of each class's annual energy usage, including energy usage in off-peak periods (for example, non-summer/winter months during off-peak hours and weekends). Dr. Wilson's recommended method sends incorrect price signals to customers and is totally inconsistent with the cost drivers inherent in the MISO capacity planning protocols.

Dr. Wilson's recommended methodology for allocating distribution costs is also flawed and does not reflect cost causation. Like his production/transmission demand allocator, Dr. Wilson proposes to allocate a significant portion of fixed distribution facilities (poles, towers, fixtures, conduit, and transformers) on the basis of a 50% demand/50% energy weighting. Effectively, Dr. Wilson assumes that 50% of distribution plant and expenses vary based on a customer's energy usage, including off-peak energy usage. He also rejects MDU's use of a minimum distribution system methodology that classifies a portion of distribution costs as customer related. These changes have the effect of shifting a significant amount of costs away from the residential class and towards general service rate classes.

Because of the lack of a cost causation foundation in the allocation methodologies Dr. Wilson recommends, the results of his class cost of service study (Exhibit JWW-8) should not be relied on in this case to apportion the overall Commission approved revenue increase to rate classes.

With regard to non-residential rate design, Dr. Wilson has again made an arbitrary recommendation that does not reflect cost causation. He recommends that 100% of any approved revenue increase to each non-residential rate class be applied to the energy charges of each rate. While this recommendation clearly benefits low load factor customers, it is not supported by reasonable evidence, is inconsistent with cost causation, and should be rejected.

Q. BEFORE ADDRESSING SPECIFIC PROBLEMS THAT YOU HAVE IDENTIFIED WITH DR. WILSON'S ANALYSIS, WOULD YOU BRIEFLY DISCUSS THE PRINCIPLES THAT SHOULD BE RELIED ON TO ALLOCATE ELECTRIC UTILITY COSTS TO RATE CLASSES IN A CLASS COST OF SERVICE STUDY?

A. Yes. The purpose of a class cost of service study is to fully allocate the test year jurisdictional electric plant investment, other rate base items, revenues, and expenses to each customer class or rate schedule so that a reasonable measure of cost responsibility can be determined for purposes of developing cost based rates. Effectively, in a fully allocated cost of service study, all of the components comprising a utility's revenue requirement are assigned to rate classes reflecting each class's responsibility for "causing" the costs to be incurred by the utility. This principle of cost causality is the fundamental underpinning of cost based rates.

Q. HOW IS THE PRINCIPLE OF "COST CAUSATION" USED TO DEVELOP A CLASS COST OF SERVICE ANALYSIS?

A. As described on in the NARUC Electric Utility Cost Allocation Manual, "Cost causation is a phrase referring to an attempt to determine what, or who, is causing the costs to be

incurred by the utility."[1] In order to assess each rate class's share of total jurisdictional costs, all of the Company's costs are first functionalized into the major functions provided by the utility: production, transmission, distribution, and customer related costs (such as customer accounting). For example, production costs, which would include generation plant in service, depreciation reserves and other rate base related costs, depreciation expense, O&M expenses, fuel, and purchased power are assigned to the production function. Once functionalized, these costs are then classified as either demand related, energy related, or customer related. Finally, the functionalized and classified costs are then allocated to rate classes based on allocation factors tied to cost causation. Fixed demand related costs are generally caused by the need for generation resources to meet peak demands, while energy related costs (such as fuel expenses) are caused by the total amount of energy use of each rate class. These general principles of cost causation are then employed to determine reasonable methodologies to allocate costs to rate classes.

Q. WHY IS IT IMPORTANT TO PERFORM A REASONABLE ALLOCATION OF COSTS TO RATE CLASSES?

A. There are a number of reasons to do so. First, economic efficiency requires that rates reflect underlying costs. For example, while one could just divide MDU's total fuel costs by the number of customers on the system and send each customer a uniform bill, that approach would clearly be unfair and result in a substantial misallocation of resources by overpricing energy related fuel costs to most customers and underpricing it to large

[1] National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual (January 1992) at page 38.

customers. Cost causation dictates that these energy related costs be assigned on the basis of the energy (kWh) use of each rate class. Similarly, fixed demand related costs, such as the return on generation plant investment and fixed production O&M, are incurred by the utility to meet the peak demand of its customers. Once these plants are constructed, these demand related costs are fixed and do not vary with the amount of energy use by customers. As a result, economic efficiency is best achieved by allocating fixed demand related costs on the basis of each class's contribution to system peak demand.

In addition to economic efficiency, a related reason for allocating costs on the basis of cost causation is to prevent cross-subsidization of one rate class by another. Cross-subsidization occurs when one set of customers pays in excess of cost and another pays less than cost of service.

A. <u>Flaws in Dr. Wilson's Generation/Transmission Demand Allocation Methodology.</u>

Q. WOULD YOU DISCUSS DR. WILSON'S PROPOSAL TO ALLOCATE GENERATION AND TRANSMISSION FIXED COSTS ON THE BASIS OF A 50/50 WEIGHTING OF ENERGY AND 12 CP DEMAND.

A. Dr. Wilson argues that a 12 CP demand allocator is more appropriate to assign cost responsibility for fixed generation and transmission costs than the Company's NCP based Average and Excess Demand ("AED") allocation method because the AED method relies on class NCP demand rather than coincident peak demand. As I discussed in my direct testimony, I also support the use of a 12 CP allocator in this case. However, Dr. Wilson then argues that these generation and transmission fixed costs are also related to energy usage (regardless of when it occurs) and proposes an allocator based on a 50%

energy/50% 12 CP weighting. He refers to this method as an "Average and Peak" method.

Q. DOES DR. WILSON PROVIDE ANY EVIDENTIARY SUPPORT FOR HIS RECOMMENDATION?

A. No, not that I can determine from a review of his testimony. On page 36 of his testimony Dr. Wilson states: "In allocating generation plant costs it is increasingly recognized that hours other than the peak hour are critical from a system planning perspective."[2] On page 37, he states: "It is now generally recognized that energy loads are a major determinant of generation plant costs."[3] Beyond these conclusory comments, Dr. Wilson offers no evidence that his recommended 50% energy/50% energy weighting scheme is consistent with the basis on which MDU incurs production and transmission investment and fixed O&M expenses. Rather, Dr. Wilson's recommendation is arbitrary and ad hoc.

While he discusses the "Equivalent Peaker" method, Dr. Wilson presents no results from any Equivalent Peaker analysis reflecting MDU's costs and generation resources. Rather, he simply decides to average the rate class allocation results of a 100% energy allocator and a 12 CP allocator. The end result does not reflect cost causation.

Q. DOES DR. WILSON EXPLAIN HOW HE DETERMINED THAT A 50/50 WEIGHTING OF CLASS ENERGY USAGE AND 12 CP DEMAND IS "COST BASED?"

A. Not that I can identify in his testimony. The 50/50 weighting is simply an ad hoc method that appears to assume that class (and therefore customer) energy usage, regardless of

[2] Direct Testimony of John Wilson at page 36, line 5.
[3] *Id.* at page 37, line 10.

when it occurs, has an equal responsibility for costs as the class's demands at the time of the MDU Montana system peak.

Q. CAN YOU PROVIDE AN EXAMPLE TO DEMONSTRATE HOW DR. WILSON'S METHODOLOGY DOES NOT REFLECT COST CAUSATION?

A. Certainly. Consider a general service customer who elects to add a third shift to its manufacturing operation in an off-peak month of April or October. This customer does not contribute any kW load to the MDU Montana system peak in any month, only additional energy usage in a clearly defined off-peak period. Yet, under Dr. Wilson's methodology, this customer is assigned cost responsibility for the Company's fixed generation and transmission costs. Dr. Wilson's method produces incorrect price signals that have no relationship to cost causation.

Q. DR. WILSON APPEARS TO EQUATE THE "EQUIVALENT PEAKER" METHOD TO HIS 50/50 AVERAGE AND PEAK METHOD. IS THIS COMPARISON REASONABLE?

A. No. Setting aside my concerns with the equivalent peaker methodology generally, Dr. Wilson's 50/50 average and peak method does not even reflect the underlying cost relationships that might be produced by a properly developed equivalent peaker study. That is, he has not demonstrated that MDU's generation resource costs, in excess of a peaker cost, are due to energy savings nor has he shown that the relationship between a peaker cost and MDU's total generation costs would produce a 50% energy, 50% demand weighting scheme. Rather, the 50% energy/50% demand weighting is simply an arbitrary methodology. Moreover, Dr. Wilson has presented no evidence that MDU incurred 50% of the fixed costs of its integrated transmission network for energy savings. This assumption by Dr. Wilson is nothing more than an unsupported assertion.

Q. IS THIS 50% ENERGY/50% DEMAND WEIGHTING CONSISTENT WITH THE CAPACITY PLANNING PROTOCOLS OF MISO?

A. No. MDU is a member of MISO and must meet the MISO capacity obligation that is based on MDU's expected load at the time of the MISO summer peak. MDU's July 2015 IRP filing clearly states this MDU capacity planning obligation in Volume IV. Below is an excerpt from the IRP:

> **Capacity Needs**
>
> The resource expansion analysis considers all planning resource options available to Montana-Dakota and produces a least-cost plan which satisfies the energy and capacity requirements to reliably serve Montana-Dakota's customers. Montana-Dakota is a member of MISO, which at this time requires a planning reserve margin (PRM) of 7.1 percent on an unforced capacity (UCAP) basis for the summer peak. The PRM is adjusted annually through MISO's Loss of Load Expectation (LOLE) study. To meet the PRM, sufficient planning resources are needed to cover the projected yearly MISO non- coincident summer peak demand with a 1.9 percent adder for MISO losses, plus 7.1 percent PRM, the product of which is referred to as the planning reserve margin requirement (PRMR).
>
> Montana-Dakota is required to meet an 80.3 percent coincident factor for the 2015-16 Planning Year in MISO based on MDU's analysis of Montana-Dakota's peak at the time of the MISO system-wide peak.[4]

As can be seen, MDU must meet a capacity obligation based on demand at the time of the system peak, coincident with the MISO system-wide peak. Dr. Wilson's 50% energy weighting is not consistent with MDU's planning criterion and therefore does not reflect cost causation.

Q. DR. WILSON PROPOSES TO USE THE SAME 50% ENERGY/50% 12 CP DEMAND ALLOCATOR TO ASSIGN INTEGRATED TRANSMISSION COSTS TO RATE CLASSES. IS THIS A REASONABLE RECOMMENDATION?

[4] MDU July 1, 2015 IRP, Volume IV, Attachments C-F, at page 1.

A. No. Once again, Dr. Wilson simply asserts that transmission investment is incurred to reduce energy costs and therefore it is appropriate to allocate costs using his 50% energy/50% demand allocator. MDU allocates integrated transmission investment and expenses to its Montana jurisdiction on the basis of a 100% 12 CP demand allocator (*i.e.*, 0% energy weighting). A change in Montana energy use in off-peak hours, for example, does not change the cost responsibility of Montana MDU customers for MDU's integrated transmission system. Moreover, because MDU is a member of MISO, which operates an RTO-wide integrated transmission system that is planned and operated on MISO basis, cost causation must reflect the impact of MISO protocols. Pursuant to the FERC approved tariff governing MISO cost allocations, the MDU transmission zone allocates transmission costs to MDU on the basis of MDU's share of the zonal 12 CP demand (*i.e.*, 0% energy). Dr. Wilson's 50% energy/50% demand cost allocation methodology simply ignores these realities.

Table 1, below, presents an excerpt from MDU's August 31, 2015 MISO Attachment O filing for the projected period 12 months ended December 31, 2016. This filing is the basis for MDU's Network Integrated Transmission Service ("NITS") rates for calendar year 2016, based on the FERC approved MISO tariff. At shown in the yellow highlighted row, the divisor for the NITS rate are the MDU 12 CP demands. This means that MDU's transmission revenue requirements are "allocated" to network and point-to-point transmission users, including MDU itself, on the basis of their respective 12 CP demands.[5] This is a further demonstration that Dr. Wilson's 50% energy/50%

[5] MDU is itself a network customer of the MDU transmission zone.

demand allocator is not based on cost causation and is therefore inappropriate as a measure of MDU Montana rate class cost responsibility.

Table 1

Formula Rate - Non-Levelized	Rate Formula Template Utilizing FERC Form 1 Data **Montana-Dakota Utilities Co.**				Attachment O page 1 of 5 **For the 12 months ended 12/31/16**
					Allocated Amount
GROSS REVENUE REQUIREMENT	(page 3, line 31)				$ 34,721,104
REVENUE CREDITS	(Note T)	Total	Allocator		
Account No. 454	(page 4, line 34)	18,752	TP	0.96329	18,064
Account No. 456.1	(page 4, line 37)	11,925,111	TP	0.96329	11,487,294
Revenues from Grandfathered Interzonal Transactions		0	TP	0.96329	0
Revenues from service provided by the ISO at a discount		0	TP	0.96329	0
TOTAL REVENUE CREDITS (sum lines 2-5)					11,505,358
Historic Year Actual ATRR					20,362,771
Projected ATRR from Prior Year	Input from Prior Year				24,419,516
Prior Year ATRR True-Up	(line 6a - line 6b)				(4,056,745)
Prior Year Divisor True-Up	(Note FF)				388,897
Interest on Prior Year True-Up					(237,677)
NET REVENUE REQUIREMENT	(line 1 - line 6 + line 6c through 6e)				$ 19,310,222
DIVISOR					
Average of 12 coincident system peaks for requirements (RQ) service				**(Note A)**	**540,717**
Divisor (sum lines 8-14)					540,717
Annual Cost ($/kW/Yr)	(line 7 / line 15)	35.712			
Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	2.976			

Q. ARE THERE OTHER PROBLEMS WITH DR. WILSON'S CLASS COST OF SERVICE STUDY (EXHIBIT JWW-8)?

A. Yes. He relied on the 12 CP data provided by the Company in response to LCG-010, which used incorrect loss factors for Rate 35, as I discussed in my direct testimony. In addition, Dr. Wilson did not correct the error in the allocation of the Pro Forma Adjustment for Other Production O&M expenses. As a result, irrespective of the

methodological flaws in Dr. Wilson's cost of service study, these uncorrected data errors in his study mean that it cannot be relied on to assess rate class cost responsibility.

Finally, without any support or discussion in his testimony, Dr. Wilson allocates revenue credits associated with sale for resale and margin sharing and A&G expenses on the basis of rate schedule total revenues. He simply states: "This is a more comprehensive and appropriate allocator than the allocators (kwh and O&M costs, respectively) used by the Company."[6] While the revenue credits are relatively small for MDU Montana, the A&G expenses are significant. There is no cost basis for either of these revisions, nor does Dr. Wilson offer one.

A&G expenses are allocated in the Company's cost of service study on the basis of O&M expenses, less fuel, purchased power, and A&G expense. This is a reasonable allocation method and reflects the nature of the A&G expenses being allocated. A&G expenses include costs in FERC Accounts 920 through 931. Total MDU Montana A&G expenses in the test year were $4,040,817. Of this amount, $1,093,178 represents Administrative & General Salaries (Account 920); $705,899 is for office supplies (Account 921); and $1,428,345 is for Employee Pensions & Benefits (Account 926). These three categories comprise 80% of A&G expense. None of these A&G expenses are associated with fuel or purchased power charges, yet the total revenue factor used by Dr. Wilson to allocate these A&G expenses to rate classes includes fuel and purchased power revenues paid by each rate class. For Rate 35, which is a high load factor rate

[6] Direct Testimony of John Wilson at page 59, lines 15-16.

class, fuel and purchased power comprises 50% of its total revenues. But for the system as a whole, fuel and purchased power is only 38% of total revenues.

To put this into perspective, Dr. Wilson is allocating such costs as employee pension expenses and office supplies using (in part) the level of fuel and purchased energy charges paid by the customers in the rate class. This allocation is totally unrelated to the "cause" for these A&G expenses. Effectively, Dr. Wilson is assuming that MDU incurs more or less office supply expense and employee pension expense as its fuel and purchased power costs rise or fall. Clearly, he is disregarding any semblance of cost causation in his analysis. By using the total revenue allocator to allocate A&G expenses in his cost of service study (Exhibit JWW-8), Dr. Wilson has unreasonably shifted hundreds of thousands of additional dollars of costs to Rate 35 and other high load factor rate classes.

B. <u>Flaws in Dr. Wilson's Distribution Demand Allocation Methodology.</u>

Q. WOULD YOU SUMMARIZE YOUR UNDERSTANDING OF DR. WILSON'S DISTRIBUTION COST ALLOCATION METHODOGY?

A. First, he rejects the use MDU's minimum distribution system methodology that reasonably classifies a portion of distribution Accounts 364, 365, 366, 367, and 368 (poles, overhead conductors, underground conduit, underground conductors, and transformers) as both customer and demand related costs. The Company's methodology is consistent with the distribution cost classification/allocation methods discussed in the 1992 NARUC Electric Utility Cost Allocation Manual ("NARUC Manual"). On page 90, the NARUC Manual states as follows:

> Distribution plan Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system.

Dr. Wilson dismisses this relationship between distribution costs and the number of customers being served by the distribution system. More significantly, Dr. Wilson then argues that rate class cost responsibility for these same distribution facilities (poles, overhead/underground conductors, transformers) is determined by a 50/50 weighting of rate class demand and rate class kWh energy, including off-peak energy.

Q. IS THE COMPANY'S USE OF A MINIMUM DISTRIBUTION SYSTEM COST METHODOLOGY CONSISTENT WITH THE ACCEPTED METHODS DISCUSSED IN THE NARUC MANUAL?

A. Yes. There are two recognized methodologies to estimate the customer component of distribution costs. These methods, which are described in the excerpt from the NARUC manual provided in Exhibit SJB-14, are the "zero-intercept" method and the "minimum size" method. These are the two approaches used by MDU. Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Neither of these two recognized methodologies include energy consumption in the analysis.

A minimum system cost of service analysis is designed to reflect the costs associated with changes in both the number of distribution customers and the loads of these customers. The conceptual basis for the minimum system method is that it reflects a classification of the distribution facilities that would be required to simply interconnect

a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to interconnect the customer to the MDU system.

This is in contrast to Dr. Wilson's recommended method, which gives recognition to demand and, inexplicably, energy usage, in explaining the need for distribution facilities. Dr. Wilson's method assumes that distribution costs associated with poles, lines and transformers vary directly with kW demand and kWh energy use ("average demand"), without any component reflecting the number of customers in each class.

Q. HAS DR. WILSON PROVIDED ANY REASONABLE SUPPORT FOR HIS USE OF A 50% ENERGY/50% DEMAND ALLOCATION METHODOLOGY FOR DISTRIBUTION FACILITIES?

A. No. Moreover, this energy/demand weighting method is not even mentioned as an option in the distribution cost classification/allocation section of the NARUC Manual. Exhibit SJB-14 contains an excerpt from the manual that discusses cost allocation methodologies for distribution facilities. A review of this chapter on the classification and allocation of distribution costs clearly shows that there is simply no reference or even acknowledgement of an "energy" component of distribution costs. Distribution facilities are designed to meet the loads placed on the facilities. In addition, regardless of the kW demand, a minimum set of facilities must be installed simply to connect the customer to the grid. A customer's energy usage, particularly in an off-peak period, does not impact the size (and thus the cost) of these distribution facilities.

Even if one were to reject a minimum system concept, the alternative is to classify all distribution plant as demand related and allocate based on each class's contribution to various measures of diversified kW demand. There is no basis to allocate *any* (let alone 50%) of distribution plant (and related expenses) on the basis of energy.

This energy/demand weighting methodology cannot be supported on the basis of cost causation. Consider high load factor customers on Rate 30 who use significant amounts of energy during off-peak and weekend hours. Dr. Wilson's proposed allocation method would assign these customers additional cost responsibility for primary and secondary lines, line transformers, poles, and other structures for each additional off-peak kWh that they used. This is not plausible from a cost causation standpoint. These distribution facilities are built to meet the maximum loading expected on them. Additional energy use during off-peak hours, as long as it does not create new, localized peak demands, does not contribute to the need for these facilities. Yet, Dr. Wilson's cost of service study keeps assigning additional cost for distribution facilities every time a Rate 30 customer uses more off-peak energy.

C. <u>Flaws in Dr. Wilson's Recommended Non-Residential Rate Design and Apportionment of the Overall Revenue Increase to Rate Classes.</u>

Q. WHAT IS DR. WILSON'S RECOMMENDATION TO APPORTION THE OVERALL APPROVED REVENUE INCREASE TO RATE CLASSES?

A. Based on the results of his class cost of service study (Exhibit JWW-8), Dr. Wilson recommends that the residential rate class receive an increase no greater than the average retail increase approved in this case. As I discussed above, there are numerous flaws in his analysis that render his recommended class cost of service study unreliable. Because

his cost of service study is flawed and does not reasonably reflect cost causation, it should not be used to assign the rate class cost responsibility.

As I showed in my direct testimony, using a corrected 12 CP methodology, many MDU Montana rate classes are significantly above cost of service and should receive lower than average increases. While I am recommending that the Commission adopt a mitigation methodology to reduce the impact on the residential rate class (and other classes to the extent that full cost based rates would produce increases in excess of 1.5 times the retail average increase), the Commission should apportion the overall revenue increase in this case in a manner that will reduce current subsidies. Dr. Wilson's recommendation does not accomplish this objective and should therefore be rejected.

Q. DR. WILSON RECOMMENDS THAT ANY APPROVED REVENUE INCREASE TO NON-RESIDENTIAL RATE CLASSES BE APPLIED TO THE ENERGY CHARGES OF THESE RATES. IS THIS A REASONABLE RECOMMNEDATION?

A. No. Again, without any substantive analysis to support his recommendation, Dr. Wilson argues that 100% of any approved revenue increase to the non-residential classes be applied to the energy charges of the rate. For example, for Rate 30, the Company proposes a 21.1% overall revenue increase. Based on the Company's proposed rate design, the energy charge of Rate 30 secondary customers *would increase by 13%*. If Dr. Wilson's arbitrary rate design recommendation was accepted, the energy charge of Rate 30 secondary customers *would increase by 83%*. This would result in a total energy charge for Rate 30 secondary customers of about 5.5¢/kWh (including the base fuel amount). This compares to the average, all hours MISO market energy price of about

2.9¢/kWh.[7] It is difficult to see the validity of Dr. Wilson's argument that applying 100% of the revenue increase to the energy charge of Rate 30 (and all other non-residential rates) is economically efficient.

Ironically, Dr. Wilson's primary argument in support of his non-residential rate design recommendation is that the energy charges of these non-residential rates should reflect marginal or incremental energy cost.[8] Based on the results of the Company's marginal cost reconciliation presented in Statement M, page 2, the residential rate class should receive an increase of 55.3% if marginal costs are used in this case to set rates. This is close to three times the increase that Dr. Wilson recommends for the residential class (55.3%. vs. 21.1%).[9]

Q. WHAT ARE THE CONSEQUENCES OF DR. WILSON'S NON-RESIDENTIAL RATE DESIGN PROPOSAL?

A. It would result in significant disincentives for high load factor customers to consume energy during off-peak hours. At the same time, his recommendation would reduce the on-peak demand charges for non-residential rates below what they otherwise would be under a more balanced rate design methodology.

Q. DO YOU HAVE ANY FINAL COMMENTS ON DR. WILSON'S TESTIMONY ON RATE DESIGN?

A. Yes. On page 63 of his testimony, Dr. Wilson presents a comparison of the average residential rate/kWh to the Rate 35, Contract energy rate. But this is an apples to oranges comparison. First, as Dr. Wilson himself points out, residential customers have no

[7] *See* Direct Testimony of Stephen J. Baron at page 20.
[8] Direct Testimony of John Wilson at page 64, line 16.
[9] Dr. Wilson recommends that the residential class receive no more than the average increase, which is 21.1% using the Company's filing in this case as a benchmark.

demand charges and therefore the entirety of residential costs (production/generation, transmission, distribution) must be recovered in the residential energy rate. For demand metered rate classes, such as Rate 35, the allocated revenue requirements are recovered through both energy and demand charges due to the availability of demand metering. This permits a demand/energy rate design that can reflect the underlying characteristics of the costs (*i.e.*, energy and demand related). Second, the contract customer on Rate 35 takes service at a high voltage rather than the secondary voltage used to serve residential customers. As a result, residential energy costs are higher due to increased electrical losses and the additional costs of distribution facilities needed to serve lower voltage customers.[10]

Q. DOES THIS CONCLUDE YOUR CROSS-ANSWER TESTIMONY?

A. Yes.

[10] Residential secondary customers require distribution facilities, such as poles, underground and overheard lines and transformers that are not required to serve high voltage customers.

Cross-Intervenor Response Testimony
of
Stephen J. Baron

Exhibit SJB-14

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

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CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1] Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines

the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.
   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.
   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.
   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. **Account 364 - Poles, Towers, and Fixtures**

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (1/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is

developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. **Account 368 - Line Transformers**

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step,

it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of

maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.