BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	)))	Docket No. 6690-UR-124

DIRECT TESTIMONY OF JONATHAN WALLACH ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN

September 2, 2015

I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric-power industry since 1981. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the past thirty years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and management; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Ex.-CUB-Wallach-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have sponsored expert testimony in more than seventy federal, provincial, or state proceedings in the U.S. and Canada. In Wisconsin, I testified before the Public Service Commission (PSC or the Commission) in Docket Nos. 6630-CE-302, 3270-UR-117, 4220-UR-117, 6680-FR-104, 3270-UR-118, 05-UR-106, 4220-UR-118, 6690-UR-122, 4220-UR-119, 6690-UR-123, 05-UR-107, and 3270-UR-120. I include a detailed list of my previous testimony in Ex.-CUB-Wallach-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Citizens Utility Board of Wisconsin (CUB).

Q: What is the purpose of your testimony?

A: On April 17, 2015, Wisconsin Public Service Corporation (WPSC or "the Company") filed an application to increase electric and gas rates for the 2016 test year. The Company subsequently filed additional supporting testimony on May 15, 2015 and on June 24, 2015 by Joylyn C. Hoffman Malueg regarding the Company's electric cost of service study (COSS) and by Ronda L. Ferguson regarding the Company's proposals for allocating and recovering through rates the 2016 test year revenue deficiency. Finally, on August 17, 2015, Commission staff provided CUB (and other parties) the results of six cost of service studies based on the Commission staff audit forecast of 2016 test year revenue requirements.

This testimony:

- Examines the different classification and allocation methods used in the six audit cost of service studies and assesses the extent to which such methods are consistent with cost-causation principles.
- Describes my proposal for allocating to customer classes the Commission staff audit forecast of the 2016 test year electric revenue deficiency.
- Addresses the Company's proposed rate design for residential and small commercial and industrial (C&I) customers, including its proposal to increase fixed charges for the residential and small C&I classes.

Q: Please summarize your findings and recommendations with regard to cost allocation.

A: The Commission staff audit finds a base revenue deficiency for the 2016 test year of about $20.4 million, or 2.01% of 2016 test year electric revenues under current rates. This revenue deficiency does not reflect an expected refund from the Statewide Energy Efficiency and Renewables Administration (SEERA) of unspent Focus on Energy funds that had been voluntarily committed by WPSC and paid for by residential and commercial customers in accordance with a decoupling pilot project stipulation entered in Docket No. 6690-UR-119 ("SEERA credit").

At the request of Commission staff, WPSC conducted six cost of service studies based on the Commission staff audit forecast of 2016 test year revenue requirements. These six studies differ with respect to the methods used to classify and allocate production and distribution plant costs, as well as with respect to the treatment of interruptible credits. Of the six studies, the Locational COSS classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs.

For the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2016 test year, it would be appropriate to consider the results of all six of the audit cost of service studies. Based on the range of results from these six studies, I recommend that base revenues (i.e., before allocation of the SEERA credit) for the residential class be increased by the system-average increase of 2.01% and that there be no increase from current base revenues for the small C&I class. My understanding is that Commission staff, as part of its direct filing in this proceeding, will be recommending an allocation of the SEERA credit back to the residential and small C&I rate classes that paid those costs in the first instance as part of the decoupling pilot.

Q: Please summarize your findings and recommendations with regard to rate design for the residential and small C&I classes.

A: The Company lacks a reasonable basis for its proposal to dramatically increase fixed charges for residential and small C&I customers. The increases proposed by WPSC would inappropriately shift load-related costs to the fixed charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and exacerbate the subsidization of larger residential customers' costs by these low-usage customers.

Moreover, contrary to Commission precedent, the Company relied solely on the results of one cost of service study as the basis for its proposal to increase fixed charges. In contrast, the range of results from the audit studies indicates that no increase to current fixed charges is warranted at this time. Consequently, the Commission should reject the Company's proposal to increase the fixed charge from $19 per month to $25 per month for residential customers and from $25 per month to $30 month for small C&I customers.

I will include in my rebuttal testimony proposed rate designs for the residential and small C&I rate classes that reflect my recommended allocation of base revenues, Commission staff's proposed allocation of the SEERA credit, and my recommendation to maintain fixed charges at current levels.

II. Cost Allocation

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2016 test year?

A: The Commission staff audit finds a base revenue deficiency for the 2016 test year, before accounting for the SEERA credit, of about $20.4 million, or 2.01% of 2016 test year electric revenues under current rates. With the SEERA credit, the audit revenue deficiency amounts to about $17.8 million, or 1.75% of 2016 test year electric revenues under current rates.

Q: Did WPSC conduct cost of service studies based on Commission staff audit revenue requirements?

A: Yes. At the request of Commission staff, WPSC conducted six cost of service studies based on the Commission staff audit forecast of 2016 test year revenue requirements. These six studies differ with respect to the methods used to classify and allocate production and distribution plant costs, as well as with respect to the treatment of interruptible credits. Below is a brief description of each of the six studies using the Company's nomenclature for these studies:[1]

- The "1P-3P COSS" adopts the Company's approach for classifying and allocating production and distribution plant costs. Specifically, the 1P-3P

[1] Much of the nomenclature for the six cost of service studies is historical and is not necessarily descriptive of the differences between each study.

COSS classifies all production plant costs as demand-related and allocates such costs on the basis of each class's contribution to the twelve monthly system peaks (12CP). In this case, the 12CP allocator is derived using class load net of interruptible load. In addition, the 1P-3P COSS classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis. Finally, the 1P-3P COSS separates three-phase from single-phase primary distribution plant costs and allocates single-phase costs solely to secondary voltage customers.

- The "4CP COSS" differs from the 1P-3P COSS in two respects. First, demand-related production plant costs are allocated on the basis of each class's contribution to system peak in the four summer months (4CP). Second, the 4CP COSS does not allocate three-phase separately from single-phase primary distribution costs.
- The "Standard COSS" differs from the 1P-3P COSS only with respect to the allocation of primary circuit plant costs. As with the 4CP COSS, the Standard COSS does not allocate three-phase separately from single-phase primary distribution costs.
- The "Capacity COSS" modifies the treatment of interruptible load in the Standard COSS. Specifically, the Capacity COSS allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load at Commission staff's estimates of the value of interruptible and direct load control capacity.
- The "Time-of-Use (TOU) COSS" modifies the Capacity COSS by classifying 40% of production plant costs as demand-related and the remaining 60% as energy-related. My understanding is that this demand/energy split is based on the results of Commission staff's Equivalent Peaker analysis in Docket No. 6690-UR-122.

- The "Locational COSS" modifies the TOU COSS by classifying all distribution plant costs, other than for meters and services, as demand-related.

Q: Please describe the results of the six Commission staff audit cost of service studies.

A: As noted above, based on Commission staff's audit, the base revenue deficiency for the 2016 test year is about $20.4 million, or 2.01% of 2016 test year electric revenues under current rates. For each of the six cost of service studies, Table 1 shows the allocation of this overall deficiency to each of the major customer classes, expressed as a percentage of 2016 test year electric revenues under current rates for each class.

Table 1: Staff Audit COSS Base Revenue Deficiency (% of Current Revenues)

`	1P-3P COSS	4CP COSS	Standard COSS	Capacity COSS	TOU COSS	Locational COSS
Residential	5.12%	5.44%	5.38%	3.32%	0.84%	-7.58%
Small C&I	-12.41%	-10.63%	-12.57%	-14.67%	-14.73%	-15.35%
Cg-5	-8.15%	-5.64%	-8.61%	-11.18%	-12.22%	-5.46%
Cg-20	4.16%	5.59%	3.65%	1.03%	-0.44%	8.19%
Cp	5.92%	3.11%	6.03%	13.21%	18.62%	23.05%
Lighting	-35.82%	-41.22%	-33.35%	-33.99%	-33.14%	-37.36%
Miscellaneous	8.84%	8.06%	8.06%	8.06%	8.06%	19.65%
Total System	2.01%	2.01%	2.01%	2.01%	2.01%	2.01%

Q: Are any of these studies more appropriate than the others?

A: Of the six studies, the Locational COSS allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs. Specifically, the Locational COSS achieves reasonable consistency with cost-causation by:

- Using the Equivalent Peaker classification method to classify production plant costs as demand- or energy-related.
- Allocating demand-related production plant costs on the basis of each class's contribution to the twelve monthly system peaks.
- Classifying all distribution plant costs, other than for meters and services, as demand-related.

A. Classification of Production Plant Costs

Q: How are production plant costs classified as demand- or energy-related in the six audit studies?

A: As noted above, four of the six studies (1P-3P, 4CP, Standard, and Capacity COSS) employ the Company's approach of classifying 100% of production plant costs as demand-related. The other two studies (TOU and Locational COSS) classify production plant costs as either demand- or energy-related using the Equivalent Peaker classification method.

Q: Please describe the Equivalent Peaker method for classifying production plant costs.

A: The Equivalent Peaker method distinguishes between investments in peaking plant and investments in baseload or intermediate plant for classification purposes. Under the Equivalent Peaker method, 100% of peaking plant costs are classified as demand-related. The Equivalent Peaker method also classifies the portion of baseload or intermediate plant costs equivalent to peaking plant costs as demand-related, but classifies the remainder of baseload or intermediate plant costs *in excess of peaking plant costs* (i.e., capitalized energy costs) as energy-related.[2]

Q: Which of these two classification approaches more reasonably reflects cost-causation?

A: The Equivalent Peaker method more reasonably reflects cost-causation because it classifies production plant costs consistent with the drivers of plant investment under typical generation expansion planning practices. Specifically, investments in peaking plant are appropriately classified as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs in excess of peaking plant costs should be classified as energy-related, since these incremental costs are typically incurred to minimize the total cost of meeting an increase in energy requirements.

In contrast, the other four studies classify all production plant costs as demand-related, as if production plant costs are incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. This classification approach is inconsistent with investment decision-making under typical generation expansion planning practices, where, as noted above, plant investment choices are driven by both reliability and energy requirements.

Thus, these four studies inappropriately classify baseload and intermediate plant costs in excess of peaking plant costs as demand-related. By doing so, these studies over-allocate such capitalized energy costs to residential and small

[2] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 52-55.

C&I rate classes, since these classes have lower load factors than the larger C&I classes.[3]

B. Allocation of Demand-Related Production Plant Costs

Q: How are demand-related production plant costs allocated to customer classes in the six audit studies?

A: With the exception of the 4CP COSS, all of the audit studies allocate demand-related production plant costs using the 12CP allocator. The 12CP allocator allocates demand-related production plant costs on the basis of each class's contribution to the twelve monthly system peaks. As discussed above, demand-related production plant costs are incurred for the purposes of meeting reserve requirements. Thus, the 12CP allocator allocates demand-related production plant costs consistent with the notion that the Company's planning reserve requirements are driven by system peaks in all months of the year.

The 4CP COSS allocates demand-related production plant costs on the basis of each class's contribution to system peaks solely in the four summer months. In this case, the 4CP allocator allocates demand-related production costs as if reserve requirements are driven by system peaks only in the four summer months.

Q: Which of these two allocators most reasonably reflects each class's responsibility for demand-related production plant costs?

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[3] A class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than that of energy-related costs, because that class's percentage contribution to total system demand is larger than its contribution to total system energy requirement.

A: The 12CP allocator more reasonably reflects cost-causation than the 4CP allocator because the Company's annual reserve requirement is determined based on demand throughout the year, not just by demand in the four summer months.

Specifically, the Midcontinent Independent System Operator (MISO) determines the amount of capacity required for planning reserve based on the results of a loss of load probability (LOLP) analysis that considers the daily contribution of the Company's demand to annual LOLP.[4] Although lower than peak demands in the summer months, non-summer peaks can also contribute to annual LOLP and thus system reserve requirements at times when margins between available capacity and demand are tight. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLP and reserve requirements. Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by summer peaks. Consequently, the 12CP allocator is a more reasonable measure of each class's contribution to the need for new reserve capacity than the 4CP allocator.[5]

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[4] Although MISO determines the amount of capacity required for planning reserve based on demand throughout the year, it expresses the Company's reserve requirement as the percentage margin of required capacity over 1CP demand.

[5] While peak demands in all months contribute to capacity reserve requirements, the effect of summer peaks on annual LOLP outweighs that of non-summer peaks. In that regard, the 12CP allocator appropriately reflects the importance of summer peaks, since the average of the twelve monthly peaks gives greater weight to the higher summer peaks than to the lower non-summer peaks. Thus, with the 12CP allocator, the allocation of demand-related production plant costs to a customer class is driven more heavily by that class's contribution to system summer peaks than to system non-summer peaks.

C. Classification of Distribution Plant Costs

Q: Please describe the methods used in the six audit studies to classify distribution plant costs.

A: The Locational COSS classifies all distribution plant costs, with the exception of meter and services costs, as demand-related. All other audit studies adopt the Company's approach, which classifies certain distribution plant costs as customer-related or demand-related based on a "minimum distribution system" analysis.

Q: Is one of these classification approaches more reasonable than the other?

A: Yes. The method used in the Locational COSS more reasonably classifies distribution plant costs than the Company's approach. As discussed below, minimum distribution system analyses typically produce classifications that are inconsistent with cost-causation and which result in an over-allocation of distribution plant costs to the residential and small C&I rate classes. As has been recognized in jurisdictions throughout the U.S., the method used in the Locational COSS offers a more reasonable alternative to minimum distribution system classification.

Q: How is the cost of the minimum distribution system generally derived?

A: The most common methods used are: (1) the minimum-size method; or (2) the minimum-intercept method.

A minimum-size analysis attempts to estimate the cost to install the same number of units (e.g., poles, conductor-feet) as are currently on the system, assuming that each of those units are the smallest size currently used on the distribution system. The minimum-size approach attempts to estimate the cost to exactly replicate the configuration of the existing distribution system using the smallest-size equipment currently used on the system.

The minimum-intercept method attempts to estimate a functional relationship between equipment cost and equipment size based on the current system, and then to extrapolate that cost function to estimate the cost of equipment that carries zero load (e.g., zero-kVA transformers), the smallest units legally allowed (e.g., 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The goal of this procedure is to estimate the cost of equipment required to connect existing customers, assuming they have virtually no load.

Under either approach, the minimum distribution system cost is deemed to be customer-related, with the remaining cost classified as demand-related.

Q: Which approach does the Company use to classify distribution costs?

A: According to Company witness Ms. Hoffman Malueg, WPSC uses the minimum-size method to classify poles (Account 364), overhead conductors (Account 365), and underground conductors (Account 367). The Company uses the minimum-intercept method to classify line transformers (Account 368).[6]

Q: Do minimum distribution system analyses generally produce reasonable classifications of costs?

A: No. The minimum distribution system approach is fundamentally flawed since it is premised on a simplistic model of cost-causation that is inconsistent with typical distribution-system planning, design, and investment practices. Where distribution-system costs may be driven by a host of design considerations – such as customer load, load growth, terrain, customer density, voltage

[6] All intangible (Account 303), land and land rights (Account 360), structures and improvements (Account 361), distribution substation (Account 362), and underground conduit costs (Account 366) are classified as demand-related. All services (Account 369) and meter costs (Account 370) are classified as customer-related.

considerations, or minimum service reliability and quality requirements – the minimum distribution system approach simplistically models cost-causation as a function of just two factors: customer load and number of customers. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, with only two explanatory variables driving cost-causation, minimum distribution system models classify as customer-related all costs not directly driven by demand, regardless of whether such costs are related to the number of customers:

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs …, while it is also denied a place among the customer costs …, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs…. But fully-distributed cost analysts dare not avail themselves of this solution, since they are prisoners of their own assumption that "the sum of the parts is equal to the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.[7]

The examples shown in Figures 1a and 1b illustrate this basic flaw in the minimum distribution system approach. In the example shown in Figure 1a, a hypothetical distribution system consists of a single one-mile feeder serving two customers: a commercial facility and a single-family home. In Figure 1b, the same hypothetical one-mile feeder serves the same commercial facility and four single-family homes.

[7] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates,* Arlington, VA: Public Utilities Reports, 1988, p. 492.

Figure 1a

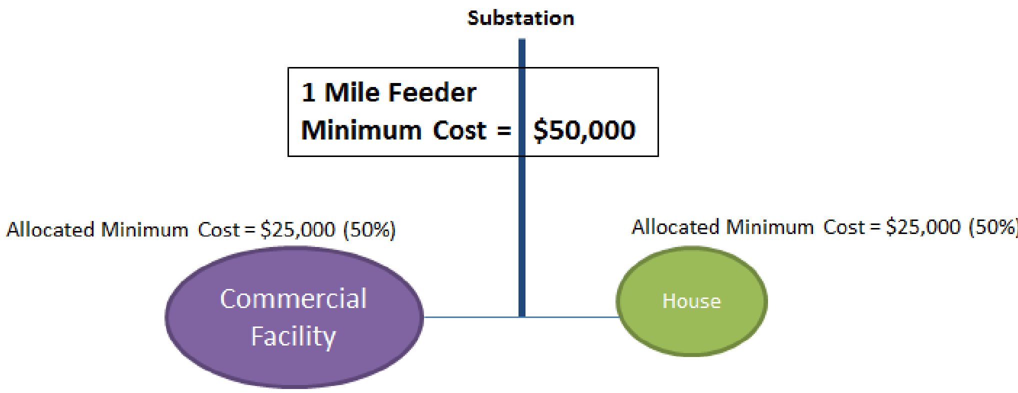
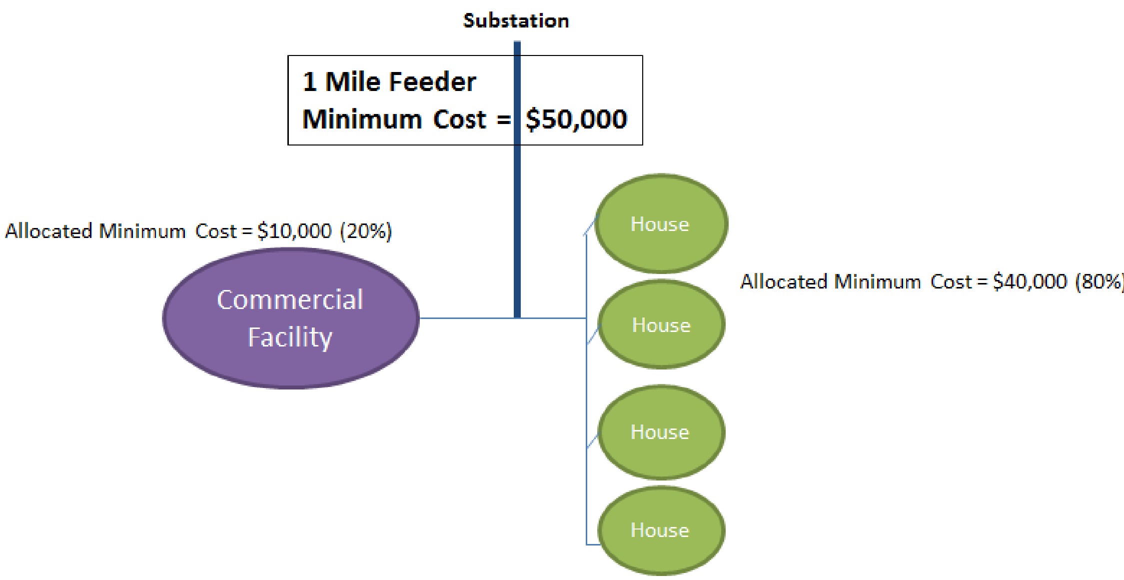


Figure 1b



As indicated in these figures, the minimum cost of the single feeder is the same in both examples, even though the number of customer accounts varies (2 in Figure 1a; 5 in Figure 1b). The minimum cost does not vary with the number of customer accounts in these examples because by definition it is the cost of the minimum-sized feeder equipment required to connect these customers regardless of the total load on the feeder. In other words, the addition of three homes does not increase the minimum cost of the feeder. Yet, even though the minimum cost is <u>**not**</u> driven by customer number, the minimum distribution system approach allocates minimum costs between the residential and commercial classes as if such costs did vary with customer number. In the example shown in Figure 1a, 50% of the minimum cost would be allocated to the residential class. In contrast, in the example shown in Figure 1b, 80% of the same minimum cost would be allocated to the residential class. Thus, the minimum distribution system approach does not allocate costs consistently with cost-causation.

Residential and small C&I customers are especially burdened because these non-customer-related minimum costs are arbitrarily classified as customer-related rather than demand-related. These classes will be allocated a greater percentage of customer-related costs than that of demand-related costs, because the ratio of customers in these classes to total number of customers is larger than the ratio of these classes' demand to total system demand.

Q: Are there other problems with the minimum distribution system method?

A: Yes. Both the minimum-size and minimum-intercept methods suffer from specific problems that tend to over-allocate distribution plant costs to the residential and small C&I customer classes.

In a 1981 article, George Sterzinger identified a flaw in the minimum-size approach that could overstate the appropriate allocation of demand-related costs to the residential and small C&I classes.[8] The problem arises because the minimum-size method typically defines the minimum system to include equipment that is large enough to cover the average load of residential

[8] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, July 2, 1981.

customers.[9] In that event, only those costs incurred for the minimum-size equipment, deemed to be customer-related, are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method not only allocates to the residential class the cost for the minimum-size equipment as customer-related, but also inappropriately allocates to residential customers a portion of the actual equipment costs in excess of the minimum-size costs as demand-related costs, even though these excess costs were not incurred to serve residential load.

Figures 2a and 2b illustrate this problem of over-allocation of demand-related costs when using the minimum-size method. As in Figures 1a and 1b, Figures 2a and 2b assume a hypothetical distribution system consisting of a single one-mile feeder. In the example shown in Figure 2a, there are 20 customers served by the feeder: 19 units in an apartment building with a combined load of 30 kW and a single commercial facility with a load of 100 kW. In this case, the minimum-size feeder is assumed to be large enough to cover the combined load on the system, meaning that the minimum cost is equal to the total cost of the feeder. Consequently, under the minimum-size approach, 100% of the total cost of the feeder is classified as customer-related and the residential class (with 19 of the 20 customer accounts served by the hypothetical distribution system) is allocated 95% of this customer-related cost.[10]

[9] In other words, the utility would not have installed equipment that is larger and more-expensive than the minimum-size equipment if it were only serving residential load.

[10] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 2a

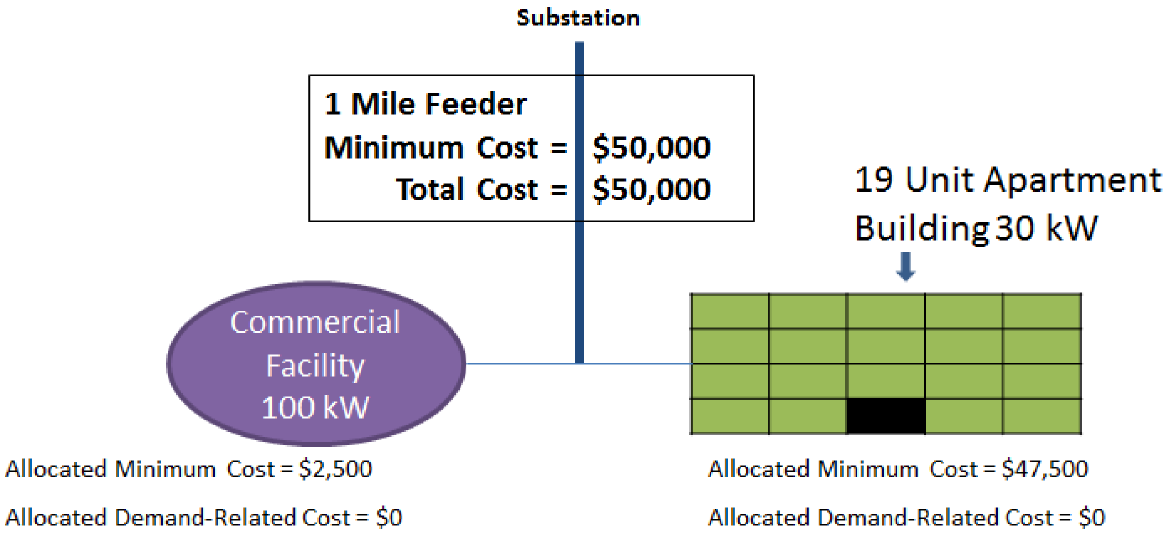
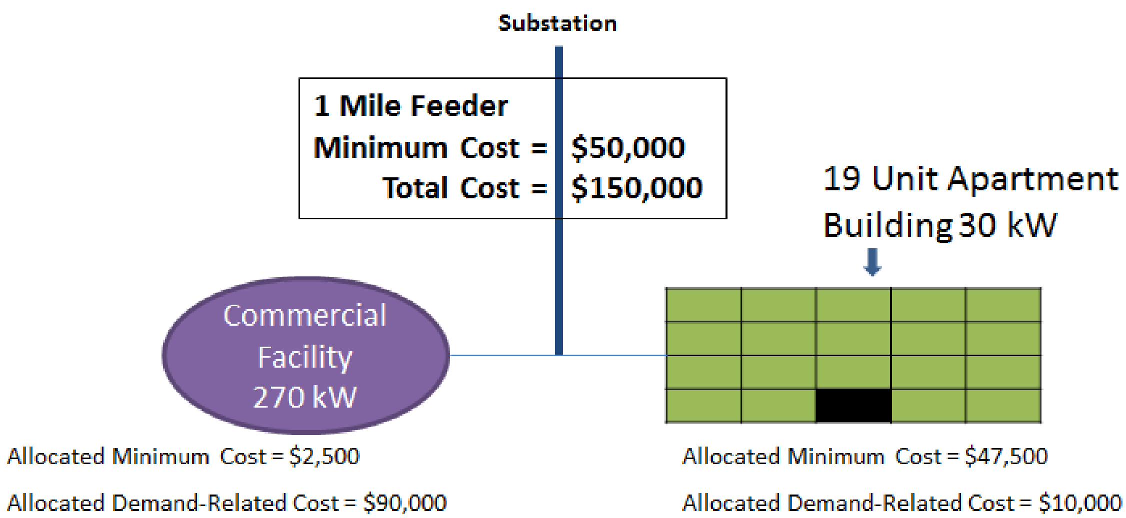


Figure 2b



The example shown in Figure 2b assumes the same number of customers as in Figure 2a. However, in this example, the commercial facility has a load of 270 kW, requiring a larger feeder. As in Figure 2a, the residential class would be allocated 95% of the minimum cost of the feeder. Unlike the case in Figure 2a, however, the residential class would also be allocated 10% of the demand-related feeder costs – those costs in excess of the cost of a minimum-size feeder – even though such costs would not have been incurred without the additional commercial load on the system. Instead, all such excess costs in this example should be allocated to the commercial class.

Q: Does the minimum-intercept method also suffer from this problem?

A: No. The minimum-intercept method avoids this over-allocation of demand-related costs by setting minimum cost at the estimated cost for a system with zero load.[11]

However, at a conceptual level, the minimum-intercept method is so abstract that its application may not yield realistic results. For example, it may not be appropriate to extrapolate from the current system to estimate the cost of a system that serves zero load. A system designed to connect customers but serve zero load would likely look very different from the existing system. For example, a zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. Without the need for high voltages to carry power, poles could be shorter and cross-arms would be unnecessary; with no transformers and cross-arms, and lighter conductors, poles could be thinner as well. The labor and equipment costs of setting those short, light poles would be much lower than the costs of real utility poles of any size. It is therefore unlikely that a cost estimate based on an extrapolation from the current system would reasonably reflect the cost of an actual zero-load system. If so, then the minimum-intercept approach would

[11] In contrast with the minimum-size approach, which sets the minimum cost at the cost of the minimum-size equipment used by the utility, where such minimum-size equipment may be large enough to cover average residential load.

misclassify demand-related costs as customer-related and thereby over-allocate distribution plant costs to the residential and small C&I classes.

Q: Is there a reasonable alternative to the minimum distribution system method for classifying distribution plant costs?

A: Yes. A reasonable and reasonably straightforward approach, and one that has been used in other jurisdictions, is to classify meters and services as customer-related and all other distribution plant costs as demand-related.[12] This is the classification approach used in the Locational COSS.

Alternatively, distribution plant costs (other than meters and services) could be classified using the approach adopted by the Company's affiliate Wisconsin Electric Power Company (WEPCO). Recognizing that minimum-sized equipment is designed to carry load, WEPCO classifies 50% of minimum-system costs as demand-related and 50% as customer-related.[13] Under this approach, for example, if minimum-system costs were 50% of total distribution plant costs, then 75% of total costs would be classified as demand-related and 25% would be classified as customer-related.

III. Base Revenue Allocation Proposal

Q: Given that the Locational COSS most reasonably reflects cost-causation, do you recommend that study's allocation of the 2016 test year revenue deficiency?

[12] According to a study by the Regulatory Assistance Project, this approach is employed in more than thirty states. See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 30.

[13] See Tr. Vol. II Direct-WEPCO/WG-Rogers-20, ll. 14-17 (Docket No. 05-UR-107) (PSC REF#: 208199).

A: No. As the Commission has long held, cost of service studies are merely guides, and no one study perfectly captures cost-causation. It therefore would be appropriate to consider the results of all six of the audit cost of service studies for the purposes of allocating the 2016 test year revenue deficiency to customer classes.

Q: Based on the results of the six audit cost of service studies, how do you propose to allocate the 2016 test year revenue deficiency?

A: I recommend that base revenues (i.e., before allocation of the SEERA credit) be allocated to customer classes as shown in Table 2. I developed my recommendation based on the directional results from the six audit studies and with the goal of narrowing the difference for all classes between the allocated revenue increase and the system average increase in order to avoid rate shock for any one class.

Table 2: Recommended Base Revenue Allocation

	Current Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential	375,336,207	382,888,982	7,552,775	2.01%
Small C&I	120,033,767	120,033,767	-	0.00%
Cg-5	35,393,006	35,393,006	-	0.00%
Cg-20	230,041,127	234,670,174	4,629,047	2.01%
Cp	240,336,689	248,574,091	8,237,402	3.43%
Lighting	13,314,649	13,314,649	-	0.00%
Miscellaneous	280,718	280,718	-	0.00%
Total System	1,014,736,163	1,035,155,387	20,419,224	2.01%

As indicated in Table 2, I recommend that base revenues for both the residential and Cg-20 classes be increased by the system-average increase of

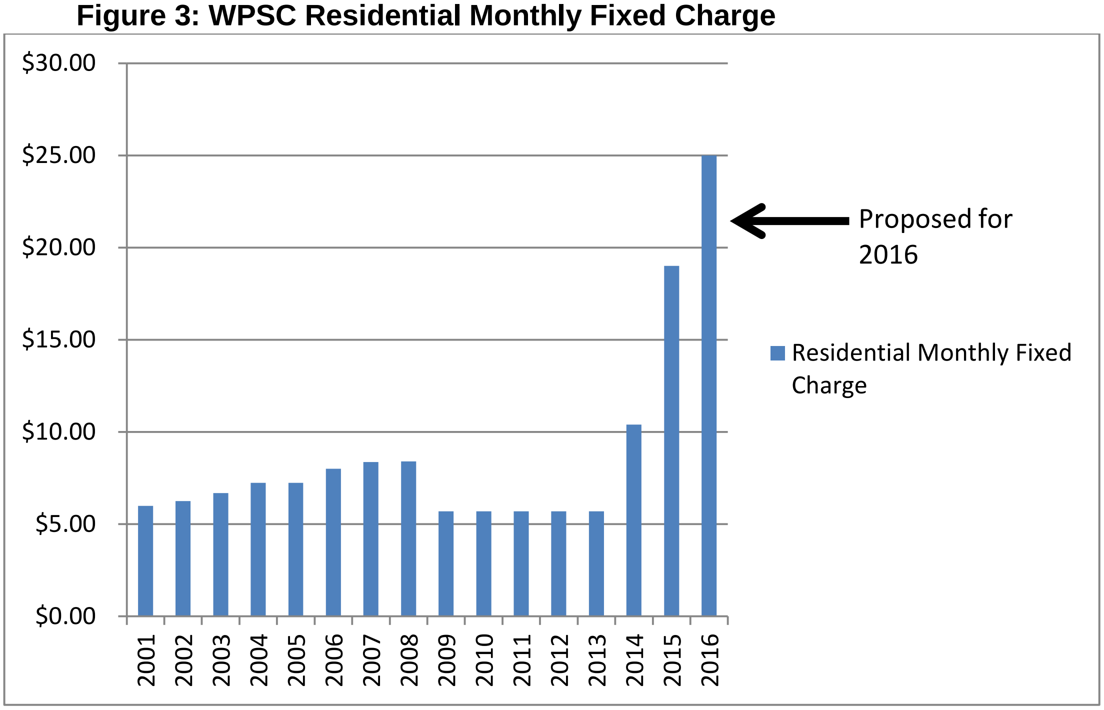
2.01%. I further recommend a 3.43% increase in Cp revenues. Base revenues for all other classes should be held constant at current levels.

IV. Rate Design

Q: What is the Company's proposal with respect to residential and small C&I rate design?

A: The Company proposes to sharply increase the monthly fixed charge from $19 to $25, or about 32%, for residential customers and from $25 to $30, or 20%, for small C&I customers. The Company's proposed increases follow another significant increase in fixed charges less than one year ago from $10.44 to $19 per month for residential customers and from $12.50 to $25 per month for small C&I customers. Figure 3 shows how the rate for the Company's residential fixed charge has changed from 2001 through its proposal for 2016.

Figure 3: WPSC Residential Monthly Fixed Charge



Q: Which costs does WPSC contend are fixed?

A: According to Company witness Ms. Ferguson, WPSC considers all production, transmission, and distribution costs that are classified as either demand-related or customer-related under the Company's cost of service study to be fixed.[14] Thus, WPSC considers only those costs classified as energy-related under the Company's cost of service study (primarily fuel and variable O&M) to be variable costs.

Q: By what amount would WPSC have to increase the residential fixed charge in order to recover all of the costs the Company considers to be fixed?

A: According to Ms. Ferguson, the fixed charge would have to increase to $68.61 per month, or by almost four times the current level, in order to recover all costs allocated to the residential class under the Company's cost of service study that WPSC alleges to be fixed.[15] Thus, a residential fixed charge of $25 per month would recover about 36% of the production, transmission, and distribution costs that WPSC considers to be fixed.

Q: What would be the effect on the residential energy charge, if recovery of all allegedly fixed costs were shifted from the energy charge to the fixed charge?

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[14] I use "Company's cost of service study" as shorthand for the cost of service study that uses the Company's preferred methods for classifying production, transmission, and distribution costs, as discussed above with regard to the 1P-3P COSS.

[15] Direct-WPSC-Ferguson-9. These amounts are based on the Company's cost of service study of the filed request for revenue requirements for the 2016 test year.

A: If the fixed charge for the Rg-1 rate class were increased to $68.61 per month, the energy charge would plummet from its current rate of 10.3¢/kWh to about 3.8¢/kWh.[16]

Q: Is the Company proposing to increase the fixed charge to recover all allegedly fixed costs?

A: Not yet. Instead, WPSC proposes to increase the fixed charge to recover most of the distribution costs classified as customer-related under the Company's cost of service study. These include the costs of services, meters, and customer services, as well as the portion of distribution plant costs classified as customer-related based on the results of a minimum distribution system analysis. According to Ms. Ferguson, WPSC considers these customer-related costs to be fixed because the Company incurs the same cost per customer regardless of a customer's usage level.

However, according to Ms. Ferguson, the Company intends to continue increasing the fixed charge over time in order to recover an ever-larger share of the total amount of allegedly fixed costs, including all demand-related production, transmission, and distribution costs:

> WPSC recognizes the need to realign rates with cost in a gradual manner over a number of rate cycles…. WPSC believes a $25 monthly charge currently represents a reasonable compromise between the competing ratemaking principles of cost causation and rate stability. WPSC will continue to evaluate the reasonableness of the fixed charge for future rate cases.[17]

Q: Would it be appropriate to recover demand-related costs through the fixed charge?

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[16] *Id.*

[17] *Id.*

A: No. Such costs may appear "fixed" from the short-term perspective of utility accounting treatment since the revenue requirements associated with debt service and maintenance in any year is unlikely to vary much with load or sales in that year.[18] However, from the longer-term perspective of cost-causation and economic efficiency, plant capital and fixed O&M are variable with respect to customer demand. Shifting recovery of such demand-related costs to the fixed charge would seriously distort price signals since consumers would no longer benefit from actions that reduce maximum demand and thus reduce demand-related costs. Likewise, consumers would no longer be penalized for increases in their peak demands. Consequently, recovering demand-related costs through the fixed charge, as proposed by WPSC, would misleadingly and inefficiently signal to consumers that there is no economic gain or loss associated with changes in peak demand.[19]

Q: Would it be reasonable to set the fixed charge to recover all costs classified as customer-related under the Company's cost of service study, as the Company proposes?

A: No. If all such costs were recovered through the fixed charge, then the smallest residential or commercial customers (with the lowest cost to connect) would be required to pay the average of customer-related costs attributable to all sizes of customers in their customer class. In this case, if all customers were to pay the

[18] This may not even be the case for demand-related transmission costs. My understanding is that the bulk of these costs are attributable to ATCLLC and MISO network transmission charges and fees. These costs therefore are not fixed, even in the short term, but vary with system demand or energy.

[19] In fact, the Company's proposal could further and needlessly increase fixed charges, in order to recover uneconomic plant investment required to meet demand growth resulting from misleading price signals.

same fixed charge regardless of size, small customers would subsidize larger customers' distribution costs.

Moreover, to the extent that the fixed charge exceeds minimum connection costs, the energy charge will understate the extent to which the Company's distribution costs are driven by customer usage. Thus, the Company's proposal to shift recovery of most customer-related costs from the energy charge to the fixed charge would yield inaccurate energy price signals.

Finally, setting the fixed charge based on the results of one cost of service study, as the Company proposes, would be contrary to Commission precedent. As the Commission noted in its final decision in Docket No. 6690-UR-123:

> Once it is determined to begin with the principle that customer charges should generally align with fixed costs, the question becomes what those fixed costs actually are. Here, the Commission relies upon its longstanding experience and approach to COSSs. COSSs attempt to classify every type of utility cost to provide information about what causes that cost and how it should be allocated. The Commission has traditionally declined to adopt specific COSSs as its preferred approach, and similarly declines here to select one party's proposed definition of "fixed cost" over another.[20]

I address each of these concerns in turn.

Q: Would WPSC agree that smaller customers would subsidize larger customers if all customer-related costs were recovered through the fixed charge?

A: No. The Company would not agree with my argument regarding subsidization because it fundamentally disagrees with my contention that customer-related

[20] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 6690-UR-123, December 18, 2014, p. 43 (PSC REF#: 226374).

costs per customer vary with usage.[21] Instead, as noted above, WPSC asserts that the customer-related cost per customer represents the minimum cost to serve a customer regardless of that customer's usage level.

Q: Is the Company's claim correct?

A: Not with respect to distribution plant costs classified as customer-related based on a minimum distribution system analysis. To the contrary, the customer-related cost per customer derived under a minimum distribution system analysis represents the minimum cost to serve an *average-usage* customer, not the minimum cost to serve any customer regardless of usage level. In fact, the minimum distribution cost per customer will vary with the usage of the customers served by the distribution equipment. Consequently, the true minimum cost to serve a customer with very little usage is likely to be less than the customer-related cost per customer.

For example, the Company's minimum distribution system analysis estimates a minimum cost for line transformers of $163.51 per *average-usage* Rg-1 customer.[22] According to the WPSC Response to 06-CUB/Inter-2(d) (PSC REF#: 272967), each transformer serves four average-usage customers, implying a minimum cost per transformer of about $654.[23]

In contrast, the minimum transformer cost per *low-usage* customer is likely to be less than that for an *average-usage* customer, because each transformer could serve more low-usage than average-usage customers. For example, with a

[21] As discussed above in Section II, costs classified as customer-related under a minimum distribution system analysis may also vary due to differences in terrain, customer density, or other factors.

[22] Ex.-WPSC-Hoffman Malueg-1, Schedule 7, p. 12.

[23] A copy of this response is attached as Ex.-CUB-Wallach-2.

minimum cost per transformer of $654, the minimum cost per low-usage customer would be only $82 if each transformer could serve eight low-usage customers. I would therefore expect the minimum distribution cost per low-usage customer to be less than the minimum distribution cost per average customer.

Q: What costs are appropriately recovered through the fixed charge?

A: The fixed charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy. Thus, the fixed charge should not be expected to cover all customer-related costs for the average residential customer, but only the incremental cost to connect one more very small customer. Since the Company would probably not need to add secondary conductor or a transformer to connect a very small customer, incremental connection costs would be limited to installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer service expenses.[24]

Q: What is the incremental cost to connect an Rg-1 customer in the Company's service territory?

A: The Locational COSS shows an incremental cost of $13.48 per customer per month.[25] Thus, the $25 per month fixed charge proposed by the Company would overstate the minimum connection cost by almost a factor of two.

Q: How does the Company's proposal to increase the fixed charge from $19 to $25 per month affect the Rg-1 energy charge?

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[24] Remote residences might also require a line extension and a small transformer in order to connect to the distribution system.

[25] See the worksheet 'RATESEP-RG1-Detailed' of 'UR124_Elec_COSS_Audit Version_Standard_Locational_Electronic v2_0.xlsx'.

A: With the fixed charge set at $25, the Company proposes to increase the energy charge to 10.644¢/kWh in order to recover the 2016 test year revenue requirement allocated to the residential class.[26] If, instead, the fixed charge remained at its current rate of $19, the energy charge would have to be increased to 11.661¢/kWh to recover the same allocated revenue requirement.[27] Thus, the energy charge under the Company's proposal to increase the fixed charge by $6 would be 1¢/kWh, or about 9%, less than the energy charge without the proposed increase to the fixed charge.

Q: To what extent would the lower energy charge under the Company's proposal for the fixed charge dampen price signals for conservation?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term.

Most studies of electric price response have estimated the change in consumption that results from a change in the customer's average rate. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run average-

[26] Direct-WPSC-Ferguson-12. This energy rate is based on the Company's filed request for 2016 test year revenue requirements, not the Commission staff audit 2016 test year revenue requirements.

[27] *Id.*

rate elasticity estimates of about −0.35 on average across studies and long-run average-rate elasticity estimates of about −0.85 on average across studies.[28]

In contrast, some studies have examined the change in usage as a function of changes in the marginal rate paid by the customer.[29] The response to marginal price incentives is typically lower than the response to average rates, but not insubstantial. Table 3 lists the results of seven studies of marginal-price elasticity over the last forty years.[30]

Table 3: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential energy rate?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the effect over a few years.

Q: What would be a reasonable estimate of the effect on energy use from the 9% reduction to the Rg-1 energy rate under the Company's proposal to increase the fixed charge?

[28] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in average rates.

[29] For an Rg-1 customer, that would be the energy rate.

[30] The citations for these studies are provided in Ex.-CUB-Wallach-3.

A: An elasticity of –0.3 and a 9% reduction in energy price would result in a 2.7% increase in energy consumption. This means that all else equal, residential load would be expected to increase by almost 3% over a several-year period as a result of implementing the Company's proposed fixed charge increase.

For comparison, I estimate that energy savings in 2014 from Focus on Energy residential programs amounted to about 1% of 2014 statewide residential sales. If we assume uniform percentage savings across utilities, the consumption increase due to the Company's proposed increase to the residential fixed charge (and the resulting decrease in the energy charge) would undo about three years of residential energy-efficiency savings in the Company's service territory.

Q: What would be a reasonable basis for setting the rate for fixed charges?

A: Consistent with Commission precedent, it would be reasonable to set the fixed charge based on the range of classification results from the various cost of service studies of the 2016 test year revenue requirement. Specifically, as discussed above in Section II, the audit cost of service studies rely on one of two basic methods for classifying distribution plant costs as either customer- or demand-related. The 1P-3P COSS, which classifies distribution costs based on a minimum distribution system analysis, estimates a customer-related cost per customer of about $26 per month for residential customers and about $29 per month for small C&I customers. The Locational COSS, which employs an alternative (and, in my opinion, more reasonable) classification method, estimates a customer-related cost per customer of about $13 per month for residential customers and about $14 per month for small C&I customers. This range of results indicates that fixed charges should not be increased from current levels.

Q: Does Ms. Ferguson offer any other basis for setting the rate for fixed charge?

A: Yes. Ms. Ferguson notes that electric cooperatives near WPSC have residential fixed charges that exceed the Company's proposed $25 charge. She then argues that:

> The comparison is useful because electric cooperatives set their own rates through a democratic process and their members choose to have a much higher fixed charge than the investor-owned utilities regulated by the PSCW.[31]

Q: Do cooperative members "choose to have a much higher fixed charge"?

A: While cooperatives may have higher fixed charges, it is not necessarily by choice. For example, according to the mission statement of Price Electric Cooperative:

> Because we operate in rural areas and have relatively low usage consumers, we cannot keep our rates as low as the investor owned utilities which serve the population centers in this area. Price Electric serves approximately 4.9 meters per mile of line compared to an average of 31 meters per mile for investor owned utilities. Their consumer base allows them to spread their expenses per mile over six times more meters, resulting in lower rates. We must continue to operate as efficiently as possible to keep our rates affordable for rural residents.[32]

Furthermore, given that a cooperative's rates are set outside of the PSC rate case process, no party has the benefit of an evidentiary record from which to analyze justifications for why rates are set at any given level, a particular rate design selected, or whether a cooperative's costs are comparable to those of a large investor-owned utility.

[31] Direct-WPSC-Ferguson-15.

[32]http://www.price-electric.com/content/mission-statement

Q: What do you recommend with regard to the Company's proposal to increase residential and small C&I fixed charges?

A: The Commission should reject the Company's proposal to increase residential and small C&I fixed charges. The Company's proposal would unreasonably shift costs to the fixed charge that are more appropriately recovered through energy charges. Such a shift would distort price signals, frustrate investments in energy efficiency and distributed resources, and inequitably burden low-usage customers.

Moreover, contrary to Commission precedent, the Company relied solely on the results of one cost of service study as the basis for its proposal to increase fixed charges. In contrast, the range of results from the audit studies indicates that no increase to current fixed charges is warranted at this time. Consequently, the Commission should reject the Company's proposal to increase the fixed charges for residential and small C&I customers.

Q: What do you recommend with regard to the design of residential and small C&I rates?

A: As I noted in Section I, I will include in my rebuttal testimony proposed rate designs for the residential and small C&I rate classes that reflect my recommended allocation of base revenues, Commission staff's proposed allocation of the SEERA credit, and my recommendation to maintain fixed charges at current levels.

Q: Does this complete your direct testimony?

A: Yes.