BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light	)	
Company for Authority to Adjust	)	Docket No. 6680-UR-120
Electric and Natural Gas Rates	)	
For 2017 and 2018 Test Years	)	

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

September 7, 2016

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, 3270-UR-120, 6690-UR-124, and 4220-UR-121. 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 May 20, 2016, Wisconsin Power and Light Company (WPL or “the Company”) filed an application to adjust electric and gas rates for the 2017 and 2018 test years. The Company also filed supporting testimony by Brian E. Penington regarding:

- The Company’s proposal to move residential customers from the current general service rate class into a new residential rate class, leaving farm and small commercial customers in the general service rate class.
- The results of five electric cost of service studies (COSS) for each test year.
- The Company’s proposals for allocating and recovering through rates the 2017 and 2018 test year revenue deficiencies.

- The Company's proposal for an optional demand rate for residential customers.
- The Company's proposal to reduce the customer charge for additional residential meters.[1]

Finally, on June 20, 2016, WPL filed supplemental direct testimony by Mr. Penington regarding the Company's proposal for a fixed-bill option for residential customers.

My testimony:

- Examines the different classification and allocation methods used in the five electric 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 2017 and 2018 test year electric revenue deficiencies.
- Addresses the Company's proposed rate designs for residential and general service customers, including its proposals to: (1) increase customer charges for the residential and general service classes; (2) reduce customer charges for additional residential meters; (3) implement an optional demand rate for residential customers; and (4) implement a fixed-bill option for residential customers.

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

A: For both the 2017 and 2018 test years, WPL finds a revenue deficiency of about $13 million, or 1.1% of test year electric revenues under current rates.

[1] The Company filed a corrected version of Ex.-WPL-Penington-1 on August 4, 2016.

The Company conducted five cost of service studies of forecasted revenue requirements for the 2017 and 2018 test years. These five studies differ with respect to the methods used to classify and allocate production and distribution plant costs. Of the five 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. However, all five studies over-allocate demand-related distribution plant costs to the residential class.

Consistent with the Company's approach to revenue allocation, my recommendation for allocating the 2017 and 2018 test year revenue deficiencies is based on the range of results from the five cost of service studies, along with consideration of the impacts of the Company's proposal to create a separate residential class for cost-allocation and rate-design purposes. In addition, I considered the fact that all five studies over-allocate costs to the residential class. Based on these considerations, I recommend that revenues for the new residential class be increased by 2.6% for the 2017 test year. For the new general service class, I recommend that revenues be increased by 1.0% for the 2017 test year.

Q: Please summarize your findings and recommendations with regard to customer charges for the residential and general service classes.

A: The Company lacks a reasonable basis for its proposal to sharply increase customer charges for residential and general service customers. As indicated by the Company's cost estimates, as well as its proposed customer charges for demand-rate customers and for additional meters, the customer charges proposed for residential and general service customers exceed the fixed cost to serve those customers. Consequently, the increases proposed by WPL would inappropriately shift load-related costs to the customer charge, reduce the energy rate, and thereby dampen price signals to consumers for reducing energy usage. The Commission should therefore reject the increases to residential and general service customer charges proposed by the Company. Instead, I recommend that customer charges for both the 2017 and 2018 test years be set at $9 per month for residential customers and $12 per month for general service customers.

Finally, I agree with the Company's recommendation to set the customer charge for an additional residential meter at $3.04 per month.

Q: Please summarize your recommendations regarding the Company's proposals for an optional demand rate and a fixed-bill option for residential customers.

A: The Company's demand rate proposal could undermine residential customers' ability to control electricity costs, impose an effective customer charge that far exceeds the Company's fixed cost to serve residential customers, and promote inefficient customer behavior. Accordingly, the Commission should deny the Company's request for approval of an optional residential demand rate. Instead, WPL should promote Time-of-Day rates as an opportunity for residential customers to effectively and efficiently control electricity costs. If the Commission is inclined to approve the proposal, it should do so as a limited-term pilot and with adjustments to the proposed rate design as discussed in Section V of this testimony.

The Commission should reject the Company's proposal for a fixed-bill option for residential customers. A fixed-bill option would eliminate the price signal provided by the energy rate, thereby encouraging increased energy consumption. Residential customers who want to dampen monthly bill volatility should instead be encouraged to enroll in budget billing.

II. Cost Allocation

Q: What does WPL find with regard to the expected revenue deficiency for the 2017 and 2018 test years?

A: For both the 2017 and 2018 test years, WPL finds a revenue deficiency of about $13 million, or 1.1% of test year electric revenues under current rates.

Q: Please describe the Company's cost of service studies of forecasted electric revenue requirements for the 2017 and 2018 test years.

A: The Company conducted five cost of service studies of forecasted revenue requirements for the 2017 and 2018 test years. These five studies differ with respect to the methods used to classify and allocate production and distribution plant costs. Below is a brief description of each of the five studies using the Company's nomenclature for these studies:

- The "Standard COSS" classifies all production plant costs as demand-related and allocates such costs on the basis of each class's contribution (net of interruptible load) to the twelve monthly system peaks (12CP).[2] In addition, the Standard COSS classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis.
- The "3CP COSS" differs from the Standard COSS by allocating demand-related production plant costs on the basis of each class's contribution to system peak in the three summer months (3CP).
- The "10% Energy COSS" modifies the Standard COSS by classifying 90% of production plant costs as demand-related and the remaining 10% as energy-related. The 10% Energy COSS also modifies the treatment of interruptible load in the Standard COSS. Specifically, the 10% Energy

[2] The system peak is also referred to as the coincident peak (CP).

COSS allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load.

- The "40% Energy COSS" modifies the 10% Energy COSS by classifying 60% of production plant costs as demand-related and the remaining 40% as energy-related.
- The "Locational COSS" modifies the 40% Energy COSS by classifying 40% of production plant costs as demand-related and the remaining 60% as energy-related. In addition, the Locational COSS modifies the 40% Energy COSS by classifying all distribution plant costs, other than for meters and services, as demand-related.

Q: Please describe the results of the Company's cost of service studies.

A: The Company finds a revenue deficiency of about $13 million, or 1.1% of test year electric revenues under current rates, for both the 2017 and 2018 test years. For each of the five cost of service studies, Table 1 shows the allocation of the 2017 test year deficiency to each of the major customer classes, expressed as a percentage of 2017 test year electric revenues under current rates for each class.[3]

Table 1: Allocated 2017 Test Year Revenue Deficiency (% of Current Revenues)

`	Standard COSS	3CP COSS	10% Energy COSS	40% Energy COSS	Locational COSS
Residential	15.4%	18.2%	13.8%	12.9%	6.2%
General Service	-7.8%	-7.4%	-8.9%	-9.1%	-8.0%
Commercial	-4.9%	-3.6%	-6.1%	-5.8%	0.5%
Industrial	-7.5%	-10.6%	-4.9%	-4.0%	0.6%
Lighting	0.8%	-8.7%	-0.6%	0.5%	-8.4%
Total System	1.1%	1.1%	1.1%	1.1%	1.1%

[3] Ex.-WPL-Penington-1r, Schedule 6, p. 10.

Table 2 shows the allocation of the 2018 test year deficiency to each of the major customer classes, expressed as a percentage of 2018 test year electric revenues under current rates for each class.[4]

Table 2: Allocated 2018 Test Year Revenue Deficiency (% of Current Revenues)

`	Standard COSS	3CP COSS	10% Energy COSS	40% Energy COSS	Locational COSS
Residential	16.9%	19.7%	15.0%	14.1%	6.7%
General Service	-7.4%	-7.1%	-8.7%	-8.9%	-7.7%
Commercial	-5.6%	-4.3%	-7.0%	-6.7%	0.2%
Industrial	-9.0%	-12.1%	-6.1%	-5.2%	-0.1%
Lighting	6.7%	-2.7%	5.3%	6.3%	-4.1%
Total System	1.1%	1.1%	1.1%	1.1%	1.1%

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

A: Of the five 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:

- Classifying production plant costs in a manner that reasonably reflects the drivers of plant investment under typical generation expansion planning practice.
- Allocating demand-related production plant costs on the basis of each class's contribution to the twelve monthly system peaks.

[4] Ex.-WPL-Penington-1r, Schedule 6, p. 18.

- Classifying all distribution plant costs, other than for meters and services, as demand-related.

On the other hand, all five studies over-allocate distribution plant costs to the residential class by allocating demand-related distribution plant costs in proportion to the sum of individual customers' maximum demands for each class rather than in proportion to each class's peak demand.

The rest of this section of my testimony addresses the shortcomings of the Standard, 3CP, 10% Energy, and 40% Energy studies when it comes to classification of production plant costs, allocation of demand-related production plant costs, and classification of distribution plant costs. I also explain why all five studies including the Locational COSS do not reasonably allocate demand-related distribution plant costs to the residential class.

A. Classification of Production Plant Costs

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

A: As noted above, the Standard and 3CP studies classify 100% of production plant costs as demand-related. The 10% Energy, 40% Energy, and Locational studies assume demand/energy splits of 90%/10%, 60%/40%, and 40%/60%, respectively.

Q: Do the Standard or 3CP studies reasonably classify production plant costs?

A: No. These two studies inappropriately classify all production plant costs as demand-related, as if production plant costs were 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 plant investment choices are driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

> For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[5]

Q: Is there a classification method that reasonably reflects cost-causation under typical generation planning practice?

A: Yes. 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.[6]

The Equivalent Peaker method 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

[5] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 38-39.

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

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.

Q: Did WPL conduct an Equivalent Peaker analysis for the purposes of classifying production plant costs in the 10% Energy, 40% Energy, or Locational studies?

A: No. However, Commission staff conducted such analyses for Northern States Power Company in Docket No. 4220-UR-119, Wisconsin Public Service Corporation in Docket No. 6690-UR-123, and for Madison Gas and Electric Company in Docket No. 3270-UR-120.[7] In all of these cases, the results of Commission staff's Equivalent Peaker analysis would have supported a 40% demand / 60% energy classification of production plant costs.[8] Thus, the results of Commission staff's analyses support the 40% demand / 60% energy classification of production plant costs in the Locational COSS as the demand / energy split that most reasonably reflects cost-causation.

B. Allocation of Demand-Related Production Plant Costs

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

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[7] Tr. Vol. I, Direct-PSC-Albrecht-5-6 (Docket No. 4220-UR-119) (PSC REF#: 192672); Tr. Vol. II, Direct-PSC-Singletary-10 (Docket No. 6690-UR-123) (PSC REF#: 222688); Tr. Vol. II, Direct-PSC-Singletary-6 (Docket No. 3270-UR-120) (PSC REF#: 225061).

[8] *Id.*

A: All of the studies other than the 3CP COSS allocate demand-related production capacity costs using a 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, a 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.

In contrast, the 3CP COSS allocates demand-related production plant costs on the basis of each class's contribution to system peaks in the three summer months. In this case, demand-related production plant costs are allocated as if reserve requirements are driven by system peaks only in the three summer months.

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

A: The 12CP allocator more reasonably reflects cost-causation than the 3CP allocator because the Company's annual reserve requirement is determined based on demand throughout the year, not just by peak demand in the three 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 loss of load expectation

(LOLE).[9] Although lower than peak demands in the summer months, non-summer peaks can also contribute to annual LOLE 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 LOLE and reserve requirements. Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by the summer peaks. Consequently, a 12CP allocator is a more reasonable measure of each class's contribution to the need for new reserve capacity than a 3CP allocator.

C. Classification of Distribution Plant Costs

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

A: The Locational COSS classifies all distribution plant costs, with the exception of meter and service costs, as demand-related. All other audit studies classify 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 minimum distribution system approach used in the other studies. As discussed below, minimum distribution system analyses typically produce classifications that are inconsistent with cost-causation and

[9] 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.

which result in an over-allocation of distribution plant costs to the residential and general service rate classes. As has been recognized in jurisdictions throughout the country, 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 estimates the cost to install the same amount and type of distribution equipment (i.e., poles, conduits, conductors, and transformers) as are currently on the distribution system, assuming that each of those pieces of equipment are the smallest size currently used on the 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.

As with the minimum-size approach, the minimum-intercept method attempts to estimate the cost to replicate the current configuration of the existing distribution system, assuming the same amount and type of equipment. However, where the minimum-size approach estimates minimum cost based on equipment cost for the smallest-size equipment actually in use, the minimum-intercept method derives minimum cost based on an estimate of what the equipment would cost in theory if it did not have to carry any load. The minimum-intercept approach derives the cost of this hypothetical zero-load equipment by estimating a functional relationship between equipment cost and equipment size based on the current system, and then extrapolating 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).

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 the Company's response to 2-CUB/Inter-2 (PSC REF#: 290393), WPL uses the minimum-size method to classify poles, conduits, conductors, and line transformers (FERC Accounts 364-368).[10]

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

A: No. The minimum distribution system approach is conceptually flawed since it is premised on a simplistic model of cost-causation that is inconsistent with typical distribution system planning, design, and investment practices.

In practice, distribution system costs may be driven by a host of planning and design considerations – such as customer load, load growth, terrain, number of customers, customer density, voltage considerations, or minimum service reliability and quality requirements. Minimum distribution system analyses disregard this multitude of cost drivers and instead simplistically model cost-causation as a function of just two factors: customer load and number of customers. With only two categories for classifying costs (i.e., as either demand-related or customer-related), minimum distribution system analyses tend to classify as customer-related all costs not directly driven by demand, even though such costs may be driven by factors other than number of customers.

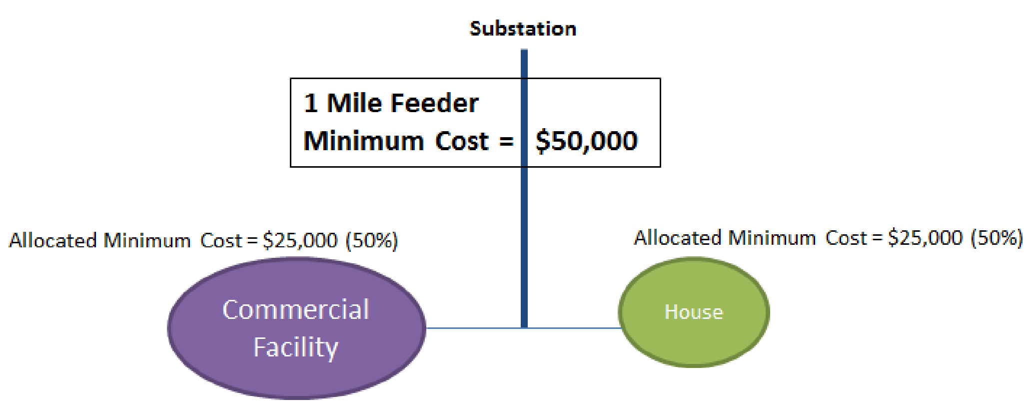
[10] All land and land rights (Account 360), structures and improvements (Account 361), and distribution substations (Account 362) are classified as demand-related. All services (Account 369) and meter costs (Account 370) are classified as customer-related.

In other words, as James Bonbright, Albert Danielson, and David Kamerschen explain in their Principles of Public Utility Rates, minimum system analyses will inappropriately dump into the customer-cost category those plant costs that are neither driven by demand nor by 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.[11]

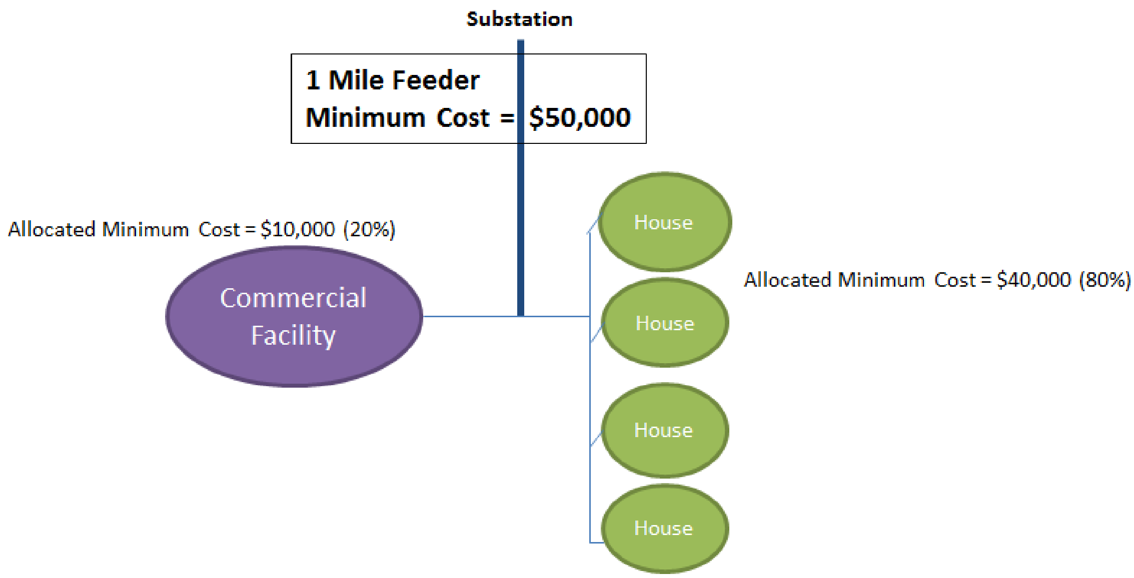
The examples shown below in Figures 1a and 1b illustrate this basic flaw in the minimum distribution system approach. In the example shown in Figure 1a, a hypothetical distribution system consists solely of a single one-mile feeder serving two customers: a commercial facility and a single-family home.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

Figure 1a



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

Figure 1b



As indicated in these figures, the $50,000 minimum cost of the hypothetical distribution system is the same in both examples, even though the number of customer accounts varies (two in Figure 1a; five 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 (or more) homes does not increase the $50,000 minimum cost of the feeder. Yet, even though the minimum cost is **not** 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 (i.e., $25,000) would be allocated to the residential class. In contrast, in the example shown in Figure 1b, 80% of the same minimum cost (i.e., $40,000) would be allocated to the residential class. In this latter case, residential customers are allocated more of the costs of the minimum system even though their presence did not cause the minimum system cost to increase. Thus, the minimum distribution system approach does not allocate costs consistently with cost-causation.

Residential and general service 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 specific to the minimum-size method used by the Company?

A: Yes. 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 class.[12] 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 customers.[13] 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.

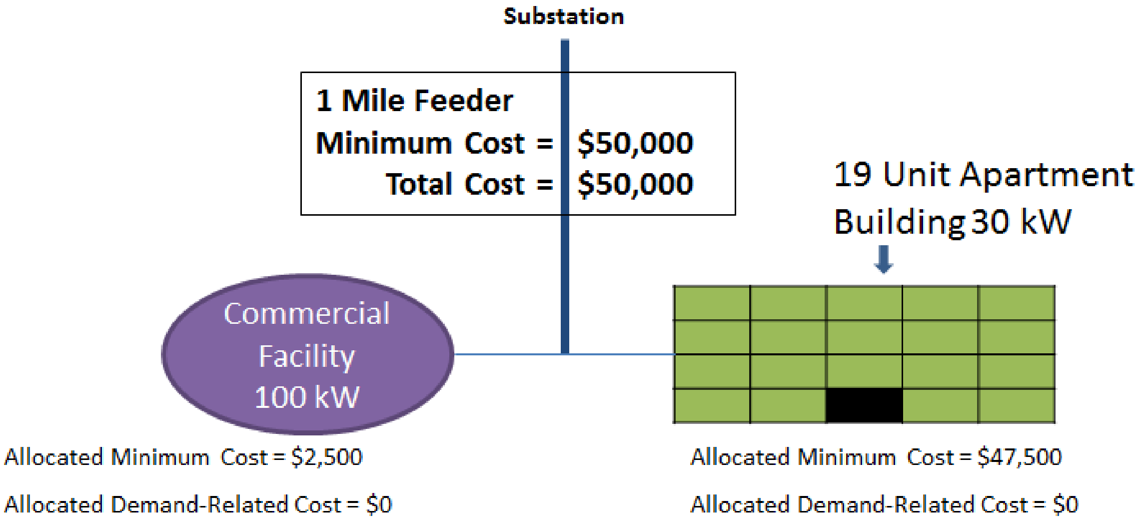
[12] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, July 2, 1981.

[13] 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.

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 solely 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.[14]

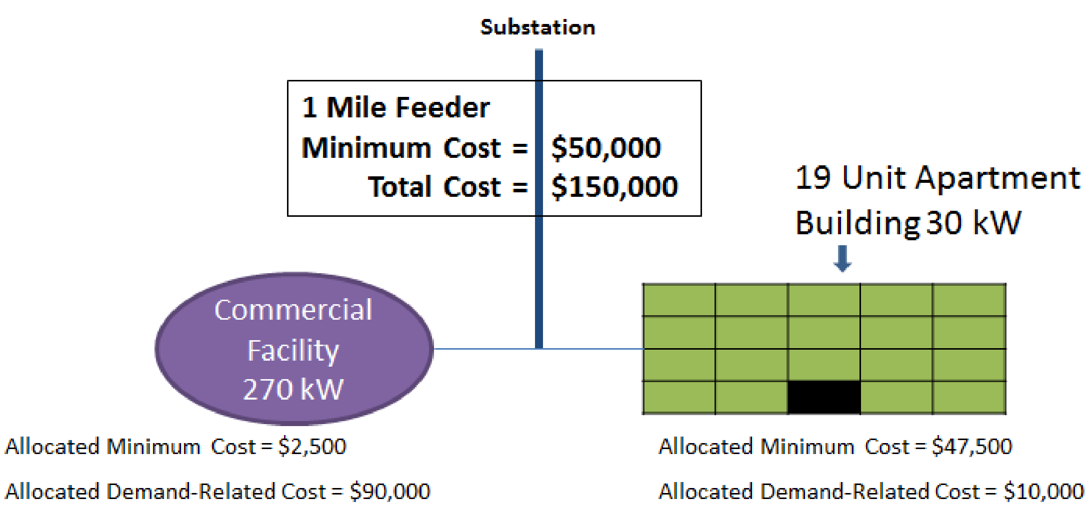
[14] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

Figure 2a



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.

Figure 2b



Similar to the over-allocation of customer-related costs to residential customers described above and depicted in Figures 1a and 1b, here the minimum distribution system approach assigns to residential customers a portion of the demand-related costs that were not incurred to serve residential demand. Thus, the minimum distribution system approach does not allocate costs consistently with cost-causation.

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

A: Yes. An alternative approach that more reasonably reflects cost-causation, 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.[15] This is the approach used to classify distribution plant costs in the Locational COSS. The other four audit studies in this case rely on the minimum distribution system method. The deficiencies with the minimum distribution system method weigh against those other studies for purposes of allocating distribution plant costs to customer classes.

D. Allocation of Demand-Related Distribution Plant Costs

Q: How are demand-related distribution plant costs allocated in the five cost of service studies?

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

A: All five studies allocate demand-related distribution plant costs based on each class's maximum customer demand (MCD), where each class's MCD is derived by summing individual customers' maximum demands.[16]

Q: Does the MCD allocator reasonably reflect cost-causation?

A: No. The MCD allocator does not account for the effect of load diversity on distribution equipment loading and thus does not reasonably reflect the drivers of distribution plant investment. By failing to account for load diversity, the MCD allocator likely overstates the residential class's contribution to distribution costs and thus over-allocates such costs to the residential class.

Q: How does load diversity affect the sizing of distribution plant?

A: Residential customers reach their individual maximum demands on different days and in different hours of the day. This diversity of demand among a group of residential customers served by a piece of distribution equipment results in a group peak demand that is lower than the sum of customers' individual maximum demands. In general, utilities size distribution plant to meet the group peak, not the sum of customers' individual maximum demands.

Q: Why does the MCD allocator over-allocate distribution plant costs to the residential class?

A: The MCD allocator over-allocates costs to the residential class because it does not account for the effect of load diversity on equipment sizing and thus on equipment cost.

Specifically, the MCD allocator does not account for the fact that distribution equipment serving many small residential customers can be smaller (and less expensive) than equipment that serves fewer large industrial

[16] Company's response to 3-CUB/Inter-1 (PSC REF#: 290872).

customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. As the number of customers served by distribution equipment increases, so too does the diversity of maximum hourly demands among those customers. And as the diversity of maximum demands increases, so too does the variance between the sum of individual customers' maximum hourly demands (i.e., group MCD) and the maximum demand for the group as a whole (i.e. group peak demand.) By not accounting for load diversity, the MCD allocator allocates cost to classes as if the sizing and cost of distribution equipment is driven by each class's MCD rather than by the class's peak demand on the equipment.

Q: How should demand-related distribution plant costs be allocated?

A: In order to reasonably account for the effect of load diversity, demand-related distribution plant costs should be allocated on the basis of each class's peak demand.[17] This is the approach used by Madison Gas and Electric Company, Northern States Power Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation.[18]

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[17] A class's peak demand is the maximum demand for the class as a whole regardless of when that peak occurs. It is often referred to as a class's "non-coincident" peak demand because a customer class may reach its peak at a different time than when the peak for the system as a whole occurs.

[18] Tr. Vol. II, Direct-MGE-Trinh-3 (Docket No. 3270-UR-120) (PSC REF#: 225061); Received Evidence List, Direct-NSPW-Marx-16 (Docket No. 4220-UR-121) (PSC REF#: 278967); Tr. Vol. II, Direct-WEPCO/WG-Rogers-9 (Docket No. 05-UR-107) (PSC REF#: 223135) Received Evidence List, Direct-WPSC-Hoffman Malueg-15 (Docket No. 6690-UR-124) (PSC REF# 278966), Wisconsin Public Service Corporation uses an MCD allocator to allocate demand-related transformer costs, but class peak demand to allocate all other demand-related distribution plant costs.

Allocating costs on the basis of class peak demand rather than on maximum customer demand could have a significant impact on cost allocation to the residential class. For example, according to the Company's response to 2-CUB/Inter-7 (PSC REF#: 290393), the sum of individual customer maximum demands in the 2017 test year are 1,853 MW for the Rg-1 class and 591 MW for the Gs-1 class. According to the Company's response to 3-CUB/Inter-2 (PSC REF#: 290872), class peak demands in the 2017 test year are 688 MW for the Rg-1 class and 306 MW for the Gs-1 class. Thus, demand-related distribution plant costs allocated to the Rg-1 and Gs-1 classes would be split 76%/24% between the Rg-1 and GS-1 classes using the MCD allocator, but 69%/31% using a class peak demand allocator.[19] The change in cost allocation between the residential and industrial classes would likely be even greater, since there is typically much less load diversity within the industrial class.

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 2017 and 2018 test year revenue deficiencies?

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 five of the audit cost of service studies for the purposes of allocating the 2017 and 2018 test year revenue deficiencies to customer classes.

[19] The Rg-1 share in each case is calculated as Rg-1 demand (either MCD or class peak) divided by the sum of Rg-1 and Gs-1 demand (either MCD or class peak.)

Q: Did you consider other factors besides the results of the five studies when developing your proposal for allocating 2017 and 2018 revenue requirements?

A: Yes. For one, I considered the fact that all five of the studies likely over-allocate demand-related distribution plant costs to the residential class, as discussed above in Section II. For another, I considered the fact that the residential revenue increases (and general service decreases) indicated by the five studies were in part due to the proposed separation of residential customers from the general service class.[20]

Q: How do you propose to allocate test year revenue deficiencies?

A: I recommend that 2017 test year revenues be allocated to customer classes as shown in Table 3. I developed my recommendation based on the directional results from the five cost of service 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 3: Recommended Allocation of 2017 Test Year Revenues

	Current Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential	414,738,377	425,707,607	10,969,230	2.6%
General Service	189,828,118	191,726,399	1,898,281	1.0%
Commercial	115,617,604	115,617,604	-	0.0%
Industrial	409,452,293	409,452,293	-	0.0%
Lighting	8,285,992	8,285,992	-	0.0%
Total System	1,137,922,385	1,150,789,897	12,867,512	1.1%

[20] According to Company witness Brian Penington, WPL also considered the impact of its proposal for a separate residential class when developing its recommendation for allocating the 2017 and 2018 test year revenue deficiencies. Direct-WPL-Penington-8.

I further recommend that the rates established to recover allocated 2017 test year revenues remain fixed for the 2018 test year as well. Based on the Company's forecast of class billing determinants, fixing rates at 2017 test year levels would allow forecasted 2018 test year revenue requirements to be recovered from each customer class in the same proportion as my recommended allocation of forecasted 2017 test year revenue requirements.

IV. Customer Charges

A. Residential and General Service Customer Charges

Q: What is the Company's proposal with respect to residential and general service customer charges?

A: For the residential class, WPL proposes to increase the monthly customer charge from $7.67 to $12 in 2017 and then to $18 in 2018. For general service customers, WPL proposes to increase the monthly customer charge from $7.67 to $13 in 2017 and then to $22 in 2018.

Q: What is the Company's rationale for these proposed increases?

A: According to Company witness Mr. Penington, "WPL seeks to better align customer charges with costs…."[21] In particular, WPL proposes to set customer charges at a level that reflects the Company's estimate of the monthly cost per customer for meters, service lines, customer services (collectively, "connection costs"), and distribution plant costs classified as customer-related under the Company's minimum distribution system analysis. Mr. Penington contends that

[21] Direct-WPL-Penington-18.

"these costs to provide service are fixed and do not vary with a customer's energy usage."[22]

Table 4 provides the Company's estimates of monthly connection and minimum distribution costs per customer, as derived in the Standard COSS.[23]

Table 4: Connection and Minimum Distribution Costs per Customer

	Residential		General Service	
	2017 Test Year	2018 Test Year	2017 Test Year	2018 Test Year
Connection Cost	8.81	9.20	11.36	11.89
Minimum Distribution Cost	9.16	10.24	11.01	12.22
Total Cost	17.97	19.44	22.37	24.11

Q: Has the Company reasonably estimated the minimum distribution cost per customer?

A: No. As discussed above in Section II, even the minimum-size equipment currently installed on the system has some amount of load-carrying capability. Consequently, some portion of the cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-size method used by the Company, that portion of minimum-equipment cost appropriately classified as demand-related is instead misclassified as customer-related.

Apart from this problem of misclassification, the minimum-size method overstates the minimum (i.e., customer-related) cost *per customer* because it assumes that a minimum system carrying minimal load would have the same amount and type of distribution equipment as are installed in a distribution system designed to carry actual distribution load. In other words, the minimum-

[22] Direct-WPL-Penington-16.

[23] The costs per customer shown in Table 5 are from Ex.-WPL-Penington-1r, Schedule 6.

size method assumes that each piece of distribution equipment would serve the same number of customers on average, regardless of whether the customers are average-sized (as for the actual system) or have minimal demand (as for the hypothetical minimum system.)

This is not a reasonable assumption, since even a minimally sized piece of distribution equipment should be able to serve more minimal-demand customers than the number of average-demand customers served by average-sized distribution equipment. Consequently, the true minimum fixed cost to serve a customer with minimal usage is likely to be less than the customer-related cost per customer derived using the minimum-size approach.

Q: Does WPL consistently treat minimum distribution costs as fixed?

A: No. To the contrary, the Company appropriately treated minimum distribution costs as variable costs when setting the proposed customer charges for the optional demand rate and for additional residential meters.

For the optional demand rate, WPL proposes a monthly customer charge of $9, which is barely adequate to recover the Company's estimate of monthly connection costs per customer.[24] This means that WPL is proposing to recover minimum distribution costs through demand and energy rates, as if such costs are variable not fixed.

For additional residential meters, WPL proposes a customer charge that, according to Mr. Penington, "would recover metering and service line expenses only."[25] Mr. Penington further notes that "this discounted charge would not be

[24] Table 4, above, provides the Company's estimate of the monthly connection cost per customer.

[25] Direct-WPL-Penington-26.

available for separate residential dwellings….”[26] Presumably, WPL proposes a discounted charge for an additional meter on, for example, an electric-vehicle (EV) charger because the Company does not expect to incur minimum distribution costs or customer-service costs to serve an EV charger. By the same token, it would be reasonable to presume that the Company is not offering a discounted charge for a meter in a separate residential dwelling because it expects to incur such costs to serve a separate dwelling. If so, then the Company treats minimum distribution costs as being driven not by the addition of a meter (i.e, a customer), but by the higher usage in a separate dwelling compared to that by an EV charger. In other words, the Company treats minimum distribution costs as variable with usage when setting the proposed customer charge for additional residential meters.

Q: How might the Company's proposal for a customer charge that exceeds fixed customer costs affect customer behavior?

A: All else equal, the Company's proposal would shift recovery of load-related costs from the energy rate to the customer charge and thereby reduce the energy rate. Residential customers would be expected to respond to this lower energy rate by increasing their usage.[27] In other words, the Company's proposal would dampen price signals for conservation provided by the energy rate.

Q: What do you recommend with regard to the Company's proposal to increase residential and general service customer charges?

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[26] *Id.*

[27] Customers' responses to changes in energy rates 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.

A: The Commission should reject the Company's proposal to increase residential and general service customer charges. As indicated by the Company's estimates, as well as by its proposed customer charges for demand-rate customers and for additional residential meters, the proposed customer charges exceed the fixed cost to serve customers. Consequently, the increases proposed by WPL would inappropriately shift load-related costs to the customer charge, reduce the energy rate, and thereby dampen price signals to consumers for reducing energy usage.

Instead, I recommend that customer charges for both the 2017 and 2018 test years be set at $9 per month for residential customers and $12 per month for general service customers. Consistent with the Company's approach for setting the customer charge for the optional demand rate and for additional residential meters, my proposed customer charges would recover the Company's estimates of the fixed connection cost to serve residential and general service customers.[28]

B. Customer Charge for Additional Meters

Q: What is the Company's proposal regarding the customer charge for additional residential meters?

A: The Company proposes a customer charge of $3.04 per month for both 2017 and 2018. As noted above, the proposed customer charge would recover only costs for meters and services.

Q: What do you recommend with regard to this proposal?

A: The Commission should approve the Company's proposal to set the charge for an additional residential meter at $3.04 per month. It is appropriate to recover

[28] Table 4, above, provides the Company's estimate of the fixed connection cost to serve residential and general service customers.

through the customer charge only those fixed costs incurred for an additional meter.

V. Residential Rate Options

A. Optional Demand Rate

Q: Please describe the Company's proposal for an optional residential demand rate.

A: The Company proposes a rate structure that combines a customer charge, two demand charges, and time-of-day (TOD) energy charges. As noted above, WPL proposes a monthly customer charge of $9. For demand charges, WPL proposes a monthly on-peak demand charge ($3/kW) to be assessed on a customer's maximum demand during on-peak hours in the month, where on-peak hours are defined as the period from 10am to 8pm on weekdays. In addition, WPL proposes a monthly customer demand charge ($1/kW) to be assessed on a customer's maximum demand at any time in the previous twelve months. Finally, the Company proposes to use the same TOD rate periods as used for the Rg-5 TOD rate.[29]

Q: Is the Company's proposal reasonable?

A: No. The proposed demand rate could lessen customers' ability to manage their electricity costs, lead to an effective customer charge much larger than the Company proposes for other residential customers, and promote inefficient customer behavior.

[29] Ex.-WPL-Penington-1r, Schedule 14.

Q: How might the proposed demand rate undermine residential customers' ability to control electricity costs?

A: As proposed by WPL, two demand charges would be assessed each month based on the customer's individual maximum demand, whenever that maximum occurs during the on-peak period during the month (for the on-peak demand charge) and during any time in the last twelve months (for the customer demand charge). In either case, it would be difficult to control demand costs since even a single failure to control load either during the month's on-peak hours or anytime during the last twelve months would result in the same demand charge as if there had been no attempt to control load at any time.

Q: Why might a residential customer on the optional demand rate effectively pay a higher customer charge than other residential customers?

A: If residential customers have little opportunity to control their maximum customer demands, then the demand charges proposed by WPL would effectively serve as fixed charges. I estimate that an average residential customer taking service under the proposed demand rate would pay an effective fixed monthly charge (customer plus demand charges) of about $28.[30] This effective customer charge is more than three times the $9 fixed cost to serve residential customers (as estimated by WPL) and even exceeds by a wide margin the $18 customer charge proposed by WPL for non-demand residential customers.

[30] Based on data provided in Schedule 9 of Ex.-WPL-Penington-1r, I estimate an average maximum customer demand of 4.8kW per residential customer. Applying this average MCD to the proposed demand charges ($1/kW for customer demand and $3/kW for on-peak demand), and adding the proposed customer charge of $9 yields an effective fixed monthly charge of about $28 per customer.

Q: How might the proposed demand rate promote inefficient customer behavior?

A: A demand charge would provide little or no incentive to take actions that reduce demand-related production or distribution costs. For example, as reflected in the Standard COSS, production plant costs are driven solely by monthly system coincident peak. An individual residential customer is unlikely to reach her maximum demand at the same time as when the system peaks. Thus, the demand charges proposed by the Company would provide an incentive to a customer to control load at the time that customer reaches maximum demand, not necessarily at the time of system peak load. In fact, customers could try to reduce on-peak demand costs merely by redistributing load within the on-peak period. Some of those customers might shift loads from their own peak to the system peak hour for the month, thereby increasing the system peak and thus the need for additional reserve capacity.

In addition, the lower energy rate resulting from a shift of demand-related costs to the demand charge would encourage increased energy consumption, some of which could occur during system peak hours or at times of peak loading on the distribution system. Shifting costs from the energy charge to a demand charge could therefore increase production or distribution costs and offset anticipated benefits from a demand charge.

Q: What do you recommend with respect to the Company's proposal to implement an optional demand rate for residential customers?

A: The Commission should deny the Company's request for approval of an optional residential demand rate. Instead, WPL should promote time-of-day rates as an opportunity for residential customers to effectively and efficiently control electricity costs. Given the potential problems with the proposed demand rate, if the Commission is inclined to approve the proposal for residential customers, it should only approve the rate as a limited-duration pilot.

Q: If the residential demand proposal were implemented on a pilot basis, what changes would you make to the proposed rate design?

A: If implemented as a limited-term pilot, I would recommend revising the rate structure as follows in order to provide clear price signals and promote efficient behavior by pilot participants:

- Redefine Customer Demand (to be assessed against the customer demand charge) as the measured maximum demand in the current month, rather than in the current and previous 11 months.
- Narrow the weekday time period for On-Peak Demand to include only those hours most likely to be the system peak hours in each month.
- Eliminate the time-of-day energy rate structure and instead charge the Rg-1 flat energy rate.

B. Residential Fixed Bill Option

Q: Please describe the Company's proposal for a fixed-bill option for residential customers.

A: The Company proposes an experimental option that would charge each residential participant a constant amount on their monthly bill for a twelve-month period. The fixed bill amount for each twelve-month period would be determined based on the participant's usage over the previous twelve months, plus a risk adder of between 0% to 10%.[31] Each month, a participant might pay

[31] Ex.-WPL-Penington-2, Schedule 2. It is not clear how WPL will determine the percentage value for the risk adder or whether the percentage value will be determined uniquely for each participant or uniformly for participants as a whole.

more or less than what they would have paid on the regular residential rate based on actual usage for the month, but any difference would not be reconciled.

According to Company witness Brian Penington, WPL designed this option for "customers who value certainty and convenience in their electric bill."[32]

Q: Is the Company's proposal a reasonable approach for providing monthly bill certainty?

A: No. Without reconciliation against actual usage, the Company's fixed-bill option would eliminate the price signal provided by the energy rate, thereby encouraging increased energy consumption during the twelve-month period when bill amounts are fixed based on usage in the previous twelve months.[33] This increased usage could impose additional production and distribution plant costs on ratepayers.

The proposed risk adder could exacerbate this tendency for participants to increase energy usage. Under the Company's proposal, a customer's fixed bill amount would exceed the expected amount under the regular residential rate by the risk adder percentage. Thus, a participant would have to increase usage by the risk adder percentage in order to at least break even relative to the regular residential rate.

Q: Is there a way for WPL to offer customers stable monthly bills that preserves price signals?

A: Yes. In fact, the Company already offers such an option through budget billing. The Company's budget billing option offers fixed bill amounts for six-month

[32] Direct-WPL-Penington-s-2.

[33] In other words, any energy usage in excess of the amount used to determine the fixed bill amount would be free.

periods at a time, with adjustments of fixed bill amounts in any six-month period to reflect reconciliation against actual usage in the previous six-month period.

Q: What do you recommend with respect to the Company's proposal to implement a fixed-bill option for residential customers?

A: The Commission should reject the Company's proposal. Residential customers who want to dampen monthly bill volatility should instead be encouraged to enroll in budget billing.

Q: Does this complete your direct testimony?

A: Yes.