BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates	)))	Docket No. 3270-UR-121

DIRECT TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
August 26, 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 April 8, 2016, Madison Gas and Electric Company (MGE or "the Company") filed an application to increase electric and gas rates for the 2017 test year. On August 12, 2016, MGE provided the results of six electric cost of service studies (COSS) based on the Commission staff audit forecast of 2017 test year electric revenue requirements. Finally, on August 24, 2016, MGE filed supplemental direct testimony describing the Company's revisions to the August 12, 2016 audit cost of service studies to reflect the impact of an amendment to the depreciation study filed by Wisconsin Power and Light on July 29, 2016.[1]

My testimony:

[1] The Company co-owns the Columbia Generating Station with Wisconsin Power and Light and Wisconsin Public Service Corporation.

- 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 2017 test year electric revenue requirements.

I will address the Company's revisions to the audit cost of service studies related to the depreciation study in my rebuttal testimony, once I have had the opportunity to evaluate the Company's supplemental direct filing and Commission staff's direct testimony.

Q: Please summarize your findings and recommendations.

A: The Commission staff audit finds a negligible revenue deficiency for the 2017 test year of about $96 thousand, or 0.02% of 2017 test year electric revenues under current rates.

At the request of Commission staff, MGE conducted six cost of service studies based on the Commission staff audit forecast of 2017 test year revenue requirements. These six studies differ with respect to the methods used to classify and allocate production and distribution plant costs. Of the six studies, the Capacity Locational (12CP) COSS classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs.

Based on the range of results from these studies, and given that there is effectively no overall revenue deficiency for the 2017 test year, I recommend that there be no change from current revenues for any customer class.

Q: Do you have any other recommendations?

A: Yes. In order point 18 of the Final Decision in Docket No. 3270-UR-120, the Commission directed MGE to work with Commission staff and other interested parties and stakeholders to further analyze low-income rate design options.[2] Although MGE has not proposed a specific low-income rate design in this case, it is important for MGE to continue analysis of low-income rate options for consideration in future rate cases. I therefore recommend that the Commission include the language of order point 18 in the order points in this case.

II. Cost Allocation

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2017 test year?

A: The Commission staff audit finds a revenue deficiency for the 2017 test year of about $96 thousand, or 0.02% of 2017 test year electric revenues under current rates.

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

A: Yes. At the request of Commission staff, MGE conducted six cost of service studies based on the Commission staff audit forecast of 2017 test year revenue requirements. These six studies differ with respect to the methods used to classify and allocate production capacity and distribution plant costs. Below is a brief description of each of the six studies using Commission staff's nomenclature for these studies:

- The "MGE 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

[2] Final Decision, Application of MGE for Authority to Change Electric and Natural Gas Rates, docket 3270-UR-120 (Dec. 23, 2014) at 67 (PSC REF#: 226563).

(12CP).[3] In addition, the MGE Standard COSS classifies distribution plant costs as customer- or demand-related on the basis of a minimum distribution system analysis.

- The "1CP COSS" differs from the MGE Standard COSS only with respect to the allocation of demand-related production plant costs. The 1CP COSS allocates demand-related production plant costs on the basis of each class's contribution to annual system peak (1CP).
- The "4CP COSS" differs from the MGE Standard COSS by allocating demand-related production plant costs on the basis of each class's contribution to system peak in the four summer months (4CP).
- The "TOU (12CP) COSS" modifies the MGE Standard COSS by classifying 60% of production plant costs as demand-related and the remaining 40% as energy-related.
- The "Capacity TOU (12CP) COSS" modifies the treatment of interruptible load in the TOU (12CP) COSS. Specifically, the Capacity TOU (12CP) COSS allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load at Commission staff's estimate of the value of interruptible and direct load control capacity.
- The "Capacity Locational (12CP) COSS" modifies the Capacity TOU (12CP) 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.

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

A: As noted above, based on Commission staff's audit, the revenue deficiency for the 2017 test year is about $96 thousand, or 0.02% of 2017 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 2017 test year electric revenues under current rates for each class.[4]

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

`	System Average	Residential and Small C&I	Business Services	Lighting and Misc.
MGE Standard COSS	0.02%	0.41%	-0.23%	-1.31%
1CP COSS	0.02%	5.12%	-3.31%	-15.75%
4CP COSS	0.02%	1.61%	-2.25%	-13.99%
TOU (12CP) COSS	0.02%	-0.07%	0.12%	-2.86%
Capacity TOU (12CP) COSS	0.02%	0.06%	0.03%	-2.77%
Capacity Locational (12CP) COSS	0.02%	-1.28%	1.01%	-7.53%

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

A: Of the six studies, the Capacity Locational (12CP) COSS allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs. Specifically, the Capacity Locational (12CP) 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.

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[4] The percentage values shown in Table 1 were derived based on data provided in spreadsheet models for the six cost of service studies. These spreadsheet models were provided as attachments to the MGE Response to 4-CUB/Inter-1 (PSC REF#: 290180).

- 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, the MGE Standard, 1CP, and 4CP studies classify 100% of production plant costs as demand-related. The three other studies classify 60% of production plant costs as demand-related and the remaining 40% as energy-related.

Q: Do the MGE Standard, 1CP, or 4CP studies reasonably classify production plant costs?

A: No. These three 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 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

[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.

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 MGE or Commission staff conduct an Equivalent Peaker analysis for the purposes of classifying production plant costs in the TOU (12CP), Capacity TOU (12CP), or Capacity Locational (12CP) studies?

A: No. However, Commission staff conducted such an analysis in Docket No. 3270-UR-120.[7] The results of that analysis indicate that the 60/40 demand/energy split assumed for the TOU (12CP), Capacity TOU (12CP), and Capacity Locational (12CP) studies more reasonably reflects the drivers of plant investment than the 100% demand / 0% energy classification assumed in the three other studies. In fact, the results of Commission staff's Equivalent Peaker analysis in Docket No. 3270-UR-120 would have supported a 40% demand / 60% energy classification of production plant costs.[8]

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: All of the studies other than the 1CP and 4CP studies 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

[7] See Tr. Vol. II, Direct-PSC-Singletary-6 (Docket No. 3270-UR-120) (PSC REF#: 225061).

[8] *Id.*

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 1CP and 4CP studies allocate demand-related production plant costs on the basis of each class's contribution to annual system peak or system peaks in the four summer months, respectively. In the 1CP COSS, the 1CP allocator allocates demand-related production plant costs as if reserve requirements are driven solely by the annual system peak. In the 4CP COSS, the 4CP allocator allocates demand-related production plant costs as if reserve requirements are driven by system peaks only in the four summer months.

Q: Which of these three 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 1 CP or 4CP allocators because the Company's annual reserve requirement is determined based on demand throughout the year, not just by annual peak demand or peak 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 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

[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.

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 annual or 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 1CP or 4CP allocator.

In fact, the Commission should give no weight to the results of the 1CP COSS. There is simply no reasonable basis for allocating demand-related production plant costs on the basis of each class's contribution to annual system peak, and no party supported use of the 1CP allocator in the Company's last base rate case.[10]

C. Classification of Distribution Plant Costs

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

A: The Capacity Locational (12CP) 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 Capacity Locational (12CP) COSS more reasonably classifies distribution plant costs than the minimum distribution

[10] Airgas Merchant Gases (Airgas) supported use of the 1CP allocator in Docket No. 3270-UR-118. However, Airgas shifted its support to use of the 4CP allocator in Docket No. 3270-UR-120. As far as I can recall, no party in any of the base rate cases in which I testified over the past six years, other than Airgas in Docket No. 3270-UR-118, supported use of the 1CP allocator.

system approach used in the other studies. 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 Capacity Locational (12CP) 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 number of units (e.g., poles, conductor-feet) as are currently on the distribution system, assuming that each of those units 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 configuration of the existing distribution system, assuming the same number of poles, conductor-feet, transformers, and services. 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-5 (PSC REF#: 289221), MGE uses the minimum-size method to classify poles (Account 364), overhead conductors (Account 365), and line transformers (Account 368).[11]

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-

[11] All land and land rights (Account 360), structures and improvements (Account 361), distribution substation (Account 362), underground conduit (Account 366), and underground conductor costs (Account 367) are classified as demand-related. All services (Account 369) and meter costs (Account 370) are classified as customer-related.

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.

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.[12]

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.

[12] 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

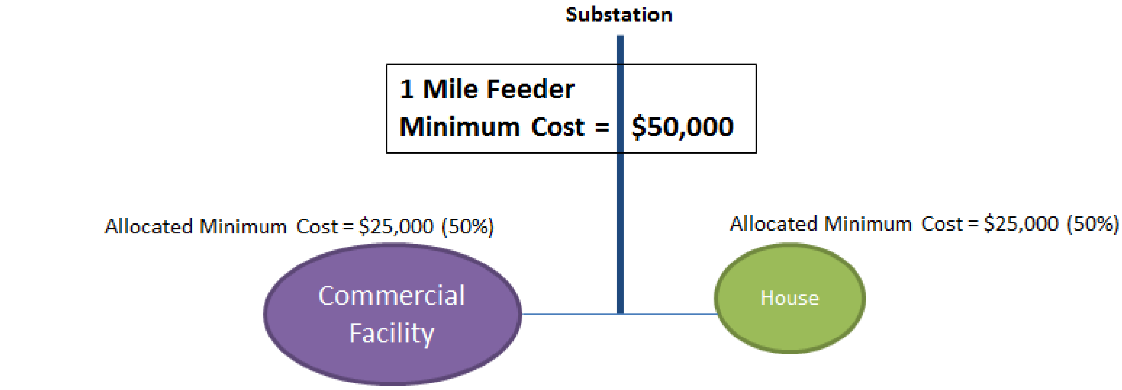
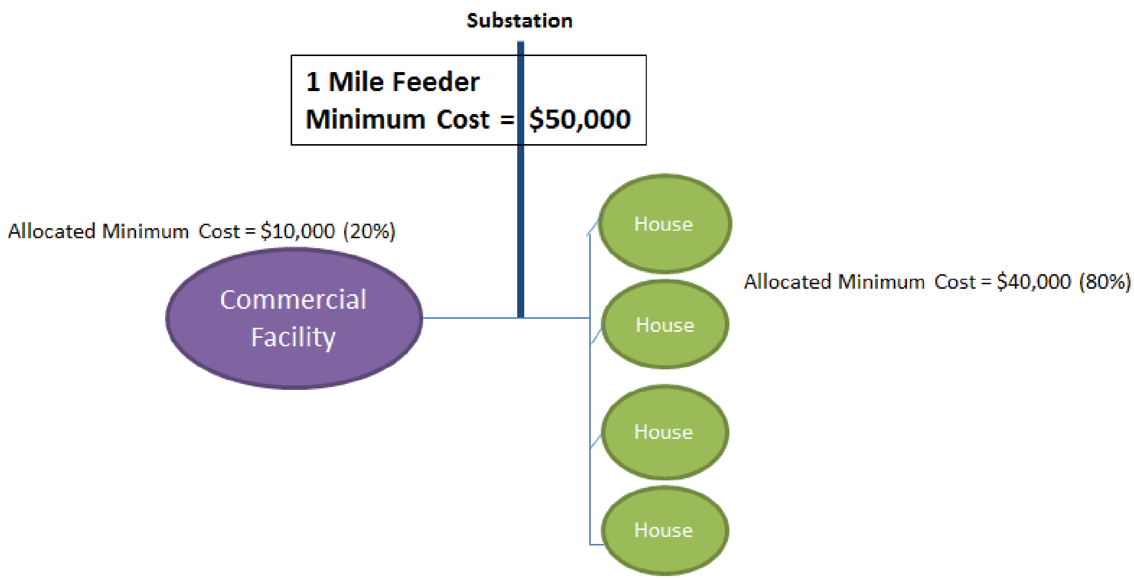


Figure 1b



As indicated in these figures, the $50,000 minimum cost of the hypothetical distribution system 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 (or more) homes does not increase the $50,000 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 (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 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 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 and small C&I classes.[13] 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

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

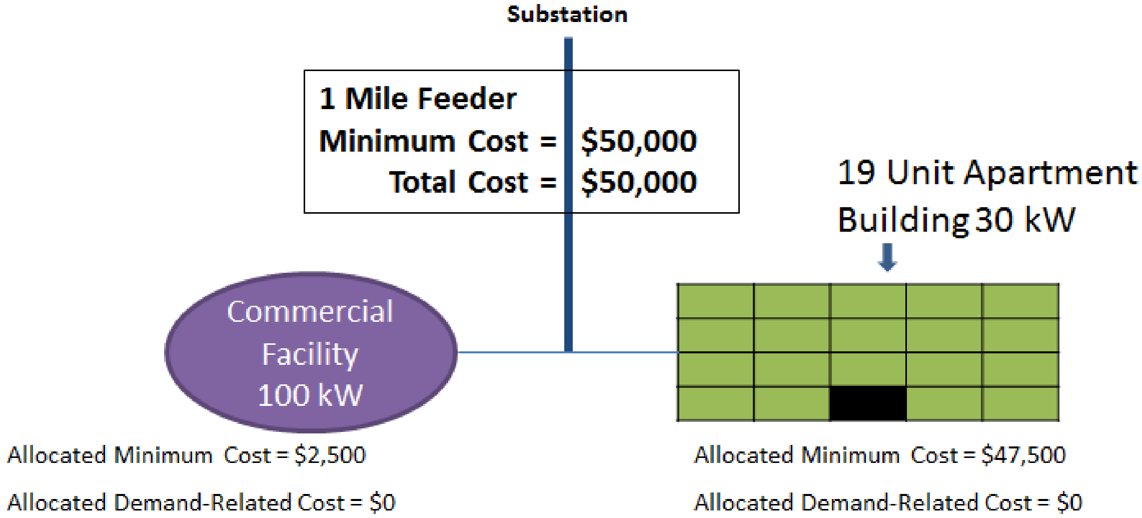
customers.[14] In that event, only those costs incurred for the minimum-size equipment, deemed to be customer-related, are appropriately attributable to, and appropriately allocated to, the residential class. However, the minimum-size method not only allocates to the residential class the cost for the 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 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.[15]

[14] 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.

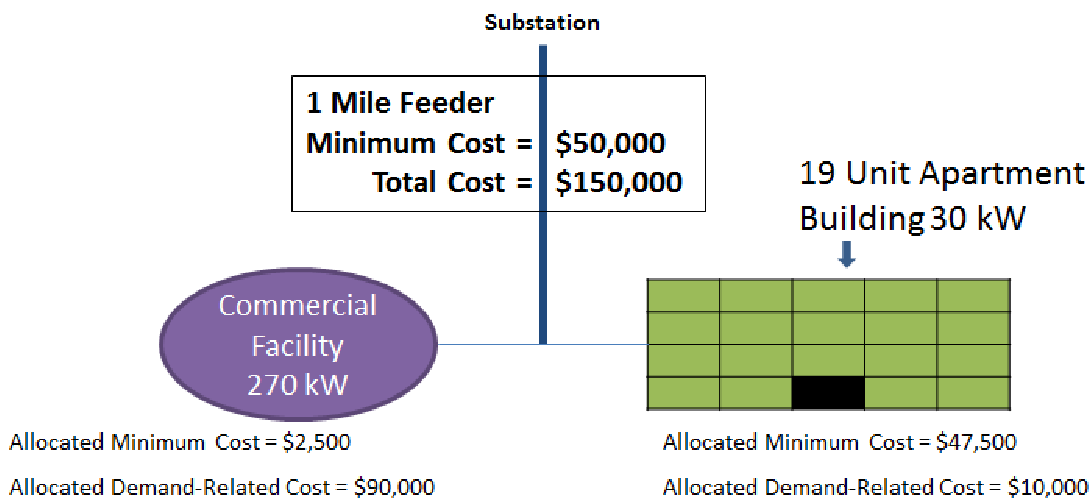
[15] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

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.[16] This is the approach used to classify distribution plant costs in the Capacity Locational (12 CP) COSS. The other five 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.

III. Revenue Allocation

Q: Given that the Capacity Locational (12CP) COSS most reasonably reflects cost-causation, do you recommend that study's allocation of 2017 test year revenue requirements?

[16] 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.

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 of the audit cost of service studies, except for the 1CP COSS, for the purposes of allocating the 2017 test year revenue requirements to customer classes.[17]

Q: Is the fact that there is an insignificant revenue deficiency for the 2017 test year a relevant consideration when deciding how to allocate the 2017 test year revenue requirements to customer classes?

A: Yes. There is effectively no overall revenue deficiency for the 2017 test year because revenues under current rates are expected to fully recover 2017 test year Commission staff audit revenue requirements. Any change to current rates would therefore amount to a revision of a revenue allocation that the Commission found to be reasonable in Docket No. 3270-UR-120.

Q: How do you propose to allocate 2017 test year revenue requirements?

A: Based on the range of results from the audit cost of service studies, and given that there is effectively no overall revenue deficiency for the 2017 test year, I recommend that there be no change from current revenues for any customer class.

Q: Does this complete your direct testimony?

A: Yes.

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[17] As discussed above in Section II, the Commission should give no weight to the results of the 1CP COSS.