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-120

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

September 18, 2014

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 sixty 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, and 6690-UR-123. 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, 2014, Madison Gas and Electric Company (MGE or “the Company”) filed an application to increase electric and gas rates for the 2015 and 2016 test years. The Company subsequently filed additional supporting testimony on June 2, 2014, supplemental testimony on July 18, 2014, and second supplemental testimony on August 15, 2014. These supplemental filings revised the Company’s forecast of the revenue deficiency to reflect the results of the Commission staff’s audit of electric revenue requirements. In addition, with these supplemental filings, the Company revised its proposal for the design of residential and small C&I rates and withdrew its rate request for the 2016 test year pursuant to the terms of a settlement agreement with CUB.

This testimony addresses the following aspects of the Company’s filing:

- The methods used by MGE in its electric cost of service study (COSS) to allocate the proposed 2015 test year electric revenue deficiency to the residential and small commercial and industrial (C&I) classes, as described in the pre-filed direct testimony of Company witness Son T. Trinh.

- The Company's proposal to restructure rates for residential and small C&I customers, including its proposals to increase customer charges and implement a new "grid connection service" charge, as described in the pre-filed direct testimony of Company witnesses Steven S. James, John D. Krueger, and Gregory A. Bollom.
- The Company's agreement to work collaboratively with CUB to develop rate designs in light of fundamental changes developing in the electric utility industry.

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

A: The Company is requesting that electric rates be increased on average by 3.7% in order to recover an expected retail revenue deficiency of $15.2 million in the 2015 test year. Based on the results of a single cost of service study, MGE proposes to allocate $7.5 million to residential and small C&I customers. This amount represents a 3.1% increase over residential and small C&I revenues under current rates.

The Company's cost of service study overstates the portion of the $15.2 million revenue deficiency appropriately allocable to the residential and small C&I classes, because it relies on classification methods that allocate more production and distribution plant costs to residential and small C&I rate classes than is appropriate.

In previous rate cases, MGE typically based its revenue allocation proposals on a range of results from multiple cost of service studies. However, in this docket, the Company conducted fewer cost of service studies than is typical and relied on the results of only one of those studies as the basis for its revenue allocation proposal. It is my understanding that Commission staff will be performing a number of cost of service studies as part of their direct filing. I intend to offer my proposed recommendation for allocation of the 2015 test year revenue deficiency in rebuttal testimony after I have had the opportunity to review the range of results from Commission staff's cost of service studies.

Q: Please summarize your concerns regarding the Company's proposal to restructure rates for the residential and small C&I classes.

A: Shifting distribution and other load-related costs from the energy charge to fixed charges disproportionately and inequitably increases bills for a utility's smallest residential customers and exacerbates the subsidization of larger residential customers' costs by these lower-usage customers.

Q: The Company has proposed increasing its monthly fixed charge for the 2015 test year. Is CUB asking the Commission to reject the Company's proposal?

A: No. It is my understanding that pursuant to the settlement agreement between MGE and CUB, CUB is not contesting the Company's proposed rates for the residential and small C&I customer and grid connection service charges for the 2015 test year. As part of the settlement, MGE withdrew its rate design proposals for residential and small C&I customers for 2016 and modified its proposals for 2015.[1]

Per the settlement, CUB and MGE are engaging in a collaborative work group with Clean Wisconsin to explore electric rate designs that are appropriate

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[1] MGE originally sought to increase the combined customer, grid connection service, and demand-based fixed charges to a total of $21.83 per month in 2015 and $48.66 per month in 2016. *See* Direct-MGE-James-6, ll. 20-22 (PSC REF #: 205589).

for a changing industry characterized by evolving technologies. As the Commission has recognized, the electric utility industry is undergoing rapid changes due to customers' growing embrace of, and demand for, distributed renewable technologies. These changes present both the promise of economic and environmental benefits for customers, but also "disruptive" challenges to the long-standing utility business model. The Company and CUB intend to work together to develop rate design approaches that appropriately consider how MGE can harness the benefits of evolving distributed generation and continue to meet its obligation to provide reliable, least-cost electricity service to all customers. The Company and CUB aim to arrive at a rate structure that fairly and reasonably balances the interests of the Company and all of its customers.

II. Cost Allocation

Q: Please describe the Company's requested electric rate increase.

A: The Company is requesting that electric rates be increased on average by 3.7% in order to recover an expected retail revenue deficiency of $15.2 million in the 2015 test year. Of the total $15.2 million requested revenue increase, MGE proposes to allocate $7.5 million to residential and small C&I customers.[2] This amount represents a 3.1% increase over residential and small C&I revenues under current rates.

Q: What is the basis for the proposed revenue allocation to residential and small C&I customers?

A: According to Company witness Mr. James, the Company relied on a single cost of service study ("MGE COSS") to develop its proposal for allocating the $15.2

[2] Ex.-MGE-James-1r (second), Schedule 1.

million revenue deficiency to the customer classes.[3] This cost of service study shows a revenue *excess* of about $0.8 million for residential and small C&I customers.[4] This amount represents a 0.5% *reduction* from residential and small C&I revenues under current rates. In other words, current residential and small C&I rates would need to be reduced on average by 0.5% to eliminate the excess of 2015 test year revenues under current rates over 2015 test year revenue requirements.

Q: Did the Company rely on only one cost of service study in prior rate cases?

A: No. In prior rate cases, the Company typically relied on the results of multiple cost of service studies as "guidelines" for allocating the revenue deficiency.[5] For example, in Docket No. 3270-UR-118, MGE relied on the results of three cost of service studies that differed with respect to the methods used to classify and allocate production and distribution plant costs. These studies varied the proportion of demand-related to energy-related production plant costs, ranging from 100% demand-related and 0% energy-related to 60%/40% demand/energy.[6] In addition, the studies classified distribution plant costs (other

[3] Notwithstanding the results of the MGE COSS, Mr. James capped the revenue increase allowed for any rate class at 4.75% "in order to moderate the impact on customers within any specific rate class that could occur by realigning the revenue allocation with cost of service all in one year." (Second Supplemental Direct-MGE-James-4, ll. 18-20.)

[4] Calculated from the results of the MGE COSS, as reported in Ex.-MGE-Trinh-1r (second).

[5] For example, see *Direct Testimony of Steven S. James on behalf of Applicant*, Docket No. 3270-UR-117, April 22, 2010, p. D.1.63, ll. 2-4 (PSC REF#: 130248).

[6] Classifying all production plant cost as demand-related implies that, from a generation planning perspective, production plant costs are incurred solely for the purposes of meeting system reliability requirements. On the other hand, classifying all costs as energy-related implies that production plant costs are incurred solely for meeting energy requirements. Classifying costs as

than for meters and services) either as 100% demand-related or as part demand-related and part customer-related as determined by the results of a minimum distribution system analysis.

In his testimony in Docket No. 3270-UR-118, Mr. James explained why the Company chose to rely on more than one cost-of-service study for revenue-allocation purposes in that proceeding:

> I have offered three studies in this case to provide the Commission with a range of costs produced by various accepted cost methodologies. In past cases, the Commission has found it reasonable to rely on the results of more than one cost of service study when allocating revenue responsibility. Depending on different factors the Commission may consider as to how the rate increase in this case should be apportioned among the customer classes, some studies may be deemed more appropriate than others.[7]

In contrast, in this docket the Company used only one cost of service study method to classify and allocate production and distribution plant costs. As a result, the Company's decision in this proceeding to abandon its long-standing practice denied the Commission the opportunity to consider a "range of costs produced by various accepted cost methodologies" in order to rule on the appropriate allocation of the overall revenue deficiency to customer classes.

Q: Why is MGE relying on the results of only one cost of service study for revenue-allocation purposes in this proceeding?

A: According to Company witness Mr. Bollom, the Company decided to abandon its long-standing practice because:

60% demand-related and 40% energy-related therefore implies that 60% of costs are incurred to meet reliability, with the remainder incurred to meet energy requirements.

[7] Direct-MGE-James-8, ll. 18-23, Docket No. 3270-UR-118, June 14, 2012 (PSC REF#: 166580).

> … a preliminary step to realigning rates to more accurately reflect the costs of service is to reach a shared understanding of the appropriate allocation of the costs of service. Reliance on a single cost of service study fosters this sort of shared understanding, since changing the method of revenue allocation can affect different classes of customers differently.[8]

Q: Would reliance on a single cost of service study necessarily foster a "shared understanding" of the appropriate revenue allocation?

A: No. Whether relying on the results of a single study or a range of results from multiple cost of service studies, the revenue-allocation process invariably entails allocations of the test-year revenue deficiency that deviate from the cost allocations in a cost of service study. Such deviations are often justified on the basis of gradualism and other equity considerations, and by the fact that cost allocation is at best an inexact science.[9] Thus, even in the unlikely event that parties could reach agreement on a single cost-allocation approach, there is no reason to believe that those same parties would agree on an allocation of the revenue deficiency.

Q: Does the MGE COSS reasonably allocate the revenue deficiency to customer classes?

A: No. The allocation of costs to customer classes in the MGE COSS does not reasonably reflect each class's responsibility for such costs. In particular, the MGE COSS allocates more production and distribution plant costs to the residential and small C&I rate classes than is appropriate.

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[8] Direct-MGE-Bollom-6, ll. 19-23.

[9] In fact, as noted in footnote 2 above, Company witness Mr. James justified his decision to deviate from the results of the MGE COSS for his proposed allocation of the 2015 test year revenue deficiency on the basis of gradualism.

A. Allocation of Production Plant Costs

Q: How does the MGE COSS over-allocate production plant costs to the residential and small C&I classes?

A: The MGE COSS classifies all production plant costs as demand-related, implying that, from a generation planning perspective, 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 assumption is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are driven by both reliability and energy requirements.

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* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements. Consequently, if a utility's generation portfolio contains intermediate and baseload generating units that are more expensive than peaking plants (as is the case for MGE), it is not appropriate to classify production plant costs for those intermediate and baseload plants as 100% demand-related and 0% energy-related. Doing so over-allocates such capitalized energy costs to residential and small C&I rate classes, since these classes have lower load factors than the larger C&I classes.[10]

[10] 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.

Q: Have you derived an alternative classification of production plant costs?

A: I have not, since it is my understanding that Commission staff, as part of their direct filing, will be deriving an alternative classification based on the "Equivalent Peaker" method for the purposes of allocating audit revenue requirements. This approach to classifying production plant costs is appropriate, since the Equivalent Peaker method reflects investment decision-making under typical generation expansion planning practices.[11]

B. Allocation of Distribution Plant Costs

Q: Does the MGE COSS reasonably allocate distribution plant costs to the residential and small C&I classes?

A: No. The MGE COSS classifies certain distribution plant costs as either customer-related or demand-related based on a minimum distribution system analysis. The minimum distribution system method is fundamentally flawed and tends to misclassify demand-related costs as customer-related. As a result, the MGE COSS overstates the appropriate allocation of distribution plant costs to the residential and small C&I classes.

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

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

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., 0-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 Response to 3-CUB/Inter-1 (PSC REF#: 215983), MGE uses the minimum-size method to classify poles (Account 364), overhead conductors (Account 365), and line transformers (Account 368).[12]

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 –

[12] 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.

such as customer load, load growth, terrain, customer density, voltage 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.[13]

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.

[13] 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

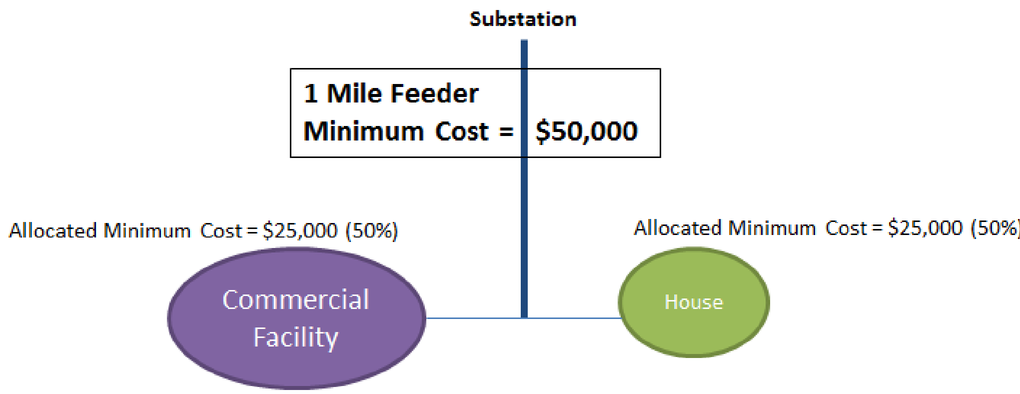
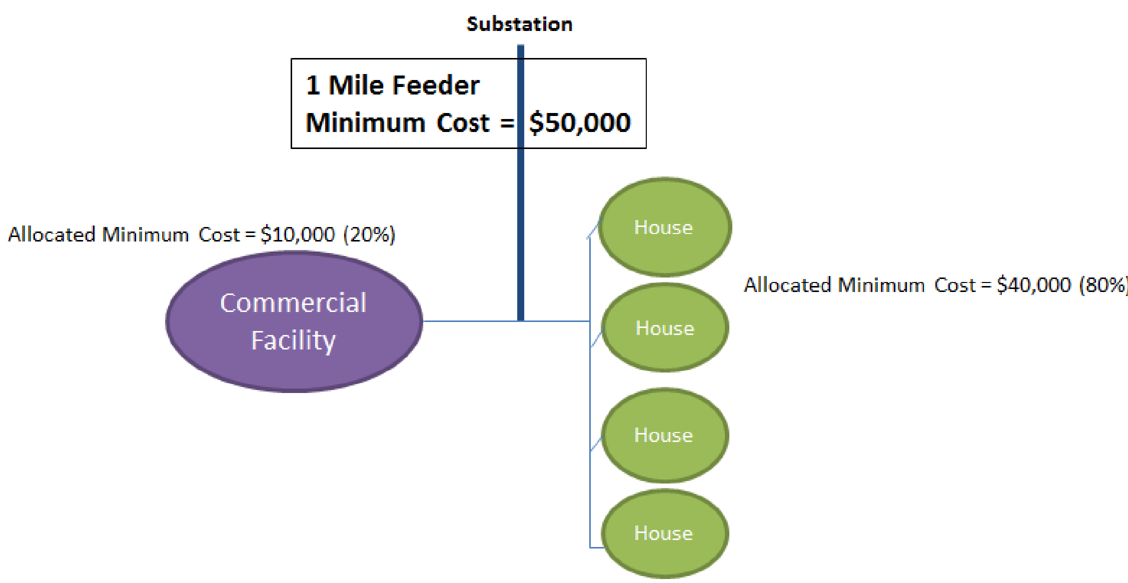


Figure 1b



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 **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 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 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.[14] 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.[15] In that event, only those costs incurred for the minimum-size equipment, deemed to be customer-related, are appropriately attributable to, and

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

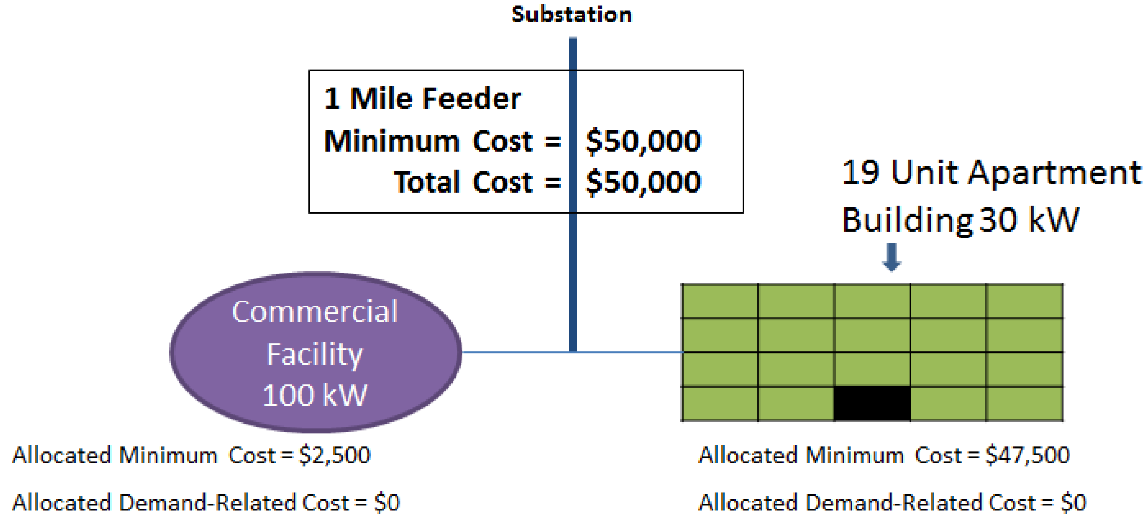
[15] In other words, the utility would not have installed equipment that is larger and more-expensive than the minimum-size equipment if it were only serving residential load.

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.[16]

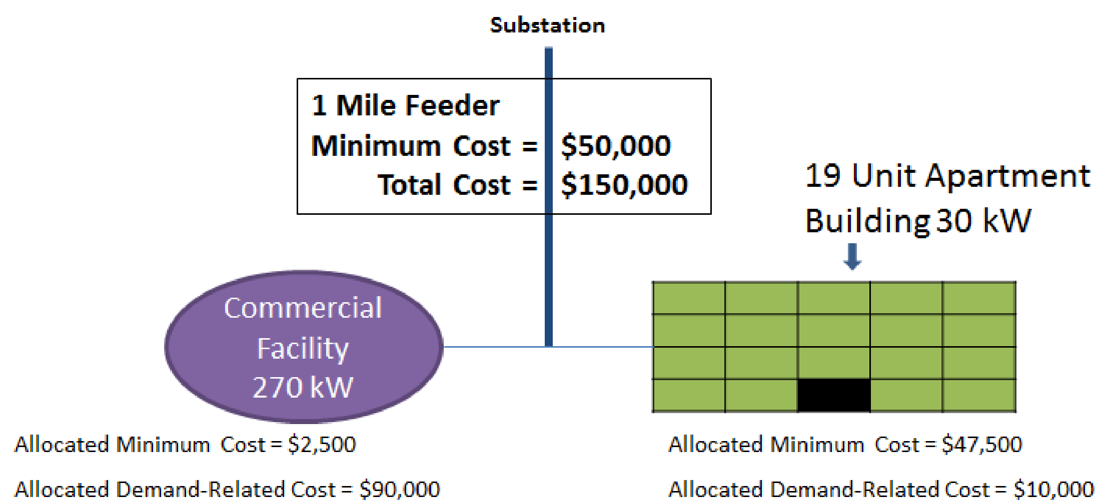
[16] As discussed above with regard to Figures 1a and 1b, allocating minimum-size costs on the basis of number of customer accounts is inconsistent with cost-causation.

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



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.[17]

III. Rate Design

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

A: According to Company witness Mr. Bollom, MGE proposes to restructure residential and small C&I rates in order to shift recovery of allegedly "fixed" costs from the energy charge to fixed charges. Specifically, for the 2015 test year, MGE proposes two changes to the design of residential and small C&I rates. First, the Company proposes to set the customer charge at a rate that recovers all customer-service and administration costs. Under this proposal, monthly customer charges would increase from $10.44 to $14.97 for residential customers and from $10.44 to $19.90 for small C&I customers. Second, MGE proposes to implement a new "grid connection service" charge to recover "the basic costs the Company incurs to connect the customer to the distribution system."[18] In other words, the grid connection service charge would recover distribution-system costs classified as customer-related in the MGE COSS. The

[17] 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.

[18] Direct-MGE-Bollom-5, ll. 21-22.

Company further proposes to set the monthly rate for residential and small C&I grid connection service at $4.03 for the 2015 test year.

Q: Does the MGE COSS appropriately classify distribution plant costs as customer-related?

A: No. As discussed above, the MGE COSS misclassifies demand-related distribution costs as customer-related by relying on the minimum distribution system method. As a result, the MGE COSS overstates the total amount of distribution costs appropriately allocated to the residential and small C&I classes, and overstates the portion of the allocated amounts that are appropriately classified as customer-related. As such, it is not appropriate to recover through fixed charges those distribution costs that are classified as customer-related under the minimum distribution system method.

Q: Is it appropriate to recover through fixed charges all of the costs reasonably classified as customer-related in the MGE COSS?

A: No. While it may be reasonable to classify certain costs as customer-related for the purposes of allocating such costs among customer classes in a cost of service study, it is not appropriate to recover all such costs allocated to the residential and small C&I classes through a fixed charge. For example, a number of customer-classified distribution costs – such as services or uncollectible accounts and collection expense – are likely to vary with the size of the customer (in revenues, sales, or demand). If such costs were recovered through a fixed charge, then the smallest residential customers (with the least-expensive distribution equipment) would be required to pay the average of customer costs attributable to all sizes of residential customers. In other words, if all customers were to pay the same fixed charge regardless of size, then small customers would subsidize larger customers' distribution costs.

Q: Are you recommending that the Commission reject the Company's proposed 2015 test year rates for the residential and small C&I customer and grid connection service charges?

A: No. Pursuant to the settlement agreement between MGE and CUB, CUB is not contesting the Company's proposed rates for the residential and small C&I customer and grid connection charges in the 2015 test year.

IV. Transformation of the Electric Utility Industry

Q: Please describe the settlement agreement between MGE and CUB as it relates to the Company's proposal to restructure residential and small C&I rates.

A: As part of its agreement with CUB, the Company agreed to withdraw its rate filing, including a proposed restructuring of residential and small C&I rates, for the 2016 test year. The Company further agreed to work collaboratively with CUB to develop rate designs that would both accommodate growing customer demand for energy efficiency and distributed generation and allow the Company to continue to meet its obligation to provide reliable, least-cost electricity service to all customers.

Q: Is there likely to be substantial growth in residential distributed generation in the Company's service territory?

A: Yes, if national trends are any indication of potential growth in the Company's service territory. According to a research report by Citigroup, distributed solar capacity in the U.S. increased by a factor of nine between 2007 and 2012, and is expected to increase by about ten-fold between 2012 and 2020.[19] According to a

[19] Citi Research, *Rising Sun: Implications for U.S. Utilities*, August 8, 2013, Figure 9.

recent article in the *Energy Law Journal*, a new rooftop solar system was installed in the U.S. at an average rate of every four minutes in 2013.[20] In addition, the Interstate Renewable Energy Council reports that the pace of new residential solar installations (in terms of capacity added) increased 68% from 2012 to 2013.[21] These statistics indicate that we can expect continued rapid growth in residential distributed generation in the Company's service territory.

Q: What factors are driving the rapid growth in residential rooftop solar installations?

A: A number of factors are driving the explosive growth in rooftop solar, including growing consumer awareness and acceptance of renewable technology, innovations in third-party financing of rooftop installations, government incentives and tax subsidies, and rapidly improving economics. In particular, solar equipment and balance-of-system (i.e., permitting, installation, and interconnection) costs have plummeted since 2008, and are expected to continue to fall through the rest of the decade.[22] At this rate of improvement, it may not be long before residential installations no longer require government incentives or tax subsidies to achieve cost-effectiveness:

> Most predict that by 2020, utilities will reach a tipping point where power from rooftop solar PV will become cheaper than power from the grid in most parts of the US.[23]

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[20] Elisabeth Graffy and Steven Kihm, "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?", *Energy Law Journal*, Vol. 35, No. 1, 2014, p. 4.

[21] Larry Sherwood, *U.S. Solar Market Trends: 2013*, Interstate Renewable Energy Council, July, 2014, p. 7.

[22] Citigroup forecasts a 42% to 53% drop in the total cost of a residential installation by 2020. See *Rising Sun: Implications for U.S. Utilities*, p. 19.

[23] Ernst & Young LLP, *From Defense to Offense: Distributed Energy and the Challenge of Transformation in the Utilities Sector*, 2014, p. 1.

Q: What does this growing embrace of distributed generation imply for the electric utility industry?

A: Although it is difficult to predict how exactly this will play out, widespread adoption of distributed renewable resources could fundamentally transform the industry: from a centrally planned and operated grid designed for reliable delivery of power to energy consumers to a distributed network with power supplied by both conventional generation and energy "prosumers." Such a transformation would entail not just a change in the core transactional relationship between utilities and customers, but would also require a reformulation of the regulatory policies, planning approaches, investment strategies, and cost-recovery mechanisms that are at the heart of the traditional utility model.

Q: How has the industry responded to the growing embrace of distributed generation?

A: For the most part, the initial response has been defensive, with a narrow focus on the "disruptive" threat to earnings from the growth in distributed generation. An influential Edison Electric Institute (EEI) report published in 2013 provides the rationale for industry's defensive posture:

> While the various disruptive challenges facing the electric utility industry may have different implications, they all create adverse impacts on revenues, as well as on investor returns, and require individual solutions as part of a comprehensive program to address these disruptive trends. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality.[24]

[24] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, Edison Electric Institute, January 2013, p. 1.

With its narrow focus on financial risk, the EEI report characterizes rate restructuring as a "near-term, must-consider action by all policy setting industry stakeholders."[25]

Q: Is rate restructuring a viable strategy for responding to these "disruptive" challenges in the longer term?

A: Not on its own. However, rate restructuring could prove to be a key component of a broader, more comprehensive strategy that is designed to accommodate expected long-term changes in the provision and delivery of electricity service. Such a long-term strategy would view distributed generation not as a competitive threat to the industry, but as a potentially valuable supply resource that could lower costs, mitigate fuel and environmental risks, and enhance distribution-system reliability.[26]

In other words, the collaborative effort by MGE, CUB, and Clean Wisconsin represents a first step in a longer process to develop a package of regulatory policies, planning procedures, investment strategies, and rate designs that, for example, could:

- Provide ratepayers with reliable, least-cost, low-risk, and sustainable electricity service;
- Reduce barriers to the adoption of cost-effective distributed renewable resources;
- Ensure that all consumers, regardless of income level, share in the benefits of distributed generation; and
- Provide for the Company's continued financial viability.

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[25] *Id.*, p. 2.

[26] For example, see Anne Hampson and Jessica Rackley, *From Threat to Asset – How CHP Can Benefit Utilities,* ICF International, Inc., 2014.

Q: Does this complete your direct testimony?

A: Yes.