BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	)))	Docket No. 6690-UR-123

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

September 8, 2014

I. Introduction

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: Are you the same Jonathan F. Wallach that filed direct and rebuttal testimony in this proceeding?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of CUB.

Q: What is the purpose of your surrebuttal testimony?

A: My surrebuttal testimony responds to rebuttal testimony filed in this proceeding regarding the following issues:[1]

[1] I do not respond to the discussion by WPSC and WIEG witnesses regarding Commission staff's treatment of interruptible credits, because I did not explicitly address this issue in my direct or rebuttal testimony. However, in my rebuttal testimony, I rely on the results of Commission

- The Equivalent Peaker method for classifying production plant costs, as discussed by WPSC witness Joylyn C. Hoffman Malueg and WIEG witness Robert R. Stephens.
- The minimum distribution system method for classifying distribution plant costs, as discussed by Ms. Hoffman Malueg and Mr. Stephens.
- The allocation of primary voltage distribution costs, as discussed by Mr. Stephens.
- Rate design for residential and small C&I rate classes, as discussed by WPSC witness Ronda L. Ferguson.

Q: Are you revising your proposal for allocating the Commission staff audit revenue deficiency for the 2015 test year in light of the Company's and WIEG's rebuttal testimony?

A: No. I continue to believe that it is appropriate to consider the range of results from the Commission staff's Standard, Capacity, TOU, and Locational cost of service studies when allocating the 2015 test year revenue deficiency. Consequently, I have not revised my proposed revenue allocation to customer classes (as shown in Table 2 of my rebuttal testimony) or to rate classes (as shown in Ex.-CUB-Wallach-5).

II. Classification of Production Plant Costs

Q: What do you recommend with regard to the classification of production plant costs?

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staff's cost of service modeling as the basis for my proposed allocation of the 2014 test year revenue deficiency, because I consider Commission staff's treatment of interruptible credits to be conceptually sound.

A: I recommend that production plant costs be classified as either demand- or energy-related using the Equivalent Peaker classification method.[2] As I discussed in my direct testimony, the Equivalent Peaker method reflects investment decision-making under typical generation expansion planning practices. Under the Equivalent Peaker approach, investments in peaking plant are classified as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. In contrast, baseload or intermediate plant costs in excess of peaking plant costs (i.e., capitalized energy costs) are classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

Q: How does Ms. Hoffman Malueg respond to your recommendation?

A: Ms. Hoffman Malueg opposes use of the Equivalent Peaker method to classify production plant costs, because "this method does not allocate fixed production costs as a system, and does not take into account required system reserve margins."[3]

Q: Do you agree with Ms. Hoffman Malueg's characterization of the Equivalent Peaker method?

A: No. The Equivalent Peaker approach classifies costs consistent with total-system resource planning, which seeks to invest in that mix of baseload, intermediate, and peaking plant that meets both reliability and energy requirements at minimum total-system cost. Thus, contrary to Ms. Hoffman Malueg's characterization, the Equivalent Peaker approach classifies costs from a total-

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[2] Commission staff witness Mr. Singletary also recommends use of the Equivalent Peaker method for classifying production plant costs.

[3] Rebuttal-WPSC-Hoffman Malueg-6, ll. 17-18.

system perspective and in a manner that reflects the fact that costs are incurred to meet both system reserve requirements and energy requirements.

Q: Please summarize WIEG witness Mr. Stephens's discussion of the Equivalent Peaker method.

A: Mr. Stephens believes that the Equivalent Peaker approach is flawed, because:

> … (1) production plant costs related to intermediate and peaking generating stations are allocated to the classes as if those units had the same construction and operating cost characteristics as baseload units; and (2) no corresponding adjustment is made to the cost of fuel so the costs of the oil, natural gas, and coal that are burned in intermediate and peaker generating stations are again allocated to the classes as if those units were baseload units.[4]

Q: Is Mr. Stephens's argument valid?

A: No. Mr. Stephens is mistaken in his belief that high load factor customers are not credited for the fuel savings associated with capitalized energy investments. The Company's energy allocator – based on load-weighted average marginal energy cost – allocates fuel costs in proportion to each class's contribution to fuel cost in each hour. Consequently, a low load factor customer, whose energy consumption is concentrated in the higher-price on-peak hours, will be allocated a greater share of on-peak fuel costs and a lesser share of off-peak fuel costs than a high load factor customer with the same annual consumption. As a result, low load factor customers are allocated a larger portion of the fuel costs in the higher-price on-peak hours, reflecting the fact that these customers are allocated a larger portion of the demand-related peaking plant costs that give rise to the on-peak fuel costs. On the other hand, high load factor customers are allocated a larger portion of the fuel costs in the lower-price off-peak hours, reflecting the

[4] Rebuttal-WIEG-Stephens-20, ll. 16-21.

fact that these customers are allocated a larger portion of the energy-related capitalized energy investments that give rise to the off-peak fuel costs. Thus, contrary to Mr. Stephens's belief, high load factor customers pay a lower fuel rate than low load factor customers because they are credited with the fuel savings associated with capitalized energy investments.

Q: Does Mr. Stephens offer any other comment regarding the Equivalent Peaker method?

A: Yes. In the event that the Commission approves use of the Equivalent Peaker method, Mr. Stephens recommends that demand-related production plant costs be allocated based on each class's contribution to system coincident peak (1CP). Mr. Stephens characterizes the 1CP allocator as a "more 'pure' demand allocator."[5]

Q: Is this proposal reasonable?

A: No. Contrary to Mr. Stephens's characterization, no demand allocator is "more pure" than any other; nor does the appropriateness of a demand allocator depend on the method selected to classify production plant costs. Instead, as I discussed in my rebuttal testimony, demand-related production plant costs should be allocated in proportion to each class's contribution to the need for new reserve capacity. No matter the method used to classify production plant costs, the 12CP allocator is the most-reasonable measure of each class's contribution to the need for new reserve capacity.

Q: Please summarize your response to the Company's and WIEG's arguments regarding the Equivalent Peaker method.

[5] Rebuttal-WIEG-Stephens-24, line 18.

A: Neither Ms. Hoffman Malueg's nor Mr. Stephens's criticisms of the Equivalent Peaker approach have merit. I therefore continue to recommend that production plant costs be classified using the Equivalent Peaker method and that demand-related production plant costs be allocated using the 12CP allocator.

III. Classification of Distribution Plant Costs

Q: Please summarize your findings and recommendations regarding the classification of distribution plant costs.

A: As I discussed in my direct testimony, the minimum distribution system approach used by WPSC to classify distribution plant costs suffers from a number of defects that result in the misclassification of demand-related costs as customer-related. This misclassification, in turn, leads to an over-allocation of distribution plant costs to residential and small C&I customers. I therefore recommend that meters and services be classified as customer-related and that all other distribution plant costs be classified as demand-related.

Q: How does Ms. Hoffman Malueg respond to your criticisms of the minimum distribution system method?

A: Ms. Hoffman Malueg does not address my substantive arguments regarding the flaws in the minimum distribution system method. Instead, she first notes that both of the studies I cited in support of my critique of the minimum distribution system approach (Bonbright and Sterzinger) claim that most jurisdictions relied on the minimum distribution system method in the 1980s. Ms. Hoffman Malueg then asserts that the examples I used to illustrate the flaws discussed in these two studies do not accurately or realistically represent how the minimum distribution system method works.

Q: Is use of the minimum distribution system method still as widespread as alleged by Bonbright and Sterzinger?

A: I have not done a comprehensive survey of classification practices in other jurisdictions. However, as I noted in my direct testimony, a study by the Regulatory Assistance Project found that more than thirty states did not use the minimum distribution system method as of the year 2000.[6]

Q: How do you respond to Ms. Hoffman Malueg's discussion of the examples you used to illustrate the flaws in the minimum distribution system method?

A: Ms. Hoffman Malueg's criticisms of these illustrative examples are misplaced, since she apparently misunderstands the examples themselves. Ms. Hoffman Malueg contends that these examples inaccurately and unrealistically apply the minimum-size method to plant costs for individual distribution assets (i.e., a single feeder), when in practice this method is applied to total plant costs for all distribution assets system-wide (i.e., all feeders in the system). However, Ms. Hoffman Malueg fails to recognize that these examples assume a distribution system that consists of only one distribution asset – a single one-mile feeder – and thus illustrate by way of simple example the application of the minimum-size method to total distribution plant costs and thus the problems that arise when total distribution plant costs are classified using the minimum-size method. Since all of Ms. Hoffman Malueg's criticisms of my illustrative examples are based on a faulty premise, namely that my examples depict a

[6] This study further notes that, in certain respects, the minimum-system method "seems absurd, since in the absence of any demand no such system would be built at all." See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, December, 2000, p. 31.

single piece of distribution equipment as opposed to an entire hypothetical distribution system, her concerns are unfounded.

Q: Please summarize Mr. Stephens's discussion of the minimum distribution system approach.

A: Mr. Stephens cites to the safety standards in the National Electrical Safety Code (NESC) to illustrate the merits of the minimum distribution system method. For example, he notes that the NESC requires a minimum height for poles regardless of the load on the conductors carried on a pole. Mr. Stephens then concludes that:

> Given that the principal reason to extend the distribution system is to serve additional customers, it is only reasonable to conclude that the costs associated with the NESC, and thus, the [minimum distribution system], vary with the number of customers.[7]

Q: Is Mr. Stephens's conclusion valid?

A: No. The fallacy in Mr. Stephens's argument is that although the NESC safety standards may require a minimum-sized system, the cost of that minimum system does not necessarily vary with the number of customers. For example, if service were extended to a new area using minimum-height poles, the total cost of those poles would likely be the same whether service was being extended to a single industrial customer or to a single apartment building with 100 residential customers. If the cost of the minimum system does not vary with the number of customers, it would not be appropriate to allocate such minimum costs to rate classes in proportion to the number of customers in each class.

This discussion illustrates the fundamental problem with the minimum distribution system approach. Even if one could reasonably estimate the cost of

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[7] Rebuttal-WIEG-Stephens-27, ll. 10-13.

a minimum system to serve the Company's customers, there is no reason to believe that those costs would vary directly with the number of customers. Instead, such costs would more likely vary with such factors as customer density or topography.

Q: Given the problems with the minimum distribution system method, is there a reasonable alternative method for classifying distribution plant costs?

A: Yes. As I discussed in my direct testimony, a reasonable and reasonably straightforward approach would be to classify meters and services as customer-related and all other distribution plant costs as demand-related. This approach recognizes that the distribution system is sized to meet customer demand and that changes to that system are largely driven by increases in that demand.

In the alternative, distribution plant costs, other than for meters and services, could be classified using Wisconsin Electric Power Company's modified minimum-size method, where minimum-system costs are classified as 50% demand-related and 50% customer-related.[8]

IV. Allocation of Primary Voltage Distribution Costs

Q: Please summarize the Company's proposal for allocating primary voltage distribution costs.

A: As I discussed in my direct testimony, the Company proposes in this proceeding to adopt a proposal by WIEG in Docket No. 6690-UR-122 that would: (1) assume that primary-system costs are 50% three-phase plant costs and 50% single-phase costs; (2) allocate 100% of single-phase costs to secondary

[8] As with the standard minimum-size method, all costs in excess of minimum-system costs would be classified as demand-related.

customers; and (3) classify and allocate three-phase costs to primary and secondary customers using the minimum-size method.

Q: What did you recommend in your direct testimony with regard to the Company's proposal?

A: I recommended that the Commission reject this proposal, as it did in Docket No. 6690-UR-122, because neither WIEG nor the Company addressed the specific defect in WIEG's proposal that led the Commission to reject that proposal in Docket No. 6690-UR-122. Specifically, the Commission cited the concern that WIEG's proposal failed to consider whether primary-voltage customers might be responsible for a larger share of three-phase costs than would be indicated under a minimum-size allocation.

In the same vein, Commission staff witness Corey Singletary also recommended in his direct testimony in this proceeding that any allocation results using the Company's proposal not be relied on until the defect in WIEG's proposal had been fully addressed.

Q: How does Mr. Stephens respond to the recommendation to reject the Company's proposal at this time?

A: Mr. Stephens ignores the Commission's express concern regarding the potential misallocation of three-phase primary costs and instead simply asserts that:

> The allocation of three-phase primary costs is a traditional allocation issue that is being addressed in the various cost of service studies and testimonies related thereto.[9]

Contrary to Mr. Stephens' contention, the Commission recognized in Docket No. 6690-UR-122 that the allocation of three-phase costs is no longer a "traditional allocation issue" once single-phase primary costs are separated from

[9] Rebuttal-WIEG-Stephens-33, ll. 19-21.

three-phase primary costs for the purposes of allocating such costs. Specifically, the Commission recognized that "traditional" methods for allocating three-phase primary costs might allocate a greater portion of such costs to single-phase customers than would be consistent with cost-causation.[10]

Given the Company's and WIEG's failure to address the Commission's express concerns, I continue to recommend that the Commission reject the Company's proposal to segregate single-phase from three-phase primary voltage distribution plant costs for the purposes of cost allocation.

V. Rate Design

Q: Please summarize your findings and recommendations regarding the Company's proposal to restructure residential and small C&I electric rates.

A: As I discussed in my direct testimony, WPSC lacks a reasonable basis for its proposal to shift costs from the energy charge to the fixed charge. In particular, the Company's intention to recover all costs other than short-run marginal energy cost through fixed charges would inappropriately shift to the fixed charge costs that are "fixed" in the short term, but avoidable in the long term. By doing so, the Company's proposal would dampen and destabilize price signals for long-lived investments in energy efficiency resources and exacerbate the subsidization of larger residential customers' costs by lower-usage customers. Consequently, I recommend that the Commission reject the Company's proposal to shift costs from the energy charge to the fixed charge. Instead, fixed charges

[10] In other words, "traditional" methods might allocate to single-phase customers more three-phase costs than would have been incurred if the primary system were built to serve only single-phase customers.

should be maintained at their current rates of $10.40/month for residential customers and $12.50/month for small C&I customers.

Q: How does Company witness Ms. Ferguson respond to your conclusion that the Company's proposal would inappropriately dampen and destabilize long-run price signals?

A: Ms. Ferguson agrees in theory with the proposition that all costs are variable, and therefore avoidable, in the long-run. However, according to Ms. Ferguson, plant investments, once sunk, are unavoidable over the life of the plant:

> Customer demand represents the distribution facilities that are sized to meet the customer's peak demand. The costs of these facilities are fixed and have plant lives of decades (about 30 years for a transformer and more than 40 years for a service). It would be uneconomical for WPSC to resize residential facilities on an individual customer basis if a customer reduced their peak demand or changed consumption on a permanent basis.[11]

Consequently, from Ms. Ferguson's perspective, it would be inappropriate for an energy charge to signal that investment costs can be avoided by reducing energy usage.

Q: Is this a valid argument for setting energy charges at short-run marginal energy cost?

A: No. The issue at hand is not whether *past* investment costs are fixed, but whether *future* plant investments (required to meet load growth or to replace ageing existing equipment) could be avoided with reductions in customer usage. As I discussed in my direct testimony, short-run marginal energy costs do not provide a reasonable price signal, because long-lived investments in energy efficiency would reduce not just current energy costs, but also future distribution, transmission, and generation capital, fuel, and O&M expenditures.

[11] Rebuttal-WPSC-Ferguson-5, ll. 19-25.

In other words, energy charges should reflect long-run marginal costs in order to provide appropriate and stable price signals for investment in long-lived efficiency measures.

If the energy charge reflects only current energy costs but not expected future capital, fuel, and O&M costs, then customers may not invest today in the energy efficiency measures that would allow the Company to forego those expected expenditures in the future. The price signal to avoid those future costs needs to be sent today in order for it not to become a self-fulfilling prophecy that those long-run marginal costs will be incurred in the future and recovered from customers through future rate increases.

Q: How would the Company's proposal exacerbate subsidization of larger customers by smaller customers?

A: As I discussed in my direct testimony, two aspects of the Company's proposal would exacerbate subsidization. First, the Company proposes to recover through fixed charges certain customer costs that vary with customer size, such as services or uncollectible accounts and collection expense. If such costs were recovered through a fixed charge, then all customers would pay the same rate for these costs (i.e., the average cost for customers of all sizes), even though such costs vary with customer size. As a result, the smallest residential customers with below-average customer costs would subsidize larger customers' above-average customer costs.

Second, the Company's proposal to shift recovery of demand-related costs from the energy charge to the fixed charge would result in low-usage customers paying for a greater portion of such demand-related costs than is appropriate from a cost-causation perspective. Just as class demands drive each class's responsibility for total system demand-related costs, individual customer demands drive each customer's responsibility for demand-related costs allocated to that class. When a lower-usage customer pays less for demand-related costs recovered through the energy charge than a higher-usage customer, that difference reflects the appropriate allocation of demand-related costs to individual customers within that class. In contrast, the Company's proposal would recover more demand-related costs from low-usage customers than is appropriate and thereby exacerbate the subsidization of larger customers by smaller customers.

Q: How does Ms. Ferguson respond to your conclusions regarding cross-subsidization under the Company's proposal?

A: Ms. Ferguson agrees that there are certain customer costs, including services and uncollectible accounts and collection expense, that vary with customer size. Moreover, she notes that shifting recovery of only services costs from the fixed charge to the energy charge would reduce the fixed charge for residential customers by $4.60/month.[12] Thus, if the fixed charge were set to recover just those costs classified as customer-related under Commission staff's Locational COSS, I estimate that shifting recovery of services costs from the fixed charge to the energy charge would reduce the residential fixed charge from about $12.30/month to $7.70/month.

On the other hand, Ms. Ferguson disagrees with my conclusion that low-usage customers with distributed generation would pay more than their fair share of demand-related costs under the Company's proposal. Using as an example a customer with rooftop solar whose peak "demand" is negative 5 kW

[12] Rebuttal-WPSC-Ferguson-5, ll. 11-12. Ms. Ferguson does not estimate the cost per month attributable to uncollectible accounts and collection expense.

(i.e., whose solar generation exceeds consumption by 5 kW), Ms. Ferguson argues that:

> Regardless of the direction of flow, the facilities have to be large enough to handle peak demand. So, although this customer has generation and may have low energy use, the customer is not a low demand customer. This customer's generation does not avoid any distribution cost.[13]

Ms. Ferguson's conclusion that no distribution costs are avoided in her example is erroneous, because the premise that facilities are sized to meet the customer's peak demand is faulty. In fact, facilities are sized to meet the *aggregate* peak demand of *all* customers served by those facilities. Consequently, the customer's net generation in Ms. Ferguson's example will reduce the aggregate load on the distribution facilities that serve that customer (and other customers) and thus reduce the cost to serve that customer and all other customers taking service from those facilities.

Q: Are you revising your rate-design recommendations in light of Ms. Ferguson's rebuttal?

A: No. Ms. Ferguson's responses to my criticisms of the Company's rate-design proposal lack merit. I therefore continue to recommend that the Commission: (1) reject the Company's proposal to shift costs from the energy charge to the fixed charge; and (2) maintain fixed charges for residential and small C&I customer at their current rates.

Q: Does this complete your surrebuttal testimony?

A: Yes.

[13] Rebuttal-WPSC-Ferguson-8, line 13 to Rebuttal-WPSC-Ferguson-9, line 3.