BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

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

SURREBUTTAL TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
October 2, 2015

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:

- 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 allocation of demand-related production plant costs, including Commission staff's treatment of interruptible credits, as discussed by Mr. Stephens.
- The minimum distribution system method for classifying distribution plant costs, as discussed by Ms. Hoffman Malueg and Mr. Stephens.
- The basis for the Company's proposal to increase residential and small C&I fixed charges, as discussed by Ms. Hoffman Malueg.

II. Classification of Production Plant Costs

Q: What is the Company's position regarding the Equivalent Peaker method for classifying production plant costs?

A: According to Ms. Hoffman Malueg, WPSC 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."[1]

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

---

[1] Rebuttal-WPSC-Hoffman Malueg-4.

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

A: Mr. Stephens states that he is aware of only one state (Minnesota) where the Equivalent Peaker method is still used and then speculates that this method is no longer used widely because of the falling price of natural gas. Mr. Stephens also presents an analysis to show that the Equivalent Peaker method results in a "skewed allocation of capital costs."[2]

Q: Is Minnesota the only state where utilities use the Equivalent Peaker method to classify production plant costs?

A: No. Although I have not done a comprehensive survey of classification practices, I am aware that utilities in California, Iowa, Massachusetts (prior to restructuring), Minnesota, Oregon, and Washington use or have used the Equivalent Peaker method or variant methods that recognize differentials in investment costs between baseload, intermediate, and peaking capacity. I am also aware that utilities in Maryland (prior to restructuring), New Brunswick, and Nova Scotia use or have used methods other than Equivalent Peaker to classify portions of production plant costs as energy-related.

Q: Is there any reason to believe that the Equivalent Peaker method is less relevant because of falling natural gas prices, as Mr. Stephens speculates?

A: No. The decline in gas prices has not changed the investment fundamentals that underpin the Equivalent Peaker method: namely, that investment in less-

[2] Rebuttal-WIEG-Stephens-20. Mr. Stephens no longer incorrectly claims as he did in his direct testimony that the allocation of fuel costs does not credit customers commensurately for the fuel savings associated with energy-related investments in baseload or intermediate plant. Instead, he now opines that this credit does not "offset the impact of the skewed allocation of capital costs" without offering any evidence supporting his opinion.

expensive peaking capacity (such as gas-fired combustion turbines) is driven primarily by increases in reserve requirements while investment in more-expensive baseload or intermediate capacity (such as gas combined-cycle plant) is driven by energy requirements.

Q: What does Mr. Stephens mean by his claim that the Equivalent Peaker method results in a "skewed allocation of capital costs"?

A: Mr. Stephens means nothing more than that the residential class is allocated a smaller share of production plant costs when such costs are classified using the Equivalent Peaker method and allocated using a 12CP allocator than when classified as 100% demand-related and allocated using a 1CP allocator. Needless to say, the latter approach is WIEG's preferred approach for classifying and allocating production plant costs.

Q: How do you respond to Mr. Stephens's contention that his analysis shows that the Equivalent Peaker method allocates to the residential class only 73% of the capacity required to meet reserve requirements?

A: Mr. Stephens's analysis shows nothing of the sort. His analysis simply assumes that 100% of the residential class's megawatt capacity obligation is met under WIEG's preferred approach. He then calculates the share of the capacity obligation met under each of the other five audit cost of service studies as the ratio of the residential allocation of production plant costs under that study to the residential allocation of production plant costs under WIEG's preferred study. Thus, Mr. Stephens's analysis simply shows that 73% of the production plant costs allocated to the residential class under WIEG's preferred study are allocated to the residential class under the TOU and Locational studies (which use the Equivalent Peaker method along with the 12CP allocator). Contrary to Mr. Stephens's contention, his analysis provides no information regarding the extent to which the residential class meets its capacity obligation under different classification and allocation approaches.[3] Instead, it merely indicates that WIEG's preferred approach yields the largest – one might say most-skewed – allocation of production plant costs to the residential class of the six audit cost of service studies.

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 "pure" demand allocator.[4]

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, 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.

---

[3] In reality, the residential class (along with all other classes) meets 100% of its capacity obligation regardless of how the costs incurred to meet that obligation are allocated.

[4] Rebuttal-WIEG-Stephens-15.

III. Allocation of Demand-Related Production Plant Costs

Q: What is Mr. Stephens's response to your endorsement of the Company's use of the 12CP allocator to allocate demand-related production plant costs?

A: Mr. Stephens alleges that the choice of allocator has a minimal cost impact because the allocator applies to only a small portion of production plant costs. He also claims that peak demands in non-summer months are unlikely to have a substantial impact on annual loss of load expectation (LOLE) because the Company's reserve capacity in excess of summer peaks provide sufficient excess capacity to offset capacity reductions in non-summer months due to planned maintenance.[5]

Q: Do you agree that the allocator applies to only a small portion of production plant costs?

A: No. The allocator for demand-related production plant costs would apply to 100% of production plant costs for the audit studies that classify all production plant costs as demand-related. Moreover, this allocator would apply to 40% of production plant costs under the TOU and Locational studies. In either case, the allocator for demand-related production plant costs would apply to a substantial portion of production plant costs.

Q: How do you respond to Mr. Stephens's argument regarding the effect on non-summer load on annual LOLE?

---

[5] Mr. Stephens also appears to misunderstand my statement that the 12CP allocator gives greater weight to higher summer peaks than lower non-summer peaks. To clarify, I meant by that statement that a percentage difference between two classes' demands in a summer month will have a greater impact than the same percentage demand difference in a non-summer month on the relative allocation of demand-related production plant costs between those two classes.

A: Mr. Stephens has it backwards in his argument regarding the availability of excess capacity to offset capacity reductions due to planned maintenance. The amount of capacity required in excess of summer peak – i.e., the annual reserve margin – is determined in part by the daily contribution to annual LOLE as a result of planned maintenance during the non-summer months. In other words, the MISO reserve requirement is set at that percentage margin over summer peak that ensures that LOLE over the year, including the contribution to LOLE during times of planned maintenance, is less than one day in ten years. Thus, it's not that capacity reserves in excess of summer peak negate the impact of planned maintenance on annual LOLE as Mr. Stephens alleges, but that the impact of planned maintenance on annual LOLE drives in part the amount of capacity needed in excess of summer peak to maintain system reliability.

Q: Do you have any comments regarding Mr. Stephens's discussion of Commission staff's treatment of interruptible credits?

A: I presume that Commission staff witness Sam Shannon will respond directly to Mr. Stephens's critique of Commission staff's treatment of interruptible credits. However, I would note that this issue is fundamentally a dispute over the appropriate valuation of interruptible load under different classification schemes. If all production plant costs are classified as demand-related, then an allocation of such demand-related costs based on net (i.e., firm) load would overvalue interruptible load at the average embedded cost of all production plant. On the other hand, if production plant costs are classified using the Equivalent Peaker method, then allocating demand-related costs based on gross load and crediting interruptible load at the market value of capacity would value interruptible load at less than embedded cost of the Company's investment in peaking plant. Consequently, it may be appropriate to use a net 12CP allocator for the TOU and Locational audit studies and a gross 12CP allocator with explicit crediting of interruptible load for the other four audit studies.

For comparison purposes, I show in Table 1 the allocation of the 2016 test year base revenue deficiency under the TOU COSS and under a modified version of the TOU COSS that allocates demand-related production plant costs using a net 12CP allocator.

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

`	TOU COSS	Net 12CP TOU COSS
Residential	0.73%	0.97%
Small C&I	-14.82%	-14.56%
Cg-5	-12.31%	-11.99%
Cg-20	-0.53%	-0.24%
Cp-1	18.51%	17.67%
Lighting	-33.23%	-33.15%
Miscellaneous	8.06%	8.06%
Total System	1.92%	1.92%

IV. Classification of Distribution Plant Costs

Q: Please summarize your findings and conclusions regarding the minimum distribution system method for classifying distribution plant costs.

A: The minimum distribution system method 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. A reasonable alternative to the minimum distribution system method, which has been used in other jurisdictions, is to classify meters and services as customer-related and all other distribution plant costs 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, 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?

---

[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.

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

Q: How does Mr. Stephens respond to your criticisms of the minimum distribution system method?

A: Mr. Stephens does not address my substantive arguments regarding the flaws in the minimum distribution system method. Instead, like Ms. Hoffman Malueg, he takes issue with the examples I used to illustrate the flaws discussed in Bonbright and Sterzinger.

None of Mr. Stephens's comments regarding my examples are substantive or relevant to the flaws illustrated in the examples. In response to my example showing how the minimum cost of a feeder would not vary with number of customers (Figures 1a and 1b), Mr. Stephens offers the irrelevant speculation that other distribution costs might vary with number of customers and then makes the unfounded claim that allocating the cost of the hypothetical feeder on demand would not be consistent with cost-causation.

Likewise, in response to my example illustrating how residential customers would be over-allocated demand-related feeder costs (Figures 2a and 2b), Mr. Stephens notes that the commercial customer in this example could be over-allocated such costs if the position were reversed, as if two wrongs make a right.

Q: How does Mr. Stephens respond to your conclusion regarding a reasonable alternative to the minimum distribution system method of classification?

A: Mr. Stephens claims that I did not offer any specific information regarding the use of this alternative in other jurisdictions. However, as I noted in CUB's Response to Data Request 1-WIEG-4, my direct testimony cited the results of the survey by the Regulatory Assistance Project discussed above.[7] I also noted in CUB's Response to Data Request 1-WIEG-4 that I am personally aware that this alternative approach is used in Maryland, Massachusetts, Michigan, and Utah.

Mr. Stephens also claims that my endorsement of an alternative approach that classifies cost based on one factor – demand – is illogical since I criticize the minimum distribution system method for simplistically modeling cost-causation on the basis of only two factors – demand and number of customers. However, Mr. Stephens apparently misunderstands the alternative approach and the reason for my endorsement. This alternative approach does not classify all distribution plant costs as demand-related. Instead, it classifies all meter and services costs as customer-related and the remaining distribution plant costs as demand-related. And I endorse the alternative approach not because it perfectly

[7] A copy of this response is attached as Ex.-CUB-Wallach-7.

reflects cost-causation but because, as has been recognized in other jurisdictions, it is the most-reasonable option for modeling cost-causation given the fatal flaws in the minimum distribution system method.

V. Rate Design

Q: How does Ms. Hoffman Malueg respond to your direct testimony regarding the Company's proposal to increase residential and small C&I fixed charges?

A: Contrary to my finding that the range of results from the audit cost of service studies indicates that fixed charges should not be increased, Ms. Hoffman Malueg contends that the Company's proposal is "supported by five out of the six COSSs provided into the record."[8] However, Ms. Hoffman Malueg's reference to the five studies is misleading, since all of these studies rely on the same minimum distribution system method to classify customer-related costs and thus all estimate the same fixed cost per customer of around $26 per month. The true range of results is thus from about $13.50 when using the Locational COSS classification approach to about $26 when using minimum distribution system classification.

Ms. Hoffman Malueg also disputes my finding that the Company's minimum distribution system analysis derives a minimum transformer cost per average-usage customer. Instead, she claims that the Company's minimum-intercept analysis derives the minimum cost per transformer, not per customer served by the transformer.

---

[8] Rebuttal-WPSC-Hoffman Malueg-12.

This claim is incorrect. According to WPSC Response to 6-CUB/Inter-8 in Docket No. 6690-UR-123, the minimum cost derived by the Company's minimum-intercept analysis "represents the fixed cost *per customer* for the transformers that are serving the customers in the Rg-1 rate schedule."[9] Thus, contrary to Ms. Hoffman Malueg's assertion, the Company's minimum-intercept analysis yields the minimum transformer cost per average-usage customer based on the number of average-usage customers served per transformer. Since each transformer could serve more low-usage customers, the minimum transformer cost per low-usage customer should be less than the cost per average-usage customer.[10]

Q: Does this complete your surrebuttal testimony?

A: Yes.

---

[9] Emphasis added. A copy of this response is attached as Ex.-CUB-Wallach-8.

[10] This discussion illustrates the fundamental conceptual flaw in the minimum-intercept method. The Company's analysis of the minimum cost per customer for transformers that serve zero load assumes that a transformer serves the same number of customers on average whether those customers have average usage or zero usage. In fact, the true minimum cost per customer must be zero since a transformer that serves zero load can serve an infinite number of customers with zero load.