**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF WISCONSIN**

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

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# REBUTTAL TESTIMONY OF JONATHAN WALLACH ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN

August 29, 2014

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## 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 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 rebuttal testimony?**

A: This rebuttal testimony describes my proposal for allocating to customer classes the Commission staff audit forecast of the 2015 test year electric revenue deficiency. This proposal is based on the results of Commission staff's electric cost of service studies, as described in the pre-filed direct testimony of Corey S.J. Singletary, and Commission staff's allocation of Revenue Stabilization

Mechanism (RSM) credits, as described in the pre-filed direct testimony of Jerry Albrecht.

In addition, I propose specific rate designs for the residential and small C&I electric rate classes, based on the recommendation in my direct testimony that there be no change to residential and small C&I fixed charges.

Finally, this rebuttal testimony responds to the proposal by Robert R. Stephens, on behalf of the Wisconsin Industrial Energy Group (WIEG), to allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the four summer monthly peaks.

## II. Cost Allocation and Rate Design

**Q: Please describe Commission staff's cost of service analysis.**

A: As I discussed in my direct testimony, Commission staff requested that WPSC conduct four cost of service studies based on the Commission staff audit forecast of 2015 test year revenue requirements.[1] These four studies differ with respect to the methods used to classify production and distribution plant costs, as well as with respect to the treatment of interruptible credits:

- The Standard COSS adopts the Company's approach for classifying production and distribution plant costs, and also adopts the Company's approach of allocating demand-related production plant costs on the basis

[1] According to Mr. Singletary, Commission staff requested two additional cost of service studies based on audit revenue requirements, for a total of six studies, simply because other parties requested such studies of the Company's forecast of revenue requirements for the 2015 test year. However, Mr. Singletary apparently gives little weight to the results of these studies.

of class load net of interruptible load.[2] However, the Standard COSS does not adopt the method used in the Company's cost of service study to segregate and allocate three-phase and single-phase primary distribution plant costs. Instead, the Standard COSS uses the Company's method from Docket No. 6690-UR-122.

- The Capacity COSS modifies the treatment of interruptible load in the Standard COSS. Specifically, the Capacity COSS allocates demand-related production plant costs on the basis of gross class load, but explicitly credits interruptible load at Mr. Singletary's estimate of the value of interruptible and direct load control capacity.
- The TOU COSS modifies the Capacity COSS by classifying 40% of production plant costs as demand-related and the remaining 60% as energy-related, based on the results of Commission staff's Equivalent Peaker analysis.
- The Locational COSS modifies the TOU COSS by classifying all distribution plant costs, other than for meters and services, as demand-related.

**Q: Please describe the results of the four Commission staff audit cost of service studies.**

A: According to Mr. Singletary, the revenue deficiency for the 2015 test year, excluding RSM revenues, is about $30.9 million, or about 3.2% of 2015 test year electric revenues under current rates.[3] For each of the four cost of service

[2] Following the Company's nomenclature, I referred to this study as the "UR-122 COSS" in my direct testimony. I adopt Mr. Singletary's nomenclature in this testimony.

[3] Ex.-PSC-Singletary-1, Schedule 1. As I reported in my direct testimony, the revenue deficiency inclusive of RSM revenues is about $28.7 million, or about 2.9% of 2015 test year electric revenues under current rates.

studies, Table 1 shows the allocation of this overall deficiency to each of the major customer classes, expressed as a percentage of 2015 test year electric revenues under current rates for each class.[4]

As indicated in Table 1, three of the four audit cost of service studies show a revenue *excess* for residential and small C&I customers, ranging from negative 0.3% in the Capacity COSS to negative 8.4% in the Locational COSS. On average across the four studies, the revenue excess for residential and small C&I customers is negative 2.8%.[5]

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

| ` | Standard COSS | Capacity COSS | TOU COSS | Locational COSS | Average |
|---|---|---|---|---|---|
| **Residential and Small C&I** | 0.1% | -0.3% | -2.7% | -8.4% | -2.8% |
| **12,500-25,000 kWh** | -7.1% | -7.7% | -10.2% | -2.4% | -6.8% |
| **Medium C&I** | 10.0% | 9.6% | 8.6% | 16.2% | 11.1% |
| **Large C&I** | 7.2% | 8.4% | 14.4% | 18.4% | 12.1% |
| **Lighting & Misc.** | -33.5% | -33.8% | -33.6% | -38.0% | -34.7% |
| **Total System** | 3.2% | 3.2% | 3.2% | 3.2% | |

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

[4] The results shown in Table 1 differ slightly from those shown in Table 1 of my direct testimony, because RSM revenues are excluded from the former and included in the latter. Also, as I discussed in my direct testimony, the Locational COSS results in Table 1 of my direct testimony reflected an error in the Company's modeling of the Locational COSS. Mr. Singletary's correction of that error is reflected in the Locational COSS results reported in Table 1 of this testimony.

[5] In other words, current residential and small C&I rates would need to be reduced on average by 2.8% to eliminate the excess of 2015 test year revenues under current rates over 2015 test year revenue requirements.

A: Of the four studies, the Locational COSS classifies and allocates production and distribution plant costs in a fashion that most reasonably reflects each class's responsibility for such costs.[6] As I discussed in my direct testimony, the Locational COSS corrects for the Company's misclassification of production plant costs as 100% demand-related and corrects for the inappropriate use of the minimum distribution system method for classifying distribution plant costs.

However, for the purposes of allocating the overall revenue deficiency to customer classes and setting rates for the 2015 test year, it would be appropriate to consider the results of all four studies. To varying degrees, all four studies indicate that it would not be reasonable to increase residential and small C&I rates in the 2015 test year.

**Q: Based on the results of Commission staff's cost of service studies, how do you propose to allocate the 2015 test year revenue deficiency?**

A: I provide my proposed revenue allocation for each customer class in Table 2 and for each electric rate class in Ex.-CUB-Wallach-5. As can be seen by comparing Tables 1 and 2, I propose to hold base revenues (excluding RSM credits) constant for the residential and small C&I customer class (as well as for the 12,500-25,000 kWh and lighting classes), even though revenue reductions would be justified by the results of Commission staff's cost of service studies. On the other hand, I propose a substantially smaller revenue increase for the medium and large C&I classes than would be warranted from a cost-causation perspective.

Table 2 and Ex.-CUB-Wallach-5 also show my proposal for the allocation to customer and rate classes, respectively, of RSM credits from 2013 over-

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[6] Mr. Singletary believes that the TOU and Locational cost of service studies "provide the most reasonable … allocation of WPSC's costs." Direct-PSC-Singletary-14, ll. 3-4.

collections. I use Mr. Albrecht's method for allocating RSM credits to classes. However, whereas Mr. Albrecht amortizes the total amount of credits over the 2015 and 2016 test years, I propose to credit the full amount of the 2013 over-collection in test year 2015. As noted by Mr. Albrecht, crediting the full amount in one year would be consistent with past practice.[7] I see no reason to deviate from past practice in this proceeding.

**Table 2: Recommended Revenue Allocation**

| | | Base Revenue Increase | | Including RSM Credit | |
|---|---|---|---|---|---|
| | Current Revenues | Revenue Increase | Percent Increase | RSM Credit | Percent Increase |
| Residential & Small C&I | $482,078,458 | $0 | 0.0% | ($2,064,762) | -0.4% |
| 12,500-25,000 kWh | $36,260,977 | $0 | 0.0% | ($190,811) | -0.5% |
| Medium C&I | $205,951,725 | $14,291,168 | 6.9% | ($2,042,419) | 5.9% |
| Large C&I | $239,211,404 | $16,599,086 | 6.9% | --- | 6.9% |
| Lighting & Misc. | $13,611,333 | $3,718 | 0.0% | --- | 0.0% |
| Total System | $977,113,896 | $30,893,973 | 3.2% | ($4,297,992) | 2.7% |

**Q: What do you recommend with regard to the design of residential and small C&I rates?**

A: I provide my recommended rate designs for the residential and small C&I rate classes in Ex.-CUB-Wallach-6. These rates reflect my proposals above regarding allocation of the 2015 test year revenue deficiency and recovery in 2015 of all RSM credits from 2013 over-collections. In addition, these rates

[7] Direct-PSC-Albrecht-5, ll. 7-10.

reflect my recommendation in direct testimony to maintain residential and small C&I fixed charges at current levels.[8]

## III. Response to Mr. Stephens

**Q: What does WIEG witness Mr. Stephens propose with regard to the allocation of demand-related production plant costs?**

A: In both the Company's and Commission staff's cost of service studies, demand-related production plant costs are allocated to customer classes based on each class's contribution to the average of the twelve monthly peaks (12CP). Mr. Stephens proposes instead that demand-related production plant costs be allocated based on each class's contribution to the average of the monthly peaks for the four summer months (4CP).

**Q: Why does Mr. Stephens recommend allocating demand-related production plant costs using a 4CP allocator?**

A: Mr. Stephen first argues generally that investments in production plant are driven by "only the hourly demands that are reasonably close to the annual system peak," because "it is only during the highest system load hours that production capacity is most likely to be fully utilized."[9] He then asserts that it is more appropriate to use a 4CP rather than a 12CP allocator, since the peaks for the four summer months fall within a reasonable range of the annual system peak, while the peaks for the remaining eight months do not.

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[8] If any increases to residential and small C&I revenues are allowed by the Commission, such increases should be recovered solely through energy charges.

[9] Direct-WIEG-Stephens-12, ll. 20-22.

**Q: Are production plant costs incurred solely for the purposes of meeting demand in the highest-load hours, as Mr. Stephens contends?**

A: No. As I discussed in my direct testimony, under typical generation expansion planning practice, plant investment is driven by both reliability requirements and system energy requirements, with the overall goal of meeting both peak and energy requirements at lowest total cost. System planners would likely invest solely in peaking capacity if plant investment were driven solely by reliability requirements, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. However, the Company has also invested in baseload and intermediate capacity, even though these units have higher fixed costs than peaking capacity, in order to minimize the total cost of meeting an increase in energy requirements.[10] In other words, investments in baseload or intermediate capacity are driven by demand in all hours of the year, not just those in the highest-load hours.

**Q: Are investments in peaking plant driven solely by monthly peaks during the summer?**

A: No. Peak demands during non-summer months also contribute to annual loss of load probability (LOLP) and thus system reserve requirements. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLP and reserve requirements. Consequently, peak demands

[10] As I argued in my direct testimony, from a cost-causation perspective, the fixed costs incurred for baseload or intermediate capacity over and above those incurred for peaking capacity are appropriately classified as energy-related, since these additional fixed costs are incurred to meet energy requirements at lowest total cost.

in non-summer months also contribute to the need for investments in demand-related production plant.

**Q: Does Mr. Stephens support allocating demand-related production plant costs using the Company's forecast of the 4CP allocator for the 2015 test year?**

A: No. Mr. Stephens believes that the Company's 4CP allocator produces "anomalous" results. Specifically, Mr. Stephens believes that the Company's 4CP allocator is flawed because, unlike in Docket No. 6690-UR-122, it allocates more demand-related production plant costs to the large industrial class than would be the case using the 12CP allocator. In light of this "anomalous" result, Mr. Stephens recommends that the Company develop 4CP and 12CP allocators based on a "more rigorous demand forecast" than currently employed by WPSC.[11] In the alternative, Mr. Stephens recommends using the 4CP and 12CP allocators from Docket No. 6690-UR-122 to allocate demand-related production plant costs in the instant proceeding.

**Q: Are Mr. Stephens's recommendations reasonable?**

A: No. Mr. Stephens's recommendation to use a "more rigorous demand forecast" is devoid of any specifics as to how the Company should go about conducting such a forecast. Moreover, it is simply unrealistic to expect that the Company would be able to conduct such a forecast, revise its 4CP and 12CP allocators based on such a forecast, and then redo its cost of service studies in time to allow full consideration by intervenors and the Commission in this proceeding.

Nor would it be reasonable to substitute the 4CP and 12CP allocators from Docket No. 6690-UR-122 for the Company's allocators in the instant

[11] Direct-WIEG-Stephens-25, ll. 4-6.

proceeding. Mr. Stephens's recommendation represents a radical departure from past practice and would open the door to parties cherry-picking favorable allocators from previous rate cases.

If WIEG believes that the Company's forecasting process is flawed, the appropriate remedy would be for the Commission to direct WPSC to work with interested parties to revise its demand forecasting methodology prior to the Company's next rate filing.

**Q: What do you conclude from your review of Mr. Stephens's proposal for allocating demand-related production plant costs?**

A: Mr. Stephens has failed to offer a reasonable basis for his proposal. The Commission should therefore reject his recommendation to allocate demand-related production plant costs using a 4CP allocator.

**Q: Does this complete your rebuttal testimony?**

A: Yes.