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

REBUTTAL TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
September 21, 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 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 proposed rate designs for the residential and small commercial and industrial (C&I) rate classes. These rate designs reflect:

- My proposal, as described in my direct testimony, for allocating to customer classes the Commission staff audit forecast of the 2016 test year base revenue deficiency, i.e., the revenue deficiency excluding the SEERA credit.

- Commission staff's proposed allocation of the SEERA credit, as described in the pre-filed direct testimony of Sam Shannon.
- The recommendation in my direct testimony that there be no change to residential and small C&I fixed charges.

In addition, this rebuttal testimony responds to proposals for classifying and allocating production plant costs by Robert R. Stephens on behalf of the Wisconsin Industrial Energy Group (WIEG). Finally, I respond to direct testimony by Mark E. Meyer on behalf of Fair Rates for Wisconsin's Dairyland, Inc. (FRWD) filed in support of the Company's proposal to increase residential and small C&I fixed charges.

Q: Do you have any preliminary comments?

A: Yes. In his pre-filed direct testimony, Mr. Stephens suggests that the Commission abandon its long-standing practice of basing its revenue allocations on a range of results from diverse cost of service studies. Instead, Mr. Stephens would have the Commission consider the results from only those studies which he deems to be "conventional" and reject the findings from studies he considers to be "non-standard" because they produce "outlier" results.

The Commission should reject Mr. Stephens's attempt to impose subjective and unreliable standards of review on the Commission's deliberations. After all, one party's "conventional" study is another party's "outlier." For example, one could validly characterize WIEG's preferred study (4CP COSS) as an "outlier" because, as shown in Table 1 below, this is the only one of the six studies conducted by WPSC where the Cp-1 class has a lower percentage increase than the residential and medium commercial classes. As the Commission has long held, no one study perfectly captures cost-causation, no matter how strongly any one party's belief to the contrary. Mr. Stephens has failed to offer a reasonably compelling argument for why the Commission should hold otherwise.

II. Rate Design Proposal

Q: What does the Commission staff audit find with regard to the expected revenue deficiency for the 2016 test year?

A: The Commission staff audit finds a base revenue deficiency for the 2016 test year, before accounting for the SEERA credit, of about $19.5 million, or 1.92% of 2016 test year electric revenues under current rates.[1] With the SEERA credit, the audit revenue deficiency amounts to about $17.8 million, or 1.75% of 2016 test year electric revenues under current rates.

Q: How do you propose to allocate the 2016 test year revenue deficiency?

A: For each of the six cost of service studies that WPSC conducted based on the Commission staff audit forecast, Table 1 shows the allocation of this overall deficiency to each of the major customer classes, expressed as a percentage of 2016 test year electric revenues under current rates for each class.

[1] I misstated these results in my direct testimony due to an overstatement of the impact of the SEERA credit on the overall revenue deficiency. I correct for this error in the revenue-allocation and rate-design proposals that follow.

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

`	1P-3P COSS	4CP COSS	Standard COSS	Capacity COSS	TOU COSS	Locational COSS
Residential	5.00%	5.31%	5.25%	3.20%	0.73%	-7.68%
Small C&I	-12.51%	-10.74%	-12.67%	-14.76%	-14.82%	-15.44%
Cg-5	-8.25%	-5.74%	-8.71%	-11.27%	-12.31%	-5.56%
Cg-20	4.05%	5.48%	3.54%	0.93%	-0.53%	8.08%
Cp-1	5.85%	3.05%	5.96%	13.12%	18.51%	22.94%
Lighting	-35.91%	-41.30%	-33.45%	-34.09%	-33.23%	-37.45%
Miscellaneous	8.84%	8.06%	8.06%	8.06%	8.06%	19.65%
Total System	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%

I provide my proposed allocation of base revenues (i.e., before accounting for the SEERA credit) for each customer class in Table 2 and for each electric rate class in Ex.-CUB-Wallach-4. I developed my recommendation based on the directional results from the six audit studies and with the goal of narrowing the difference for all classes between the allocated revenue increase and the system average increase in order to avoid rate shock for any one class. Table 2 and Ex.-CUB-Wallach-4 also show Commission staff's proposal for allocating the SEERA credit to customer and rate classes, respectively.[2]

[2] Commission staff's proposal for SEERA credits is found in Ex.-PSC-Shannon-1, Schedule 6.

Table 2: Recommended Revenue Allocation

		Base Revenue Increase		Including SEERA Credit	
	Current Revenue	Revenue Increase	Percent Increase	SEERA Credit	Percent Increase
Residential	375,336,211	7,199,494	1.92%	(823,569)	1.70%
Small C&I	120,033,767	-	0.00%	(263,380)	-0.22%
Cg-5	35,393,006	-	0.00%	(77,660)	-0.22%
Cg-20	230,117,390	4,426,008	1.92%	(504,760)	1.70%
Cp-1	240,336,675	7,893,092	3.28%	-	3.28%
Lighting	13,314,649	-	0.00%	-	0.00%
Miscellaneous	280,718	-	0.00%	-	0.00%
Total System	1,014,812,416	19,518,593	1.92%	(1,669,369)	1.76%

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-5. These rates reflect my recommended allocation of base revenues and Commission staff's proposed allocation of the SEERA credit, as shown in Ex.-CUB-Wallach-4. In addition, these rates reflect my recommendation in direct testimony to maintain residential and small C&I fixed charges at current levels.[3]

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

III. Response to Mr. Stephens

Q: What is WIEG witness Mr. Stephens's position with regard to the classification and allocation of production plant costs?

A: Mr. Stephens opposes classification or allocation of any portion of production plant costs as energy-related. Instead, Mr. Stephens supports classification of all production plant costs as demand-related and allocation of such demand-related costs using the 4CP allocator.

Q: Why does Mr. Stephens oppose classifying production plant costs as energy-related?

A: Mr. Stephens asserts that it would not be appropriate to classify any portion of production plant costs as energy-related because such costs "do not vary with the energy produced."[4] Mr. Stephens also claims that energy allocations of production plant costs "typically fail to fairly attribute the lower fuel costs associated with higher fixed cost production units when allocating energy costs."[5]

Q: Should cost classification depend on whether production plant costs vary with generation, as Mr. Stephen contends?

A: No. It makes no sense to classify production plant costs (or, for that matter, transmission or distribution plant costs) on the basis of what drives variations in those costs once they are ratebased. Instead, investments in production plant should be classified on the basis of what drove those investments in the first place. And what typically drives such investments are both reliability and system energy requirements. Consequently, investments in peaking plant are

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[4] Direct-WIEG-Stephens-12.

[5] Direct-WIEG-Stephens-12.

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 should be classified as energy-related, since these incremental costs are typically incurred to minimize the total cost of meeting an increase in energy requirements.

Q: Is Mr. Stephens correct in his claim that fuel costs are not allocated in a manner that is consistent with a classification of production plant costs as energy-related?

A: No. Mr. Stephens is mistaken in his belief that customers will not be credited commensurately for the fuel savings associated with energy-related investments in baseload or intermediate plant. 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. 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. Consequently, low load factor customers will be 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 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: Why does Mr. Stephens recommend allocating demand-related production plant costs using a 4CP allocator?

A: Mr. Stephens 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."[6] 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. Finally, Mr. Stephens claims that his recommendation to use the 4CP allocator "offers a reasonable transition or 'middle ground' from the 12CP that WPSC currently uses to a 1CP used by MISO."[7]

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 discuss above, 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. Thus, contrary to Mr. Stephens's belief, investments in baseload or intermediate capacity are driven by demand in all hours of the year, not just those in the highest-load hours.

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[6] Direct-WIEG-Stephens-11.

[7] Direct-WIEG-Stephens-19.

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

Q: Is Mr. Stephens correct in his claim that MISO determines the Company's reserve requirement based on 1CP?

A: No. Mr. Stephens apparently mistakes the *measure* MISO uses to express the Company's planning reserve requirement for the *method* MISO uses to determine that requirement. The measure MISO uses to express the Company's reserve requirement is a simple percentage margin above 1CP demand.[8] However, the method MISO uses to determine the amount of capacity required for planning reserve is an LOLP analysis that considers the daily contribution of the Company's demand to annual loss of load expectation. In other words, contrary to Mr. Stephens's claim, the Company's annual capacity requirement is determined based on the Company's demand throughout the year, not just by its 1CP demand.

Q: What do you conclude from your review of Mr. Stephens's testimony regarding the classification and allocation of production plant costs?

A: Contrary to Mr. Stephens's claim, the Company's investments in production plant are driven by both reliability and energy requirements. Consequently, production plant costs are appropriately classified as both demand- and energy-related.

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[8] MISO calculates the reserve margin as the ratio of capacity required for planning reserve to 1CP demand minus one.

Moreover, demand-related plant costs incurred to meet reserve requirements are driven by demand in every month, not just by 4CP or 1CP demand. The 12CP allocator is therefore the most-reasonable measure of each class's contribution to the need for new reserve capacity.

IV. Response to Mr. Meyer

Q: What is FRWD witness Mr. Meyer's position regarding the Company's proposal to increase residential and small C&I fixed charges?

A: Mr. Meyer requests that the Commission approve the proposal by WPSC, a financial supporter of FRWD.[9] Mimicking the Company's arguments in this proceeding and Docket No. 6690-UR-123, Mr. Meyer offers the following reasons for supporting the Company's proposal:

- The proposal to shift costs from energy charges to fixed charges is consistent with the cost-allocation guidelines set forth in a 2005 issue paper titled "Cost Allocation and Methods for Distribution and Supply."[10]
- The current energy charges create a false price signal.
- The current energy charges create a confusing price signal.

I address each rationale in turn.

Q: Does the 2005 issue paper endorse shifting of costs to a fixed customer charge, as Mr. Meyer contends?

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[9] See WPSC Response to 11-CUB/Inter-1 (PSC REF#: 275051), 11-CUB/Inter-2 (PSC REF#: 275052), and 11-CUB/Inter-3 (PSC REF#: 275053) for information regarding the nature of the Company's financial relationship with FRWD, attached hereto as Ex.-CUB-Wallach-6

[10] Mr. Meyer provides a copy of this paper in Ex.-FRWD-Meyer-1.

A: No. To the contrary, the issue paper finds that customer-service costs, such as metering and billing costs, are the only costs that should be recovered through the customer charge. All other costs, according to the issue paper, should be recovered through energy or demand charges.[11]

As I discussed in my direct testimony, the fixed charge for the Rg-1 class would be less than $14 per month if it were set to recover only customer-service costs.

Q: Why does Mr. Meyer believe that the current energy charges create false price signals?

A: Mr. Meyer believes that the current energy charges create false price signals by recovering allegedly fixed costs through a volumetric rate.

Q: Do the current energy charges create false price signals?

A: No, because the allegedly fixed costs recovered through the current energy charges are fixed in the short run but marginal in the long run. As James Bonbright, Albert Danielson, and David Kamerschen explain in their *Principles of Public Utility Rates*, energy charges should reflect long-run marginal costs in order to provide appropriate and stable signals for investments in long-lived efficiency measures:

> By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time…. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the own price elasticity of demand for utility services can be

[11] Ex.-FRWD-Meyer-1, p. 13.

> expected to be much greater in the fairly long run than in any very short period of time.[12]

In fact, the authors of Mr. Meyer's "go-to resource for utility regulation" emphasize that energy rates would create false price signals if long-run marginal costs were shifted from volumetric to fixed charges:

> But if utility rates were to be made as volatile as may be required by the mandate of conformity to short-run marginal costs, they would deprive consumers of those expectations of reasonable continuity of rates and of rate relationships on which they must rely in order to make rational advance preparations for the use of service.[13]

Q: Why does Mr. Meyer believe that the current energy charges create confusing price signals?

A: Mr. Meyer is concerned about a hypothetical scenario where customer investments in energy efficiency reduce sales to such an extent that WPSC is required to raise energy rates to recover the same amount of fixed costs from a smaller sales base. In this hypothetical situation, Mr. Meyer believes that customers who invested in energy efficiency to reduce costs would be confused by rate increases resulting from their efficiency investments.

Q: Is Mr. Meyer's hypothetical scenario realistic?

A: No. It is extremely unlikely that rate increases from one test year to the next would be due solely or in large part to efficiency investments. For that to happen, savings from energy efficiency would have to be large enough to cause a decline in total sales from the previous test year (as opposed to reducing sales growth) *and* all fixed and variable costs would have to remain constant from one

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[12] Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, VA: Public Utilities Reports, 1988, p. 451.

[13] *Id.*

test year to the next. If only one or none of these unlikely conditions holds, efficiency savings would not be the sole or primary cause of any rate increase.

Even if rate increases are being driven by reduced sales, increasing the fixed charge is likely to create further confusion and frustration as consumers realize that their investments in efficiency improvements are not going to yield as much bill savings as they had anticipated. If customers are confused about the relationship between bill savings and rate increases, whatever the reason for the increase, WPSC should not exacerbate customers' frustration by increasing the fixed charge. Instead, the Company should enhance its efforts to educate customers about the bill savings achievable with efficiency investments, even when energy rates increase, and about the economic benefits that accrue to all customers when ratepayers reduce usage through energy efficiency.

Q: What do you conclude from your review of Mr. Meyer's testimony in support of the Company's proposal to increase residential and small C&I fixed charges?

A: Mr. Meyer has failed to offer any valid arguments for increasing residential and small C&I fixed charges. Consequently, the Commission should give no weight to Mr. Meyer's testimony in support of the Company's proposal.

Q: Does this complete your rebuttal testimony?

A: Yes.