BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light	)	
Company for Authority to Adjust	)	Docket No. 6680-UR-120
Electric and Natural Gas Rates	)	
For 2017 and 2018 Test Years	)	

SURREBUTTAL TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
September 27, 2016

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 by WPL witness Brian Penington and by WIEG witness Kavita Maini.

II. Response to Mr. Penington

Q: At Rebuttal-WPL-Penington-11, Company witness Mr. Penington asserts that your direct testimony suggests that current demand rates for commercial and industrial customers promote inefficient behavior by those customers. How do you respond?

A: My direct testimony suggests nothing of the sort. Instead, I take issue with the Company's presumption that what is good for the commercial and industrial goose is necessarily good for the residential gander. My concern is that WPL has not accounted for important differences between residential and larger commercial and industrial customers in terms of their respective usage patterns and in terms of their ability to understand and control their maximum demands. After all, larger commercial and industrial customers can often profitably employ personnel and sophisticated energy management systems to control loads throughout the day for the purposes of minimizing electric bills. What I am suggesting in this case is that what is larger commercial and industrial customers' meat in fact turns out to be residential customers' poison when such differences are considered.

Q: At Rebuttal-WPL-Penington-13, Mr. Penington contends that your argument that the proposed residential demand charges would serve effectively as fixed charges conflicts with your finding that the proposed residential customer charge would inappropriately recover variable costs through a fixed charge. Do you agree?

A: No. Mr. Penington misunderstands my argument regarding the proposed residential demand rate. I am not arguing that the costs to be recovered through the proposed demand charges are fixed. To the contrary, I contend that these costs are demand-related and driven by customer load. It would therefore not be appropriate to recover such costs through either the customer charge, which is truly fixed, or a demand charge, which is effectively fixed because of residential customers' inability to control their maximum demands.

Q: At Rebuttal-WPL-Penington-15, Mr. Penington states that you have not quantified the impact on price signals from the Company's proposal to increase the residential customer charge and that your concerns about the impact are overstated. How do you respond?

A: With the monthly customer charge set at $18, the Company proposes an average annual energy charge of 11.3¢/kWh in order to recover the 2018 test year revenue requirement allocated to the Rg-1 rate class.[1] If, instead, the customer charge were set at $9 (as I recommend), the energy charge would have to be increased to 12.6¢/kWh to recover the same allocated revenue requirement.[2] Thus, the average annual energy charge under the Company's proposal is about 11% less than the energy charge would be if the customer charge were set at $9 per month.

Residential customers would be expected to vary their usage in response to the difference in energy rates between these two customer charge scenarios. Specifically, based on my review of a number of studies of residential electricity price response, it seems reasonable to assume that residential customers would increase their usage by 0.3% for every 1% decrease in the energy rate.[3] Thus, with an energy rate that is 11% lower than it would be if the customer charge were set at $9, I would expect residential customers' usage under the Company's

[1] My estimate of the average annual energy rate is based on data provided in Schedule 4 of Ex.-WPL-Penington-1r.

[2] *Id.*

[3] The citations for these studies are provided in Ex.-CUB-Wallach-2.

proposal to set the customer charge at $18 to be about 3% greater than if the customer charge were set at $9.

For comparison, I estimate that energy savings in 2015 from Focus on Energy residential programs amounted to about 1% of 2015 statewide residential sales. If we assume uniform percentage savings across utilities, the consumption increase due to the Company's proposed increase to the Rg-1 customer charge (and the resulting decrease in the energy charge) would undo about three years of residential energy-efficiency savings in the Company's service territory.

Q: How do you respond to Mr. Penington's statement at Rebuttal-WPL-Penington-20 that "it is possible that incorporating an NCP allocator alternative to assign distribution costs may be considered reasonable for substations and primary distribution, but Mr. Wallach's approach to apply it to all distribution costs is questionable?"

A: My approach in this regard is the same as that used by the other major investor-owned electric utilities in Wisconsin. That WPL is the outlier on this issue would indicate that it is the Company's approach, not mine, that is questionable.

III. Response to Ms. Maini

Q: At Rebuttal-WIEG-Maini-5, WIEG witness Ms. Maini supports classifying all production plant costs as demand-related because "these costs are fixed and plant capacity is required to meet peak demand and reserve margin requirements." How do you respond?

A: From a cost-causation perspective, the fact that production plant costs are fixed once such costs are incurred and approved for inclusion in ratebase is irrelevant.

As explained in the NARUC Cost Allocation Manual, what is relevant is what factors drove the Company's decision to incur such costs in the first place:

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, *cost causation attempts to determine what influences a utility's production plant investment decisions*.[4]

Ms. Maini is correct when she says that reserve requirements drive decisions on the *amount* of capacity needed. However, she overlooks the fact that it is energy requirements that drive decisions on the *type* of capacity (i.e., baseload, cycling, or peaking) added to the system:

> Cost causation considers … that the utility's energy load or load duration curve is a major indicator of the *type* of plant needed. The *type* of plant installed determines the cost of the additional capacity.[5]

To the extent that energy requirements drove the Company's decision to add baseload or cycling capacity rather than cheaper peaking capacity, the additional costs incurred for the more-expensive capacity should be classified as energy-related.

Q: At Rebuttal-WIEG-Maini-6 through Rebuttal-WIEG-Maini-9, Ms. Maini explains why she believes that reserve requirements (and thus production plant costs) are driven solely by peak demands in the summer months. How do you respond?

A: For the most part, Ms. Maini repeats the arguments she made in her direct testimony and to which I already responded in my rebuttal testimony.

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[4] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, p. 38. Emphasis added.

[5] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January, 1992, pp. 38-39. Emphasis added.

Q: At Rebuttal-WIEG-Maini-10, Ms. Maini contends that "a pure allocator such as 1CP" should be used to allocate production plant costs classified as demand-related under the Equivalent Peaker method. Do you agree?

A: No. Contrary to Ms. Maini'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.

Q: At Rebuttal-WIEG-Maini-10 through Rebuttal-WIEG-Maini-11, Ms. Maini questions the validity of the Equivalent Peaker classification method based on an analysis that purports to show that "the Company's generation related price offers reflecting all energy related costs would most likely not clear economically and WPL's generation would not be dispatched by MISO." How do you respond?

A: The results of Ms. Maini's analysis are meaningless since the analysis assumes unrealistic bidding practices by the Company. Ms. Maini's analysis attempts to show that the Company's generation would not be economically dispatched in the MISO energy market if WPL were to offer its generation into the market at a price that included both short-run marginal (i.e., fuel and variable O&M) costs and production plant costs classified as energy-related under the Equivalent Peaker method. Yet, it is unlikely that WPL would bid more than short-run marginal cost because of the risk that the Company's price offer would not be economic compared to other bid prices (since all other bidders are likely to bid their short-run marginal cost.)[6] In other words, the only thing that Ms. Maini's analysis shows is that WPL has a strong financial incentive to not price its offers in the way that Ms. Maini posits for her analysis.[7]

Q: Does Ms. Maini's analysis provide any relevant information regarding what drove the Company's investments in baseload or cycling plant?

A: No. Ms. Maini's analysis simply indicates that the Company's investments in its existing baseload and cycling plant might not be economic if made today and if current market conditions were to persist over the life of those investments. However, this finding is irrelevant to the issue of cost causation, which is concerned solely with market conditions prevailing at the time WPL made its decision to invest in its generation plant and the Commission approved such investments. And at that time, the Company justified, and the Commission approved, investments in baseload and cycling plant rather than cheaper peaking plant based on prevailing expectations regarding energy prices. Consequently, the additional costs incurred for the more-expensive capacity should be classified as energy-related, as would be the case under the Equivalent Peaker method.

Q: Does this complete your surrebuttal testimony?

A: Yes.

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[6] This is by design. The MISO energy market is structured as a uniform clearing price auction in order to provide a strong financial incentive to bidders to price their offers at short-run marginal cost.

[7] Instead, WPL probably would bid at short-run marginal cost and generate an energy profit whenever its short-run marginal cost was less than the market-clearing price. This energy profit would then be credited against the market price of energy purchased from the MISO energy market so that ratepayers effectively pay no more than actual fuel and variable O&M costs for generation from the Company's production plant.