BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates	))))	Docket No. 4220-UR-121

REBUTTAL TESTIMONY OF JONATHAN WALLACH
ON BEHALF OF THE CITIZENS UTILITY BOARD OF WISCONSIN
October 19, 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 the Citizens Utility Board of Wisconsin (CUB).

Q: What is the purpose of your rebuttal testimony?

A: This rebuttal testimony describes my proposal for allocating the Commission staff audit forecast of the 2016 test year electric revenue deficiency to the residential and small C&I rate classes. This proposal is based on my recommendation for allocating the audit revenue deficiency to customer classes, as described in my direct testimony. In addition, I propose specific rate designs for the residential and small C&I electric rate classes to recover my recommended allocations of the audit revenue deficiency.

Finally, this rebuttal testimony responds to direct testimony by Richard A. Baudino, on behalf of the Wisconsin Industrial Energy Group (WIEG), and by Sam Shannon, on behalf of Commission staff.

II. Revenue Allocation and Rate Design

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 revenue deficiency for the 2016 test year of about $10.4 million, or 1.48% 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 five cost of service studies that NSPW 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. Table 1 also shows the allocation results from my modification to the Method 5 COSS, as described in my direct testimony.

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

`	Method 1 COSS	Method 2 COSS	Method 3 COSS	Method 4 COSS	Method 5 COSS	Method 5 COSS with NCP Allocator
Residential	1.25%	1.09%	2.25%	-0.73%	-7.12%	-3.59%
Small C&I[1]	1.46%	-0.56%	0.56%	-2.08%	-3.94%	-2.75%
Medium C&I	0.17%	0.20%	0.15%	0.87%	3.00%	3.07%
Large C&I	2.29%	2.84%	1.79%	4.16%	9.74%	6.24%
Lighting	-3.37%	-7.68%	-13.15%	3.95%	-21.09%	-10.96%
Total System	1.48%	1.48%	1.48%	1.48%	1.48%	1.48%

I provide my proposed allocation of the 2016 test year revenue deficiency for each customer class in Table 2 and for each residential and small C&I rate class in Ex.-CUB-Wallach-6. I developed my recommendation based on the directional results from the five audit studies and my modification of the Method 5 COSS, 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.

[1] For cost-allocation purposes, the Company includes rate schedules Mp-1, Mz-3, and interdepartmental sales in the Small C&I customer class.

Table 2: Recommended Allocation of 2016 Test Year Revenues

	Current Revenue	Proposed Revenue	Revenue Increase	Percent Increase
Residential	250,347,773	252,218,167	1,870,394	0.75%
Small C&I[2]	45,851,056	45,855,115	4,059	0.01%
Medium C&I	110,294,593	111,121,803	827,209	0.75%
Large C&I	288,420,595	296,122,180	7,701,586	2.67%
Lighting & Misc.	7,780,641	7,780,641	-	0.00%
Total System	702,694,658	713,097,906	10,403,248	1.48%

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-7. These rates reflect my recommended revenue allocation, as shown in Ex.-CUB-Wallach-6. In addition, these rates reflect my recommendation in direct testimony to maintain residential and small C&I fixed charges at current levels.[3]

III. Response to Mr. Baudino

Q: What does WIEG witness Mr. Baudino propose with regard to the classification and allocation of production capacity costs?

[2] Includes interdepartmental sales revenues.

[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.

A: Mr. Baudino proposes that all production capacity costs be classified as demand-related, and that all such demand-related costs be allocated using a 4CP allocator.

Q: What is the basis for Mr. Baudino's proposal that all production capacity costs be classified as demand-related?

A: Mr. Baudino offers three arguments in support of his proposal to classify all production capacity costs as demand-related. First, Mr. Baudino argues that only peak loads, and not system energy requirements, drive investments in production plant. Second, Mr. Baudino asserts that classifying fixed production costs as energy-related would result in off-peak prices that exceed marginal off-peak energy costs and therefore provide economically inefficient price signals.[4] Finally, Mr. Baudino argues that all production capacity costs should be classified as demand-related, because such costs, once incurred, do not vary with energy usage.

Q: Are production capacity costs incurred solely for the purposes of meeting peak demand, as Mr. Baudino contends?

A: No. 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

[4] Mr. Baudino also argues that energy classification of production capacity costs would penalize customers with high load factors, because these customers would incur higher costs than would be the case with demand classification if they were to shift usage to off-peak periods. However, this argument appears to be the same as his second argument that energy classification would drive off-peak prices above marginal energy costs.

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.

From a cost-causation perspective, the fixed costs incurred for baseload or intermediate capacity over and above those incurred for peaking capacity, i.e., capitalized energy costs, are appropriately classified as energy-related because these additional fixed costs are incurred to meet energy requirements at lowest total cost.

Q: Do you agree that classifying fixed production costs as energy-related would result in economically inefficient price signals?

A: I do not. The process of classifying and allocating costs has little bearing on whether demand or energy rates provide efficient price signals.

Mr. Baudino's concern is one of rate design, not cost allocation. The cost-allocation process is primarily concerned with the assignment of system costs to customer classes based on cost causation. Once those costs have been allocated to customer classes, the rate-design process attempts to create rate structures that recover those allocated costs while promoting efficient outcomes. In other words, it is the rate-design process, not the cost-allocation process, that determines whether rates provide efficient price signals and promote economic improvements to load factor or reductions in peak demand.

Q: Should cost classification depend on whether production capacity costs vary with energy usage once such costs are ratebased, as Mr. Baudino contends?

A: No. From a cost-causation perspective, the relevant consideration for classifying production capacity costs is not the extent to which such costs vary with energy usage once those costs have been placed in ratebase, but the extent to which the Company's investments in production capacity were driven by increases in planning-reserve or energy requirements. From this perspective, it would be unreasonable to classify all production capacity costs as demand-related, since investments in baseload and cycling plant were driven by the need to meet both reliability and energy requirements.

Q: Why does Mr. Baudino recommend allocating demand-related production capacity costs using a 4CP allocator?

A: Mr. Baudino argues that using a 4CP allocator is justified by the fact that the average peak demand over the four summer months is 29% higher than the average peak demand over the winter months. In addition, Mr. Baudino argues that a 4CP allocator is appropriate because there is excess capacity on the Company's system during the non-summer months which allows the Company to schedule planned maintenance. Mr. Baudino's argument appears to be that the 4CP allocator is justified because reliability requirements, and thus demand-related production capacity costs, are driven solely by peak demands in the four summer months.

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

A: No. Peak demands during non-summer months also contribute to annual loss of load expectation (LOLE) and thus system reserve requirements. Consequently, peak demands in non-summer months also contribute to the need for investments in demand-related production capacity.

Mr. Baudino mistakes cause for effect with regard to the availability of excess capacity to offset capacity reductions from planned maintenance in non-summer months. 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 allow for planned maintenance in non-summer months, as Mr. Baudino contends. Instead, it's 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.

Furthermore, excess winter capacity on the NSPW system has reliability value, because of the impact of the Company's system diversity agreements with Manitoba Hydro. These agreements require Manitoba Hydro to make capacity available to the Company during the summer months and the Company to do the same for Manitoba Hydro during the winter. Consequently, in exchange for providing excess winter capacity to Manitoba Hydro, the Company receives capacity in the summer months which can be used to meet its summer reserve requirements. Thus, because of the diversity exchanges, excess winter capacity provides reliability value to the NSPW system in the form of exchanged reserve capacity imports in the summer months.

Q: What do you conclude from your review of Mr. Baudino's proposal for classifying and allocating production capacity costs?

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

Moreover, demand-related production capacity costs incurred to meet reserve requirements are driven by demand in both summer and non-summer months. The 12CP allocator is therefore a more-reasonable measure of each class's contribution to the need for new reserve capacity than the 4CP allocator.

IV. Response to Mr. Shannon

Q: How do you respond to Commission staff witness Mr. Shannon's direct testimony?

A: I have two comments regarding Mr. Shannon's direct testimony. First, I want to correct Mr. Shannon's statement that Northern States Power Minnesota (NSPM) proposed increasing the customer charge to $11 per month in its last rate case.[5] In fact, NSPM proposed increasing the residential customer charge from $8 per month to $9.25 per month.[6]

Second, I want to note that CUB generally supports efforts to improve the efficacy and increase customer acceptance of Time of Use (TOU) rates. However, CUB has a number of concerns regarding Mr. Shannon's specific suggestion in this case that the Commission make the optional Rg-2 and Cg-1 TOU rates the default rate for all residential and small C&I new construction. In particular, CUB is concerned about potential adverse impacts on low-income or other vulnerable residents in new multi-family buildings who may not be able to modify usage patterns in order to avoid high on-peak prices. If relatively few customers have chosen to opt-in to the current voluntary TOU rate, the solution

[5] Direct-PSC-Shannon-6r.

[6] This was the proposed increase for the largest subclass of residential customers. On average across the entire residential class, NSPM proposed an increase from $8.72 per month to $9.97 per month. See Ex.-CUB-Wallach-3, p. 15, Table 8.

should not be to require customers to opt out of a default TOU rate. Instead, the Commission should direct NSPW to identify where and how the current rate structure creates barriers to customer participation and to evaluate design modifications to make the TOU rate more attractive to residential customers.

Q: Does this complete your rebuttal testimony?

A: Yes.