BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric	)	
Company for Authority to Change	)	Docket No. 3270-UR-118
Electric and Natural Gas Rates	)	

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

September 10, 2012

I. Introduction and Summary

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 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 addresses the following issues raised in direct testimony filed in this proceeding:

- Adjustments to the Company's production cost allocators with respect to the treatment of interruptible load, as proposed by Commission staff member Corey S. Singletary.
- Allocation of demand-related production plant costs on the basis of each customer class's contribution to system peak (1CP), as proposed by Kenneth Lyons on behalf of Airgas Merchant Gases (Airgas).
- Redesign of the UW Sp-3 rate, as proposed by Robert R. Stephens on behalf of the University of Wisconsin (UW).

Q: Please summarize your findings and conclusions.

A: Commission staff's primary proposal to allocate demand-related production costs to Cp-1 interruptible load and to explicitly credit Airgas for the value of that interruptible load is reasonable. However, Commission staff's secondary proposal to not allocate certain demand-related production costs to Cg-2, -4, and -6 interruptible load would inappropriately double-credit those classes for the value of their interruptible load. Commission staff's "Location" COSS, as modified to eliminate the inappropriate treatment of Cg interruptible load, would therefore be a reasonable basis for establishing residential rates. Considering that the Location COSS likely over-allocates demand-related production costs to the residential class, the results of that study would appear to support a residential rate increase of no more than 3.9%.

Airgas lacks a reasonable basis for its proposal to allocate demand-related production plant costs using a 1CP allocator. Airgas is incorrect when it asserts that investments in reserve capacity are driven solely by coincident peak load. In fact, peak demands in other months are likely to contribute to annual loss of load probability and thus the need for additional reserve capacity. The Company should therefore continue to allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the twelve monthly peaks (12CP).

The University of Wisconsin's proposed redesign of the Sp-3 rate appears to be a rehash of its proposal in Docket No. 3270-UR-117. As with the prior proposal, the University's proposal for nominating and pricing standby demand would allow UW to lean on the Company's system for standby capacity without paying the full cost for that capacity. It would not be reasonable for other ratepayers to have to compensate MGE for the revenue losses associated with the University paying less than the full cost of standby capacity. Given these recurring problems, MGE and UW should continue to pursue a negotiated resolution of this issue. Until then, the current Sp-3 rate design should not be modified.

II. Staff Adjustments to Production Plant Cost Allocators

Q: Please describe the 2013 test year rate increase and residential revenue allocation proposed by Commission staff.

A: Commission staff proposes that electric rates be increased on average by 3.4% in order to recover an expected revenue deficiency of $13.1 million in the 2013 test year. Of the total $13.1 million proposed revenue increase, Commission staff proposes to allocate $5.3 million to residential customers.[1] This amount represents a 4.2% increase over residential revenues under current rates.

Q: What is the basis for the proposed residential rate increase?

A: According to Mr. Singletary, the proposed residential rate increase was derived based on modified versions of the Company's three cost of service studies

[1] Ex.-PSC-Singletary-1, Schedule No. 2, p. 1 (PSC REF #:170858).

("Standard" COSS, "Time-of-Day" COSS, and "Location" COSS). Specifically, Commission staff ran these three studies using staff's forecast of sales and revenue requirements for the 2013 test year and with modified demand allocators for: (1) production plant costs; (2) production O&M and labor costs for other power generation; and (3) purchased power capacity costs.[2]

Q: Why does Commission staff recommend modifications to these three demand allocators?

A: According to Mr. Singletary, Commission staff is recommending these modifications in order to address an inconsistency in the valuation of interruptible load for different rate classes. For the Cg-2, -4, and -6 rate classes, the value of interruptible load is determined explicitly through the provision of Interruptible Service (IS) rider credits for such interruptible load. In contrast, the value of Cp-1 interruptible load is determined implicitly through application of the Company's production cost allocators. Specifically, the Company's allocators do not allocate any demand-related costs to Cp-1 interruptible load.[3] As a result, Cp-1 interruptible load is implicitly valued at the amount of demand-related production costs that would have been allocated to an equivalent level of firm load.

In order to rectify this inconsistency, Commission staff recommends the following modifications:

[2] Commission staff also modified the allocators applied to Account 507 (Rents) costs in the Time-of-Day and Location studies to correct for the fact that these production plant-related costs were not being allocated consistently with the allocation of production plant costs.

[3] In contrast, the Company does allocate *energy-related* production costs to Cp-1 interruptible load.

- Allocate demand-related production plant costs to the Cp-1 class on the basis of the class's 12CP interruptible load.
- Impute a credit of $4/kW-month to the Cp-1 class for the Cp-1 interruptible load.
- Exclude Cg-2, -4, and -6 interruptible load from the determination of the demand allocators for production O&M and labor costs for other power generation and for purchased power capacity costs.[4]
- Allocate all interruptible credit costs, whether explicit IS rider costs or imputed Cp-1 credit costs, on the basis of 12CP load net of interruptible load.

Q: Is Commission staff's proposal reasonable?

A: Commission staff's primary proposal to explicitly determine the value of Cp-1 interruptible load is reasonable. As with the IS rider credits, it would be appropriate and consistent with good regulatory practice to explicitly determine the value of the planning reserves avoided by Cp-1 interruptible load, and to subject that determination to regulatory review. Accordingly, for the purposes of allocating the revenue deficiency in this proceeding, it would be reasonable to allocate demand-related production costs to the Cp-1 class and to impute an explicit credit for Cp-1 interruptible load.

However, it would not be appropriate to exclude Cg-2, -4, and -6 interruptible load from the determination of the demand allocator for production O&M and labor costs for other power generation or the demand allocator for purchased power capacity costs. Commission staff's proposal in this regard would inappropriately double-credit the Cg-2, -4, and -6 classes for the value of

[4] In other words, such demand-related costs would be allocated to the Cg-2, -4, and -6 classes solely on the basis of their firm loads, rather than on firm plus interruptible loads.

their interruptible load, implicitly by not allocating these demand-related costs to interruptible load and then explicitly through IS rider credits which reflect the value of avoiding such demand-related costs.

It would also not be appropriate to allocate imputed Cp-1 credit costs to other customer classes on the basis of each class's 12CP load net of interruptible load (rather than on gross 12CP). Commission staff's proposal would inappropriately double-credit the Cg-2, -4, and -6 rate classes for the value of their interruptible load, directly through the provision of IS rider credits attributable to those classes' interruptible load and then indirectly by not allocating any of the costs of imputed Cp-1 credits to those classes' interruptible load.

Q: Would it be reasonable to set residential rates on the basis of the Commission staff cost of service studies?

A: Commission staff's Location COSS, as modified to eliminate the double-crediting of Cg interruptible load, would be a reasonable basis for establishing residential rates. As I discussed in my direct testimony, of the three studies, the Location COSS allocates costs in a fashion that most reasonably reflects each class's responsibility for such costs. In contrast, the Standard COSS appears to allocate more production and distribution plant costs to the residential class than is appropriate, while the Time-of-Day COSS appears to overstate the appropriate residential allocation of distribution plant costs.

Relying on the COSS spreadsheet model provided in Commission staff's response to Interrogatory No. 01-Airgas-01, I have modified the Location COSS to eliminate the Commission staff adjustments that give rise to the double-crediting of Cg interruptible load. This modified Location COSS allocates $6.4 million of the total $13.1 million revenue deficiency to the General Services classes. This amount represents a 4.1% increase over General Services revenues under current rates.

Q: Do you have any concerns about the Location COSS?

A: As I discussed in my direct testimony, I am concerned that the generic 60%/40% demand/energy split used to classify production plant costs may overstate the actual proportion of demand to energy-related investments in the Company's production plant. If so, the Location COSS over-allocates production plant costs to the General Services classes.

For example, in Docket No. 05-UR-106, I derived a 43%/57% demand/energy split for Wisconsin Electric Power Company's production plant costs.[5] And in Docket No. 4220-UR-117, I derived a 30%/70% demand/energy split for Northern States Power Company's production plant costs.[6] Using a 40%/60% demand/energy split for MGE would reduce the General Services rate increase from 4.1% to 3.8%.

Q: What do you conclude from these results?

A: Considering that the Location COSS likely over-allocates demand-related production costs to the residential class, the results of the corrected Commission staff's Location study would appear to support a residential rate increase of no more than 3.9%.

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[5] Docket No. 05-UR-106, Direct-CUB-Wallach-7, ll. 13-15 (PSC REF#: 171702).

[6] Docket No. 4220-UR-117, Direct Testimony of Jonathan Wallach, p. D2.33, ll. 12-13 (PSC REF#: 154438).

III. The 1CP Demand Allocator

Q: What does Mr. Lyons recommend with regard to the allocation of demand-related production plant costs?

A: Mr. Lyons recommends that demand-related production plant costs be allocated using a 1CP allocator, rather than the 12CP allocator that MGE has traditionally used.

Q: Why does Mr. Lyons argue for using the 1CP allocator?

A: Mr. Lyons appears to believe that the Company's investments in reserve capacity are driven solely by system coincident peak, and therefore that such investments should be allocated on the basis of each customer class's contribution to that single peak. According to Mr. Lyons:

> MGE must have generation to meet customer use at the period of greatest need (the system peak) and … that need currently is for a very short period of time. MGE plans for this peak and knows that it will peak for a brief period of time. We cannot believe that MGE looks to a non-peak month like March to determine whether it needs to build additional capacity, when its peak in June (652 mWs) is already more than 200 mWs greater than its peak in March (418 mWs).[7]

> What we know is that MGE has acquired sufficient capacity to meet the system peak. But by allocating the cost of that capacity to its customer classes using the 12CP methodology, MGE['s] allocation is not reasonable because it does not assign appropriate costs to those customers who are driving the need for that generation that is needed for only a few hours every year.[8]

Q: Are investments in reserve capacity driven solely by coincident peak demand, as alleged by Mr. Lyons?

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[7] Direct-Airgas-Lyons-8, ll. 15-21 (PSC REF#: 170887).

[8] Direct-Airgas-Lyons-10, ll. 18-22.

A: No. Although planning reserve requirements are typically stated in terms of a margin over system coincident peak, such requirements are determined by the margin of available capacity over demand throughout the year. Specifically, utilities typically plan to maintain sufficient capacity in reserve so that the annual loss of load probability (LOLP) does not exceed one day in ten years. Peak demands throughout the year may contribute to annual LOLP and thus system reserve requirements. For example, the scheduling of plant maintenance during low-demand shoulder months may reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLP and reserve requirements. If so, peak demands in these shoulder months would also contribute to the need for investments in reserve capacity.

Q: Does the fact that MGE dispatches reserve capacity infrequently indicate that the need for such capacity is driven solely by system peak?

A: No. We would expect such capacity to be dispatched infrequently, if at all, since it is by definition excess capacity, i.e., capacity in excess of expected coincident peak demand. Its purpose is not to serve expected demand, but to be held in reserve in the event that demand is higher than expected or available capacity is less than expected.

Q: Should the Commission adopt Airgas' proposal to rely on the 1CP allocator for allocating demand-related production plant costs?

A: No. Airgas lacks a reasonable basis for its proposal to allocate demand-related production plant costs using a 1CP allocator. The Company should therefore continue to allocate demand-related production plant costs on the basis of each customer class's contribution to the average of the twelve monthly peaks.

IV. Sp-3 Rate Design

Q: Please describe the University of Wisconsin's proposal for reformulating Rate Schedule Sp-3.

A: According to Mr. Stephens, the University proposes to restructure the current generation credit applied to Charter Street Heating Plant (CSHP) generation into a charge for standby service to back up CSHP capacity.

Under the current tariff, the Company assesses the Sp-3 demand charge for electricity service on a gross demand (i.e., metered demand plus CSHP generation) basis. The Company then applies a generation credit based on nominated CSHP generation.

Under the tariff proposed by the University, the Company would instead assess the Sp-3 demand charge for electricity service on a net demand basis (i.e., metered load) and, in addition, assess a standby charge based on CSHP generation.

Q: Has the University proposed this reformulation in prior rate cases?

A: Yes. The University offered a similar redesign in Docket No. 3270-UR-117.

Q: Would the University's proposal fully compensate MGE for the cost of standby capacity required to back up CSHP generation?

A: No. The University proposes to pay standby demand charges not for the full amount of capacity that must stand ready to back up CSHP, but only for the amount of standby capacity that is actually required in each hour to cover the shortfall in hourly output from CSHP. In essence, the University apparently proposes to pay for capacity-reservation service as if it were replacement-energy service, paying only for that portion of the capacity standing in reserve to back up CSHP that it actually relies on to firm up CSHP generation.

Q: How might residential ratepayers be affected by the University's proposal for standby service?

A: The Company would incur a revenue shortfall to the extent that the University avoids paying the full cost of standby capacity. Residential ratepayers would be adversely affected to the extent that they are required to compensate MGE for these revenue losses.

Q: What do you recommend with regard to the University's proposed redesign of the Sp-3 rate structure?

A: Given the potential adverse impact on other customer classes, the Commission should reject the University's proposal at this time. Instead, the Commission should direct MGE and UW to continue discussions on this issue and to provide regular reports to the Commission regarding the course of those discussions.

Q: Does this conclude your rebuttal testimony?

A: Yes.