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

Application of Madison Gas and Electric for Approval of Proposed Changes to its Parallel Generation Tariffs	3270-TE-114

SURREBUTTAL TESTIMONY OF DIVITA BHANDARI ON BEHALF OF RENEW WISCONSIN

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Divita Bhandari, and I am a Senior Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. Are you the same Divita Bhandari that provided direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to the rebuttal testimony offered by witness Mr. Smith from Madison Gas and Electric (MGE) on the subject of avoided transmission costs.

II. AVOIDED TRANSMISSION COSTS

Q. Does Mr. Smith acknowledge that Customer Owned Generation Systems (COGS) have the ability to avoid transmission investments?

A. Yes. Mr. Smith identifies two transmission planning processes through which an increase in the level of COGS could help avoid transmission investments. The first is through the Midcontinent Independent System Operator's (MISO) Transmission Expansion Plan (MTEP) process. The second is through American Transmission Company's (ATC) annual "10-Year Transmission System Assessment" planning process, which is done outside of MISO's regional planning process and performed to ensure reliability, to upgrade assets for age and performance degradation, and for new generation interconnections.

In response to the question "Do you believe that transmission costs could be avoided by the addition of COGS in the MTEP process," Mr. Smith states: "Yes. I believe, over time, there is potential to avoid new transmission projects if a large enough volume of COGS is added to the system." (Rebuttal-MGE-Smith-5). Similarly, in response to the question "Could an increase in the level of COGS reduce the need for new transmission as determined through the ATC 10-year Transmission System Assessment," Mr. Smith states: "Yes, it could." (Rebuttal-MGE-Smith-6).

However, Mr. Smith qualifies both answers.

Q. How does Mr. Smith qualify the ability of COGS to reduce transmission investment through the MTEP process?

A. Mr. Smith suggests that near-term incremental additions of new COGS "will not change the current MISO [Long Range Transmission Planning] process, which will provide the basis for new transmission build-out taking place over the next decade or more. Therefore, the impact of new COGS will not be felt until the next MISO planning cycle after the current LRTP process is completed." (Rebuttal-MGE-Smith-5-6). Mr. Smith also appears to suggest that while a certain level of current and future distributed generation is already assumed in the MISO transmission planning process, "unexpected" changes in the cumulative level of new COGS may change the power flow across the MISO transmission system over time, "but the potential cost impact of this change cannot be determined without a transmission planning study comparing transmission costs with and without the unexpected change in the level of COGS." (Rebuttal-MGE-Smith-5).

Q. How do you respond to those assertions?

A. I have two reactions to that assertion.

First, as Mr. Smith himself acknowledges, the impact of new COGS would be felt within MISO's next planning cycle. That planning cycle will more than likely occur within the lifetime of COGS added to MGE's system today.

Second, and more importantly, as Mr. Smith's testimony acknowledges, MISO's *current* planning models incorporate the impacts of existing and anticipated COGS and other distributed generation. (Rebuttal-MGE-Smith-4). Those distributed generation systems would have lowered the load forecast on which MISO's *current* transmission plan was based, thereby impacting the transmission investments required by that plan (avoiding, or deferring transmission investments that would have otherwise been required). By ignoring this, and focusing on future "unexpected" additions, Mr. Smith indicates a key flaw in the way that MGE is thinking about avoided transmission payments to distributed generation.

Q. Please elaborate.

A. Mr. Smith's testimony simultaneously: (1) acknowledges that distributed generation avoids transmission investments that would otherwise be identified through MTEP, and (2) asserts that distributed generation would somehow only start having that impact on transmission cost in the next MISO planning cycle. But Mr. Smith ignores that nothing about the way in which distributed generation works—and avoids transmission cost—changes with this case. Distributed generation has the potential to avoid transmission cost particularly when exporting electricity to the grid during peak hours and thereby reducing the load forecasts based on which transmission investments are planned—RENEW Wisconsin (RENEW) and the Company appear to agree about this fundamental relationship.

Distributed generation installed in MGE's service territory prior to this proceeding likely exported electricity to the grid during peak hours, and by doing so, reduced load forecasts on which MISO relied to plan transmission investments. Distributed generation being installed in MGE's service territory during this proceeding are likely exporting electricity to the grid during peak hours, and by doing so, are reducing load forecasts on which MISO will rely to plan transmission investments. Distributed generation that is installed in MGE's service territory after this proceeding will export electricity to the grid during peak hours, and by doing so, will reduce load forecasts on which MISO will rely to plan transmission investments. Again, nothing about *the way in which* distributed generation avoids transmission investments is changing. The only thing that is changing is that now the Commission has asked Wisconsin utilities to update their avoided cost rates to reflect avoided costs — to fairly compensate distributed generation for the costs they have been avoiding and will avoid in the future.

Q. How does Mr. Smith qualify the ability of COGS to avoid transmission investment through the ATC system assesssment process?

A. Mr. Smith states: "ATC uses a variety of criteria to determine how generation is modeled including the size of the generator, the interconnection voltage, and how it has been historically traditionally modeled. How a new COGS is modeled by ATC will impact how the addition will affect future transmission planning." Mr. Smith also states that: "ATC will use load forecasts provided by ATC's end-use load-serving customers, such as MGE, as input into future reliability model-building efforts. . . these load forecasts may be adjusted by ATC if adjustments are needed for transmission planning purposes either with concurrence from the Company's customers or independent of the Company's customers. Therefore, it cannot be assumed that new COGS on the MGE system will always be treated as an offset in the ATC planning process. The impact to the ATC transmission system due to the addition of new COGS needs to be determined by ATC following their reliability planning and modeling criteria in order to provide meaningful results. MGE cannot perform such an analysis independently to determine the avoided transmission value." (Rebuttal-MGE-Smith-6-7). Mr. Smith further states that: "MGE is willing to continue working with ATC to provide input for its planning process to help quantify an incremental or decremental cost due to new COGS. MGE has had discussions with ATC regarding the development of an avoided transmission value for COGS; this effort is ongoing and is not insignificant. MGE is not able to estimate avoided transmission costs independently since this analysis would need to be performed by ATC as the transmission system owner and operator to provide meaningful results." (Rebuttal-MGE-Smith-7).

Q. How do you respond?

A. I have two responses.

First, Mr. Smith states that "ATC updates their transmission planning and reliability models with the most current information as it becomes available." (Rebuttal-MGE-Smith-6). This suggests that the ATC assessments rely on up-to-date load forecasts that reflect distributed resources generation when making decisions about prioritization and deferral of projects.

Second, Mr. Smith's testimony appears to suggest that even though distributed generation systems connected to MGE's system might avoid transmission cost (that would otherwise by paid by all MGE ratepayers) through the ATC system assessment process, and even though the Commission has directed MGE to analyze that avoided transmission cost, MGE will defer the primary responsibility of modeling avoided transmission cost to ATC because of certain uncertainties regarding the manner in which ATC accounts for COGS. I find this position to be deeply concerning.

Q. Please elaborate.

A. To be clear, I do not think it is unreasonable for MGE (or any of the utilities for which ATC provides transmission services) to work with ATC to better understand how COGS are incorporated into ATC's system assessment process. I applaud MGE for apparently starting discussions with ATC on this subject. I am, however, concerned that MGE has provided no detail on the status of its efforts to analyze avoided transmission costs in collaboration with ATC, no explanation of why it did not complete its avoided transmission cost analysis prior to filing its application in this proceeding (or prior to filing its rebuttal testimony in this proceeding), no estimate on when that analysis will be complete, no proposal for how and when it will update its avoided transmission payment to reflect the results of that analysis, and no explanation of why it did not complete a preliminary analysis of avoided transmission costs with reasonable assumptions pending the completion of its more detailed avoided cost analysis in collaboration with ATC. Further, I am concerned that MGE simultaneously (correctly) acknowledges that distributed generation avoids transmission investments while also proposing a $0.00 avoided transmission payment to distributed generation customers, without so much as acknowledging the resulting adverse impacts on its customers. As Mr. Kell has explained, continuing to offer a purchase rate below avoided costs will not only perpetuate a subsidy from MGE's distributed generation customers to its non-distributed generation customers, it will also result in the sub-optimal *future* development of distributed generation, to the detriment of *all* MGE customers.

Q. Mr. Smith states that major transmission additions made by MISO and ATC have not been driven by load growth but by the expansion of intermittent renewable generation and the retirement of existing fossil fuel resources. (Rebuttal-MGE-Smith-8). As a result, Mr. Smith states that he "would expect incremental changes in load growth to have little or no impact on the need for new transmission". (Rebuttal-MGE-Smith-8). How do you respond?

A. There is no question that transmission investments are driven by a variety of factors. Certain transmission investments are driven by the expansion of intermittent renewable generation, other transmission investments are driven by the retirement of existing fossil fuel resources, and other transmission investments are driven by load growth. I do not dispute this. But my analysis of MGE's transmission investments accounts for this. As I have indicated in my direct testimony, I have isolated load growth-related investments that were identified in MTEP since distributed energy resources avoid load growth-related investments by reducing peak load. As I explained in my direct testimony, there is a direct and well-understood relationship between peak load reductions and reductions in load growth-related transmission investments. This relationship is not theoretical—it has been observed and documented by transmission system operators.

For instance, CAISO has canceled several planned transmission projects as a result of distributed generation. CAISO observed that:

> "As part of its annual transmission planning process conducted in 2017-2018, the ISO identified opportunities to address reliability needs and reduce new transmission infrastructure. The ISO recommended canceling 20 projects, and reducing the scope on another 21 projects, saving more than $2.6 billion. Another six projects were eliminated in the 2018-2019 planning cycle, saving $440-$550 million in costs. The reductions were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation." (Ex.-RENEW-Bhandari-14).

Q. Mr. Smith continues to propose an avoided transmission payment of $0.00/kWh (Rebuttal-MGE-Smith-7) "until such time as a methodology can be developed by working with ATC to determine avoided transmission cost." Is that reasonable?

A. No. Again, I Am concerned that despite having acknowledged that new COGS have the potential to reduce transmission investments, Mr. Smith advocates for a zero dollar avoided transmission payment, simply because MGE has not yet developed a methodology to calculate avoided transmission costs with precision. It is important to keep in mind that any methodology for estimating avoided costs—whether avoided energy, capacity, transmission, environmental, distribution, or any number of other avoided costs—involves uncertainty. I believe that utilities and regulators should generally strive for increasing accuracy and precision (while balancing those objectives with other important objectives), but reasonable assumptions and estimates are required in any avoided cost modeling exercise. I have submitted rigorous analysis including conservative assumptions showing that a $70.82/kW-year payment reasonably represents the

Company's avoided transmission costs. Neither MGE nor any other party has submitted any quantitative analysis regarding the Company's avoided transmission costs and therefore I believe based on the record evidence the Commission should adopt my proposed avoided transmission payment. However even if the Commission were to reject my avoided transmission payment calculations and agree that MGE should continue to work with ATC to determine its avoided transmission costs with more precision, I do not believe that a $0 avoided transmission payment strikes a reasonable compromise until such time as MGE develops a more accurate methodology for estimating avoided transmission costs. $0 would only be an appropriate placeholder if the Commission were seeking to strike a balance between a negative avoided transmission payment and a positive avoided transmission payment—which is not the case here.

Q. How would you suggest the Commission resolve Mr. Smith's concerns that MGE cannot perform an analysis of avoided transmission costs independently since this would need to be performed by ATC (Rebuttal-MGE-Smith-7)?

A. First, it is important that the Commission adopt an avoided transmission payment to distributed generation customers in this proceeding, to avoid perpetuating the below avoided cost rates that MGE has made available to its customers to date. As I have stated, the Commission should adopt the avoided transmission payment that I propose based on my analysis of the Company's avoided transmission costs. In the alternative, I believe Mr. Singletary's recommendation, which is a credit based on the utility's total transmission expense, applied via either an on-peak energy credit or as a per-kW-day credit, is reasonable. (Direct-CUB-Singletary-8). The Commission might adopt a transmission credit set at 50% of MGE's embedded transmission expense, similar to the avoided transmission credit that Northern States Power Company – Wisconsin (NSPW) proposed and the Commission adopted in NSPW's parallel generation case, Docket 4220-TE-109. (Ex.-RENEW-Kell-12). NSPW proposed an avoided transmission value based on 50 percent of its embedded transmission cost to "represent that long term avoided transmission costs may exist but that they are difficult to value precisely." (Ex.-RENEW-Bhandari-15). In addition, NSPW assumed that a range of reasonable values is 0 to 100 percent of embedded cost and that a 50 percent embedded transmission cost would represent a reasonable compromise within that range. (Ex.-RENEW-Bhandari-16).

Q. NSPW builds and operates the transmission system serving that utility's customers in coordination with its affiliate, whereas MGE is served by a transmission system owned by ATC, which also serves other Wisconsin utilities. Does this difference merit the Commission taking a different approach to the avoided transmission payment in each case?

A. No. As I have explained, in both cases, the avoided transmission payment should be based on an analysis of the transmission owner's marginal transmission costs. The identity of the transmission owner and its relationship to the load-serving entities (i.e., the Wisconsin utilities) does not matter for the purposes of the math—in both cases, the load-serving entities must identify the avoidable transmission investments planned by the transmission owner.

Similarly, the Commission can adopt an avoided transmission payment based on each utility's embedded transmission cost as an interim payment notwithstanding the identity of the transmission owner. The fact that ATC owns the transmission system serving MGE, whereas NSPW and Northern States Power – Minnesota build and operate the transmission system serving NSPW, is irrelevant to a transmission credit based on embedded cost. Both MGE and NSPW have a readily identifiable embedded transmission cost paid by their respective ratepayers.

Mr. Smith argues that Wisconsin utilities that are ATC customers experience a "zero-sum" impact of cost assignments—if MGE experiences a change in peak load due to the addition of COGS and therefore is allocated a lower ATC transmission cost, other ATC utilities will be allocated a higher proportion of total cost. (Rebuttal-MGE-Smith-9). This ignores that over the long-term, ATC's transmission costs are not fixed, they are variable. As Mr. Singletary points out, "in addition to reducing its transmission expense by reducing its allocated transmission cost, MGE can affect the trajectory of total transmission system costs by decreasing its future transmission demands at the utility level." (Direct-CUB-Singletary-7)

I would also point out that the NSP transmission system is also shared between NSPW and NSP-Minnesota (similar to the way in which ATC's transmission system is shared between several Wisconsin utilities), with costs shared between NSPW and NSP-Minnesota via an Interchange Agreement. In its testimony, NSPW argued that allocation shifts occurring between the two entities as a result of the addition of distributed generation are a “zero sum game”, similar to MGE’s argument here. (Ex.-RENEW-Bhandari-16). Despite that “zero sum game”, NSPW supported an avoided transmission payment set at 50 percent of embedded transmission costs, presumably recognizing that distributed generation has the potential to avoid total NSP system transmission costs (and thereby avoid transmission costs allocated to both NSPW and NSP-Minnesota) over the long-term.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.