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

Application of Wisconsin Public Service Corporation for Approval of Proposed Changes to its Parallel Generation Tariffs	6690-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. Nelson from Wisconsin Public Service Corporation (WPSC). My surrebuttal testimony addresses claims made by Mr. Nelson regarding avoided transmission and capacity costs and avoided losses.

II. AVOIDED TRANSMISSION COSTS

Q. How do you respond to Mr. Nelson's claims that your avoided transmission results are "speculative"(Rebuttal-WPSC-Nelson-26)?

A. Mr. Nelson has made no attempt to propose an analytical approach or a methodology that could address his concerns with specific aspects of my analysis. Instead, Mr. Nelson continues to support an unsubstantiated value of $0 for WPSC's avoided transmission cost.

Q. Please restate your fundamental concerns with WPSC's proposal to award parallel generation resources a $0 avoided transmission credit.

A. The major flaw in Mr. Nelson's proposal is the failure to address the long term rate impacts of marginal transmission investments that have been identified by American Transmission Company (ATC). As I havedescribed in my direct testimony and accompanying exhibits, ATC's planned transmission investments have been identified through the Midcontinent Independent System Operator (MISO) Transmission Expansion Planning Process (MTEP) . The costs of those identified investments will increase retail rates for WPSC customers notwithstanding the fact that these investments are owned by ATC and notwithstanding the fact that WPSC's transmission rates are Federal Energy Regulatory Commission (FERC) regulated rates—nothing in Mr. Nelson's rebuttal testimony refutes these facts. A portion of these transmission investments are "load growth-related"—in other words, increasing load drives the need for those investments. Those investments are avoidable through the installation and operation of distributed energy resources. While I agree that avoided cost calculations generally involve some degree of uncertainty, the fact that ATC has included load growth related investments in MTEP makes clear that the value of avoiding transmission costs on WPSC's system is not zero.

Q. What is Mr. Nelson's basis for asserting that your results are speculative and how would you like to address these concerns?

A. Mr. Nelson claims that I incorrectly assume that each distributed generation resource has the potential to help avoid transmission related costs and that I incorrectly assume that all load growth projects are avoidable. (Rebuttal-WPSC-Nelson-26-27) However, Mr. Nelson has not provided any suggestions on how to refine my methodologyto address his concerns, nor is the basis for his criticism clear.

In fact, my analysis correctly assumes that load growth-related transmission investments can be avoided through distributed generation. That is because exports from distributed generation resources (whether front-of-the-meter or behind-the-meter) can reduce peak demand, and thereby reduce the transmission investments necessary to meet that peak demand. As I explained in my direct testimony, there is a direct relationship between load reduced on the system through distributed generation and a reduction in load growth related transmission investments. This relationship is well-understood.

Q. Mr. Nelson suggests that applying an identical avoided transmission cost rate to all distributed generation resources increases the likelihood that WPSC's retail customers will pay more for transmission service than they otherwise would. (Rebuttal-WPSC-Nelson-27) How do you respond?

A. I disagree. I have proposed a system-wide avoided transmission cost that is intended to capture the average avoided costs across the system. As I have indicated in my direct testimony, I have relied on system-wide peak growth, because this information is publicly available. I agree that peak growth may not be uniform across ATC's transmission system, and that with more information, it may be possible to identify the areas of anticipated load growth and calculate location-specific avoided transmission values. But that analysis is likely to show that in particular locations, the value of avoided transmission costs is higher than the average value (because all of the load-growth-related transmission costs would be assigned to a smaller portion of overall load), and in other locations the value of avoided transmission costs would likely be lower than the average value.

However, given the data available and the purpose of my analysis (to inform avoided cost-based buyback rates for tariffed resources), calculating a system wide average value for avoided transmission costs is appropriate. A system-wide value also accommodates uncertainty regarding where future load growth may occur during the lifetime of a distributed resource, which may exceed the horizon of current transmission planning.

Given that the system-wide value captures the variation across the system, there is no risk or justification for Mr. Nelson's claim that applying an identical avoided transmission cost rate to all distributed generation resources increases the likelihood that WPSC's retail customers will pay more for transmission service than they otherwise would.

Q. Mr. Nelson has also suggested that ATC transmission assets are large and in order to avoid transmission expansion due to load growth, distributed generation resources would need to be connected in an area that has been identified as needing additional transmission due to load growth, and the generator(s) would need to deliver enough energy to the grid during the times driving the identified need for transmission investment. (Rebuttal-WPSC-Nelson-27) How do you respond?

A. Mr. Nelson's testimony suggests that distributed generation should only receive an avoided transmission value when the resource is strategically sited to avoid a *specific* transmission investment by generating during *specific* times. This approach would resemble a "non-wires alternative" procurement, and is not the appropriate way to determine (and compensate) the long-run avoided transmission costs associated with "naturally-occurring" distributed generation. Non-wires alternative procurements avoid or defer specific defined, planned transmission projects. Naturally occurring distributed generation defers or avoid transmission investments over the long-run by lowering the load forecast, which in turn avoids certain marginal transmission investments from being required or planned at all. Therefore, whereas the "avoided transmission value" of a non-wires alternative procurement is ascertained by considering the specific project that is avoided or deferred, the avoided transmission value of naturally-occurring distributed generation must be ascertained by determining the transmission owner's long-run avoidable marginal transmission investments.

Mr. Nelson is correct that over the short-run, avoided transmission value can vary based on location. However, as I have indicated above, a system-wide avoided transmission value captures variation in avoided costs across different locations and accommodates uncertainty regarding the location of future load growth occurring during the lifetime of a distributed resource, which may exceed the horizon of current transmission planning.

For example, consider a hypothetical scenario where there is an identified need for a transmission investment to address load growth in a specific location A over a short term planning horizon (e.g., five years) and similarly, an adjacent location B that has no identified load growth (thereby eliminating the immediate need for additional transmission investments) over the five year horizon. However, that situation may be reversed when looking over a longer term horizon. Over a ten year horizon, location B may experience load growth requiring a transmission investment, whereas location A may not experience load growth. However, if we were to only identify a need based on a five year planning horizon then the transmission need at location B may only be identified well after a significant amount of naturally occurring distributed resources are already in operation. These distributed energy resources will have the impact of reducing the need of the transmission investment required at location B when the need is eventually identified, but will not have been appropriately compensated for avoiding that cost. If we were to assess avoided transmission value based only on the five year planning horizon (i.e., when no need was identified at location B), without considering the longer-term (i.e., when a need is eventually identified at location B) , then naturally-occurring distributed energy resources would not receive any transmission value for avoiding a transmission investment at location B, *even if those resources ultimately avoid or defer the transmission need at location B.*

This relationship is not theoretical—the impact of distributed energy resources on load forecasts, and the consequent impact transmission investments, has been observed and acknowledged by transmission operators. The California Independent System Operator (CAISO), for instance, acknowledged 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-15).

Q. How would you suggest addressing Mr. Nelson's concerns regarding any uncertainty associated with your avoided transmission analysis?

A. Any uncertainty associated with calculating an avoided transmission value does not justify assigning $0 to that component. Given that the Company has provided no avoided transmission modeling and has not attempted to identify long run avoided costs based on transmission investments that have been made by ATC, I suggest that the Commission either adopt my proposed credit (which is based on a rigorous marginal cost analysis), or direct WPSC to provide an avoided transmission credit that is equivalent to 50% of the Company's embedded transmission costs, until such time as the Company calculates a more accurate avoided transmission credit based on its own analysis of marginal load growth-related transmission investments. This credit would align with the avoided transmission cost that Northern States Power Company-Wisconsin (NSPW) proposed and the Commission approved in Docket 4220-TE-109. 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-16) 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-17).

III. AVOIDED LOSSES

Q. How do you respond to Mr. Nelson's concerns regarding application of loss factors to primary and secondary distribution?

A. Mr. Nelson's characterization of distribution loss factors does not align with my understanding of avoided losses.

First, I would like to clarify the concept of avoided losses. There are numerous stages that occur in transmission of electricity from a generating unit (i.e., a power plant) to a customer. Energy losses occur at each of those stages. When the demand for energy is lower, losses decrease; when demand increases, losses increase.

Distributed energy resources decrease losses because they generate energy close to customer load, and therefore reduce the need to procure energy from a power plant that is connected to the transmission system, so transmission loads and losses are lower. That is, by reducing the need to procure that energy from a power plant connected to the transmission system, there is an associated reduction in losses that also occurs due to reduced energy flows on the grid.

I agree with the statement made in Mr. Nelson's testimony that there are higher distribution losses for secondary customers than for primary customers. Both primary and secondary losses are a result of the energy flow at any given time, so lower loads reduce these losses. The loss factors applied to secondary customers should account for a higher loss factor than a primary customer to account for the higher avoided losses. This theory aligns with loss factor data provided by NSPW (Ex.-RENEW-Bhandari-18)

However, Mr. Nelson goes on to assert that the reverse is true for losses incurred as electrical energy flows in the other direction, when it is generated by a distributed generation resource (Rebuttal-WPSC-Nelson-8). Mr. Nelson reasons that distribution losses applied to excess generation for secondary customers should therefore be lower than the distribution losses applied to excess energy for primary customers and that this is commensurate with the amount of energy that WPSC would avoid purchasing (Rebuttal-PSC-Nelson-9).

Although Mr. Nelson's testimony on this point is unclear, I believe that Mr. Nelson is suggesting that if excess energy is exported on the secondary network then there will be additional losses incurred since the energy must pass through a service drop and transformer in order to serve primary customers and therefore the excess generation should be discounted to account for this. Assuming that is correct, Mr. Nelson is describing a very specific and narrow circumstance that cannot be generalized across the Company's system (unlike the avoidance of marginal losses *by* distributed generation, which can be generalized). To the extent that any losses occur when energy is exported by a distributed generation resource, the magnitdue of those losses will depend on whether the resource is connected to the secondary network and whether there are coincident loads on the low-side of the same transformer. This in turn relies on the secondary configuration in the area where the distributed energy reources are connected and the diversity of load on the feeder to which the resources is connected. Any narrow circumstance in which the energy exported by a distributed generation resource creates losses has no bearing on the appropriateness of the application of marginal versus average loss factors. I maintain that the Company should apply marginal and not average loss factors to its avoided energy, capacity and transmission values.

Q. Please elaborate.

A. All avoided costs should be based on the concept of avoiding marginal costs. For energy, this is captured through the marginal energy prices. The marginal energy price is the price that is paid for the last increment of energy that is purchased. The last increment of energy that is purchased will always be at the same or a higher price than the increment of energy preceding it. In simpler terms, the higher the load of the system, the higher the incremental cost of energy since the incremental unit of energy will be served by a more expensive generating unit. This same argument holds true for losses. The higher the load on the system the higher the associated losses. This is because losses increase quadratically as power lines become more heavily loaded during peak hours. Therefore, during these peak hours avoiding an incremental amount of energy has a higher impact on avoided losses than the losses associated with the increment of energy preceding it. Therefore, at any point in time, the price paid for the last increment of energy includes the cost of paying for higher losses due to the higher load. The average losses on the other hand are the losses that are averaged across the system for all hours and do not account for the magnitude of loading on the system. Avoided costs should be based on marginal concepts (i.e, costs that are avoided when serving an incremental unit of demand). Based on this, marginal losses should be applied to avoided transmission and capacity cost calculations.

IV. AVOIDED CAPACITY COSTS

Q. How do you respond to Mr. Nelson's defense of WPSC's capacity accreditation methodology ?

A. I disagree with Mr. Nelson. The capacity accreditation of distributed generation resources should be aligned with MISO's accreditation process. Mr. Nelson has not provided any evidence of how the proposed monthly credit methodology aligns with the MISO's proposed seasonal resource adequacy construct. Although MISO has proposed a seasonal resource adequacy construct and seasonal capacity accreditation, approving WPSC's methodology prior to approval of MISO's seasonal resource adequacy construct may risk the possibility of misalignment with the MISO's most current approved resource adequacy construct. There is no rationale for deviating from MISO's resource accreditation methodology.

Mr. Nelson suggests that "Following MISO's current accreditation methodology would overvalue some capacity resources, require intervention and determinations to be made on an annual basis for each resource, be subject to change, and may still need to be adjusted for various other factors" (Rebuttal-WPSC-Nelson-19). I disagree. In fact the exact opposite is true – if approved, the utility methodology risks misalignment with the MISO-vetted and approved accreditation methodology.

Q. Do you agree that behind-the-meter (BTM) resources should not receive capacity value since the energy output from those resources is highly unpredictable?

A. I disagree. Mr. Nelson has suggested that the amount of excess energy supplied to WPSC by BTM resources, if any, depends on the amount of on-site retail load during each interval of the day and that configuration is not reliable enough for capacity planning purposes because the energy output to WPSC is highly unpredictable – excess energy will vary based on the amount of on-site consumption, which will vary depending on the time of day and year (Rebuttal-WPSC-Nelson-14). I agree that the amount of excess energy supplied to WPSC by BTM resources will depend on the amount of on site retail load. However, the credit for avoided transmission and capacity, as RENEW has proposed it be structured, would only be applied when the BTM resource is exporting the excess energy during peak hours. If a BTM resource does not export energy during peak hours then it will not receive a capacity or transmission credit. However, if a resource does export this energy it is contributing to peak reduction and should be provided the credit.

Q. But aren't BTM resources already compensated for capacity value by serving on-site load and lowering the need for purchases from the utility?

A. When a BTM resource serves retail load it is also reducing the need for more capacity and as Mr. Nelson indicates that is accounted for in the avoided retail rates. However, avoiding retail rates does not account for the additional reduction in peak that occurs through the excess energy exports. The capacity value of that exported energy must be fairly compensated; else the system owner would be providing that value to the utility for free.

Q. Would you like to add anything else?

A. Yes, I would like to clarify the difference between customer or third party-owned and utility owned resources in terms of their dispatchability and how this relates to avoided transmission and capacity costs for customer owned BTM resources.

Q. Please elaborate

A. First, to clarify, "dispatchable" resources are resources that can be controlled by the utility such as thermal power plans, nuclear plants and certain demand response programs. However, dispatchable resources are not the same as utility owned resources. There are utility owned resources such as solar and wind resources that are inherently variable resources and cannot be "dispatched" whether they are owned by the utility or by any other party. There is no difference in terms of their "dispatchability" since they depend on solar and wind resources (unless they are paired with a storage resource). In other words, a 1 MW customer-owned solar unit and a 1 MW utility-owned solar unit that have the same technical specifications will have the same production patterns and will have the same peak reduction impact whether the unit is owned by the utility or by the customer. Therefore, despite the fact that BTM resources are not utility-owned or utility-controlled, these resources should receive the same avoided transmission and capacity credit for peak demand reduction as a utility owned resource using the same technology (e.g. solar PV or wind).

Q. Does this conclude your testimony?

A. Yes, it does.