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Public Service Commission of Wisconsin
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OFFICIAL FILING
BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light Company, a Wisconsin Corporation, for Approval of Parallel Generation Tariff Modifications and Avoided Costs	6680-TE-107

DIRECT 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. Please summarize your professional experience.

A. At Synapse, I provide research and consulting services on a wide range of energy and electricity issues, focusing on grid infrastructure issues, resource planning, policies around distributed energy resources, energy efficiency, and electricity markets. I also have significant experience with electric system modeling, and the development of avoided energy, transmission, and capacity costs for different jurisdictions including New England, New York, District of Columbia, Hawaii, and Puerto Rico.

I have been employed at Synapse since 2018. Before that, I was a Senior Energy Analyst at DNV GL. My early career was spent working as an electrical engineer on gas turbine, wind turbine, and solar product development.

Q. Please summarize your educational background.

A. I hold a Master of Environmental Management from the Yale School of Forestry and Environmental Studies, a Master of Science in Electrical Engineering, specializing in Electric Power systems, from the Georgia Institute of Technology, and a Bachelor of Science in Electrical Engineering, also from the Georgia Institute of Technology. A copy of my current resume is attached as Ex.-RENEW-Bhandari-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of RENEW Wisconsin, Inc.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate the reasonableness of Wisconsin Power and Light Company's (WPL) proposed avoided transmission and capacity costs, including the methodologies underlying the calculation for the proposed avoided costs. I present alternative avoided cost calculation methodologies, values, and credit structures that more appropriately capture the value of avoided costs for transmission and capacity. I also evaluate the reasonableness of WPL's proposed application of those avoided costs to front-of-the-meter (FTM) and behind-the-meter (BTM) Qualifying Facilities (QFs) through buyback rates in the Company's proposed tariffs.

Q. Have you testified previously before the Public Service Commission of Wisconsin?

A. Yes, I have previously provided direct testimony in Docket No. 4220-TE-109, which is Northern States Power Company Wisconsin's application for updates to its parallel generation tariffs. My testimony in this proceeding includes many of the same concepts that I discussed in my testimony in Docket No. 4220-TE-109.

I have also submitted expert testimony in Colorado in a proceeding regarding Public Service Company of Colorado's 2021 Electric Resource and Clean Energy Plan on behalf of the Colorado Energy Office (Proceeding No. 21A-0141E). I have also assisted in preparing testimony in proceedings related to rate cases and infrastructure investment programs in New Jersey, evaluating distribution system investments on behalf of the New Jersey Division of Rate Counsel.

Q. Have you developed methodological approaches for avoided costs used by utilities when evaluating the cost-effectiveness of DERs?

A. I co-wrote the chapter on Avoided Transmission and Distribution costs for the Avoided Energy Supply Components (AESC) study which outlines a methodological approach for the development of avoided costs in New England for cost-effectiveness testing of energy efficiency programs. The study is sponsored by a combination of electric and gas utilities and efficiency program administrators in New England.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I conclude that:

- WPL's assessment that QFs do not avoid transmission cost ignores the benefit that QFs provide through load reduction.
- The Company does not justify its proposal to compensate BTM resources for avoided capacity cost based on the MISO PRA.
- The Company does not justify its proposal to compensate FTM resources for avoided capacity cost based on the PRA in the short term and CONE only in the long term.
- The Company has not addressed the application of loss factors to avoided transmission, capacity and energy.
- The Company's proposed capacity credit design for FTM resources underestimates the transmission and capacity benefits that FTM resources provide during peak hours.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission:

- Approve the value of $70.82 $/kW-year for avoided transmission costs;
- Approve my proposed methodology that accounts for marginal load growth-related transmission investments going forward and require that the utilities conduct a similar analysis and provide all stakeholders transparency concerning the inputs, assumptions, and results from such analysis;

- Approve the use of marginal losses for both avoided transmission and avoided capacity, valued at double the average losses on WPL's system;
- Approve the use of marginal losses for avoided energy valued at 1.5 times the average losses on WPL's system;
- Approve the use of MISO Cost of New Entry (CONE) for Local Resource Zone 2, which includes WPL's service territory, to compensate QF capacity for both BTM and FTM resources. MISO CONE in Local Resource Zone 2 for the 2022/2023 planning year is $89.49 per kW-year;
- Approve longer contract periods for separately metered resources in addition to the 5 and 10 year contract periods that the Company has proposed;
- Approve the application of both transmission and capacity credits to FTM resources on a $/kW-month basis; and
- Approve the application of both transmission and capacity credits to BTM resources on a $/kWh basis consistent with RENEW witness Kell's testimony.

III. AVOIDED TRANSMISSION COSTS

A. Concerns with WPL's Proposal

Q. Does WPL propose to credit QFs for avoided transmission costs?

A. No. The Company states that it was not able to identify avoided transmission costs resulting from parallel generation resources in either the near- or long-term.

Q. How does the Company explain its failure to identify avoided transmission costs resulting from parallel generation resources in the near-term?

A. The Company claims that transmission costs are "fixed in the near term" and are not impacted by any change in resource availability resulting from QFs (Direct-WPL-Cook-13). The Company asserts that this is because transmission costs are driven by the transmission owner's (American Transmission Company or ATC) costs and that these costs are passed down to WPL customers through Federal Energy Regulatory Commission (FERC) regulated formula rates. Therefore, the Company reasons, if transmission demands are reduced, transmission rates will increase to fully recover the cost of investments that have already been made.

Q. How does WPL explain its failure to identify avoided transmission costs resulting from parallel generation resources in the long-term?

A. The Company asserts that transmission needs and investments are identified through extensive planning initiatives performed by transmission owners and MISO. These local and regional planning initiatives involve multiple varied drivers such as compliance with North American Electric Reliability Corporation (NERC) planning criteria, replacements of aging infrastructure, accommodating new resources, and addressing potential new flows on the system (Direct-WPL-Cook-13). According to WPL, resolving these needs would require "a significant amount of parallel generation resources in the proper area" along with the need for effective coordination of these individual resources for reliability planning functions. As a result, WPL claims that long-term transmission costs are not sensitive to relatively small incremental changes in resource availability.

The Company also claims that transmission costs may *increase* when new generation resources connect to the grid because the transmission system was not planned and designed with DERs in mind and pushing energy onto the transmission system from these resources can increase the transmission loadings in some areas (Direct-WPL-Cook-14).

Q. How do you respond to WPL's discussion regarding the near-term avoided transmission costs resulting from parallel generation resources?

A. I agree that investments that have already occurred are driven by the transmission owner's costs and are passed down to WPL's customers through FERC-regulated formula rates. Investments that have already been incurred and are reflected through rates are embedded transmission investments. If demand on the transmission system is reduced over any time frame, FERC-regulated formula rates will likely increase in subsequent time frames to fully recover the cost of embedded investments. In that narrow sense, with respect to embedded investments, load reductions (resulting from distributed generation or any other resource) will have no impact on the utility's transmission costs in the near-term since the utility will recoup the entirety of its embedded investments from its customers notwithstanding the load reduction.

However, embedded investments do not include investments that may occur going forward (i.e., marginal investments). Forward looking marginal investments that will address future transmission needs have the potential to further increase transmission costs beyond current embedded costs. Load reductions *can* avoid marginal investments. The Company should have developed avoided transmission costs based on *marginal* costs, instead of limiting its analysis to embedded costs.

Q. How do you respond to WPL's discussion of the long-term avoided transmission costs resulting from parallel generation resources?

A. I agree that transmission needs have various drivers. However, one of the key drivers for transmission investments is load growth. Distributed generation resources (and all demand side resources including energy efficiency) avoid load growth and peak demand. By doing so, those resources can avoid transmission costs.

It is entirely possible to assess the value of avoided transmission costs within a reasonable range of certainty. For every kW of peak load growth that distributed generation reduces on the transmission system, the utility avoids a transmission-related cost (in $). I will discuss in more detail how load growth-related investments can be isolated from all other transmission investments.

The Company suggests that transmission costs are not sensitive to "relatively small incremental or decremental changes" and that "individual resources" would need to be coordinated to provide reliability functions. I disagree. The Company should not be looking at QFs as individual resources that produce small incremental or decremental changes but rather should consider QFs interconnecting to the Company's system in aggregate and calculate those resources' contribution to the avoidance of transmission investments as a whole.

Q. Please elaborate.

A. A comparison to generation capacity costs might be helpful. In the context of generation capacity, as discussed in a guidebook developed by Interstate Renewable Energy Council (IREC) for regulators (Ex.-RENEW-Bhandari-2), utility resource planning typically adds capacity resources in large and "lumpy" blocks as opposed to smooth incremental additions. Therefore, as IREC indicates, if a utility had sufficient capacity to meet its reserve margin and its next capacity addition were a 500 MW CCGT, for instance, a utility might argue that relatively smaller incremental additions of load-reducing resources do not result in the utility avoiding capacity costs.

An example provided within the IREC guidebook illustrates this concern in more detail. A typical utility resource plan might state that the utility has adequate capacity until the year 2018, at which time the company forecasts a need for an additional 200 MW of generation capacity. In this scenario, a QF would receive no capacity value if it were installed before 2018 (because per the utility's resource plan, it would have no capacity need prior to 2018), and would receive no capacity value in 2018 unless the QF provided the equivalent to 200 MW of capacity. This "catch-22" undermines the benefit of QFs' modularity. Continuing with the above scenario, if QFs were installed prior to 2018, the utility would no longer need 200 MW of capacity in 2018. And QFs installed in 2018 and thereafter would reduce the need for capacity on a going forward basis. Since each unit of parallel generation installed provides immediate benefit by reducing load growth on the system the resources should be valued accordingly.

Although the examples above discuss generation capacity, the same argument holds for transmission capacity as well. Similar to capacity investments, transmission investments are large and lumpy, and planning for transmission investments occurs in advance of when the investments themselves are required. There are numerous "lumpy" load growth-related investments that have been identified through the MISO Transmission Expansion Planning (MTEP) process and I will provide further information regarding these specific investments in Section III.B. Similar to generation capacity, QF's can reduce transmission capacity requirements and should be valued accordingly.

In planning for transmission and generation capacity additions, the utility should account for the impact of QF installations. In aggregate, QF resources can help meet capacity and transmission needs and allow the utility to defer or avoid the "lumpy" additions discussed above. Specifically, utilities should account for QFs in their load growth forecasts so that ratepayers benefit from the capacity and transmission value of aggregated distributed resources. Although ATC may conduct transmission planning (as I will explain later), the transmission investments identified through ATC's planning processes rely on the load forecasts conducted by the respective end-use load serving customers (utilities) as input to its planning analysis (Ex.-RENEW-Bhandari-3).

Q. How do you respond to WPL's contention that distributed generation resources can increase transmission costs?

A. I do not agree with WPL's contention. The utilization of transmission lines by any resource depends on the resource's point of interconnection. QFs are generally located either at or near customer sites to serve customer load and are interconnected to the distribution rather than the transmission system. QFs therefore do not generally utilize the transmission system or increase transmission cost. Instead, they avoid transmission cost by reducing load, as I have explained above.

Q. How should WPL have evaluated avoided transmission costs?

A. I will describe my methodology for developing avoided transmission costs in further detail in Section III. To summarize at a high level, rather than considering embedded transmission costs, the Company should have evaluated avoided transmission costs by determining *marginal load-growth*-related costs.

Q. Why should the Company develop avoided transmission costs based on marginal costs?

A. Distributed generation resources can avoid (or cause) changes in utility infrastructure needs going forward; they cannot change past investments. Load reductions from distributed generation can contribute to avoiding the further addition of load-related transmission facilities. Marginal costs are defined as the change in per unit costs as the result of a small change in output and therefore represent the cost of having to produce an incremental unit of output. A marginal cost approach aims to capture the forward-going avoidable costs, while not including past, embedded costs. Where data are available, the marginal costs should be based on prospective transmission capital investments for the purpose of accommodating load growth.

Historical data regarding investment and load growth would only be used in circumstances where forward looking costs are not available or when there is not substantial relevant data available into the future. Historical load growth related capital costs are not the same as embedded costs since they represent load growth related investments in transmission system whereas embedded costs represent the revenue requirements that have been developed for the purpose of setting rates. The methodologies applied to developing revenue requirements do not capture the costs that can be avoided since they are developed for an entirely different purpose. In cases where historical data are used to develop marginal costs, the capital investments would likely already be a part of the embedded transmission revenue requirements. However, they can still present the best available way to value avoided costs going forward since they calculate a value based on investment that could have been avoided through load reductions from distributed generation.

Q. Please explain why the Company should focus on load growth-related investments to evaluate its avoided transmission costs.

A. Not all transmission investments are avoidable. Transmission-related investments can fall into numerous categories. This may include investments meant to replace aging assets, investments required to meet reliability standards, investments required to interconnect new generation resources, and load growth-related investments.

Load growth-related investments are those that are required to accommodate increased peak demand on the transmission system. This may also include "upsizing" of assets built for a non-load growth-related purpose. For example, if a transformer needs to be replaced due to its age or condition, the utility may choose to "upsize" it by replacing it with a larger transformer in anticipation of forecasted load growth. Therefore, for every kW of peak load growth that is reduced on the transmission system through investments in distributed generation, there is an equivalent transmission-related cost (in $/kW) that can be avoided due to these investments.

Q. Does WPL own transmission assets?

A. My understanding is that WPL does not own transmission assets. Transmission assets in WPL's territory are owned and operated by ATC. ATC is the transmission owner for transmission assets that serve WPL, Madison Gas and Electric (MGE), Wisconsin Electric Power Company (WEPCO),Wisconsin Public Service (WPS) and for investor owned utilities in the Upper Peninsula of Michigan.

Q. Have you estimated WPL's avoided transmission costs?

A. Yes. However, since WPL itself does not own transmission, the transmission needs assessment is driven by planning initiatives conducted by ATC which serves transmission needs in parts of Wisconsin including WPL territory. Therefore, our assessment of avoided transmission costs is based on estimated costs and future transmission needs that are identified by ATC and which will eventually be passed down to customers within WPL territory. In Section III.B. of my testimony, I will describe methods that can be used to estimate ATC's (and thereby WPL's) avoided transmission costs within a reasonable range of certainty.

I will also describe my application of those methods and the results of my analysis.

Q. Please describe your next concern with WPL's proposal for calculating and crediting avoided transmission costs for QFs.

A. My next concern is that the Company has not addressed how these avoided transmission costs can be translated to applied rates. As discussed above, since the Company has not identified a value for avoided transmission costs, they have also chosen to ignore how these costs could be translated to rates if they were to identify a transmission value in the future. I discuss this concern in greater detail in Section VI of my testimony—Application of Avoided Costs in Rates—and suggest a methodology for how these transmission costs can be translated into rates for different resources.

B. Proposed Methodology for Calculating Avoided Transmission Cost

Q. You mentioned earlier that it is possible to estimate the value of avoided transmission within a reasonable range of certainty. Please describe your proposed method for calculating avoided transmission cost.

A. The following method can be used to calculate avoided transmission costs:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two. (A prospective period is preferred if data are available.)
- Step 2: Determine the actual or expected relevant load growth in the analysis period, in megawatts (MW).

- Step 3: Estimate the load-related transmission investments in dollars incurred to meet that load growth.
- Step 4: Divide the result of Step 3 by the result of Step 2 to determine the cost of load growth in \$/MW or \$/kW.
- Step 5: Multiply the results of Step 4 by a levelized annual carrying charge to derive an estimate of the avoidable capital cost in \$/kW per year.
- Step 6: Add an allowance for operation and maintenance (O&M) of the equipment, to derive the total avoidable cost in \$/kW per year.

Q. Have you analyzed WPL's avoided transmission costs based on this six-step methodology?

A. Yes. As discussed above, our assessment of avoided transmission costs is based on the costs incurred by ATC to meed load growth within the region (which includes WPL territory). Therefore, I have analyzed ATC's avoided transmission costs that will be passed down to WPL customers. As indicated in Ex.-RENEW-Bhandari-4, based on zonal rates for February 2022, the \$/MW-year rate for each of ATC's Wisconsin customers is identical. Therefore, my analysis of WPL's avoided transmission costs is substantially identical to my analysis of avoided transmission costs for each of the other three utilities that drive ATC transmission costs in Wisconsin (MGE, WEPCO and Wisconsin Public Service (WPSC)). Below, I describe my analysis of avoided transmission costs for all four utilities in Wisconsin that fall within ATC transmission service territory.

Q. Please describe each step of your analysis, starting with your choice of a time period for the analysis (Step 1).

A. My choice of time period was based on the availability of data for historical and future transmission capital investments. Based on the publicly available data, I selected an analysis period that extends from 2021 to 2029. This is consistent with transmission planning and modeling processes that typically look five to ten years into the future.[1] However, the value represents forward-looking costs and can continue to be used outside of this analysis period.

Q. How did you determine the actual or expected relevant load growth during the analysis period (Step 2)?

A. In order to determine the relevant load growth in the analysis period, I used the various filings from the 2028 Strategic Energy Assessment (SEA) data labeled Assessment of Electric Demand and Supply Conditions Monthly Peak Demand (MW) (Ex.-RENEW-Bhandari-5) for each of the utilities that drive ATC transmission costs in Wisconsin. These utilities include WPL, WEPCO, WPSC and MGE. Based on the respective attached monthly peak demand data, I added up the monthly peak load growth for each of the utilities to derive the transmission load on ATC's system for each month. I then took the maximum combined peak growth over the year to represent the annual peak demand on ATC's transmission system in Wisconsin. As discussed above, the load growth timeframes were based on the availability of the transmission-related capital cost

[1] On an annual basis, MISO builds 2-year out, 5-year out, and 10-year out power flow models.

data which I will discuss in Step 3.[2] I present a few different load growth estimates below based on the SEA load forecast. My eventual analysis used the load growth from 2021–2029.[3] However, in **Table 1** below, I have provided some sample load growths based on some different analysis periods for illustrative purposes.

Table 1. Load Growth across different timeframes.

Load Growth Timeframe	Load Growth (MW)
2021- 2024	338
2021-2026	348
2020- 2028	439
2021-2029	348

Q. How did you estimate the load-related transmission investments to meet that load growth (Step 3)?

A. The MISO Transmission Expansion Plan (MTEP) is conducted on an annual basis and evaluates studies and planning initiatives that help MISO address future grid needs. As an outcome of this study, MTEP identifies specific transmission infrastructure improvements that are required to address a variety of needs including reliability, aging infrastructure, load growth investments, etc.

[2] I have presented my analysis in the order that transmission planning typically occurs. A transmission planning process would typically involve estimating the required load growth on the system and then identifying the transmission investments required to meet that load growth. However, given that ATC conducts transmission planning, I have first gathered data on investments identified by ATC and then attempted to assess the load growth on which ATC has based these identified investment needs.

[3] SEA load growth forecasts only extended out until 2028. The 2029 load forecast was based on the growth rate from prior five years.

Based on the latest MTEP data provided (Ex.-RENEW-Bhandari-6), I identified load growth-related investments identified by ATC in both Wisconsin and Michigan. I calculated the total load growth investments made by ATC for each state in order to isolate the portion of investments that span both states.

Table 2. State Specific Transmission Investments made by ATC

State	Capital Expenditure ($)	% Total
MI	$21,393,000	21%
WI	$80,642,672	79%
WI and MI	$85,056,542	-

Based on the above, for load growth-related investments that span Wisconsin and Michigan, I allocated 79% of costs to Wisconsin. Table 3 below illustrates ATC's load growth-related transmission investments by year for the state of Wisconsin after removing the load growth related investments in Michigan and allocating Wisconsin's portion of projects that span both states.

Table 3. Annual capital expenditure data for load growth projects in Wisconsin (after removing capital expenditures for load growth investments in Michigan)

Year	Capital Expenditure ($)
2021	$217,565
2022	$27,712,567
2023	$48,667,677
2024	$44,365,232
2025	$26,903,050
Total	**$147,866,092**

In addition to the MTEP data, there are transmission line investments identified through the Strategic Energy Assessment through 2028 (Ex.-RENEW-Bhandari-

7: Schedule 11).[4] However, I concluded that projects identified through SEA did not consist of any projects that could be directly classified as load growth related projects. In addition, the SEA projects overlapped significantly with MTEP data and I removed these projects from further analysis to be conservative. If any projects identified through SEA are not included in MTEP, the avoided transmission cost results should be adjusted for these projects.

Q. Does the table above capture all of WPL's load growth-related transmission investments in the analysis period?

A. No. Based on my experience, certain transmission investments that are not explicitly classified as "load growth-related" that could potentially have a load growth component. In other words, while a project may be classified as "Reliability", "Age and Condition", or some other category that is not "Load Growth," the project may nevertheless serve a load-growth purpose.

For example, to illustrate this issue, for one project that NSPW proposed to relocate and rebuild two existing transmission lines between Gingles substation in Ashland and its Ironwood substation. (Ex.-RENEW-Bhandari-8). The project costs are anticipated to range from approximately $131 million to $139 million depending on the final route selected. Based on our review of the proposal, NSPW states that the identified project will "address all reliability concerns and increase load-serving capability in the area to meet anticipated customer needs

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[4] Since WPL is not a transmission owner, the respective SEA Schedule 11 identifying transmission lines is not applicable. However, ATC (i.e., the transmission owner) also submits SEA data on new transmission lines as part of Schedule 11.

through the mid-century." (Ex.-RENEW-Bhandari-8). Although I cannot confirm with certainty, it appears that this project may have been identified in MTEP20 but was not classified explicitly as a load growth project.

However, while the transmission line rebuild between the Gingles substation and the Ironwood substation is not expressly classified as a "load-growth-related" project, the project has a load-growth purpose, among other purposes.

Q. How do you determine the load growth component of projects that serve more than one purpose and are not classified as "load growth-related"?

A. This is challenging and we cannot be certain about the exact load growth component. The load growth-related component of projects that serve more than one purpose may vary substantially from project to project. As a proxy, I estimate that ten percent of the costs of projects not explicitly classified as "load growth-related" is associated with aspects of the projects that will address load growth needs going forward. I have assumed that this proxy estimate includes projects that are either being built sooner because of load growth or are being built to a larger capacity due to load growth.

Q. How did you identify the capital expenditures associated with projects that have a load growth component but are not classified as load growth-related?

A. I used a process very similar to my assessment of capital expenditures associated with load growth-related projects. I identified all the projects from MTEP that could have a load growth-related component but were not explicitly classified as load growth-related projects. (Ex.-RENEW-Bhandari-6) These categories are: 1)

Reliability projects, 2) Age and Condition, 3) Other Local Needs, 4) Distribution and 5) Unclassified projects. I then applied my proxy estimate of ten percent as discussed above to estimate the portion of the costs associated with these projects that may be load growth-related. As discussed earlier, I concluded that the SEA projects overlapped significantly with MTEP data and removed these projects from further analysis to be conservative. If any projects identified through SEA are not included in MTEP, the avoided transmission cost results should be adjusted for these projects.

In **Table 4** below, I show annual capital expenditure data for transmission projects that may have a load growth component but are not explicitly classified as load growth-related projects. I have estimated load growth-related costs based on my estimate that ten percent of these costs will be load growth-related. In addition MTEP indicated that amongst the projects identified there are some project costs that would be shared with other transmission owners. For projects that are expected to have a cost sharing component, I assumed that 50% of the costs would be incurred by ATC's customers (i.e., customers in the respective utility territories served by ATC). This assumption may vary significantly on a project by project basis. However, according to the last set of new project cost allocations from MTEP21, the total allocation of costs to ATC (for which ATC is the transmission owner) ranged from approximately 80% to 100% of the total project costs (Ex.-RENEW-Bhandari-9: Appendix A-1). In addition, I continue to assume that for projects that span Michigan and Wisconsin, 79% of the total costs are allocated to Wisconsin.

Table 4. Capital cost of projects that are expected to have a load growth-related component but are not directly classified as load growth projects; 50% project cost allocation and 79% state cost allocation

In Service Year	ATC Load related Capital Expenditure ($)	ATC's Wisconsin Capital Expenditure Portion ($)
2021	$126,493,395	$21,493,395
2022	$320,487,035	$252,186,930
2023	$554,763,307	$385,092,343
2024	$315,638,402	$238,550,020
2025	$105,943,551	$87,869,945
2028	$21,090,000	$21,090,000
Total Estimated Cost	$1,444,415,690	$1,006,282,633
Load Growth Related Costs		**$100,628,263**

Q. Please describe how you used your estimate of load growth and your estimate of load growth-related investments to determine the cost of load growth-related investments in $/MW or $/kW (Step 4).

A. In calculating the avoided transmission cost, I matched the timing of the capital investments with the timing of load growth. Investments and utility spending to address load growth typically occur in advance of when the load growth actually occurs on the system. In other words, to maintain reliable service, a load-growth-related investment precedes the year in which the expected load requires the asset to be in service. Therefore, in order to determine the cost of load growth-related transmission investment, it is necessary to understand the utility's process of mapping these investments to the specific time period that is driving those investments. As a simple example: an investment in 2019 may be driven by some future load growth expected to occur in 2020 while another 2019 investment may be driven by some load growth expected in 2022.

Mapping load growth to capital expenditures can be challenging, partly because capital expenditure data are lumpy. I do not have full insight into what load growth is driving the above capital expenditures since I do not have insight into ATC's transmission planning process. If the utility (with relevant insight from ATC) had conducted an analysis that did not have the gaps I identified above, we would have better data with which to conduct this analysis.

I based my load growth timeframe on the expected need dates for each of the transmission investments as indicated in MTEP, based on the assumption that load-growth-related investments would not be built too far in advance of when they are required. I took the relevant load growth based on Step 2 and applied it to the capital expenditures in Step 3 to get a $/kW value. First, I looked at only the projects that have been explicitly identified as load-growth-related. These projects have investment dates that range from May 2021 through December 2025, so I assume they are caused by load growth between 2021 and 2026, as shown in **Table 5** below.[5]

Table 5. $/kW for projects classified as load growth-related

Load Growth Timeframe	**2021 -2026**
Capex Timeframe	**2021-2025**
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	147,866
$/kW	425

Second, for capital expenditures that were not explicitly classified as load growth-

[5] I assumed that any investments made after August were being made for purposes of addressing the following year's peak since the monthly forecasted peak starts declining beyond August. So, investments with in-service dates between September and December were driven by the following year's peak growth.

related (but may have a load growth-related component), I performed a similar calculation as shown in **Table 6** below. The timeframe for this analysis is longer because I have information about planned capital projects through 2028, which I associate with load growth through 2029.[6]

Table 6. $/kW for projects not classified as load growth-related (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021-2029
Capex Timeframe	2021-2028
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	100,628
$/kW	289

Q. Please describe how you estimated the avoidable transmission cost in $/kW per year (Step 5 and 6).

A. To turn an upfront capital cost into an annual value reflecting what ratepayers would actually pay, I annualized the $/kW values developed in Step 4 based on my calculation of the nominal levelized revenue requirement (or carrying factor). I based this nominal levelized revenue requirement on historical FERC Form 1 data (Ex.-RENEW-Bhandari-10), book depreciation factors based on NSPW rate case filing (Ex.-RENEW-Bhandari-11), and Attachment O submitted to MISO (Ex.-RENEW-Bhandari-12).[7] The calculation accounts for recovering the capital invested (through depreciation), the asset owner's return on the capital (both debt

[6] I assumed that any investments made after August were being made for purposes of addressing the following year's peak. The investments with in service dates between September and December were driven by the following year's peak growth.

[7] The calculations are based on publicly available data and should be replaced by data provided by ATC for annualization of different types of transmission investments, if available. I was not able to find book depreciation factors for ATC so I based these on book depreciation factors for transmission investment from the NSPW rate case filings.

and equity), and both property and income taxes. While the annual cost of a given asset varies over the asset's life, I developed a levelized result because the purpose of our analysis is to develop a factor that transforms a portfolio of future avoided assets into a single avoided cost to apply over time. Assets that are not constructed also do not have operation and maintenance (O&M) costs, so I also included an allowance for avoided O&M in the derivation of the levelized nominal revenue requirements. The resulting annual levelized carrying cost factor is 9.91 percent. Please see Ex.-RENEW-Bhandari-13 for the relevant data sources and calculations used to derive this value.

Q. What are the annual avoided transmission costs resulting from your analysis?

Based on the process described above, I calculated the annual levelized values for each component of the avoided transmission costs (i.e., load growth-related and projects that may have a load growth portion). **Table 7** below shows the annual avoided transmission costs for load growth-related projects and

A. **Table 8** shows the annual avoided transmission costs for the approach using capital expenditures that were not classified as load growth-related (but may have a load growth-related component).

Table 7. $/kW-Year for projects classified as load growth

Load Growth Timeframe	2021 - 2026
Capex Timeframe	2021-2025
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	147,866
$/kW	425
Carrying Charges	9.91%
Annualized ($/kW-Year)	42.14

Table 8. $/kW-Year for projects not classified as load growth (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021-2029
Capex Timeframe	2021-2028
Load Growth (MW)	348
Load Growth related Capital Expenditure (000's)	100,628
$/kW	289
Nominal Carrying Charges	9.91%
Annualized ($/kW-Year)	28.68

Per this analysis above, the avoided transmission cost associated with projects that are explicitly classified as load growth projects is $42.14/kW-year, which should serve as the floor value for avoided transmission costs.

The avoided transmission costs associated with projects that are not explicitly classified as load growth-related projects is more uncertain. This could be higher or lower depending on the assumptions made concerning the portion of projects that may have a load growth-related component. As discussed above, I have proposed a proxy estimate of ten percent which results in an avoided transmission cost of $28.68 $/kW-year. I believe this is a reasonable estimate based on our analysis of FERC data (to be presented below in my testimony) and that this results in a value that is in the range of avoided transmission costs across other jurisdictions.

Therefore, per my analysis, and as described in **Table 9** below, ATC's total avoided transmission cost (exclusive of losses) is $70.82 $/kW-year. This includes both the avoided transmission cost of load growth projects and the avoided cost of transmission for projects for which a portion of the costs may be load growth-related.

Table 9. Total annualized avoided transmission costs (not including losses)

Avoided Transmission Costs	Annualized $/kW
Projects classified as load growth-related	42.14
Load Growth Component of projects not expressly classified as load growth-related	28.68
Total Avoided Transmission Costs	**70.82**

Q. Could concentration of growth in localized areas complicate the calculation of avoided transmission costs?

A. Yes. For my analysis I have used system-wide peak growth, because this is the publicly available information. However, it is possible that peak growth may not be uniform across ATC's transmission system, and that localized growth is driving transmission investments. With more information, it would be possible to identify the areas of load growth and calculate area-specific avoided transmission values. In these particular areas, the value of avoided transmission costs would likely be higher (because all of the load-growth-related transmission costs would be assigned to a smaller portion of overall load), and it would likely be lower in other areas.

However, I believe it is sufficient and appropriate to calculate an area-wide average value for the purpose of avoided transmission value attributed to QFs. This is because the purpose of this proceeding is to set a single value across WPL's service territory. The locations of future load growth (and associated transmission costs) may vary drastically across the system if assessed on a locational basis (some locations will have a high value and some locations may have a lower value). However the single system wide value allows us to capture these differences across these different locations in the longer term.

Q. Please describe the checks and calibration that you conducted on your analysis.

A. I based my avoided transmission cost analysis on bottom-up data related to future expenditures on a project-by-project basis, which is the correct way to conduct avoided transmission cost analysis. However, as a cross-check, I compared my results with results produced using historical top-down accounting data from ATC's annual FERC Form 1 filing (Ex.-RENEW-Bhandari-10). I used historical transmission capital expenditures for the period from 2016 to 2020 and associated this with load growth between two separate timeframes (2017 – 2021) and (2016 – 2020).[8] This is because the load growth in 2017 dips significantly resulting in a very high load growth estimate between 2017-2021. I present results for both these ranges in order to indicate the sensitivity to assuming a certain load growth timeframe in developing the avoided transmission values. Because these historical expenditures are not classified based on purpose, I had to make an assumption about what portion could have been avoided with lower loads. I analyzed results assuming that 5 percent, 10 percent, or 15 percent of these costs were associated with load growth (The 5 percent, 10 percent, and 15 percent ranges chosen are conservative estimates. The estimated percentage of total load growth related projects across MISO is 20 percent. (Ex.-RENEW-Bhandari-14). Similarly, the overall estimated percentage of projects that are load growth related in Wisconsin

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[8] 2017–2020 loads were actuals and not forecasts.

is approximately 14 percent based on Wisconsin's Strategic Energy Assessment – 2026, Table 2-1 (Ex.-RENEW-Bhandari-15).

In my cross-check analysis, I used the same levelized carrying cost for annualization as I did for my bottom-up analysis. **Table 10a-c** below illustrate the results of my cross-check analysis, which produces an annualized avoided transmission cost ranging from $12.80 to $84.49/kW-year (before adjusting for losses). Assuming between 10 percent and 15 percent of the capital expenditures are load growth-related results in a value that aligns closely with the $70.82/kW-year avoided transmission cost value that my bottom-up analysis produced. This suggests that my bottom-up analysis produces a reasonable estimate.

Table 10a. Avoided Transmission Cost based on FERC Form 1; assuming 5% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	96,628	96,628
$/kW	129	284
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	12.80	28.16

Table 11b. Avoided Transmission Cost based on FERC Form 1; assuming 10% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	193,255	193,255
$/kW	258	568
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	25.60	56.33

Table 12c. Avoided Transmission Cost based on FERC Form 1; assuming 15% capital expenditures are load growth related

Load Timeframe	2017 - 2021	2016-2020
Capex Timeframe	2016-2020	2016-2020
Load Growth (MW)	748	340
Load Growth related Capital Expenditure (000's)	289,883	289,883
$/kW	388	853
Carrying Charges	9.91%	9.91%
Annualized ($/kW-Year)	38.41	84.49

Q. How does this compare with other jurisdictions?

A. Based on my review, an avoided transmission cost of $70.82/kW-yr (before adjusting for losses) is within the range of avoided transmission costs produced in other jurisdictions. Based on a study conducted in 2014, a review of nationwide averages show that the values can vary substantially. The average results are $20.21 $/kW-year, while the values range from $0 to $88.64. (Ex.-RENEW-Bhandari-16). Based on a study conducted by Regulatory Assistance Project (RAP), in 2011, the avoided transmission costs ranged from $20/kW-year to $100/kW-year for transmission (Ex.-RENEW-Bhandari-17). In Northern States Power – Minnesota's MN Value of Solar proceeding, Xcel proposed an avoided transmission cost of $49.72 $/kW-year (Ex.RENEW-Bhandari-18). These results suggest that the value that I have derived is reasonable.

Q. Would you like to add anything else regarding your analysis of WPL's avoided transmission costs?

A. I have developed these values based on publicly available data. This is particularly challenging given limited insight into ATC's transmission planning processes and data. I believe that our analysis estimates the avoided transmission cost within a reasonable range of certainty. Our key challenges in developing this estimate relate to the fact that transmission planning is a process that remains largely under the purview of the utilities (and in this case ATC). Hence, the data required for the analysis is often not readily available to external stakeholders or regulators. This results in significant information asymmetry that makes it difficult to capture the future investment needs and appropriately value the contribution of distributed energy resources.

Q. Please summarize your recommendations regarding avoided transmission cost.

A. I recommend that the Commission (1) adopt an avoided transmission cost of $70.82 $/kW-year for both contracted front-of-the-meter resources as well as behind-the-meter resources, and (2) direct WPL to use the above methodology and conduct a similar analysis of avoided transmission costs. The utility should be clear and transparent and make their analysis readily available to stakeholders.

IV. AVOIDED CAPACITY COSTS

Q. Please describe WPL's proposal for calculating and crediting avoided capacity costs.

A. The Company proposes to use a calculated market capacity value. Specifically, WPL proposes a capacity credit based on the MISO Planning Reserve Auction (PRA) clearing price in the short term and on the MISO Cost of New Entry (CONE) in the long term. Compensation for the first year of an extended 5- or 10-year contract is set based on an average of five recent PRA clearing prices. Over eight years, the compensation value rises linearly until it reaches CONE, where it remains for the remaining duration of the contract. In addition, WPL modeled a one megawatt ("MW") incremental change in system capacity to act as a proxy for the addition of a QF or customer-owned generation system to calculate a modeled value of avoided capacity. WPL ran the Aurora model using the five varied future planning scenarios that it developed in its resource planning process. Based on this process, the modeling showed no change to WPL's planned resource additions resulting from the addition of the 1 MW modeled resource, and thus no incremental avoided capacity cost resulted from the addition of the QF. As a result, WPL proposes to use the calculated market capacity value for parallel generation resources, depending upon whether the QF is available for only the short term (e.g., up to a year) which is referred to as Option A or a longer term (e.g., five or ten years), while also being separately metered, which is referred to as Option B. (Direct-WPL-Cook-7-12)

Q. Do you have concerns with WPL's approach of modeling a 1 MW incremental change in system capacity?

A. Yes. Modeling a 1 MW incremental change in system capacity is not an appropriate methodology to evaluate the avoided capacity associated with distributed energy resources.

As mentioned earlier, (Ex.-RENEW-Bhandari-2) utility resource planning typically adds capacity resources in large and "lumpy" blocks. In addition, utility planning for capacity typically occurs well in advance of when a resource is required. Adding capacity in these lumpy blocks could potentially overshoot capacity requirements beyond what is needed for resource adequacy.

An example provided within the IREC guidebook illustrates this concern. A typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 MW of generation capacity. In this process, a distributed energy resource will receive no capacity value if it is installed before 2018, and none in 2018 unless the systems provide the equivalent to 200 MW of capacity. As suggested by IREC, this ignores the benefit of a distributed energy resources's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. QFs can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued distributed resource installations.

Q. How did WPL estimate avoided capacity costs for non-contracted behind-the-meter QFs?

A. WPL proposes to credit non-contracted behind-the-meter (BTM) QFs at the capacity value established by the MISO Planning Resource Auction (PRA). WPL calls this "Option A" the proposed PgS-1 tariff.

Q. How did WPL estimate avoided capacity costs for contracted front-of-the-meter QFs?

A. WPL proposes a new "Option B" for capacity credit valuation under PgS-1. Option B would allow parallel generation customers who make longer-term capacity commitments to receive a higher capacity credit rate. This option would be available to retail customers who: (1) have separately metered generation and (2) enter into either a five-year or ten-year agreement under the tariff. Option B, therefore, will allow WPL to rely on the generation from these facilities as needed to respond to future capacity needs.

To estimate the capacity value for resources that make longer-term commitments, WPL considered both the short-term value of capacity, as identified through the PRA, and the long-term cost of new entry (CONE) value for capacity determined by MISO. WPL then used a linear trend line between the near-term PRA capacity price and the longer-term CONE price after eight years, consistent with the five-year or ten-year proposed capacity commitments and similar to third-party capacity price forecasts from Wood Mackenzie. Using this methodology, with a five-year average of historic MISO PRA clearing prices (to reduce volatility) and the most recent CONE data, yielded a capacity value of

$21.81 per kW-year for a five-year contract and $46.17 per kW-year for a ten-year contract. The MISO CONE for Local Resource Zone 2, which includes WPL's service territory, is $89.49 per kW-year (Ex.-RENEW-Bhandari-19).

Based on this above analysis, as a simplification, WPL proposes to compensate customers taking service under PgS-1 Option B by multiplying the MISO CONE value for the current Planning Year, as of January 1 in the year the resource is added, with a contract duration multiplier of either 25 percent or 50 percent for five- and ten-year commitments, respectively. WPL suggests that the use of these contract duration multipliers allows for a straight-forward calculation of capacity credit that is consistent with the trend line methodology for capacity value.

Q. What are your concerns with WPL's proposed avoided capacity credit for BTM resources under Option A?

A. My main concern is that WPL's proposal treats BTM resources as if they will provide only "short-term" capacity (for a year or less) and ignores the fact that these resources will provide avoided capacity value for periods beyond one year. While BTM resources may not sign contracts with the Company, they can reasonably be expected to remain in operation for periods beyond one year. The capacity compensation for such resources should be based on the duration over which they provide a capacity contribution to the system, rather than on the short term PRA value only. This is an essential step toward treating BTM resources on an equal footing with the Company's own resources within its resource planning processes. Failing to recognize the extended duration of BTM resources both in resource planning and in QF capacity compensation will result in excess capacity procurement and cost for the Company's customers and incomplete compensation for QFs. By not incorporating BTM resources in its planning processes, the utility is effectively giving priority to its own resources in meeting system capacity needs. In other words, parallel generation resources only provide such limited capacity value if you assume that Company-owned capacity resources should be allowed to meet the Company's capacity needs before parallel generation resources are allowed to meet those capacity needs—a fundamentally unfair and unreasonable position. Going forward, in assessing longer term capacity needs, parallel generation resources should not receive lower priority than WPL resources in satisfying the system's requirements. Since each unit of parallel generation does provide immediate benefit by reducing load growth on the system, they should be valued accordingingly by factoring the aggregate portfolio of distributed generation resources into the utility planning process and consequently reflecting these resources in their load growth forecasts. The benefit from these aggregate set of distributed resources should be valued as a capacity resource.[9]

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[9] As I have discussed earlier, this same argument holds for transmission capacity as well.

Q. What are your concerns with WPL's proposed avoided capacity credit for contracted front-of-the-meter QFs under Option B?

A. My concerns with the proposed avoided capacity credit for long term resources are that the Company does not offer contracts longer than 10 years and that it does not show that it has no capacity need during the eight year CONE phase-in period.

Q. Please elaborate on your first concern.

A. My first concern is that WPL's proposed capacity compensation for QFs is substantially limited by the duration of the contracts available to QFs. The Company should offer longer contracts that better match the potential useful lifetime and potential capacity contribution of QFs. RENEW witnesses Kell and Vickerman describe this concern in greater detail.

Q. Please elaborate on your second concern.

A. My second concern is that the Company appears to have chosen an arbirtrary eight year phase in period during which the calculated capacity value is less than CONE. WPL does not establish that it has no capacity need during this eight year period. The decision about when the resources should get credit for a longer term capacity value (i.e., CONE) should be based on a capacity needs assessment by the utility and each of the QFs should be treated on equal footing to utility resources. In other words, if a utility plans to bring in a supply side capacity resource prior to the end of the eight year CONE phase in period then QFs should should be treated similarly and receive the long term value for capacity beginning in the same year.

Q. Do you agree that BTM resources and FTM resources should receive different capacity values?

A. No. It is not clear why this separation exists between BTM and FTM resources and why the capacity credits for these resources are different. BTM resources (particularly those that generate and export during the peak hours of the day) reduce peak demand and thereby reduce the cost that WPL incurs to meet that peak demand through additional capacity acquisitions. In its proposal, the Company has ignored the contribution of BTM resources towards meeting peak demand. The ability of a BTM resource to contribute towards peak reduction depends on the nature of the resources and the nature of the on-site load that it serves. However, for every unit of energy exported by a BTM resource during peak hours it has at least as much impact on peak reduction (and thereby avoided transmission costs) as an FTM resource.[10] As an extreme example, if a BTM resource exports the same amount of energy as a FTM resource of equivalent size during the peak hours of the year, they are providing an equivalent magnitude of peak reduction and thereby an equivalent reduction in avoided capacity and transmission costs. Therefore, for such a resource that does export energy during the peak hours, these resources should be valued through the same credit as an FTM resource.

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[10] A BTM resource may actually provide a higher impact on peak reduction since it avoids more losses compared with an FTM resource.

Q. What are your suggestions?

A. I suggest that the Commission approve the use of MISO Cost of New Entry (CONE) for Local Resource Zone 2, which includes WPL's service territory, to compensate QF capacity. MISO CONE in Local Resource Zone 2 for the 2022/2023 planning year is $89.49 per kW-year (Ex.-RENEW-Bhandari-19, Attachment B). This value should be used for all years except those for which WPL has demonstrated that there is no capacity need on its system. This should apply to both BTM and FTM resources.

For multi-year contracts, avoided capacity costs can be projected by applying an anticipated inflation rate to the latest CONE value. There is significant uncertainty in inflation going forward, so for simplicity we assume a 2 percent inflation rate. The value of capacity in the 2023/2024 planning year, for example, would be calculated by applying one year of inflation to the CONE value for the 2022/2023 planning year. This process would be repeated for all future years. I also suggest that the Commission approve longer contract periods for separately metered resources in addition to the 5 and 10 year contract periods that the Company has proposed.

V. AVOIDED LOSSES

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I will outline a methodology for application of losses in the determination of avoided costs.

Q. Please describe your concerns with WPL's application of losses in determining avoided costs.

A. The Company has not proposed a loss factor that should be applied to energy, transmission or capacity.

Q. What is a "loss factor" and how is this relevant to energy, transmission and capacity avoided costs?

A. Loss factors represent the energy loss on the transmission and distribution system between the point of generation and the point of consumption. Since DERs typically provide load reduction through reduced use of the distribution and transmission system (i.e., they provide energy close to the site of consumption), they reduce losses. This results in further reduced energy generation, reduced need for generating capacity, and reduced need for transmission capacity.

Q. Please describe the relationship between loading and losses.

A. The amount of energy loss in any hour is affected by a number of factors including resistance in wires, system utilization rates, and weather conditions. The formulae for losses is I^2R or the square of the current multiplied by resistance. The "I" on the system is a direction function of the load on the system and therefore increases proportionally with load. Therefore, loss factors are generally higher when loads are higher and are significantly higher during peak periods because resistive losses in wires increase proportional to the square of the load.

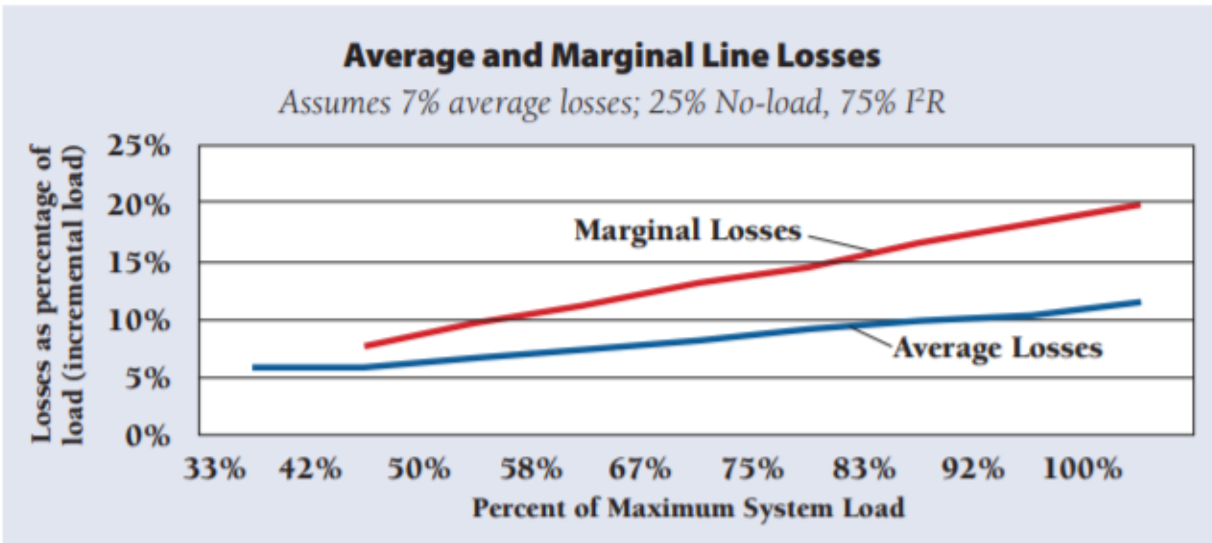
Q. How do marginal and average loss factors differ?

A. There are two types of loss factors that exist i.e., average losses and marginal losses. The average losses represent the average system wide losses. When the system is loaded during peak hours, the average losses are higher because of the relationship between losses and load as described above. The second factor is the marginal loss. The marginal loss reflects the losses incurred to meet incremental demand at any point in time. These losses are always higher than average losses, especially during the peak hours. This is because of the I^2R nature of losses, wherein the derivative of losses with respect to load goes up in proportion to load. Therefore, the marginal loss factors during peak hours are significantly higher than the marginal or average loss factors during off peak hours during the year. This means that line losses for incremental loads ("marginal losses") that would be avoided by resources that contribute to peak load are higher than average line losses.

Q. Please elaborate.

A. A 2011 Regulatory Assistant Project (RAP) paper, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," discusses line losses in detail (Ex.-RENEW-Bhandari-17). This paper presents an example of line losses and demonstrates how marginal and average losses vary at different system load levels as shown in Figure 1 below. This Figure shows that the increases in marginal losses are greater than the increases in average losses as the system load levels increase. For example, when the system is loaded at 50 percent of the capacity, average and marginal losses are approximately 6 percent and 8 percent respectively. In contrast, when the system is loaded at near its capacity, average and marginal losses are approximately 12 percent and 20 percent respectively.

Figure 1: Average and Marginal Line Losses



Q. Why is it not reasonable to apply average loss factors to avoided transmission and capacity costs?

A. The costs for transmission and capacity are driven by load growth on the system during peak hours of the year. The avoided costs represent the marginal costs in meeting an incremental unit of demand (an incremental unit of demand that a QF would avoid). As discussed above, the marginal losses during peak hours would represent the incremental losses that would occur due to a small increase in demand during peak hours. Loss factors are significantly higher during peak periods due to the relationship between losses and load as described above. Therefore, average losses underestimate the value of avoided transmission and capacity during the peak hours. For this reason, the utility should apply marginal loss factors to avoided transmission and capacity costs.

Q. Should marginal loss factors apply to avoided energy costs as well?

A. Yes, the utility should apply marginal loss factors to avoided energy costs as well. However, as I will explain below, the marginal loss factors that apply to energy are lower than the marginal loss factors that apply to transmission and capacity since the marginal loss factors for energy apply across all hours of the year and across all ranges of system utilization and not just the peak hours.

Q. Did WPL provide an average or marginal loss factor for its system?

A. No. WPL has not identified any losses. Average line losses are typically more easily available but marginal losses typically require more detailed analysis and information. WPL has not provided either.

Q. In the absence of any useful information from WPL regarding its average or marginal system loss factors, how do you estimate loss factors for the purposes of adjusting avoided energy, transmission and capacity cost values?

A. Given that WPL has not provided any useful data about its average or marginal system losses, we suggest using the average loss factors on NSPW system (Ex.-Bhandari-RENEW-20: Ex.-NSPW-Zich-1) as a foundation for our analysis going forward. I will describe how we can derive marginal loss factors using these average loss factors and describe how these can be applied to transmission, capacity and energy.

Q. Were you able to estimate a marginal loss factor for NSPW's system?

A. To estimate marginal losses associated, I would need to know the system utilization factor at peak hours, or in other words, the degree to which the transmission and distribution system is stressed. While the utilization rates at the peak hours are by definition higher than the average rate for an entire year, detailed data for system utilization rates for the entire NSPW system during peak hours is not readily available.

As established, in any hour, across all ranges of system utilization, the marginal losses are higher than the average losses. Therefore, in order to accurately estimate annual average marginal losses, the RAP paper suggests a rule of thumb value that marginal losses are about 1.5 times average losses. Thus, we use a factor of 1.5 to convert annual average line losses to marginal line losses.

For transmission and capacity, in addition to the higher marginal loss factors we also have to account for the higher system utilization rates since the investments driven by hours that are at the highest peak. I have estimated a marginal loss factor based on NSPW's average loss factor, and using the relationship between marginal and average losses illustrated in Figure 1 above (from the RAP paper) at high system utilization rates. Based on the data in Figure 1, marginal losses are 1.4 times greater than average losses at 50 percent system utilization, and 2.6 times greater than average losses at 92 percent system utilization. Based on this range, I rely on a simple factor of 2.0 to convert average losses to marginal losses during higher system utilization periods, including at peak (and thus for generation and transmission capacity).

Q. How do you propose to adjust the avoided transmission costs you calculated above to account for losses?

A. Energy losses increase when demand on the system increases (i.e., at higher system utilization rates) and increase exponentially during peak hours. The avoided transmission costs should be adjusted based on the higher peak-hour marginal loss factors instead of the average loss factors in order to account for higher losses during peak hours. The results shown in Table 13 below are based on losses identified at the secondary voltage.

Table 13. Avoided Costs for Transmission
including marginal losses at secondary voltages

Avoided Cost Component	$/kW-year before marginal losses are applied	$/kW-year after marginal losses are applied
Transmission	70.82	84.22

Q. How do you propose to adjust the avoided capacity costs you calculated above to account for losses?

A. Energy losses increase when demand on the system increases (i.e., at higher system utilization rates) and increase exponentially during peak hours. The avoided capacity costs should be adjusted based on the higher peak-hour marginal loss factors instead of the average loss factors in order to account for higher losses during peak hours. The results shown in Table 14 below are based on losses identified at the secondary voltage.

Table 14. Avoided Costs for Capacity
including marginal losses at secondary voltages

Avoided Cost Component	$/kW-year before marginal losses are applied	$/kW-year after marginal losses are applied
Capacity	89.49	106.41

VI. APPLICATION OF AVOIDED COSTS IN RATES

Q. What is WPL's current proposal for translating avoided transmission and capacity costs to QF credits?

A. WPL has provided two different options for avoided capacity credits. (Ex.-WPL-Dorn-1):

- Option A: The default option that applies to all resources between 20kW to 5MW.
- Option B: This is a Sell-All Option. This applies to resources that sign 5 or 10 year contracts, are separately metered and are located at same premise as the customer's load.

Under both options, the Company proposes a volumetric ($/kWh) capacity credit calculated by dividing the avoided capacity value corresponding to each option across the number of hours within the Company's "High Rate" periods (Direct-WPL-Dorn-3). The Company has not addressed the application of transmission avoided costs in rates because the Company asserts that it was not able to identify any avoided transmission value associated with QF generation.

Q. What are your concerns with the Company's proposed design of capacity and transmission credits for FTM QFs?

A. For FTM resources, which export all generated energy to the grid, the Company's proposed credit design should not be based on hourly energy generation since this may not provide an accurate mapping of a resource's contribution to peak hours. These resources should be credited for their contribution to reducing peak demand (and thereby avoiding capacity and transmission costs) based on the most current MISO Capacity Accreditation rules for each resource type (i.e, solar, wind, thermal, hybrid etc.). This includes the appropriate capacity credit for wind and solar resources based on the most current MISO Wind & Solar Capacity Credit study (Ex.-RENEW-Bhandari-21). These values reflects resource availability during the peak hours and should be used as the basis for estimating the total annual avoided transmission and capacity cost (i.e., multiplying the accredited capacity (in kW) of the specific resource with the appropriate avoided transmission and capacity costs on a $/kW-year basis) since this best reflects the value these resources provide in meeting MISO's capacity obligations.

Based on this, I propose that both the capacity and the transmission avoided costs for front-of-the-meter resources be credited on a $/kW-month basis as opposed to tying the credit to hourly generation on a $/kWh basis. In addition to this concern, please see Section IV of my testimony for the concerns I have with the Company's proposed avoided capacity and transmission values for FTM resources.

Q. What are our concerns with the Company's proposed design of capacity and transmission credits for BTM QFs?

A. I have no concerns with a volumetric capacity credit for BTM resources. Please see Mr.Kell's testimony regarding translation of the avoided transmission and capacity costs from a $/kW-year basis to $/kWh based on the utility's definition of peak periods. However, please see Section IV of my testimony for the concerns I have with the Company's proposed avoided capacity and transmission values for BTM resources. As I have explained, exported energy from BTM resources can avoid transmission and capacity costs in much the same way as FTM resources and therefore BTM resources should receive the same avoided capacity and transmission value as FTM resources.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q. Please summarize your primary conclusions.

A. I conclude that:

- WPL's assessment that QFs do not avoid transmission cost ignores the benefit that QFs provide through load reduction.
- The Company does not justify its proposal to compensate BTM resources for avoided capacity cost based on the MISO PRA.
- The Company does not justify its proposal to compensate FTM resources for avoided capacity cost based on the PRA in the short term and CONE only in the long term.
- The Company has not addressed the application of loss factors to avoided transmission, capacity and energy.
- The Company's proposed capacity credit design for FTM resources underestimates the transmission and capacity benefits that FTM resources provide during peak hours.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission:

- Approve the value of $70.82 $/kW-year for avoided transmission costs;
- Approve my proposed methodology that accounts for marginal load growth-related transmission investments going forward and require that the utilities conduct a similar analysis and provide all stakeholders

transparency concerning the inputs, assumptions, and results from such analysis;

- Approve the use of marginal losses for both avoided transmission and avoided capacity, valued at double the average losses on WPL's system;
- Approve the use of marginal losses for avoided energy valued at 1.5 the average losses on WPL's system;
- Approve the use of MISO Cost of New Entry (CONE) for Local Resource Zone 2, which includes WPL's service territory, to compensate QF capacity for both BTM and FTM resources. MISO CONE in Local Resource Zone 2 for the 2022/2023 planning year is $89.49 per kW-year;
- Approve longer contract periods for separately metered resources in addition to the 5 and 10 year contract periods that the Company has proposed;
- Approve the application of both transmission and capacity credits to FTM resources on a $/kW-month basis; and
- Approve the application of both transmission and capacity credits to BTM resources on a $/kWh basis consistent with RENEW witness Kell's testimony.

Q. Does this conclude your testimony?

A. Yes, it does.