OFFICIAL FILING
BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company, a Wisconsin Corporation, for Approval of Parallel Generation Tariff Modifications and Avoided Costs	4220-TE-109

AFFIDAVIT OF DIVITA BHANDARI

The undersigned, Divita Bhandari, swears or affirms the following:

1. My name is Divita Bhandari.
2. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.
3. I am a Senior Associate with Synapse Energy Economics, Incorporated.
4. In response to RENEW's Second Data Request to NSPW (PSC ERF# 429178), Request RENEW IR-5, NSPW provided confidential cost information in RENEW IR-2 Attachment 5 CONFIDENTIAL (PSC ERF# 430561). My testimony includes a reference to information in that confidential attachment.
5. This testimony satisfies the criteria specified in Wis. Admin. Code PSC § 2.12(3)(a) for the same reasons that the original data response filed by NSPW satisfies those criteria.

Dated this 2nd day of March, 2022,

/s/ Divita Bhandari

Divita Bhandari
Synapse Energy Economics
485 Massachusetts Ave. Ste 3
Cambridge, MA 02139

DIRECT TESTIMONY OF DIVITA BHANDARI
ON BEHALF OF RENEW WISCONSIN, INC.

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.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate the reasonableness of Northern States Power Company - Wisconsin's (NSPW) proposed avoided transmission and capacity costs, including the methodologies underlying the calculation of those 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 NSPW'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. No. I have, however, 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 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.

- The avoided transmission cost proposed by the utility does not accurately value the benefit that distributed energy resources provide through load reduction because they are based on embedded transmission revenue requirements which do not accurately capture forward-looking load growth-related transmission investments.
- The Company's proposed avoided capacity cost is based on sources that deviate significantly from those of regional grid operators, including MISO and PJM, that oversee the capacity markets.
- The Company is underestimating both transmission and capacity avoided cost during peak hours by applying average energy loss factors as opposed to marginal energy loss factors.

- The Company has ignored the contribution of behind-the-meter resources in providing transmission and capacity benefits during peak hours.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission

- approve the value of $35.93 $/kW-year for avoided transmission costs;
- approve my proposed methodology for calculating avoided transmission costs 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 currently proposed;
- approve the use of marginal losses for avoided energy valued at 1.5 the average losses currently proposed;
- approve the Cost of New Entry (CONE) based on MISO's calculation for valuation of avoided capacity costs; and
- approve the application of both transmission and capacity credits to BTM resources on a $/kWh basis during peak hours.

III. AVOIDED TRANSMISSION COSTS

A. Concerns with NSPW's Proposal

Q. Please describe the NSPW proposal for calculating and crediting avoided transmission costs under its revised Pg-2A tariff.

A. For customers taking service under its revised Pg-2A tariff (which is relevant to FTM QFs), the Company proposes an avoided transmission cost that is based on 50 percent of its embedded transmission revenue requirements for 2022 and 2023 as approved in the Company's most recent rate case in Docket No. 4220-UR-125. (Direct-NSPW-Zich-8). The Company takes the resulting value and averages it over all NSPW system kWh to derive a volumetric transmission credit. This results in an avoided transmission cost of $7.31/MWh for 2022 and $7.69/MWh for 2023. (Ex.-NSPW-Application-Attachment B). In addition, the Company has proposed an administrative fee of $1/MWh which results in an avoided transmission cost (before losses) of $6.31/MWh for 2022 and $6.69/MWh for 2023. (Direct-NSPW-Zich-24).

The Company has proposed loss factors from its most recent rate case that will apply to the transmission credit rate. (Direct-NSPW-Zich-24). For energy metered at the secondary voltage the resulting loss factor is 9.45%. (Ex.-NSPW-Application-Attachment A). Therefore, for energy metered at the secondary voltage, the resulting avoided transmission cost is $7.33/MWh. (Ex.-NSPW-Application). The Company has proposed that all QFs under Pg-2A will be credited at this avoided transmission rate for delivery of energy to the Company in all hours. (Ex.-NSPW-Application). The Company further proposes that it will update its avoided transmission costs in future rate cases. (Direct-NSPW-Zich-7).

Q. Do you have concerns with NSPW proposal for calculating avoided transmission costs for FTM QFs?

A. Yes, I have several concerns with NSPW's proposal. First and foremost, the Company has not provided a rationale for basing avoided transmission costs on 50 percent of its embedded transmission revenue requirement. The Company appears to have selected a 50 percent value based on the reasoning that "precise valuation of avoided transmission costs [is] difficult." (Ex.-NSPW-Application). While it may be difficult, estimating avoided transmission costs within a reasonable range of certainty is entirely possible and the Company should have done so.

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

A. Yes. In Section III.B. of my testimony, I will describe methods that can be used to estimate NSPW'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. What is your next concern with NSPW's proposal for calculating avoided transmission costs for FTM QFs?

A. My second concern is that NSPW's value is based on its *embedded* transmission revenue requirement. Embedded transmission costs include sunk costs related to transmission investments and do not accurately capture avoidable future investments. Rather than considering embedded transmission costs, the Company should be developing avoided transmission costs based on *marginal* load-growth-related costs.

Q. Why should the Company develop avoided transmission costs based on marginal costs as opposed to embedded 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 deferring or 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 DERs.

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

A. My next concern is that the Company has derived its transmission credit by dividing 50 percent of its embedded transmission revenue requirements by the total energy consumed by its customers within a year. (Ex.-NSPW-Application-Attachment B). However, load growth-related transmission infrastructure, which distributed generation can avoid, is driven by peak demand and not by total energy consumed during the year. NSPW's methodology therefore does not accurately map costs that are driven by peak demand to a credit for avoiding those costs. I discuss this concern in greater detail in Section VI of my testimony – Application of Avoided Costs in Rates.

Q. Does the Company propose to offer any credit for avoided transmission costs to its customers taking service under its revised Pg-2B tariff?

A. No. The Company does not propose any transmission credit for customers taking service under the revised Pg-2B tariff (relevant to BTM QFs).

Q. Do you have any concerns with that proposal?

A. Yes. BTM resources (particularly those that generate and export during the peak hours of the day) reduce peak demand and thereby reduce the cost that NSPW incurs to meet that peak demand through additional transmission builds. In their 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.[1] Therefore, for those resources that do export energy during the peak hours, these resources should be valued through the same credit as a FTM resource. 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 transmission costs. There are likely certain resources that will not export energy during any of the peak hours and should consequently receive no credit for avoided transmission. In Section VI of my testimony I describe how the transmission credit can be structured to accommodate these different scenarios.

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).

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

- 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 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 NSPW's avoided transmission costs based on this six-step methodology?

A. Yes.

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 extended from 2020 to 2027. This is consistent with transmission planning processes and modeling that typically look five to ten years into the future.[2] However, the value represents forward-looking costs and can continue to be used outside of this analysis period.

---

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

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 NSPW's Strategic Energy Assessment (SEA) 2028 load forecast. (Ex.-RENEW-Bhandari-2: Schedule 5). As discussed above, the load growth timeframes were based on the availability of the transmission-related capital cost data which I will discuss in Step 3.[3] I present a few different load growth estimates below based on the SEA load forecast. Our eventual analysis used the load growth from 2021–2023 and the load growths from 2021–2027. 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)
2021–2023	49
2019–2028	119
2021–2027	95
2020–2022	7

[3] 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 the transmission planning is done by NSPW, I have first gathered data on investments identified by NSPW and then attempted to assess the load growth on which NSPW has based these identified investment needs.

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. In addition, there are additional transmission line investments identified through the Strategic Energy Assessment through 2028. (Ex.-RENEW-Bhandari-2: Schedule 11). In response to RENEW's discovery request, the Company has provided a summary of all the MTEP and SEA investments and their respective estimated costs. (Ex.-RENEW-Bhandari-3).

Based on the data that NSPW provided in discovery (Ex.-RENEW-Bhandari-3) and the list of in-service projects identified as part of MTEP (Ex.-RENEW-Bhandari-4), I identified two load growth-related investments in Wisconsin with expected need dates in 2020 and 2022 respectively. **Table 2** below illustrates NSPW's load growth-related transmission investments by year.

Table 2. Annual capital expenditure data for load growth projects

Year	Capital Expenditure ($)
2020	$4,000,000
2022	$3,500,000
Total	**$7,500,000**

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

A. No. I found that there are other investments 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, NSPW proposed to relocate and rebuild two existing transmission lines between Gingles substation in Ashland and its Ironwood substation. (Ex.-RENEW-Bhandari-5). 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 through the mid-century." (Ex.-RENEW-Bhandari-5). 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 and SEA data that could have a load growth-related component but were not explicitly classified as load growth-related projects. (Ex.-RENEW-Bhandari-3 and Ex.-RENEW-Bhandari-4).[4] These categories are: 1) Reliability projects, 2) Age and Condition, and 4) Unclassified projects. I then applied my proxy estimate of ten

[4] I removed two projects that were classified as having been through a prior MTEP process since I was unclear about their status in relation to addressing prospective load growth. Both of these had expected in service dates of January 2025.

percent as discussed above to estimate the portion of the costs associated with these projects that may be load growth-related.

In **Table 3** 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.

Table 3. Capital cost of projects that are expected to have a load growth-related component but are not directly classified as load growth projects

In Service Year	Capital Expenditure ($)
2020	$371,000
2021	$20,370,000
2022	$58,708,976
2023	$29,160,000
2024	$87,560,000
2026	$5,000,000
Total Estimated Cost	**$201,169,976**
Load growth-related costs	$20,116,998

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 NSPW's transmission planning process. If the utility had conducted an analysis that did not have the failings 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 and SEA, 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 of September 2020 and December 2022, so I assume they are caused by load growth between 2021 and 2023, as shown in **Table 4** below.[5]

---

[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.

Table 4. $/kW for projects classified as load growth-related

Load Growth Timeframe	2021–2023
Capex Timeframe	2020–2022
Load Growth (MW)	49
Load Growth related Capital Expenditure (000's)	7,500
$/kW	153

Second, for capital expenditures that were not explicitly classified as load growth-related (but may have a load growth-related component), I performed a similar calculation as shown in **Table 5** below. The timeframe for this analysis is longer because I have information about planned capital projects through 2026, which I associate with load growth through 2027.[6]

Table 5. $/kW for projects not classified as load growth-related (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021–2027
Capex Timeframe	2020–2026
Load Growth (MW)	95
Load Growth related Capital Expenditure (000's)	20,117
$/kW	212

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 levelized nominal revenue requirement. I based this nominal

[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.

levelized revenue requirement on historical FERC Form 1 data (Ex.-RENEW-Bhandari-11), the rate case filing, and Attachment O submitted to MISO.[7] The calculation accounts for recovering the capital invested (through depreciation), the asset owner's return on the capital (both debt 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 9.85 percent.

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

A. 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 6** below shows the annual avoided transmission costs for load growth-related projects and **Table 7** 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).

[7] Please note that RENEW asked the utility for this data but were not provided it. The calculations are based on publicly available data and should be replaced by data provided by NSPW for annualization of different types of transmission investments.

Table 6. $/kW-Year for projects classified as load growth

Load Growth Timeframe	2021- 2023
Capex Timeframe	2020 - 2022
Load Growth (MW)	49
Load Growth related Capital Expenditure (000's)	7,500
$/kW	153
Carrying Charges	9.85%
Annualized ($/kW-Year)	15.08

Table 7. $/kW-Year for projects not classified as load growth (but still may have a load growth component); assuming 10% load growth portion

Load Timeframe	2021–2027
Capex Timeframe	2020–2026
Load Growth (MW)	95
Load Growth related Capital Expenditure (000's)	20,117
$/kW	212
Carrying Charges	9.85%
Annualized ($/kW-Year)	20.86

Per this analysis above, the avoided transmission cost associated with projects that are explicitly classified as load growth projects is $15.08/kW-year, which should serve as the floor value for avoided transmission costs.

The avoided transmission cost 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 $20.86 $/kW-year. I believe this is a reasonable estimate based on our analysis of FERC data 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 8** below, NSPW's total avoided transmission cost (exclusive of losses) is $35.93 $/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 8. Total annualized avoided transmission costs (not including losses)

Avoided Transmission Costs	Annualized $/kW
Projects classified as load growth-related	15.08
Load Growth Component of projects not expressly classified as load growth-related	20.86
Total Avoided Transmission Costs	**35.93**

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 NSPW's annual FERC Form 1 filing. I used historical transmission capital expenditures for the period from 2016 to 2020 and associated this with load growth between 2017 and 2021.[8] Because these historical expenditures are not

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

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-12) Similarly, the overall estimated percentage of projects that are load growth related in Wisconsin is approximately 14 percent based on Wisconsin's Strategic Energy Assessment – 2026, Table 2-1 (Ex.-RENEW-Bhandari-13).

In my cross-check analysis, I used the same levelized carrying cost for annualization as I did for my bottom-up analysis. **Table 9a-c** below illustrate the results of my cross-check analysis, which produces an annualized avoided transmission cost ranging from $19.08 to $57.23/kW-year (before adjusting for losses). Assuming 10 percent of the capital expenditures are load growth results in a value that aligns closely with the $35.93/kW-year avoided transmission cost value that my bottom-up analysis produced. This suggests that my bottom-up analysis produces a reasonable estimate.

Table 9a. Avoided Transmission Cost based on FERC Form 1; assuming 5% capital expenditures are load growth related

Load Timeframe	2017–2021
Capex Timeframe	2016–2020
Load Growth (MW)	105
Load Growth related Capital Expenditure (000's)	20,335
$/kW	194
Carrying Charges	9.85%
Annualized ($/kW-Year)	19.08

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

Load Timeframe	2017–2021
Capex Timeframe	2016–2020
Load Growth (MW)	105
Load Growth related Capital Expenditure (000's)	40,669
$/kW	387
Carrying Charges	9.85%
Annualized ($/kW-Year)	38.15

Table 11c. Avoided Transmission Cost based on FERC Form 1; assuming 15% capital expenditures are load growth related

Load Timeframe	2017–2021
Capex Timeframe	2016–2020
Load Growth (MW)	105
Load Growth related Capital Expenditure (000's)	61,004
$/kW	581
Carrying Charges	9.85%
Annualized ($/kW-Year)	57.23

Q. How does this compare with other jurisdictions?

A. Based on my review, an avoided transmission cost of $35.93/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-6). 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-7). 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-8). These results suggest that the value that I have derived is reasonable.

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

A. I have developed these values based on publicly available data. This is particularly challenging given limited insight into NSPW'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. 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.

I recommend that the Commission (1) adopt the value of $35.93 $/kW-year that I developed, and (2) direct the utilities to use the above methodology and conduct a similar analysis as I have described, informed by their internal transmission planning process in the future. The utility should be clear and transparent about the drivers and designs for its transmission investments and make their analysis readily available to stakeholders.

IV. AVOIDED CAPACITY COSTS

Q. Please describe NSPW's proposal for calculating and crediting avoided capacity costs for FTM QFs.

A. The Company proposes a capacity credit derived from Northern States Power's Integrated Resource Plan. To develop avoided capacity costs, it relies on a peaker unit methodology which it refers to as the surplus capacity credit (SCC) methodology. (Direct-NSPW-Zich-9). Per that methodology, the valuation of capacity is based on the lowest cost new capacity resource modeled in the NSP System IRP, which is an H-Class combustion turbine. For 2022, NSPW proposes an avoided capacity cost of $4.95/kW-month, which is equivalent to $59,400/MW-year. (Ex.-NSPW-Application). This value of $4.95/kW-month would be multiplied by the accredited capacity that is derived using the MISO's capacity accreditation rules for the resource type. (Ex.-NSPW-Application). The Company does not intend to provide any credit for avoided capacity until 2026 because its most recent IRP does not observe a need for capacity until 2026. (Ex.-NSPW-Application).

Q. What are your concerns with NSPW's proposed avoided capacity credit for front-of-the-meter resources?

A. The Company's proposed avoided capacity cost is based on sources that deviate significantly from those of regional grid operators, including MISO and PJM, that oversee the capacity markets. The Company's proposed avoided capacity value of $59,400/MW-year is 35 percent less than the MISO cost of new entry (CONE) value for the 2022/2023 planning year of $91,270/ MW-yr in Local Resource Zone 1, which includes NSPW's service territory (Ex.-RENEW-Bhandari-9).

Q. Please elaborate on the gap between MISO's CONE value and NSPW's proposed avoided capacity cost.

A. There are several differences between the Company's calculations and MISO's calculations. The most impactful difference is the assumed capital cost. MISO bases its analysis on the U.S. Energy Information Administration's estimates of capital costs for new combustion turbines in each state. Based on the values for Minnesota and North Dakota, MISO finds that the capital cost of a new combustion turbine in LRZ 1 is $759/kW (Ex.-RENEW-Bhandari-9). In the neighboring PJM region, Brattle Group and Sargent & Lundy estimated capital costs of a combustion turbine at between $835/kW and $938/kW in a Cost of New Entry study (Ex.-RENEW-Bhandari-10). By contrast, in response to RENEW's Second Data Request to NSPW (PSC ERF# 429178), Request RENEW IR-5, NSPW provided cost information in Attachment 5 CONFIDENTIAL (PSC ERF# 430561) showing that NSPW assumes a capital cost for a combustion turbine is [redacted]. The deviation between NSPW's cost estimate and other established sources suggests NSPW's estimate may be too low. Given that MISO's CONE is a publicly vetted, location-specific capacity value for NSPW's service territory, the Company should set the value of avoided capacity at MISO's CONE since there is no clear justification for not using this publicly vetted source.

Q. What do you recommend with respect to the calculation of NSPW's avoided capacity costs?

A. In the MISO footprint, CONE is an established estimate of the long-run marginal capacity cost. According to the 2021 MISO CONE filing, the value of CONE in Wisconsin for the 2022/2023 planning year is $91,270/MW-yr in Local Resource Zone 1 (which includes western Wisconsin and NSPW's service territory) (Ex.-RENEW-Bhandari-9). Each year, avoided capacity costs should be updated to reflect the latest CONE value.

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.

Q. Does the Company propose to offer any credit for avoided capacity costs to customers taking service under its revised Pg-2B tariff?

A. No.

Q. How do you respond?

A. It is not reasonable to offer BTM generation resources a zero value for avoided capacity. BTM resources (particularly those that generate during the peak hours of the day) reduce the peak demand and thereby reduce the cost of the utility in meeting that peak demand through additional generation capacity builds or contracts. As I explained above, 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 capacity costs) as an FTM resource. Therefore, for those resources that do export energy during peak hours, these resources should be valued through the same credit as an FTM resource.

V. AVOIDED LOSSES

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

A. In this section of my testimony, I will explain my concerns with NSPW's application of losses in their determination of avoided costs.

Q. Please describe your concerns with NSPW's application of avoided costs.

A. The Company has applied what appears to be an average loss factor as opposed to a marginal loss factor. In addition, the Company has proposed similar average loss factors for transmission, capacity and energy.

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

A. The 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.

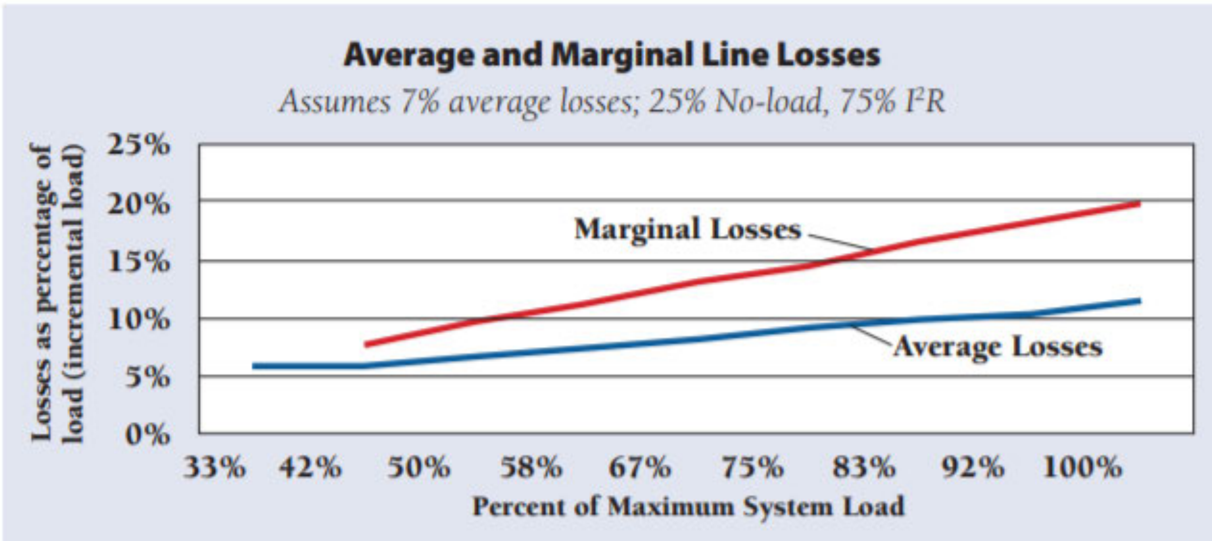
A. The amount of energy loss in any hour is affected by a number of factors including resistance in wires, system utilization rates, and weather conditions. The formulae for losses is I^2R or the square of the current multiplied by resistance. The "I" on the system is a direction function of the load 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-7). 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.



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, marginal loss factors should be applied.

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

A. Yes, marginal loss factors should be applied 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 will 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 NSPW provide a marginal loss factor for its system?

A. No. Average line losses are typically more easily available but marginal losses typically require more detailed analysis and information.

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 X, 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 12** below are based on losses identified at the secondary voltage.

Table 12. 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	35.93	42.73

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 13** below are based on losses identified at the secondary voltage.

Table 13. 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	91.27	108.53

VI. APPLICATION OF AVOIDED COSTS IN RATES

Q. What are your concerns regarding NSPW's proposed design of avoided capacity and transmission credits for FTM QFs?

A. In Sections III and IV, I have outlined my concerns with the values that have been proposed by the utility for avoided transmission and capacity credits, respectively. In terms of the structure of the tariff, I agree with the proposed methodology whereby capacity is credited on a $/kw-month basis and energy on a $/kWh basis.[9] However, I have concerns with the application and tariff structure of the transmission avoided costs to front-of-the-meter resources. The current proposal put forward by the utility credits front-of-the-meter resources on a $/kWh basis for each hour of generation during the year. This methodology provides an inaccurate mapping of peak demand-related costs to hourly energy costs. Transmission costs are driven by peak demand and the resource should be credited for their contribution in reducing peak demand.

Q. What are your proposed suggestions?

I propose that transmission avoided costs for front-of-the-meter resources be credited on a $/kW-month basis similar to the capacity credit.

Q. Please summarize how NSPW proposes to credit BTM resources for avoided transmission and capacity value.

A. NSPW does not propose any avoided transmission or capacity value for BTM resources. As I have explained above, I do not believe that this is reasonable.

---

[9]Application, pg. 9

Exported energy from BTM resources can avoid transmission and capacity costs in much the same way as FTM resources.

Q. Please elaborate.

A. When a BTM resource is generating energy, it may either (1) serve customer-sited load or (2) export to the grid. In hours when the BTM resource is serving the customer's load, the customer benefits through avoided retail rates. However, BTM resources that export energy during the peak hours will reduce the peak demand (which the utility would otherwise have to meet) and thereby reduce the costs that the utility incurs by avoiding additional transmission and capacity infrastructure required to meet the higher peak demand.

Q. What do you recommend?

A. The avoided transmission and capacity costs that I propose in my testimony should apply equally to BTM and FTM resources. BTM resources should receive avoided transmission and capacity credits for their exports during peak hours. In order to credit a BTM resource for exports during peak hours, I suggest that avoided transmission and capacity costs be converted to a $/kWh credit. In order to translate a $/kW-year transmission or capacity cost to an hourly avoided cost, I suggest dividing this $/kW-year by the total number of peak hours as defined by NSPW. This will be discussed in more detail in Mr. Kell's testimony.

VII. RECOMMENDATIONS AND CONCLUSIONS

Q. Please summarize your primary conclusions.

- NSPW's avoided transmission cost does not accurately value the benefit that distributed energy resources provide through load reduction because it is based on embedded transmission revenue requirements which do not accurately capture the forward-looking load growth-related transmission investments.

- The Company's proposed avoided capacity cost is based on sources that deviate significantly from those of regional grid operators, including MISO and PJM, that oversee the capacity markets.
- The Company is underestimating both transmission and capacity avoided cost during peak hours by applying average energy loss factors as opposed to marginal energy loss factors.
- The Company has ignored the contribution of behind-the-meter resources in providing transmission and capacity benefits during peak hours.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission

- approve the value of $35.93 $/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 currently proposed;
- approve the use of marginal losses for avoided energy valued at 1.5 the average losses currently proposed;

- approve the Cost of New Entry (CONE) based on MISO's calculation for valuation of avoided capacity costs; and
- approve the application of both transmission and capacity credits to BTM resources on a $/kWh basis during peak hours.

Q. Does this conclude your testimony?

A. Yes, it does.