

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

1 **I. INTRODUCTION AND QUALIFICATIONS**

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

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

6 **Q. Please summarize your professional experience.**

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

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

17 **Q. Please summarize your educational background.**

18 A. I hold a Master of Environmental Management from the Yale School of Forestry
19 and Environmental Studies, a Master of Science in Electrical Engineering,

1 specializing in Electric Power systems, from the Georgia Institute of Technology,
2 and a Bachelor of Science in Electrical Engineering, also from the Georgia
3 Institute of Technology. A copy of my current resume is attached as Ex.-
4 RENEW-Bhandari-1.

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

6 A. I am testifying on behalf of RENEW Wisconsin.

7 **Q. What is the purpose of your testimony?**

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

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

19 A. No. I have, however, submitted expert testimony in Colorado in a proceeding
20 regarding Public Service Company of Colorado's 2021 Electric Resource and
21 Clean Energy Plan on behalf of the Colorado Energy Office (Proceeding No.
22 21A-0141E). I have also assisted in preparing testimony in proceedings related to
23 rate cases and infrastructure investment programs in New Jersey, evaluating

1 distribution system investments on behalf of the New Jersey Division of Rate
2 Counsel.

3 **Q. Have you developed methodological approaches used by utilities when**
4 **evaluating the cost-effectiveness of DERs?**

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

11 **II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

12 **Q. Please summarize your primary conclusions.**

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

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

3 **Q. Please summarize your primary recommendations.**

4 A. I recommend that the Commission

- 5 • approve the value of \$35.93 \$/kW-year for avoided transmission costs;
- 6 • approve my proposed methodology for calculating avoided transmission
7 costs that accounts for marginal load growth-related transmission
8 investments going forward and require that the utilities conduct a similar
9 analysis and provide all stakeholders transparency concerning the inputs,
10 assumptions, and results from such analysis;
- 11 • approve the use of marginal losses for both avoided transmission and
12 avoided capacity, valued at double the average losses currently proposed;
- 13 • approve the use of marginal losses for avoided energy valued at 1.5 the
14 average losses currently proposed;
- 15 • approve the Cost of New Entry (CONE) based on MISO’s calculation for
16 valuation of avoided capacity costs; and
- 17 • approve the application of both transmission and capacity credits to BTM
18 resources on a \$/kWh basis during peak hours.

1 **III. AVOIDED TRANSMISSION COSTS**

2 **A. Concerns with NSPW's Proposal**

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

5 A. For customers taking service under its revised Pg-2A tariff (which is relevant to
6 FTM QFs), the Company proposes an avoided transmission cost that is based on
7 50 percent of its embedded transmission revenue requirements for 2022 and 2023
8 as approved in the Company's most recent rate case in Docket No. 4220-UR-125.
9 (Direct-NSPW-Zich-8). The Company takes the resulting value and averages it
10 over all NSPW system kWh to derive a volumetric transmission credit. This
11 results in an avoided transmission cost of \$7.31/MWh for 2022 and \$7.69/MWh
12 for 2023. (Ex.-NSPW-Application-Attachment B). In addition, the Company has
13 proposed an administrative fee of \$1/MWh which results in an avoided
14 transmission cost (before losses) of \$6.31/MWh for 2022 and \$6.69/MWh for
15 2023. (Direct-NSPW-Zich-24).

16 The Company has proposed loss factors from its most recent rate case that
17 will apply to the transmission credit rate. (Direct-NSPW-Zich-24). For energy
18 metered at the secondary voltage the resulting loss factor is 9.45%. (Ex.-NSPW-
19 Application-Attachment A). Therefore, for energy metered at the secondary
20 voltage, the resulting avoided transmission cost is \$7.33/MWh. (Ex.-NSPW-
21 Application). The Company has proposed that all QFs under Pg-2A will be
22 credited at this avoided transmission rate for delivery of energy to the Company

1 in all hours. (Ex.-NSPW-Application). The Company further proposes that it will
2 update its avoided transmission costs in future rate cases. (Direct-NSPW-Zich-7).

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

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

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

13 A. Yes. In Section III.B. of my testimony, I will describe methods that can be used to
14 estimate NSPW's avoided transmission costs within a reasonable range of
15 certainty. I will also describe my application of those methods and the results of
16 my analysis.

17 **Q. What is your next concern with NSPW's proposal for calculating avoided**
18 **transmission costs for FTM QFs?**

19 A. My second concern is that NSPW's value is based on its *embedded* transmission
20 revenue requirement. Embedded transmission costs include sunk costs related to
21 transmission investments and do not accurately capture avoidable future
22 investments. Rather than considering embedded transmission costs, the Company

1 should be developing avoided transmission costs based on *marginal* load-growth-
2 related costs.

3 **Q. Why should the Company develop avoided transmission costs based on**
4 **marginal costs as opposed to embedded costs?**

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

15 Historical data regarding investment and load growth would only be used
16 in circumstances where forward looking costs are not available or when there is
17 not substantial relevant data available into the future. Historical load growth
18 related capital costs are not the same as embedded costs since they represent load
19 growth related investments in transmission system whereas embedded costs
20 represent the revenue requirements that have been developed for the purpose of
21 setting rates. The methodologies applied to developing revenue requirements do
22 not capture the costs that can be avoided since they are developed for an entirely
23 different purpose. In cases where historical data are used to develop marginal

1 costs, the capital investments would likely already be a part of the embedded
2 transmission revenue requirements. However, they can still present the best
3 available way to value avoided costs going forward since they calculate a value
4 based on investment that could have been avoided through load reductions from
5 DERs.

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

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

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

1 **Q. Please describe your next concern with NSPW’s proposal for calculating and**
2 **crediting avoided transmission costs for FTM QFs.**

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

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

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

16 **Q. Do you have any concerns with that proposal?**

17 A. Yes. BTM resources (particularly those that generate and export during the peak
18 hours of the day) reduce peak demand and thereby reduce the cost that NSPW
19 incurs to meet that peak demand through additional transmission builds. In their
20 proposal, the Company has ignored the contribution of BTM resources towards
21 meeting peak demand. The ability of a BTM resource to contribute towards peak
22 reduction depends on the nature of the resources and the nature of the on-site load
23 that it serves. However, for every unit of energy exported by a BTM resource

1 during peak hours it has at least as much impact on peak reduction (and thereby
2 avoided transmission costs) as an FTM resource.¹ Therefore, for those resources
3 that do export energy during the peak hours, these resources should be valued
4 through the same credit as a FTM resource. As an extreme example, if a BTM
5 resource exports the same amount of energy as a FTM resource of equivalent size
6 during the peak hours of the year, they are providing an equivalent magnitude of
7 peak reduction and thereby an equivalent reduction in avoided transmission costs.
8 There are likely certain resources that will not export energy during any of the
9 peak hours and should consequently receive no credit for avoided transmission. In
10 Section VI of my testimony I describe how the transmission credit can be
11 structured to accommodate these different scenarios.

12 **B. Proposed Methodology for Calculating Avoided Transmission Cost**

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

- 16 A. The following method can be used to calculate avoided transmission costs:
- 17 ○ Step 1: Select a time period for the analysis, which may be historical,
18 prospective, or a combination of the two. (A prospective period is
19 preferred if data are available.)
 - 20 ○ Step 2: Determine the actual or expected relevant load growth in the
21 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.

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

9 **Q. Have you analyzed NSPW’s avoided transmission costs based on this six-step**
10 **methodology?**

11 A. Yes.

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

14 A. My choice of time period was based on the availability of data for historical and
15 future transmission capital investments. Based on the publicly available data, I
16 selected an analysis period that extended from 2020 to 2027. This is consistent
17 with transmission planning processes and modeling that typically look five to ten
18 years into the future.² However, the value represents forward-looking costs and
19 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.

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

3 A. In order to determine the relevant load growth in the analysis period, I used
4 NSW's Strategic Energy Assessment (SEA) 2028 load forecast. (Ex.-RENEW-
5 Bhandari-2: Schedule 5). As discussed above, the load growth timeframes were
6 based on the availability of the transmission-related capital cost data which I will
7 discuss in Step 3.³ I present a few different load growth estimates below based on
8 the SEA load forecast. Our eventual analysis used the load growth from 2021–
9 2023 and the load growths from 2021–2027. However, in **Table 1** below, I have
10 provided some sample load growths based on some different analysis periods for
11 illustrative purposes.

12 **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

13

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 NSW, I have first gathered data on investments identified by NSW and then attempted to assess the load growth on which NSW has based these identified investment needs.

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

3 A. The MISO Transmission Expansion Plan (MTEP) is conducted on an annual basis
4 and evaluates studies and planning initiatives that help MISO address future grid
5 needs. As an outcome of this study, MTEP identifies specific transmission
6 infrastructure improvements that are required to address a variety of needs
7 including reliability, aging infrastructure, load growth investments, etc. In
8 addition, there are additional transmission line investments identified through the
9 Strategic Energy Assessment through 2028. (Ex.-RENEW-Bhandari-2: Schedule
10 11). In response to RENEW’s discovery request, the Company has provided a
11 summary of all the MTEP and SEA investments and their respective estimated
12 costs. (Ex.-RENEW-Bhandari-3).

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

1 **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

2
3 **Q. Does the table above capture all of NSPW’s load growth-related transmission**
4 **investments in the analysis period?**

5 A. No. I found that there are other investments not explicitly classified as “load
6 growth-related” that could potentially have a load growth component. In other
7 words, while a project may be classified as “Reliability”, “Age and Condition”, or
8 some other category that is not “Load Growth,” the project may nevertheless
9 serve a load-growth purpose.

10 For example, NSPW proposed to relocate and rebuild two existing
11 transmission lines between Gingles substation in Ashland and its Ironwood
12 substation. (Ex.-RENEW-Bhandari-5). The project costs are anticipated to range
13 from approximately \$131 million to \$139 million depending on the final route
14 selected. Based on our review of the proposal, NSPW states that the identified
15 project will “address all reliability concerns and increase load-serving capability
16 in the area to meet anticipated customer needs through the mid-century.” (Ex.-
17 RENEW-Bhandari-5). Although I cannot confirm with certainty, it appears that
18 this project may have been identified in MTEP20 but was not classified explicitly
19 as a load growth project.

20 However, while the transmission line rebuild between the Gingles
21 substation and the Ironwood substation is not expressly classified as a “load-

1 growth-related” project, the project has a load-growth purpose, among other
2 purposes.

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

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

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

15 A. I used a process very similar to my assessment of capital expenditures associated
16 with load growth-related projects. I identified all the projects from MTEP and
17 SEA data that could have a load growth-related component but were not explicitly
18 classified as load growth-related projects. (Ex.-RENEW-Bhandari-3 and Ex.-
19 RENEW-Bhandari-4).⁴ These categories are: 1) Reliability projects, 2) Age and
20 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.

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

3 In **Table 3** below, I show annual capital expenditure data for transmission
4 projects that may have a load growth component but are not explicitly classified
5 as load growth-related projects. I have estimated load growth-related costs based
6 on my estimate that ten percent of these costs will be load growth-related.

7 **Table 3. Capital cost of projects that are expected to have a load growth-related**
8 **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

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

12 **A.** In calculating the avoided transmission cost, I matched the timing of the capital
13 investments with the timing of load growth. Investments and utility spending to
14 address load growth typically occur in advance of when the load growth actually
15 occurs on the system. In other words, to maintain reliable service, a load-growth-
16 related investment precedes the year in which the expected load requires the asset
17 to be in service. Therefore, in order to determine the cost of load growth-related
18 transmission investment, it is necessary to understand the utility's process of

1 mapping these investments to the specific time period that is driving those
2 investments. As a simple example: an investment in 2019 may be driven by some
3 future load growth expected to occur in 2020 while another 2019 investment may
4 be driven by some load growth expected in 2022.

5 Mapping load growth to capital expenditures can be challenging, partly
6 because capital expenditure data are lumpy. I do not have full insight into what
7 load growth is driving the above capital expenditures since I do not have insight
8 into NSPW's transmission planning process. If the utility had conducted an
9 analysis that did not have the failings I identified above, we would have better
10 data with which to conduct this analysis.

11 I based my load growth timeframe on the expected need dates for each of
12 the transmission investments as indicated in MTEP and SEA, based on the
13 assumption that load-growth-related investments would not be built too far in
14 advance of when they are required. I took the relevant load growth based on Step
15 2 and applied it to the capital expenditures in Step 3 to get a \$/kW value. First, I
16 looked at only the projects that have been explicitly identified as load-growth-
17 related. These projects have investment dates of September 2020 and December
18 2022, so I assume they are caused by load growth between 2021 and 2023, as
19 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.

1

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

2

3 Second, for capital expenditures that were not explicitly classified as load growth-
 4 related (but may have a load growth-related component), I performed a similar
 5 calculation as shown in **Table 5** below. The timeframe for this analysis is longer
 6 because I have information about planned capital projects through 2026, which I
 7 associate with load growth through 2027.⁶

8 **Table 5. \$/kW for projects not classified as load growth-related (but still may have a**
 9 **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

10

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

13 **A.** To turn an upfront capital cost into an annual value reflecting what ratepayers
 14 would actually pay, I annualized the \$/kW values developed in Step 4 based on
 15 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.

1 levelized revenue requirement on historical FERC Form 1 data (Ex.-RENEW-
2 Bhandari-11), the rate case filing, and Attachment O submitted to MISO.⁷ The
3 calculation accounts for recovering the capital invested (through depreciation), the
4 asset owner's return on the capital (both debt and equity), and both property and
5 income taxes. While the annual cost of a given asset varies over the asset's life, I
6 developed a levelized result because the purpose of our analysis is to develop a
7 factor that transforms a portfolio of future avoided assets into a single avoided
8 cost to apply over time. Assets that are not constructed also do not have operation
9 and maintenance (O&M) costs, so I also included an allowance for avoided O&M
10 in the derivation of the levelized nominal revenue requirements. The resulting
11 annual levelized carrying cost factor is 9.85 percent.

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

14 A. Based on the process described above, I calculated the annual levelized values for
15 each component of the avoided transmission costs (i.e., load growth-related and
16 projects that may have a load growth portion). **Table 6** below shows the annual
17 avoided transmission costs for load growth-related projects and **Table 7** shows
18 the annual avoided transmission costs for the approach using capital expenditures
19 that were not classified as load growth-related (but may have a load growth-
20 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.

1

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

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3

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

4

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

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6

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.

7

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9

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

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13

14

1 based on our analysis of FERC data and that this results in a value that is in the
2 range of avoided transmission costs across other jurisdictions.

3 Therefore, per my analysis, and as described in **Table 8** below, NSPW's
4 total avoided transmission cost (exclusive of losses) is \$35.93 \$/kW-year. This
5 includes both the avoided transmission cost of load growth projects and the
6 avoided cost of transmission for projects for which a portion of the costs may be
7 load growth-related.

8 **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

9

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

12 A. I based my avoided transmission cost analysis on bottom-up data related to future
13 expenditures on a project-by-project basis, which is the correct way to conduct
14 avoided transmission cost analysis. However, as a cross-check, I compared my
15 results with results produced using historical top-down accounting data from
16 NSPW's annual FERC Form 1 filing. I used historical transmission capital
17 expenditures for the period from 2016 to 2020 and associated this with load
18 growth between 2017 and 2021.⁸ Because these historical expenditures are not

⁸ 2017–2020 loads were actuals and not forecasts.

1 classified based on purpose, I had to make an assumption about what portion
 2 could have been avoided with lower loads. I analyzed results assuming that 5
 3 percent, 10 percent, or 15 percent of these costs were associated with load growth
 4 (The 5 percent, 10 percent, and 15 percent ranges chosen are conservative
 5 estimates. The estimated percentage of total load growth related projects across
 6 MISO is 20 percent. (Ex.-RENEW-Bhandari-12) Similarly, the overall estimated
 7 percentage of projects that are load growth related in Wisconsin is approximately
 8 14 percent based on Wisconsin’s Strategic Energy Assessment – 2026, Table 2-1
 9 (Ex.-RENEW-Bhandari-13).

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

18 **Table 9a. Avoided Transmission Cost based on FERC Form 1; assuming 5% capital**
 19 **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

1

2 **Table 10b. Avoided Transmission Cost based on FERC Form 1; assuming 10%**
3 **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

4

5 **Table 11c. Avoided Transmission Cost based on FERC Form 1; assuming 15%**
6 **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

7 **Q. How does this compare with other jurisdictions?**

8 A. Based on my review, an avoided transmission cost of \$35.93/kW-yr (before
9 adjusting for losses) is within the range of avoided transmission costs produced in
10 other jurisdictions. Based on a study conducted in 2014, a review of nationwide
11 averages show that the values can vary substantially. The average results are
12 \$20.21 \$/kW-year, while the values range from \$0 to \$88.64. (Ex.-RENEW-
13 Bhandari-6). Based on a study conducted by Regulatory Assistance Project
14 (RAP), in 2011, the avoided transmission costs ranged from \$20/kW-year to

1 \$100/kW-year for transmission (Ex.-RENEW-Bhandari-7). In Northern States
2 Power – Minnesota’s MN Value of Solar proceeding, Xcel proposed an avoided
3 transmission cost of \$49.72 \$/kW-year (Ex.RENEW-Bhandari-8). These results
4 suggest that the value that I have derived is reasonable.

5 **Q. Would you like to add anything else regarding your analysis of NSPW’s**
6 **avoided transmission costs?**

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

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

1 **IV. AVOIDED CAPACITY COSTS**

2 **Q. Please describe NSPW’s proposal for calculating and crediting avoided**
3 **capacity costs for FTM QFs.**

4 A. The Company proposes a capacity credit derived from Northern States Power’s
5 Integrated Resource Plan. To develop avoided capacity costs, it relies on a peaker
6 unit methodology which it refers to as the surplus capacity credit (SCC)
7 methodology. (Direct-NSPW-Zich-9). Per that methodology, the valuation of
8 capacity is based on the lowest cost new capacity resource modeled in the NSP
9 System IRP, which is an H-Class combustion turbine. For 2022, NSPW proposes
10 an avoided capacity cost of \$4.95/kW-month, which is equivalent to
11 \$59,400/MW-year. (Ex.-NSPW-Application). This value of \$4.95/kW-month
12 would be multiplied by the accredited capacity that is derived using the MISO’s
13 capacity accreditation rules for the resource type. (Ex.-NSPW-Application). The
14 Company does not intend to provide any credit for avoided capacity until 2026
15 because its most recent IRP does not observe a need for capacity until 2026. (Ex.-
16 NSPW-Application).

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

19 A. The Company’s proposed avoided capacity cost is based on sources that deviate
20 significantly from those of regional grid operators, including MISO and PJM, that
21 oversee the capacity markets. The Company’s proposed avoided capacity value of
22 \$59,400/MW-year is 35 percent less than the MISO cost of new entry (CONE)

1 value for the 2022/2023 planning year of \$91,270/ MW-yr in Local Resource
2 Zone 1, which includes NSPW's service territory (Ex.-RENEW-Bhandari-9).

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

5 A. There are several differences between the Company's calculations and MISO's
6 calculations. The most impactful difference is the assumed capital cost. MISO
7 bases its analysis on the U.S. Energy Information Administration's estimates of
8 capital costs for new combustion turbines in each state. Based on the values for
9 Minnesota and North Dakota, MISO finds that the capital cost of a new
10 combustion turbine in LRZ 1 is \$759/kW (Ex.-RENEW-Bhandari-9). In the
11 neighboring PJM region, Brattle Group and Sargent & Lundy estimated capital
12 costs of a combustion turbine at between \$835/kW and \$938/kW in a Cost of New
13 Entry study (Ex.-RENEW-Bhandari-10). By contrast, in response to RENEW's
14 Second Data Request to NSPW (PSC ERF# 429178), Request RENEW IR-5,
15 NSPW provided cost information in Attachment 5 CONFIDENTIAL (PSC ERF#
16 430561) showing that NSPW assumes a capital cost for a combustion turbine is
17 [REDACTED]. The deviation between NSPW's cost estimate and other established
18 sources suggests NSPW's estimate may be too low. Given that MISO's CONE is
19 a publicly vetted, location-specific capacity value for NSPW's service territory,
20 the Company should set the value of avoided capacity at MISO's CONE since
21 there is no clear justification for not using this publicly vetted source.

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

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

9 For multi-year contracts, avoided capacity costs can be projected by
10 applying an anticipated inflation rate to the latest CONE value. There is
11 significant uncertainty in inflation going forward so for simplicity, we assume a 2
12 percent inflation rate. The value of capacity in the 2023/2024 planning year, for
13 example, would be calculated by applying one year of inflation to the CONE
14 value for the 2022/2023 planning year. This process would be repeated for all
15 future years.

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

18 A. No.

19 **Q. How do you respond?**

20 A. It is not reasonable to offer BTM generation resources a zero value for avoided
21 capacity. BTM resources (particularly those that generate during the peak hours of
22 the day) reduce the peak demand and thereby reduce the cost of the utility in
23 meeting that peak demand through additional generation capacity builds or

1 contracts. As I explained above, the ability of a BTM resource to contribute
2 towards peak reduction depends on the nature of the resources and the nature of
3 the on-site load that it serves. However, for every unit of energy exported by a
4 BTM resource during peak hours, it has at least as much impact on peak reduction
5 (and thereby avoided capacity costs) as an FTM resource. Therefore, for those
6 resources that do export energy during peak hours, these resources should be
7 valued through the same credit as an FTM resource.

8 **V. AVOIDED LOSSES**

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

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

12 **Q. Please describe your concerns with NSW's application of avoided costs.**

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

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

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

1 **Q. Please describe the relationship between loading and losses.**

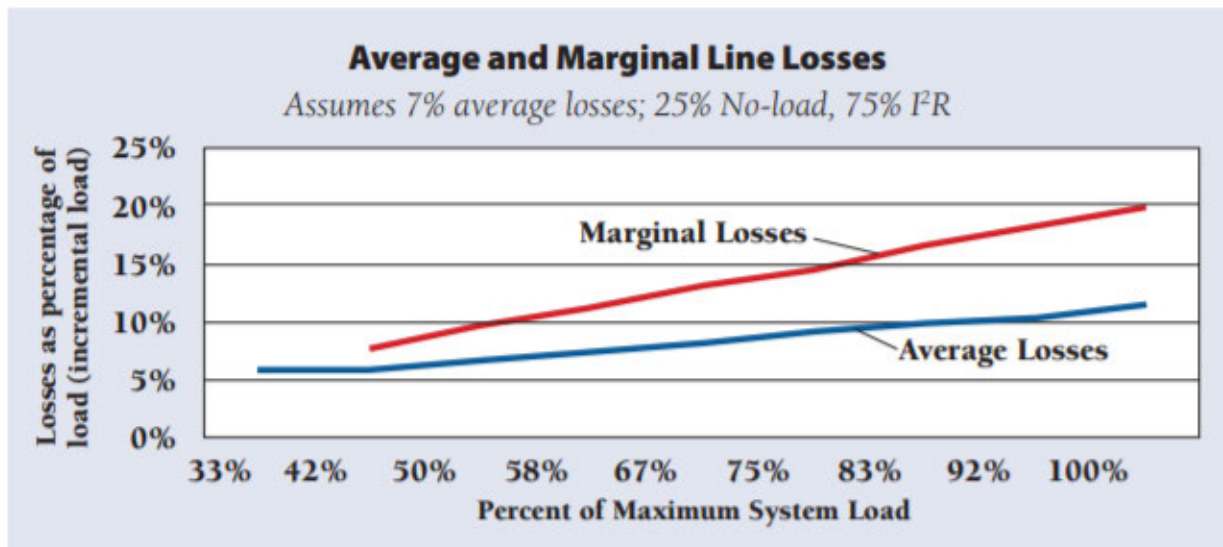
2 A. The amount of energy loss in any hour is affected by a number of factors
3 including resistance in wires, system utilization rates, and weather conditions. The
4 formulae for losses is I^2R or the square of the current multiplied by resistance.
5 The “I” on the system is a direction function of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

9 **Q. How do marginal and average loss factors differ?**

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

1 **Q. Please elaborate.**

2 A. A 2011 Regulatory Assistant Project (RAP) paper, “Valuing the Contribution of
3 Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements,”
4 discusses line losses in detail (Ex.-RENEW-Bhandari-7). This paper presents an
5 example of line losses and demonstrates how marginal and average losses vary at
6 different system load levels as shown in Figure 1 below. This Figure shows that
7 the increases in marginal losses are greater than the increases in average losses as
8 the system load levels increase. For example, when the system is loaded at 50
9 percent of the capacity, average and marginal losses are approximately 6 percent
10 and 8 percent respectively. In contrast, when the system is loaded at near its
11 capacity, average and marginal losses are approximately 12 percent and 20
12 percent respectively.



1

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

4 A. The costs for transmission and capacity are driven by load growth on the system
5 during peak hours of the year. The avoided costs represent the marginal costs in
6 meeting an incremental unit of demand (an incremental unit of demand that a QF
7 would avoid). As discussed above, the marginal losses during peak hours would
8 represent the incremental losses that would occur due to a small increase in
9 demand during peak hours. Loss factors are significantly higher during peak
10 periods due to the relationship between losses and load as described above.

11 Therefore, average losses underestimate the value of avoided transmission and
12 capacity during the peak hours. For this reason, marginal loss factors should be
13 applied.

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

15 A. Yes, marginal loss factors should be applied to avoided energy costs as well.

16 However, as I will explain below, the marginal loss factors that apply to energy

1 are lower than the marginal loss factors that will apply to transmission and
2 capacity since the marginal loss factors for energy apply across all hours of the
3 year and across all ranges of system utilization and not just the peak hours.

4 **Q. Did NSW provide a marginal loss factor for its system?**

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

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

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

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

19 For transmission and capacity, in addition to the higher marginal loss
20 factors we also have to account for the higher system utilization rates since the
21 investments driven by hours that are at the highest peak. I have estimated a
22 marginal loss factor based on NSW's average loss factor, and using the
23 relationship between marginal and average losses illustrated in Figure 1 above

1 (from the RAP paper) at high system utilization rates. Based on the data in Figure
2 X, marginal losses are 1.4 times greater than average losses at 50 percent system
3 utilization, and 2.6 times greater than average losses at 92 percent system
4 utilization. Based on this range, I rely on a simple factor of 2.0 to convert average
5 losses to marginal losses during higher system utilization periods, including at
6 peak (and thus for generation and transmission capacity).

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

9 A. Energy losses increase when demand on the system increases (i.e., at higher
10 system utilization rates) and increase exponentially during peak hours. The
11 avoided transmission costs should be adjusted based on the higher peak-hour
12 marginal loss factors instead of the average loss factors in order to account for
13 higher losses during peak hours. The results shown in **Table 12** below are based
14 on losses identified at the secondary voltage.

1 **Table 12. Avoided Costs for Transmission including marginal losses at secondary**
 2 **voltages**

Avoided Cost Component	\$/kW-year before marginal losses are applied	\$/kW-year after marginal losses are applied
Transmission	35.93	42.73

3

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

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

12 **Table 13. Avoided Costs for Capacity including marginal losses at secondary**
 13 **voltages**

Avoided Cost Component	\$/kW-year before marginal losses are applied	\$/kW-year after marginal losses are applied
Capacity	91.27	108.53

14

1 **VI. APPLICATION OF AVOIDED COSTS IN RATES**

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

4 A. In Sections III and IV, I have outlined my concerns with the values that have been
5 proposed by the utility for avoided transmission and capacity credits, respectively.

6 In terms of the structure of the tariff, I agree with the proposed methodology
7 whereby capacity is credited on a \$/kw-month basis and energy on a \$/kWh
8 basis.⁹ However, I have concerns with the application and tariff structure of the
9 transmission avoided costs to front-of-the-meter resources. The current proposal
10 put forward by the utility credits front-of-the-meter resources on a \$/kWh basis
11 for each hour of generation during the year. This methodology provides an
12 inaccurate mapping of peak demand-related costs to hourly energy costs.
13 Transmission costs are driven by peak demand and the resource should be
14 credited for their contribution in reducing peak demand.

15 **Q. What are your proposed suggestions?**

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

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

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

⁹Application, pg. 9

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

3 **Q. Please elaborate.**

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

11 **Q. What do you recommend?**

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

20 **VII. RECOMMENDATIONS AND CONCLUSIONS**

21 **Q. Please summarize your primary conclusions.**

22 • NSPW's avoided transmission cost does not accurately value the benefit
23 that distributed energy resources provide through load reduction because it

1 is based on embedded transmission revenue requirements which do not
2 accurately capture the forward-looking load growth-related transmission
3 investments.

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

12 **Q. Please summarize your primary recommendations.**

13 A. I recommend that the Commission

- 14 • approve the value of \$35.93 \$/kW-year for avoided transmission costs;
- 15 • approve my proposed methodology that accounts for marginal load
16 growth-related transmission investments going forward and require that
17 the utilities conduct a similar analysis and provide all stakeholders
18 transparency concerning the inputs, assumptions, and results from such
19 analysis;
- 20 • approve the use of marginal losses for both avoided transmission and
21 avoided capacity, valued at double the average losses currently proposed;
- 22 • approve the use of marginal losses for avoided energy valued at 1.5 the
23 average losses currently proposed;

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

5 **Q. Does this conclude your testimony?**

6 **A. Yes, it does.**