BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company for Approval of Proposed Changes to its Parallel Generation Tariffs	6630-TE-107

DIRECT TESTIMONY OF RACHEL S. WILSON ON BEHALF OF RENEW WISCONSIN

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Rachel Wilson, and I am a Principal 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 conduct analysis and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models, and have reviewed input and output data for several other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

Q. Please summarize your educational experience.

A. I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California. A copy of my current resume is attached as Ex.-RENEW-Wilson-1.

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate the reasonableness of Wisconsin Electric Power Company's (WEPCO) proposed energy component of its revised parallel generation rates, to present a more reasonable avoided energy cost forecasting methodology, and to present the results from my own analysis using that methodology.

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

A. Yes, I have previously provided direct testimony in Docket Nos. 4220-TE-109 and 6680-TE-107, which are the applications for updates to parallel generation tariffs for Northern States Power Company Wisconsin and Wisconsin Power and Light Company respectively. My testimony in this proceeding includes many of the same concepts that I discussed in my testimony in those dockets.

II. SUMMARY OF OBSERVATIONS AND RECOMMENDATIONS

Q. Please summarize the basis for WEPCO's current avoided energy cost rates.

A. WEPCO's current avoided energy cost rates for its Customer Generating Systems – Net Metered (CGS-NM) and Customer Generating Systems – Direct Sale Fixed Price (CGS-DS-FP) tariffs were derived from the forecasted average day-ahead locational marginal price (LMP) at the WEC.S pricing load zone for 2015 (Direct-WEPCO-Nelson-7). Avoided energy costs for WEPCO's Customer Generating Systems – Direct Sale Variable Price (CGS-DS-VP) tariff are based on the day-ahead LMPs at the WEC.S pricing load zone and vary by day (Direct-WEPCO-Nelson-7).

Q. What is WEPCO's proposed methodology for calculating avoided energy costs going forward?

A. For the CGS-NM and CGS-DS-FP tariffs, WEPCO proposes to continue to use a single year forecast of LMPs as the basis for avoided energy costs, but to update those costs annually in each fuel plan docket, and to differentiate by season and time-of-day (on-peak versus off-peak) where applicable (Direct-WEPCO-Nelson-8). For the CGS-DS-VP tariff, WEPCO proposes to use actual day-ahead hourly LMPs by time of use period (Direct-WEPCO-Nelson-7).

Q. At a high level, what is your reaction to WEPCO's proposal?

A. It is more appropriate to use a long-run forecast of LMPs to set the rate for the energy component of avoided costs. My testimony presents a forecast of LMPs over a 20-year analysis period from 2021 to 2040.

Q. What are your recommendations to the Commission in this proceeding?

A. I recommend that the Commission direct WEPCO to base the energy component of its avoided costs for front-of-the-meter resources on a long-run forecast of LMPs, consistent with the methodology described in the technical report attached to my direct testimony (Wisconsin Avoided Energy Costs, Ex.-RENEW-Wilson-2).

III. WEPCO'S AVOIDED ENERGY COSTS

Q. What is WEPCO proposing in this docket with respect to the energy component of its avoided costs?

A. WEPCO proposes to compensate customers at market energy prices consistent with the forecasted day-ahead LMP values that underlie the Company's annual fuel plan dockets, updated each year and simplified into averaged values for its time-of-use pricing periods for its CGS-NM and CGS-DS-FP tariffs (Direct-WEPCO-Nelson-7). For its CGS-DS-VP tariff, WEPCO proposes to use actual day-ahead hourly LMPs (Direct-WEPCO-Nelson-7).

Q. Is this a reasonable methodology to forecast the energy component of avoided costs?

A. Neither a single-year forecast of day-ahead LMPs nor actual day-ahead hourly LMPs are reasonably representative of the avoided energy value of distributed generation. A single-year forecast of LMPs only captures the variable cost of generation (fuel costs as well as operations and maintenance costs) from the generating units that are online in that particular year. It does not capture changes in the variable cost of generation that would occur as new capacity comes online in future years. Additional investments in renewable capacity would lower the variable cost of generation, while investments in fossil-fueled generators would increase the variable cost of generation.

Q. WEPCO witness Nelson states that the Company's proposal is informed by "total economic and engineering modeling as required by the 2021 Order" (Direct-WEPCO-Nelson-8). Do you agree with that statement?

A. No. The modeling that Witness Nelson refers to is a single year of production cost modeling, which dispatches only units that are existing or expected to be coming online within the year. This is problematic for the reasons I describe above, and differs from the modeling approach that I present below, which includes both capacity optimization and production cost components.

Q. Why is it more appropriate to calculate avoided energy costs based on a long-run forecast of LMPs?

A. A long-run forecast of LMPs includes any changes to variable costs that result from the addition of new generators to a utility's system, or the retirement of existing generators. A long-run LMP forecast accounts for the energy costs over the entire analysis period or the period at which a Qualifying Facility (QF) would receive payments commensurate with the avoided energy cost component under a long-term contract. Depending on the length of the contract, the long-run LMP forecast may also account for the avoided energy value over the likely life of the generation asset.

Q. Do you have other concerns with the use of a single-year forecast or actual day-ahead market prices?

A. Yes. Developers are unlikely to enter into a contract in which the avoided energy payments over the life of the asset are both variable and unknown. Use of a single-year forecast means that the avoided energy payment from year-to-year would be both variable and unknown. Developers, then, cannot know if the avoided energy payment they would receive would be sufficient to cover the costs associated with the construction of new resources. Long-term certainty is essential to the development of new resources.

Q. Wouldn't the use of fixed pricing lead to compensation for distributed generation at a rate that deviates from avoided energy cost?

A. Over the duration of the contract, actual energy prices will likely be higher or lower than the fixed energy price at any given time, but that is true with any forecast. Further, our long-term forecasts are conservative, and are more likely to be lower than future actual energy prices in the MISO market.

Matching buyback rates to hour-to-hour changes in market prices is not a reasonable way to encourage renewable resource development. As additional QFs with low to no variable cost are added to a utility's system, the effect is to lower the resulting LMPs in the hours in which these resources are generating. This effect on LMPs is magnified as more QFs are added to the system.

Use of hourly market prices would produce, for any given QF, an avoided cost that does not reflect the impact of that QF on LMPs, because the forecast would include the presence of that QF. In other words, under WEPCO's proposal, while that QF resource would benefit the system by lowering LMPs, it would not be compensated for the avoided energy value it adds. Instead, WEPCO's buyback rate would essentially discount that QF's impact on lowering LMPs. The QF resource should instead be compensated using a long-term price forecast that determines the value of the generator "but-for" its presence on the system.

Q. Is WEPCO also proposing to subtract a transaction cost from the LMP it is proposing to pay to QFs?

A. Yes, WEPCO is proposing to subtract a transaction cost that it says is charged and credited to the Company by MISO from the most recently completed November 1 to October 31 period (Direct-WEPCO-Nelson-7). For the most recent period, that transaction cost was approximately $0.00056/kWh (Direct-WEPCO-Nelson-7). WEPCO Witness Nelson does not explain the reasoning for this adjustment, and at the very least, sufficient justification should be provided to the Commission before this adjustment is adopted. It seems to me, however, that if this transaction charge were to be applied, it should be *added* to the LMP paid to the QF given that it is another cost that is avoided through the purchase of generation from that QF rather than from the MISO market.

Q. What is the best way for WEPCO to develop a long-term LMP forecast?

A. The most rigorous way for WEPCO to develop a long-term LMP forecast is to use power sector capacity optimization and production cost modeling tools to calculate the long-term impacts of new QF generation on energy dispatch and prices. This modeling exercise requires the development of a future scenario, or scenarios, which includes forecasts of peak demand and annual energy, commodity price forecasts, existing generating unit characteristics, forecasts of costs and availability of new generating units, and relevant environmental regulations. The capacity optimization algorithm then selects the least-cost future resource portfolio. Dispatch of the system with these new additions is simulated over the analysis period and produces a long-term forecast of LMPs.

Q. Did you use power sector optimization and production cost modeling tools to produce a long-term forecast of LMPs?

A. Yes. I used the EnCompass model, licensed by Anchor Power, to first perform a capacity expansion simulation of the Eastern Interconnect. Once an optimal resource build had been calculated by the model, hourly dispatch of both new and existing generating units was simulated to produce a forecast of LMPs over the period from 2021 to 2040. A more detailed description of the input assumptions that went into that analysis, as well as the modeling methodology used, is provided in the technical report attached to my testimony (Wisconsin Avoided Energy Costs, Ex.-RENEW-Wilson-2).

Q. Briefly describe your input assumptions.

A. I modeled the entire Eastern Interconnect in order to account for energy flows between markets but focused on MISO for the purposes of this analysis. MISO loads were taken from the *2021 MISO Energy and Peak Demand Forecasting for System Planning* report published by the State Utility Forecasting Group (SUFG) at Purdue University[1] (Ex.-RENEW-Wilson-3) and were adjusted for energy efficiency and future electrification. The system was modeled with unit-level granularity, meaning that we modeled the operating characteristics of each unit that makes up the 180 GW of existing MISO capacity. We included planned additions and retirements as part of the capacity mix and offered new resources to the model using data on capital and operating costs from sources

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[1] Lu, Liewei, F. Wu, D. J. Gotham, D. G. Nderitu, T. A. Phillips, P. V. Preckel, M. A. Velástegui. *2021 MISO Energy and Peak Demand Forecasting for System Planning*. Purdue University State Utility Forecasting Group for Midcontinent Independent System Operator, Inc. Available at: [https://] [www.] purdue.edu/discoverypark/sufg/docs/publications/MISO/MISO%20forecast%20report%202021 [.pdf.]

like the U.S. Energy Information Administration (EIA) and the National Renewable Energy Laboratory's (NREL) *Advanced Technology Baseline*.

Q. Briefly describe your modeling methodology.

A. I used the EnCompass capacity expansion and production cost model, licensed from Anchor Power Solutions, to simulate the Eastern Interconnect over a 20-year period from 2021 through 2040. Each year is first modeled in capacity optimization mode, in which EnCompass determines the most cost-effective capacity additions over the duration of the analysis period. The simulation uses a "typical on-peak/off-peak day," in which two days are used to represent the characteristics of each month.

When the capacity optimization is complete, the resulting resource build-out is locked down and the model is re-run in production cost mode to simulate the dispatch of those resources. This simulates the least-cost dispatch over all 8,760 hours in the year and of all units in the Eastern Interconnect, subject to transmission constraints. The model will determine the least-cost mix of generators needed to meet load during a given time interval, typically one year in 8,760-hour increments. The production cost model produces the avoided energy cost in the form of energy prices across MISO.

Q. Did you model more than one scenario in your analysis?

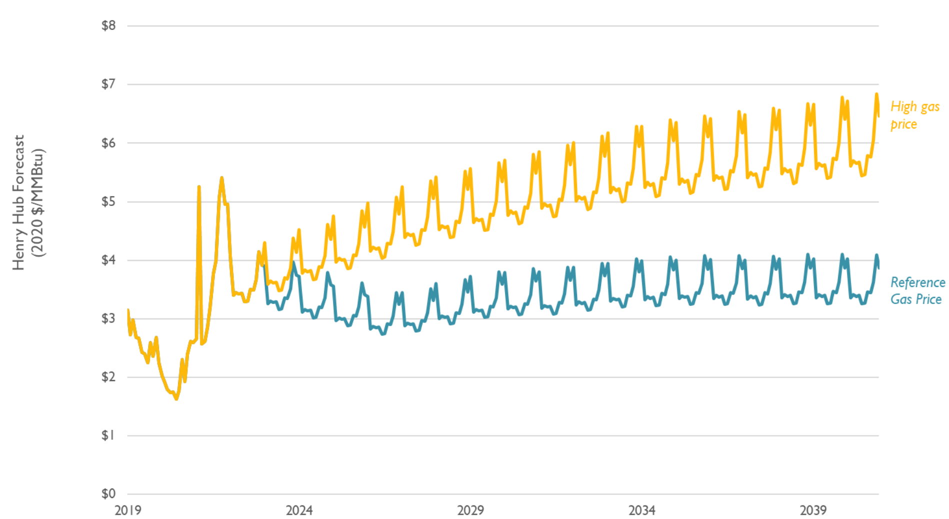
A. Yes. I modeled a Reference scenario and a High Gas Price scenario, which use two different forecasts for natural gas prices.

Q. Describe how you derived the Reference and High Gas Price forecasts.

A. Both gas price forecasts rely on a combination of New York Mercantile Exchange (NYMEX) futures and the EIA's *2021 Annual Energy Outlook* (AEO). The NYMEX futures prices represent the actual valuation of gas by the market but become less certain the further the forecast goes into the future. The AEO's forecast, on the other hand, represents long-term fundamentals pricing. The gas price forecasts used in this analysis are based on NYMEX futures in the short-term, the AEO forecast in the long-term, and a blend of the two in the interim years.

Specifically, the Reference scenario assumes a gas price forecast that relies on NYMEX futures in 2022, a blend of NYMEX and AEO in 2023 through 2025, and the 2021 AEO Reference Case forecast from 2026 through 2040. The High Gas price forecast utilizes the same methodology but uses AEO's Low Oil and Gas Supply forecast rather than the Reference Case to derive medium- and long-term values. The range of gas prices created by the Reference Gas Price and High Gas Price scenarios is shown in Figure 1.

Figure 1. Monthly Henry Hub gas price forecast, Reference and High



Q. Why was it reasonable to create two scenarios with different gas price forecasts?

A. LMPs are highly correlated with gas prices. Gas-fired generators are often "the marginal generator" in MISO, meaning that they are the generating units that are called upon to meet the next increment of load. As a result, they often set the LMP in many hours. While less volatile than in the past, gas prices in both the short- and the long-term are still uncertain and utilities will often produce modeling scenarios or sensitivities that examine the effects of high gas prices on both capacity optimization (the future resource build) and dispatch of new and existing units in order to make resource decisions. Given that the future gas price forecast will directly impact the energy component of the avoided cost payment, and thus the payments to new QFs, it was also reasonable to model a second scenario that utilizes a higher gas price forecast.

Q. Have gas price futures changed at all since the date of your analysis?

A. Yes. Since the beginning of 2022, gas price futures have more than doubled, increasing from $3.730/mmBtu to $7.854/mmBtu in mid-May.[2] These prices are higher than the expected prices used for 2022 in my analysis.

Q. What were the results of your analysis?

A. As described in Section 3 of Ex.-RENEW-Wilson-2, the LMP forecast for Wisconsin averages the hours designated by WEPCO as Summer On-Peak, Summer Off-Peak, Non-Summer On-Peak, and Non-Summer Off-Peak. These four time periods reflect the same time-of-use periods as proposed by WEPCO in its application. The EnCompass forecast is representative of the price in Local Resource Zone (LRZ) 2 for Wisconsin. The LMP forecast under Reference gas prices is shown in Table 1, below. EnCompass produces its outputs in nominal dollars. These values have been converted to real 2021 dollars using an assumed inflation rate of two percent.

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[2] de Luna, Marcy and Biana Flowers. May 16, 2022. *Surging natural gas prices squeeze U.S. industrial sector*. Reuters. Available at: [https://] [www.] reuters.com/markets/us/surging-natural-gas-prices-squeeze-us-industrial-sector-2022-05-16/.

Table 1. Long-run Reference LMP forecast, Wisconsin

	Wisconsin adjusted ($2021)			
Year	Summer On-Peak	Summer Off-Peak	Non-Summer On-Peak	Non-Summer Off-Peak
2021	$36.20	$24.83	$29.08	$19.14
2022	$33.83	$24.74	$29.64	$20.47
2023	$34.42	$25.66	$31.52	$23.66
2024	$36.22	$26.52	$32.55	$25.60
2025	$36.40	$26.58	$32.98	$26.28
2026	$34.86	$26.18	$32.51	$26.31
2027	$34.66	$26.26	$32.13	$26.29
2028	$34.53	$26.40	$31.25	$25.42
2029	$34.88	$26.65	$30.98	$25.02
2030	$35.20	$26.71	$30.47	$24.78
2031	$35.64	$26.89	$30.19	$24.59
2032	$35.77	$27.50	$30.48	$24.85
2033	$36.09	$27.81	$30.51	$24.77
2034	$37.20	$28.41	$30.61	$24.65
2035	$36.01	$27.40	$29.72	$23.76
2036	$34.01	$26.24	$28.41	$23.08
2037	$32.82	$25.92	$27.57	$22.44
2038	$32.20	$25.36	$26.67	$21.42
2039	$33.43	$26.16	$27.82	$22.38
2040	$33.00	$25.70	$27.29	$21.62
2041	$33.62	$26.22	$27.84	$22.05
2042	$34.25	$26.74	$28.39	$22.49

The LMP forecast under the High Gas Price forecast is shown in Table 2. Note that for both scenarios, the EnCompass analysis period extended through 2040 only. Prices for 2041 and 2042 were extrapolated based on the forecasted growth in gas prices due to RENEW Wisconsin's presentation of a 20-year contract term from 2023 to 2042.

Table 2. Long-run High Gas Price LMP forecast, Wisconsin

	Wisconsin adjusted ($2021)			
Year	Summer On-Peak	Summer Off-Peak	Non-Summer On-Peak	Non-Summer Off-Peak
2021	$36.20	$24.83	$29.08	$19.14
2022	$33.83	$24.74	$29.64	$20.47
2023	$36.64	$27.19	$32.83	$24.48
2024	$40.66	$29.66	$35.25	$27.31
2025	$43.12	$31.11	$36.22	$27.98
2026	$42.03	$30.97	$35.09	$26.55
2027	$42.37	$31.85	$33.84	$26.19
2028	$42.29	$31.55	$31.85	$24.17
2029	$43.35	$32.40	$31.89	$24.47
2030	$44.15	$32.82	$31.52	$24.73
2031	$43.73	$33.03	$30.08	$24.03
2032	$43.76	$34.10	$30.33	$23.95
2033	$43.94	$34.41	$29.72	$23.78
2034	$45.05	$35.29	$29.97	$23.75
2035	$44.61	$34.68	$29.41	$23.15
2036	$43.08	$33.93	$28.94	$23.65
2037	$42.71	$34.66	$29.60	$24.00
2038	$43.14	$35.22	$29.83	$24.49
2039	$43.82	$35.51	$29.90	$24.09
2040	$43.72	$34.98	$29.76	$23.68
2041	$44.53	$35.68	$30.35	$24.16
2042	$45.37	$36.40	$30.96	$24.64

IV. CONCLUSION

Q. Please restate your recommendations to the Commission in this proceeding.

A. An annually updated forecast of short-run LMPs is insufficient to set the energy component of WEPCO's avoided cost because it represents only those costs that are incurred to generate electricity absent additional investments in new generation capacity. A long-run forecast of marginal energy costs, or LMPs, is a more appropriate representation of the avoided energy cost component for the following reasons: (1) it captures changes in the variable cost of generation that would occur as new capacity comes online in future years; (2) it accounts for the energy costs over the entire analysis period, or the period at which a QF would receive payments commensurate with the avoided energy cost component under a long-term contract; (3) the long-run LMP forecast may also account for the avoided energy value over the likely life of the QF asset; and (4) a long-run forecast gives project developers certainty around future revenue streams, ensuring that QFs are constructed. For those reasons, I recommend that the Commission direct WEPCO to (a) use a long-term LMPs forecast for the purposes of determining its avoided energy costs and (b) create more than one gas price forecast scenario as a part of its long-term LMP forecasting exercise.

Q. Does this conclude your testimony?

A. Yes, it does.