DIRECT TESTIMONY OF MIRIAM MAKHYOUN ON BEHALF OF ADVANCED ENERGY UNITED

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q: Please state your name, title, and business address.

A: My name is Miriam Makhyoun, CEO of EQ Research. EQ Research is a consulting firm specializing in state- and utility-level rate design and resource planning. EQ Research's business address is 1155 Kildaire Farm Rd., Ste 203, Cary, NC 27511.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Advanced Energy United ("United").

Q: What experience do you have with utility resource planning?

A: In my current role as the CEO of EQ Research, I served as an expert witness in a Kentucky proceeding addressing Louisville Gas and Electric Company's and Kentucky Utilities Company's Integrated Resource Plan ("IRP") on behalf of Southern Renewable Energy Association in Docket 2021-00393. I was also the principal author and analyst for Valley Clean Energy's (a California Community Choice Aggregator ("CCA") and load serving entity ("LSE")) 2022 IRP, and assisted three CCAs with their 2020 IRPs submitted to the California Public Utilities Commission.

At Marin Clean Energy ("MCE") CCA, from 2017-2019, I successfully managed the 2018 energy storage request for proposal, negotiated multimillion-dollar contracts, and implemented advanced market forecasting strategies that resulted in significant cost savings. I was the lead on energy storage, carbon-free hydropower, and Asset Controlling Supply at MCE and I managed several long-term renewable energy contracts as well. It was my job to optimize the scheduling, delivery and terms for the buyer.

As an analyst in Portfolio Management at Pacific Gas and Electric Company from 2015-2017, I worked on both the transactions and the policy and compliance teams. I was involved in transactions for Congestion Revenue Rights, Resource Adequacy ("RA") capacity, Greenhouse Gas Allowances, and Qualifying Facilities. I personally executed over $22 million in RA capacity sales and purchases, managing every aspect from origination to negotiation to final sign-off, including Requests for Offers.

II. PURPOSE AND STRUCTURE OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to (1) identify costs of Wisconsin Electric Power Company's ("WEPCO") South Oak Creek Combustion Turbine Project ("Project") exceeding or nearly exceeding industry standards; (2) identify flaws and shortcomings of WEPCO's capacity expansion modeling; (3) identify an alternative, more reasonable capacity expansion modeling plan; and (4) request the Commission direct WEPCO to (a) remedy certain shortcomings I identify in WEPCO's modeling in this case and (b) consider in future Certificate of Public Convenience and Necessity ("CPCN") cases a specified set of alternatives to new fossil generation.

Q: Please summarize your recommendations to the Commission.

A: I recommend the Commission reject WEPCO's application for a CPCN, unless WEPCO revises its modeling and remedies the flaws I identify in my testimony. In the alternative, I recommend the Commission approve WEPCO's application with modifications that direct WEPCO to use non-combustion assets and strategies and non-utility owned assets.

Q: How is your testimony structured?

A: My testimony is organized into the following sections:

- Section III: Background on the Project – This section provides an overview of the proposed South Oak Creek Combustion Turbine Project, including its operational characteristics and costs.
- Section IV: Transmission Capacity as a Barrier to Alternative Generation Sources – Here, I evaluate whether transmission capacity presents a barrier to renewable generation alternatives.
- Section V: WEPCO's Capacity Expansion Modeling – This section identifies flaws in WEPCO's modeling efforts and proposes remedies to ensure unbiased and comprehensive capacity planning.

- Section VI: Capacity Expansion Plan Alternatives – In this section, I describe more cost-effective and sustainable alternatives to the Project and recommend that the Commission consider those options.
- Section VII: Deployment of Distributed Energy Resources ("DERs") – This section outlines the benefits of DERs, such as virtual power plants ("VPPs") and Volt/VAR optimization ("VVO") as viable and rapidly deployable alternatives to the Project.
- Section VIII: Conclusions and Recommendations – Finally, I summarize my conclusions and present recommendations to the Commission.

III. BACKGROUND ON THE PROJECT

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

A: The purpose of this section is to provide an overview of the Project, including its proposed components, operational characteristics, and associated costs. I also identify specific concerns regarding the project's cost estimates, which frequently exceed or approach the high end of industry standards and highlight the availability of lower-cost renewable generation options that WEPCO has not sufficiently explored. I make the argument that over its lifetime, the Project is generally higher-cost than alternative generation sources. See Table 1 for a comparison of the Levelized Cost of Energy ("LCOE") of various resources.

Table 1. LCOE Comparison for Alternative Resources ($/MWh)

Resource	Lazard 2024	NREL ATB 2024	WEPCO
Wind[1]	50	35	
Solar PV[2]	60.5	57	
Wind + Storage	89	N/A	
Solar PV (C&I and Community)	122.5	104	
Solar PV + Storage[3]	135	105	
Gas Peaking	169	N/A	[redacted]
Solar PV (Rooftop Residential)	203	157	

Q: Please describe the Project.

A: The Project is comprised of 1,100 net megawatts ("MW") of natural gas combustion turbines consisting of five new General Electric 7FA.05c simple cycle combustion generators, with each generator having a nominal capacity of approximately 220

[1] For NREL, Land-Based Wind - Class 6 - Technology 1 because Wisconsin wind speed is 7.75 MPH at 100 meters above sea level according to this source: U.S. Department of Energy. (n.d.). WINDExchange Wisconsin. Wind Energy Technologies Office. Retrieved December 12, 2024, from https://windexchange.energy.gov/maps-data/356. Any information contained in this citation, based solely on this citation, is not record evidence (NRE).

[2] For NREL, Class 9 was used since solar resource is less than 4 kWh/m2/day according to this source: NREL. 2024. "2024 ATB Utility-Scale PV." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/utility-scale_pv. Any information contained in this citation, based solely on this citation, is NRE.

[3] For NREL, this is a DC-coupled system with a 100 MWAC bidirectional inverter, single axis tracking PV system with a capacity of 134 MWDC, and 4-hour lithium-ion battery storage system with a capacity of 60 MWAC.

[4] Ex.-WEPCO-Application-Application: 4-5.

MW.[5] Notably, WEPCO has also filed a CPCN Application in Docket 6630-CE-316 for a 128 MW Reciprocating Internal Combustion Engine ("RICE") generator set it plans to use at the Paris site ("Paris RICE"). The Paris RICE is proposed to be located on the site of the Lakeshore Capacity Improvement Project regulator station in the Town of Paris near Union Grove, Wisconsin.[6]

Q: At a high level, why does WEPCO propose the Project and the Paris RICE?

A: WEPCO asserts the Project and the Paris RICE are necessary to serve a significant increase in projected load and an open planning position of between [redacted] MW by 2030.[7]

WEPCO expects the load increase driving its requests for new generation to be concentrated near the "I-94 corridor." From 2025 to 2029 WEC Energy Group ("WEC"), the parent of WEPCO, forecasts an increase in volumetric energy sales of [redacted] MWh and an increase of [redacted] MW in peak demand in that corridor. Specifically, the sales forecast increases from [redacted] MWh in 2025 to [redacted] MWh by 2029, and the peak demand forecast increases from approximately [redacted] MW to almost [redacted] MW over the same time period.[8]

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[5] *Id*. at 1-5.
[6] Docket No. 6630-CE-316, Wisconsin Electric Power Company (WEPCO) Paris RICE Engineering Plan at 1-1 (Feb. 5, 2024). Any information contained in this citation, based solely on this citation, is NRE.
[7] Ex.-WEPCO-Application-Application: 2-13 and 2-14.
[8] Ex.-WEPCO-Application-Volume III Appendix B.

Q: What are the operational characteristics of the Project?

A: The annual capacity factor for the Project is expected to be between 10 and 20% over its life with monthly variations and it will be operated in a peak load configuration.[9] The facility is designed to operate for at least 30 years–until the end of 2058 or longer.[10] Apparently, due to the nature of its modeling software, WEPCO does not know the capacity factor of the five individual units, so it is possible that some of the units operate at substantially less than 20% annually.[11]

Q: What is WEPCO's estimated cost for the Project?

A: WEPCO estimates the Project will cost approximately $1.2 billion.[12]

Q: What are the components of WEPCO's cost estimate?

A: WEPCO's estimate includes overnight capital cost, other capital expenditures ("CAPEX"), and levelized cost of energy. I will discuss each component in more detail below.

Q: Please define and explain overnight capital cost.

A: The National Renewable Energy Laboratory ("NREL") defines "overnight capital cost" as "capital expenditures excluding construction period financing and excluding grid connection costs. Includes on-site electrical equipment (e.g.,

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9 Ex.-WEPCO-Application-Application: 1-7.
10 *Id*. at 1-8; 1-9.
11 Ex.-United-Makhyoun-1 (WEPCO response to UNITED-IR-2-6).
12 Ex-WEPCO-Application-Application: Section 4.1.1.

switchyard)."[13] NREL does not mention it specifically, but industry sources such as the United States Energy Information Administration ("EIA") also include "owner's costs", defined as "development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system" in the definition of overnight capital costs.[14] The overnight capital cost excludes financing costs and interest during construction, known as the Allowance for Funds Used During Construction ("AFUDC").

Q: What is WEPCO's estimated overnight capital cost of the Project?

A: WEPCO estimates the overnight capital cost of the Project to be $1,205,000,000.[15] This includes [redacted] in engineering, procurement, and construction contractor costs, [redacted] in equipment supplier costs, and [redacted] in owner's costs.[16]

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[13] NREL (National Renewable Energy Laboratory). 2024. "Definitions - 2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/definitions. Any information contained in this citation, based solely on this citation, is NRE.

[14] U.S. Energy Information Administration. (2016, November). Capital cost estimates for utility scale electricity generating plants (pp. 1–2). https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Any information contained in this citation, based solely on this citation, is NRE.

[15] Ex.-WEPCO-Application-Application: 1-10 and 4-1; Ex.-PSC-DRR (Response-Data Request-PSC-Chee-DG-1.15_CONFIDENTIAL).

[16] Ex.-WEPCO-Application-Application: 4-1.

Q: Are WEPCO's overnight capital costs generally accurate?

A: While WEPCO's estimates for CTs are more in line with industry ranges, its estimates for onshore wind, utility-scale solar, and battery energy storage systems ("BESS") are much higher. See Appendix D to my testimony for a comparison. Below are some key observations comparing WEPCO's capital cost assumptions[17] with data from the EIA,[18] NREL,[19] and Lazard:[20]

- **Combustion Turbine—Industrial Frame:**
  - WEPCO's estimate ($1,023/kW) is within Lazard's range ($700–$1,150/kW) but higher than the EIA's ($867/kW) and lower than NREL's ($1,093/kW).
- **BESS:**
  - WEPCO's estimate ($2,435/kW) is vastly higher than EIA ($1,270/kW), NREL ($1,770/kW), and Lazard ($76–$157/kW), suggesting an overestimate for this technology.

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[17] Ex.-WEPCO-Application-Volume III Appendix B: 25.

[18] U.S. Energy Information Administration. (2023, March). Assumptions to the Annual Energy Outlook 2023: Electricity Market Module (p. 5). Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf. Any information contained in this citation, based solely on this citation, is NRE.

[19] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. Any information contained in this citation, based solely on this citation, is NRE.

[20] Lazard. (2024, June). 2024 Levelized Cost of Energy+ (pp. 35-44). Retrieved from https://www.lazard.com/research-insights/levelized-cost-of-energyplus. Any information contained in this citation, based solely on this citation, is NRE.

- **Wind:**
  - WEPCO's estimate ($2,384/kW) is higher than all other sources like the EIA ($2,098/kW), especially compared to NREL ($1,481/kW) and Lazard ($1,300–$1,900/kW).
- **Utility-Scale Solar:**
  - WEPCO's estimate ($1,952/kW) is significantly higher than EIA ($1,448/kW), NREL ($1,379/kW), and Lazard ($850–$1,400/kW).

Q: Is it possible that WEPCO will exceed its overnight capital cost estimate?

A: Yes. Any estimated cost can be exceeded, and an overnight capital cost is no exception. WEPCO has requested the ability to "notify" the Commission upon actual project costs exceeding 10% or more of the $1,205,000,000 in what it is calling "Total Project Costs," exclusive of AFUDC.[21] I note that 10% of the Total Project Costs amounts to $120,500,000, which is a very significant sum that is almost half the cost of the Paris RICE. Stated another way, the impact on ratepayers could increase by another $120 million before WEPCO thinks it is appropriate to notify the Commission regarding an exceedance in its actual project costs.

Q: Please define and explain CAPEX.

A: CAPEX does not include operations and maintenance ("O&M") costs, or decommissioning costs, but it does encompass various other cost items including:

[21] Ex.-WEPCO-Application-Application: 4-1.

- Overnight Capital Cost as described above.
- Grid Connection Costs ("GCC"): Starting in 2024, grid connection costs are assumed to be $100 per kilowatt (kW) (in 2022 dollars) for utility-scale technologies.[22] These costs include typical expenses for a spur line (short radial transmission lines from the generator to the bulk grid), point of interconnection, and nominal network upgrades. NREL based GCC on costs for connecting new natural gas plants in most U.S. market regions, as reported by Seel et al. (2023) and Ramasamy et al. (2022), and include the cost of a 1-mile spur line.
- Construction Finance Factor: Also known as construction finance cost, this represents the portion of all-in capital costs associated with construction period financing. It depends on the construction duration, the proportion of capital spent during construction, and the interest incurred.
- Site Costs: This encompasses access roads, buildings for operation and maintenance, fencing, land acquisition, site preparation, transformers, and underground utilities.

Q: What other CAPEX will the Project impose that are excluded from the overnight capital cost estimate?

A: The Project will also impose additional CAPEX, including:

[22] NREL (National Renewable Energy Laboratory). 2024. "Definitions - 2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/definitions. Any information contained in this citation, based solely on this citation, is NRE.

- GCC: Estimated at $100/kW, which covers the cost of spur lines, point of interconnection, and nominal network upgrades. For the Project's capacity of 1,100 MW, this equates to approximately $110 million. The utility will use existing transmission interconnection points from the retired plants however, it needs to tie-in to the Rochester Lateral gas pipeline and purchase a new meter set for natural gas fuel supply and interconnections to the existing 138-kilovolt ("kV") and 345 kV switchyard so there are still GCC included in the CAPEX that are not accounted for in the Application.[23]
- Construction Financing Costs: Costs incurred during the construction period, such as interest on loans, which are excluded from the overnight capital cost but contribute to the total CAPEX. WEPCO is also requesting as part of its application to earn AFUDC on 100% of the Construction Work in Progress ("CWIP") balance. The AFUDC amount is estimated to be another $138.6 million.[24]

Q: Do you believe that WEPCO's CAPEX estimate is realistic?

A: No. WEPCO estimates CAPEX of $1,221.45/kW based on the estimate of another $138.6 million for AFUDC[25] on top of the $1,205,000,000 overnight capital cost, but this excludes GCC estimated as $110 million as described above. When including GCC, the CAPEX is $1,453,600,000 or $1,321.45/kW, which is much closer to NREL ATB's 2024 cost estimate of the CAPEX for this type of project

[23] Ex.-WEPCO-Application-Application: 1-12 and 1-13.
[24] *Id*. at 4-1, footnote 14.
[25] *Id*.

($1,329/kW)[26] and a more realistic assumption. Therefore, it is highly likely that WEPCO underestimated the CAPEX of the Project.

Q: Please define and explain LCOE.

A: The LCOE is a measure used to compare the total cost of producing electricity from different energy generation technologies over their operational lifetimes. It represents the per-unit cost of electricity, typically expressed in dollars per megawatt-hour ($/MWh), accounting for all costs, including CAPEX, O&M, fuel costs (if applicable), and decommissioning costs.

Q: How does LCOE impact a utility's customers?

A: A higher LCOE for a generating facility indicates that the electricity produced is less economical, increasing the risk that customers will face higher rates or pay more than necessary for their electricity. Conversely, a lower LCOE suggests that the facility provides electricity at a more competitive cost, helping to minimize customer expenses.

Q: How does the LCOE of the Project compare to alternative resources?

A: The LCOE of the Project is high compared to alternatives and is on the higher end of some industry benchmarks as well. Based on WEPCO's estimates, the Project's

[26] NREL. 2024. "2024 ATB Utility-Scale PV." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/utility-scale_pv. Any information contained in this citation, based solely on this citation, is NRE.

LCOE is $[redacted]/MWh in Year 20 and $[redacted]/MWh in Year 30.[27] The average of the LCOE of a natural gas peaking plant in Lazard's 2024 Levelized Cost of Energy Analysis, is $169/MWh at Year 20.

Table 1, which was shown earlier in my testimony, compares the LCOE of renewable resources such as wind and solar with that of the Project. Renewables have LCOEs ranging between $35 - $50/MWh for utility-scale wind and $57/MWh to $60.50/MWh for utility-scale solar. When storage is added to these facilities to make them more flexible, the LCOE is still lower than for a natural gas combustion turbine. Assumptions for these costs are presented in Appendices A & B to my testimony.

Q. Why is it important to compare the operational characteristics, overnight capital costs, and CAPEX of the Project to industry standards and to renewable and energy storage alternatives?

A: It is important to evaluate the operational characteristics, overnight capital costs, and overall CAPEX of the Project and other resource options for several reasons. Examining each option's operational characteristics ensures that its ability to meet grid reliability, flexibility, and peak demand requirements is fully understood. This includes assessing its capability to provide essential grid services, such as ramping, frequency regulation, and backup power. Comparing the Project's overnight capital

[27] Ex.-WEPCO-Application-Application: 4-5.

costs to industry standards provides a benchmark to determine whether the proposed costs are reasonable and competitive. This comparison helps identify whether the project delivers value for money or whether alternative technologies, such as renewable energy with storage, might achieve similar or better outcomes at a lower cost. Finally, evaluating the CAPEX relative to industry norms ensures a comprehensive understanding of the project's total upfront costs, including construction and related expenses. This allows decision-makers to assess whether the project's financial requirements are aligned with broader market trends and whether the costs are justified given the availability of lower-cost renewable and storage solutions.

Q: What do you conclude regarding WEPCO's estimated Project costs?

A: I conclude that WEPCO's cost estimates are generally higher than alternative options, and do not support WEPCO's assertion that the Project is lower-cost than alternatives.

IV. TRANSMISSION CAPACITY AS A BARRIER TO ALTERNATIVE GENERATION SOURCES.

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

A: In this section of my testimony, I refute WEPCO's claim that transmission capacity is a barrier to its use of renewable generation resources instead of the full gas-fired scale of the Project.[28]

Q. Please provide an example of WEPCO claiming that transmission capacity is a barrier to use of renewable generation resources.

A. In WEPCO's capacity expansion plan modeling, use of wind generation is constrained to just 800 MW due to (1) constraints on the amount of wind capacity that can be developed in MISO LRZ 2 due to wind siting and setback regulations, as well as increasing local opposition[29] and (2) because of transmission infrastructure limitations and the need to have capacity sourced in MISO LRZ 2 given the significant need for capacity and energy.[30] WEPCO states in its response to Data Request-CW-6.13[31] that even with additional near-term improvements such as the Cardinal Hickory Creek transmission line, more wind capacity cannot be brought online before 2030 unless those projects are already in the MISO queue for Zone 2 or have been recently added to the queue, given the time required for new resources to secure interconnection services and become operational. For reference,

[28] Ex.-WEPCO-Application-Volume III Appendix B: 18; Ex.-United-Makhyoun-1 (WEPCO response to United Data Request IR-3.4).
[29] Ex.-WEPCO-Application-Volume III Appendix B: 24.
[30] Ex.-United-Makhyoun-1 (WEPCO response to United Data Request IR 3.4).
[31] Ex.-United-Makhyoun-1 (WEPCO response to CW Data Request 6.13).

the Cardinal-Hickory Creek Transmission Line Project, a 102-mile, 345-kilovolt line connecting Iowa and Wisconsin, was fully energized and placed into service on September 26, 2024.[32] Even if that were not the case, WEPCO's arguments presume all new wind modeled must be located in LRZ 2 but that is a faulty assumption since wind can be transmitted from other zones.

Q: Could use of renewable generation resources instead of gas-fired generation at the Oak Creek site offer additional benefits?

A: Yes. If WEPCO were to build a renewable energy facility combined with BESS on the same site as the retired Oak Creek coal facility, there would be less of a need for upgrades to store energy and manage the variability of renewable energy generation. Additionally, other grid stabilization equipment such as synchronous condensers or advanced inverters can defer upgrades.

Q: Please elaborate on why building BESS would require fewer upgrades.

A: Because BESS can provide critical grid services, such as peak shaving, voltage and frequency regulation, and congestion management, it reduces the strain on existing transmission and distribution infrastructure. This minimizes the need for costly upgrades to accommodate new generation or increased load. Additionally, BESS can enhance the efficiency and reliability of renewable energy integration, allowing

[32] ITC Midwest, Dairyland Power Cooperative, & ATC. (2024, September 27). Joint news release: Cardinal-Hickory Creek transmission line energized. Retrieved from https://www.cardinal-hickorycreek.com/joint-news-release-cardinal-hickory-creek-transmission-line-energized. Any information contained in this citation, based solely on this citation, is NRE.

the grid to absorb more renewable energy without significant infrastructure investment.

Q: On a broader scale than just the Oak Creek site, is transmission capacity a barrier for renewable energy development in Wisconsin?

A: No. Wisconsin is actively expanding its transmission infrastructure to enhance grid reliability and support renewable energy integration. Experts forecast this will support at least 6.6 gigawatts of new renewable energy capacity by 2030.[33] Key projects include:

- The Western Wisconsin Transmission Connection Project, a 345-kV line by Xcel Energy expected online in 2028, connecting the Tremval Substation to western Wisconsin communities;[34]
- The Cardinal-Hickory Creek Transmission Line, a 102-mile 345-kV line co-owned by ITC Midwest, ATC, and Dairyland Power, became operational in September 2024, providing a crucial renewable energy pathway;[35]

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[33] Barrilleaux, A. (2024, December 13). Midwest grid operator approves plan that will support dramatic clean energy growth in Wisconsin. Clean Wisconsin. https://www.cleanwisconsin.org/midwest-grid-operator-approves-plan-that-will-support-dramatic-clean-energy-growth-in-wisconsin/. Any information contained in this citation, based solely on this citation, is NRE.

[34] Xcel Energy. (n.d.). Western Wisconsin transmission connection. Retrieved December 31, 2024, from https://www.xcelenergytransmission.com/projects/western-wisconsin-transmission-connection/. Any information contained in this citation, based solely on this citation, is NRE.

[35] Associated Press. (2024, September 27). Utilities complete transmission line linking Iowa and Wisconsin. Retrieved from https://apnews.com/article/wisconsin-iowa-power-line-13ddfab7e90bbcf8ced09dfdd96fb66f. Any information contained in this citation, based solely on this citation, is NRE.

- The Grid Forward Project by ATC and Northern States Power involves rebuilding 175 miles of lines and constructing a new 345-kV line, with completion anticipated by 2030;[36] and
- In Racine County, a high-voltage transmission line project has been proposed to address growing energy demands and enhance grid reliability.[37]

Q: More broadly still, is transmission capacity a barrier for renewable energy development in MISO Territory?

A: No. On December 12, 2024, MISO's Board of Directors unanimously approved the largest portfolio of transmission projects in U.S. history. This plan includes 488 projects spanning over 5,000 miles across 15 states within the MISO footprint. The projects encompass local reliability and growth initiatives, the LRTP Tranche 2.1 portfolio, and Joint Targeted Interconnection Queue ("JTIQ") projects in collaboration with the Southwest Power Pool ("SPP"). The LRTP Tranche 2.1 consists of 24 projects totaling 3,631 miles, representing a $21.8 billion investment with a cost-to-benefit ratio of 1.8 to 3.5, potentially yielding benefits exceeding $72 billion.[38]

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[36] Public Service Commission of Wisconsin. (n.d.). Grid Forward - Central Wisconsin transmission line project. Retrieved December 31, 2024, from https://psc.wi.gov/Pages/CommissionActions/CasePages/GridForwardCentralWisconsin.aspx. Any information contained in this citation, based solely on this citation, is NRE.

[37] Lockwood, D. (2024, November 22). New transmission lines proposed in Racine County: What residents need to know. Racine County Eye. Retrieved from https://racinecountyeye.com/2024/11/22/high-voltage-transmission-lines/. Any information contained in this citation, based solely on this citation, is NRE.

[38] MISO. (2024, December 12). MISO Board approves historic transmission plan to strengthen grid reliability. Retrieved from https://www.misoenergy.org/meet-miso/media-center/2024/miso-board-approves-historic-transmission-plan-to-strengthen-grid-reliability/. Any information contained in this citation, based solely on this citation, is NRE.

On November 13, 2024, the Federal Energy Regulatory Commission ("FERC") approved proposals by MISO and SPP to advance $1.8 billion in transmission projects identified through their JTIQ process. These projects are expected to enable approximately 29 GW of new generation along the MISO-SPP seam, primarily benefiting interconnection customers such as wind and solar generation developers.[39]

Q: What do you conclude about the assertion that transmission capacity is a barrier to renewable generation alternatives?

A: I conclude that WEPCO has not justified its claim that transmission capacity is a barrier to renewable generation alternatives. I further conclude that transmission capacity is not a barrier to WEPCO using renewable generation alternatives.

V. WEPCO'S CAPACITY EXPANSION MODELING

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

A: In this section I analyze WEPCO's capacity expansion modeling and identify significant biases that undermine the reliability and objectivity of that modeling. I address specific ways in which WEPCO's modeling is biased, explain why these issues should concern the Commission, and propose remedies to mitigate the negative impacts of these biases. By highlighting these flaws and recommending

[39] Utility Dive. (2024, November 15). FERC approves MISO, SPP transmission plan expected to spur 29 GW of renewables. Retrieved from https://www.utilitydive.com/news/ferc-miso-spp-jtiq-joint-transmission-interconnection/733047/. Any information contained in this citation, based solely on this citation, is NRE.

corrective actions, this section aims to ensure that the Commission has the necessary information to evaluate WEPCO's application fairly and promote better alignment with public and regulatory interests.

Q: Have you reviewed the capacity expansion modeling WEPCO conducted in support of the Project?

A: Yes, I have reviewed WEPCO's capacity expansion modeling conducted in support of the Project.

Q: At a high level, what is your reaction to WEPCO's capacity expansion modeling effort?

A: At a high level, I find WEPCO's capacity expansion modeling effort to be flawed and biased. The modeling appears to favor the inclusion of the Project, while failing to fully explore or accurately represent lower-cost, non-combustion alternatives like renewable energy, BESS, energy efficiency, and demand response ("DR") programs. This lack of objectivity raises concerns about the validity of WEPCO's conclusions and the potential impacts on ratepayers.

Q: Please elaborate on your concerns.

A: WEPCO has not conducted unbiased capacity expansion modeling. This leads to at least two situations that are against the public interest: first, WEPCO's stated desire to own all its generation assets appears to produce inaccurate O&M cost estimates;

and second, WEPCO's professed preference to own generation assets encourages WEPCO to avoid alternatives that could be more beneficial to its customers.

Q: Please elaborate on your first concern, that WEPCO's preference to own all generation assets appears to produce inaccurate cost estimates.

A: WEPCO's claim that it prefers asset ownership over power purchase agreements ("PPA") in order to manage O&M costs and increase the value of the unit in the marketplace[40] is misleading. This claim is misleading because it underestimates the O&M cost associated with natural gas combustion turbines. WEPCO used a levelized fixed O&M cost of [redacted]/kW/year over thirty years for the Project.[41] While this is conservative compared to Lazard's range of $10 - $17/kW/year,[42] in contrast, NREL's ATB estimate for a similar facility is $26/kW-year.[43] WEPCO provides a variable O&M rate for the Project of [redacted]/MWh[44] but NREL's ATB for a similar facility gives an estimate of $6.94/MWh[45] and Lazard's estimate is $3.50 - $5.00/MWh.[46]

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[40] Ex.-WEPCO-Application-Application: 2-14.
[41] Direct-WEPCO-Gerlikowski-c-25.
[42] Lazard. (2024, June). 2024 Levelized Cost of Energy+ (p. 38). Retrieved from https://www.lazard.com/research-insights/levelized-cost-of-energyplus/. Any information contained in this citation, based solely on this citation, is not NRE.
[43] NREL. (2024). ATB Assumption - Natural Gas_FE - 2024 - Moderate Case. National Renewable Energy Laboratory. Retrieved from https://atb.nrel.gov/electricity/2024/data. Any information contained in this citation, based solely on this citation, is not NRE.
[44] Direct-WEPCO-Gerlikowski-c-25.
[45] NREL. (2024). ATB Assumption - Natural Gas_FE - 2024 - Moderate Case. National Renewable Energy Laboratory. Retrieved from https://atb.nrel.gov/electricity/2024/data. Any information contained in this citation, based solely on this citation, is not NRE.
[46] Lazard. (2024, June). 2024 Levelized Cost of Energy+ (p. 38). Retrieved from https://www.lazard.com/research-insights/levelized-cost-of-energyplus/. Any information contained in this citation, based solely on this citation, is not NRE.

Q. Does WEPCO explain how it will achieve variable O&M costs so far below NREL ATB and Lazard estimates?

A. WEPCO's modeling of its variable O&M rate used only consumables.[47] Consumables in this context are materials and supplies that are used up or depleted during the operation and maintenance of equipment, such as lubricants, filters, water treatment chemicals, and emissions-control materials. This likely excludes several important cost components, resulting in an unrealistically low estimate. Key omissions could include labor costs for maintenance activities, which cover routine inspections, repairs, and corrective actions, as well as waste disposal costs for materials like spent catalysts, liquid waste streams, and other byproducts from emissions control systems. Additionally, maintenance materials beyond consumables, such as replacement parts and wear-and-tear items for starts-based[48] or routine maintenance, appear to be left out. Costs associated with short-term outages, unplanned repairs, and starts-based maintenance intervals, including inspection and minor repair expenses, are also missing. Other variable operating costs, such as water treatment for cooling systems or emissions-related consumables like ammonia for NOx control, are not accounted for. By focusing solely on consumables, WEPCO's variable O&M rate overlooks these significant cost drivers, leading to an incomplete and likely understated estimate.

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47 Ex.-WEPCO-Application-Volume III Appendix B: 27.

48 Starts-based maintenance is due to frequent starts and stops that put significant stress on turbine components due to thermal cycling and mechanical wear.

Q: Please elaborate on your second concern, that WEPCO's preference to own all generation assets encourages WEPCO to avoid beneficial alternative generation.

A: WEPCO's preference to own all of the generation it uses to serve customers belies an interest to rate base the maximum possible amount of assets. Seeking to rate base the maximum possible amount of assets weakens WEPCO's incentive to use generation resources it does not own, even if they are renewable, safer, lower-cost, or otherwise better for ratepayers, public health, or state policy goals. This runs counter to the public interest. For example, if the Project and the Paris RICE are built but become stranded assets, customers still have to pay for them. A PPA, on the other hand, could secure the capacity expansion WEPCO needs without the risk of imposing stranded asset costs on its customers. But at least right now, there is no mechanism for WEPCO to earn a rate of return on a PPA. Power purchased from the market or contracted by the utility with an Independent Power Producer for a PPA is essentially passed through to the customer like a fuel cost mechanism.

Q: Do you have concerns regarding specific flaws or shortcomings in WEPCO's modeling in this case?

A: Yes, I have several such concerns, regarding the following ten factors in WEPCO's modeling: (1) forced inclusion of Project units' timing and quantity; (2) lack of VVO; (3) lack of DR and VPP; (4) the restriction on MISO Market purchases and inclusion of other third-party-owned options; (5) lack of consistent use of DLOL; (6) limitations on wind energy despite new transmission and the availability of market purchases from MISO; (7) modeling BESS as utility-owned only; (8) lack of inclusion of hybrid solar and hybrid wind also with third-party ownership as an option; (9) absence of the SCOC; and (10) modeling constraints of the ITC due to utility-ownership default.

Q: What concerns you about forced inclusion of the Project units in WEPCO's modeling?

A: Forcing inclusion of these units in 2027 biases the modeling by predetermining outcomes that favor WEPCO's preferred generation resources, rather than allowing optimization based on least-cost or most efficient options. Additionally, WEPCO modeled the start year for the facilities coming online rather than letting PLEXOS choose the year. Modeling the start year in this way further limits the value of the modeling results.

Q: What is VVO?

A: VVO refers to smoothing out the voltage impacts from renewable intermittency, making it easier to maintain grid stability. By optimizing voltage levels, VVO reduces peak demand and overall energy losses on the grid. This reduction in peak demand can defer or decrease the reliance on natural gas peaking plants, which are often used to meet high demand.

Q: What concerns you about the lack of VVO in WEPCO's modeling?

A: The exclusion or underrepresentation of these measures ignores their proven ability to reduce demand and defer costly infrastructure investments.

Q: What concerns you about the lack of DR and VPPs in WEPCO's modeling?

A: By failing to fully account for the potential of DR and VPPs, the modeling overlooks cost-effective, quickly deployed, scalable alternatives that enhance grid flexibility. I discuss these options in greater detail further below in my testimony.

Q: What concerns you about the lack of MISO market interaction in WEPCO's modeling?

A: WEPCO's restrictive assumptions about market purchases and sales limit the ability to optimize energy procurement and unnecessarily inflate the need for new capacity. This is because WEPCO's "Capacity Assurance" modeling ensures "that energy requirements can be met with utility-owned generating resources" and set the modeling constraint such that "by 2026 there will not be any access to purchase or sell energy to the MISO market."[49] This is a faulty assumption that is costly to customers who would otherwise benefit from lower costs if WEPCO purchased some of its capacity from the MISO market.

[49] Ex.-WEPCO-Application-Volume III Appendix B: 16.

Q: What concerns you about the lack of use of DLOL in WEPCO's modeling?

A: WEPCO's methodology for this Application involved modeling the Planning Year 2024/25 Installed Capacity ("ICAP") seasonal Planning Reserve Margins ("PRMs"), alongside a declining seasonal capacity accreditation for solar, wind, and battery storage resources.[50] WEPCO indicated in its Application that DLOL estimates for these resources would be applied beginning in 2028. For existing units, however, WEPCO stated that the seasonal capacity tested rating was used.[51] I recommend that WEPCO adopt the full MISO DLOL approach, which would involve adjusting the seasonal PRMs and capacity accreditation for thermal, renewable, and battery storage resources to align with the accreditation framework for these resource types under the DLOL construct.

Q: What concerns you about the limitations on wind energy in WEPCO's modeling?

A: WEPCO constrained wind to just 800 MW in its capacity expansion plan.[52] Artificial constraints on wind resources in the modeling ignore their economic and environmental benefits and fail to explore their potential as a competitive alternative. This is evident in the NPV savings shown in WEPCO's responses to Staff data requests.[53] WEPCO's concerns about the time it would take to build new wind capacity due to setback rules and lack of ready transmission, as I explain above, are

[50] *Id*. at 12.
[51] *Id*. at 14.
[52] *Id*. at 24.
[53] *See* Ex.-PSC-DRR (Response-Data Request-PSC-Bushey-DG-4.4 Attach 01; Response-Data Request-PSC-Bushey-DG-2.06; Response-Data Request-PSC-Bushey-DG-4.4).

not valid reasons for artificially constraining wind. For reference, the Cardinal-Hickory Creek Transmission Line Project, a 102-mile, 345-kilovolt line connecting Iowa and Wisconsin, was fully energized and placed into service on September 26, 2024.[54] Even if that were not the case, WEPCO's arguments presume all new wind modeled must be located in LRZ 2 but that is a faulty assumption since wind can be transmitted from other zones.

Q: What concerns you about the modeling of hybrid solar/wind and BESS in WEPCO's modeling?

A: The lack of modeling for hybrid systems disregards innovative solutions that could better integrate renewable energy and provide consistent, cost-effective power. Additionally, modeling BESS as utility-owned forces tax normalization of the ITC, which is less economic.

Q: What concerns you about the absence of the SCOC in WEPCO's modeling?

A: Not incorporating the SCOC undervalues the long-term societal and environmental costs of fossil fuel-based generation. The SCOC represents the comprehensive economic cost of carbon dioxide emissions, including societal impacts such as health effects, environmental damage, and climate adaptation costs. The most recent U.S. Interagency Working Group report estimates the SCOC at $51/ton (2020 dollars) for

[54] ITC Midwest, Dairyland Power Cooperative, & ATC. (2024, September 27). Joint news release: Cardinal-Hickory Creek transmission line energized. Retrieved from https://www.cardinal-hickorycreek.com/joint-news-release-cardinal-hickory-creek-transmission-line-energized. Any information contained in this citation, based solely on this citation, is NRE.

emissions in 2020, with values increasing over time due to compounding damages. In Virginia, Appalachian Power Company modeled a 2024 SCOC value of \$59.53/ton.[55] In contrast, WEPCO's carbon penalty price—based on Lazard's April 2023 Levelized Cost of Energy report—ranges from \$20/ton to \$40/ton,[56] a value significantly below the SCOC estimates provided by federal and international benchmarks.

Q: What concerns you about the ITC constraints in WEPCO's modeling?

A: WEPCO's approach to ITC assumptions relies on tax credit normalization, which spreads the financial benefits over a 30-year period. This approach significantly dilutes the upfront economic advantages of energy storage and renewable projects, underestimating their cost-effectiveness compared to fossil generation. By not exploring alternative ownership or financing structures, such as tax equity partnerships or PPAs, WEPCO fails to fully account for the immediate and substantial cost reductions these tax credits can provide.

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[55] Virginia State Corporation Commission. (2024, October 21). PUR-2024-00020 final order on Appalachian Power Company's 2024 RPS plan application. Retrieved from https://www.scc.virginia.gov/docketsearch/DOCS/826m01!.PDF. Any information contained in this citation, based solely on this citation, is NRE.

[56] Ex.-WEPCO-Application-Volume III Appendix B: 20-21.

Q: How can the flaws and shortcomings identified above be remedied or corrected by the Commission?

A: The Commission should order WEPCO to correct the following factors in its capacity expansion modeling:

- The Project: Allow the modeling software (PLEXOS) to optimize decisions about the inclusion of the Project units instead of forcing the scenarios. WEPCO should have included the Project as a modular option, allowing for flexibility in deployment (e.g., up to five 237 ICAP MW Project generators) without presuming a 2027 implementation for all five generators. Instead, WEPCO modeled three main scenarios, which confined the model to select a predetermined outcome of selecting the Project as the best option[57]:
    - The first case assumes the Project is in-service in 2027;
    - The second case assumes the Project is not included in the resource mix and all generic units (including generic CT) are available to be selected as a replacement; and
    - The third case assumes the Project is not included in the resource mix but is instead replaced with an equivalent amount of battery capacity in 2027.
- VVO: Incorporating VVO can reduce demand by 1-2.5% on average and as much as 4% depending on the scale of the project (see section below).

[57] Direct-WEPCO-Gerlikowski-c-16.

- DR and VPP: Incorporate residential and behavioral DR and VPP programs instead of WEPCO's generic DR assumptions. For reference, WEPCO states 50 MW of DR was modeled based on data from the U.S. Energy Information Administration File 861 dataset.[58] I recommend WEPCO model 1) a residential VPP program similar to the PowerPair Solar and Battery ("PPSB") program launched in May 2024 by Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") which deployed about 3 MW per month.[59] The PPSB incentives are set at \$0.36/W-AC for solar and \$400/kWh of energy capacity for the battery; incentives are limited to 10 kW-AC for solar and 13.5 kWh of energy capacity for the battery; and there is a separate battery control incentive (\$4.61/kW-month) for a customer to allow DEC/DEP to dispatch the battery (see details below);[60] 2) a residential DR program leveraging smart thermostats for summer and winter cycling of heat pumps and summer cycling of air conditioning units to achieve a conservative savings estimate of 62 MW at 30% participation or up to 280-300 MW with pre-cooling capabilities for a cost of approximately \$208.20/kW enrolled; and 3) a behavioral DR program using automated metering infrastructure to notify customers of DR events during peak hours

[58] Ex.-WEPCO-Application-Application: 2-18.
[59] Duke Energy. (2024, December 6). PowerPair capacity summary. Retrieved from https://www.duke-energy.com/Home/Products/PowerPair. Any information contained in this citation, based solely on this citation, is NRE.
[60] North Carolina Utilities Commission. (2024, January 11). *Order approving Duke Energy's application in dockets E-7 Sub 1261 & E-2 Sub 1287*. Retrieved from https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=183c0a0c-4a81-48d0-b1bd-37e76bd3b331&Class=Filing. Any information contained in this citation, based solely on this citation, is NRE.

to achieve a 1.5% reduction in peak load, equivalent to 84 MW in summer and 54 MW in winter, with per-customer savings ranging from 0.25 to 0.5 kW per event and a cost of approximately $87 per kW-year.[61] See the economics of VPP and DR programs further below in my testimony.

- MISO Market Interaction: Relax the purchase limits used in the capacity assurance model for a more flexible market interaction scenario rather than strictly limiting purchases and sales to 800 MW per hour.
- DLOL: Model MISO's capacity accreditation method it plans to implement in 2028 called DLOL instead of a modified ICAP approach.
- Wind: Do not limit wind in the model given the Net Present Value ("NPV") savings shown in the Commission Staff Response in file 525565 per 514065-PSCW-DG -2.6 and 525564-PSCW-DG -4.4.
- Hybrid Solar/Wind and BESS: Model renewables such as wind and solar paired with 20% to 50% of nameplate as BESS in order to shape the generation and performance of these variable resources.
- SCOC: Model the SCOC for power plants emitting greenhouse gas emissions using the most recent U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases ("IWG") report.[62] For example,

[61] Ex.-United-Makhyoun-2 (excerpt from Clean Wisconsin witness Sherwood testimony in Docket 6630-CE-316, Direct-CW-Sherwood-14-16).

[62] Technical Support Document on the Social Cost of Carbon (2010, 2013, 2016, updates in 2021). U.S. IWG (2021): $51/ton CO_2 at a 3% discount rate (2020 dollars). Any information contained in this citation, based solely on this citation, is NRE.

in Virginia, Appalachian Power Company modeled a 2024 SCOC value of $59.53/ton.[63]

- ITC: WEPCO modeled battery storage capital costs by assuming the ITC would be amortized over 30 years through utility ownership of the asset,[64] which diluted its immediate financial benefits and reduced the upfront value of the tax credit. Instead, it should model alternative pathways to avoid amortization, such as PPAs, third-party leases, or tax equity financing to address uncertainties around ITC normalization rules and ownership structures for energy storage projects.

VI. CAPACITY EXPANSION PLAN ALTERNATIVES

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

A: In this section, I describe potential alternatives to WEPCO's capacity expansion plan.

Q: Are you aware of any existing alternative capacity expansion plans that the Commission should consider in this proceeding?

A: Yes. In the pending Paris RICE docket, Clean Wisconsin witness Hotaling offered alternative capacity expansion plan modeling for WEPCO.[65]

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[63] Virginia State Corporation Commission. (2024, October 21). PUR-2024-00020 final order on Appalachian Power Company's 2024 RPS plan application. Retrieved from https://www.scc.virginia.gov/docketsearch/DOCS/826m01!.PDF. Any information contained in this citation, based solely on this citation, is NRE.
[64] Direct-WEPCO-Gerlikowski-c-16.
[65] Ex.-United-Makhyoun-3 (excerpt from Clean Wisconsin witness Hotaling testimony in Docket 6630-CE-316, Direct-CW-Hotaling).

Q: Why do you recommend the Commission consider Witness Hotaling's alternative capacity expansion plan modeling?

A: Because WEPCO's Applications for the Project and the Paris RICE total 1,128 MW of nameplate capacity by 2027, I recommend the 2027 output of the capacity expansion plan called the Alternative Plan New Customer Load Low Sensitivity Capacity Additions Plan ("Hotaling Alternative Plan"). This plan is shown in Table 7 of Chelsea Hotaling's testimony on behalf of Clean Wisconsin in the Paris RICE docket.[66] In 2027, the result of witness Hotaling's Alternative Plan is 237 MW of nameplate/ICAP capacity from the Project, 55 MW of the Paris RICE capacity, 800 MW of solar, 300 MW of wind, 780 MW of BESS, and 178 MW of demand response, assuming Energy Efficiency ("EE") is a DR program. [67] See Table 2 below for a modified version of Witness Hotaling's Table 7.

Table 2. Alternative Plan New Customer Load Low Sensitivity Capacity Additions Plan - 2027 Output Only[68]

Type of Capacity	The Project	Paris RICE	Solar	Wind	Battery	EE	DR
ICAP MW	237	55	800	300	780	7	171
Average 2030 DLOL %	73.00	73.00	2.77	10.80	93.19	93.19	93.19
DLOL MW	173.01	40.15	22.12	32.41	726.82	6.52	159.34

[66] *Id.*
[67] Based on the programs proposed in Ex.-United-Makhyoun-2.
[68] Ex.-United-Makhyoun-3.

Q: Why do you recommend this capacity expansion plan instead of the Project?

A: I recommend the Hotaling Alternative Plan because Witness Hotaling took into account most of the modeling factors I mentioned above in the question regarding deficiencies in the modeling. For example, witness Hotaling included: (1) PLEXOS' ability to select the years to incorporate the Paris RICE and Project units; (2) EE; (3) DR; (4) MISO Market Interaction; (5) DLOL; (6) Wind; and (7) options for the ITC that do not rely on utility ownership of assets and tax normalization.

Q: What modeling attributes did Witness Hotaling not take into account that would improve the outputs of the capacity expansion plan?

A: Witness Hotaling did not model hybrid (paired) facilities, account for the SCOC, model VPP, or VVO.

Q: Does the Hotaling Alternative Plan meet or exceed the capacity being proposed by WEPCO for the Project and the Paris RICE?

A: Yes. The total 2030 DLOL-based effective capacity of the Hotaling Alternative Plan based on MISO's 2030 DLOL estimates shown below, is 1,160.37 MW (2,350 MW nameplate), which exceeds the 896.44 MW of effective capacity from the 1,100 MW Project and the 128 MW nameplate Paris RICE using a 2030 estimated DLOL of 73% as the seasonal average.

MISO DLOL ESTIMATES[69]

		Coal	Oil	Gas	Nuclear	Hydro	Other	Combined Cycle	4-hour Battery	Wind	Solar
2030	Spring	58.80	37.54	65.39	72.21	66.97	60.40	65.39	97.29	10.65	2.68
	Summer	82.09	73.02	78.35	91.38	87.47	83.11	81.21	96.12	10.52	4.80
	Fall	77.24	53.29	71.72	89.26	77.37	79.58	72.05	99.83	11.21	2.98
	Winter	90.02	16.64	76.54	96.08	77.12	88.47	92.28	79.49	10.83	0.60
2033	Spring	52.50	67.78	64.50	72.50	61.75	59.98	62.35	81.03	9.60	2.96
	Summer	82.72	74.36	78.38	89.64	84.98	82.48	79.61	95.58	9.71	4.81
	Fall	80.02	64.98	71.54	88.52	80.82	79.69	71.14	94.66	13.47	3.63
	Winter	89.16	14.38	76.81	95.52	66.31	86.96	92.54	77.42	14.63	0.36
2043	Spring	53.12	8.76	54.96	66.74	60.61	27.58	67.79	74.69	11.38	0.97
	Summer	84.38	3.19	52.52	91.10	67.41	22.28	78.96	82.39	8.43	1.80
	Fall	78.98	3.34	32.89	88.04	68.62	11.87	71.10	76.61	8.66	0.95
	Winter	89.41	43.59	69.21	95.05	65.32	74.39	94.27	31.01	11.47	0.31

Q: How did you calculate the effective capacity of the Hotaling Alternative Plan?

A: The total 1,160 MW of effective capacity was calculated by multiplying MISO's 2030 DLOL estimates per technology to the nameplate capacity outputs. The natural gas combustion turbine from the Project has a capacity of 237 MW with an effective contribution of 73%, resulting in an effective capacity of 173.01 MW. Similarly, the Paris RICE capacity is 55 MW with a 73% effective contribution, providing 40.15 MW of effective capacity. The 800 MW of solar capacity, adjusted to a MISO capacity accreditation of 3% DLOL, translates to an effective capacity of 22.12 MW. The 300 MW of wind capacity has an average MISO accreditation of 11%, resulting in an effective capacity of 32.41 MW. BESS, with a capacity of 780 MW, is estimated by MISO to have a 93% effective contribution for 4-hour durations,

[69] Midcontinent Independent System Operator. (2024, November 6). 2024 Regional Resource Assessment (p. 25). Retrieved from https://cdn.misoenergy.org/20241106%20RASC%20Item%2010%202024%20RRA%20Update658159.pdf. Any information contained in this citation, based solely on this citation, is NRE.

providing 726.82 MW of effective capacity. MISO does not assign EE or DR DLOLs so I assume the same DLOL as BESS since the programs I recommend typically include customer-sited BESS: EE's 7 MW capacity is effectively 6.52 MW and 171 MW of DR is effectively 159.34 MW.

Q: What other resources were modeled by WEPCO for 2027 apart from the Project and the Paris RICE?

A: WEPCO modeled several scenarios. The example used in Witness Hotaling's testimony for comparison came from the PLEXOS expansion plans contained in a WEPCO response to discovery in the Paris RICE case (PSC REF # 505820). The modeling run Ms. Hotaling referenced is labeled 206A, which was optimized under the CFC Pathway and no GHG restrictions. Apart from the Project and the Paris RICE, this model includes in Year 2027 another 1,422 MW of Generic CT, 129 MW of Generic RICE, 800 MW of solar, 300 MW of wind, and 15 MW of EE.

Q: Does the Hotaling Alternative Plan meet or exceed the capacity being proposed by WEPCO for the Project and the Paris RICE plus all other generic resources modeled?

A: No. This is because the Hotaling Alternative Plan is based on a modeling assumption that WEPCO will contract only 50% of the projected load. However, the DLOL capacity of the Hotaling Alternative Plan exceeds that of the Project and Paris RICE, which is why the Hotaling Alternative Plan is a suitable alternative for the Project.

Q: What is the cost difference between WEPCO's Plan and the Hotaling Alternative Plan?

A: Witness Hotaling's plan is significantly more cost-effective than WEPCO's plan in terms of both overnight capital cost and CAPEX using NREL's ATB 2024 assumptions in Appendix A. The overnight capital cost for Witness Hotaling's plan is approximately $3.26 billion, which is $1.42 billion lower than WEPCO's overnight capital cost of $4.68 billion. Similarly, the total CAPEX for Witness Hotaling's plan is $3.66 billion, which is $1.89 billion less than WEPCO's CAPEX of $5.55 billion. These differences highlight the substantial cost savings associated with Witness Hotaling's approach, which provides a more economical solution for meeting capacity needs.

Q: How did you determine the overnight capital cost of the Hotaling Alternative Plan?

A: Using NREL's ATB cited in Appendix A, I estimate the overnight capital cost for the Hotaling Alternative Plan is approximately $3.26 billion USD.

<u>Cost Breakdown</u>

- NGCT (292 MW): $319,156,000
- Solar (800 MW): $1,103,200,000
- Wind (300 MW): $444,300,000
- BESS (780 MW): $1,380,600,000

- EE/DR/VPP (178 MW): 15,486,000 (based on Sherwood testimony)[70]
- Total OCC: $3,262,742,000 (approximately $3.26 billion USD).

Q: How did you determine the overnight capital cost of WEPCO's 206A scenario as modeled by Witness Hotaling?

A: Using NREL's ATB cited in Appendix A, I estimate the overnight capital cost for the buildout up to 2027 is approximately $4.68 billion USD. The breakout is as follows:

<u>Cost Breakdown</u>

- NGCT (2,865 MW): $3,131,445,000
- Solar (800 MW): $1,103,200,000
- Wind (300 MW): $444,300,000
- EE/DR/VPP (15 MW): 1,305,000 (based on Sherwood testimony)[71]
- Total Cost: $ 4,680,250,000 (approximately $4.68 billion USD).

Q: How did you determine the CAPEX of the Hotaling Alternative Plan?

A: Using NREL's ATB cited in Appendix A, I estimate the CAPEX of the Hotaling Alternative Plan to be approximately $3.66 billion USD.

<u>Cost Breakdown</u>

- NGCT (292 MW): $388,068,000
- Solar (800 MW): $1,240,800,000

[70] $87,000/MW as proposed in Ex.-United-Makhyoun-2.
[71] $87,000/MW as proposed in Ex.-United-Makhyoun-2.

- Wind (300 MW): $502,800,000
- BESS (780 MW): $1,511,640,000
- EE/DR/VPP (178 MW): 15,486,000 (based on Sherwood testimony)[72]
- Total CAPEX: $3,658,794,000 (approximately $3.66 billion USD).

Q: How did you determine the CAPEX of WEPCO's 206A scenario as modeled by Witness Hotaling?

A: Using NREL's ATB cited in Appendix A, I estimate the CAPEX to be approximately $5.55 billion.

<u>Cost Breakdown</u>

- NGCT (2,865 MW): $3,807,585,000
- Solar (800 MW): $1,240,800,000
- Wind (300 MW): $502,800,000
- EE/DR/VPP (15 MW): 1,305,000 (based on Sherwood testimony in Ex.-United-Makhyoun-2)[73]
- Total CAPEX: $ 5,552,490,000 (approximately $5.55 billion USD).

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[72] $87,000/MW as proposed in Ex.-United-Makhyoun-2.
[73] $87,000/MW as proposed in Ex.-United-Makhyoun-2.

VII. DEPLOYMENT OF DER

Q: You indicated above that the Commission should reject WEPCO's CPCN Application for the Project. Considering the Application is for resources to be deployed and online by 2027, what alternative resources can be deployed in less than two years?

A: Considering the CPCN Application for the Project aims for resources to be deployed and operational by 2027, while WEPCO is revising its model in accordance with my recommendations, resources that can feasibly be built and deployed in under two years include DR, VPPs, and VVO to enhance grid efficiency.

Q: You referenced VPP earlier. What is VPP and what is the cost and speed of deploying a VPP program?

A: A VPP is a system that relies upon software and a smart grid to remotely and automatically dispatch retail DER to a distribution or wholesale market via an aggregation and optimization platform. One can think of it as a "chorus of devices" (energy storage; thermostats; water heaters; EVs; other curtailable load). When a utility is short on capacity it issues a signal to enrolled DERs, which either automatically curtail demand or, if capable of exporting energy, deliver energy to the grid. The speed of deployment is tens of MWs in just a few months. For example, DEC and DEP launched the PPSB program in its North Carolina territories on May

10, 2024 and deployed about 3 MW per month. As of December 6, 2024, approximately 21 MW of capacity was enrolled into the PPSB program.[74]

The value to the utility depends on whether a resource's benefits exceed utility costs (the "Utility Cost Test"). The Utility Cost Test ("UTC") results for DEC and DEP combined is a benefit/cost ratio UTC of 1.75, indicating the program is cost-effective. This is because the projected total benefits are $11,833,004 ($7,503,792 of avoided transmission and distribution costs and $4,329,212 of avoided capacity costs) compared to the total costs (program administration, implementation, and incentives) of $6,774,170.[75]

Q: Did WEPCO consider implementing a VPP program?

A: No, according WEPCO's response to UNITED-IR-2-2, it does not consider VPP reliable.[76] However, several other utilities use VPP as a supply-side resource:

- Green Mountain Power's ("GMP") two BESS VPP programs, a Bring Your Own Device ("BYOD") program, where customers own their BESS, and an Energy Storage System ("ESS") lease program, began as pilots in 2015. Under the BYOD program, customers that enroll their self-purchased energy

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[74] Duke Energy. (2024, December 6). PowerPair capacity summary. Retrieved from https://www.duke-energy.com/Home/Products/PowerPair. Any information contained in this citation, based solely on this citation, is NRE.
[75] See North Carolina Utilities Commission Docket Nos. E-7 Subs 1032 and 1261 and E-2 Subs 927 and 1287, May 3, 2024 Duke Energy PowerPair Program Cost Filing Retrievable at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=0f460728-117f-42ba-be27-c328f674b957. Any information contained in this citation, based solely on this citation, is NRE.
[76] Ex.-United-Makhyoun-1 (WEPCO response to United-IR-2-2).

storage system choose how much access they provide to GMP, with a minimum of 2 kW and a maximum of 10 kW, equating to an incentive of up to $10,500. The ESS Tariff provides GMP with an additional 10-11.5 kW of capacity for demand response, energy arbitrage, and frequency regulation for each installed Tesla Powerwall system, at either a $55/month fee or a one-time upfront payment of $5,500. GMP reports there are more than 7,000 Tesla Powerwalls installed in its territory, representing approximately 35 MW of capacity that is being used for peak reduction.[77]

- Arizona Public Service's Cool Rewards for Summer Peak Reduction was launched in 2018 and as of October 2024, has enrolled 95,000+ thermostats and 160 MW of load-shedding capacity, up from 42 MW in 2020.[78]
- DTE Energy's Smart EV Charging for a Cleaner, Better Optimized Grid launched in July 2023 and ran through December 2024 as an expansion of a 2019-2022 EV Smart Charge Pilot. The 2022 -2023 pilot saw a reduction of 14 MWh between 44 events from 663 participants. The program is expected to continue through June 2025.[79]

[77] Green Mountain Power. (2024, December 10). 2024 integrated resource plan (pp. 2-38–2-39). https://epuc.vermont.gov/?q=downloadfile/743232/202366. Any information contained in this citation, based solely on this citation, is NRE.
[78] Arizona Public Service. (2024, October 7). APS customers served with reliable power during record-breaking heat. Arizona Public Service. https://www.aps.com/en/About/Our-Company/Newsroom/Articles/APS_Customers_Served_With_Reliable_Power_During_Record-Breaking_Heat. Any information contained in this citation, based solely on this citation, is NRE.
[79] DTE Energy. (n.d.). DTE Smart Charge. https://www.dteenergy.com/content/dam/dteenergy/deg/website/residential/Service-Request/pev/plug-in-electric-vehicles-pev/SmartChargeBrochure.pdf. Any information contained in this citation, based solely on this citation, is NRE.

- California's Emergency Load Reduction Program and Demand Side Grid Support launched in May of 2021 and by the Summer of that same year, it dispatched 200 MW from non-residential customers four times using $1 million in incentives. In the Summer of 2023 Nearly 950 MW were enrolled in the programs.[80]

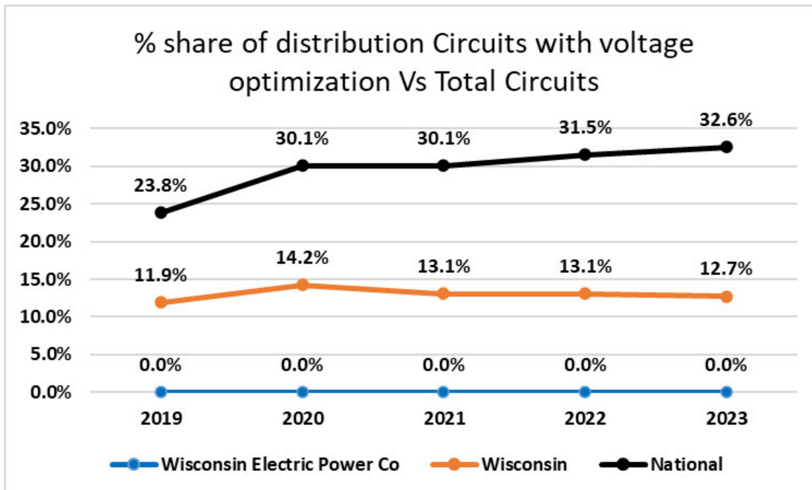
Q: What is VVO and did WEPCO consider it?

A: As described above, VVO can smooth out the voltage impacts from renewable intermittency, making it easier to maintain grid stability. VVO is accomplished through the use of voltage regulating devices, like tap changers on substation transformers, voltage regulators on feeders, capacity banks for reactive power control, a communication network to gather data and send control signals, advanced data analysis tools to optimize settings, and a detailed model of the distribution system to accurately simulate voltage and reactive power flows. WEPCO did not consider implementing VVO to defer or decrease the need for the Project.[81] Furthermore, according to data from the Annual Electric Power Industry Report, Form EIA-861, WEPCO lags far behind the U.S. and Wisconsin for VVO adoption

[80] California Public Utilities Commission. (n.d.). Emergency load reduction program. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program. Any information contained in this citation, based solely on this citation, is NRE.
[81] Ex.-United-Makhyoun-1 (WEPCO response to UNITED-IR-2-3).

(see image below). In fact, it appears from Figure 1 below that WEPCO has not implemented *any* VVO.

Figure 1. Percent Share of Distribution Circuits with Voltage Optimization vs. Total Circuits.[82]



Q: What are examples of VVO?

A: There are several ongoing projects that provide evidence of peak demand reduction and energy savings achieved through VVO technologies. The results from conservation voltage reductions suggest a potential peak demand reduction of approximately 1% to 2.5%. Table 3 shows the results from two Conservation Voltage Reduction ("CVR") projects implemented in Ohio and Kansas:

[82] U.S. Energy Information Administration. (2024, October 10). Annual Electric Power Industry Report, Form EIA-861 detailed data files: Distribution_Systems_2023. https://www.eia.gov/electricity/data/eia861/. Any information contained in this citation, based solely on this citation, is NRE.

AEP Ohio's gridSMART demonstration project deployed a comprehensive suite of innovative smart grid technologies across 70 circuits, serving 132,000 customers in Central Ohio in its first phase. The total investment in this project was $150 million. Of the 70 modernized circuits, AEP Ohio tested 11 circuits and demonstrated a potential energy reduction of 2-4% in kilowatt-hours ("kWh") consumed and in power demand ("kW").

KCP&L undertook a $50 million project that demonstrated, tested, and evaluated the feasibility of integrating new and existing technologies in a complete smart grid. This project served 13,427 customers.

Table 3. Demand and Energy Reduction Results for Utilities in SGDP testing CVR[83]

Parameters	Utility	Voltage reduction	Energy reduction
Energy	AEP Ohio	3-5%	2.90%
	KCP&L	2.05%	1.63%
Peak Demand	AEP Ohio	3-4%	2-3%
	KCP&L	1.64%	1.13%

Another piece of evidence is from the Ameren Illinois Company 2022 Voltage Optimization Program, which showed the energy and peak demand savings for the

[83] DOE. (2017). Voltage and Power Optimization Saves Energy and Reduces Peak Power. Washington, DC: Department of Energy. https://www.energy.gov/sites/prod/files/2017/01/f34/Voltage-Power-Optimization-Saves-Energy-Reduces-Peak-Power.pdf. Any information contained in this citation, based solely on this citation, is NRE.

181 circuits that became operational in 2022. Overall, the program achieved verified net energy savings of 86,892 MWh and verified net peak demand savings of 13.52 MW.[84]

Q: How quickly can VVO be deployed?

A: Depending on the scope of the project, VVO implementation can take between one and five years. AEP Ohio's gridSMART® Demonstration Project in Central Ohio was awarded funding in 2009 and was commissioned by March 2010, indicating an implementation period of approximately one year.[85]

Q. Are there other considerations missing from WEPCO's planning?

A. Yes. Given that this element alone among the aspects of WEPCO's plan to meet demand will by its own estimates cost at least $1.2 billion dollars, it seems reasonable to expect WEPCO to cast a broad net as it evaluates ways to minimize the impact on its ratepayers. DR and VPP are two ways to reduce customer demand, but a third way involves encouraging more customers to satisfy their energy needs through behind-the-meter generation; in other words, treat distributed generation as a capacity resource. This would entail WEPCO modeling what level of utility-

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[84] Opinion Dynamics. (2023, April 21). Ameren Illinois Company 2022 voltage optimization program impact evaluation [Report]. Illinois Stakeholder Advisory Group. https://www.ilsag.info/wp-content/uploads/AIC-2022-Voltage-Optimization-Impact-Evaluation-Report-FINAL-2023-04-21.pdf (p. 6). Any information contained in this citation, based solely on this citation, is NRE.

[85] DOE. (2017). Voltage and Power Optimization Saves Energy and Reduces Peak Power. Washington, DC: Department of Energy. https://www.energy.gov/sites/prod/files/2017/01/f34/Voltage-Power-Optimization-Saves-Energy-Reduces-Peak-Power.pdf. Any information contained in this citation, based solely on this citation, is NRE.

provided financial incentive ($/kW installed) would produce a desired MW volume of behind-the-meter distributed generation and then evaluating whether the total incentive program cost is cost-effective compared to constructing the Project.

Q. Did WEPCO consider this opportunity?

A. No. According to its response to UNITED-IR-2-4, WEPCO has not considered using distributed generation as a resource.[86] Specifically, WEPCO claims that providing any incentive beyond the compensation it provides for energy exported from distributed generation facilities would constitute an unfair cost-shift.

Q. Do you agree with this opinion?

A. No. WEPCO fails to acknowledge that an appropriately sized financial incentive from the utility that effectively reduces the need for additional utility investment in generation by encouraging more distributed generation could benefit all customers if the financial incentive costs less than the new utility generation investment. Due to the very large price tag for the Project, it is reasonable and appropriate for WEPCO to consider all options before seeking to recover from customers more than $1.2 billion for a generation facility that will only operate up to 20% of the time. When considering distributed generation as a resource, WEPCO could couple it with an EE program and target low-income customers. I note that the concept of

[86] Ex.-United-Makhyoun-1 (WEPCO response to UNITED-IR-2-4).

distributed generation as a resource was explored in a recent DTE Electric Company Integrated Resource Plan case before the Michigan Public Service Commission.[87]

VIII. CONCLUSION AND RECOMMENDATIONS

Q: What is the primary conclusion of this testimony?

A: This testimony concludes that WEPCO's proposed South Oak Creek Combustion Turbine Project does not represent the most cost-effective option for meeting future capacity needs. The project's estimated costs are significantly higher than alternatives, and its capacity expansion modeling contains critical flaws that undermine WEPCO's conclusions.

Q: What are the key flaws identified in WEPCO's proposal?

A: The primary flaws include:

- Overestimated costs for renewable energy alternatives and underexplored integration of distributed resources.
- Bias in capacity expansion modeling, including forced inclusion of WEPCO's preferred projects and exclusion of viable alternatives.
- Failure to incorporate critical considerations such as the SCOC and advanced energy technologies like VPPs and hybrid renewable systems.

[87] MPSC Case U-21193, testimony of William Kenworthy and Boratha Tan, available at: https://mi-psc.my.site.com/s/case/5008y000002yQhVAAU/in-the-matter-of-the-application-of-dte-electric-company-for-approval-of-power-purchase-agreements-and-other-relief. Any information contained in this citation, based solely on this citation, is NRE.

Q: What are the cost implications of WEPCO's plan compared to alternatives?

A: Witness Hotaling's Alternative Plan demonstrates overall potential system cost savings of $1.89 billion in CAPEX compared to WEPCO's plan. The alternative relies on a mix of natural gas turbines, solar, wind, and battery energy storage, all of which align better with industry benchmarks and emerging trends in energy planning.

Q: What alternatives should the Commission consider?

A: The Commission should consider:

- Witness Hotaling's Alternative Plan, which balances renewable energy and storage with EE/DR/VPP programs.
- Accelerating the deployment of distributed resources to meet immediate capacity needs.
- Exploring financing models that maximize the benefits of tax credits and reduce upfront costs for renewable energy projects.

Q: How do you recommend the Commission act on WEPCO's Application?

A: The Commission should reject WEPCO's application for a CPCN unless WEPCO revises its modeling and remedies the flaws I identify in my testimony (i.e., include unbiased evaluations of renewable alternatives and distributed resources in accordance with my testimony). In the alternative, I recommend the Commission approve WEPCO's application with modifications that direct WEPCO to use non-combustion assets and strategies and non-utility owned assets.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A. NREL ATB COST INFORMATION

NREL ATB Cost Information[88]

NREL ATB Assumption - Land-Based Wind - 2024 - Moderate Case

Wind speed is 7.75 MPH at 100 meters above sea level[89] so Land-Based Wind - Class 6 - Technology 1

Net Capacity Factor (%): 42
Annual Energy Production (kWh/kW): 3,651
CAPEX ($/kW): 1,676
Construction Financing Cost ($/kW): 95
Overnight Capital Cost ($/kW): 1,481
Fixed Operation and Maintenance Expenses ($/kW-yr): 32
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 100
Levelized Cost of Energy ($/MWh): 35

NREL ATB Assumption - Utility-Scale PV - 2024 - Moderate Case

Less than 4 kWh/m^2/day, making it Class 9[90]

Net Capacity Factor (%): 22%
Annual Energy Production (kWh/kW): 1,919
CAPEX ($/kW): 1,551
Construction Financing Cost ($/kW): 54
Overnight Capital Cost ($/kW): 1,379
Fixed Operation and Maintenance Expenses ($/kW-yr): 22
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 119
Levelized Cost of Energy ($/MWh): 57

NREL ATB Assumption - Solar - PV Dist. Comm - 2024 - Moderate Case

Less than 4 kWh/m^2/day, making it Class 9[91]

Net Capacity Factor (%): 13.5
Annual Energy Production (kWh/kW): 1,183
CAPEX ($/kW): 1,795
Construction Financing Cost ($/kW): N/A

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[88] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. Any information contained in this citation, based solely on this citation, is NRE.

[89] U.S. Department of Energy. (n.d.). WINDExchange Wisconsin. Wind Energy Technologies Office. Retrieved December 12, 2024, from https://windexchange.energy.gov/maps-data/356. Any information contained in this citation, based solely on this citation, is NRE.

[90] NREL. 2024. "2024 ATB Utility-Scale PV." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/utility-scale_pv. Any information contained in this citation, based solely on this citation, is NRE.

[91] *Id.*

Overnight Capital Cost ($/kW): 1,731
Fixed Operation and Maintenance Expenses ($/kW-yr): 18
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 0
Levelized Cost of Energy ($/MWh): 104

NREL ATB Assumption - Solar - PV Dist. Res - 2024 - Moderate Case

Less than 4 kWh/m^2/day, making it Class 9[92]

Net Capacity Factor (%): 13.2
Annual Energy Production (kWh/kW): 1,154
CAPEX ($/kW): 2,601
Construction Financing Cost ($/kW): N/A
Overnight Capital Cost ($/kW): 2,601
Fixed Operation and Maintenance Expenses ($/kW-yr): 30
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 0
Levelized Cost of Energy ($/MWh): 157

NREL ATB Assumption - Natural Gas_FE - 2024 - Moderate Case

NG Combustion Turbine (F-Frame)

Heat Rate (MMBtu/MWh): 9.72
Net Capacity Factor (%): N/A
Annual Energy Production (kWh/kW): N/A
CAPEX ($/kW): 1,329
Construction Financing Cost ($/kW): 136
Overnight Capital Cost ($/kW): 1,093
Fixed Operation and Maintenance Expenses ($/kW-yr): 26
Variable Operation and Maintenance Expenses ($/MWh): 6.94
Grid Connection Costs (GCC) ($/kW): 100
Levelized Cost of Energy ($/MWh): N/A

NREL ATB Assumption - Utility-Scale Battery Storage - 2024 - Moderate Case

Li-Ion Battery Storage, 60 MW, 240 MWh storage (4 hours)

Capacity Factor (%): 16.7
Annual Energy Production (kWh/kW): N/A
Battery Energy Capital Cost ($/kWh): 356
Battery Power Capital Cost ($/kW): 347
CAPEX ($/kW): 1,938
Construction Financing Cost ($/kW): 68
Overnight Capital Cost ($/kW): 1,770
Fixed Operation and Maintenance Expenses ($/kW-yr): 44
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 100

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[92] *Id.*

Round-Trip Efficiency (%): 85
Levelized Cost of Energy ($/MWh): N/A

NREL ATB Assumption - Commercial Battery Storage - 2024 - Moderate Case

Li-Ion Battery Storage, AC-coupled 1800 kW, 7200 kWh storage (4 hours)

Capacity Factor DC (%): 8.3
Annual Energy Production (kWh/kW): N/A
Battery Energy Capital Cost ($/kWh): 237
Battery Power Capital Cost ($/kW): 905
CAPEX ($/kW): 2,040
Construction Financing Cost ($/kW): 74
Overnight Capital Cost DC ($/kW): 1,967
Total Installed Cost ($): 3,540,097
Fixed Operation and Maintenance Expenses DC ($/kW-yr): 49
Variable Operation and Maintenance Expenses DC ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 0
Round-Trip Efficiency (%): 85
Levelized Cost of Energy ($/MWh): N/A

NREL ATB Assumption - Residential Battery Storage - 2024 - Moderate Case

Li-Ion Battery Storage, AC-coupled 5 kW, 12.5 kWh storage (4 hours)

Capacity Factor DC (%): 10.4
Annual Energy Production (kWh/kW): N/A
Battery Energy Capital Cost ($/kWh): 520
Battery Power Capital Cost ($/kW): 632
CAPEX ($/kW): 3,592
Construction Financing Cost ($/kW): 130
Overnight Capital Cost DC ($/kW): 3,462
Total Installed Cost ($): 17,312
Fixed Operation and Maintenance Expenses DC ($/kW-yr): 87
Variable Operation and Maintenance Expenses DC ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 0
Round-Trip Efficiency (%): 85
Levelized Cost of Energy ($/MWh): N/A

NREL ATB Assumption - Utility-Scale PV-Plus-Battery - 2024 - Moderate Case

Less than 4 kWh/m^2/day, making it Class 9[93]*. DC-coupled system with a 100 MWAC bidirectional inverter, Single axis tracking PV system with a capacity of 134 MWDC, and 4-hour lithium-ion battery storage system with a capacity of 60 MWAC. Overnight Capital Cost, Capacity Factor, Fixed O&M, and Variable O&M costs represent $/kW AC, unlike the commercial and residential PV cases which are represented in $/kW DC.*

Net Capacity Factor (%): 29
PV-only Capacity Factor (%): 22

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[93] *Id.*

Annual Energy Production (kWh/kW): 2,039
Capital Cost ($/kWh): N/A
CAPEX ($/kW): 2,456
Construction Financing Cost ($/kW): 85
PV System Cost ($/kW): 1,379
Battery Storage Cost ($/kW): 1,770
Overnight Capital Cost ($/kW): 2,252
Total Installed Cost ($): N/A
Fixed Operation and Maintenance Expenses ($/kW-yr): 61
Variable Operation and Maintenance Expenses ($/MWh): 0
Grid Connection Costs (GCC) ($/kW): 119
Round-Trip Efficiency (%): N/A
Levelized Cost of Energy ($/MWh): 105

APPENDIX B. LAZARD COST INFORMATION

Lazard Cost of Energy ($/MWh)[94]

Solar PV—Rooftop Residential: 122-284
Solar PV—Community & C&I: 54-191
Solar PV—Utility: 29-92
Solar PV + Storage—Utility: 60-210
Geothermal: 64-106
Wind—Onshore: 27-73
Wind + Storage—Onshore: 45-133
Wind—Offshore: 74-139
Gas Peaking: 110-228 (102 - 238 with fuel price sensitivity[95])
U.S. Nuclear: 142-222
Coal: 69-168
Gas Combined Cycle: 45-108

- Lazard Cost of Capital ($/kW)[96]

Cost of Capital Range by Technology
Gas Combined Cycle (New Build): $850 - $1,300[97]
Gas Peaking (New Build): $700 - $1,150[98]
Utility-Scale Standalone Storage (100 MW/400 MWh): $76 - $157[99]
Wind—Onshore: $1,300 - $1,900[100]
Solar PV + Storage—Utility (249 - 421 for storage portion): $1,099 - $1,821[101]
Solar PV - Utility-Scale: $850 - $1,400[102]

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[94] Lazard. (2024, June). 2024 Levelized Cost of Energy+ (p. 9). Retrieved from https://www.lazard.com/research-insights/levelized-cost-of-energyplus/. Any information contained in this citation, based solely on this citation, is NRE.
[95] *Id*. at 11.
[96] *Id*. at 35-44.
[97] *Id*. at 38.
[98] *Id*.
[99] *Id*. at 44.
[100] *Id*. at 36.
[101] *Id*. at 37.
[102] *Id*. at 35.

APPENDIX C. U.S. EIA COST INFORMATION

U.S. EIA 2023 Annual Energy Outlook Cost Information[103]

Combustion Turbine—Industrial Frame

First Available Year: 2024
Size (MW): 237
Lead Time (years): 2
Base Overnight Cost (2022$/kW): $867
Technological Optimism Factor: 1.00
Total Overnight Cost (2022$/kW): $867
Variable O&M (2022$/MWh): $5.06
Fixed O&M (2022$/kW-yr): $7.88
Heat Rate (Btu/kWh): 9,905

Battery Storage

First Available Year: 2023
Size (MW): 50
Lead Time (years): 1
Base Overnight Cost (2022$/kW): $1,270
Technological Optimism Factor: 1.00
Total Overnight Cost (2022$/kW): $1,270
Variable O&M (2022$/MWh): $0.00
Fixed O&M (2022$/kW-yr): $45.76
Heat Rate (Btu/kWh): NA

Wind

First Available Year: 2025
Size (MW): 200
Lead Time (years): 3
Base Overnight Cost (2022$/kW): $2,098
Technological Optimism Factor: 1.00
Total Overnight Cost (2022$/kW): $2,098
Variable O&M (2022$/MWh): $0.00
Fixed O&M (2022$/kW-yr): $29.64
Heat Rate (Btu/kWh): NA

[103] U.S. Energy Information Administration. (2023, March). Assumptions to the Annual Energy Outlook 2023: Electricity Market Module (p. 5). Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf. Any information contained in this citation, based solely on this citation, is NRE.

Solar PV with Tracking

First Available Year: 2024
Size (MW): 150
Lead Time (years): 2
Base Overnight Cost (2022$/kW): $1,448
Technological Optimism Factor: 1.00
Total Overnight Cost (2022$/kW): $1,448
Variable O&M (2022$/MWh): $0.00
Fixed O&M (2022$/kW-yr): $17.16
Heat Rate (Btu/kWh): NA

Solar PV with Storage

First Available Year: 2024
Size (MW): 150
Lead Time (years): 2
Base Overnight Cost (2022$/kW): $1,808
Technological Optimism Factor: 1.00
Total Overnight Cost (2022$/kW): $1,808
Variable O&M (2022$/MWh): $0.00
Fixed O&M (2022$/kW-yr): $32.42
Heat Rate (Btu/kWh): NA

APPENDIX D. COMPARISON OF CAPITAL COST INFORMATION

The following table and chart show a comparison of WEPCO's capital cost assumptions with data from the U.S. EIA 2023 Annual Energy Outlook, NREL's 2024 ATB, and Lazard's 2024 LCOE Report.

Sources:

- WEPCO Cost of Capital Assumptions[104]
- NREL ATB Cost Information[105]
- Lazard Cost of Capital ($/kW)[106]
- U.S. EIA 2023 Annual Energy Outlook Cost Information[107]

Table 4. Cost of Capital Comparison by Technology and Source

Technology	**WEPCO (2023$/kW)**	**U.S. EIA (2022$/kW)**	**NREL ATB (2024 $/kW)**	**Lazard (2024 $/kW)**
Combustion Turbine	1,023	867	1,093	925
Battery storage	2,435	1,270	1,770	117
Wind	2,384	2,098	1,481	1,600
Utility-Scale Solar	1,952	1,448	1,379	1,125

[104] Ex.-WEPCO-Application-Volume III Appendix B: 25.
[105] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. Any information contained in this citation, based solely on this citation, is NRE.
[106] Lazard. (2024, June). 2024 Levelized Cost of Energy+ (pp. 35-44). Retrieved from https://www.lazard.com/research-insights/levelized-cost-of-energyplus/. Any information contained in this citation, based solely on this citation, is NRE.
[107] U.S. Energy Information Administration. (2023, March). Assumptions to the Annual Energy Outlook 2023: Electricity Market Module (p. 5). Retrieved from https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf. Any information contained in this citation, based solely on this citation, is NRE.