**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF WISCONSIN**

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Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project, Consisting of Five Natural Gas-Fired Single-Cycle Combustion Turbines Generating up to 1100 MW total at the South Oak Creek Facility in the City of Oak Creek, Milwaukee County, Wisconsin

Docket No 6630-CE-317

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**DIRECT TESTIMONY OF EDWARD BURGESS**
**ON BEHALF OF CITIZENS UTILITY BOARD**

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Contents

# I. Introduction

**Q. Please state your name, business address, and occupation.**

A. My name is Edward Burgess. I am a Founding Partner of Current Energy Group LLC. My business address is 528 North Treat Avenue, Tucson, Arizona 85716.

**Q. Please state your educational background and experience.**

A. I have spent over 12 years working as a consultant in the energy and utilities industry with a focus on providing technical support on power system planning issues. I have provided expert testimony on over 27 occasions before 12 state utility commissions on issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, and distributed energy resources. Prior to co-founding Current Energy Group in 2024, I was a Consulting Partner at Strategen, where I worked for over 8 years. While at Strategen, I directed the company's grid planning practice area. I also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies. Prior to joining Strategen, I worked as an independent consultant, providing technical support to clients before state utility commissions and legislatures. During that time, I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Bachelor's Degree in Chemistry from Princeton University. I also have master's degrees in Solar Energy Engineering and Commercialization (P.S.M.) and in Sustainability (M.S.) both from Arizona State University. My resume is attached as Ex.-CUB-Burgess-1.

**Q. Have you testified before this Commission before?**

A. Yes. I recently provided testimony in WEPCO's application to construct new RICE generation units (Docket No. 6630-CE-316). Much of that testimony overlaps with this case.

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

A. I am testifying on behalf of the Wisconsin Citizens Utility Board (CUB).

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

A. My testimony discusses the economic evaluation and needs assessment that Wisconsin Electric Power Company (WEPCO) conducted in support of its Application in this case. I identify several shortcomings in this assessment and potential risks to existing ratepayers. I also offer some recommendations for the Commission's consideration as it evaluates the Company's request, including several conditions that would be warranted along with granting any CPCN request.

## II. Summary of Findings and Recommendations

**Q. Please summarize your conclusions from your review of WEPCO's application and proposed generation units.**

A. First and foremost, it is important to recognize that WEPCO's system is planned and operated as a whole portfolio, and as such it is impossible to evaluate either the Paris RICE project,[1] the Oak Creek CT project (this proceeding), the Rochester Lateral Pipeline,[2] or the Oak Creek LNG project[3] in isolation. The central tension in these cases is the fact that WEPCO is asking the Commission to approve construction of new facilities with $2.2

[1] *See* CPCN Application in Docket No. 6630-CE-316 (PSC REF#: 517491) (Sept. 20, 2024), Ex.-CUB-Burgess-2.
[2] *See* CA Application in Docket No. 6630-CG-139 (PSC REF#: 518981) (Oct. 1, 2024), Ex.-CUB-Burgess-3.
[3] *See* CA Application in Docket No. 6630-CG-140 (PSC REF#:498476) (Apr. 19, 2024), Ex.-CUB-Burgess-4.

billion in combined capital costs,[4] primarily to serve large new loads for which no underlying service agreements have been executed.[5] The uncertainty surrounding these new loads poses a potential financial risk and cost burden to all of the Company's existing customers, as I further explain in Section IV of my testimony herein. Moreover, recent developments in early January 2025 have raised new questions about the accuracy of WEPCO's load forecast.[6] If we assume momentarily that WEPCO's load forecast is accurate, and that the corresponding service agreements will soon be executed, then some amount of new generation is likely needed in the coming years. What is much less clear -- due to many shortcomings in WEPCO's analysis -- is the exact magnitude, type and timing of new generation that is prudent.

Regarding the magnitude and timing of new generation, WEPCO may have correctly identified a significant capacity need on its system but has subsequently exaggerated this need beyond what is reasonable by inflating its planning reserve margin among other factors (see Section V herein). Given the fact that WEPCO unreasonably inflated its supply-side capacity needs, the Commission should consider approving only a portion of the proposed generation capacity now, while approving the remainder requested only as certain conditions are met which I discuss in greater detail in my testimony.[7]

Regarding the type of new generation that is most prudent, WEPCO's analysis is not sufficiently robust to draw firm conclusions. First, WEPCO's modeling inputs and methodology contain many problematic assumptions that skew towards CT units (see

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[4] Includes $279 million in estimated costs for the Paris RICE project, $1,205 million in estimated costs for the Oak Creek CT project, $212 million in estimated costs for the Rochester Lateral pipeline, and $456 million in estimated costs for the Oak Creek LNG project.
[5] *See* response to 2-CUB-3, Ex.-CUB-Burgess-5.
[6] See discussion in Section IV herein, including Table 2.
[7] Note that this consideration is most important for the Oak Creek CT proposal (this proceeding) which comprises 90% of the installed capacity between the two projects.

Section VI of my testimony herein). Meanwhile, WEPCO's own findings using these assumptions still show that the benefits of pursuing CT units at Oak Creek are within a few percent of potential alternatives (i.e., 1.0-2.5% lower net present value [NPV] cost than battery storage). Under many plausible scenarios that WEPCO could evaluate with corrected assumptions, the OCCT units may not be part of the least-cost solution (see Section VII of my testimony herein). For example, if WEPCO's BESS cost assumptions were corrected, I believe the BESS resources would provide a better value while carrying less risk of becoming a stranded asset and less risk of requiring additional infrastructure costs.

Given the urgent need to meet new load growth, adding new capacity at the existing Oak Creek interconnection is a sensible approach that makes efficient use of the existing grid. However, if the Commission were to consider approving any capacity additions at Oak Creek, pursuing BESS resources (in lieu of CTs) would likely be both more cost effective and more timely as part of a "Least-Regrets Pathway" (see Section X herein). As an alternative, the Commission could consider CT additions at Oak Creek, however I believe only partial approval (i.e., 2 CT units) should be considered now, with certain conditions and guardrails tied to this approval (see Section X herein). Meanwhile, the value of any option pursued now can also be improved (including potential deferral) if coupled with sufficient incremental demand side management (DSM) resources which should be pursued regardless.

**Q. Please provide your general recommendations for how the Commission should evaluate WEPCO's proposal for the Oak Creek CT units.**

A. My recommendations are as follows:

1. The proposed OCCT project should not be approved as is. Instead, the Commission should direct WEPCO to pursue a "Least-Regrets Pathway" as outlined in Section X of my testimony which is better suited than OCCT for meeting the Company's 2027 summer peak needs.
2. As an alternative option, the Commission could consider approving a scaled back version of the Company's proposal (i.e., the "Low Regrets Pathway") as outlined in Section X of my testimony which includes just two OCCT units.
3. If any OCCT units are approved now, some portion of that capacity's approval should be contingent on certain conditions being met. These conditions would help to better balance the risk between WEPCO and its existing customers and should include the following:
    a. Cost recovery, including any allowance for funds used during construction (AFUDC), should not be permitted until certain milestones are met regarding projected new load growth. These milestones could include actual metered demand and/or executed contractual terms that provide greater certainty and protections for existing customers.
    b. WEPCO should immediately conduct a competitive solicitation for capacity resources including BESS. To the extent possible, incremental BESS resources should be considered at Oak Creek in lieu of the proposed CT units.
    c. Additional DSM should be pursued, including new forms of demand response, with a goal of achieving at least 168 MW in incremental load

reduction from energy efficiency (beyond current policy) by 2030, and additional demand response beyond that.

4. In addition to acting on the CPCN and any related conditions, the Commission should also seek to establish a more comprehensive process for resource planning and procurement to avoid the current piecemeal approach and ensure that customers benefit from a broader pool of competitive options going forward.

# III. Overview of WEPCO's Application and supporting analysis

**Q. Please provide a brief summary of the WEPCO application and supporting economic analysis.**

A. On June 13, 2024, WEPCO submitted a CPCN application to construct a natural gas electric generating facility consisting of five combustion turbine generators at the Oak Creek site in Wisconsin. Each CT will have a nominal capacity of approximately 220 MW under typical operating conditions, with the Project's total capacity being approximately 1,100 MW. As part of its application, WEPCO conducted an analysis to evaluate the Project's economics, which is presented in Volume III, Appendix B of the Application. This analysis includes both scenario and sensitivity evaluations.

The scenario analysis "assesses the effect of changing multiple input variables or assumptions to define a specific planning future that could reasonably occur," while the sensitivity analysis "examines the effect of changing a single variable at a time." The scenario analysis evaluates multiple planning futures, variations in emissions regulations, and resource planning methodologies to determine the economic and operational impact of the Oak Creek CT Project. The sensitivity analysis examines the effects of varying critical parameters, including CT CapEx, load forecasts, and capacity accreditation for solar and battery systems, and wind availability, all under the Company's base planning case and specific regulatory assumptions.

Detailed modeling assumptions, inputs, and methodologies are included in Appendix B, and the results provide a basis for the economic case presented for the CT Project. These inputs, alongside other key planning futures, are further referenced throughout this testimony.

*Table 1: Cases examined in the WEPCO Scenario and Sensitivity Analysis*

| | | | | | Capacity Assurance Resource Planning | | | | Energy Assurance Resource Planning | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Emission Regulations | Case ID | Sensitivity Parameter | Planning Future / Resource Action | Continued Fleet Change (Base) | Slow Economic Growth | Enhanced Decarbonization | High Economic Growth | Continued Fleet Change (Base) | Slow Economic Growth | Enhanced Decarbonization | High Economic Growth |
| | | | | | A | B | C | D | E | F | G | H |
| Scenario Analysis | S1 GHG Rule (High) | 100 | | Oak Creek CTs | 100A | 100B | 100C | | 100E | 100F | 100G | |
| | | 101 | | Unconstrained | 101A | 101B | 101C | | 101E | 101F | 101G | |
| | | 102 | | Battery | 102A | | 102C | | 102E | 102F | 102G | |
| | S2 GHG Rule (Medium) | 103 | | Oak Creek CTs | 103A | 103B | | 103D | 103E | 103F | | 103H |
| | | 104 | | Unconstrained | 104A | 104B | | 104D | 104E | 104F | | 104H |
| | | 105 | | Battery | 105A | 105B | | 105D | 105E | 105F | | 105H |
| | S3 GHG Rule (No) | 106 | | Oak Creek CTs | 106A | | | 106D | 106E | | | 106H |
| | | 107 | | Unconstrained | 107A | | | 107D | 107E | | | 107H |
| | | 108 | | Battery | 108A | | | 108D | 108E | | | 108H |
| Sensitivity Analysis | S1 GHG Rule (High) | 109 | Summer Solar Accreditation | Oak Creek CTs | 109A | | | | 109E | | | |
| | | 111 | | Battery | 111A | | | | 111E | | | |
| | | 112 | High New Load | Oak Creek CTs | 112A | | | | 112E | | | |
| | | 114 | | Battery | 114A | | | | 114E | | | |
| | | 115 | Low New Load | Oak Creek CTs | 115A | | | | 115E | | | |
| | | 117 | | Battery | 117A | | | | 117E | | | |
| | | 118 | Limited Wind Availability | Oak Creek CTs | 118A | | | | 118E | | | |
| | | 120 | | Battery | 120A | | | | 120E | | | |
| | | 100(H) | High OCCT Capital Cost | Oak Creek CTs | 100(H)A | | | | 100(H)E | | | |
| | | 102 | | Battery | 102A | | | | 102E | | | |
| | | 100(L) | Low OCCT Capital Cost | Oak Creek CTs | 100(L)A | | | | 100(L)E | | | |
| | | 102 | | Battery | 102A | | | | 102E | | | |
| | | 127 | Battery 100% Accreditation | Oak Creek CTs | 127A | | | | 127E | | | |
| | | 129 | | Battery | 129A | | | | 129E | | | |

**Q. Please describe the modeling framework that WEPCO used in the economic evaluation of the proposed resource additions including both the Paris RICE units and the Oak Creek CT units?**

A. While separate analyses were conducted for the proposed Paris RICE units and the Oak Creek CT units, a similar methodology and approach was used in both cases. In both cases, WEPCO used the PLEXOS LT model to conduct capacity expansion modeling for various scenarios with different input assumptions. In general, capacity expansion models like PLEXOS LT are designed to identify the optimal, least-cost portfolio of resource additions required to meet the projected energy and capacity need, which includes the peak demand and a specified planning reserve margin (PRM) over a certain time horizon. Key inputs generally include the existing portfolio of resources and their operating characteristics; forecasts for energy (i.e., MWh) and peak demand plus reserve margin (i.e., MW); commodity price forecasts; and the cost, performance, and availability of candidate resources that can be economically selected through the model's optimization algorithm. For each of the cases presented in Table 1, WEPCO conducted a capacity expansion run under the respective scenario assumptions.

**Q. Please briefly explain the different scenarios and sensitivities that WEPCO used in its evaluation of the Project's economics.**

A. As already mentioned, WEPCO's scenario analysis consists of 47 runs examining portfolios across four possible planning futures, three variations of emissions regulations, two resource planning methods, and finally three different resource actions associated with the construction of the Oak Creek CT project. An additional 28 runs were conducted as sensitivity analyses for a total of 75 model runs.

- The four "planning futures" incorporate varying assumptions for demand and energy growth, natural gas prices, general inflation, and CO2 cost and are:
    - Slow Economic Growth
    - Continued Fleet Change
    - Enhanced Decarbonization
    - High Economic Growth

- The three “emissions regulations” reflect three different stringency levels: High, Medium, and No regulations.
- The two “resource planning methods” labeled as “Capacity Assurance” and “Energy Assurance” refer to whether the Company allows energy imports from MISO.
- The three “resource actions” are:
    - Forcing in Oak Creek CTs in the model in 2027 (labeled “Oak Creek CTs” in Table 1).
    - Not Forcing Oak Creek CTs in the model (labeled “Unconstrained” in Table 1).
    - Oak Creek CTs not included and replaced by batteries (labeled “Battery” in Table 1)

Although WEPCO defines scenarios as futures that “could reasonably occur,” not all parameters that are changing between scenarios are factors that occur outside of the utility’s control. The various “planning futures” and “emissions regulations” can be considered different futures that are largely outside of the Company’s control, and thus reflect the more common definition of scenario analysis. However, variations between the “resource planning method” and “resource actions” reflect decisions about how the Company chooses to plan its overall portfolio. In Section V-B of my testimony I explain why the Capacity Assurance Method is a more reasonable planning method in this case compared to the Energy Assurance Method, which carries little informational value. Meanwhile, comparing the three “resource actions” provides some limited insight regarding the cost and value of the specific project being considered (i.e., the Oak Creek CT units). While not a comprehensive analysis of potential resource actions, comparing these limited set of options may be useful for informing the Commission's decision.

**Q. Did WEPCO allow PLEXOS to economically select all future resource additions?**

A. No. All of WEPCO's model runs preselected or "hardwired" certain resource additions. In the Oak Creek CT analyses, all 75 of the model runs WEPCO conducted presumed that all seven of the Paris RICE units (~130 MW total) would be included, as well as the High Noon solar and battery project additions. Additionally, 57 of the 75 model runs also hardwired in either 1,100 MW of CT units at the Oak Creek location or equivalent BESS resources in 2027 without allowing the model to select the optimal portfolio.

**Q. What are your key concerns regarding the WEPCO modeling approach, methodology, and assumptions?**

A. My key concerns regarding the WEPCO analysis are:

1. WEPCO's analysis includes critical flaws that exaggerate the need and timing for new supply-side generation resources. These flaws include:
    a) The inflation of the planning reserve margin, and consequently the capacity need, due to the use of the installed capacity (ICAP) planning reserve margin, instead of the margin calculated based on unforced capacity (UCAP) values.
    b) WEPCO's Energy Assurance methodology inappropriately assumes no interaction with the MISO market, which is not realistic even under potential scarcity conditions.
    c) The potential contribution of demand side resources is significantly underestimated.
2. WEPCO's PLEXOS analysis includes assumptions that bias resource selection towards utility-owned thermal generation.

a) The proposed CT Units' capacity accreditation is overestimated due to lack of firm fuel supply.

b) WEPCO's analysis significantly restricted the ability for its generation needs to be met by other potential resources.

c) WEPCO's resource cost assumptions in PLEXOS -- which underpinned the selection of CT units and their projected benefits – overestimated the cost of batteries and failed to incorporate all the cost components of the CT units.

3. Even with these biases, WEPCO's scenario analysis does not definitively demonstrate that CT additions would be superior to alternative resource choices either in terms of cost or risk.

**Q. What is your conclusion regarding WEPCO's determination that they need construct the Oak Creek CT units?**

A. I am concerned that even under the assumption that the load growth materializes at the pace and scale projected in the Application, WEPCO's conclusion that:

> "the Project is a necessary and cost-effective part of the portfolio for dispatchable resources to effectively and economically serve its customers' load." [8]

is the result of an analysis that has not comprehensively investigated all alternatives and includes several flaws. Based on its analysis, the Company has not proven that the Project in its entirety (i.e., all 5 proposed CT units) is either necessary, or the most cost-effective option to address the system's needs versus a scaled back proposal (i.e., 2 units) that includes other resources.

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[8] Ex.-WEPCO-Application-Application: 2-19.

## IV. Approval of significant new capacity resources prior to the execution of contracts for new load places significant risk on all customers

**Q. What are the key drivers of WEPCO's load forecast projections?**

A. As summarized in the Company's response to 2-CW-25,[9] WEPCO's native load is expected to experience moderate growth of around 0.6% annually, which is roughly consistent with historical trends. However, in the next few years, WEPCO anticipates a significant increase in "New Load" additions, comprising a small number of new large customers and accounting for over [redacted] MW of increased peak demand between now and 2028.

**Q. What is the basis for the "New Load" component of WEPCO's forecast?**

A. According to WEPCO's response to 6-CW-17,[10] "The Company used customer-provided monthly demand forecasts without modification." The Company then "divided the provided monthly demand forecasts into three project phases: construction, commissioning, and full production operations. The Company assumed a load factor of [redacted]% during the construction phase, [redacted]% during the commissioning phase, and [redacted]% during full production operations."

**Q. What is the certainty that these "New Load" additions will materialize on the trajectory that WEPCO has forecasted?**

A. It is unclear. In particular, it does not appear that WEPCO had entered any contractual agreements to serve this New Load at the time of its application nor has it done so to date. As the Company stated as recently as January 10, 2025: "No customers have executed an energy supply agreement related to the load forecasted in the New Load component."[11] Additionally, it is not clear that the ramp up trajectory the Company assumed will be

[9] Ex.-CUB-Burgess-7.
[10] Ex.-CUB-Burgess-6.
[11] Response to 2-CUB-3, Ex.-CUB-Burgess-5.

accurate. Generally, this ramp up schedule is one of the key terms of a signed energy service agreement, whereby the customer is committing to consuming a certain level of electricity demand each year and the contracted MW level grows over time. Since no service agreement has been executed, both the overall demand increase and the timing of the ramp up is still somewhat speculative. Even if the final demand level is known, the exact timing of its ramp up could have significant implications for WEPCO's resource planning and procurement strategy. As an indication of this, WEPCO's "Low New Load" sensitivity demonstrated that overall generation portfolio costs could be more than $3.3 billion lower if the load ramps up more slowly and to a lesser extent than WEPCO currently projects.[12]

**Q. Are there any recent developments that could significantly affect the magnitude and timing of WEPCO's forecasted "New Load" additions?**

A. Yes. On January 2, 2025 Microsoft announced that the company was pausing construction on additional phases of its Mount Pleasant data center facility beyond the initial Phase 1.[13] Microsoft also disclosed that Phase 1 accounted for 450 MW, which it still expects to complete by the end of 2026.[14] 450 MW is consistent with WEPCO's forecast for Microsoft load through [redacted]. However, WEPCO's forecast for Microsoft load further increases by [redacted] MW (to [redacted], which must correspond with future phases of the Mount Pleasant site.[15] In other words, the construction of future customer facilities accounting for [redacted] MW of WEPCO's near-term load forecast were recently paused for further evaluation. This equates to more than [redacted]% of the generation capacity of both the

[12] Calculated from WEPCO workpaper labeled "WEPCO – OC CT NPV Results.xlsx." (PSC REF#: 505821).(NRE)
[13] *Microsoft pauses construction on portions of Mount Pleasant project*, Wisconsin Public Radio, Ex-CUB-Burgess-39
[14] *Microsoft data center will be the state's largest electricity user. Power needs equal 300,000 homes*, Milwaukee Journal Sentinel, Ex-CUB-Burgess-39
[15] *See* excerpt of confidential attachment to response to 2-CW-25, Ex.-CUB-Burgess-7.

Oak Creek CT and Paris RICE projects combined, and [redacted]% of the Company's forecasted 2028 demand.

**Q. What other recent developments demonstrate uncertainty in WEPCO's load forecast?**

A. In its January 2025 Investor Update, WEC Energy Group forecasted increasing its Wisconsin Segment electricity demand by 1,800 MW from 2025-2029[16] compared to the [redacted] MW increase forecasted by WEPCO for its analysis in this application.[17] This is a [redacted] of approximately [redacted] MW or approximately [redacted]% of the generation capacity of both the Oak Creek CT and Paris RICE projects combined.

**Q. Given this lack of certainty in WEPCO's load forecast, what are the implications from a ratepayer risk perspective?**

A. Until there is an executed contract (or contracts) to serve "New Load" that includes a clearly defined ramp-up schedule, any new generation additions approved to serve that new load will be a risk borne entirely by existing customers. If a "New Load" customer ultimately decides to abandon their planned facility or only builds the facility to half of its original design, then existing customers will still bear the cost burden of any generation that is approved on the basis of the original forecast. Similarly, if the ramp up to the full load happens on a timeline that is twice as long as initially expected, then existing customers are still at risk for additional costs until that ramp up is completed.

**Q. Are there tools to minimize this cost risk to existing customers?**

A. Yes. In fact, many large load customers have started to implement these tools in recent months in other jurisdictions. For example, Indiana and Michigan Power recently entered into a settlement agreement with several large load customers that included a variety of

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[16] Ex.-CUB-Burgess-8.

[17] *See* Ex.-CUB-Burgess-7.

provisions for new energy service agreements designed to ensure greater certainty and protections for existing consumers.[18] These provisions include:

- Long-term financial commitments, with initial 12-year contract terms, and a 5-year ramp-up period.
- Parameters regarding future modifications to load levels, including required notices and potential exit fees.
- Collateral requirements for prospective large load customers.
- Direct financial contributions from the large load customers towards low-income weatherization efforts.
- Commitments to explore additional opportunities for demand response, grid enhancing technologies, and clean transition tariffs.

# V. Despite recent increases in forecasted demand, WEPCO's analysis includes critical flaws that further exaggerate the need and timing for new supply-side generation resources beyond what is reasonable

**Q. What are the major factors that determine the overall magnitude and timing of WEPCO's need for new generation resources?**

A. WEPCO projects a considerable need for additional capacity and energy resources to meet their load obligations starting in the 2026 timeframe, when significant additional new load is expected to begin increasing. As shown in Table 2-6 of its Application, WEPCO projects a shortfall in its capacity position (i.e., firm capacity resources relative to capacity obligations) in the coming years, which becomes significantly more acute in the 2028 timeframe. Among the key factors driving this shortfall are:

[18] Ex.-CUB-Burgess-9.

1. A rapid increase in forecasted peak demand, including over [redacted] MW in increased load obligations from new large customer additions by 2028.

2. Coal resource retirements, including a 500 MW reduction from Oak Creek 7 and 8 by 2026.

3. The assumed PRM WEPCO applies to its resource portfolio. This equates to a significant share of WEPCO's assumed 2028 capacity obligation accounting for over [redacted] MW in winter and [redacted] MW in summer.

**Q. Do you agree with WEPCO's assessment of the magnitude of the near-term energy and capacity need?**

A. I do not disagree that WEPCO is forecasting a significant near-term energy and capacity need, even though there are significant uncertainties in this forecast that I explained earlier. However, I believe that the magnitude of the need, especially the need for supply-side resources, is actually overstated by WEPCO based on a number of factors each of which I explain in further detail below. These factors include:

a) WEPCO's inflation of the planning reserve margin, and consequently the capacity need, due to the use of a installed capacity (ICAP) planning reserve margin, instead of a margin calculated based on unforced capacity (UCAP) values.

b) WEPCO's Energy Assurance methodology inappropriately assumes no interaction with the MISO market, which is not realistic even under potential future scarcity conditions. Even the Company's more conventional Capacity Assurance methodology assumes very limited interaction that is overly conservative.

c) The potential contribution of demand side resources is significantly underestimated.

*A. WEPCO's analysis uses a reserve margin based on installed capacity (ICAP) rather than unforced capacity (UCAP) values, exaggerating the magnitude of the Company's capacity need.*

**Q. Does the Commission have any rules or guidelines regarding the use of a Planning Reserve Margin for resource adequacy planning?**

A. Historically, the Commission had set a state level planning guideline of 14.5 percent for the reserve margin. Recently, however the Commission opened an investigation to review whether that guideline remains appropriate in light of evolving resource adequacy considerations at MISO and elsewhere.[19]

**Q. In WEPCO's analysis supporting the proposed generation capacity additions at Paris and Oak Creek, what does the Company assume is the required Planning Reserve Margin for its overall generation portfolio?**

A. Mirroring recent developments at MISO, WEPCO chose to implement a seasonal resource adequacy construct, estimating a different reserve margin for peak day requirements in each season. As shown in Table 2-6 of its Application, WEPCO uses the following seasonal PRM levels:

*Table 2: Seasonal PRM level used in WEPCO's analysis*

| | Summer | Fall | Winter | Spring |
|---|---|---|---|---|
| WEPCO Analysis | 17.7% | 25.2% | 49.4% | 40.8% |

**Q. What was the basis for these assumed values?**

[19] Docket No. 5-EI-161.

A. These values seem to originate from the MISO's Planning Year 2024-2025 Loss of Load Expectation Study Report.[20] The report presents MISO-wide PRM values on both an ICAP basis and a UCAP basis.

*Table 3: Planning Year 2024-2025 MISO PRM Results*

| | Summer 2024 | Fall 2024 | Winter 2025 | Spring 2025 |
|---|---|---|---|---|
| MISO PRM ICAP | 17.7% | 25.2% | 49.4% | 40.8% |
| MISO PRM UCAP | 9.0% | 14.2% | 27.4% | 26.7% |

A resource's ICAP represents the physical generating capacity adjusted for ambient weather conditions, while its UCAP represents the portion of the ICAP available after the unit's forced outage rate is taken into account. UCAP is a more accurate representation of firm capacity.

**Q. Does MISO primarily use the ICAP-based values that WEPCO used to assess resource adequacy and determine its PRM?**

A. No. MISO primarily uses UCAP-based values for determining PRMs as defined in MISO's FERC-approved tariff. WEPCO confirmed that MISO's PRM is based on UCAP,[21] which is also clearly shown in the Executive Summary of the same MISO report WEPCO referenced in its Application, as shown in the excerpt below.

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[20] Planning Year 2024-2025 Loss of Load Expectation Study Report MISO — Resource Adequacy, available at: https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf. NRE.
[21] Response to 2-CUB-7, Ex.-CUB-Burgess-10.

## Executive Summary

In preparation for the annual Planning Resource Auction, MISO conducts an annual Loss of Load Expectation (LOLE) study to determine Resource Adequacy Requirements for the upcoming Planning Year 2024-2025. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Planning Reserve Margin (PRM) determined through this year's study are:

| Season | PRM UCAP % |
|---|---|
| Summer 2024 | 9.0% |
| Fall 2024 | 14.2% |
| Winter 2024-2025 | 27.4% |
| Spring 2025 | 26.7% |

**Q. Do you agree with WEPCO's use of an ICAP-based PRM in its portfolio analysis?**

A. No. The use of an ICAP-based PRM is not consistent with MISO's planning approach, inappropriately inflates WEPCO's projected capacity obligation by a significant amount, and overestimates the reliability contribution of thermal units relative to other resources. Instead, WEPCO should apply a UCAP-based methodology that is more consistent with utility best practices and MISO's approach to resource adequacy.

**Q. Is MISO's upcoming transition to the DLOL accreditation method consistent with the current UCAP-based methodology for calculating the PRM?**

A. Yes. In its application to FERC (which was ultimately approved), MISO stated that it "is proposing to maintain the calculations of the PRMR and simply account for the determination of UCAP for Capacity Resources."[22]

**Q. Has WEPCO used an ICAP-based method in other recent applications?**

A. Not exactly. It is true that in response to 2-CW-28[23] the Company stated: "Wisconsin Electric models the MISO planning reserve margin on an ICAP basis, as identified in Section 2.1.4.2 of the Application. This methodology is consistent with Wisconsin Electric's long-term planning analyses used in recent approvals for new projects such as Paris solar

[22] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240328-5329&optimized=false. NRE.
[23] Ex.-CUB-Burgess-11.

and battery (Docket No. 5-BS-254)…" However this statement is misleading. For example, on page 12 of the referenced application in Docket No. 5-BS-254, the Company briefly refers to the Paris solar facility's installed capacity (ICAP) of 250 MW but goes on to discuss how it calculated the facility's capacity accreditation based on its "UCAP or unforced capacity" value in accordance with MISO's Resource Adequacy Business Practices Manual, which also refers to UCAP.

**Q. Have you determined the impact on WEPCO's projected capacity needs if the PRM were calculated on a UCAP basis instead of an ICAP basis?**

A. Yes. The table below summarizes the increase in WEPCO's capacity position when calculated using the more appropriate UCAP basis.

*Table 4: Difference in Capacity Position based on UCAP versus ICAP calculations (MW)*

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 |
|---|---|---|---|---|---|---|---|---|---|---|
| Winter | [redacted] | | | | | | | | | |
| Spring | | | | | | | | | | |
| Summer | | | | | | | | | | |
| Fall | | | | | | | | | | |

Notably, this simple change from ICAP to UCAP leads to an increase in WEPCO's 2028 capacity position (i.e., a reduced capacity need) of approximately [redacted] MW in Summer and over [redacted] MW in Winter. This corresponds to a significant fraction of the 1230 MW in combined capacity additions WEPCO is seeking from the Paris RICE and Oak Creek CT applications. In other words, simply correcting WEPCO's PRM assumption may be able to reduce the Company's projected generation needs by a significant fraction of the capacity the Company is currently proposing to build.

**Q. How did you calculate the increased capacity position from the use of the UCAP PRM?**

A. To calculate the increase, I constructed a table similar to Table 2-6 in WEPCO's application, but simply recalculated the capacity position using a UCAP PRM instead of an ICAP PRM. To do that, I first changed the Reserve Requirement to reflect MISO's UCAP values, then calculated the Company's firm capacity resources accounting for each resource's outage rate (thus calculating their firm UCAP value), and then recalculated the Company's capacity position. Finally, I compared these recalculated capacity positions to the values WEPCO reported in Table 2-6.

### *B. WEPCO's modeling methodology inappropriately assumes extremely limited interaction with the MISO market, which is not realistic even under potential future scarcity conditions.*

**Q. Can you describe WEPCO's approach to conducting Capacity Assurance and Energy Assurance model runs?**

A. Yes. Both approaches are fundamentally similar in that they are capacity expansion model runs in PLEXOS LT based on a simplified load profile (e.g. based on 12 representative hours within each month). The Capacity Assurance approach develops a portfolio that is required to meet the total capacity need (peak demand plus reserve margin) with Company resources. The Energy Assurance approach is more restrictive, i.e. has the same capacity requirement, but further requires the model to meet the forecasted energy needs during all hours only with Company resources - without relying on the market for energy purchases. While I generally agree with WEPCO that emerging trends might lead to tighter energy supply conditions and should be evaluated, I do not believe that WEPCO's Energy Assurance approach accomplishes this objective. Since WEPCO is not proposing to withdraw from MISO participation, the Energy Assurance model runs are of limited value in assessing WEPCO's proposed resource additions. Assuming no MISO market interactions does not appear realistic -- even under occasional scarcity conditions – or reflective of recent trends.

**Q. Can you explain why WEPCO's assumption that there would be no MISO market interactions is unrealistic?**

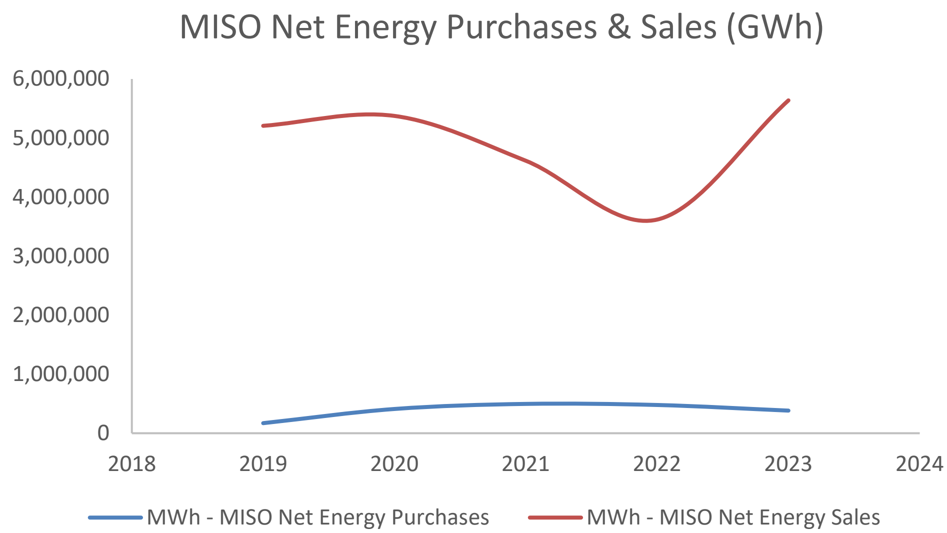
A. Yes. Even if energy scarcity conditions were to become more frequent in the future, this would not necessarily lead to fewer MISO market interactions between WEPCO and other MISO participants during all times of the year. While there may be periods where WEPCO cannot rely on market purchases being available, there may be other periods where that is decidedly not the case. Furthermore, there may be periods where increased market sales are indeed more likely.

**Q. Is there any evidence in recent years that emerging scarcity conditions have led to fewer market purchases and sales between WEPCO and other MISO participants?**

A. No. As shown in WEPCO's response to 3-CW-1,[24] and the chart below, WEPCO has engaged in a robust level of both market purchases and market sales over the last 5 years. In fact, in most recent months WEPCO's market sales have far outpaced its purchases, indicating that the Company itself is not facing emerging energy scarcity conditions currently. If anything, WEPCO may have significant headroom in the coming years before energy scarcity becomes a concern.

[24] Ex.-CUB-Burgess-12.

*Figure 1: WEPCO's net energy Purchases & Sales to MISO (annual GWh)*[25]




**Q. Did WEPCO provide any analysis to justify the restriction on market purchases and sales in the coming years?**

A. No. WEPCO provided a vague explanation that MISO's evolving resource adequacy construct has "introduced more uncertainty in resource planning."[26] However, the Company did not explain why these changes would lead to even more restrictive energy market interactions than was already assumed in the more conventional Capacity Assurance approach. Already, under WEPCO's Capacity Assurance approach, interchanges are assumed to be limited to 800 MW – which is far below the >4000 MW import limit MISO assumes for WEPCO's location (i.e., LRZ2).[27] Reducing this import limit to 0 MW in just a few years is overly restrictive in my opinion.[28]

**Q. What is the effect of these overly restrictive assumptions WEPCO used in its Energy Assurance analysis?**

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[25] Based on attachment to response to 3-CW-1, Ex.-CUB-Burgess-13.
[26] Ex.-WEPCO-Application-Volume III: Appendix D at 28.
[27] *See* response to 3-CW-2f, Ex.-CUB-Burgess-14; *See also*, MISO's Planning Year 2024-2025 Loss of Load Expectation Study Report, Table 2-3, https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf. NRE.
[28] *See* WEPCO's response to 3-CW-2f, Ex.-CUB-Burgess-14.

A. WEPCO's assumptions distort the analysis in such a way that the model would artificially favor locally sited, utility-owned generation resources instead of either a) more cost-effective generation sited in other parts of the broader MISO region, or b) more cost-effective BESS resources whose value is artificially diminished by the inability to participate in market transactions. Notably, the value of batteries can benefit greatly from the growing frequency of negative wholesale pricing events, whereas CT and RICE units cannot benefit from these events.

### *C. Energy Efficiency (EE) and Demand Response (DR) potential contributions are significantly underestimated.*

**Q. Could incremental deployment of demand side resources such as EE and DR in the coming years (i.e., beyond current policy) reduce the need for WEPCO to add supply-side capacity resources?**

A. Yes. Incremental EE and DR resources both can reduce a utility's peak demand and thus could contribute to WEPCO's capacity position. Even if the overall amount of EE and DR deployed does not fully equate to the proposed capacity resource, it can still reduce the size or delay the timing of the capacity resource need. Both reducing the size or delaying the timing of capacity resource additions can provide significant economic benefits to WEPCO customers.

**Q. In its PLEXOS analysis, did any of the Capacity Assurance scenarios WEPCO analyzed include DR resources?**

A. Based on the Confidential PLEXOS output files I reviewed [redacted].[29]

**Q. Do you find this to be a reasonable result?**

A. No. WEPCO's analysis appears to have assumed a very traditional approach to DR that only considers direct MISO market participation or interruptible tariffs.[30] This does not reflect more recent industry developments. In recent years, many utilities have modernized their approach to DR through utility-offered programs that incorporate new technologies such as smart thermostats, distributed storage, managed EV charging, and other controllable loads. Some leading utilities of comparable size have been able to significantly grow participation levels in recent years to include hundreds of MW of cost-effective DR. If WEPCO's analysis had included more up-to-date assumptions for DR, I would have expected the results to show more DR included across a wider number of the scenarios analyzed.

**Q. Can you provide any examples of these other utility DR programs?**

A. Yes. NV Energy achieved over 142 MW of savings from its Residential DR program in 2023. The cost of this was also significantly lower than what WEPCO has assumed for DR resources in its analysis. Specifically, NV Energy's annual expenditures for the program was approximately $14.9 million, which equates to about $105/kW-yr, or about [redacted]% less than what WEPCO has assumed for DR resources.[31]

**Q. Did any of the Capacity Assurance scenarios modeled by WEPCO in PLEXOS include incremental EE resource additions between now and 2030?**

[29] OCCT PLEXOS Outputs (3 of 3)_CONFIDENTIAL.
[30] *See* response to 4-CW-3, Ex.-CUB-Burgess-15.
[31] Compared to Table 6 in Ex.-WEPCO-Application-Volume III: Appendix D.

A. Yes. However, WEPCO did not allow any incremental EE additions prior to year 2027, thus imposing an artificial restriction on EE resource considerations. Subsequently, almost all of the scenarios modeled included incremental EE additions in years 2027-2029. As part of its modeling assumptions WEPCO appears to have limited EE additions to just 14.5 MW per year, or about 43.5 MW total over these three years. Notably however, in most scenarios, PLEXOS appears to have economically selected the full amount of EE assumed possible by 2030 (i.e., 43.5 MW) as part of the least cost solution. However, because of the annual limits WEPCO assumed on the amount of incremental EE, the PLEXOS model as configured by the Company would have been unable to displace a larger supply side generator by 2030, even though it may be technically feasible to do so, as I will explain in more detail below.

**Q. Do you think that WEPCO's assumptions regarding incremental EE and DR resources were reasonable?**

A. No. I think WEPCO both underestimated the amount of demand reduction possible from EE and DR while also overestimating the cost of these resources. I will further explain why in the remainder of this section of my testimony.

**Q. How did WEPCO derive its assumptions for the cost of EE and DR resources?**

A. Regarding its cost assumptions, WEPCO provided its workpapers for these cost assumptions in response to 2-CW-31,[32] which I have reviewed.

**Q. Can you describe WEPCO's general approach used in this workpaper?**

A. Yes. To estimate a $/kW value for incremental EE resource costs WEPCO uses a relatively simple set of calculations to find the cost per MW of EE that is in turn derived from the

[32] Ex.-CUB-Burgess-16.

statewide Focus on Energy (Focus) 2021 Potential Study's +100% Funding Scenario. To estimate DR costs, the Company uses aggregated national statistics compiled by the EIA.

**Q. Based on your review, do you believe the Company's workpapers adequately support the cost assumptions that WEPCO used for EE and DR in its PLEXOS analysis?**

A. No. For DR I don't believe that the historical EIA data WEPCO relied upon is useful for assessing the cost of forward-looking DR programs that use more modern approaches. As I discussed earlier, programs being implemented by utilities today (such as the NV Energy example) can be much more cost effective. For EE, Table 6 in Volume III Appendix D shows that WEPCO assumed $[redacted]/kW for incremental EE resources. This value is approximately [redacted]% higher than the value calculated in the workpaper attached to 2-CW-29, even after adjusting for two years of high inflation.[33]

**Q. In your opinion, is there a reasonable basis for this [redacted]% discrepancy in EE costs?**

A. No. According to the response to 2-CW-41 Attachment (Confidential),[34] the Company applied an adjustment to EE costs described as follows "[redacted]." This explanation does not make logical sense to me since a corresponding adjustment was not applied to other technologies and would be duplicative of any inflation rates that are already represented. Additionally, WEPCO's workpaper includes some errors and faulty assumptions that further inflate the costs of EE and DR, which I will discuss later in my testimony.

**Q. What were the findings of the Focus Potential Study regarding peak demand savings potential in MW from incremental EE resources?**

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[33] The initial $1,035/kW cost of EE calculated in WEPCO's workpaper attached to 2-CW-29 can be adjusted for inflation assuming 4.7% annual inflation in 2021 and 8% inflation in 2022. This leads to an adjusted value of $1,171/kW in 2023 dollars which is still [redacted]% less than the $[redacted]/kW value reported in Table 6.

[34] Ex.-CUB-Burgess-17.

A. Over the 12-year period analyzed, the Focus Potential Study found that there was 3,029 MW of cost-effective, economic EE potential, which equates to 252 MW per year.[35] This also equates to 1,370 MW more than the current policy potential (or about 114 MW per year in incremental EE potential).

**Q. How did WEPCO derive its assumptions for the annual MW potential for incremental EE and DR resources?**

A. It is not totally clear. However, the same workpapers WEPCO used to calculate EE and DR costs also included a calculation labeled "WEPCO % Share of Annual Peak Demand Reduction (MW)" which corresponds to the 14.5 MW per year EE limit the Company assumed in its PLEXOS modeling.

**Q. Does the 14.5 MW per year limit on EE additions appear reasonable to you based on this calculation?**

A. No. There are two reasons this 14.5 MW limit is unreasonably low. First, the 14.5 MW per year limit in the workpaper only reflects the incremental EE for WEPCO and does not include any incremental EE for WPS, even though both companies are jointly owned and operated by WEC Energy Group within the same LRZ. According to WECPO's calculations, including WPS would increase the total EE available to 21.1 MW per year. Second, WEPCO arbitrarily and incorrectly reduces the amount of peak demand reduction achieved from incremental EE by 50%.[36] This reduction appears to be an arbitrary assumption WEPCO introduced that is seemingly linked to national data on DR resource performance and has no relation to EE resources in Wisconsin or the Focus Potential Study that WEPCO used as the starting point for its analysis.

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[35] https://focusonenergy.com/sites/default/files/inline-files/Potential_Study_Report-Focus_Efficiency-2021.pdf. NRE.
[36] See Response to 2-CW-31 Att, "FOE Scenarios" tab, row 12, Ex.-CUB-Burgess-16.

**Q. Would the national DR participation rates WEPCO cites as the basis for this adjustment factor be applicable to EE measures?**

A. No. I agree that DR participation rates could vary over time, however this concept is not applicable to EE. In contrast to DR resources, once EE measures are deployed, there is no need to adjust for future participation rates. The installed EE measures continue to provide energy and demand savings at a 100% participation rate throughout their measure life.

**Q. What is the impact of correcting this assumption?**

A. Correcting this assumption would further increase the incremental EE potential to 42 MW per year, which would lead to 126 MW in demand reduction over the 2027-2029 period (or about an 81 MW increase relative to WEPCO's proposed portfolio). As mentioned, WEPCO also assumes no incremental EE in 2025 or 2026. Allowing just one additional year of incremental EE deployment could increase total EE demand reduction to 168 MW through 2029 (or about a 123 MW increase relative to WEPCO's modeled resource portfolio). If this increase in EE were pursued in conjunction with new demand response resources, there may be sufficient incremental and cost-effective demand reduction opportunities to defer constructing at least one OCCT unit, if not more.

**Q. Does correcting WEPCO's arbitrary 50% reduction factor also affect the EE cost per kW calculation?**

A. Yes. This has a significant effect on the assumed cost of EE in $/kW. Correcting for this further reduces the cost of EE compared to the assumption included in Table 6 of Volume III Appendix B such that it would be [redacted]% lower than what WEPCO included in its PLEXOS analysis. This would make EE the lowest cost option from a $/kW standpoint.

**Q. What do you recommend regarding DSM in this case?**

A. I recommend that as a condition of any CPCN approval, or partial approval, in this case that WEPCO (in coordination with WPS) be required to pursue at least 168 MW of incremental demand reduction from EE by 2030. To the extent there are budget limitations or other restrictions preventing WEPCO from pursuing EE resource beyond the current policy, the Company should seek opportunities for this incremental EE to be supported directly by large load customers as a means to expedite connecting these large loads. Additionally, the Company should be required to explore additional DR opportunities beyond its current offerings that could further increase its demand reduction potential by 2030.

# VI. Several assumptions in WEPCO's PLEXOS analysis bias the results towards local utility-owned thermal generation resources.

**Q. In addition to an inflated need for supply side resources, you mentioned that the WEPCO analysis has additional flaws that result in a bias towards thermal generation to meet this energy and capacity need. Please describe those flaws.**

A. The inputs and assumptions that result in a bias towards locally-sited thermal generation are:

1. The proposed CT units' capacity accreditation is overestimated due to lack of firm fuel supply.
2. WEPCO's analysis significantly restricted the ability for its generation needs to be met by other potential resources.
3. WEPCO's resource cost assumptions in PLEXOS -- which underpinned the selection of CT units and the projected savings -- did not accurately reflect the true cost of different resources as follows:
    a) The cost of the CT units did not include AFUDC, or any necessary upgrades to ensure firm capacity.

b) The Company's assumption for the cost of batteries is inflated.

I will describe each of these in more detail throughout this section of my testimony.

**Q. Do vertically-integrated utilities like WEPCO have a financial incentive to pursue locally sited thermal generation instead of other types of capacity resources?**

A. Yes. Utilities like WEPCO have an inherent incentive to pursue locally sited thermal generation since they are more likely to be owned by the utility and would thus provide an opportunity for its shareholders to earn a regulated rate of return on the related capital expenditures. In contrast, WEPCO has a disincentive to pursue other potential capacity resources that do not provide the same shareholder earnings opportunity. This would include capacity resources owned by independent power producers (i.e., secured through competitive bidding process) as well as demand-side resources including energy efficiency and demand response.

### *A. The proposed CT units' assumed capacity accreditation in PLEXOS is overestimated and lacks certainty.*

**Q. How did WEPCO's modeling assumptions overestimate the capacity accreditation for the proposed CT units?**

A. A key factor that WEPCO did not properly account for in its analysis that should have caused the proposed CT units to have a lower capacity accreditation in the Company's PLEXOS modeling than what the Company ultimately assumed is the lack of firm fuel supply.

**Q. Please explain how lack of firm fuel supply may be causing an overestimation of the CT unit's capacity accreditation in the WEPCO analysis?**

A. WEPCO's application stated that the project will be targeting firm fuel supply of 240,000 MMBtu/day, which is only sufficient "for greater than 20 hours/day of full load operation" hours of full load operation" and will otherwise need to rely upon interruptible pipeline service.[37] This equates to firm service during only 83.3% of peak day hours. However, the Company does not appear to have discounted the capacity accreditation of the CT units accordingly in its PLEXOS modeling. Indeed, the Company appears to assume that the CT units would be able to provide firm capacity of [redacted] MW equal to nearly the entirety of their nameplate rating of 1100 MW.[38] Furthermore, even the target level of firm capacity WEPCO proposes (i.e., 240,000 MMBtu/day) is contingent on other facilities being built that will increase the overall cost of the OCCT project beyond what WEPCO has assumed in PLEXOS. According to WEPCO's application, these facilities include the Rochester Lateral Project, ANR 2027 Capacity Expansion, and the proposed Oak Creek LNG facility, none of which have been approved by the Commission.

**Q. Is there any public information about what some of those additional costs could be?**

A. Yes. WEPCO's Gas Operations recently submitted an Application to the Commission in docket 6630-CG-140 seeking a Certificate of Authority (CA) to construct an LNG facility at the Oak Creek Generating Site.[39] The Company's purported need for this project is primarily to provide firm gas service to three new or recently converted electric generation facilities, namely the Elm Road Generating Station, Paris RICE, and Oak Creek CTs. The Oak Creek LNG project is expected to cost $456 million and provide 300,000 Dth/day of incremental firm transportation capacity.[40] Meanwhile, Wisconsin Electric has requested

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[37] Ex.-WEPCO-Application- Section 3.2.6.2.1
[38] OCCT PLEXOS Outputs (3 of 3)_CONFIDENTIAL
[39] Ex-CUB-Burgess-4.
[40] *See id.* at p. 1-10 and 2-2.

240,000 Dth/day of firm service from WE-GO associated with the OCCT project,[41] or about 80% of the LNG facility's total capability. Thus, a proportional share of the capital costs would equate to over $365 million. Additionally, WEPCO's Gas Operations recently submitted an Application to the Commission in docket 6630-CG-139 seeking a Certificate of Authority (CA) to construct the Rochester Lateral Pipeline (RLP).[42] As the Application states, the project is expected to cost $212 million and will "provide additional required firm natural gas service to Wisconsin Electric's proposed Oak Creek Combustion Turbine generation facility ("OCCT"), the proposed Paris Reciprocating Internal Combustion Engine ("RICE") generation facility, and subsequently to the Elm Road Generating Station."[43]

**Q. Did WEPCO's economic analysis using PLEXOS include the cost of these new gas infrastructure projects?**

A. No. Based on the Company's response to 3-CW-7,[44] it appears that WEPCO's PLEXOS analysis did include an assumed firm gas rate of $[redacted]/kW-year that was based on a different LNG facility than the one proposed for Oak Creek (specifically WEC's Bluff Creek LNG facility). The Company asserts in its response that this is a conservative cost estimate since the equivalent firm gas rate for Oak Creek LNG would likely be [redacted] percent lower. However, while the firm gas rate assumed by the company may have been a reasonable proxy for the Oak Creek LNG facility, it did not include any of the costs associated with RLP, which is also needed for firm gas delivery, would increase capital expenditures by 46 percent, and would lead to a corresponding increase in the firm gas rate. Thus, I still conclude that WEPCO has underestimated the costs of the OCCT project if firm

[41] *See id.* at Table 2-2.
[42] Ex-CUB-Burgess-3.
[43] *See id.* at p. 1
[44] Ex.-CUB-Burgess-18.

gas delivery (i.e., full capacity accreditation) is assumed as the Company has in its PLEXOS analysis.

### *B. WEPCO's PLEXOS analysis significantly restricted the ability of other potential resources to meet its generation needs.*

**Q. Did WEPCO pursue a competitive solicitation process in identifying the proposed RICE units?**

A. No. It appears that WEPCO pursued a sole-source procurement strategy without any serious attempt to identify potential alternatives or issue a competitive solicitation. As the Company confirmed in response to 2-CW-2, the Company had already selected an engineering, procurement, and construction (EPC) contractor prior to its Application, and there was no Request for Proposals (RFP).[45]

**Q. Does this reflect industry best practices for generation procurement by a vertically integrated utility?**

A. No. Industry best practices would typically include issuing a competitive solicitation to meet an identified energy and/or capacity need. This would allow for the identification of the least-cost set of resources to meet that need among as broad a pool of potential candidates as possible – including those that are not owned by the utility or locally sited. Ideally this solicitation process would come after identifying the overall resource need through a wholistic planning analysis including capacity expansion modeling. Instead, it appears that WEPCO's approach was to pre-select the Company's desired resource option and then use its planning analysis to justify this decision after the fact.

[45] Response to 2-CW-2, Ex.-CUB-Burgess-19.

**Q. Despite the lack of a competitive solicitation, did the Company's Capacity Assurance analysis in PLEXOS sufficiently allow for as broad a pool of potential resource options as possible?**

A. No. The Company included several restrictive assumptions that significantly limited the potential pool of candidate resources available in the model to meet the Company's energy and capacity needs. Important among these are the following limitations or constraints the Company assumed in PLEXOS LT:

- 800 MW limit on energy market interchange (i.e., purchases and sales),[46]
- 0 MW limit on market capacity purchases.[47]
- 800 MW cumulative limit on wind capacity additions by 2030,
- 14.5 MW per year limit on EE additions.

The table below summarizes these build limits as well as other limits in the Company's configuration of the PLEXOS model.

*Table 5: Annual and Cumulative Limits for each resource type*[48]

| | 2027 | 2028 | 2029 | 2030 and beyond | Cumulative |
|---|---|---|---|---|---|
| Battery | [redacted] | | | | |
| Combined Cycle 1x1 | | | | | |
| Combined Cycle 90% CCS | | | | | |
| Combustion Turbine A | | | | | |
| Combustion Turbine B | | | | | |
| Demand Response | | | | | |
| Energy Efficiency | | | | | |
| RICE 7U | | | | | |
| Solar A | | | | | |
| Wind A | | | | | |

[46] *See* Response to 3-CW-2f, Ex.-CUB-Burgess-14.
[47] *See* Response to 2-CUB-11, Ex.-CUB-Burgess-20.
[48] Based on PLEXOS Export 2024-04-01 17-01.

Each of these constraints significantly disadvantages the ability for resources other than the Company's proposed solution to be selected. For example, the assumed 800 MW wind limit was reached in every single one of WEPCO's PLEXOS modeling runs.[49] Similarly, [redacted].[50] This indicates that the model would have selected more wind resources as part of the least-cost solution but for this assumed limitation. Additionally, the 800 MW interchange limit significantly restricts the ability for non-local resources to be considered for meeting the Company's energy and/or capacity needs even if they could be a viable option.

**Q. Did the Company provide a clear rationale for using 800 MW as the interchange limit in its Capacity Assurance analysis?**

A. No. The only explanation provided was that "This assumption is consistent with previous modeling…"[51] However, WEPCO was unable to provide any historical data to validate the appropriateness of the 800 MW value.[52] Meanwhile, this value seems to contrast significantly with relevant information provided through MISO planning documents (which WEPCO also relies upon for its own analysis). For example, it is worth noting that MISO recently identified the Capacity Import Limit for Local Resource Zone 2 (LRZ2) – where WEPCO resides -- to be as high as 4,506 MW in Summer and 5,523 MW in Winter.[53] Similarly, WEPCO reported that the PY24 local capacity requirement (LCR) for LRZ2 was between 60-70% depending on the season,[54] meaning that up to 30% of its capacity needs

[49] *See* response to 5-CW-12, Ex.-CUB-Burgess-21.
[50] Based on Paris RICE PLEXOS Outputs (3 of 3).
[51] *See* response to 5-CW-5a, Ex.-CUB-Burgess-22.
[52] *See* response to 5-CW-5b, Ex.-CUB-Burgess-22, and to 5-CW-7, Ex.-CUB-Burgess-23.
[53] https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf. NRE.
[54] Response to 5-CW-26, Ex.-CUB-Burgess-24.

could theoretically be met from imports. Based on the Company's 2024 Summer capacity obligation ([redacted] MW)[55], this would equate to approximately [redacted] MW – much higher than the 800 MW limit assumed for market energy and 0 MW limit assumed for market capacity.

**Q. What are the implications of this more restrictive limitation on interchange?**

A. It suggests that the model was configured in a way that would artificially limit the selection of resources other than local, utility-owned thermal generation.

**Q. Are there any recent developments that could further unlock the potential for non-local resources beyond the current import limit?**

A. Yes. On December 12, 2024 MISO's Board approved its MTEP24 transmission expansion plan, which included $30 billion in new transmission investments.[56] Among the benefits cited for this approval are $16 billion in avoided capacity costs, partly due to the ability of these transmission investments to provide access to a broader pool of non-local resources. Realizing these benefits, however, will depend upon the investment decisions made by individual utilities like WEPCO and their willingness to procure non-local resources that are more affordable but not owned by the incumbent utility.

## *C. WEPCO's resource cost assumptions in PLEXOS -- which underpinned the economic evaluation of the CT units -- do not accurately reflect the true cost of the OCCT or BESS options.*

### *i) The cost of the Oak Creek CT units, as modeled, is too low since it does not include AFUDC or additional upgrades needed for firm deliverability.*

**Q. Is WEPCO requesting AFUDC as part of its application?**

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[55] *See* Ex.-WEPCO-Application-Application: Table 2-6.

[56] https://cdn.misoenergy.org/MTEP24%20Executive%20Summary658126.pdf. NRE.

A. Yes. As noted in its Application, WEPCO is "requesting as part of this application to earn AFUDC on 100% of the CWIP balance. The AFUDC amount is estimated to be $138.6 million."[57]

**Q. From a ratepayer perspective, would approval of AFUDC affect the calculation of the Oak Creek CT project's NPV costs?**

A. Yes. Even if there is no change to the project's capital costs, AFUDC accounting treatment would accelerate some of the project's cost recovery and thus would increase the NPV from a customer perspective.

**Q. Is this increase in the NPV cost of the CT units due to AFUDC accounted for in the PLEXOS resource selection process?**

A. No. WEPCO confirmed this in its response to 2-CW-43,[58] while asserting that this provided an "apples to apples" comparison since the alternative technologies in PLEXOS did not include any AFUDC costs.

**Q. Do you agree with the rationale that the Company was correct to exclude AFUDC to provide an "apples to apples" comparison?**

A. No. While the Company's rationale presumes that it is equally likely for all candidate resources to receive AFUDC accounting treatment, this is not the case. For several of the alternative resource options, it is not a foregone conclusion that they would require or even be eligible for AFUDC treatment. For example, if a wind facility were procured through a Power Purchase Agreement (PPA), there likely would be no reason to even consider AFUDC as part of that resource's cost recovery. This would also be true for energy efficiency or demand response resources. Thus, a true "apples to apples" comparison would

[57] Ex.-WEPCO-Application-Application: Section 4.1.2
[58] Ex.-CUB-Burgess-25.

be to include AFUDC costs for resources that are more likely to have it (e.g., the Paris RICE units and Oak Creek CTs) while excluding it from resources that are not likely to have it.

**Q. Has WEPCO modeled the Oak Creek CT units as having firm capacity equal to their nameplate rating?**

A. Yes. However, as I explained earlier in Section V this is inappropriate since the CT units being proposed do not have firm fuel supply absent additional transportation costs (e.g. pipeline upgrades).

**Q. Should these costs have been included in WEPCO's analysis?**

A. Yes. Since WEPCO's analysis assumed the CT units would have firm capacity equal to their nameplate rating, the analysis should necessarily have included the additional costs of pipeline and transmission line upgrades required to ensure this firm capacity. Alternatively, WEPCO could have derated the firm capacity contribution of the proposed CT units if these costs were not included. In either case, the per unit cost (i.e., $/kW) of the CT units would be higher than what WEPCO has assumed.

*ii) The cost of BESS resources, as modeled, is too high compared to independent estimates.*

**Q. How did the Company construct its capital cost estimates that informed the capacity expansion analysis?**

A. The Company's estimates for the generic units that the model can select as part of the capacity expansion optimization are presented in Table 6 of Volume III Appendix D. They include natural gas units, renewable resources, energy storage, and demand side resources. According to the Company:

> "Assumed costs for these technologies is based on a combination of EIA's 2023 AEO technology assessment, adjusted for inflation, as well as internal data based on recent estimates from vendors. Solar and battery facilities are all modeled with the

same cost and performance characteristics as Wisconsin Electric's recently-proposed jointly owned High Noon Project."

However, in contrast to this statement, the Company's response 5-CW-9[59] reveals that generic battery capital costs were actually based on the recent Paris battery project.

**Q. How do the capital cost estimates used in the Company's PLEXOS analysis compare to the AEO data?**

A. The table below compares EIA's 2023 AEO data (inflated by 4.1% to convert to 2023 dollars for a consistent comparison) with the data used in the WEPCO analysis.

*Table 6: WEPCO vs AEO Cost assumptions for generic units*

| | WEPCO | | | 2023 Annual Energy Outlook | | |
|---|---|---|---|---|---|---|
| | Overnight Cost (2023$) ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-year) | Overnight Cost (2023$) ($/kW) | Variable O&M ($/MWh) | Fixed O&M ($/kW-year) |
| Combined Cycle | [redacted] | | | $ 1,385 | $ 2.99 | $ 16.52 |
| Combined Cycle w/90% CCS | [redacted] | | | $ 3,269 | $ 6.84 | $ 32.33 |
| Combustion Turbine 1 | [redacted] | | | $ 1,487 | $ 5.51 | $ 19.10 |
| Combustion Turbine 2 | [redacted] | | | $ 903 | $ 5.27 | $ 8.20 |
| RICE - 7 unit site | [redacted] | | | | Not included | |
| Wind | [redacted] | | | $ 2,184 | $ - | $ 30.86 |
| Solar | [redacted] | | | $ 1,507 | $ - | $ 18.01 |
| Battery | [redacted] | | | $ 1,322 | $ - | $ 47.64 |
| Energy Efficiency | [redacted] | | | | Not included | |
| Demand Response | [redacted] | | | | Not included | |

As clearly seen from the comparative table, WEPCO's overnight cost assumptions are slightly higher than the 2023 AEO for all resources but the difference is significantly higher for solar resources and battery resources.

**Q. What technology cost curves did WEPCO use to model how capital costs for each technology will change in the future?**

[59] Ex.-CUB-Burgess-26.

A. According to the Company's response to 2-CW-41,[60] general inflation was applied to the $/kW costs. This assumption fails to capture the technological learning that will enable technologies to lower their capital expenses. Indeed, the capital costs of renewable resources and energy storage are projected to fall more rapidly than those of gas units. For example, a CT unit according to the 2024 Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL) projects that the cost of a CT (in constant dollars) would fall by less than 5% between 2024 and 2030, while the cost of a four-hour battery in the same period will fall by approximately 27%.[61]

**Q. How does the Paris battery cost compare to the assumed generic battery cost in this application?**

A. Appendix B from the WEC Utilities' Economic Analysis in docket 5-BS-254 notes that:

> The total capital cost estimate for the entire Paris Solar/BESS used in the economic analysis is approximately $433 million. The solar capacity component is estimated at $1,360/kW and the BESS component is estimated at $1,459/kW for Paris.

It is unclear why the $1,459/kW cost identified for the Paris BESS in 2021 was adjusted upwards by [redacted]% to reach the $[redacted]/kW value in this Application. This far exceeds recent inflation rates that could explain a more modest increase in the last few years.[62]

**Q. Would the High Noon Solar or Paris Solar projects be reasonable proxies for the modeling of future solar and battery project capital costs?**

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[60] Ex.-CUB-Burgess-17.

[61] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. NRE.

[62] If the $1,459/kW cost identified for Paris BESS includes a 30% Investment Tax Credit as it is co-located with solar, then the increase would be [redacted]% (compared to $[redacted]/kW as identified in Table-6 of Ex.-WEPCO-Application-Volume III: Appendix D), which still far exceeds inflation rates.

A. Not necessarily. My understanding is that those projects are not the result of a competitive procurement process. Consequently, if the Company were to go to the market and solicit competitive bids for different resources, a lower cost might be possible.

**Q. Are there other factors that could further lower the cost of battery resources?**

A. Yes. Co-locating the battery resource with solar or other resources could enable savings in the project's overnight cost. For example, the 2024 NREL ATB assumes that a hybrid solar plus storage resource would result in 8% cost savings over the sum of its individual components.[63] This option has not been modeled in the WEPCO analysis.

**Q. Based on these factors, do you think that the Company's cost assumptions for BESS resources are reasonable?**

A. No. I believe the Company's assumptions for BESS costs are too high.

**Q. What is the impact of assuming a higher capital cost for BESS in the Company's modeling?**

A. By assuming a significantly higher cost for batteries, the PLEXOS model is more likely to not select batteries due to their artificially inflated cost in the unconstrained runs. Additionally, in scenarios where the BESS resources are hardwired in, the NPV costs will be inflated. This would have a significant effect on the NPV cost comparisons shown in Tables 8 and 9 of Volume III Appendix B. More specifically, any benefits identified when comparing the OCCT scenarios to the BESS scenarios might simply be the result of artificially inflated battery cost in the BESS scenarios.

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[63] NREL (National Renewable Energy Laboratory). 2024. "2024 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/. NRE.
2024 v2 Annual Technology Baseline Workbook Errata 7-19-2024, tab "Utility-Scale PV-Plus-Battery" includes 92.3% co-location savings rate.

# VII. Even with these biases, WEPCO's scenario analysis does not definitively demonstrate that all 1,100 MW of CT unit additions would be superior to alternative resource options (e.g. full or partial replacement with BESS, DSM, etc.).

*A. NPV cost differences between WEPCO's modeled CT and BESS scenarios are in the 1.0-2.5% range. Changes to key assumptions (e.g., BESS capital costs, CT capacity accreditation) would significantly affect this comparison.*

**Q. Based on the Company's analysis, how did the OCCT units compare in terms of cost to an equivalent BESS resource?**

A. Volume III Appendix B, Table 8 and Table 9 provide a summary of the comparative analysis the Company performed on scenarios that included the proposed OCCT units versus corresponding scenarios that replaced those units with equivalent BESS resources. While these tables provide the differences in cost between the two options (in NPV terms), they lack context for what the overall portfolio NPV costs are. An analysis of these overall portfolio costs reveals that the difference in NPV cost between the RICE and BESS options range from 1.0-2.5%.[64] Below are revised versions of Tables 8 and 9 that include the WEPCO-calculated differences in cost in million dollars, as well as the same differences in percentage terms:

[64] Calculated from WEPCO workpaper labeled "WEPCO – OC CT NPV Results.xlsx." (PSC REF#: 505821). (NRE)

*Table 7: WEPCO Scenario Analysis NPV Results ($Millions, %)*

| Planning Future | GHG Rule Assumptions | Resource Planning Methodology | Case IDs | NPV Savings | NPV Savings |
|---|---|---|---|---|---|
| Continued Fleet Change | High Restrictions | Capacity Assurance | 100A vs 101A | **480** | **1.9%** |
| | | Energy Assurance | 100E vs 101E | **504** | **2.0%** |
| | Medium Restrictions | Capacity Assurance | 103A vs 105A | **442** | **1.8%** |
| | | Energy Assurance | 103E vs 105E | **428** | **1.8%** |
| | No Restrictions | Capacity Assurance | 106A vs 108A | **439** | **1.8%** |
| | | Energy Assurance | 106E vs 108E | **399** | **1.6%** |
| Slow Economic Growth | High Restrictions | Capacity Assurance | 100B vs 101B | **444** | **1.7%** |
| | | Energy Assurance | 100F vs 101F | **427** | **1.7%** |
| | Medium Restrictions | Capacity Assurance | 103B vs 105B | **378** | **1.5%** |
| | | Energy Assurance | 103F vs 105F | **319** | **1.3%** |
| Enhanced Decarbonization | High Restrictions | Capacity Assurance | 100C vs 101C | **533** | **1.8%** |
| | | Energy Assurance | 100G vs 101G | **516** | **1.8%** |
| High Economic Growth | Medium Restrictions | Capacity Assurance | 103D vs 105D | **432** | **1.6%** |
| | | Energy Assurance | 103H vs 105H | **401** | **1.5%** |
| | No Restrictions | Capacity Assurance | 106D vs 108D | **386** | **1.4%** |
| | | Energy Assurance | 106H vs 108H | **403** | **1.5%** |
| | | | **Average NPV Savings** | **433** | **1.7%** |
| | | | **Minimum NPV Savings** | **319** | **1.3%** |
| | | | **Maximum NPV Savings** | **533** | **2.0%** |

*Table 8: Sensitivity Analysis NPV Results ($Millions, %)*

| Sensitivity | Resource Planning Methodology | Case IDs | NPV Savings | NPV Savings |
|---|---|---|---|---|
| Solar Accreditation | Capacity Assurance | 109A vs 111A | **487** | **2.0%** |
| | Energy Assurance | 109E vs 111E | **465** | **1.9%** |
| Battery Accreditation | Capacity Assurance | 127A vs 129A | **258** | **1.0%** |
| | Energy Assurance | 127E vs 129E | **255** | **1.0%** |
| Limited Wind | Capacity Assurance | 118A vs 120A | **570** | **2.2%** |
| | Energy Assurance | 118E vs 120E | **568** | **2.2%** |
| High OCCT Capital Cost | Capacity Assurance | 100A vs 102A | **360** | **1.4%** |
| | Energy Assurance | 100E vs 102E | **385** | **1.5%** |
| Low OCCT Capital Cost | Capacity Assurance | 100A vs 102A | **599** | **2.4%** |
| | Energy Assurance | 100E vs 102E | **624** | **2.5%** |
| High New Load | Capacity Assurance | 112A vs 114A | **569** | **2.0%** |
| | Energy Assurance | 112E vs 114E | **576** | **2.0%** |
| Low New Load | Capacity Assurance | 115A vs 117A | **427** | **2.0%** |
| | Energy Assurance | 115E vs 117E | **402** | **1.9%** |

**Q. What do you conclude from this analysis?**

A. This suggests that, according to WEPCO's own analysis, the CT and BESS options are within a few percentages in terms of cost. Thus, changes to one or more key assumptions could easily tip the balance towards BESS instead. Additionally, as discussed earlier, there are several such key assumptions that appear to be biased towards the RICE units and against BESS resources. These assumptions include: the capacity accreditation for the CT units, exclusion of AFUDC costs, exclusion of incremental firm fuel transportation costs (e.g., for RLP), BESS capital cost assumptions, limitations on market interaction, and so on. If one or all of these were corrected, the NPV cost of the BESS scenarios is likely to be lower than the CT scenarios.

**Q. Have you estimated how the NPV cost comparison might change if any of these corrections were applied?**

A. Yes. Specifically, I calculated the reduction in NPV cost of the BESS scenarios assuming the capital cost of the 2027 BESS resource addition consistent with the EIA's Annual Energy Outlook rather than the input values WEPCO selected as shown in Volume III Appendix B Table 6. This one simple change led to a reduction in the NPV cost of the BESS scenarios by $817 million (NPV). Thus, this difference would be sufficient to eliminate the purported economic benefits of the CT units in every scenario (i.e., the "NPV Savings" relative to BESS shown in Table 8).

# VIII. WEPCO's argument that the OCCT project is required to address MISO-wide "wind droughts" lacks context

**Q. What concerns did WEPCO raise in its application regarding periods of low wind generation?**

A. WEPCO raised concerns about periods of low wind generation that could last for several days in some cases (i.e., "wind droughts"), and would exceed the capability of short duration batteries (i.e., 4-hours) to resolve. The Company asserts that "only fully dispatchable gas plants can provide needed energy over days and even weeks when renewable energy generation resources are limited."[65] The implication of this is that OCCT is a necessary solution to address future wind drought conditions.

**Q. Do you agree with WEPCO's concerns about wind droughts and the implication that only the OCCT, as proposed, can resolve this?**

A. Not exactly. I do agree that it is important for system planners to anticipate extended periods of low wind output and plan the system accordingly to handle those conditions. However, it is also worth noting that this is an interconnection-wide issue and is not just WEPCO's responsibility to resolve. At present, this issue has been recognized and is being addressed by MISO through its evolving approach to resource adequacy. For example, MISO's upcoming transition to the DLOL accreditation methodology is motivated in part by a need to account for correlated risks like low wind conditions. Thus, as long as WEPCO is using up-to-date MISO planning methods (e.g., UCAP PRMR calculation, DLOL accreditation, etc.), there should be no additional effort needed on WEPCO's part to procure resources "above and beyond" what MISO requires. Additionally, OCCT is not the only resource that might be able to resolve any shortfall due to low winter wind conditions. In fact, there may be other options that WEPCO has not sufficiently considered including long-duration energy storage options ("LDES"), increased EE deployment, and modern DR programs. Beyond lithium-ion batteries, a suite of LDES technologies, like iron-air storage systems, are increasingly commercially ready and have been procured by other utilities. For example, Georgia Power has recently announced a 15 MW / 1.5 GWh iron-air battery;[66]

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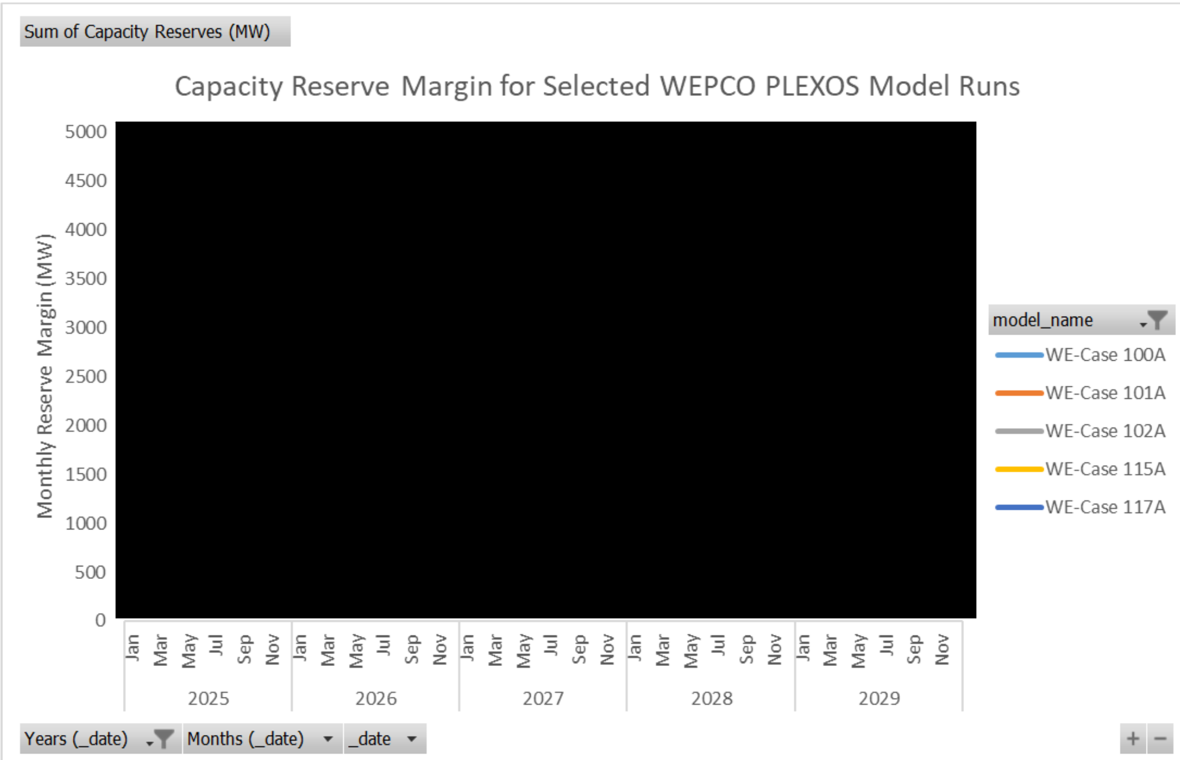
[65] Volume III Appendix B, page 5.
[66] *Form Energy to deploy 100-hour iron-air battery system in Georgia*, PV-Magazine, Ex.-CUB-Burgess-39

Xcel in Minnesota has received approval for a 10 MW / 1 GWh battery; [67] Dominion Energy is piloting two storage technologies with 12 and 100 hours of duration;[68] and Puget Sound Energy is exploring a 10 MW /1 GWh battery.[69]

**Q. Is the Company's projected near-term capacity need anticipated to occur in winter?**

A. No. Based on my review of the Company's PLEXOS model outputs,[70] summer capacity reserves are significantly more scarce than winter reserves and appear to be the primary driver of needed capacity additions. For example, the chart below was created from the Company's PLEXOS model runs and shows consistently lower reserve margins in summer months – particularly in the 2026 timeframe – that drive capacity additions in the 2027 timeframe.

[67] *Minnesota PUC Approves Xcel's Plan to Install a 10-MW/1,000-MWh Form Energy Battery System*, Utility Dive, Ex.-CUB-Burgess-39
[68] *Dominion Energy in 'innovative and timely' pilot of long-duration energy storage technologies*, Energy Storage News Ex.-CUB-Burgess-39
[69] Puget Sound Energy, Form Energy explore 10-MW, 100-hour iron-air battery pilot, Utility Dive, Ex.-CUB-Burgess-39
[70] OCCT PLEXOS Outputs (3 of 3)_CONFIDENTIAL




**Q. Has the Company conducted any analysis to justify the addition of 1,100 MW of new gas generation on the basis of future winter wind droughts?**

A. No. As the Company stated: "Wisconsin Electric has not performed any studies or analysis of potential wind drought conditions."[71] Witness Hagerty did appear to conduct some preliminary analysis on this topic and determined that if a period of low wind similar to January 2021 were included in WEC's simulations for 2029 then it would result in a shortfall of about 415 MW on average over 11 days.[72] Thus, while not a comprehensive analysis of available solutions, this does suggests that 415 MW of additional firm dispatchable generation would be helpful for avoiding shortfalls during future low wind conditions. Notably however this amount is 66% less than the 1,230 MW of new generation

[71] Response to 2-CUB-16, Ex.-CUB-Burgess-27.
[72] Direct-WEPCO-Hagerty-39.

the company has proposed. Additionally, 415 MW is likely a conservative estimate due to some of the faulty assumptions in WEC's simulation analysis that I discussed above in Section V and uncertainties regarding the magnitude and timing of large New Load.

# IX. General concerns regarding WEPCO's approach to resource planning and procurement

## *A. The lack of Integrated Resource Planning leads to a piecemeal approach, leading to a suboptimal resource portfolio.*

**Q. Can you explain how WEPCO's general approach to planning may be leading to suboptimal outcomes for WEPCO customers?**

A. Yes. Generally, I'm concerned WEPCO's approach to planning (and perhaps more generally in Wisconsin) is to conduct its analysis "Application-by-Application" through the CPCN process. This piecemeal approach prevents the ability to conduct more holistic and optimal portfolio-level planning. Presently, WEPCO has submitted three separate CPCN applications within a short span that the Commission and intervenors will need to review separately, without an adequate opportunity to examine whether the combination of those investments comprises a truly optimal or least cost, least risk portfolio. For instance, in the current Application (Docket No. 6630-CE-317), WEPCO has hardwired in all of the Paris RICE units proposed in Docket No. 6630-CE-316, even though that project has not been reviewed or approved by the Commission. In essence, WEPCO's starting assumption for its OCCT unit analysis is that the Paris RICE units still under review are a foregone conclusion. Meanwhile, in the Company's analysis supporting the Paris RICE Application, WEPCO has assumed that all of the Oak Creek CT units are a foregone conclusion by hardwiring them into the analysis. Thus, neither Application considers any portfolio without at least one of those projects (i.e., Paris RICE or Oak Creek CT) being a foregone conclusion. For the present Application in this docket (6630-CE-317), presuming the Paris RICE units exist has implications for the economics of all other resources modeled and might cause the analysis to overlook portfolio options that better serve the overall need at lower cost.

Another example would be the Liquified Natural Gas facility which is proposed through yet another CPCN application in Docket 6630-CG-140 and the Rochester Lateral Pipeline proposed in Docket 6630-CG-139. The presence or absence of these facilities could have a significant impact on the economics and firm fuel supply of both the Paris RICE and Oak Creek CT projects and vice versa. If the OCCT units are first approved in isolation, then this could significantly alter the subsequent evaluation of the Oak Creek LNG facility and Rochester pipeline. In contrast, an approach that considered the cost of these projects simultaneously might be able to identify lower cost solutions that defer or avoid both facilities.

**Q. What are the customer cost implications of considering some of these Applications one-by-one?**

A. I'm concerned about the potential for a "snowball effect" in project costs. In essence, one project might be approved on the basis of only a limited view of the ultimate, total costs for all interrelated proposed projects. For example, the CT units could be approved without full firm fuel supply or transmission deliverability. Later, this lack of firm supply and deliverability might be used to justify additional costs related to the proposed LNG facility or other costs related to pipeline and transmission upgrades that were not initially considered.

**Q. What are some potential remedies to avoid this piecemeal approach to planning?**

A. The piecemeal approach ultimately stems from the lack of an integrated system plan (IRP) process. I believe that such a process, if established for Wisconsin, would help avoid some of these potential pitfalls and would allow the Commission to better exercise its regulatory oversight in lieu of planning through a CPCN-by-CPCN approach. In each of the recent applications, WEPCO has presented a wide range of scenarios that makes it difficult to discern the incremental value and cost of the specific project being considered for a CPCN in each individual Application. Development of a parallel IRP process would allow for more thorough examination and exploration of these disparate futures while allowing the CPCN process to focus on more specific project details. The IRP process would also allow stakeholders better opportunity to review the wide range of critical inputs, assumptions and methods used in WEPCO's planning analysis (e.g., the planning reserve margin).

**Q. Why is it difficult to discern the incremental value and cost of the specific project being considered in each Application?**

A. As an example, the modeling analysis used to support this application might appear robust, since it includes 47 modeling runs in the scenario analysis and several more in the sensitivity analysis. However, these modeling runs are of limited usefulness for isolating the impacts of the specific project in question and evaluating its economics. This is because there are significant differences between the resource portfolios of each modeled scenario, beyond just the presence or absence of the OCCT units and/or the BESS alternative. Thus, any benefits in terms of the NPV of the revenue requirement (or any other metric) cannot be confidently attributed to the presence or absence of the OCCT units versus other portfolio differences. A better approach would be to conduct more comprehensive scenario analysis through an earlier step in the IRP process to identify general resources needs. Then in a later step, once those needs have been sufficiently narrowed, the value of a specific project could be evaluated.

**Q. Can you summarize the steps in your recommended approach going forward?**

A. Yes. Ideally, the planning and procurement process would proceed as follows. First, an IRP would be conducted through which key resource inputs and assumptions (e.g., load forecast, PRM) could be adequately reviewed. Through this process, specific resource needs could be identified, and subsequently a competitive RFP could be conducted based on these identified needs. Finally, once specific projects have been selected through the RFP process, a project-specific analysis could be conducted for inclusion in the related CPCN Application. This final analysis would not focus on changes to key planning variables (e.g. load forecast) that were determined through the IRP.

### *B. WEPCO's procurement approach lacks any competitive process to identify least cost resources.*

**Q. What are your general concerns with WEPCO's approach to resource procurement?**

A. As I discussed earlier, in this case WEPCO pursued a sole-source procurement of its preferred resource option with no attempt at conducting a competitive solicitation to meet its identified resources.[73] In recent years, competitive solicitations such as "all source RFPs" have been an effective method for vertically-integrated utilities like WEPCO to attract a broad pool of potential resource options while identifying the most competitive prices for meeting energy and capacity needs.

[73] As discussed in responses to 2-CUB-7 and 2-CUB-8 (Ex.-CUB-Burgess-28), Burns and McDonnell was already selected for the EPC role and no solicitation was issued. The EPC agreement is included as Ex.-CUB-Singletary-1.

The lack of a truly competitive solicitation process is especially concerning to me because as a vertically integrated utility, WEPCO is not just the sole seller of electricity to its customers (i.e., a monopoly), but also is the sole purchaser of generation resources (i.e., a monopsony) for its service territory. An important role of the Commission is to approximate market competition, which applies not only to the sale of electricity to end customers, but also to the purchase of electricity sources from suppliers. As the sole buyer, WEPCO can exert significant control over the market to disadvantage potential suppliers in favor of its own interests. Not only can this monopsony power lead to a suboptimal outcome for specific projects, but it can also have a long-term effect on whether there is a robust market for potential suppliers to WEPCO going forward. If project developers have very little prospect of selling power to WEPCO and its customers in the future, then they will be less willing to take initial steps towards developing a competitive project pipeline. Ultimately this will cause WEPCO customers to suffer from a smaller pool of resource options that come at a higher price.

**Q. What do you recommend going forward?**

A. The Commission should require WEPCO to conduct competitive solicitations for specific resource needs identified in advance of any future CPCN requests. These solicitations should follow industry best practices.

## X. Due to timing constraints, near-term resource additions should prioritize "least-regrets" options that can be brought on within 1-2 years (i.e., OC BESS, EE, DR). As an alternative, certain "low-regrets" options could be considered (i.e., 2 OCCT units) while "high risk" options should be rejected (i.e., 5 OCCT units, Paris RICE).

**Q. Has WEPCO adequately demonstrated a need for new generation capacity to be added?**

A. At a high level, based on WEPCO's assumed load forecast (which is still relatively uncertain), some new generation capacity appears needed within the next 5 years. However, as I discussed throughout my testimony, the exact magnitude, type, and timing of new generation that is needed has not been clearly demonstrated. This is in large part due to uncertainties in the Company's projections for New Load customers and other limitations in the Company's PLEXOS analysis.

**Q. Considering these uncertainties and limitations, what would be the ideal process for addressing the Company's near-term needs to meet its load in the 2026-2028 timeframe and beyond?**

A. Under ideal circumstances, the Company would have already conducted a competitive solicitation to identify the least-cost resources to meet its identified need as discussed above. However, given the compressed timeline for the first phase of New Load customers to be added (i.e., approximately 450 MW by summer 2027) there may not be sufficient time for a robust "all source" solicitation process targeting new resources by summer 2027. Such a competitive all-source solicitation would still be worth pursuing but may be best targeted towards resource additions in the 2028-2030 timeframe. For example, the typical development timelines reported by many utilities for new gas-fired CT projects is 3-5 years (see table below). This is consistent with the Company's expected schedule for OCCT which, absent any delays, would not see commercial operation until late 2027 for 2 units and mid-2028 for the remaining 3 units. Thus, OCCT could conceivably assist with meeting the Company's 2028 summer peak but would be unable to assist with projected peak load growth in 2026 and 2027.

| Utility | Locations | CT | CC | BESS | DR | Sources |
|---|---|---|---|---|---|---|
| **PacifiCorp** | WA, OR, UT, WY, ID, CA | 3.5 - 5 yrs | 5 yrs | 1 – 2 yrs | 1 yr | 2025 Draft IRP[74] |
| **Duke Energy** | NC, SC | 5 yrs | 5 yrs | <3 yrs | 1 yr | 2024 CPIRP[75] |
| **I&M Power** | IN, MI | 5 yrs | 5 – 6 yrs | 1 yr | 1 yr | 2021 IRP[76] |
| **Salt River Project** | AZ | 2-4 yrs | 5 yrs | 2 yrs | 1 yr | 2023 ISP[77] |
| **NV Energy** | NV | 3-4 yrs | >10 yrs | 2 yrs | 1 yr | 2024 IRP[78] |

That said, there are also some resources that can generally be developed on a more expeditious development timeline (e.g., 1-2 years) and could assist with 2026 and 2027 peak loads. Those very near-term resources would include:

1) incremental energy efficiency resources through expansion of current and/or new customer programs which typically have annual program development cycles,

[74] PacifiCorp 2025 Draft IRP (see Table 7.2 and p 168), https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025_DRAFT_IRP_Vol.1.pdf (NRE)
[75] Based on first year of availability as reported in Duke Energy's 2024 Carolinas Resource Plan (see Appendices C and H), https://www.duke-energy.com/our-company/about-us/irp-carolinas (NRE)
[76] I&M 2021 IRP, (See Tables 7 and 8, and p 74), https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/2021IMIRPReportRevised.pdf (NRE)
[77] Based on first year of availability as reported in SRP's 2023 ISP (see pp 77 and 99). Note however that SRP's Coolidge CT project has been in development since 2021 and is expected to be online in 2026. https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf (NRE)
[78] Based on first year of availability as reported in NV Energy's 2024 IRP (see Appendix ECON-10), https://ob.nv.gov/puc/api/Document/AWIwp3nuGnLh5%C3%89RSHv7sBlDRI%C3%81PJsXqcY1Fr3h15Hmy%C3%81EpzzUEKdYJP9Zq9aVC5OkMDbAdPARsAFm4qbhD0aT88%3D/?OverlayMode=View (NRE)

2) incremental demand response programs which typically have annual procurement cycles, and

3) expedited deployment of BESS resources, which typically have 1-2 year development cycles, especially if leveraging existing interconnections at Oak Creek or other locations. As explained in Section VII my testimony above, BESS additions are likely to be lower in cost than OCCT if appropriate cost assumptions are used.

These could be considered "least regrets" actions that should be pursued in any case and could assist with WEPCO's 2027 summer peak (which OCCT cannot address) and could also reduce the need for some or all of the OCCT units proposed for the 2028 summer peak and beyond.

**Q. Could the "least regrets" actions you identified be sufficient to address any shortfalls in WEPCO's capacity position for the 2028 summer peak as well?**

A. Yes. The table below calculates the Company's capacity position over this period under a feasible scenario ("Least Regrets Pathway") that addresses summer peak loads through 2028.

*Table 9. WEPCO Capacity Position for Summer Peak under a "Least Regrets Pathway"*

| **Year – Month** | **26-Jul** | **27-Jul** | **28-Jul** |
|---|---|---|---|
| Initial Capacity Position | | | |
| Peak Demand (MW) - WEPCO Initial Forecast | [redacted] | | |
| Peak Demand (adj. for Phase 1 only) | | | |
| PRMR % (UCAP, Summer) | 9% | 9% | 9% |
| Capacity Obligation (MW) | [redacted] | | |
| Existing Capacity Resources (adj for UCAP) | | | |
| Initial Capacity Position (MW) | | | |
| | | | |
| Recommended Near-term Actions (MW) | | | |
| Incremental EE | 21 | 42 | 84 |
| Incremental DR | 50 | 100 | 150 |

| | | | |
|---|---|---|---|
| OCCT Batteries (May 2027) | 0 | 400 | 774 |
| OCCT Units 1&2 (Dec 2027) | 0 | 0 | 0 |
| Other CT Units | 0 | 0 | 0 |
| RICE Units | 0 | 0 | 0 |
| High Noon Solar (Dec 2026) | 0 | 110 | 47 |
| High Noon BESS (Dec 2026) | 0 | 124 | 105 |
| Darien and Koshkonong BESS (May 2026) | 180 | 180 | 153 |
| Imports | 650 | 0 | 0 |
| Final Capacity Position | **3** | **28** | **3** |

This pathway includes the following:

- Indicative amounts of the "least regrets" actions I described above including:
  - Incremental EE resources consistent with Section V-C of my testimony above (i.e., 42 MW per year)
  - Incremental DR resources roughly consistent with those modeled by Clean Wisconsin (i.e., ~150 MW total)
  - Incremental 4-hr duration BESS at Oak Creek (400 MW in 2027 plus 400 MW in 2028, adjusted for DLOL)
- Expected resources that were not included in the Company's initial calculation of its capacity position (i.e., Table 2-5 of the Application) including:
  - High Noon Solar and BESS
  - Darien and Koshkonong BESS
- Specific adjustments to the initial capacity position, including:
  - Adjustment to WEPCO's initial Peak Demand forecast to include only Phase 1 of the Mt. Pleasant facility.
  - Adjustment to the PRMR and Existing Capacity Resources to make consistent with MISO's UCAP methodology as described in Section V-A above.

This analysis focuses on WEPCO's summer capacity position since that is the Company's peak demand season and is the primary driver of new capacity needs according to its PLEXOS modeling.

**Q. What amount of costs to WEPCO customers could be avoided under the Least-Regrets Pathway compared to the Company's proposed projects?**

A. Under this option, WEPCO customers could avoid at least $2.2 billion in estimated capital costs associated with the following projects:

- Paris RICE ($279 million)
- Oak Creek CT ($1,205 million)
- Rochester Lateral Pipeline ($212 million)
- Oak Creek LNG ($456 million)
- Additional transmission upgrades at Paris RICE for full deliverability (unknown)
- Additional firm gas transportation costs at Paris RICE and Oak Creek CT for full accreditation (unknown)

Some of the benefits from avoiding these project costs will be offset by incremental costs for BESS, EE, and DR resources under the Least-Regrets Pathway. However, I'm reasonably confident that those incremental costs will not exceed the items listed above.

**Q. Does the Commission need to approve the OCCT and Paris RICE projects for construction now in order to meet peak loads in 2028 and beyond?**

A. No. As mentioned, the Least Regrets Pathway I outlined above could address these needs. Given the uncertainties and risks involved, a full buildout of the OCCT and Paris RICE resource additions could be deferred until more information is known about a) the results of any competitive solicitation for new resources in the 2028-29 timeframe and b) the exact timing of future phases of New Load additions. However, the Commission may believe it appropriate to consider an alternative option that includes approving construction of a more limited amount of new thermal generation now. I recommend taking a phased approach whereby only a portion of the proposed new thermal generation proposed is approved now as part of a "Low Regrets Pathway" and the remainder of the gas facilities that are higher risk (i.e., "higher risk options") could be deferred until a later date.

**Q. What new gas generation facilities would you consider to be a part of a "Low Regrets Pathway"?**

A. I would consider 2 units of the OCCT project to be in the "low regrets" category. This would equate to approximately 440 MW of new generation capacity (474 MW winter rating, 430 MW summer rating), which is roughly consistent with each of the following:

- 450 MW of demand projected for the first phase of the Mount Pleasant data center.
- 474 MW of new CTs selected in Clean Wisconsin's modeling under the 50% load scenario.[79]
- 415 MW of firm dispatchable generation needed to avoid future "wind drought" conditions as estimated by WEPCO (see section VIII above).

**Q. What action should the Commission take if pursuing this "Low Regrets Pathway"?**

A. While not secured through an open or competitive process, it appears that WEPCO has taken steps to develop the OCCT resources through a non-competitive, sole-source contract. Thus, if the Commission is so inclined, authorizing just two OCCT units for construction could be a simple (albeit suboptimal) solution to address WEPCO's 2028 summer peak demand while also allowing for a more competitive process to address any remaining needs,

[79] See Direct Testimony of Douglas Jester in Docket No. 6630-CE-316. (NRE)

particularly for 2029 and beyond. However, if such authorization is granted, it should be paired with specific conditions as outlined in the next section of my testimony, as well as the "least regrets" options identified above that will still be needed to meet the 2027 summer peak. The table below calculates the Company's capacity position through summer 2028 under this Low Regrets Pathway.

| **Year – Month** | **26-Jul** | **27-Jul** | **28-Jul** |
|---|---|---|---|
| <u>Initial Capacity Position</u> | | | |
| Peak Demand (MW) - WEPCO Initial Forecast | [redacted] | | |
| Peak Demand (adj. for Phase 1 only) | | | |
| PRMR % (UCAP, Summer) | 9% | 9% | 9% |
| Capacity Obligation (MW) | [redacted] | | |
| Existing Capacity Resources (adj for UCAP) | | | |
| Initial Capacity Position (MW) | | | |
| | | | |
| <u>Recommended Near-term Actions (MW)</u> | | | |
| Incremental EE | 21 | 42 | 84 |
| Incremental DR | 50 | 100 | 150 |
| OCCT Batteries (May 2027) | 0 | 400 | 374 |
| OCCT Units 1&2 (Dec 2027) | 0 | 0 | 430 |
| Other CT Units | 0 | 0 | 0 |
| RICE Units | 0 | 0 | 0 |
| High Noon Solar (Dec 2026) | 0 | 110 | 47 |
| High Noon BESS (Dec 2026) | 0 | 124 | 105 |
| Darien and Koshkonong BESS (May 2026) | 180 | 180 | 153 |
| Imports | 650 | 0 | 0 |
| Final Capacity Position | **3** | **28** | **33** |

**Q. What new gas generation facilities would you consider to be a part of the "higher risk options"?**

A. Higher risk facilities wlould include:

- additional CT units beyond the first two at Oak Creek,
- all of the Paris RICE units (at full deliverability), and

- the Oak Creek LNG facility.

These are higher risk since it is not yet certain that they will be needed, are part of a least-cost portfolio, or could even be built in time to meet any near-term reliability needs in the 2026-2027 timeframe. Additional time could assist in identifying alternatives that are lower in cost or could provide greater confidence in the underlying load forecasts.

**Q. What amount of costs to WEPCO customers could be deferred or avoided if the "higher risk options" are not ultimately needed?**

A. If these facilities are not ultimately needed, that could yield a reduction in capital expenditures of approximately $1.4 billion. The benefits of avoiding these costs would accrue to all WEPCO customers, including both new and existing loads. Below is a table summarizing each facility or action based upon the risk categories outlined in this section.

| **Risk Category** | **Facilities/Actions** | **Near-Term Action Recommended** |
|---|---|---|
| Least Regrets | • Incremental EE<br>• Incremental DR<br>• Incremental BESS at Oak Creek | Direct Company to pursue immediately |
| Low Regrets | • 2 CT units at Oak Creek | Consider approval with conditions |
| Higher Risk | • Additional units at Oak Creek<br>• Paris RICE<br>• Oak Creek LNG | Defer to later date |

**Q. Are there other potential cost advantages to considering just two CT units at Oak Creek?**

A. Yes. As the Company confirmed in response to CW-2.20, there are $42.7 million in Gen-Tie transmission costs associated with the project. This includes costs associated with a new 138 kV transformer serving two CTs and a new 345 kV transformer serving three CTs.

Thus, if the project were limited to just two CTs, the Company may be able to defer the need for a new 345 kV transformer and related costs. However, this cost may still be necessary if incremental BESS resources are developed at Oak Creek that still require the 345 kV transformer.

## XI. Recommendations and Conclusion

**Q. Please provide your general recommendations for how the Commission should evaluate WEPCO's proposal for the OCCT units.**

A. My recommendations are as follows:

1. The proposed OCCT project should not be approved as is. Instead, the Commission should direct WEPCO to pursue a "Least-Regrets Pathway" as outlined in Section X of my testimony, which is better suited than OCCT for meeting the Company's 2027 summer peak needs.
2. As an alternative option, the Commission could consider approving a scaled back version of the Company's proposal (i.e., the "Low Regrets Pathway") as outlined in Section X of my testimony which includes just two OCCT units.
3. If any OCCT units are approved now, some portion of that capacity's approval should be contingent on certain conditions being met. These conditions would help to better balance the risk between WEPCO and its existing customers and should include the following:
    a. Cost recovery, including any allowance for funds used during construction (AFUDC), should not be permitted until certain milestones are met regarding projected new load growth. These milestones could include actual metered

demand and/or executed contractual terms that provide greater certainty and protections for existing customers.

   b. WEPCO should immediately conduct a competitive solicitation for capacity resources including BESS. To the extent possible, incremental BESS resources should be considered at Oak Creek in lieu of the proposed CT units.

   c. Additional DSM should be pursued, including new forms of demand response, with a goal of achieving at least 168 MW in incremental load reduction from energy efficiency (beyond current policy) by 2030, and additional demand response beyond that.

4. In addition to acting on the CPCN and any related conditions, the Commission should also seek to establish a more comprehensive process for resource planning and procurement to avoid the current piecemeal approach and ensure that customers benefit from a broader pool of competitive options going forward.

**Q. Does that conclude your direct testimony?**

A. Yes.