UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southwest Power Pool, Inc.	)	**Docket No. ER24-1317**
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PROTEST OF PUBLIC INTEREST ORGANIZATIONS TO SOUTHWEST POWER POOL'S PROPOSED ACCREDITATION METHODOLOGIES FOR THERMAL AND RENEWABLE GENERATORS

March 29, 2024

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Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] Sierra Club, Natural Resources Defense Council, and the Sustainable FERC Project (collectively, "Public Interest Organizations" or "PIOs") submit this protest to Southwest Power Pool, Inc's ("SPP") Submission of Tariff Revisions to Implement Effective Load Carrying Capability ("ELCC") Methodology and Performance Based Accreditation ("Tariff Filing").[2] SPP's proposed accreditation methodology for thermal resources ("Proposed Thermal Methodology") perpetuates a fundamental mismatch between how SPP values thermal resources and the value those resources actually provide to the grid. In conjunction with SPP's proposed accreditation methodology for renewable resources ("Proposed Renewable Methodology"; collectively, the "Proposed Methodologies"), the Proposed Thermal Methodology also perpetuates a longstanding inequity in how the RTO values different resource types: in stark contrast to thermal resources, which SPP proposes to accredit based on their average availability when called upon over the course of a season, SPP proposes to accredit renewable resources based on their net contribution to reducing loss of load risk.

PIOs agree with SPP that the Proposed Methodologies marginally improve on the existing accreditation methodologies for thermal units (which treats coal and gas plants as if they never malfunction) and for renewable units (which treats peak load events as the only potential source of grid reliability challenges). As PIOs' expert Michael Milligan discusses at length via affidavit (attached hereto as Exhibit A), a Demand Equivalent Forced Outage Rate ("EFORd") mechanism, which considers forced outages that occur when a unit is called upon to perform, is

[1] 18 C.F.R. § 385.211 (2022).
[2] Submission of Tariff Revisions to Implement Effective Load Carrying Capability Methodology and Performance Based Accreditation, Docket No. ER24-1317-000 (Feb. 23, 2024), Accession No. 20240223-5157 ("Tariff Filing").

going to be more accurate than an Installed Capacity ("ICAP") mechanism that ignores them.[3] And a modeled ELCC mechanism that specifically measures the contribution of wind, solar, and storage resources to reducing loss-of-load events represents an improvement over a peak-hours-performance mechanism that only crudely approximates renewable resources' actual value to the system.[4] However, merely improving on the status quo is not enough: the Tariff Filing must be just and reasonable in its own right, and SPP has failed to accomplish that here.

PIOs also share SPP's concern that a straight rejection of the Tariff Filing might force a return to the status quo and another lengthy stakeholder process, based on the limited review available to the Commission under Federal Power Act (the "Act") Section 205.[5] To address that concern, PIOs are also filing today a complaint under Section 206 of the Act, under which the Commission may impose a much broader array of remedies. In any event, concern about backsliding to the status quo is not a valid basis for the Commission to approve a Section 205 filing that is unjust or unreasonable.

For these reasons, PIOs urge the Commission to reject SPP's Tariff Filing.

I. PROCEDURAL BACKGROUND

As SPP has highlighted in its filing, the RTO's Tariff Filing is the result of a multi-year stakeholder process.[6] That process focused first on an update to the existing accreditation methodology for renewable resources ("Existing Renewable Methodology"), which resulted in

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[3] Exhibit A (Affidavit of Michael Milligan, Ph.D.) at 6, 13-14 ("Milligan Aff.").
[4] *Id.* at 11-12, 16-18.
[5] Tariff Filing, *supra* note 2, at 43; *see NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 110 (D.C. Cir. 2017) ("Section 205 does not allow FERC to make modifications to a proposal that transform the proposal into an entirely new rate of FERC's own making").
[6] Tariff Filing, *supra* note 2, at 43.

SPP's filing proposed tariff revisions on November 10, 2021 ("November 2021 Proposal").[7] PIOs and other stakeholders from the SPP protested that filing, highlighting for the Commission the deep disparity between SPP's existing accreditation methodology for thermal resources ("Existing Thermal Methodology"), and the Proposed Renewable Methodology.[8] After the Commission originally approved SPP's November 2021 Proposal, PIOs and other parties filed an appeal to the District of Columbia Circuit Court of Appeals.[9] While that case was pending, the Commission in March 2023 set aside its previous approval of, and then ultimately rejected on procedural grounds, the November 2021 Proposal.[10]

Commissioner Clements' concurring opinion in the March 2023 decision highlights the crucial flaw that prompted PIOs and other parties to protest the November 2021 Proposal: it was "unduly discriminatory because it reduce[d] the capacity accreditation of wind and solar resources based on historically demonstrated performance, while failing to account in any way for non-performance of other resource types."[11] SPP highlighted this portion of Commissioner Clements' concurrence in the Tariff Filing, and indicated that it took this guidance "to heart."[12]

PIOs have engaged extensively throughout the stakeholder process SPP highlighted in the Tariff Filing, on both "Revision Requests" (or "RRs") that form the basis for this combined filing: RR #554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR #568 (Effective Load Carrying Capability Accreditation for Wind, Solar and

[7] Submission of Tariff Revisions to Implement Effective Load Carrying Capability Methodology of Southwest Power Pool, Inc., Docket No. ER22-379-000 (Nov. 10, 2021), Accession No. 20211110-5076 ("November 2021 Proposal").
[8] Motions to Intervene, Protest, and Comments of the Clean Energy Advocates under ER22-379., Docket No. ER22-379-000 (Dec. 1, 2021), Accession No. 20211201-5286.
[9] *See generally American Clean Power Ass'n v. FERC*, 54 F.4th 722 (D.C. Cir. 2022).
[10] *Sw. Power Pool, Inc.*, 182 FERC ¶ 61,100 (2023) ("March 2023 Order"); *see also* Tariff Filing, *supra* note 2, at 4-7 (sharing an overall timeline of SPP's years long stakeholder process on accreditation issues).
[11] March 2023 Order, *supra* note 10, (Clements, Comm'r, concurring at P 2).
[12] Tariff Filing, *supra* note 2, at 6-7.

Storage). In that commentary, PIOs explained at each stage why SPP's proposals were unjust, unreasonable, and unduly discriminatory. In particular, in 2023 (as the two proposals were finalized), PIOs submitted three sets of written commentary (attached hereto as Exhibits B, C, and D):

- May 2023: Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), May 23, 2023.[13]

- July 2023: Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), July 27, 2023.[14]

- September 2023: Clean Energy Organizations Comments and Proposal RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources), September 25, 2023.[15]

In these written comments, PIOs: 1) highlighted concerns that SPP's EFORd mechanism, by itself, was incapable of accurately accounting for the degree to which thermal generators provided value during the highest-risk periods on the grid when that value was most needed;[16] 2) pointed out the risk of ignoring correlated outages when accrediting the thermal fleet, particularly when those correlated outage periods are associated with extreme weather events such as recent winter storms;[17] 3) explained that failing to account for thermal performance during high-risk periods was additionally problematic because SPP's Proposed Renewable

[13] Exhibit B (Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), May 23, 2023).
[14] Exhibit C (Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), July 27, 2023).
[15] Exhibit D (Clean Energy Organizations Comments and Proposal RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources), September 25, 2023).
[16] *See, e.g.*, Exhibit B, *supra* note 13, at 2-3.
[17] *See, e.g.*, *id.*; *see also infra* Sec. III(A)(3).

Methodology does account for performance during high-risk periods;[18] and 4) suggested a range of alternative accreditation methodologies, including one comprehensive proposal based on a modified EFORd assessment, that could more realistically account for those correlated outages.[19] PIOs made staff available at multiple subsequent stakeholder meetings to discuss the details of these critiques.

Unfortunately, although SPP made some improvements to its initial proposals in the course of the stakeholder process, it did not meaningfully address PIOs' central concerns with basing thermal capacity accreditation entirely on an EFORd mechanism that does not account for unit performance during high-risk periods. As a result, the final Proposed Thermal Methodology ultimately fails to satisfy the requirements of Section 205 of the Act and the Commission's regulations and guidance.

II. LEGAL STANDARD

A. The Commission's Just and Reasonable Standard Under the Act and SPP's Burden of Proof

Under Section 205 of the Act, the Commission must ensure that "[a]ll rates and charges . . . by any public utility for or in connection with the transmission or sale of electric energy" are "just and reasonable."[20] The Commission must also ensure that utilities do not "make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage" or "maintain any unreasonable difference in rates."[21] A utility proposing to

[18] *See, e.g.*, *id.*, Exhibit C, *supra* note 14 at 3.
[19] *See, e.g.*, *id.,* at 4-5, Exhibit D, *supra* note 15, at 2-4.
[20] 16 U.S.C. § 824d(a).
[21] *Id*. § 824d(b).

change its rates bears "the burden of proof to show that the increased rate . . . is just and reasonable."[22]

Under this standard, where SPP proposes tariff changes to "better align prices" with periods of potential risk, SPP "must show that any such proposed methodology produces just and reasonable rates."[23] If SPP "fail[s] to substantiate that its proposed [methodology]…will achieve that purpose," the Commission must find that SPP has failed to carry its burden under Section 205 of the Act and will reject SPP's proposal.[24] To "show that [a proposed change] is just and reasonable," SPP must do more than merely show "an improvement over the [existing] approach."[25] Instead, SPP must demonstrate that its proposal properly accounts for "actual system conditions" and does not "produce a misalignment between prices and actual system conditions" that will "result in artificially inflated prices and thus prevent [SPP] from achieving a least cost [] solution" to the issues before it.[26]

B. The Commission's Undue Discrimination Standard Under the Act

As the Commission has observed, the Act "bristles with concern about undue discrimination."[27] Section 205(b) states that no public utility may "subject any person to any undue prejudice or disadvantage" or "maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."[28]

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[22] *Id*. § 824d(e).
[23] *See PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,089 at P 51 (2022).
[24] *Id*.
[25] *Id*. at P 47.
[26] *Id*.
[27] *Am. Elec. Power Serv. Corp.*, 67 FERC ¶ 61,168, at 61,490 (1994) (citing *Associated Gas Distribs. v. FERC*, 824 F.2d 981, 998 (D.C. Cir. 1987)).
[28] 16 U.S.C. § 824d(b).

This standard prohibits one type of market participant from receiving preference over another type that can provide a similar service without an adequate justification.[29] The Commission has explained that different treatment is unduly discriminatory "when there is a difference in rates or services among similarly situated entities."[30] Determining that entities are similarly situated "does not mean that there are no differences between them; rather, it means there are no differences that are material to the inquiry at hand."[31] Entities are similarly situated "if they are in the same position with respect to the ends that the law seeks to promote or the abuses that it seeks to prevent, even if they are different in many other respects."[32] Irrelevant differences will not make parties dissimilarly situated.[33] Consistent with those precedents, the Commission has, for example, determined that new and existing generators were similarly situated for "reactive power compensation purposes" because they were equally capable of providing that service, notwithstanding other significant differences.[34]

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[29] *"Complex" Consol. Edison Co. of N.Y., Inc. v. FERC*, 165 F.3d 992, 1012 (D.C. Cir. 1999); *see also Town of Norwood v. FERC*, 202 F.3d 392, 402 (1st Cir. 2000) ("Specifically, the Federal Power Act outlaws unjustifiably disparate treatment of similarly situated entities under the rubric of 'undue preference'"); *Mkt. Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 697, 119 FERC ¶ 61,295, at P 963 (2007) ("The standard for judging undue discrimination or preference remains what it has always been: disparate rates or service of similarly situated customers."); 16 U.S.C. § 824e(a) (requiring the Commission to fix a rate found "unjust, unreasonable, unduly discriminatory or preferential").

[30] *Calpine Oneta Power, L.P.,* 116 FERC ¶ 61,282 at P 36 (2006); *El Paso Nat. Gas Co.,* 104 FERC ¶ 61,045 at P 115 (2003); *Towns of Alexandria, Minn. v. Fed. Power Comm'n*, 555 F.2d 1020, 1028 (D.C. Cir. 1977).

[31] *N.Y. Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,124 at P 10 (Feb. 15, 2018) (Order granting, in part, and denying, in part, rehearing and clarification, and requiring further compliance).

[32] *Id.* The Commission further explained that "[c]onsistent with those precedents, the Commission has, for example, determined that new and existing generators were similarly situated for 'reactive power compensation purposes' because they were equally capable of providing that service, notwithstanding significant differences" (citing *Calpine Oneta Power, L.P.*, 116 F.E.R.C. ¶ 61282 (Sep. 26, 2006); *see also* *PJM Interconnection, L.L.C.*, 168 FERC ¶ 61,121 (2019) ("[N]on-federal renewable resources are similarly situated to federal hydroelectric and thermal resources for purposes of transmission curtailments because they all take firm transmission service").

[33] *Calpine Corp., et al. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61035 at 124 (Apr. 16, 2020).

[34] *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 at P 36 (2006); *see also Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 137 FERC ¶ 61,185 at P 62 (2011) (explaining that that "non-[f]ederal renewable resources are similarly-situated to [f]ederal hydroelectric and thermal resources for purposes of transmission curtailments because they all take firm transmission service").

Tariffs and market rules must be designed to compensate all resources capable of providing services needed by the grid without specifying eligibility requirements or operating procedures that exclude innovative or new technologies capable of providing the same service.

C. Independence of the Just and Reasonable Standard from Past Provisions and Commission Determinations

When evaluating whether a tariff or market rule is just and reasonable, the Commission evaluates it entirely based on its own merits. Improvement to the status quo is not the standard by which the Commission judges rate proposals.[35] Similarly, the Commission is not bound by its previous determinations if subsequent information and/or experience reveals a tariff or market rule that was previously approved is now unjust or unreasonable. Commission precedent establishes that changed circumstances may cause a tariff provision to be no longer just and reasonable, or to be newly revealed as unduly discriminatory or unduly preferential.[36]

D. Completeness Requirement

As noted above, the filing utility bears the burden under Section 205 to establish that a rate change is just and reasonable, and not unduly discriminatory or preferential.[37] A filing that lacks important details regarding how the proposal will operate is incomplete and does not meet that burden.[38] For instance, the Commission has rejected a filing where "significant issues

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[35] *See PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,089, at P 47 n.111 (2022) (finding that even if PJM's contention that its Intelligent Reserve Deployment proposal is an improvement over its current approach is correct, that does not render the proposal just and reasonable).

[36] *See Ameren Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,205, at P 33 (2007) (finding that "a tariff provision implementing a particular rate [or practice that was found reasonable at one time] does not preclude the Commission from later reviewing the tariff provision to determine whether it continues to be just and reasonable").

[37] *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 662 (D.C. Cir. 2017) (citing 16 U.S.C. § 824d(e)).

[38] *See Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,087, P 37 (2010) (finding that, "without the submission of the transition cost methodology, the functionality of the CAISO's proposal, outside of its registration provisions, is incomplete and, therefore, has not yet been shown to be just and reasonable"); *Sw. Power Pool, Inc.*, 112 FERC ¶ 61,303, P 24 (2005) (rejecting filing that did "not provide the Commission with sufficient detail to evaluate whether SPP's proposed rules will provide stable market operations at just and reasonable rates").

related to the implementation and utilization of the . . . tariff revisions remain[ed] to be determined through the course of an upcoming stakeholder process."[39]

III. ARGUMENT

PIOs agree with the stated goal of SPP's Tariff Filing, which is to select accreditation methods that "fully and accurately reflect the actual performance of [all] resources and their true contribution to reliability and resource adequacy."[40] However, SPP's proposal does not accomplish that basic goal, because it compensates thermal resources using an accreditation method that bears only passing resemblance to those resources' true contribution to reliability and resource adequacy. In order to accurately reflect resources' true contribution to resource adequacy, an accreditation methodology must evaluate that contribution during the grid operator's highest risk periods. SPP does propose an accreditation method for the wind, solar, and storage fleets that accurately reflects those fleets' respective contributions to reliability; but this only further undercuts the reasonableness of the Tariff Filing, because holding one group of resources to a higher standard than another group is a textbook example of undue discrimination. SPP has therefore failed to comply with the Commission's standards under Section 205 of the Act, and the Commission should reject the Tariff Filing in full.

A. The Proposed Thermal Methodology Is Unjust and Unreasonable Because It Does Not Accurately Capture the Capacity Value Thermal Resources Provide

The fundamental problem with SPP's Proposed Thermal Methodology is that it does not evaluate resources based on their performance during high-risk hours. SPP has proposed an

[39] *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,196, 62,027 (2010); *see also Cal. Indep. Sys. Operator Corp.*, 137 FERC ¶ 61,143, P 15 (2011) (denying rehearing of rejection of those "premature and incomplete" tariff revisions).
[40] Tariff Filing, *supra* note 2, at 3.

EFORd mechanism that measures the outage rate of each plant during demand periods (i.e., when the system has called on the resource to perform).[41] SPP describes the period tested by the EFORd mechanism as "times resources are needed in the relevant season."[42] But the RTO does not distinguish between normal operational periods when the RTO may call upon a resource to perform but has sufficient excess capacity available, and the high-risk periods where there is a significant loss-of-load risk.[43] As a result, EFORd functionally bases the accreditation of thermal resources on their average performance across the season when they are expected to be operational (i.e., are not on a planned outage).

The danger of valuing resources based on their average performance across each season is that risks to the electricity grid do not present themselves equally across each season. To the contrary, as SPP discusses at length in its Tariff Filing, risks to the system arise most commonly during extreme weather events, in the form of summer heat waves and winter storms.[44] During the rest of the year, there is typically enough replacement generation capacity to fill in for any individual generator that unexpectedly trips offline. As a result, resources that disproportionately underperform during high-risk periods necessarily provide less reliability value to the system than resources in the same class that disproportionately overperform during those same periods. Yet SPP's Proposed Thermal Methodology values those two hypothetical sets of resources identically: a resource that experiences the full 5% of its forced outages or derates in a year during winter storms and heat waves will receive the same capacity value as a different resource whose 5% forced outage rate is spread evenly across a season and is not

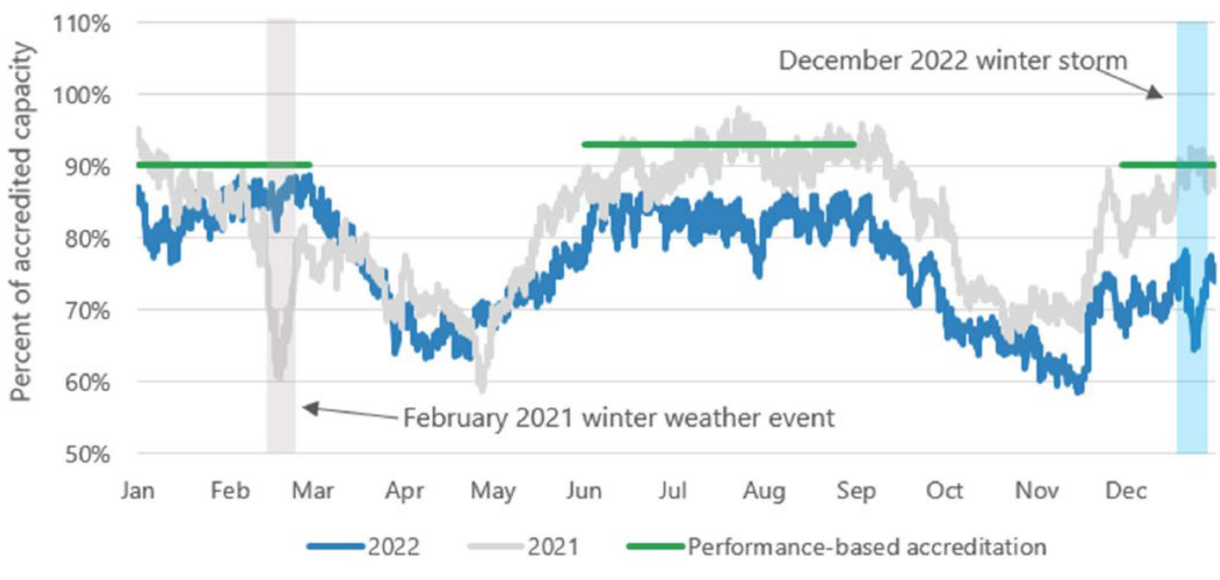
[41] *Id.* at 32-44.
[42] *Id.* at 3.
[43] Business Practice 8100 Resource Adequacy requirements for Demand Response Programs and Behind-The-Meter Generation, Docket No. ER24-1317-000 (Feb. 23, 2024), Accession No. 20240223-5157, at 7 (defining "service hours" as "hours where the resource is generating in serving load or operating reserves").
[44] Tariff Filing, *supra* note 2, at 2; Exhibit A, Milligan Aff., *supra* note 3, at 7, 16-18.

correlated with the weather, even though the latter facility provides more reliability value to the grid. Thus, PIOs respectfully disagree with SPP that the Proposed Thermal Methodology tests for times "when resources are needed."

1. Recent Winter Storms Demonstrate that the EFORd Mechanism Will Not Accurately Value Thermal Resources

The problem of EFORd overstating thermal resources' value is not a purely hypothetical problem: recent experience with major reliability threats has demonstrated time and again that thermal resources are regularly underperforming during the highest risk events. SPP's market monitor has observed this phenomenon at length.[45] This can be seen most pointedly in Figure 1 below, in which the green line represents expected thermal accreditation using the Proposed Thermal Methodology.[46]

Figure 1: Conventional Resource Availability Compared to PBA



[45] Southwest Power Pool Market Monitoring Unit, 2022 Annual State of the Market Report, at 70-76 (May 15, 2023), *available at* https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf.

[46] *Id*. at 71. This line represents roughly 93 percent of ICAP, on average, for the summer, and about 90 percent for the winter.

Looking at the gray and blue lines, which represent actual availability of conventional accredited capacity,[47] it becomes clear that thermal fleet performance is dipping exactly when the system needs it most. As noted by SPP's market monitor in subsequent comments to SPP's Supply Adequacy Working Group, "[t]he data show that the expected availability determined by [EFORd] is *much higher than actual availability*."[48] Therefore, the proposed methodology for thermal resources "will not provide an accurate picture of capacity available to the SPP region," undermining the very purpose of SPP's Tariff Filing.[49]

These observations are not limited to SPP's market monitor. In multiple presentations describing resource performance during Winter Storms Uri and Elliott, as well as Winter Storm Gerri, which stressed the grid in January 2024, SPP acknowledges significant gas and coal underperformance compared to their current accredited capacity.[50] In the Tariff Filing, SPP only shares the charts associated with Winter Storm Uri, which PIOs reproduce below.

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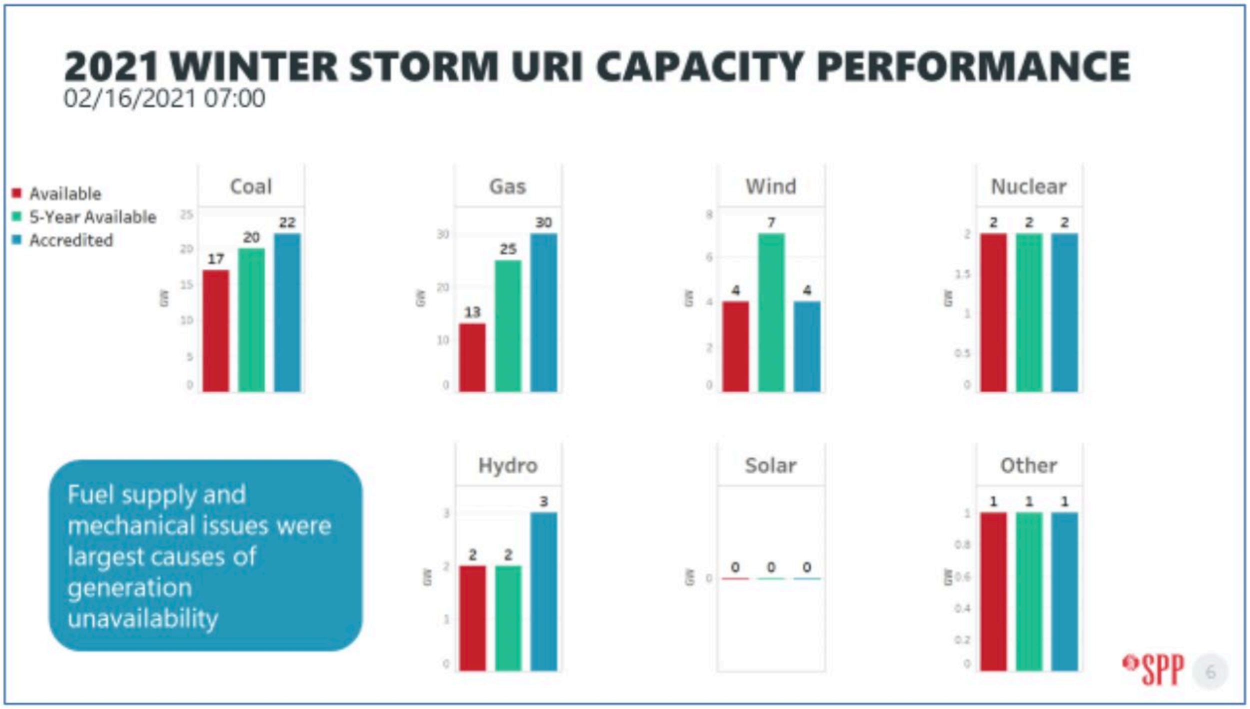
[47] *Id.* This value is measured by the total megawatts offered into the day-ahead market in 2021 and 2022, respectively.

[48] John Luallen, SPP Market Monitoring Unit Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) (May 22, 2023), *available at* https://www.spp.org/Documents/69255/RR554.zip (compendium of documents), at 2-3.

[49] *Id.* at 2.

[50] *See, e.g.*, Southwest Power Pool, A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations (Jul. 19, 2021), *available at* https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf ("SPP Uri Report"); Brown, C.J., December 2022 Winter Storm Elliott, Market and Operations Policy Committee presentation (Jan. 17, 2023), *available at* https://spp.org/Documents/68583/2023-01-17%20MOPC%20agenda%20&%20materials.zip (compendium of documents); Garrett Crowson, System Operations, January 2024 Winter Storm Gerri, Operating Reliability Working Group presentation (Feb. 8, 2024), *available at* https://www.spp.org/spp-documents-filings/?id=19845 (compendium of documents) ("SPP Gerri Presentation").

Figure 2: 2021 Winter Storm Uri Capacity Performance[51]



As SPP correctly observes, coal generators collectively underperformed their accredited capacity by 5 GW, and gas resources underperformed by 17 GW (an amount that represents *over 50%* of their total accredited value).[52] Interestingly, although the wind fleet was correctly identified as underperforming its average 5-year performance during the storm (the green bar in this image), it did not actually underperform its *accredited* value. This is a crucial point: even during a storm where wind generators were widely characterized as struggling compared to their

[51] Tariff Filing, *supra* note 2, at 10.
[52] *Id.* at 9-10.

historical value,[53] they still provided exactly the value to SPP's system that the RTO expected them to provide. Wind generation output went up and down over the course of the storm, but that is to be expected: resource accreditation is a statistical exercise and should never be expected to perfectly match actual output hour-for-hour every day.[54]

Tellingly, while SPP identifies underperformance by thermal resources compared to their accreditation levels during winter storms as a basis for revising the Existing Thermal Methodology,[55] the RTO makes no effort to show thermal generators' performance compared to what their accreditation levels would have been under the Proposed Thermal Methodology. This omission is glaring: generally, when a problem is identified as a justification for a policy change, some demonstration is made that the change will fix the problem. But SPP's failure to include that analysis makes sense here, because its proposed change will not fix the problem of significant thermal generator underperformance. To understand why, one need only look at the green bars for the coal and gas fleets, which represent the average availability of those fleets during the same winter periods as the occurrence of these winter storms, as measured over the past five years. Average performance over a five-year period is a reasonable approximation of the metric by which an EFORd mechanism accredits resources, making the green bar a reasonable predictor of what the coal and gas fleets' accredited values would have been under the Proposed Thermal Methodology.[56] Thus, the same charts SPP used to explain the inaccuracy of its existing ICAP methodology based on coal and gas underperformance of their currently accredited value, also show that the coal and gas fleets *would still have*

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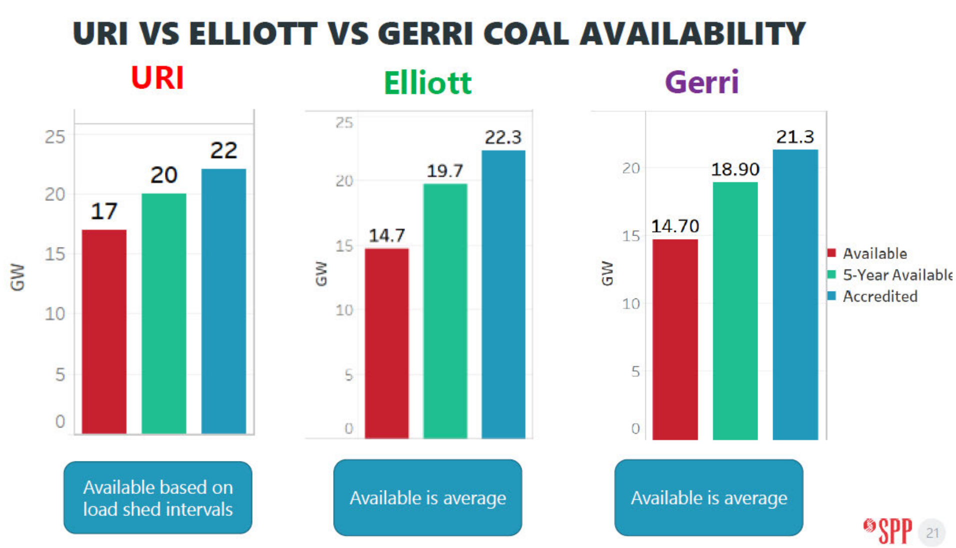
[53] SPP Uri Report, *supra* note 50, at 51-52; FERC-NERC-Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, (Nov. 16, 2021), *available at* https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and, at 75-81.
[54] *Id.* at 48-52; *see also infra.* Sec. III(B)(2) for further discussion on this point.
[55] Tariff Filing, *supra* note 2, at 9–10.
[56] Exhibit A, Milligan Aff., *supra* note 3, at 15.

underperformed their accredited value even if SPP's Proposed Thermal Methodology were already in place, by roughly 3 GW and 12 GW (still almost half of what would have been the gas fleet's total accredited value) respectively.

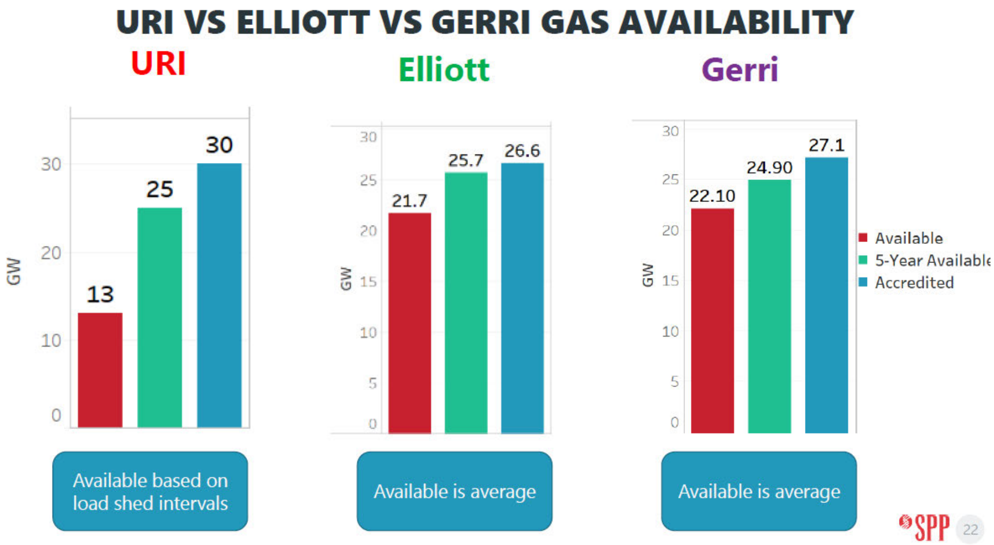
Winter Storm Uri was a single, particularly extreme, storm; but this discussion is relevant because these types of events are exactly what system planners need to focus on to maximize resource adequacy. Indeed, SPP has specifically flagged its Tariff Filing as necessary to "better anticipate[] the availability of resources based on how they have historically performed during [Winter Storm Uri and] similar periods."[57] Thus, SPP cannot ignore Winter Storm Uri in its resource adequacy planning. But also, there have been two major winter storms since Uri; and as the following figures demonstrate, a recent pattern of SPP's coal and gas fleets underperforming both their existing and proposed new accreditation methodologies has developed.

Figure 3: Coal Generator Availability During Recent Winter Storms[58]



[57] Tariff Filing, *supra* note 2, at 9-10.
[58] SPP Gerri Presentation, *supra* note 50, at 21.

Figure 4: Gas Generator Availability During Recent Winter Storms[59]



As Figure 3 demonstrates, the underperformance of the coal fleet was even worse during Winter Storms Elliott and Gerri: it underperformed its ICAP accredited value by 7.6 GW and 6.7 GW respectively in the two storms, and underperformed what its accredited value might be in the Proposed Thermal Methodology by 5.0 GW and 4.2 GW respectively. Meanwhile, Figure 4 reveals that although the gas fleet was not as deeply deficient in Winter Storms Elliott and Gerri, it still underperformed its ICAP accredited value by 4.9 GW and 5.0 GW, and underperformed what its expected accredited value in the Proposed Thermal Methodology might be by 4.0 GW and 2.8 GW respectively.

These three storms illustrate an emerging pattern: they demonstrate both that SPP's existing accreditation methodology is very problematic (as SPP readily admits[60]), and that SPP's Proposed Thermal Methodology is still problematic. And that pattern highlights what is so

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[59] *Id.* at 22.
[60] Tariff Filing, *supra* note 2, at 9-10.

challenging about these events: in recent years, coal and gas generators' operational failures have correlated with a limited number of extreme weather events. Correlated outages among a large swath of similarly situated generators present a serious risk to a system that is not currently set up to accommodate them. Systems are generally well prepared to address the types of disruptions presented by individual facilities tripping offline or even entire transmission lines failing during localized windstorms; models account for these types of events, and it is usually relatively simple to bring online the replacement generation needed to stabilize the system. But when the backup generation for a gas or coal plant is another gas or coal plant, and gas/coal plants are experiencing correlated failures across the region, this can result in significantly increased risk of loss of load.

2. A Growing Consensus Among Experts and Other RTOs Has Emerged that EFORd-Based Accreditation Mechanisms Do Not Accurately Capture Thermal Resources' Contributions to Grid Reliability

The problem of EFORd mechanism-based accreditation systems failing to accurately capture thermal performance during extreme weather events is not unique to SPP: a growing cadre of policy experts and grid operators have concluded that the EFORd mechanism no longer accurately values thermal resources. Weather-dependent correlated outages are a well understood risk at this point, and the industry has increasingly come to the understanding that such events can cause thermal resources "to perform below their EFORd based rating in a statistically significant manner."[61] Multiple parties have observed the "unique vulnerabilities"

[61] *Getting Capacity Right: How Current Methods Overvalue Conventional Power Sources*, Advanced Energy Economy (Mar. 2022), *available at* https://info.aee.net/hubfs/2022%20Folders/2022%20Reports%20With%20Stickers/STICKER%20Getting%20Capacity%20Right%20%20How%20Current%20Methods%20Overvalue%20Conventional%20Power%20Sources.pdf, at 4 ("Advanced Energy Economy Report").

thermal resources[62] have displayed during recent winter storms, as well as "the impacts of correlated outages on resource adequacy."[63] Furthermore, there is no reason to think such events will recede: to the contrary, "[e]xtreme weather events are becoming more frequent, disrupting fuel delivery systems, stressing generator performance, and causing correlated generator outages."[64]

The cause for these correlated outages is also well documented. As the Commission has recently explained, a common thread between generator outages during winter storms in 2011, 2014, 2018, 2021, and 2022 was freezing-related equipment failures.[65] These equipment problems include but are not limited to: "freezing of particular components, including valves, water lines, inlet air systems, and sensing lines," and "wiring failure[s], mechanical wear of valves, and embrittlement of flexible seal materials like rubber and silicone."[66] "Across all generator types, the top direct causes of plant outages in each of the major winter storm events related to equipment freezing . . ."[67] A second source of these correlated outages is fuel unavailability. "Cold weather events can impact availability of fuel supply itself (such as natural

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[62] Except nuclear generation. *See supra* Fig. 2.
[63] Derek Stenclik, *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation*, ESIG (Feb. 2023), *available at* https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf, at X ("Capacity Accreditation Design Report").
[64] *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022) (Clements, Comm'r, dissenting at P 3) ("[E]xtreme weather events are becoming more frequent, disrupting fuel delivery systems, stressing generator performance, and causing correlated generator outages").
[65] *See, e.g.*, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott Winter Storm Elliot: FERC, NERC and Regional Entity Staff Report* (Oct. 2023), *available at* https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf, at 15, 18-19, 165 ("FERC Winter Storm Elliot Report").
[66] *Gas Malfunction: Calling into Question the Reliability of Gas Power Plants*, Union of Concerned Scientists, *available at* https://www.ucsusa.org/sites/default/files/2024-01/Gas%20Malfunction_brief_1.8.pdf, at 4 ("Gas Malfunction Report").
[67] *Id*.

gas) independent of particular acute impacts on generation resources themselves and result in correlated outages that may not be captured in the EFORd average availability calculation."[68]

Thermal gas generation has been identified as particularly susceptible to these disruptions. When considering the last five major storms, a "key commonality among all five was that gas plants accounted, by far, for the largest source of generating capacity knocked offline."[69] And a "pattern" of outages has emerged "largely of gas plants . . . that [] generally took place when temperatures were *above* the plants' minimum ambient temperature ratings."[70] And gas generation is particularly vulnerable to fuel availability disruptions, because gas units "depend on the real-time delivery of gas via pipeline, burning it upon delivery to produce electricity," making them "vulnerable to running out of fuel."[71] This is relevant because gas supply disruptions occurred "in the first calendar quarter of every year between 2013 and 2018,"[72] "as liquids in the gas wells, wellheads, and ancillary equipment froze up and blocked the flow of gas."[73] As a result of these dual vulnerabilities, as Figure 5 shows below, "the cumulative gas plant capacity that failed during each event was more than twice that of the second-most-impacted category of capacity."[74]

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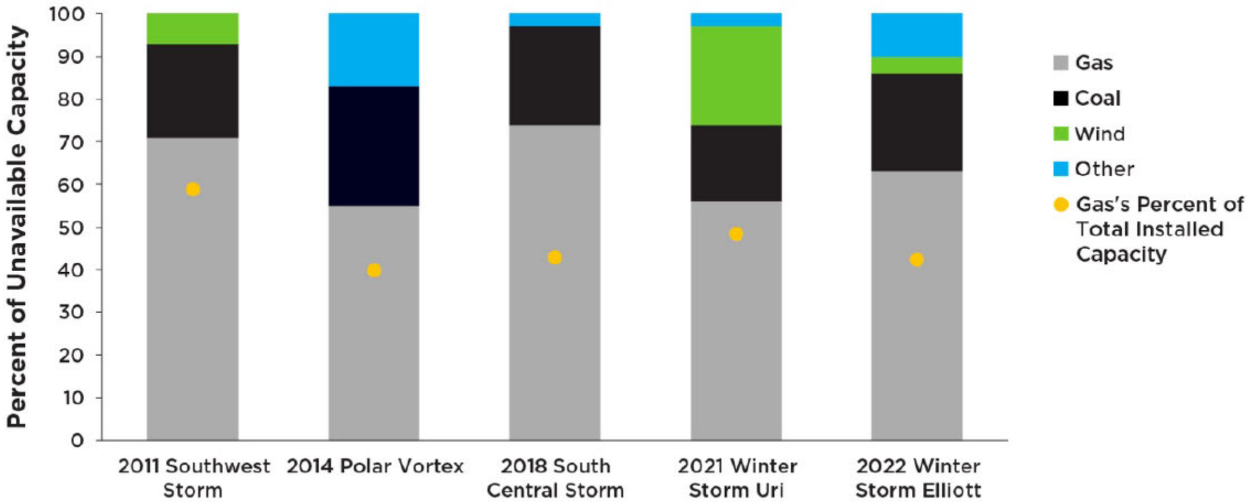
[68] Advanced Energy Economy Report, *supra* note 61, at 4.
[69] *Id*. at 3.
[70] *Id*. at 4.
[71] Gas Malfunction Report, *supra* note 66, at 4.
[72] Gerad M. Freeman et al., *What causes natural gas fuel shortages at U.S. power plants*, Energy Policy, Vol. 147 (Dec. 2020), *available at* https://www.sciencedirect.com/science/article/pii/S0301421520305243, at 1.
[73] Gas Malfunction Report*, supra* note 66, at 4. These events are often called "freeze-offs."
[74] *Id*. at 3.

Figure 5: Generation Failures by Fuel Type During Five Extreme Winter Storms[75]



Although the most significant grid-stressing events in recent years have been associated with winter storms, PIOs also note that heat waves remain a significant concern, and one that both coal and gas generation may also be uniquely vulnerable to. Extreme heat can result in correlated outages or derates for multiple thermal plants within a region.[76] For example, the NERC 2022 Summer Reliability Assessment found that in SPP's territory, specifically in the Missouri River Basin, common-mode outages can occur where drought conditions result in

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[75] *Id*. ("Gas plants accounted for most of the failed capacity in all five recent extreme winter weather events. *Gas plants failed disproportionately in comparison with gas's percentage of total installed capacity, indicating that they are more susceptible to extreme winter weather than are other resource types*. Notes: (1) 2011 data are specific to Texas's main grid operator, ERCOT; it had the most customers experiencing rolling blackouts. (2) 2014 data do not include wind generator outages because NERC had no mandatory reporting protocol for them. (3) 2018 data are specific to failures caused by freezing issues at generators. (4) In its 2011 report, FERC adjusted wind outages downward to account for expected output based on actual wind speed conditions. It did not do so for the 2021 and 2022 storms. This could have made the wind outages in 2021 and 2022 appear more substantial than they actually were, since grid operators rarely expect wind generators to operate at full output. (5) Gas's Percent of Total Installed Capacity is specific to the areas impacted by the storm") (emphasis added).

[76] *Id.* at 5; *2022 Summer Reliability Assessment*, NERC (May 2022), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf, at 5 ("NERC 2022 Summer Reliability Assessment").

reduced "output from thermal generators that use the Missouri for cooling."[77] This lack of access to cooling water was also an issue for coal plants during Winter Storm Gerri, when ice blocking prevented river flow, forcing about 2,000 megawatts offline.[78] This type of problem is not unique to the Missouri River Basin in SPP, but could occur anywhere where drought conditions or ice blocking persist, and can affect any generation resource reliant on hydronic cooling or flow.[79] NERC warns that "outages and reduced output from thermal and hydro systems could lead to energy shortfalls at peak demand."[80] Common mode outages can also occur where resources share equipment like step-up transformers; and in extreme heat, it is also well understood that thermal plants will need to derate their output even in the absence of active drought conditions, to keep their facility cool enough to operate.[81]

The consensus among grid observers that correlated thermal outages are a meaningful challenge extends also to other RTOs, which have near-uniformly concluded that continued reliance on EFORd values as a basis for capacity accreditation is indefensible. MISO has directly stated as such to the Commission, noting that "[r]elying on installed capacity" for resource accreditation is no longer acceptable, even where "adjusted for forced outages," because it "no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather."[82] MISO's experience with an accreditation

[77] NERC 2022 Summer Reliability Assessment, *supra* note 76, at 5.
[78] SPP Gerri Presentation, *supra* note 50, at 7.
[79] *See* Gas Malfunction Report, *supra* note 66, at 5 (describing how prolonged drought in Texas forced a plant operator to take "three gas plant units, totaling 403 MW, offline for almost a year until rain replenished the reservoir from which they pulled cooling water").
[80] NERC 2022 Summer Reliability Assessment, *supra* note 76, at 4.
[81] Coffel, E. and Mankin, J., Thermal Power Generation is Disadvantaged in a Warming World, 2021 Environmental Research Letters, (Feb. 2021), *available at* https://iopscience.iop.org/article/10.1088/1748-9326/abd4a8, at 16.
[82] Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct, Docket No. ER22-495 (Nov. 30, 2021), Accession No. 20211130-5166, at 5.

accounting convention that calculates forced outages (essentially an EFORd-based method) but does not consider correlated outages provides additional evidence that such an accreditation convention will neither be accurate nor reliable.[83]

Similarly, PJM is transitioning away from an accreditation methodology that fails to consider correlated outages based on its assessment that any resulting accreditation would be based on false underlying assumptions.[84] PJM's new proposal, which adopted a methodology that accounts for correlated and forced outages for all resources, was recently approved by the Commission.[85] In that docket, PJM's Senior Lead Engineer in Resource Adequacy Planning, stated:

> PJM currently accredits [thermal resources] based on their respective equivalent demand forced outage rate ("EFORd"). However, the emergence of further evidence that some [thermal resources] experience correlated, non-random outages and outage patterns and the switch to accrediting Unlimited Resources using the ELCC model undermines the usefulness of EFORd in PJM's capacity market. That is, *the logic underlying use of EFORd as the main accreditation metric assumes that unplanned outages experienced by the [thermal resources] are random and thus each resource's forced outage pattern is independent from other resources' forced outage patterns, and we now know this to not be the case*. . .[86]

PJM's expert further stated that the recent winter storms have changed PJM's position on this issue:

> In my 2021 affidavit supporting adoption of PJM's current average ELCC approach, which is used for accrediting the capacity capability of intermittent and storage resources, I stated that using ELCC for [thermal resources] would not be appropriate "due to the fact that the large majority of unplanned outages experienced by these resources are random, which means that the chance of having a large amount of these resources on an outage simultaneously is small." *However, recent events have demonstrated that my understanding is no longer correct, and ELCC provides an appropriate accreditation approach for*

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[83] *Id*.
[84] Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, Docket No. ER24-99 (Oct. 13, 2023), Accession No. 20231013-5157, at 35 ("PJM Capacity Market Reforms").
[85] *Order Accepting Tariff Revisions Subject to Condition*, 186 FERC ¶ 61,080, Docket No. ER24-99 (Jan. 30, 2024) at P 42 ("PJM Accreditation Order").
[86] PJM Capacity Market Reforms, Rocha-Garrido Aff., *supra* note 84, at P 14 (emphasis added).

> *determining UCAP of [thermal resources]. Indeed, the performance of a large number of [thermal resources] during Winter Storm Elliott belies my prior understanding. The correlated outages of [thermal resources] during Winter Storm Elliott can be thought of as akin to the outages experienced by Variable Resources because of their non-random nature and their established patterns*, two reasons that I used to argue in favor of applying ELCC for Variable Resources in my 2021 affidavit.[87]

Recent operating experiences in PJM with methodologies that do not consider correlated outages show that, "particularly in the winter periods, such as Winter Storm Elliott, . . . current modeling approaches focused on peak load conditions and average performance do not fully capture all of the risks that impact resource adequacy needs and resource performance."[88]

Moreover, PJM has concluded that its "current approach of determining a resource's capacity capability based solely on that resource's historical average forced outage rate or nominated capability, without considering the outages of any other resource or alignment with resource adequacy risk periods, *fails to properly account for the actual reliability benefit that the resource provides during hours of expected system risk*."[89] A methodology that does not account for correlated outages "understates winter risk, and therefore does not provide accurate accreditation values and an accurate reliability requirement value."[90]

The Commission ultimately agreed with PJM's analysis, stating that it found the proposal "just and reasonable because it", among other things, "incorporates the risk of correlated outages, especially in cold weather conditions, of all supply-side resources, including thermal resources. . . ."[91] As noted by the Commission, this methodology, "is a clear improvement over the current approach for [thermal resources] . . . because it better captures a given resource's performance

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[87] *Id*. at P 13 (emphasis added).
[88] PJM Capacity Market Reforms, *supra* note 84, at 10.
[89] *Id*. at 24 (emphasis added).
[90] PJM Capacity Market Reforms, Rocha-Garrido Aff. *supra* note 84, at P 47.
[91] PJM Accreditation Order, *supra* note 86, at P 42 (*citing* PJM Capacity Market Reforms, Rocha-Garrido Aff., *supra* note 84, at P 27).

over a wider range of high risk periods."[92] Specifically, the Commission's order notes that PJM's experiences with "Winter Storm Elliott have demonstrated that modeling approaches focused on peak load conditions and average generator performance do not fully capture all of the risks that impact resource adequacy needs and resource performance."[93] The Commission also summarized, and found just and reasonable, PJM's position that "[its] current approach of accrediting [thermal resources] based solely on their historical EFORd . . . fails to properly account for the actual reliability benefit these resources provide during hours of expected system risk," and further states "that a more robust analysis than the conventional EFORd metric is required to" ensure that "a MW of capacity offered by one resource . . . be comparable to a MW of capacity offered by another resource."[94]

In short, it is well established, by technical experts, other grid operators, the Commission, and even the news media, that thermal resources are uniquely underperforming in correlation with each other during extreme weather events. This has caused them to also significantly underperform relative to their accredited capacity value, even in regions that were already using an EFORd mechanism-based accreditation methodology. These regions and several others have therefore taken steps to revise their accreditation strategies.[95] SPP's proposal to move into an

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[92] *Id*. at P 79.
[93] *Id.* at P 15.
[94] *Id.* at P 39.
[95] The list of regions either moving away or already moved away from EFORd or UCAP-based accreditation also includes ISO-NE and NYISO on top of the PJM and MISO examples that are discussed in this section. *See* NYISO, 179 FERC ¶ 61,102 (2022); Robert Walton, ISO New England proposes 1-year delay to 2025 forward capacity auction, Utility Dive (Nov. 7, 2023), https://www.utilitydive.com/news/iso-new-england-delay-FCA19-capacity-auction-accreditation/698973 (quoting ISO-NE as stating that "[t]he current capacity accreditation methodology overvalues gas resources' reliability contributions, which likely means that the region is over-relying on natural gas-fired generators to meet peak winter demand," and noting that ISO-NE is in the process of revising its capacity accreditation to account for outages).

EFORd regime, while an improvement over an ancient ICAP based accreditation approach, is not just unsupportable in its own right; it is out of step with much of the rest of the country.

3. SPP's Proposed Thermal Methodology Exacerbates the Limitation of the EFORd Mechanism by Excusing Too Many "Out of Management Control" Performance Failures

After proposing an accreditation methodology that fails to evaluate thermal units based on their contribution to grid reliability, SPP then compounds the problem by proposing to exclude from thermal units' accreditation any generator outages that result from "Out of Management Control" or "OMC" events, without limitation.[96] OMC events, generally speaking, are events leading to underperformance of a generator that cannot be attributed to "plant operation and equipment" issues. To help illustrate the purpose of this list: it includes natural disasters such as fires, earthquakes, and tornadoes; and failure of transmission infrastructure connecting generators to the broader grid.[97]

Excluding certain OMC events (i.e., those that are unlikely to recur) can often be good policy: it shields individual generators from the secondary risk of major accreditation losses that might accompany certain significant disrupting events, and it avoids unnecessary disruptions to the accreditation system from such events. However, the list of OMC events proffered by NERC includes several weather and supply disruptions that contributed to the grid disruptions during Winter Storms Uri, Elliott, and Gerri, and/or are likely to recur, causing further correlated disruptions. Examples of such events include "9130 failure of fuel supplier to fulfill contractual obligations," "9036 Storms (ice, snow, etc.)," "9280 frozen coal," and "9001 Drought."[98] These

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[96] Tariff Filing, *supra* note 2, at 33; *see* Generating Available Data System ("GADS") Data Reporting Instructions, Appendix K: Outside Management Control, *available at* https://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.Aspx ("GADS OMC List").
[97] GADS OMC List, *supra* note 96, at K-3-4.
[98] *Id.*

events are at the heart of recent extreme weather events that have exposed the vulnerability of coal and gas fleets during high-risk periods on the grid. Excluding generator nonperformance connected to those events from the EFORd calculation will only further dilute the (already inadequate) signal that the Proposed Thermal Methodology is able to send to SPP to indicate how much capacity they have available to serve load, and to thermal generators to incentivize improved performance to support reliability.

PIOs note here that SPP staff has initiated a multiple-month stakeholder process to consider whether to fill this gap: conversations are ongoing at SPP's Supply Adequacy Working Group regarding which OMC events to exclude and why.[99] However, as discussed further below,[100] the existence of an ongoing stakeholder process that will likely substantially revise the Proposed Thermal Methodology weighs further in favor of rejecting the Tariff Filing in full.

4. Using an Accreditation Methodology that Consistently Overvalues Underperforming Thermal Resources Will Lead to Costly and Inefficient Planning Decisions, and Could Impact Reliability

The over-accreditation of thermal resources in SPP's Proposed Thermal Methodology, if not corrected by the Commission, will impose undue costs on ratepayers, and presents a long-term risk to the reliability of the RTO's grid. This is because ultimately the risk that a unit underperforms will inevitably be addressed somewhere. From a system planning perspective, over-accreditation of thermal resources will force SPP's planning reserve margins (i.e., the percent additional capacity a system needs beyond its load projections to ensure a reliable grid) to increase accordingly, increasing the total amount of accredited capacity Load Responsible

[99] Southwest Power Pool, Fuel Assurance Discussion, Supply Adequacy Working Group presentation (Mar. 12, 2024), *available at* https://www.spp.org/Documents/71255/SAWG%20Meeting%20Materials%20for%2020240312-13.zip (compendium of documents) ("SPP Fuel Assurance Discussion").
[100] *See infra* Sec. III(C).

Entities ("LREs") in SPP are required to procure.[101] This will have the result of socializing the cost of thermal generators' underperformance to the rest of SPP's system: instead of reducing the accreditation of individual gas or coal plants that cannot be relied upon during winter storms, the Proposed Thermal Methodology forces every Load Responsible Entity ("LRE") on SPP's system to buy extra capacity to compensate for the difference between the coal and fleets' accredited value and their actual value.

In such a system, the winners are clear: namely, any gas or coal plant that is given more capacity accreditation than it deserves, and any LRE that owns a disproportionate number of such resources. The losers are equally clear: first, any resources that are appropriately accredited based on their actual contributions to resource adequacy will be squeezed out, constituting a smaller relative share of the total capacity requirement than their contributions to reliability warrant. As PIOs discuss more below,[102] such an outcome will result in deeply inequitable treatment of non-coal-and-gas resources (including wind, solar, and storage, but also hydro and nuclear) that are appropriately valued relative to their contribution to reliability during winter storms and other high-risk periods. But this inequitable treatment will be equally felt by gas and coal plants that have performed reliably during the recent winter storms (e.g. those located in northern LREs that have made investments in better winter-weatherized facilities[103]).

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[101] This outcome presupposes that SPP does not make the same mistake of also failing to adequately consider correlated high-risk period thermal outages in its LOLE model. On this front, SPP has factored into its LOLE model an additional Cold Weather Outage Adder that is intended to be a proxy for lower availability of coal and gas resources during extreme cold periods. However, members of SPP's Supply Adequacy Working Group have recently voted to only include 50% of the impact of this Cold Weather Outage Adder, as they do not believe all generator outages during Uri should be considered in the LOLE model. Again, evidence suggests that the risk of extreme weather is only increasing. As such, to the extent the LOLE model is modified to reduce consideration of weather disruptions, the system overall will likely see disruptions at a higher rate than 0.1 outage day per year, particularly during the types of major weather disruptions that have led to system crunches (and correlated outages) in the past decade.

[102] *Infra* Sec. III(B)(3).

[103] As a general rule, LREs located further north have generation facilities that are better adapted to low-temperature conditions because those conditions occur more often independently of major winter storms.

Second, LREs within SPP's footprint that own larger quantities of renewable generation, or that operate more reliable fleets of gas and coal plants, will be forced to procure significant excess capacity beyond what is actually needed to meet their share of capacity to maintain a reliable grid—at significant cost to their ratepayers. And ultimately, ratepayers across SPP's footprint will face inflated energy prices as the market moves away from the lowest-cost capacity solution, and toward resources that have inflated accreditation values, resulting in a costly thermal buildout that is not fully justified.

Additionally, and separately from the system skewing effects described above, an EFORd-based accreditation regime cannot possibly provide any incentive for individual generators to improve their availability during high-risk periods (such as through winterization, dual fuel contracts, or efforts to obtain a more firm fuel supply). This was one of the principal motivations for PJM's shift away from its EFORd mechanism-based accreditation methodology: it concluded that under an EFORd regime, "the capacity market will provide insufficient incentives to retain and attract sufficient Capacity Resources necessary to maintain reliability."[104]

Failing to account for correlated outages provides inaccurate information to utilities, state regulators, and other SPP stakeholders about the reliability contributions of thermal resources. The "proper objective" of the Commission with regard to capacity accreditation is to "ensure that each resource's capacity supply obligation does not exceed its expected contribution to system reliability."[105] SPP's Proposed Thermal Methodology interferes with that objective. The Commission should reject it.

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[104] PJM Capacity Market Reforms, *supra* note 84, at 11, 15.
[105] *PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,084, 61,484 (2021).

B. The Proposed Methodologies Are Unduly Discriminatory Because They Do Not Treat Similarly Situated Resources Comparably

As discussed above, SPP's Proposed Thermal Methodology fails to evaluate the reliability value of thermal resources based on their performance during the high-risk hours when the system needs them (hours which arise in large part as a result of correlated thermal outages). Thermal units are not the only units to suffer correlated outages: similar weather-related correlation also occurs among wind and solar resources. But the ELCC mechanism SPP has proposed to use when accrediting renewable resources accomplishes exactly what the EFORd mechanism does not: it evaluates the three fleets of resources (wind, solar, and storage) specifically based on the contribution those fleets of resources make to system reliability, by measuring their contribution to the reduction of pre-existing high-risk periods on the grid. In other words, the Proposed Renewable Methodology focuses on resource availability in high-risk hours, while the Proposed Thermal Methodology does not: it is based on availability over all hours that thermal resources are called upon to serve load. This contrast is striking, and it forms the basis for a fundamentally inequitable treatment of thermal generation vis-à-vis renewable generation. SPP's current proposed dichotomy of treatment between thermal and non-thermal resources is not defensible.

1. Unlike the Proposed Thermal Methodology, the Proposed Renewable Methodology Focuses on Performance During High-Risk Periods and Evaluates the Possibility of Correlated Outages

SPP's Proposed Renewable Methodology centers on operation of an ELCC mechanism. ELCC is a probabilistic approach that begins with a class average accreditation value. To calculate the ELCC of a resource, a four-step process is conducted using probabilistic loss-of-load modeling.[106] For the first step, "[t]he system is first brought to the reliability criterion (e.g., 1-day-in-10-year [Loss of Load Event ("LOLE"]).''[107] Next, in step 2, "a resource is added to the system, thus reducing LOLE and making the system more reliable."[108] In step 3, "[t]he modeler then adds a fixed amount of load to the model (i.e., fixed block of load across all hours) . . . until the original LOLE criterion is reached (step 4)."[109] The difference between the amount of load added relative to the capacity added for a given resource is its ELCC.

The process described above has two key effects that distinguish the ELCC accreditation mechanism from an EFORd mechanism. First, the ELCC mechanism SPP has presented here will determine accredited capacity values for wind, solar, and storage resources based on their direct impact on the amount of load that can be sustained consistent with the LOLE standard of 0.1 outage day per year (as measured by the LOLE Model), which focuses on the elimination of LOL events via a reduction of the highest-risk hours. ELCC analysis can avoid both under and over accrediting resources as it evaluates the capacity availability of a resource class across all hours of the year with a specific focus on the most challenging hours when setting the capacity accreditation value for the class. In other words, the ELCC mechanism focuses on resource availability during the hours with highest risk of loss of load.

Second, the ELCC mechanism in its very operation accounts for the possibility of correlated outages within a resource class. It is exactly the fear of a major low-wind event, or the concern that high-risk hours may shift into summer evenings or the winter as solar penetration increases, that causes the reduction of wind and solar accreditation as saturation of those

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[106] Capacity Accreditation Design Report, *supra* note 63, at 14.
[107] *Id*.
[108] *Id*.
[109] *Id*.

generation resources on the system occurs.[110] SPP has extolled this as a central feature and purpose of the ELCC analysis, as part of its basis for the Proposed Renewable Methodology; and the RTO has conducted multiple ELCC studies that confirm this pattern for wind, solar, and storage resources.[111] We agree that the ELCC methodology completed using appropriate modeling assumptions can accurately assess resource capacity accreditation values.

SPP's Tariff Filing would implement an accreditation regime in which wind, solar, and storage resources are held accountable both for their performance and contribution during the highest-risk periods of the year, and for their performance when like resources are underperforming; and in which coal, gas, and other thermal resources are accredited mostly on their performance during favorable weather, and are largely given a pass on their documented underperformance during major disruptions to the grid in recent years. On its face, this disparate treatment is neither just nor reasonable. The Commission need not require that similarly situated resources be treated identically[112]—indeed, PIOs have ourselves proposed a non-ELCC accreditation methodology for thermal generators in SPP's stakeholder process[113]—but it must require equivalent treatment.[114] SPP's proposals accomplish neither.

2. SPP's Inequitable Focus on Correlated Outage Risk in the Renewable and not the Thermal Fleets Is Particularly Misplaced Because Renewable Resources Have Actually Overperformed During Recent Grid-Destabilizing Events

SPP's proposal to implement an overall accreditation methodology that accounts for the risk of correlated generator underperformance only in the renewable fleet (and not in the thermal

[110] Exhibit A, Milligan Aff., *supra* note 3, at 16-17.
[111] Tariff Filing, *supra* note 2, at 15-20.
[112] *Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,096, (2023), at P 36 (citations omitted) ("It is often the case that the operating characteristics of different resource classes require various different accreditation frameworks."); *see id.* at 3 (making the claim that SPP's Proposed Methodologies are comparable).
[113] Exhibit C, *supra* note 14, at 4-5; Exhibit D, *supra* note 15, at 2-4.
[114] *PJM Interconnection, L.L.C.*, 168 FERC ¶ 61,121 (2019).

fleet) is especially nonsensical because the incidence of correlated outages during high-risk periods has been limited to the thermal fleet in recent years.

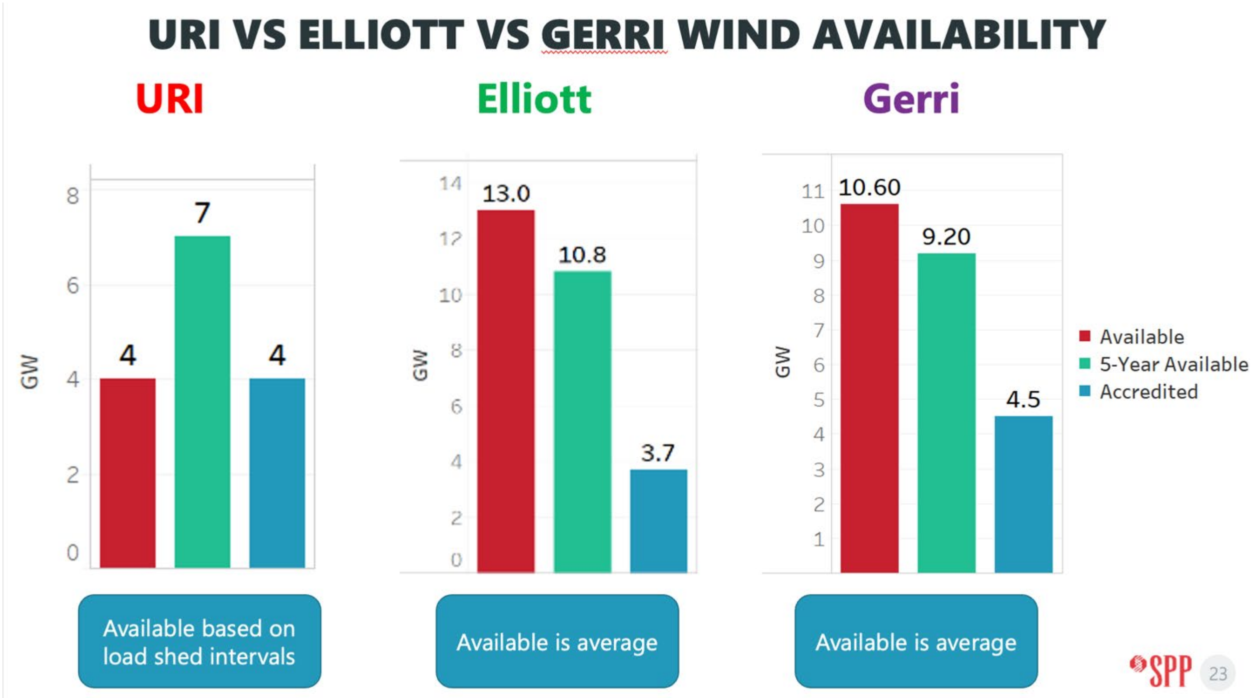
SPP opens its discussion of the correlated outages problem by suggesting otherwise: it frontloads its concerns about variable resources' (i.e., wind and solar) underperformance, and focuses on a period on June 6, 2023 when wind generation fell significantly below its accredited value.[115] PIOs do not object to the discussion, nor to the point that renewable generators cannot always perform as expected: it is widely understood that it is not always windy or sunny, and sometimes large weather patterns can cause correlated output reductions across a larger region. For that reason, PIOs do not oppose SPP's Proposed Renewable Methodology, which values the wind, solar, and storage fleets based on their specific contribution to improving system reliability. The low wind event on June 6 should be incorporated into an ELCC model for full evaluation of that event as it relates to actual load and grid conditions at that time, and as it relates to other risky periods in a multi-year model. But SPP has not offered evidence demonstrating that wind underperformance on June 6, 2023, had a material impact on overall grid stability (i.e., that it coincided with a period of elevated risk to the grid). Again, the crucial question from the perspective of a grid operator is not whether a generation resource performs across the board: it is whether that resource can be relied upon to perform when the system really needs it to.

If SPP had examined renewable performance during the three major winter storms it highlighted on the thermal side (Uri, Elliott, and Gerri), it would have found that the wind fleet generally overperforms when the RTO needs it. During those three storms, the wind fleet met or

[115] *Id*. at 8.

exceeded its accredited value, unlike the gas and coal fleets. Which is to say, as Figure 6 shows, the wind fleet's performance in the three winter storms has been exemplary.

Figure 6, Wind Generator Availability During Recent Winter Storms[116]



After performing at its accredited capacity value during the particularly challenging Winter Storm Uri, the wind fleet in SPP performed above its accredited value by 9.3 GW and 6.1 GW in Winter Storms Elliott and Gerri, respectively. It is for this reason that multiple LREs in the SPP footprint have specifically called out the wind fleet's high productivity (along with imports from neighboring regions) during those two storms as making up for the coal and gas fleets' underperformance and helping to keep the lights on.[117] While this graphic represents

[116] SPP Gerri Presentation, *supra* note 50, at 23.

[117] *See, e.g.*, Robert Zullo, "How Did Renewables Fare During Winter Storm Elliott," *Idaho Capital Sun* (Jan. 30, 2023), *available at* https://idahocapitalsun.com/2023/01/30/how-did-renewables-fare-during-winter-storm-elliott/; Jason Alatidd, "When Cold Coal Froze, Wind Farms Helped Evergy Power Kansas Through Winter Weather," *Topeka Capital-Journal* (Jan. 21, 2024), *available at* https://www.cjonline.com/story/news/state/2024/01/21/evergy-kept-electricity-flowing-kansas-wind-farms-coal-froze/72259414007/; Julie Anderson, "OPPD Customers Helped Conserve When Cold Temporarily Shuttered Coal Plants," *Omaha World-Herald* (Feb. 23, 2024), *available at*

wind's accredited values using SPP's Existing Renewable Methodology, PIOs do expect the accreditation value that would result from SPP's proposed ELCC analysis to be more in line with the existing methodology (the blue bars) than with the average 5-year Available value (the green bars).[118]

PIOs are not suggesting that the wind fleet should get a specific bonus to its accreditation based on its performance during those winter storms. There is no need: if SPP's ELCC analysis finds that major grid-stressing winter storms tend to bring high winds with them, then higher wind accreditation will be identified systematically via the models. But this is exactly the type of analysis SPP should be, and is not, proposing to do in the Proposed Thermal Methodology: the RTO should be required to accredit thermal resources based on their availability during risky hours considering multiple years of performance data.

3. Utilizing Inequitable Resource Accreditation Methodologies Undermines Effective System Planning and Imposes Unnecessary Costs on Ratepayers

Effective system planning requires a level playing field. To ensure the nondiscriminatory treatment of resources, resource accreditation methodologies must all be based on the same, or at least equivalent parameters.[119] Anything else will increase consumer costs, implicitly subsidize or penalize particular technologies, provide incorrect price signals for efficient market entry and exit, potentially threaten grid reliability, and ultimately fail to satisfy the requirements of Section 205 of the Act. And more broadly, if capacity accreditation does not ensure that planners and stakeholders reach a reliable system, then the proposed accreditation revisions serve no meaningful purpose.

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https://omaha.com/news/local/weather/oppd-customers-helped-conserve-when-cold-temporarily-shuttered-coal-plants/article_96143c6c-b48f-11ee-ae47-fbe103f57fb5.html.

[118] Exhibit A, Milligan Aff, *supra* note 3, at 15.

[119] *Id.* at 13.

The specific impact of SPP's Proposed Methodologies, which impose differential treatment of thermal and renewable resources, will be to bias resource decision making across the SPP footprint in favor of retaining coal generation and building gas generation beyond what would be appropriate given those resources' actual value to the grid. This is true because there is now ample evidence that the EFORd mechanism over-accredits thermal generation compared to their performance during high-risk hours,[120] and there is no corresponding evidence, nor reason to suspect, that ELCC is similarly inflating the accreditation of renewable generation. Given the significant costs of building and operating coal and gas generators, this overinvestment in coal and gas resources will impose unnecessary costs on ratepayers. [121] In addition, EFORd socializes any correlated outage risk among all generators in a class, thus eliminating an appropriate signal to underperforming generators to improve their availability during risk periods by investments in weatherization and firm fuel contracts, among other things.

4. Alternatives to the Proposed Thermal Methodology that Better Align with the Proposed Renewable Methodology Are Available to SPP

There are straightforward non-discriminatory solutions available to SPP to address its mis-accreditation of thermal generators. These solutions are discussed more at length in PIOs' separately filed Complaint; but they bear discussing here as well. The most obvious method, and the one most analogous to SPP's proposal for wind, solar, and storage resources, would be to conduct an ELCC analysis for thermal resources. A universal ELCC analysis using an LOLE model that factors in the possibility of correlated outages is far and away the cleanest way to

[120] *Id.* at 14-16; *see* discussion *supra* Sec. III(A)(1).
[121] Exhibit A, Milligan Aff., *supra* note 3, at 8.

move towards equitable treatment of all resource types; and with SPP already conducting this analysis for renewable units it would be a natural step to expand it to thermal fleets.[122]

If SPP does not move forward with an ELCC methodology for both resource types, then it must consider alternatives that can account for correlated outage risk and performance during high-risk periods. Other RTO/ISOs' recent accreditation plans also offer helpful examples of (mostly) successful accreditation methodologies. For example, without endorsing any one proposal, we note that CAISO accredits resources using a "Slice of Day" method; and MISO is currently proposing to shift to an accreditation method, "Direct-LOL," that offers a simpler calculation focused on resource performance during high-risk periods.[123]

Finally, even if SPP feels constrained to an accreditation methodology resembling EFORd for thermal resources, SPP should consider modifications to the methodology that would account for reduced thermal performance during high-risk hours and/or forced outages that occur simultaneously with other thermal resources. For instance, SPP staff could evaluate the possibility of limiting its EFOR analysis to historical thermal unit performance during high-risk periods rather than all demand hours, using the modified calculation (based on a limited hour set) that it has already developed for resources with less than 100 service hours in a season.[124]

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[122] PIOs note that an ELCC analysis that is based solely on EFORd assumptions for thermal resource availability also would not account for correlated outage risk within the thermal fleet. The fundamental need here is not to engage in any one specific analysis; it is to ensure that whatever analysis is selected accounts for generator performance during high-risk hours. SPP must ensure that correlated outage risk is modeled in the ELCC analysis using a robust approach such as the Cold Weather Outage Adder that it has included, but which SPP members have voted to mute the impact of. *See supra* note 101.

[123] Midcontinent Independent System Operator's Filing to Reform MISO's Resource Accreditation Requirements, Docket No. ER24-1638 (Mar. 28, 2024), Accession No. 20240328-5329.

[124] PIOs discuss this proposal at length in the separately filed Complaint. *See also* Exhibit A, Milligan Aff., *supra* note 3, at 21.

C. The Proposed Thermal Methodology Should Be Rejected Because Significant Issues Related to Its Implementation Are Currently Under Development in SPP Stakeholder Processes

Finally, as has been discussed above, SPP's Tariff Filing should be rejected because it is effectively a partial draft. SPP's Supply Adequacy Working Group and Resource and Energy Adequacy Leadership Team have both met continuously over the past couple of years to continue reforming SPP's accreditation methodologies. The Proposed Methodologies included in SPP's Tariff Filing are already out of date, because they do not include any of the following policy updates that are under active development in SPP stakeholder processes:

- Revisions to the list of OMC events that may be excluded from a thermal resource's accreditation;[125]
- Potential major modification to the LOLE model that underpins SPP's entire resource adequacy process that might underemphasize the importance of extreme weather disturbances including removal of any planned and maintenance outages and reduction of the Cold Weather Outage Adder to 50%;[126] and
- Allocation of additional winter correlated outages reflected in the LOLE model via the Cold Weather Outage Adder to individual gas and coal generators.[127]

The Commission cannot reasonably conclude that the Proposed Methodologies will result in just and reasonable rates until SPP has made these important policy decisions. For example, inclusion of a Cold Weather Outage Adder would fundamentally change resources' accreditation, and therefore the accuracy of SPP's accreditation using the Proposed Methodologies, depending on how effectively it is structured. Further, as detailed above,[128] SPP's revisions to the list of OMC events will determine whether winter storm performance continues to be *excluded entirely* from thermal resources' EFORd calculation.

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[125] SPP Fuel Assurance Discussion, *supra* note 99, at 2, 6.
[126] *Id.* at 4-5.
[127] Southwest Power Pool, PRM Recommendation, Supply Adequacy Working Group presentation (Mar. 12, 2024), *available at* https://www.spp.org/Documents/71255/SAWG%20Meeting%20Materials%20for%2020240312-13.zip (compendium of documents).
[128] *See supra*, Sec. III.A.3.

The Commission has previously rejected similarly incomplete and premature tariff filings where "significant issues related to the implementation and utilization of the . . . proposed . . . tariff revisions remain to be determined through the course of an upcoming stakeholder process."[129] That almost perfectly describes the current state of the SPP stakeholder process. The additional changes noted above will significantly impact resource accreditation values before the Proposed Methodologies are even scheduled to go into effect (during SPP's proposed transition period). It would be improper for the Commission to approve SPP's Proposed Methodologies when ongoing stakeholder conversations are likely to significantly change the methodologies before they even take effect.

IV. CONCLUSION

For the reasons stated above, PIOs request that the Commission reject the SPP's Tariff Filing. This rejection should be without prejudice toward bringing forward any future accurate and non-discriminatory capacity accreditation proposals.

Dated: March 29, 2024.

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[129] *CAISO* Order, 132 FERC ¶ 61,196, 62,027 (2010) ("Issues such as the operational or market protocols that will govern the hierarchy of generation reduction and the circumstances in which the power management capabilities will be utilized are of sufficient import to the affected stakeholders that it would not be just and reasonable to accept the CAISO's proposed tariff revisions at this time.")

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this filing has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated: March 29, 2024.

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EXHIBIT A

Affidavit of Michael Milligan, Ph.D.

(March 29, 2024)

SPP Capacity Accreditation Report

I. Introduction

Q: Please provide a conceptual overview of your testimony in this document.

A: I open my affidavit with a discussion of resource adequacy and capacity accreditation. I then discuss in turn Southwest Power Pool's ("SPP's") existing accreditation methodology for thermal resources; SPP's existing accreditation methodology for renewable resources; SPP's proposed replacement accreditation methodology for thermal resources; and SPP's proposed replacement accreditation methodology for renewable resources. Finally, I close with a discussion of modern accreditation best practices, and suggest a path forward for SPP. Each of these sections is delineated separately from individual questions and answers.

II. Resource Adequacy and Accreditation Overview

Q: Please provide a short description of resource adequacy and accreditation.

A: Resource adequacy is the process of determining whether there are sufficient resources that can supply electrical demand at some future date. Resource adequacy can be applied to near-future dates, such as upcoming summer or winter seasons, or to longer-range time periods, often up to 10 or more years. Resource accreditation is the process of determining how much an individual resource, or group of resources, contributes to resource adequacy. This contribution can be expressed as a numeric value, either in MW terms or as a percentage of the resource's installed capacity ("ICAP").

Q: Are there specific metrics that can measure the extent to which a system has adequate resources?

A: Yes. Methods that are based on probabilistic assessments and can evaluate some combination of the number and size of different resources, provide different measures of adequacy. Such measures include the statistically expected number of loss of load[1] events in a given time period, which may also include the energy shortfall of these events. These calculations are based upon the expected availability of resources during high-demand periods, or other high-risk periods.

Q: Would you please provide an example of this type of resource adequacy assessment?

A: There are two widely recognized metrics that can be used, although more exist. The first of these is loss of load expectation ("LOLE"). This is often expressed in terms of the statistically expected supply shortfall, in terms of the number of events per year (or other time period). A common resource adequacy target is a LOLE of 1 day per 10 years, often interpreted as 0.1

[1] "Loss of load" indicates disconnecting load. In today's interconnected system, it is possible that emergency reserves can be acquired so as to avoid disconnection.

days/year. Another metric is expected unserved energy, expressed in GWh/year, or similar metric.

A grid system that has a 1d/10y LOLE is more reliable than a system with 5d/10y LOLE. In a regime that requires a 1d/10y resource adequacy target, we could objectively say that the second system with its 5d/10y LOLE has insufficient adequacy or does not meet its resource adequacy objective.

Q: Are all approaches to ensuring resource adequacy able to provide a similar objective measure of RA?

A: No. As I discuss in the next question/section, resource adequacy assessments of the past were sometimes based upon determining whether the summation of all installed capacity exceeded the estimated peak demand by some percentage (often in the range of 11-15%). Methods such as this do not provide any direct assessment of whether a system has resource adequacy or not, because they do not account for trends in generator performance, particularly correlated outages that can cause significant strain to the grid either during or separate from peak demand periods.

Current methods of assessing resource adequacy are generally based upon probabilistic analysis. These methods quantify either the number of times during a year that resources are *not* adequate, or a variation. SPP uses a LOLE analysis to establish its planning reserve margin, as do many other Balancing Authority Areas. LOLE methods provide measures of some combination of (1) number of hours/year that resources are not adequate, or *may not* be adequate to serve demand, (2) measure of energy that *may* not be served as a result of insufficient resources, or (3) number of events or other measure of system shortfall. These are all measures that can be used to tell us how much, or how often, the system may underperform, and are the basis of any good resource adequacy analysis.

Historical methods of comparing the estimated peak demand to installed capacity provide no such measure. At best, they could be considered as “rules of thumb” that might indicate that the system is adequate, but do not provide any assurance of this adequacy.

Q: Have resource adequacy and accreditation evolved in recent years? If so, please provide an overview.

A: Resource accreditation in the past was often based upon resources’ ICAP. To determine resource adequacy, the total of all ICAP would then be compared to the peak demand forecast for a future date or dates. Some reserve margin would also be added to the peak forecast, usually including a term for load forecast error, and another term for unplanned resource outages, or forced outages. This extra “margin” above the peak demand forecast is often called the planning reserve margin (“PRM”).

Academic research in the 1950s began to establish more rigorous approaches to resource adequacy that included considerations of unplanned forced outages of resources. Forced outages result from mechanical or electrical failures or lack of fuel availability, and generally occur with little or no warning. This distinguishes them from maintenance outages, which are preventative measures designed to increase the availability and longevity of the resource and are usually planned with advance warning of the outage. The rate at which forced outages occur is the forced outage rate ("FOR"), typically represented as a percentage of nameplate capacity.[2] However, these new methods remained largely in the research domain for many years.

Different resources may have different FORs. This implies that we can't count on the full capacity of all resources as being available when needed, and plants with higher FORs cannot be counted on as much as plants with lower FORs, all else equal. For example, two 100 MW units with FORs of 10% and 20%, respectively, could not be equally depended on. One companion metric to FOR is unforced capacity ("UCAP"), calculated as (1 – FOR) x ICAP, where ICAP = installed capacity. The UCAP of our two example resources is 90% and 80%, respectively; this illustrates the typical relationship between UCAP and ICAP, which is that ICAP is generally 100% of net generating capability, whereas UCAP represents a "deduction" in delivered capacity that is caused by forced outages. Furthermore, although UCAP itself accounts for FORs and can provide an assessment of how the resource might perform over a year's time, it doesn't directly measure the reliability contribution of a plant during the year, especially during extreme weather when the risk of correlated outages in a resource class is often elevated.

The academic and research communities moved early on from comparisons of ICAP with peak demand forecasts, to efforts to quantify the number of times that one could expect demand to exceed supply. These "new" methods, generally based upon LOLE or loss-of-load probability ("LOLP") modeling,[3] could quantify the probable times and quantities of shortfalls, and the resulting load that could not be served. Resources with higher forced outage rates were considered less reliable than similar units with lower forced outage rates.

This effort eventually led to the development of a new metric, effective load carrying capability ("ELCC"), which was designed to describe a resource's contribution to reliability. ELCC measures the additional demand that can be "carried" by a generator at the same reliability level as a lower quantity of demand without that generator. By the mid-1960s, the notion of ELCC had been widely accepted in research circles, and research efforts focused on developing techniques to approximate ELCC without extensive computer run times.[4]

However, ELCC remained largely unknown outside research circles until the 1990s, when I and others began applying ELCC metrics to wind energy, and later to solar energy. This probabilistic

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[2] There are several additional metrics that are related to FOR, such as mean-time-to-failure, mean-time-to-repair, and others. There are also variations of the FOR metric itself, including EFORd which is commonly used in loss-of-load modeling because it differentiates the FOR during times when there is demand on the resource to generate. However, these are not critical for the discussion herein.

[3] LOLP measures the probability of loss of load, while LOLE measures the expected number of such events. For example, the probability of tossing a fair coin and getting a "head" is 0.50, whereas the probabilistically expected number of "heads" after 10 coin tosses is 5 (= 10 x 0.50).

[4] Len Garver, *Effective Load Carrying Capability of Generating Units*, Pas-85 Inst. Elec. & Elecs. Eng'rs ("IEEE") Transactions on Power Apparatus & Sys. 910 (1966) ("Garver").

framework offered distinct advantages over ICAP accreditation methodologies: (1) the "adequacy" of the system could be evaluated in terms of how many failures per time period could be expected; (2) otherwise identical resources with different FORs would naturally have different accreditation values, in accordance with their FORs; and (3) renewable resources, such as wind and solar generators, could be incorporated into probabilistic methods, and were found to have ELCC values that generally were a significantly lower percentage of their ICAP.[5]

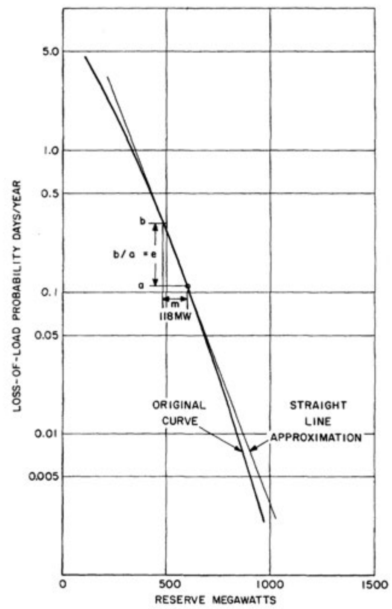

Fig. 3. Approximation of annual risk function by linear exponential function.

Figure 1. Example of ELCC approximation by Len Garver, 1966[6]

In the past few decades, there has been significant research and adoption of LOL-based modeling methods such as ELCC[7] into resource planning and resource adequacy analysis. The North American Electric Reliability Corporation ("NERC"), the non-profit entity in the United States that sets and enforces reliability standards, published a technical guideline document for

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[5] The advantage of incorporating renewable resources into an LOL modeling framework is significant because the timing of the wind or solar energy delivery can be explicitly accounted for. This is particularly important during extreme weather, but also provides a more realistic expectation of when, and how much, solar and wind energy contribute to both balancing and towards resource adequacy.

[6] Garver, *supra* note 4.

[7] There are several variations of ELCC that are based upon alternative reliability metrics. The most common of these is expected unserved energy.

practitioners of probabilistic assessments.[8] Recently, Energy Systems Integration Group ("ESIG"), a non-profit focusing on how to effectively move to a predominately renewable energy-based future, produced a report that focused on resource adequacy for modern power systems.[9] This report and emerging theory and practice stresses the use of a consistent framework for resource adequacy and accreditation, along with consistency in the way that different resources are treated.[10]

Today, the industry is in a transition, and different entities are going through different phases of evolving into more sophisticated and more accurate approaches to both resource adequacy and accreditation. There is widespread agreement in the research community that many factors can and should contribute to both resource adequacy and accreditation, including (but not limited to) forced outage rates, timing of capacity and energy deliveries, explicit risk accounting, transmission connections with neighboring systems, and severe weather. All of these factors, if accounted for in the modeling framework, can help system planners better assess the true value of individual generators to the reliability of the grid writ large, which in turn can enable more accurate resource accreditation values.

III. Existing Thermal Accreditation

Q: How does SPP currently accredit thermal resources?

A: SPP uses a variation of ICAP to accredit thermal resources ("Thermal Methodology").[11] Accreditation is based on a Capability Test, performed every 5 years on the unit. The Capability Test is carried out during the Summer Season, at a specified ambient temperature, for a period of at least 1 hour, once the resource has reached a stable operating level. If the unit has a higher Winter Season claimed capability, then the resource must conduct a separate Winter Season Capability Test, for which there is no ambient temperature requirement.

SPP also requires that a thermal unit conduct an annual Operational Test. The test must be conducted at a minimum of 90% of the unit's net generating capability as determined in the Capability Test. There are no ambient temperature requirements for an Operational Test and any hour where the unit operates above the 90% minimum can qualify as the Operational Test. If a

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[8] NERC, Probabilistic Assessment: Technical Guideline Document (Aug. 2016), https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf.

[9] Derek Stenclik et al., Report: Redefining Resource Adequacy for Modern Power Systems, ESIG (2021) ("ESIG Resource Adequacy Report"), https://www.esig.energy/resource-adequacy-for-modern-power-systems/.

[10] *See generally id.*

[11] The thermal accreditation approach is explained in SPP, SPP Planning Criteria Revision 4.2 § 7.1 (June 7, 2023), https://www.spp.org/Documents/69467/SPP%20Planning%20Criteria%20v4.2.pdf. I am aware that SPP recently revised its planning criteria as part of proposed tariff revisions to its accreditation methodologies, *see* SPP, SPP Planning Criteria Revision 4.3 § 7.1 (Nov. 6, 2023), which are currently pending before the Commission. My evaluation and discussion of SPP's *existing* methodologies is therefore based on Revision 4.2 and earlier versions.

thermal unit is capable of supplying its accredited capacity for at least 4 continuous hours in an Operational Test, then the unit receives accreditation at the capacity level attained through the Capability Test.

Q: Does the ICAP methodology account for forced outages?

A: No. The accreditation of each generating unit within a resource is based upon sustained output during the 4-hour test period. Conceptually, two otherwise identical units, but with different FORs, could perform equally during the 4-hour test, but would contribute different, perhaps substantially different, levels towards resource adequacy using a method that accounts for forced outages.

Additionally, prior to commencing the 4-hour test, the unit is brought online and allowed to stabilize at full output, avoiding potential problems associated with start-ups and ramping. This amounts to a "steady-state" test of capability under near-ideal conditions. The results of this test will have little bearing on the actual reliability value of the resource. FORs are calculated based on best-available information for each specific resource over a long period of time, and are therefore extremely unlikely to be experienced during a four-hour test.

Equivalent Forced Outage Rate Demand ("EFORd") is a closely related measure to forced outage rate. It differs from a FOR in that the EFORd is an "equivalent" forced outage rate during demand periods or hours that the resource is called upon to serve demand. It is generally the forced outage rate of choice in LOLE/ELCC modeling because resource performance during these demand periods contributes more to reliability than during periods the resource was not called upon, all else equal.

Figure 2[12] shows the forced outage rates, measured as EFORd, collected by NERC for 2022. The graph breaks out the EFORd by unit sizes and types, showing coal and gas plants. These are SPP's primary thermal resource types.

The chart clearly shows a wide variation in EFORds, varying from 7.07% to 22.46%. This chart shows the large difference in the plants' expected performance, with large coal outages at more than triple the rate of small gas units.

[12] NERC, Generating Unit Statistical Brochure 1 (2022), https://www.nerc.com/pa/RAPA/gads/Reports/Generating%20Unit%20Statistical%20Brochure%201%20-%202022%20-%20Units%20Reporting%20Events.xlsx.

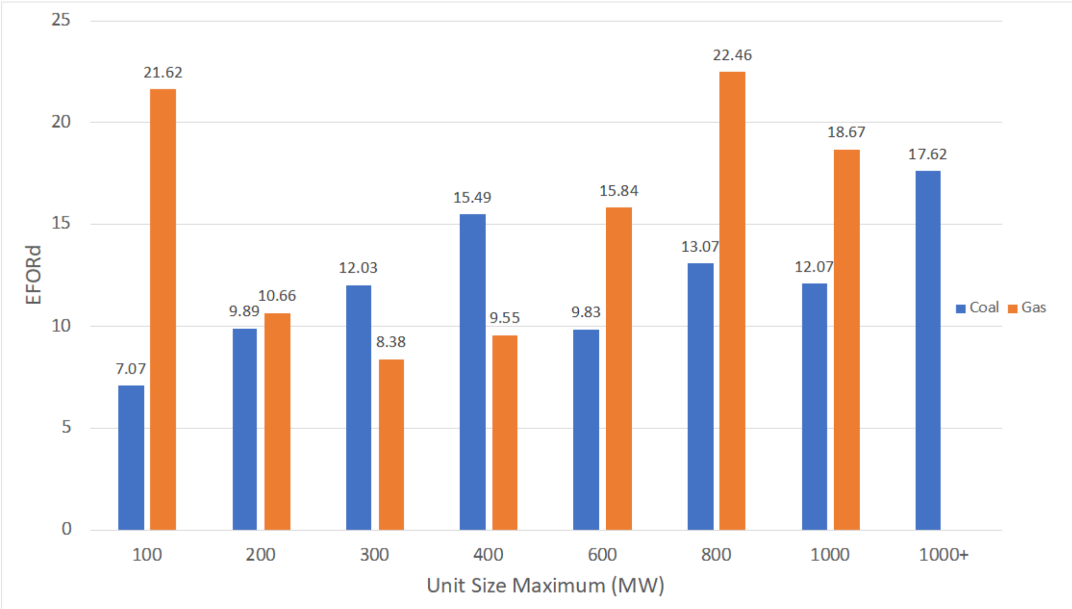

Figure 2. EFORd by unit size and type, coal and gas, 2022

Q. Does the ICAP methodology account for the possibility of correlated outages?

A. No. As an initial matter, there is no indication that the thermal accreditation test is done during peak periods, or other times when capacity is needed. Peak conditions in SPP generally occur during the summer months. When resources have run for many days or hours, as can happen during summer heat periods, they may be more likely to suffer a forced outage. More broadly though, because SPP's Thermal Methodology ignores "routine" forced outages, it also ignores forced outages that are correlated. This includes temperature-induced forced outages and other outages attributable to extreme weather.[13] And this failure is problematic because recent research has shown that for most thermal plants, there is a significant temperature-induced increase in forced outage rates that is not generally accounted for in reliability calculations.[14] Failure to include these changes in FORs leads to the overvaluation of resources that are not as reliable as they appear to be. And in addition to these temperature-induced increases in FORs during extreme hot or cold weather, there can be correlated outages that arise because of the lack of fuel, or malfunctions of equipment during extreme temperatures that can affect multiple resources, further diminishing those resources' actual value to the grid.

[13] Average FORs are typically computed over an entire year, or a subset of the year that corresponds to high demand. EFORd is an example of the latter. However, extreme temperatures have been shown to have an impact on FORs during unusually high or low temperatures. This has an impact on risk during extreme weather, increasing LOL risk, perhaps significantly. Examples of this impact can be seen in recent storms such as winter storms Uri, Elliot, and Gerri, among others.

[14] *See generally* Sinnott Murphy et al., *Resource adequacy implications of temperature-dependent electric generator availability*, Applied Energy (2020), https://www.sciencedirect.com/science/article/pii/S0306261919321117.

Q: What impact might an ICAP accreditation methodology have on SPP's system reliability and costs?

A: SPP's ICAP accreditation ignores the occurrence and correlation of thermal unit outages. If the RTO's LOLE model doesn't account for these failures, the reliability estimate from the model could be overstated, resulting in a less reliable system. The system will experience more numerous and severe outages. Service outages, such as those that SPP experienced in recent severe storms, can be costly, or in the extreme, compromise health and life.

Additionally, faulty accreditation doesn't provide incentives for plants to improve reliability. ICAP-based accreditation will result in the over-procurement of less-reliable thermal resources because the valuation of such resources will be unaffected by their overall reliability: two otherwise identical units with different FORs will receive the same accreditation value despite providing different contributions during contingency or extreme weather events. As a result, unreliable thermal resources will have no incentive to become more reliable; and the overall reliability of thermal units will go down as a result of this distortion. This creates a "free rider" scenario, where the less reliable resource is accredited the same as a more reliable resource, and has no incentive to improve. And in the medium term, this lost incentive for units to become more reliable will hurt overall system reliability.

Because ICAP does not capture the impact of forced outage rates, and because forced outage rates are a key element of determining reliability, any market signal provided by ICAP may incentivize adding new capacity; however, new capacity does not necessarily support long-term reliability because forced outages are not part of the accreditation method. If resources do not deliver significant reliability benefits, then consumers and ratepayers will likely need to pay for more capacity than would otherwise be needed.

It is difficult to quantify the precise costs to ratepayers without a comprehensive analysis of both the buildout that would occur to meet Load Responsible Entities' ("LREs'") future resource adequacy obligations under SPP's ICAP accreditation versus the buildout that would occur under an accreditation approach that appropriately accounts for forced and correlated outages. But given that the existing thermal accreditation method doesn't account for outages during times of risk, application of SPP's LOLE study would likely prompt the construction of more thermal capacity than a more rigorous accreditation method would prompt. In my experience, the cost of a "generic" combustion turbine, a proxy for a capacity resource, has generally been in the range of $500-$800/kW. Using a relatively low value of $500/kW, a 100 MW combustion turbine would cost approximately $50 million.[15] Prices tend to fluctuate, but it is safe to estimate that for each 100 MW of unnecessary capacity built, costs will increase in the tens of million dollars. In other words, even if SPP's ICAP accreditation prompts construction of only a single unnecessary gas plant, it could impose millions of dollars in unnecessary costs on ratepayers.

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[15] My estimate should be considered at the low end of the range. *See* U.S. Energy Info. Admin., Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, at III (Feb. 2020), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

Q: Has SPP experienced actual risks to its system reliability due to forced outages?

A: Yes. The most recent impact on SPP's operations came during winter storm Gerri in 2024, although winter storm Elliott in December 2022 and winter storm Uri in 2021 also had significant reduced reliability due to forced outages. The following statements are taken from relevant SPP reports:

> (Uri, 2021): SPP observed up to approximately 33 GW of forced outages during the week of the event, with an average of 30.5 GW of forced outages Feb. 16. Natural gas generation experienced an average of nearly 18 GW of forced outages during Feb. 16, and of those outages, nearly 75% cited lack of fuel supply as the cause.[16]
>
> (Elliott, 2022): The average unavailable accredited capacity was 14,300 MW (around 35–40% was coal, and 45–60% was gas). This is two times the average summer level of 7,500 MW unavailable accredited capacity. Unavailability due to fuel supply issues was between 1,600 MW and 4,000 MW during Elliott. SPP experienced losses of multiple key generation units on Dec. 22 and Dec. 23.[17]

SPP's report on winter storm Gerri in 2024 is not available; however, there is information from SPP that indicates a reduction in availability of about 12.5 GW that was caused by extreme weather.[18]

SPP data shows the impact of these severe storms on generator availability. Figure 3 is taken from the 2024 SPP Staff Presentation, and shows a significant reduction in generation availability that was caused by the extreme weather. In all cases there is a significant weather-correlated increase in outages, none of which are accounted for in SPP's thermal accreditation approach.

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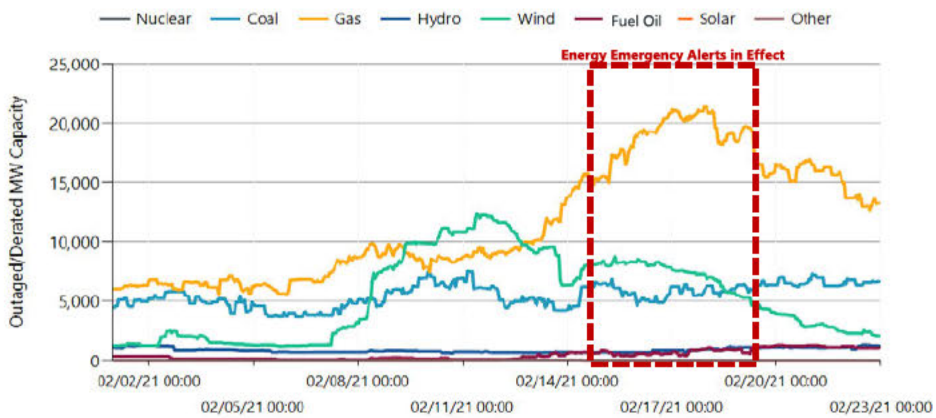
[16] SPP, A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations, Version 1.0, at 47 (July 19, 2021), https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf.

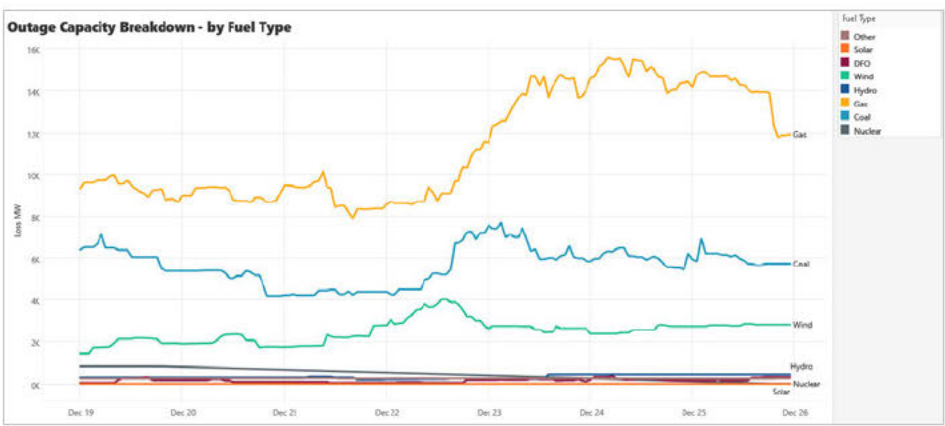
[17] SPP, Southwest Power Pool's Response to the December 2022 Winter Storm: A Comprehensive Review, Analysis and Recommendations, at 15 (Apr. 17, 2023), https://www.spp.org/documents/69218/review%20of%20spp%27s%20response%20to%20the%20dec.%202022%20winter%20storm.pdf.

[18] Garrett Crowson, January 2024 Winter Storm Gerri, SPP, at 15 (2024).

GENERATING CAPACITY OUTAGES URI



GENERATING CAPACITY OUTAGES ELLIOTT



GENERATING CAPACITY OUTAGES GERRI

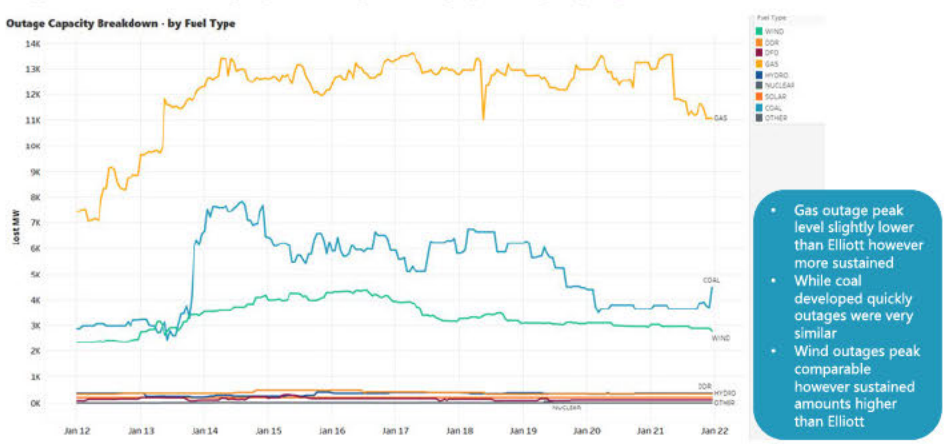


Figure 3. Extreme weather increased forced outages during the recent storms in SPP

Q: What is your overall assessment of SPP's existing thermal accreditation method?

A: In my judgement, SPP's existing thermal accreditation process is deeply flawed, and should be reformed for the reasons explained above. The ICAP accreditation has little relationship to resource performance at all, let alone during times of need. Resources can obtain a high accreditation if absent or otherwise unavailable, including during critical times, resulting in a total disconnect between accreditation and the objective of providing a reliable grid.

IV. Existing Renewable Accreditation and Comparison to Thermal

Q: How does SPP currently accredit renewable resources?

A: SPP uses a percentage exceedance approach to evaluate renewables' accreditation. The procedure begins by selecting, for the LRE in which the renewable is located, the top 3% of load hours for each month of the year. The 60^{th} percentile of net power for these time periods is selected from the coincident hourly output of the resource. This means that the monthly accreditation is the power level that was achieved at least 60% of the time during the 3% of hours in each month with the highest load.

Annual capability is based upon the above calculation during the LRE's peak month, and the seasonal capability is based upon applying this approach to the peak month within the season in question.

To this basic approach, there are additional rules that apply to new facilities, or facilities with three or fewer years of actual operation.

Q: How does this accreditation method differ from the thermal accreditation?

A: Unlike SPP's thermal accreditation, which as I discus above is based on resources' ICAP value, the RTO's accreditation of renewable resources is based upon the resources' availability during peak load periods. Although this likely does not accurately capture renewable generators' actual contributions to grid reliability, as I discuss further below, it nonetheless creates at least a rudimentary comparison between resource performance and elevated risk periods.

Q: Do you see any flaws in the renewable accreditation methodology?

A: The current renewable accreditation comes closer to providing an assessment of risk because it includes a component of performance of the resource. However, percentile exceedance methods have been shown to ignore some deliverable (or delivered) capacity, and therefore are faulty methods for calculating performance during risk periods. The use of peak periods, in the past, may have been a relatively good indicator or proxy of risk. However, with the significant and growing level of renewable energy in SPP, it is clear that risk periods are shifting as more wind and solar are added to the system. SPP itself recognizes the importance of better risk-based planning:

> SPP should include in its planning process more risk-based planning that incorporate[s] the impact of extreme weather events and climate change. The increasing frequency and

> volatility of weather patterns will drive increasing unavailability of resources and transmission paths, as well as volatility in weather-affected data sets such as demand and renewable forecasts.[19]

I agree completely with SPP on this point. However, I take strong issue with both the existing accreditation of thermal resources and the accreditation of renewable resources. Although the latter is perhaps less objectionable, they both fall short.

SPP's approach to accrediting renewable resources is flawed also because it uses a percentile exceedance approach in the calculation. This has been shown to undervalue a resource's contribution to resource adequacy because some of its availability, even during times of risk, is discarded in the calculation.[20] Even MW generation values that are dropped by the exceedance calculation have some value and contribute to long-term reliability and resource adequacy.

Q: Are there any specific attributes of wind and solar resources as compared to conventional generation that justify failing to account for outages for conventional resources, but accounting for them for renewable resources?

A: No. A truly technology-neutral market would be based upon *how a resource performs*, which would include the power, energy, and timing of delivery to the grid (and other services, as appropriate). Performance of different resources can therefore be directly assessed, regardless of the underlying technology. This is good market design because it:

- Does not "care" how the technology works.
- Allows for and incentivizes improvement of any technology, including improved ongoing maintenance, weatherization, and installation of new devices behind the interconnection to improve performance or timing of delivery, assuming proper incentives exist.
- Does not require a market redesign for new technology entrants because they are assessed *purely* on performance.
- Allows new technology to demonstrate its capabilities.
- Does not require a market re-design when one or more types of incumbent generation retire, undergo retrofits, or other upgrades or downgrades.
- Is non-discriminatory.

Performance-based accreditation doesn't care "what you are," only "what you can do." A resource that offers significant contribution to risk periods will perform better than a resource that does not, and this performance can be translated directly into accreditation.

A renewable resource can mitigate the risk of load shedding during the times that it is available; as such, it is an as-delivered resource. Although it may be more complicated to efficiently

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[19] SPP, Grid of the Future, at 9 (Apr. 11, 2023), https://www.spp.org/documents/69220/spp%20future%20grid%20report.pdf.

[20] This is clearly shown in Michael Milligan & Kevin Porter, Determining the Capacity Value of Wind: A Survey of Methods and Implementation; Preprint, NREL (May 2005), http://www.nrel.gov/docs/fy05osti/38062.pdf.

operate a power system with high levels of renewables,[21] one MW of renewable capacity that is delivered during a risk period is fundamentally the same as one MW of conventional capacity that is delivered during the same time period. Even though thermal and renewable generation have different characteristics, on a MW-to-MW basis they each have the same ability to mitigate risk during tight margin periods or other operationally risky periods.

Q: Why is it important to have consistency in the accreditation of different resource types?

A: If SPP wants to incentivize resources to perform during tight margins or other periods of operational risk, incentives for *all* resource types must be aligned. All oars must pull in the same direction. On a MW-to-MW basis, all MWs delivered to the SPP system during times of risk are equal. As such, each MW of capacity during risk periods, from all resource types, should be accredited identically.

As an example: if Resource A delivers one MW during a time of no significant risk, then it should receive a lesser (or zero) accreditation for that MW. In contrast, if Resource B delivers one MW during a time of high risk, it should receive a relatively high accreditation for that MW. This is an example of the *vertical consistency* principle that appears in the ESIG report, to be described later herein.

Without a consistent framework, it is impossible to assess the system performance during potential future periods of high demand or high risk. This is because some measures of individual resource performance, such as ICAP, contain no information about the likelihood that resource can perform when needed.

The current renewable accreditation method, based upon an exceedance level during peak periods, also does not capture the important point that periods of risk are no longer accurately approximated by the level of demand. Only rigorous probabilistic approaches, based upon loss of load expectation, can distinguish risk periods from peak demand periods.

V. Proposed Thermal Accreditation

Q: How is SPP proposing to accredit thermal resources?

A: SPP's proposal at the Federal Energy Regulatory Commission is to use EFORd in the calculation of thermal accreditation. The proposed accreditation metric is a form of UCAP, or unforced capacity. In this case, SPP is proposing the use of EFORd "during times resources are needed in the relevant season.[22] The formula is:

Accredited Capacity = demonstrated net generating capability x (1 – EFORd)

[21] For the most part, the non-renewable resources were planned, and built under the tacit assumption that there would be an insignificant level of renewable generation.
[22] Submission of Tariff Revisions to Implement Effective Load Carrying Capability Methodology and Performance Based Accreditation, at 3, Docket No. ER24-1317 (Feb. 23, 2024), Accession No. 20240223-5157.

With this formula, SPP establishes the accredited thermal capacity that accounts for forced outages during the times the unit is called upon (committed/dispatched) to deliver capacity.

SPP correctly describes the EFORd metric, but the RTO does not describe the period over which EFORd is typically calculated. The metric depends on the resource's performance during the times that it is asked to respond to a commitment and/or dispatch instruction. This can vary substantially from unit to unit, depending on the type of unit and how often, and when, it is needed. Times when a generator is called upon to serve demand are not all, or even predominantly, high-risk periods with regard to resource adequacy.

Thermal resources such as coal and some gas units can be called upon throughout the year, and those run as "base load" units may run for many or most days of the year. In such cases, the EFORd will be calculated based on a relatively large number of hours that span much or most of the year. In the case of peaking resources, EFORd may be calculated based on a relatively small number of hours, many of which are during peak periods.

Q: What is your assessment of SPP's proposed EFORd methodology?

A: SPP's proposed method improves upon its current method, but still falls short. SPP's own words and graphic can be used to show why this is the case:

> Underperformance by a resource class is not limited to wind resources. Figure 3 [from SPP's filing] below depicts an example of how conventional resources similarly underperformed during 2021's Winter Storm Uri on February 16, 2021, as compared to the accreditation those resources received under SPP's existing accreditation method. Figure 3 shows that on February 16, 2021, coal and gas resources (among others) performed below their overall accredited capacity. Only 17 gigawatts ("GW") of coal resources were available as compared to their 22 GW of accredited capacity and only 13 GW of gas resources were available in SPP compared to their 30 GW of accredited capacity.

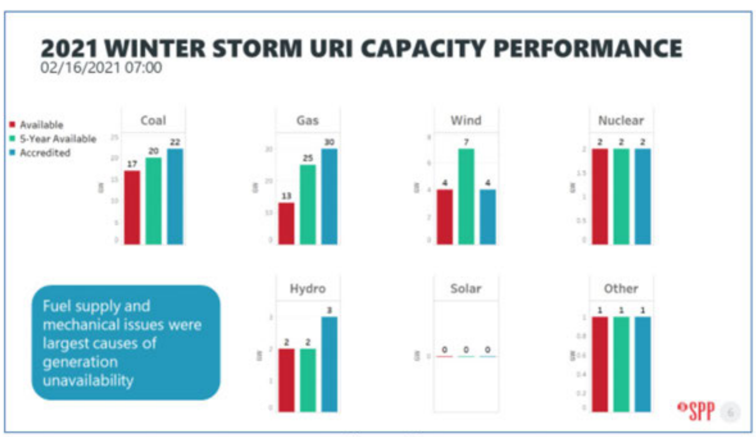

Figure 3

> These factors mandate that SPP adopt a methodology for accrediting capacity that better anticipates the availability of resources based on how they have historically

performed during similar periods.[23]

In this section of SPP's proposal, SPP calls for an accreditation method that "*better anticipates the availability of resources based on how they have historically performed during similar periods.*" Focusing on the coal and gas resources, the graph shows accredited values in blue. Because SPP's current accreditation is still in effect, this would correspond to the summation of all thermal ICAP values. The green bars show the 5-year available capacity for these resources. For both gas and coal, this is somewhat lower than ICAP, which is to be expected, because average performance would likely approximate resources' UCAP values that incorporate some level of forced outages. The red bars show the *actual* performance during storm Uri. Both coal and gas *actual* performance is less than the UCAP proxy, and gas is significantly lower than the UCAP proxy.

This disconnect between accreditation and resource availability during times of system stress is problematic on its own because incentives do not line up with SPP's objectives. To illustrate, consider a simple example of a thermal resource that has a hypothetical EFORd of 10% during "normal" times (i.e. no severe weather) but cannot operate thru a severe storm. To keep this example simple, assume that the severe weather-induced outage is exactly one week, and it is a non-leap year. In this base case, EFORd values are 0.10, 1.00, and 0.117 for the normal weather, severe weather, and annual composite. The deliverable capacity of the resource is 100 MW.

Using SPP's proposed thermal accreditation method, this resource would have a capacity accreditation of 88.27 MW.

Continuing with this example, suppose that the resource undergoes maintenance or upgrades that reduce its non-severe weather EFORd, but is still unable to produce power during the extreme storm. Its annual EFORd falls from 0.117 to 0.068, and its accreditation increases from 88.27 MW to 93.18 MW. However, this resource's performance during the time that it is needed the most, during the severe weather, does not improve whatsoever. The various parameters appear in the table below. I note that in practice, EFORd does not cover all hours in the year except in unusual cases.

Example of Unearned Capacity Accreditation

Base Case	**Partial Year EFORd**	**Hours**	**Annual EFORd**	**Accreditation (MW)**
Extreme Weather	1.00	168		
Balance of Year	0.10	8592	0.117	88.27
Improved EFORd in non-severe weather				
Extreme Weather	1.00	168		
Balance of Year	0.05	8592	0.068	93.18

[23] *Id.* at 9–10. I note that in SPP's graph on page 10, wind capacity delivers at its accredited level during winter storm Uri, whereas coal, gas, and hydro under-delivered.

This example shows that not all oars are aligned – that the incentives associated with the proposed accreditation method do not line up with SPP's objective of weathering the storm. By their very nature, severe storms do not occur "regularly." Even if this example unit experienced a 1-week weather-induced outage every year, the preponderance of its accredited value is earned during times of relatively low levels of system stress. Such a resource will likely have a small incentive to improve its operational profile during extreme events with this accreditation method. It receives, but does not earn, additional capacity accreditation.[24]

The example shows a perverse incentive that is conveyed by the use of EFORd; resources may have an incentive to improve performance during non-extreme periods to increase accreditation, and yet make no improvements to the most critical time periods. I conclude that SPP's proposed accreditation for thermal resources, particularly gas and coal, is inherently flawed.

VI. Proposed Renewable Accreditation and Comparison to Thermal

Q: How is SPP proposing to accredit renewable resources, and what is your assessment of that proposal?

A: SPP proposes the probabilistic metric ELCC for renewable resources. As I discussed previously, ELCC was originally proposed as a reliability metric for thermal resources, and was established in the research community by 1966 when L. Garver's approximation method was published.[25] I mention this again because SPP appears to believe that ELCC is somehow appropriate for renewable resources, but not for thermal resources. Nothing could be further from the truth.

The ELCC metric is calculated the same way for any resource. The difference between resource types is often represented by alternative input data. Renewable resources' ELCC is best calculated using one or more years of actual production data, properly synchronized with demand data.[26]

In my experience during the past 32 years, most systems have at most a few hundred hours throughout the year with any non-zero LOLE once the base system has been adjusted to 1 day/10 years LOLE. This means that most hours of the year – over 8,000 hours (out of 8,760 total per year) have no measurable risk as measured by loss of load expectation in all cases I've examined. For example, SPP estimates that 69 winter and 189 summer hours contribute to LOLE; thus, there are about 8,500 hours with no measurable LOLE risk.[27] For a resource to

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[24] The example above over-simplifies EFORd; in practice, EFORd would be calculated over a smaller number of hours. But, although changing the number of hours over which EFORd is calculated changes the numerical results, it does not impact the fundamental conclusion I have explained above.
[25] *See* Garver, *supra* note 4.
[26] Michael Milligan et al., *Assessment of Simulated Wind Data Requirements for Wind Integration Studies*, 3 IEEE Transactions on Sustainability 620, 620–26 (2012), http://dx.doi.org/10.1109/TSTE.2011.2160880.
[27] SPP, PRM Recommendation, at 46 (Mar. 2024) (slideshow prepared by SPP's Supply Adequacy Working Group for their March 13-14 meeting).

"earn" ELCC, it must reduce risk in some or all of those hours. ELCC is then "earned" *only* in the hours in which there was originally risk, 258 hours in SPP's case, which is then reduced or eliminated by addition of a resource.

Renewable generation has a more variable pattern than conventional resources, and especially in the case of wind energy, is not very highly correlated with demand. That is why the ELCC of wind energy can range from as low as about 5% to 50-60% of rated capacity. Solar energy is more highly correlated with demand, because demand is generally higher during the day, and so generally has higher ELCC values. However, wind and solar energy "earn" their ELCC by reducing risk in some, or all, of the 258 hours that have LOLE risk. The performance of renewable resources—in fact all resources—in times of no risk is not relevant to the calculation of ELCC.

ELCC analysis, if done properly, can produce a reasonable accreditation level for renewable resources. During times of risk, as measured by LOLE calculations each hour, accreditation is earned for each MW that is delivered during these risk periods. ELCC can distinguish between multiple resource types, and between multiple resources' contribution to overall resource adequacy.

When actual hourly renewable generation profiles are inputted into an ELCC model, the calculations accurately capture the correlated nature of resource performance based on the wind and solar "fuel," which arises as a function of weather systems that can drive correlated outputs over potentially large geographic and electrical regions. Correlated events, or "common mode failures" that are caused by underlying factors that influence generator output, are critically important to evaluate because these events are common drivers of the grid failures that have occurred during extreme weather.

Accreditation that is based upon ELCC does not result in unearned capacity accreditation. To see this, we again use a simple example. In this case, we use a 100 MW wind plant. To keep the example as close as possible to the thermal example above, we assume that there are 168 hours in the year that have LOLE risk.

The table below shows the results of the example calculations. If the renewable resource improves its availability during *non*-LOLE hours, its accreditation does not change. Conversely, if availability is improved during LOLE hours, the accreditation does increase, fulfilling SPP's stated objective. Such an improvement could come from wind turbine upgrades, installing behind-the-meter storage, or other improvements. The incentive here is properly aligned with the objective of increasing resource availability during times of need, as calculated by a LOLE model.

Example of Renewable Capacity Accreditation with ELCC

Base case	Avg MW	Hours	Accreditation
LOLE Hours	40	168	40
Non-LOLE Hours	30	8592	
Improved Availability During Non-LOLE Hours			
LOLE Hours	40	168	40
Non-LOLE Hours	50	8592	
Improved Availability During LOLE Hours			
LOLE Hours	80	168	80
Non-LOLE Hours	30	8592	

As a conceptual test, we can also compare the properties of ELCC with SPP's stated objective, as stated in its transmittal letter to FERC:

> [To] adopt a methodology for accrediting capacity that better anticipates the availability of resources based on how they have historically performed during similar periods.

Because ELCC will capture the performance of renewable resources during severe storms such as Uri, it does fulfill SPP's stated objective.

Q: How does SPP's proposed renewable accreditation method differ from SPP's proposed thermal accreditation?

A: SPP's proposed methods for thermal and renewable resources are inconsistent. Thermal resources' accreditation is based heavily on EFORd, which as noted above, may be calculated across a broad number of hours of the year. Many, if not most, of these hours have zero LOLE risk, which means that thermal accreditation can be based upon many non-risk hours. Renewable ELCC accreditation is earned *only* during risk hours. Thus, I conclude that SPP is mixing two very different approaches in its proposed accreditation methods.

One may reasonably ask how the thermal accreditation approach might be applied to renewables. SPP's proposed thermal accreditation is essentially a UCAP value, calculated by EFORd and Net Deliverable Capacity. The term

(1 – EFORd)

in the calculation is essentially a capacity factor, adjusting for forced outages. The similar calculation for renewables would be:

renewable accreditation = capacity factor x net deliverable capacity

Based upon my analysis, SPP's proposed thermal approach falls short, and does not meet SPP's stated objective, whereas the proposed method for renewables is a plausible approach that does meet SPP's stated objective.

Q: Do you believe these differences are justified?

A: No. As I have described in a previous answer, although thermal generation and renewable generation have different attributes, they provide the same fundamental service, although in different quantities; and the differential treatment SPP engages in is not justified by the different attributes of the resource categories.

VII. Accreditation Best Practices

Q: Are there any emerging practices for resource adequacy and thermal accreditation?

A: The power system industry has been grappling with the question of resource accreditation for decades, and with the recent increases in wind and solar, interest and effort during the past 10-15 years has intensified significantly.

ESIG has conducted workshops over the past several years that focused on this issue. In recent years, ESIG has released one collaborative report on resource adequacy and another on accreditation principles.[28]

The ESIG Resource Adequacy Report highlights several principles that it recommends. I restate the relevant ones here (quotes in *italics*):

- *Quantifying size, frequency, duration, and timing of capacity shortfalls is critical to finding the right resource solutions.*

  This builds upon existing LOLE analysis, recommending that additional data outputs from these models are generated so that potential outage events can be better understood.

- *Chronological operations must be modeled across many weather years.*

[28] ESIG Resource Adequacy Report, *supra* note 9 (resource adequacy); Derek Stenclik et al., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation, ESIG (Feb. 2023), https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf (accreditation principles).

To ensure that planning and markets properly account for the varying weather patterns that can be significant for grid operations, generator availability data across all hours of multiple weather years should be factored into resource adequacy calculations.

- *There is no such thing as perfect capacity.*

  All resources experience forced outages, and these should be properly factored into the analysis.

- *Reliability criteria should be transparent and economic.*

  Resource adequacy criteria should be transparent and should address economic trade-offs.

The ESIG report on Capacity Accreditation stresses some consistency principles that can be used to help establish performance-based resource-agnostic accreditation. These are particularly relevant to address the disparity in SPP's approach to thermal and renewable accreditation, and are highlighted here.

Capacity credit for all resources:

- *Resource Consistency*

  All resources' contributions to resource adequacy should be addressed in a comparable manner.

- *Horizontal Consistency*

  If two resources have the same performance during risk periods, then they should receive the same accreditation.

- *Vertical Consistency*

  If one resource contributes more than another, the latter should receive a lower accreditation.

- *Order Independence*

  Resource accreditation should be robust against the ordering of resources. For example, if resource A receives a 100 MW accreditation followed by B receiving an accreditation of 50 MW, then if B is accredited first, it should still receive 50 MW and A should receive 100 MW.

Q: Does SPP appear to be conforming to best practices?

A: No, for all the reasons I discussed above. Existing thermal accreditation has little to do with performance. The proposed thermal accreditation approach takes account of performance generally, but instead of zeroing in to times of extreme need, provides a broad average performance rate.

The existing renewable accreditation approach is deeply flawed, as I discuss above. The proposed renewable accreditation is improved, and conveys incentives for renewables to provide output during the times of need, which are calculated by the LOLE model.

Q: Are there alternative accreditation methodologies that SPP could adopt to address the flaws in its current and proposed accreditation frameworks?

A: SPP can and should adopt a method that is consistent across all resource types. I see no justifiable reason to differentiate between resource types, because all the important information required for accreditation appears in the actual hourly MW generation data from each resource.

Any reasonable method for thermal unit accreditation should focus on resource availability *during times of risk*. There are likely several alternative approaches, which could include:

- Calculation of a modified EFORd during risk periods for each resource. Periods of risk could be determined by a LOLE model, by actual historical conditions that risked supply shortfalls, or a combination of both. The modified EFORd metric might be referred to as an EFORr metric, where the "r" represents potential periods of reliability risk. The calculation of EFORr would therefore be similar to that of EFORd.
- Using ELCC for each resource or each resource type.
- Developing a "benchmark" unit with ELCC = 100% that only generates during risk periods, and assess all resources, one at a time, against that benchmark.

SPP is not the only entity that is grappling with this important issue, and accreditation methods are likely to evolve somewhat as the resource mix changes. However, the ESIG reports, assembled from experts in resource adequacy and accreditation, should be used for reference; and any proposed method should be rigorously tested against the principles put forth by ESIG.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Sierra Club; Natural Resources Defense Council, Inc; and Sustainable FERC Project	)	Docket No. EL24-_____
v.	)	
Southwest Power Pool, Inc.	)	

AFFIDAVIT OF DR. MICHAEL MILLIGAN, PH.D.

I, Michael Milligan, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the same Michael Milligan referred to in the foregoing document entitled "Affidavit of Dr. Michael Milligan, Ph.D." that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Dr. Michael Milligan, Ph.D.

Executed on
this day of March 28, 2024

Attachment to Exhibit A

Curriculum Vitae of Michael Milligan, Ph.D.

(March 29, 2024)

Michael R. Milligan, Ph.D.

Education and Training

Ph.D., Economics, University of Colorado, Boulder
M.A., Economics, University of Colorado, Denver
B.A., Mathematics, Albion College, Albion, MI

Professional Experience

Dr. Michael Milligan recently retired as Principal Researcher at the National Renewable Energy Laboratory, and he is now an independent power system consultant. He has more than 38 years' experience in analysis and modeling the bulk power system, and 32 years focusing on the impacts of wind and solar generation integration into the bulk system. Most recently he contributed to several ESIG (esig.energy) publications on resource adequacy andHe is the author/coauthor of more than 230 journal articles, conference papers, technical reports, and book chapters on topics that include the physical impacts of variable generation on power system operations, reserves, economics, and resource adequacy (links at milligangridsolutions.com). He has also published articles and book chapters on variable generation and energy markets, the impacts of variability pooling and wide-area energy management, conditional firm transmission potential in the West, the application of genetic algorithms and fuzzy logic to wind power plant location optimization, and short-term wind forecasting. He has given papers and presentations in in China, Japan, India, Portugal, Spain, Italy, France, Ireland, England, Scotland, Germany, Netherlands, Malaysia, Canada, Denmark, Sweden, Norway, and Finland, and has developed methods that are used for many aspects of integration analysis.

As a consultant, Michael has undertaken a wide range of projects that include (a) advising a wind plant owner/operator on ancillary services tariffs, (b) submitting comments to FERC on reliability and resilience, and wholesale markets (c) writing papers for publications, (d) providing workshops on grid reliability at state commissions, FERC, NERC, RTOs, and other stakeholders. He has provided expert review for technical publications by the International Energy Agency, advised stakeholders in Alaska regarding the impacts of control area consolidation on the Railbelt system, and has advised many stakeholder groups on utility economics and reliability as part of ISO/RTO transmission planning processes, especially related to renewable integration on the bulk power system. He has submitted expert testimony in several state public utility commission proceedings, focusing on resource adequacy and planning, ancillary services, and renewable integration issues. His clients include RTOs, trade groups, and educational organizations. He is a member of GridLab's expert team, and also serves as an ad hoc technical advisor to the Western Interstate Energy Board.

Dr. Milligan has provided expert testimony in public utility proceedings and workshops around the United States. For many years when he was at NREL, he collaborated with the Western Interstate Energy Board, was a member of the Western Governors' Association's Clean and

Diverse Energy Advisory Committee (CDEAC), and he was the primary author of the wind integration and scenario chapters. He led and contributed to multiple projects analyzing the potential benefits of the then-proposed Energy Imbalance Market in the West, including reserves and ramping analysis and electricity production simulation. This work was influential in the formation of the EIM, which is now operating and expanding in the Western Interconnection—parts of California, Nevada, Arizona, Utah, Wyoming, Idaho, Oregon, and Washington are participating. Since its launch in 2014 the EIM has enhanced grid reliability and reduced costs by more than $5 Billion for the market participants. The EIM improves the ability of the bulk power system to effectively manage the increasing levels of wind and solar power, now and in the future.

Michael has advised the 21st Century Clean Power Partnership (http://www.21stcenturypower.org/projects.cfm), a multilateral effort of the Clean Energy Ministerial, operated by the Joint Institute for Sustainable Energy Analysis. In this role, he has provided guidance to governments and utilities in China, India, South Africa and others on methods to improve the ability of their power systems to efficiently integrate renewable energy. He recently served as a principal technical advisor to a large-scale renewable energy integration study in India. His work was influential in influencing the Indian Grid Operator (POSOCO) to embark on a Pilot Project on 5-Minute Scheduling in India that is currently underway.

Dr. Milligan is an internationally recognized expert in loss-of-load probability analysis and resource adequacy. He led the North American Electric Reliability Corporation (NERC) Task Force for Capacity Value of Variable Generation and co-led the Institute of Electrical and Electronics Engineers (IEEE) Wind Power Coordinating Committee Capacity Value Task Force. He advises regional transmission organizations and utilities on resource adequacy methods and has advised many power system industry task forces and working groups. He was a charter member of the NERC Integrating Variable Generation Task Force and Essential Reliability Services Task Force (now Working Group) and the Western Electricity Coordinating Council's (WECC's) Variable Generation Subcommittee; and has served on multiple WECC committees and has been a key contributor to multiple NERC and WECC reports.

Michael led the Bulk Electric Power System Task Force for NREL's groundbreaking Renewable Electricity Futures study (http://www.nrel.gov/analysis/re_futures/). On behalf of the U.S. Department of Energy, he led the Power System Integration and Transmission task forces for the Wind Vision (https://energy.gov/eere/wind/wind-vision) and the Hydro Power Vision (https://energy.gov/eere/water/new-vision-united-states-hydropower) studies.

Dr. Milligan has advised many power system industry and utility commissions, including the Mid-Continent Independent System Operator; New York Independent System Operator; Independent System Operator of New England, California Independent System Operator; Xcel Energy (Minnesota and Colorado); Portland General Electric; Arizona Public Service; PacifiCorp; Grant County Public Utility District; Nebraska Public Power District; Western Electricity

Coordinating Council; Western Interstate Energy Board; North American Electric Reliability Corporation; British Columbia Hydro; Hydro Quebec; Alberta Electric System Operator; commissions in New Mexico, Michigan, Washington, Oregon, Utah, California, Alaska, Minnesota, and Colorado; and the Public Utility Commissioners' (PUC) Energy Imbalance Market (EIM) group in the West. He has also provided technical reviews for several National Renewable Energy Laboratory (NREL) studies, including the Western Wind and Solar Integration Study, the Eastern Wind Integration and Transmission Study, and the Nebraska Statewide Wind Integration Study. Many of these studies are available at www.esig.energy.

Dr. Milligan has presented at hundreds of technical conferences, stakeholder meetings, and webinars. Audiences range from experts in the power system industry to groups with little background in power system operations, design, or markets. He has regularly presented at the Utility Variable-Generation Integration Group (UVIG, now ESIG), including as a keynote speaker on variable-generation integration state of the art, and is on the faculty for the UVIG Short Course on Variable Generation Integration, offered bi-annually. His sustained participation on the International Energy Agency Task 25 for large-scale wind integration (https://www.ieawind.org/task_25.html) helped launch a continuing series of international technical papers on integration issues. International collaborations include papers and projects with VTT Finland, Royal Institute of Technology Sweden, DTU Delft Netherlands, University College Dublin, University of Castilla-La Mancha Spain, LNEG Portugal, Energinet.dk Denmark, ECAR Ireland, Sintef Norway, and Kansai University Japan. He was an invited panelist in 2012 to the Royal Irish Academy in Dublin and an invited keynote speaker at the 2011 Power System Computation Conference in Stockholm. He has hosted visiting researchers from Germany, Ireland, Spain, Australia, and France, and has served on Ph.D. dissertation committees and mentored Ph.D. students at MIT, Stanford, University of Colorado, University College Dublin, Northern Arizona University, University of Delaware, and University of California Berkeley.

In response to the Federal Energy Regulatory Commission (FERC) Notice of Inquiry, he provided comments based on research results to FERC. Based in part on this input, FERC eventually issued Order 764, which directs the conditions under which a transmission provider can assess integration charges for variable generation. His work on cost-causation and integration charges has also influenced the development of integration rates and resulted in an international paper with IEA collaborators and has influenced regulatory agencies to drop integration costs from integrated resource plans.

Awards

- *Lifetime Achievement Award for sustained contributions to wind and solar power system integration studies*, awarded by the Energy Systems Integration Group (formerly UVIG): 2018.
- *Technical Achievement Award for sustained advances in renewable energy integration methods*. Utility Variable-Generation Integration Group (UVIG): 2012.

- *H.M. Hubbard (Lifetime) Award for two decades of outstanding research contributions and leadership in research and technology*, National Renewable Energy Laboratory: 2010.
- *President's Award* (team, 2010), National Renewable Energy Laboratory,
- *National Wind Technology Center Technical achievement awards* in 2008 and 2009, National Renewable Energy Laboratory (team).
- *Best paper awards*, including papers at the 12th and 13th International Workshops on Large-Scale Integration of Wind Power.

Employment History

2017 – present:	Independent Power System Consultant
2015-2016:	Ph.D. advisor, University of California, Berkeley
2014 – 2020:	Adjunct Professor and Ph.D. Advisor, Northern Arizona University
2013 – 2014	Ph.D. advisor, MIT, Cambridge, MA
2013 – 2015:	Adjunct Professor, University of Denver
2009 – 2013:	Ph.D. advisor (3), University College, Dublin
2008 – 2009:	Ph.D. advisor, University of Maryland
2008 – 2017:	Principal Researcher, Power Systems Engineering Center, NREL
2006 – 2007:	Ph.D. advisor, University of Colorado, Boulder
1992 – 2008	Consultant, Power System Integration, NREL
1982 – 2008:	Professor, Economics (1998–2008); Professor, Computer Science and Mathematics (1995–1998); Professor (1982–1995) and Chair (1990–1992), Computer and Information Science Department, Front Range College
1975 – 1982:	Power system planner, Tri-State G& T. Developed software for load forecasting and resource analysis. Developed long-range planning models and documents for power and energy requirements, resource utilization, and long-term planning

Technical Articles, Reports, Book Chapters, FERC Filings

1. Energy Systems Integration Group. 2023. Weather Dataset Needs for Planning and Analyzing Modern Power Systems (Full Report). A Report of the Weather Datasets Project Team. Reston, VA. https://www.esig.energy/weather-data-for-power-system-planning

2. Energy Systems Integration Group. 2023. Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. A Report of the Redefining Resource Adequacy Task Force. Reston, VA. https://www.esig.energy/new-design-principles-for-capacity-accreditation.

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6. Reply Comments of Michael Milligan, Ph.D.: Grid Resilience in Regional Transmission Organizations and Independent System Operators. Docket AD18-7-000. Available at http://www.milligangridsolutions.com/milligan%20ferc%20comments%20AD%2018-7-000%20from%20FERC%20web.pdf. 2018.

7. Reply Comments of Michael Milligan, Ph.D. Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000. Available at http://www.milligangridsolutions.com/Milligan-Comments-FERC%20from%20ferc%20web.pdf. 2017

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EXHIBIT B

Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), May 23, 2023

(March 29, 2024)

CLEAN ENERGY ORGANIZATION COMMENTS REGARDING RR #554 (RESOURCE ADEQUACY PERFORMANCE BASED ACCREDITATION FOR CONVENTIONAL RESOURCES) AND RR #568 (EFFECTIVE LOAD CARRYING CAPABILITY ACCREDITATION FOR WIND, SOLAR AND STORAGE)

SUBMITTER INFORMATION

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RR OBJECTIVES (FROM RR FORMS)

What is the objective of this RR?

Describe the objective and end result

Per the original RR 554 submission: "*Current accreditation methodologies for conventional resources consist of one hour performance testing of the resources on an annual basis (for the operational test) and a more stringent one-hour capability test (while maintaining a four-hour continuous availability requirement) every five (5) years. The current methodology does not consider past performance (i.e. outages) or availability and generally closely aligns with the nameplate of the conventional resource. The objective of this RR is implement performance based accreditation methodology, to better align capacity accreditation to the capacity value provided by conventional resources starting with the 2025 Summer Season.*"

Per the original RR 568 submission: *"The intent of this RR is to file revisions to the Tariff to implement the policy that was previously approved by the SPP Board of Directors and the Regional State Committee for the ELCC methodology for wind and solar resources but rejected by the Federal Energy Regulatory Commission ("FERC"). These proposed Tariff revisions are also indented to address that concerns stated by FERC in its rejection of the previous filing at FERC, as well as reflect the language that presented to FERC to address requests for additional information. Originally, the ELCC methodology for energy storage resources ("ESR") approved policy did not have any proposed Tariff language changes, but the goal of this RR is to propose similar Tariff revisions used for the ELCC methodology for wind and solar."*

The current accreditation methodology for thermal resources does not capture correlated outage risk, such as we have seen during recent winter storms. Accreditation for thermal resources is also not probabilistic. For these primary reasons, Clean Energy Organizations argue that the proposed policies and tariff language do not result in comparable treatment with the current or proposed accreditation methodologies for wind and solar resources. We suggest that comparable treatment of all resource types should be a principal objective, and reasonably capturing correlated outage risk is a crucial element of achieving that objective and ensuring reliability.

How RR addresses the objectives:

Describe how this RR addresses or solves the objectives

Per the original RR 554 submission: "*This RR meets the objective for implementing the performance based accreditation policy paper as approved by the SPP Board of Directors, Regional State Committee, and additional SPP working groups and committees in 2022. This RR also addresses, at least partially, the IRATF Resource Planning & Availability 2.1 & 2.2 initiatives to identify the appropriate accreditation of all resources.*"

Per the original RR 568 submission: "*The RR implements to the previously approved requirements for wind, solar and storage into the SPP Planning Criteria, SPP Business Practices, and Attachment AA of the SPP Tariff.*"

SUBMITTER COMMENTS

The Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, and Earthjustice (collectively "Clean Energy Organizations"), appreciate the opportunity to provide both additional comments on the proposed revisions to the accreditation methodology for conventional resources (Revision Request 554), and new comments on the proposed revisions to the ELCC methodology for wind, solar, and energy storage resources (Revision Request 568). We submit these comments relative to both revision requests as our concerns related to both and how the two proposals are part of SPP's whole resource adequacy construct and must work together.

We continue to agree with the stated goal of RR 554 to better align resource accreditation of conventional resources with the capacity value these resources can reasonably be expected to provide. However, we do not believe SPP's current proposals to evaluate thermal resources based on a basic EFORd calculation (RR554), and simultaneously evaluate wind, solar, and storage resources using an advanced ELCC methodology (RR568), are reasonable. In our previous comments on RR 554, we highlighted our concern that the revisions will not result in comparable treatment for capacity accreditation of thermal resources and nonthermal resources. SPP's newly posted proposed revisions in RR 568 do not fix this fundamental disconnect; in some cases, proposing to take back to the Commission the same concepts that were criticized by Commissioners in the first submission. We look forward to discussing these concerns going forward; and we also include some clarifying questions in these comments and request that SPP staff address them at a future SAWG discussion of RR 554 and/or 568.

<u>Proposed EFORd Accreditation Methodology:</u>

1. Correlated Outage Risk:

In our previous comments discussing RR 554, we explained the importance of selecting an accreditation methodology that accurately captures the risk of correlated outages. Those comments remain applicable today**.** Fundamentally, SPP needs to implement a way to account for thermal correlated outages, and to assess thermal performance during high-risk hours (which may arise in part from correlated outages), because it otherwise runs a significant risk of mis-accrediting thermal resources. This is problematic for a few distinct reasons. First, an EFORd-based accreditation regime provides no incentive for individual generators to improve their availability during high-risk periods (such as through winterization, dual fuel contracts, or efforts to obtain a more firm fuel supply).

Second, failing to account for correlated outages also provides inaccurate information to utilities, state regulators, and SPP about the reliability contributions of thermal resources. As we also explained in our last set of comments, thermal units receiving capacity accreditation entirely based on their EFORd rates that perform poorly during extreme events will likely be accredited at a higher rate than they deserve because the EFORd analysis does not consider that under extreme weather conditions or other high-risk periods, the odds of forced outages for many thermal resources also increases. This over-accreditation of thermal resources will necessarily result in one of two outcomes. First, if SPP makes the same mistake of failing to adequately consider correlated high-risk period thermal outages in its LOLE model, then it will likely see system disruptions at a higher rate than 0.1 outage day per year, particularly during the types of major weather disruptions that have led to system crunches (and correlated outages) in the past decade. Evidence suggests that the risk of extreme weather is only increasing. Alternatively, if SPP does not make the same mistake in its LOLE, and implements modeling changes to account for the possibility of correlated outages, which we do not believe it has yet done, then the model will inevitably ensure a reliable system only by securing more overall capacity. In such a system, resources (like wind, solar, and storage) that are appropriately accredited based on their actual contributions to resource adequacy will be squeezed out, constituting a smaller share of the total capacity supply than their contributions warrant. While such an outcome would preserve the reliability of SPP's system, it would come at the costs of deeply inequitable treatment of different resources; and higher charges to customers across the region by moving the market away from cheap and clean energy sources.

In our last comments on RR 554, we urged SPP to work with stakeholders to determine a method of capturing correlated outage risk. Failure to do so, while implementing ELCC for wind, solar, and storage resources, results in an overall scheme that is unduly discriminatory, and unjust and unreasonable. We look forward to discussing this issue more in upcoming SAWG meetings; but as fodder for that discussion, we note that there are in fact different ways to accomplish this. The most obvious method, and the one most analogous to SPP's proposal for wind, solar, and storage resources, is of course simply conducting an ELCC analysis for thermal resources following roughly the same procedures as discussed in RR 568. We are aware that this has already been discussed and was not taken up by the SAWG membership at the May SAWG. But it is nonetheless worth revisiting, because a universal ELCC analysis using an LOLE model that factors in the possibility of correlated outages is far and away the cleanest way to move towards equitable treatment of all resource times; and with SPP already conducting this analysis for nonthermal units it would be a natural step to expand it to thermal fleets. We do note that ELCC analysis that is based solely on EFORd assumptions for thermal resource availability, still will not account for correlated outage risk of these resource classes. Thus, we urge SPP to look at additional LOLE modeling adjustments to address correlated outage risk, as discussed further below.

If SPP does not move forward with an ELCC methodology, then it should consider alternatives that can still account for correlated outages and performance during high-risk periods. We suggested previously that SPP examine other RTOs' proposals; without endorsing any one proposal, we note that CAISO accredits resources using a "Slice of Day" method; and MISO is currently proposing to shift to an accreditation method, "Direct-LOL," that offers a simpler calculation focused on resource performance during high-risk periods.[1] Even if SPP feels constrained to an accreditation methodology resembling EFORd for thermal resources, SPP should at least consider modifications to the methodology that would account for reduced thermal performance during high risk hours and/or forced outages that occur simultaneously with other thermal resources. For instance, SPP staff could evaluate the possibility of limiting its EFORd analysis to historical thermal unit performance during high-risk periods, using the modified calculation (based on a limited hour set) that it has already developed for resources with less than 100 service hours in a season.[2] We look forward to discussing any alternative offered by SPP staff and supported by the SAWG membership that more accurately evaluates all resources' contribution to system stability than a simple EFORd calculation.

1. High-Risk Hours (Hours of Need) versus Accreditation Methodologies:

We also note that EFORd based accreditation does not result in accrediting thermal resources based on the same hours as ELCC accreditation. ELCC based accreditation is focused on resource availability during the hours with highest risk of loss of load, whereas EFORd is based on all hours, including those with and those without loss of load risk. Similarly, the resource adequacy requirement in SPP is based upon the selection of the most vulnerable periods for the SPP BA, yet accreditation values of the individual resources is based on a different timeframe, the vulnerable periods for individual LREs, which may or may not correspond to the SPP BA peak load periods. The resource adequacy construct, including all accreditation methodologies, and the determination of the planning resource margin requirement, should all be based on the same hours: those where the risk of losing load is the highest.

<u>Differential Treatment of Thermal and Nonthermal Resources</u>

The current proposal to accredit thermal resources based exclusively on an EFORd determination is also problematic because it differs fundamentally from the ELCC methodology SPP has presented in RR 568, which will determine accredited capacity values for wind, solar, and storage resources based on their direct impact on the amount of load that can be sustained consistent with the LOLE standard of 0.1 outage day per year (as measured by the LOLE Model). At the most basic level, ELCC is a probabilistic approach, where EFORd is not. SPP's continued work assessing the value of wind, solar, and storage resources based on their actual contribution to that standard accounts for the possibility that like resources are more likely to experience correlated down periods, especially for weather-related causes. This is a reasonable accreditation approach; but it is not reasonable to apply that approach only to some resource

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[1]Resource Accreditation White Paper Version 1.0 - Draft May 2023, MISO, https://cdn.misoenergy.org/MISO%20Draft%20Resource%20Accreditation%20Design%20White%20Paper628865.pdf
[2] May 2023 SAWG Meeting, SPP Staff Presentation, *PBA (RR 554) Policy Concepts*, at 34.

types while continuing to accredit other types based on an average annualized measurement of their performance in all hours regardless of the risk in those hours. Nor is our concern about inequitable treatment merely theoretical: much of that same weather-related correlation occurs in the thermal fleet as well as for renewable and storage resources, but SPP's basic EFORd methodology accounts for neither correlated outages nor does it focus on performance during high-risk hours. The current proposed dichotomy of treatment between thermal and non-thermal resources is not defensible.

This dichotomous treatment of thermal and nonthermal resources is also evident in the allocation of capacity value to individual resources once a class-wide accreditation is determined using the ELCC analysis. SPP proposes to allocate the total accreditation for a given resource class among individual wind or solar resources based on their performance during the top three percent of Net Peak Load hours of the LRE they are serving. This means that wind or solar resources that are contributing the most during the highest peak hours, which we assume to also be hours with high risk of loss of load, will receive the highest accreditation values. Yet EFORd does not provide a similar value or incentive for thermal resources that provide higher amounts of capacity during high-risk hours. One obvious result of this allocation method is that wind and solar resources' accreditation will ultimately be determined in part by how other resources of the same type perform during their LREs' peak load periods and other high-risk hours. And of course, the ELCC analysis itself measures the net contribution of a given resource assuming all other existing resources are online and operational; so the performance of non-like resources will also have some influence on wind, solar, and storage. This interdependence of capacity contribution on other resources' performance does not exist under an EFORd regime because units are accredited entirely based on their own forced outage rate. And there is no defensible reason to allow only some resources' accreditation to be impacted by variation in the grid writ large.

<u>Tiered Classifications for Wind, Solar, and Storage Resources</u>

RR 568's continuation of the original proposed tiering of wind and solar resources is hard to justify from a policy perspective. For instance, SPP has failed to justify its selected thresholds for wind resources meeting the first 35% of a given LRE's Net Peak Load (or solar resources meeting the first 20% of Net Peak Load). In its response to FERC's first deficiency letter in ER22-379 noting the lack of justification for the 35% threshold for wind resources, SPP stated as follows:

> "[t]he 35% of nameplate point equates to an ELCC accreditation of approximately 21%. The majority of SPP stakeholders supported the idea of the Tier 1 threshold for wind resources. At the time SPP's ELCC whitepaper was approved, the majority of the LREs had not yet surpassed the 35% threshold of procured firm transmission service compared to their individual LRE's peak demand."

This does not explain why 35% is a reasonable threshold, instead merely suggesting that the number was generally agreeable to SPP members several years ago. Given the significant impacts of the Tier 1 threshold on the capacity accreditation of wind resources, SPP must determine this threshold based on evidence of how wind resources' contributions to resource adequacy actually changes at various levels of penetration. In the same response to FERC, SPP did have some evidence for the 20% threshold for solar resources, namely, that the average

ELCC value of solar begins to decline more steeply after 10,000 MW of solar is operational on the SPP system, and that this is approximately 20% of SPP's peak load. However, SPP offers no explanation for why 20% is relevant on an LRE-level, as each LRE may have a different daily or seasonal load profile from the system as a whole, or a different generation mix. The translation of a systemwide inflection point to the LRE-level renders the 20% threshold arbitrary.

SPP's decision to set these thresholds on a LRE basis rather than an SPP system basis is also problematic. The declining marginal ELCC of wind, solar, and energy storage relates to their penetration across SPP's entire system, not the penetration within a certain LRE's service area, or the even more arbitrary grouping of which LRE various resources are contracted to serve. By setting the tier thresholds based on a percentage of each LRE's Net Peak load, the capacity value of renewable energy and storage resources will be artificially capped when an individual LRE reaches the threshold, even if the overall SPP system remains far below the 20% or 35% thresholds. The only justification CEOs are aware of for this unreasonable approach is a desire by LREs to guarantee favorable accreditation treatment for the wind and solar capacity resources of each individual LRE, even if they lag in developing these. Such an approach systematically undervalues the capacity offered by wind and solar contracted for by early-mover LREs, to the detriment of consumers. We understand that such approach offers more certainty to LREs for existing (or near-term investments in) wind and solar resources which will maintain a more stable capacity value, but believe that these benefits are outweighed by the inefficiencies of artificially capping the capacity accredited to wind and solar resources. If SPP maintains the tiered approach to wind and solar accreditation, we urge SPP to consider allowing individual LRE's to capture the higher value of Tier 1 resources until that tier reaches 35% or 20% of SPP BA load. This would mean that early movers could have more than 35% or 20% of their load served by wind or solar included in Tier 1 until other LRE's and the full SPP BA also reach that level of wind and solar penetration.

<u>Questions and tariff comments relating to RR 568:</u>

1. In Section 15.4 of the RR, "Allocation to Individual ELCC Resources," SPP proposes allocating accredited capacity to individual wind and solar units based on their "average historical production output from the top three percent (3%) Net Peak Load hours of the SPP Balancing Authority Area's Load."[3] But different Balancing Areas will naturally reach their Net Peak Load at different times and on different days of the year, resulting in potentially very different accreditation for wind and solar resources depending on which LRE they are associated with. Can SPP explain the justification for this policy proposal, focusing on why basing allocation on performance during individual LREs' risk hours makes sense in an integrated footprint like that offered by SPP?

2. A related impact of accrediting resources based on individual LREs' risk hours is that a resource located in one LRE but attached to another LRE can have a far different value than identical nearby resources, even though it contributes exactly the same amount of capacity to the reliability of the SPP BA. For instance, a solar resource that has a value in the summer for the SPP BA peaking in the heat of the day may have zero accredited

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[3] RR 568 at 31-32.

value if the resource is tied to an LRE that has a non-coincident peak at night. The result does not make sense in the context of the reliability of the SPP BA and it is unduly discriminatory. This has the potential to create significant complexity, causing unnecessary treatment discrimination between resources, without a discernible corresponding benefit. How does SPP plan to ensure an accreditation and resource adequacy construct that is internally consistent?

3. Relatedly, allocation of accredited capacity among storage units apparently does not depend on where those storage resources are located. Why was this distinction drawn between storage and wind and solar resources? Please describe the all the differences between the accreditation approaches for storage versus wind and solar resources, including any differences in the tariff language structure.

4. SPP proposes to allocate storage capacity on a tiered basis depending on whether those resources bid in to discharge on a 4, 6, or 8 hour timeframe.[4] What was SPP's basis for selecting those three categories of storage? In selecting those categories, what input did SPP staff seek or receive from the storage industry or regarding the relevance of these particular class definitions, whether "equipment parameters" are definitive of duration or resource adequacy contributions, or similar considerations?

5. The Business Practice edits section 2.0 Determination of System ELCC Example states "The ELCC Study will consist of analyses utilizing Loss of Load Expectation (LOLE) metrics to determine the capacity provided by the wind resources, solar resources or Energy Storage Resources. The LOLE metric used for the ELCC Study shall be a 1 day in 10 year (0.1 day/year)." How will the 0.1 day/year metric be divided to determine accreditation values in the winter and the summer? What analysis has been done to determine in which seasons and hours the risk of loss of load is the highest?

6. We are concerned with the proposed use of the term Net Peak Load. This term tends to be used in the industry today to mean peak load minus wind and solar generation at that time. SPP's proposed term in the definitions section has a different meaning, which may be confusing. We urge SPP to use a different term, possibly Actual Net Peak Demand versus Forecast Net Peak Demand.

Respectfully submitted,

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[4] RR 568 at 32-33.

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IN THE APPROPRIATE SECTIONS BELOW, PLEASE PROVIDE THE LANGUAGE FROM THE CURRENT RR SUBMISSION FORM FOR WHICH YOU ARE PROPOSING REVISION(S), WITH ALL EDITS REDLINED.

EFFECTIVE LOAD CARRYING CAPABILITY STUDY

No specific edits are included, but we recommend changes be made to the entire proposal as necessary to bring nonthermal resources in line with thermal resources.

ALLOCATION TO INDIVIDUAL ELCC RESOURCES

No specific edits are included, but we recommend changes be made to Section 15.4 to implement a more sensible allocation methodology.

EXHIBIT C

Clean Energy Organizations Comments Regarding RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources) and RR#568 (Effective Load Carrying Capability Accreditation for Wind, Solar and Storage), July 27, 2023

(March 29, 2024)

Southwest Power Pool

CLEAN ENERGY ORGANIZATION COMMENTS REGARDING RR #554 (RESOURCE ADEQUACY PERFORMANCE BASED ACCREDITATION FOR CONVENTIONAL RESOURCES) AND RR #568 (EFFECTIVE LOAD CARRYING CAPABILITY ACCREDITATION FOR WIND, SOLAR AND STORAGE)

SUBMITTER INFORMATION

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RR OBJECTIVES (FROM RR FORMS)

What is the objective of this RR?

Describe the objective and end result

Per the original RR 554 submission: "*Current accreditation methodologies for conventional resources consist of one hour performance testing of the resources on an annual basis (for the operational test) and a more stringent one-hour capability test (while maintaining a four-hour continuous availability requirement) every five (5) years. The current methodology does not consider past performance (i.e. outages) or availability and generally closely aligns with the nameplate of the conventional resource. The objective of this RR is implement performance based accreditation methodology, to better align capacity accreditation to the capacity value provided by conventional resources starting with the 2025 Summer Season.*"

Per the original RR 568 submission: *"The intent of this RR is to file revisions to the Tariff to implement the policy that was previously approved by the SPP Board of Directors and the Regional State Committee for the ELCC methodology for wind and solar resources but rejected by the Federal Energy Regulatory Commission ("FERC"). These proposed Tariff revisions are also indented to address that concerns stated by FERC in its rejection of the previous filing at FERC, as well as reflect the language that presented to FERC to address requests for additional information. Originally, the ELCC methodology for energy storage resources ("ESR") approved policy did not have any proposed Tariff language changes, but the goal of this RR is to propose similar Tariff revisions used for the ELCC methodology for wind and solar."*

The current accreditation methodology for thermal resources does not capture correlated outage risk for individual resources, such as we have seen during recent winter storms. Accreditation for thermal resources is also not probabilistic. For these primary reasons, Clean Energy Organizations argue that the proposed policies and tariff language do not result in comparable treatment with the current or proposed accreditation methodologies for wind and solar resources.

We suggest that comparable treatment of all resource types should be a principal objective, and reasonably capturing correlated outage risk is a crucial element of achieving that objective and ensuring reliability.

How RR addresses the objectives:

Describe how this RR addresses or solves the objectives

Per the original RR 554 submission: "*This RR meets the objective for implementing the performance based accreditation policy paper as approved by the SPP Board of Directors, Regional State Committee, and additional SPP working groups and committees in 2022. This RR also addresses, at least partially, the IRATF Resource Planning & Availability 2.1 & 2.2 initiatives to identify the appropriate accreditation of all resources.*"

Per the original RR 568 submission: "*The RR implements to the previously approved requirements for wind, solar and storage into the SPP Planning Criteria, SPP Business Practices, and Attachment AA of the SPP Tariff.*"

SUBMITTER COMMENTS

Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, and Earthjustice (collectively "Clean Energy Organizations") appreciate the work of SPP's Supply Adequacy Working Group ("SAWG") over the past several months to improve its proposal to implement new accreditation methodologies for conventional resources under RR554, and wind, solar, and storage resources under RR568 (along with the related tariff and business practice manual redlines). We submit these comments relative to both revision requests as our concerns relate to both and how the two proposals are part of SPP's whole resource adequacy construct and must work together. While we do not fully support the proposals as they stand following the July 20-21st SAWG meeting, some of the recently proposed changes do address some of our concerns, and we do believe result in an improved proposal over earlier policy directions. However, Clean Energy Organizations remain concerned about the legal defensibility of an overall accreditation methodology that treats resources differently without sufficient justification for that differential treatment. As such, we continue to urge SPP to adopt a single accreditation methodology that would apply in a comparable way to all resource types, whether that be ELCC for all or a different accreditation method entirely.

Absent an accreditation proposal that treats all resource types in the same way, we generally support the following changes that have been made recently:

- The alignment of the stakeholder discussions, FERC filing, and implementation timelines for both PBA and ELCC proposals.
- The removal of the 1-in-5-year exemption whereby conventional resources could use only 4 out of 5 years of data to determine their EFORd.
- The commitment not to remove catastrophic outages and Out of Management Control outages from the calculation of EFORd values for conventional resources.
- The use of 10 years of availability data instead of 5 years, and the use of class average data to fill in years where no GADS data exists for a resource.
- The movement from 3 tiers to 2 tiers for wind, solar, and storage ELCC accreditation, which avoids an arbitrary cap on Tier 1 resources.

Our remaining concerns with the PBA and ELCC proposals following policy changes made at the July SAWG meeting are:

- That EFORd and ELCC methodologies for accrediting different resource types do not result in comparable treatment. ELCC is a probabilistic approach, and begins with a class average accreditation value, whereas PBA uses average historic availability for individual resources.
- That use of EFORd for conventional resources does not accurately capture the impact of correlated outages on an individual resource's accreditation value, whereas ELCC does capture correlated outage risks when accrediting wind, solar, and storage resources.
- That class wide ELCC values should be allocated to individual resources based on their contribution to meeting SPP's needs rather than the needs of individual LREs to which those resources happen to be connected.
- That the proposed allocation also focuses on performance during the 3% of highest peak load hours, when it should focus on performance during the tightest margin hours.
- That the proposal continues to use two definitions for Planning Resource Margin under Section 5.4. Specifically, "The PRM established in accordance with this Attachment AA shall be converted to an Accredited Capacity Planning Reserve Margin ("Accredited Capacity PRM") and utilized in calculating the Resource Adequacy Requirement for the Summer Season and Winter Season." The PRM established in accordance with Att. AA is a legacy definition of a PRM based on installed capacity for conventional resources and accredited capacity for wind and solar resources. Not only is this construct discriminatory, but it will also become more and more meaningless as SPP improves is accreditation methodologies, and the resource mix shifts. A single PRM definition and construct based on accredited capacity is a simpler and clearer path forward based on SPP's proposed changes in accreditation methodology.
- That the proposal does not base any accreditation on performance and/or availability during the spring or fall, nor is there consideration of developing a Planning Resource Margin requirement for the spring or fall seasons. We understand that SAWG and REAL intend to address outage coordination separately, but we note that without improved outage coordination rules, the proposed two season accreditation construct will incent LREs to schedule outages in the shoulder season, increasing the risk of emergency events due to insufficient capacity resources in the spring and fall.

Respectfully submitted,

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EXHIBIT D

Clean Energy Organizations Comments and Proposal RR#554 (Resource Adequacy Performance Based Accreditation for Conventional Resources), September 25, 2023

(March 29, 2024)

SPP Southwest Power Pool

CLEAN ENERGY ORGANIZATION COMMENTS AND PROPOSAL RR #554 (RESOURCE ADEQUACY PERFORMANCE BASED ACCREDITATION FOR CONVENTIONAL RESOURCES)

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RR OBJECTIVES (FROM RR FORMS)

What is the objective of this RR?

Describe the objective and end result

Per the original RR 554 submission: "*Current accreditation methodologies for conventional resources consist of one hour performance testing of the resources on an annual basis (for the operational test) and a more stringent one-hour capability test (while maintaining a four-hour continuous availability requirement) every five (5) years. The current methodology does not consider past performance (i.e. outages) or availability and generally closely aligns with the nameplate of the conventional resource. The objective of this RR is implement performance based accreditation methodology, to better align capacity accreditation to the capacity value provided by conventional resources starting with the 2025 Summer Season.*"

The current proposed PBA accreditation methodology for thermal resources does not capture correlated outage risk, such as we have seen during recent winter storms. Clean Energy Organizations remain concerned that the proposed policies and tariff language do not result in comparable treatment with the current or proposed accreditation methodologies for wind and solar resources. We suggest that comparable treatment of all resource types should be a principal objective, and reasonably capturing correlated outage risk is a crucial element of achieving that objective and ensuring reliability. To that end we include in these comments a proposal for a modification of the EFORd calculation that we believe will be a reasonably close approximation to a thermal resource ELCC if it were calculated.

How RR addresses the objectives:

Describe how this RR addresses or solves the objectives

Per the original RR 554 submission: "*This RR meets the objective for implementing the performance based accreditation policy paper as approved by the SPP Board of Directors, Regional State Committee, and additional SPP working groups and committees in 2022. This RR also addresses, at least partially, the IRATF Resource Planning & Availability 2.1 & 2.2 initiatives to identify the appropriate accreditation of all resources.*"

SUBMITTER COMMENTS

The Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, and Earthjustice (collectively "Clean Energy Organizations"), appreciate the opportunity to provide these additional comments suggesting a modified EFORd approach to the proposed accreditation methodology for conventional resources (Revision Request 554).

We continue to agree with the stated goal of RR 554 to better align resource accreditation of conventional resources with the capacity value these resources can reasonably be expected to provide. This capacity value is, in general, intended to measure a resource's likelihood of being available during periods of tight supply and when the system needs capacity the most. However, Clean Energy Organizations and the SPP MMU have continued to highlight that the parallel PBA (for conventional resources) and ELCC (for wind, solar, and battery storage resources) accreditation methodologies do not result in comparable treatment. Effective capacity accreditation requires a level playing field. Anything else will increase consumer costs, implicitly subsidize or penalize particular technologies, provide incorrect price signals for efficient market entry and exit, and potentially threaten grid reliability.

One key area of concern we have raised is that PBA is based on an EFORd approach that is not equivalent to the ELCC methodology:

- Because of how it is calculated, ELCC effectively evaluates resources based entirely on their performance during simulated loss of load events (or near-loss of load events), which is 1-day-in-10 years, or about 2 hours every ten years. This equates roughly to the most-risky 0.002% of hours in a given period.[1]
- EFORd, in contrast, is based on a generator's "demand hours," or when it is expected to generate. For peaking resources this could be several hundred hours per year and for more economic resources this could be several thousand.

We agree with the MMU that ELCC consistently applied for all resources would be the best path forward. However, recognizing the increased effort and modeling challenges, and in the spirit of the instruction sent by REAL to the SAWG to consider modifications to the PBA calculation, we offer the following proposed changes to PBA that we believe would make conventional resource accreditation reasonably comparable to ELCC. Although our proposed approach would not be identical to ELCC accreditation, we believe it is sufficiently comparable in treatment to ELCC to warrant approval by FERC.

In preparing this proposal, we sought to identify an accreditation methodology that accomplished two distinct purposes simultaneously, both of which we understand to be fundamental goals of the SAWG and of SPP more broadly in developing an accreditation regime. First, the accreditation methodology should give system planners accurate and predictable information regarding the capacity accreditation of their existing generation

[1] ELCC is calculated based on a resource's ability to avoid a loss of load event, which occurs once every ten years (1-day-in-10-years LOLE) in a resource adequacy system. If a loss of load event is, on average, two hours in duration, that equates to two hours every 10 years, or 2 out of 87,600 hours (0.002%). Note that in a system with high penetration of energy storage, a resource could reduce loss of load probability even if it was not available immediately during the tight supply conditions because storage could shift the energy to other periods.

resources, so that they can plan for the lowest-cost future that ensures reliability at a 1-in-10-year LOLE standard. And second, the methodology should provide a price signal to individual generators that encourages those resources to make investments or operational changes needed to maximize their availability during the highest-risk hours of the year.

To accomplish those parallel but interrelated goals, we propose a two-step accreditation process in line with that proposed for renewable resources under RR568: first, conventional resources would be evaluated on a class-wide based on their forced outage rates (EFOR) during the highest-risk hours of the year (a measurement we are calling EFORr, as detailed below); and second, this class-wide accredited capacity would be allocated to individual generators within that class based on a weighted average of their EFORd' and their EFORr. This two-step metric would ensure that overall accreditation of conventional resources is based specifically on when the system is most at risk of supply shortfalls, specifically addressing concerns about correlated outages due to fuel supply and weather conditions and considering risk periods that may occur outside of peak demand (like periods of high maintenance). It would also maintain a sufficiently large data set of hours, for resource classes, to avoid undue volatility in accreditation values for individual generators.

The following Attachment A provides a detailed summary of the proposal, although we acknowledge it leaves some details in need of resolution. We appreciate SAWG's work on capacity accreditation reform and look forward to discussing this potential alternative to the current proposed PBA accreditation methodology at the next SAWG meeting.

Respectfully submitted,

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Attachment A: Proposed Modified EFORd Approach for PBA Capacity Accreditation Methodology

- Determination of Class-wide Accreditation using EFORr: We suggest accrediting the overall classes of PBA resources (i.e., gas, coal, etc.)[2] using a modified UCAP and EFORd based methodology, which we have provisionally labeled "EFORr":
  - o EFORd' – Equivalent Forced Outage Rate (demand) – the average forced outage rate of a resource during demand periods (or a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate)[3]
  - o EFORr – Equivalent Forced Outage Rate (risk hours) – the average forced outage rate of a resource during "high-risk hours" (or a measure of the probability that a generating unit will not be available due to forced outages or forced deratings during hours of greatest risk and tightest supply margin)
    - ▪ Defining "high-risk hours" is important here: we propose that they be defined as the top 1% of tightest hours in a given season (summer or winter), where the gap between net load and available generation is the smallest. This would equate to 88 hours per year (44 per season). (MMU has proposed "evaluating resources during the top 3 percent of intervals where the margin between available capacity and net peak load obligation was the tightest.")
    - ▪ Alternatively, the top 2% or top 3% of tightest intervals could be considered, in line with the MMU's suggestion.
    - ▪ Class-Wide Accredited Capacity = ∑ demonstrated net generating capability * (1 – modified-EFORd) (Same general formula as included in PBA proposal today)
  - o This approach is similar to proposals being considered or used by SPP's neighbors, such as MISO's proposed Direct Loss of Load (DLOL) approach based on availability during Loss of Load and tight margin hours and ERCOT's performance credit mechanism.

- Allocation of Class-wide Accreditation to Individual Resources using EFORd' and EFORr: After calculating a class-wide total accredited value, SPP could then allocate that value to individual resources using a weighted average approach between EFORd' and EFORr, which would hold individual resources accountable for their performance during high-risk hours, but reduce the volatility of that signal (and provide better certainty to system planners) by combining it with the EFORd' measure of resources' overall performance.
  - o Individual Resource Available Capacity = demonstrated net generating capacity * [1-(EFORd' * Y% +EFORr * Z%)]
  - o Accredited Capacity = Class-wide Accredited Capacity *
    Individual Resource Available Capacity/Class-wide ∑ Individual Resource Available Capacity
  - o Note here that Y + Z must always equal 100. The SAWG could simply weigh each of these at 50%, or use a different split such as 60%/40%. We believe this question would merit further discussion, and perhaps some numerical analysis.

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[2] SAWG could consider further differentiating classes of PBA resources, specifically to address location and fuel security. For example, the accreditation of gas resources split into more than one class based on (1) SPP Load Zone, and (2) whether or not dual fuel capability is available. This would ensure that gas resources in colder climates (LRZ1) with dual fuel capability, for example, receive a class-wide accreditation different than gas resources in warmer climates (LRZ6) without duel fuel capability.

[3] This is based on the currently defined EFORd' methodology that SPP has proposed for use in PBA.