The Empire District Electric Company d/b/a Liberty
Case No. EA-2025-0299
Office Public Counsel Data Request - 8527

Data Request Received: **2026-04-02** Response Date: 2026-04-14
Request No. 8527 Witness/Respondent: Aaron Doll
Submitted by: John Robinett, John.Robinett@opc.mo.gov

REQUEST:

When does SPP's new winter capacity requirements become effective? (namely meaning penalties may be enforced by SPP)

RESPONSE:

SPP's new Planning Reserve Margin ("PRM") requirements became effective for the Summer 2026 and Winter 2026/27 seasons.

Liberty

The Empire District Electric Company d/b/a Liberty
Case No. EA-2025-0299
Office Public Counsel Data Request - 8529

Data Request Received: **2026-04-02**
Request No. 8529
Submitted by: John Robinett, John.Robinett@opc.mo.gov

Response Date: 2026-04-14
Witness/Respondent: Aaron Doll

REQUEST:

Is Liberty aware of any discussions currently ongoing at the SPP to increase the winter capacity requirements at SPP? If so, please identify any estimate of which Liberty is aware about the projected values of what the capacity may increase to. Further, please identify any estimate of when a decision might be made about increasing the reserve margin of which Liberty is aware.

RESPONSE:

Yes. The current approved Base Planning Reserve Margin ("PRM") for the winter season 2026/27 is 36% and 38% for the 2029/30 winter season. There are ongoing discussions in the SPP stakeholder groups regarding the 2030/31 and 2032/33 winter PRM requirements. Most recently, the Supply Adequacy Working Group ("SAWG") voted to approve a 38% PRM in the 2030/31 winter season and a 36% PRM for the 2032/33 winter season based on the results of the 2025 Loss of Load Expectation ("LOLE") Study. This is an ongoing process with an annual LOLE Study cadence that results in an "initial setting" and "final adjustment" of the PRM on a forward-looking basis.

The Empire District Electric Company d/b/a Liberty
Case No. EA-2025-0299
Office Public Counsel Data Request - 8524

Data Request Received: **2026-04-02** Response Date: 2026-04-14
Request No. 8524 Witness/Respondent: Aaron Doll
Submitted by: John Robinett, John.Robinett@opc.mo.gov

REQUEST:

When did the Southwest Power Pool ("SPP") approve the increase in the winter capacity requirement?

RESPONSE:

SPP's Regional State Committee and Board of Directors approved the increases to the planning reserve margins (including the winter) at their August 5-6, 2024 meetings.

The press release can be found on SPP's website at the link below.

https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/#:~:text=%E2%80%94%20At%20their%20August%205%2D6,support%20of%20regional%20grid%20reliability.

August 6, 2024

SPP board approves new planning reserve margins to protect against high winter, summer use

LITTLE ROCK, ARK. — At their August 5-6 meetings, Southwest Power Pool's (SPP) Regional State Committee and Board of Directors approved increases to the planning reserve margins (PRM) member utilities are required to maintain in support of regional grid reliability. PRM represents the amount of back-up power utilities must have to guard against unplanned conditions or events on the regional power grid.

SPP's action will further help the region prepare for extreme weather events and other circumstances that lead to higher-than-usual demand for electricity. Such episodes have become increasingly common in recent years, such as with Winter Storm Uri in 2021 and Winter Storm Elliott in 2022.

SPP's Regional State Committee and board approved minimum requirements of a 36% winter-season PRM and a 16% summer-season PRM, effective beginning summer 2026 and winter 2026/27. This means that load responsible entities in SPP's region must have access to enough generating capacity to serve their peak consumption with at least 36% margin during the winter season and at least 16% margin during the summer.

This action marks the first time a winter PRM requirement has been defined separately from SPP's summer PRM requirement and was taken to ensure member utilities appropriately acquire enough generating capacity for both seasons. The current 15% summer PRM requirement was previously applied to the winter season also. The new requirements support SPP's efforts to reliably and continuously meet the region-wide demand for electricity from residents, commercial centers and industries throughout the SPP footprint.

The board also received a report detailing the challenges SPP and its members face with the increasing risk of having inadequate electricity supply to meet demand. The report, titled ***Our Generational Challenge: A Reliable Future for Electricity***, is a comprehensive summary of SPP's work to leverage diverse energy resources to meet the ever-rising demand for electricity. It calls for increased engagement, collaboration and consensus among government energy regulators, elected policymakers, utilities, regional transmission organizations and customers.

"As the real-time grid operator and transmission planner for a 14-state region, our job is to ensure electric reliability for millions of consumers. We've been successfully doing this work since 1941. But we can't do it alone. A concerted, collective effort is needed to ensure we have a reliable power grid today and in the future," said SPP Chief Executive Officer Barbara Sugg in the report's opening statement.

The report and an **infographic** are available at **spp.org/ourchallenge**. Sugg further pointed out that SPP is increasingly forced to issue grid advisories in winter and summer due to the heightened risk of inadequate power supplies during those times. She said harnessing enough energy to meet demand has become more and more complicated due to the rapidly evolving power grid.

"Demand for electricity is outpacing supply from our generation fleet," Sugg said. "While SPP always focuses on affordability, we need continued investment to add the generating and transmission facilities needed to mitigate risks and keep the lights on."

Meghan Sever, 501-482-2393, msever@spp.org

Stakeholder Groups

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201 Worthen Drive • Little Rock, AR 72223-4936
(501) 614-3200

Liberty™

The Empire District Electric Company d/b/a Liberty
Case No. EA-2025-0299
Office Public Counsel Data Request - 8526

Data Request Received: **2026-04-02** Response Date: 2026-04-14
Request No. 8526 Witness/Respondent: Aaron Doll
Submitted by: John Robinett, John.Robinett@opc.mo.gov

REQUEST:

Does Liberty have any personnel on the group/committee/team at SPP that approved the increase in winter capacity identified in response to Data Request No. 8523? If so, are the Liberty personnel voting members of that group/committee/team? If so, what was Liberty's employee's vote on the issue of increasing winter capacity?

RESPONSE:

Yes, Liberty either monitors or has voting members on the stakeholder groups that approved RR622 (Planning Reserve Margin). A list of the voting members and their votes are in the table below. It is important to note that, while the working groups identified below each cast votes on RR622, the Winter and Summer PRM percentages evolved throughout the stakeholder process. Accordingly, the votes reflected below should not be interpreted as endorsement of the final PRM values ultimately approved by the Regional State Committee ("RSC") and the SPP Board of Directors ("BOD").

The RR622 Recommendation Report is attached for additional detail regarding working group motions and voting outcomes. See attachment "RR622 Planning Reserve Margin Recommendation Report 8-26-2024.pdf".

Stakeholder Group	Liberty Voting Member	RR622 Vote
Supply Adequacy Working Group	Brian Berkstresser	Yes
Cost Allocation Working Group	N/A	N/A
Resource and Energy Adequacy Leadership Team	N/A	N/A
Regional Tariff Working Group	Todd Tarter	Yes
Market and Operations Policy Committee	Aaron Doll	Yes
Regional State Committee	N/A	N/A
Member's Committee	Tim Wilson	No
Board of Directors	N/A	N/A

The Empire District Electric Company d/b/a Liberty
Case No. EA-2025-0299
Office Public Counsel Data Request - 8503

Data Request Received: 2026-02-02
Request No. 8503
Submitted by: John Robinett, John.Robinett@opc.mo.gov

Response Date: 2026-02-23
Witness/Respondent: Aaron Doll

REQUEST:

Has Liberty performed an analysis of how the combustion turbine will affect capacity for summer and winter in 2026 and 2029? If yes, please provide the analysis or the information as presented in the June resource adequacy reports for the Southwest Power Pool ("SPP").

RESPONSE:

Yes. SPP Business Practice 8400 Section 3.8 describes the EFORd adjustment for capacity accreditation for new conventional resources. Currently, the summer class average EFORd for a combustion turbine with onsite fuel storage is 9.90%. The official winter class averages will be posted by SPP in April 2026. However, using SPP's last informational winter accreditation study, we can assume a 15.0% EFORd/EFOF adjustment for the winter season is a reasonable proxy. For a 240 MW combustion turbine, this would equate to an additional 216.2 MW of accredited capacity in the summer and an additional 204.1 MW of accredited capacity in the winter once the unit is in commercial operations in mid 2030. Note that these seasonal accredited capacity levels are based on the percentages discussed and a 240 MW unit. The accredited capacity would shift accordingly based on the nameplate capacity of the actual unit(s). There will be no impact from this unit in 2026.

Attachments:
"BP 8400 Performance Based Accreditation for Conventional Resources.pdf"
"conventional unit class averages – summer 2026.pdf"

Conventional Resources Class Averages – Summer 2026

Category	EFORd
Conventional Hydroelectric	0.58%
Conventional Steam Coal	9.77%
Combustion Turbine w/ Onsite Fuel Storage	9.90%
Combustion Turbine w/o Onsite Fuel Storage	6.65%
Hydroelectric Pumped Storage	5.29%
Natural Gas Fired Combined Cycle	4.73%
Natural Gas Steam Turbine	11.62%
Nuclear	2.09%
RICE w/ Onsite Fuel Storage	5.30%
RICE w/o Onsite Fuel Storage	2.89%

For more information on the Performance Based Accreditation (PBA) and class averages methodology, please refer to RR554 and RR707.

SPP Southwest Power Pool

Southwest Power Pool, Inc.

OPEN ACCESS TRANSMISSION TARIFF

BUSINESS PRACTICES

Business Practice 8400

Performance Based Accreditation for Conventional Resources

MAINTAINED BY

SOUTHWEST POWER POOL STAFF

PUBLISHED: 8/5/2025

LATEST REVISION: 11/4/2025

Contents

1.0 Background

The purpose of this Business Practice is to describe the Accredited Capacity (ACAP) methodology and calculations for conventional resources in accordance with Attachment AA of the SPP OATT. Effective June 1, 2025 (Effective Date) for the 2026 Summer Season Resource Adequacy process, the Transmission Provider will use a performance based accreditation method to calculate the ACAP for conventional resources. Conventional resources, for the purposes of this Business Practice (BP 8400), are defined as thermal fuel type resources (i.e. natural gas, petroleum, coal, nuclear, biomass, geothermal, waste heat), pump storage hydroelectric resources, and hydroelectric resources with reservoir storage capability not subject to hourly river flow limitations similar to run-of-river hydro.

Conventional resources that are deemed controllable and dispatchable by the LRE, Market Participant, or Generator Owner will have their ACAP determined in accordance with this BP 8400. Behind-The-Meter Generation resources that are considered non-controllable and non-dispatchable by the Transmission Provider, Market Participant, or the LRE will not receive an ACAP value. The determination of ACAP for other resource fuel types are outlined in Attachment AA of the SPP OATT, SPP Planning Criteria, and other SPP Business Practices.

2.0 Data Timeline and Requirements

The Transmission Provider will determine for each applicable season the Conventional Resource Performance Adjustment for qualified conventional resources under Attachment AA with data provided for the resources from the LRE, Market Participant, or Generator Owner. Conventional Resource Performance Adjustment is defined in Attachment AA of the SPP OATT. The data will be supplied to the Transmission Provider with the appropriate information to perform the Conventional Resource Performance Adjustment calculation for each applicable season in accordance with the following timeline requirements:

1. By June 1 of every year, the LRE, Market Participant, or Generator Owner will submit the latest Summer Season performance information to the Transmission Provider. By December 1 of every year, the LRE, Market Participant, or Generator Owner will submit the latest Winter Season performance information to the Transmission Provider. This information shall include, but is not limited to, the following information:

    a. For NERC registered resources:

i. Generator Availability Data System (GADS) event specific data from the events screen for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
ii. Monthly GADS information from the performance screen for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
iii. For resources modeled in the Control Room Outage Window (CROW), a designation for each planned and maintenance event indicating if it is an Authorized Outage in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when the event is submitted or modified in CROW at the time of the first pre-approval or approval designation.
iv. For resources modeled in CROW, a designation indicating if a forced event in GADS has been partially or entirely approved as an Authorized Outage in accordance with Attachment AA of the SPP OATT. The approved events (wholly or partially) will not contribute to a resource's Conventional Resource Performance Adjustment.

b. For non-NERC registered resources:
   i. Performance information as specified in the submission file for non-NERC registered resources posted on the SPP Website for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
   ii. Event specific data as specified in the submission file for non-NERC registered resources posted on the SPP Website for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
   iii. For resources modeled in the Control Room Outage Window (CROW), a designation for each planned and maintenance event indicating if it is an Authorized Outage in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when the event is submitted, or modified, in CROW at the time of the first pre-approval or approval designation.

2. The Transmission Provider will post individual resource Conventional Resource Performance Adjustment results for each season in accordance with Attachment AA of the SPP OATT. The Transmission Provider will also post class average EFORd results for the Summer Season and class average EFORd and EFOF results for the Winter Season. These results will be utilized for the upcoming Summer Season or Winter Season in the following calendar year to calculate the ACAP of resources qualified under Attachment AA of the SPP OATT.

3.0 ACAP Calculation and Assumptions

3.1 Determination of Net Generating Capability and ACAP

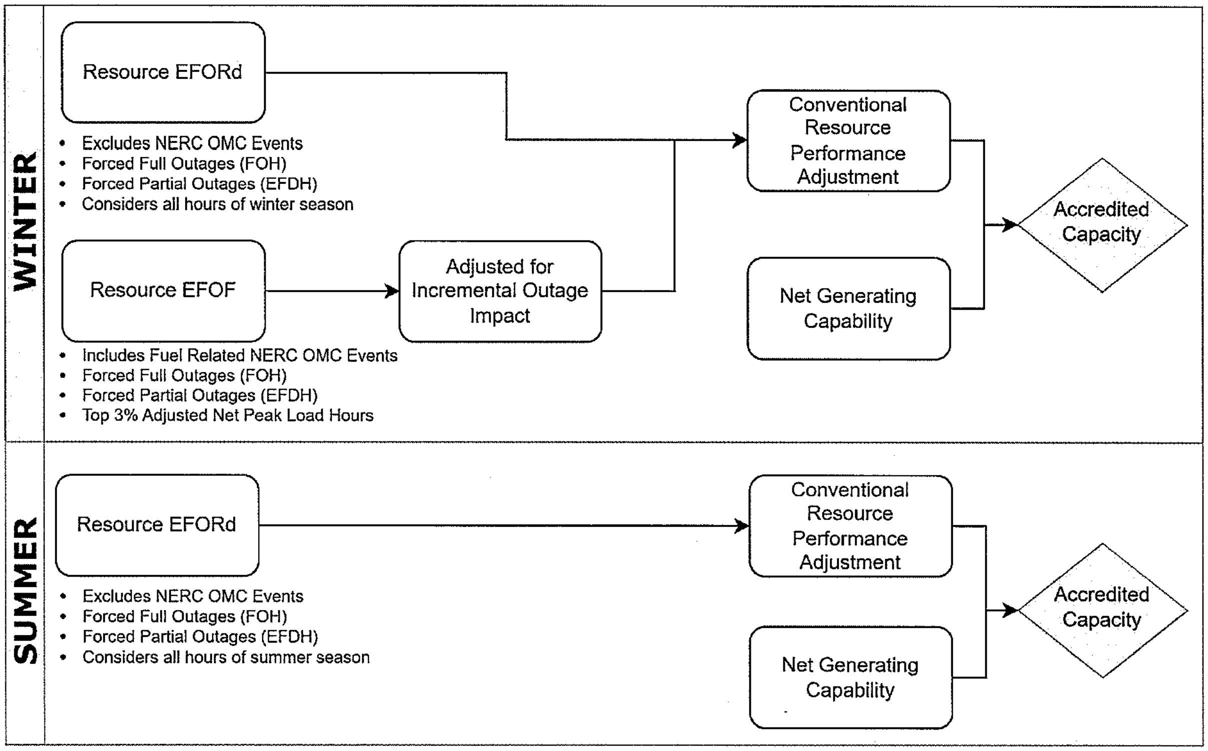
Each conventional resource's ACAP shall be determined using the resource's most recent Net Generating Capability. Net Generating Capability is defined in Attachment AA of the SPP OATT. The calculated Conventional Resource Performance Adjustment value shall be applied to the resource's Net Generating Capability to determine each resource's Accredited Capacity as follows. The individual resource's adjusted EFOF is dependent upon the Incremental Outage Impact compared to the EFOF impact of all conventional resources. A resource's EFOF shall only be considered during the Winter Season.

$$
\begin{aligned}
&Accredited\ Capacity\ (ACAP) \\
&\qquad = Net\ Generating\ Capability \\
&\qquad \times\ (1 - \text{Conventional Resource Performance Adjustment})
\end{aligned}
$$

$$
\begin{aligned}
&\text{Conventional Resource Performance Adjustment} \\
&\qquad = EFORd \\
&\qquad + (\text{EFOF x Incremental Outage Impact / total system EFOF impact})
\end{aligned}
$$

Total system EFOF impact = Sum of [Net Generating Capability x EFOF] of all resources

The figure below shows the Accredited Capacity calculation and considerations for the Summer Season and Winter Season.



A resource specific example calculation is given below for the Winter Season.

Data Values

Net Generating Capability = 100 MW

EFORd = 15%

EFOF = 10%

Incremental Outage Impact = 4,500 MW

Total system EFOF impact =7,000 MW

Calculated Values

Conventional Resource Performance Adjustment = 15% + (10% x 4,500 MW / 7,000 MW) = 21.43%

Accredited Capacity = 100 MW x (1 - 21.43%) = 78.57 MW

3.2 EFORd Formula

The Transmission Provider will use the demand equivalent forced outage rate (EFORd) equation, similar to the equation outlined in NERC GADS Appendix F Formulas, when determining the forced outage rate for qualified conventional resources. The formula for EFORd is as follows:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} \times 100\%$$

Where:

SH = Service Hours (Hours where the resource is generating in serving load or operating reserves)

Synch Hours = Synchronous Condensing Hours (Hours the resource is in the synchronous condensing mode. The units are considered to be in non-generating service operation.)

FOHd = f × FOH = Forced Outage Hours demand (Hours which the resource experienced full forced outages and startup failures, and the resource would have operated had it been available.) The demand factor (f) is determined using the following formula:

$$f = \frac{\left(\frac{1}{r}\right) + \left(\frac{1}{T}\right)}{\left(\frac{1}{r}\right) + \left(\frac{1}{T}\right) + \left(\frac{1}{D}\right)}$$

Where:

r = Average forced outage duration = FOH / (Number of full forced outage occurrences)

D = Average demand time = (SH + Synch Hours) / (Number of resource actual starts)

T = Average Reserve Shutdown time = RSH / (Number of resource attempted starts)

RSH = Reserve Shutdown Hours (Hours the unit is available but not committed for Service Hours.)

FOH = Forced Outage Hours (Hours which the resource experienced full forced outages and startup failures)

EFDHd = fp × EFDH = Equivalent Forced Derate Hours demand (Hours which the resource is in forced derate, and the resource would have operated had it been available.) Each individual forced derating event would need to be transformed into equivalent full outage hours by using the formula (Derating hours × Size of reduction) / net generating capability. The partial demand factor (fp) is determined using the formula:

$$\frac{(SH + \text{Synch Hours})}{\text{AH}}$$

Where AH = Available Hours (Summation of all Service Hours, Reserve Shutdown Hours, Pumping Hours, and Synchronous Condensing Hours for the specified time period.)

Special cases will be considered in the following order for the specified time period and season:

If reserve hours < 1, $f = 1$,

$f = 1$ when (SH + Synch Hours) = 0

$f = 0$ when (1/r + 1/T + 1/D) = 0

1/r = 0 when the number of full forced outage occurrences = 0 or FOH = 0

1/T = 0 when RSH = 0 or the number of unit attempted starts = 0

1/D = 0 when the number of unit actual starts = 0 or (SH + Synch Hours) = 0

fp = 0 when (SH + RSH + Synch Hours) = 0

EFORd = 0 when (SH + Synch Hours + FOHd) = 0

Resources with less than 100 Service Hours per season and year will have their Service Hours adjusted in accordance with the formula below.

Where Service Hours < (Months of Operation/4 * 100) and attempted starts is greater than zero:

$$SH' = \left[\left(\frac{Actual\ Starts}{Attempted\ Starts}\right) * \left(\frac{Months\ of\ Operation}{4} * 100 - SH\right)\right] + SH$$

An example calculation is given below for a resource based on one year and season of data.

Data Values

Demonstrated net generating capability = 150 MW

Months of Operation = 4 months for one season and one year

FOH = 192 Hours

EFDH =10 Hours

FO Events = 2

Actual Starts = 15

Attempted Starts = 15

RSH = 346 Hours

SH = 1,995 Hours

AH = 2,341 Hours

Sync Cond Hours = 0 Hours

Calculated Values

1/r (average forced outage derated hours) = 0.0104

1/D (Average demand Time) = 0.0075

1/T (Average Reserve Shutdown Time) = 0.0434

f (Demand Factor) = 0.8774

SH' = Not Applicable since SH is above 100 Hours

FOHd = 168.45 Hours

fp (Demand Factor) = 0.8523

EDFHd = 8.41 Hours

EFORd = 8.20%

3.3 EFOF Formula

The Transmission Provider will use the equivalent forced outage factor (EFOF) equation, similar to the equation outlined in NERC GADS Appendix F Formulas, when determining the forced outage factor for qualified conventional resources. The formula for EFOF is as follows:

$$\frac{(FOH + EFDH)}{(\text{ANPLH})} \times 100\%$$

Where:

FOH = Forced Outage Hours (Hours which the resource experienced full forced outages and startup failures) during the top 3% of Adjusted Net Peak Load hours for each season and year

EFDH = Equivalent Forced Derate Hours (Hours which the resource is in forced derate) during the top 3% of Adjusted Net Peak Load hours for each season and year. Each individual forced derating event would need to be transformed into equivalent full outage hours by using the formula (Derating hours × Size of reduction) / Net Generating Capability.

ANPLH = Adjusted Net Peak Load Hours (Hours which are the top 3% Adjusted Net Peak Load hours for each season and year). Adjusted Net Peak Load is defined in Attachment AA of the SPP OATT and described in more detail below.

An example calculation is given below for a resource based on one year and season of data.

Data Values

Net Generating Capability = 150 MW

FOH = 15 Hours

EFDH = 5 Hours

ANPLH = 88 Hours

Calculated Values

EFOF = (15 + 5) / 88 = 22.7%

3.3.1 <u>Calculation of Adjusted Net Peak Load Hours (ANPLH) and determination of top 3% ANPLH</u>

The Transmission Provider will determine the ANPLH based on the actual SPP Balancing Authority (BA) Area demand and the actual production output of wind and solar facilities registered in the SPP Marketplace. An updated list of SPP BA ANPLH values, representing data from all applicable years, will be posted by the Transmission Provider no later than April 1 of each year. An example is given below for eight consecutive hours. This calculation will be performed on an hourly basis for each applicable historical year.

Hour	SPP BA Demand (MW)	Wind Output (MW)	Solar Output (MW)	Adjusted Net Peak Load (MW)
1/17/2023 10:00	30,974	3,889	42	27,043
1/17/2023 11:00	30,509	3,311	48	27,149
1/17/2023 12:00	30,022	4,057	61	25,904
1/17/2023 13:00	29,850	4,847	62	24,942
1/17/2023 14:00	29,476	5,711	44	23,720
1/17/2023 15:00	29,319	6,509	42	22,767
1/17/2023 16:00	29,642	7,162	62	22,418
1/17/2023 17:00	30,626	8,348	28	22,250

The top 3% will be calculated based on the total number of hours in each season and year. For example, during the Winter Season for one historical year, there are 2,904 hours (121 days x 24 hours). Therefore, 87 hours would be considered as the top 3% ANPLH in this example. The determination of the top 3% ANPLH for the Winter Season will consider the timeframe of December 1st of the previous year and March 31st of the subsequent year. Since EFOF will not be calculated for the Summer Season, the ANPLH will not be determined for the Summer Season. To determine the top 3% ANPLH for each year, the ANPLH values will be ranked from highest to lowest. The top 3% will be selected as the ANPLH and the FOH and EFDH occurring on these hours will be considered for each year when determining the resource's EFOF. An example is given below for determining the FOH and EFDH during the top eight ANPLH for an individual season and year.

Hour	Adjusted Net Peak Load (MW)	FOH	EFDH
2/1/2023 10:00	34,885	0.75	
1/31/2023 18:00	34,722		0.5
1/31/2023 11:00	34,565		0.5
1/31/2023 10:00	34,488	1	
1/31/2023 12:00	34,378	1	
1/31/2023 17:00	34,352		0.5
1/31/2023 19:00	34,278		
2/1/2023 9:00	34,266		

3.4 Determination of Incremental Outage Impact

The Incremental Outage Impact shall be performed by the Transmission Provider on a biennial basis in accordance with the LOLE Study scope. The most recent Incremental Outage Impact shall be used when determining the adjusted EFOF impact for all conventional resources. The Incremental Outage Impact will be modeled as the incremental forced outages in excess of the normally modeled forced outages experienced during timeframes of extreme temperatures from the LOLE Study. A sensitivity in the LOLE study shall be performed without the inclusion of the Incremental Outage Impact modeling component. The resulting impact on the Base PRM between the two scenarios, one with and the other without the incremental forced outages, will be calculated and set as the Incremental Outage Impact. The impact shall be determined for the two scenarios by adding or removing the same amount of load in every hour of the assessment period until a total LOLE is achieved across the totality of the historical weather years analyzed for the applicable season and where the resulting LOLE is equivalent between the two scenarios. Incremental Outage Impact shall only be considered during the Winter Season.

An example calculation is given below for determining the Incremental Outage Impact for the Winter Season.

Incremental load added to achieve a Winter Season LOLE of 0.03 while modeling the incremental correlated forced outages = 8,000 MW

Incremental load added to achieve a Winter Season LOLE of 0.03 without the incremental correlated forced outages = 12,700 MW

Incremental Outage Impact = 12,700 MW – 8,000 MW = 4,700 MW

3.5 Conventional Resource Performance Adjustment outage considerations

Each resource will have its Conventional Resource Performance Adjustment calculated independently for both the Summer Season and Winter Season. A resource's Summer Season EFORd shall include events occurring during all hours between June 1st and September 30th. A resource's Winter Season EFORd shall include events occurring during all hours between December 1st of the previous year and March 31st of the subsequent year.

For full and partial forced outage events, only the outage hours that occurred during the applicable season will be used when calculating the EFORd. For example, if a resource has a full forced outage event lasting from May 15th to June 15th, the amount of forced outage hours used from the event will be 336 hours instead of 744 hours for the EFORd calculation.

A resource's Winter Season EFOF shall include events occurring during the top three percent (3%) Adjusted Net Peak Load hours for the Winter Season for each historical year. The EFOF calculation would only consider the forced event if the event occurred during the top 3% of Adjusted Net Peak Load hours. The Conventional Resource Performance Adjustment calculated for the Summer Season will not consider the resource's EFOF.

3.5.1 Authorized Outages

For resources modeled in CROW, data submitters are required to identify whether each outage or derate event was authorized by the applicable Balancing Authority (BA). An Authorized Outage is defined in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when the event is submitted or modified in CROW at the time of the first pre-approval or approval designation.

Outages or derates not authorized by the applicable BA shall be considered "unauthorized" and will be treated as forced outages in the calculation of EFORd and EFOF, unless the event is classified as Outside Management Control (OMC).

Authorized outages (whether full or partial) are excluded from the calculation of a resource's Conventional Resource Performance Adjustment.

For NERC-registered resources, a supplemental submission must be provided to SPP identifying GADS planned and maintenance events that were not partially or fully authorized by the applicable BA. For resources not registered with NERC, the non-NERC outage data submission form includes a column which must be used to indicate whether planned and maintenance events were authorized by the applicable BA. Resources not modeled in CROW are exempt from this specific identification requirement.

3.5.2 Out of Management Control Events

OMC events, as defined by NERC GADS Appendix K, shall be excluded from determining the resource's EFORd, regardless of event type designation. NERC GADS Appendix K outlines each OMC event type, including events related to fuel supply.

Certain fuel related OMC events, as outlined below, shall be included when determining the resource's EFOF, which means the event types will impact a resource's Accredited Capacity for the Winter Season. Any remaining OMC events shall be excluded when determining the resource's EFOF for the Winter Season. Any modifications to this list of outages will need to be discussed and approved through the Supply Adequacy Working Group (SAWG) and other applicable governing bodies.

The OMC events to be included when calculating a resource's EFOF are as follows:

GADs Cause Code	Description
9036	Storms (ice, snow, etc)
9130	Failure of fuel supplier to fulfill contractual obligations or a pre-arranged deal due to physical fuel disruptions or operational impairments (e.g. force majeure on a pipeline or compressor down; making the pipeline incapable of making its firm deliveries.)
9132	Wet fuel – Biomass (OMC)
9135	Lack of water (hydro)
9138	High Water Level in Tailrace (too much water)
9200	High ash content (OMC)
9210	Low grindability (OMC)

9220	High sulfur content (OMC)
9230	High vanadium content (OMC)
9240	High sodium content (OMC)
9250	Low BTU coal (OMC)
9260	Low BTU oil (OMC)
9270	Wet coal (OMC)
9280	Frozen coal (OMC)
9290	Other fuel quality problems (OMC)

3.5.3 Data not provided during season-specific data submission window

All commercially operable resources qualified as internal to the SPP Balancing Authority Area through the Resource Adequacy Workbook submission process where historical performance data exists but is not provided for the applicable season and historical year will receive 100% EFORd for the Summer Season and will receive 100% EFORd and 100% EFOF for the Winter Season for the applicable historical year in determining the resource's Conventional Resource Performance Adjustment. Once a resource has been qualified for the purposes of meeting SPP Resource Adequacy requirements, the resource will be required to continually submit historical performance data during the data submission window to avoid a 100% EFORd and 100% EFOF being used in the resource's determination of Conventional Resource Performance Adjustment for the applicable historical year and season.

If data are provided beyond the applicable season's data submission window but during the next applicable season's data submission window, they will be used in the upcoming year's Convention Resource Performance Adjustment calculation, allowing the 100% EFORd and 100% EFOF value to be replaced with EFORd and EFOF values based on historical performance data.

For example, if 2024 Summer Season information is not provided by June 1, 2025, and causes the resource's calculations to consider 100% EFORd for historical year 2024 in the EFORd values posted on October 1, 2025, the entity may not resolve the data deficiency until the following submission deadline of June 1, 2026. The 100% EFORd for year 2024 shall be considered in the resource's Conventional Resource Performance Adjustment value used for compliance with the 2026 Summer Season Resource Adequacy Requirement. However, if 2024 data is provided by June 1, 2026 for the specific resource, the data will be considered in the 2026 EFORd calculations used for the 2027 Resource Adequacy Requirement, resolving the 100% EFORd application on historical year 2024. The same would be applicable for the Winter Season except the due date for Winter Season data would be December 1 of every year.

3.5.4 Intermittently qualified resources

For a resource that is not qualified in the Resource Adequacy process every year, the resource's historical EFORd and EFOF values used for the calculation will be utilized for the determination of the resource's Conventional Resource Performance Adjustment, regardless of whether historical data is provided. The resource will not be considered a new resource for determining its Conventional Resource Performance Adjustment since it has been previously qualified in the SPP Resource Adequacy process.

3.6 Years considered in determining EFORd and EFOF

The most recent seven (7) years of historical performance data will be used to determine a resource's EFORd for the Summer Season. The most recent seven (7) years of historical performance data will be used to determine a resource's EFORd and EFOF for the Winter Season. Each historical year shall have the same weight applied and averaged together to calculate the seasonal EFORd and EFOF. The example shown below demonstrates the derivation of the Conventional Resource Performance Adjustment for the Winter Season applied to an individual resource using 7 years of data.

Season	Current Year – 7	Current Year – 6	Current Year – 5	Current Year – 4	Current Year – 3	Current Year – 2	Current Year – -1	Average of 7 years
Winter EFORd	5.7%	1.8%	6.4%	3.3%	4.0%	2.7%	9%	4.7%
Winter EFOF	21%	15%	10%	15%	2%	1%	14%	11%

$$\text{Conventional Resource Performance Adjustment} = 4.7\% + \left(11\% \text{ x } \frac{4{,}500 \text{ MW}}{7{,}000 \text{ MW}}\right)$$

$$= 11.77\%$$

Where 4,500 MW is the Incremental Outage Impact and 7,000 MW is the total system EFOF impact

3.7 Implementation timeline for existing resources

The Conventional Resource Performance Adjustment shall consider the most recent 7 years in the calculation. For the first four (4) years of the performance based accreditation policy, 2026 through 2029, seven years of historical data will not be available to calculate the Conventional Resource Performance Adjustment on each resource. Therefore, the most recent three years of historical data from the individual resource and four years of class average EFORd and EFOF values for the specific resource will be utilized for year 2026 seasonal Conventional Resource Performance Adjustment calculations. This means that the 2026 Summer Season values posted by October 1, 2025 will contain class averages in place of actual data for years 2018, 2019, 2020, and 2021 while actual data years 2022, 2023, and 2024 will be used for the resource calculations. By year 2030, seven years of historical data from the individual resource will be used when determining the resource's seasonal EFORd and EFOF values, while a seven-year rolling average is calculated for each subsequent year. Class average values are indicated with an asterisk (*). The Conventional Resource Performance Adjustment year is shown in the first column and the historical performance data years are shown along every other row.

2026	2018	2019	2020	2021	2022	2023	2024	Average
	5.0%*	5.0%*	5.0%*	5.0%*	3.1%	4.2%	7.3%	4.9%
2027	2019	2020	2021	2022	2023	2024	2025	Average
	5.0%*	5.0%*	5.0%*	3.1%	4.2%	7.3%	1.5%	4.4%
2028	2020	2021	2022	2023	2024	2025	2026	Average
	5.0%*	5.0%*	3.1%	4.2%	7.3%	1.5%	3.5%	4.2%
2029	2021	2022	2023	2024	2025	2026	2027	Average
	5.0%*	3.1%	4.2%	7.3%	1.5%	3.5%	8.2%	4.7%
2030	2022	2023	2024	2025	2026	2027	2028	Average
	3.1%	4.2%	7.3%	1.5%	3.5%	8.2%	2.3%	4.3%

For non-NERC registered units, event-specific performance records may be unavailable for periods prior to Summer Season 2024. In such instances, monthly performance summaries may be submitted for historical years to support the calculation of EFORd.

However, the calculation of EFOF requires event-level detail. If event-specific data is not provided, the resource will be assigned the applicable EFOF class average, based on the appropriate technology classification, as outlined in this Business Practice. This exception will be permitted only for Winter Season 2022–2023 and Winter Season 2023–2024.

Beginning with Winter Season 2024–2025, failure to submit event-specific data will result in assignment of a 100% EFOF for the applicable season and year.

3.8 Conventional Resource Performance Adjustment determination for new conventional resources

3.8.2 EFORd

For newly constructed conventional resources and newly submitted conventional resources, class average EFORd values will be used when calculating their Conventional Resource Performance Adjustment for years where historical data does not yet exist when calculating the resource's Conventional Resource Performance Adjustment up to the required number of years. The Generation Owner will have the ability to provide the resource's design performance projections (EFORd projections) in lieu of the class average EFORd if desired. The EFORd value initially chosen would then be phased out of the calculation as historical data is available. The same EFORd initially chosen would continue to be utilized in all future calculations for the resource until it is phased out. If an entity does not submit outage data following its initial accreditation year for a newly accredited resource or new unit, the resource will receive a 100% EFORd and 100% EFOF for that historical year where no historical performance data is provided.

The table below shows an example on how a new natural gas resource with a design performance projection of 3% EFORd would be applied within the first eight years of commercial operation for the Summer Season. The EFORd values with an asterisk (*) indicate the design performance projection of 3% while the other values indicate the actual performance of the generating facility for each applicable operating year.

Operating Years	(Current Year – 1) EFORd	(Current Year – 2) EFORd	(Current Year – 3) EFORd	(Current Year – 4) EFORd	(Current Year – 5) EFORd	(Current Year – 6) EFORd	(Current Year – 7) EFORd	Average EFORd (7 years)
0	3%*	3%*	3%*	3%*	3%*	3%*	3%*	**3.0%**
1	4%	3%*	3%*	3%*	3%*	3%*	3%*	**3.1%**
2	7%	4%	3%*	3%*	3%*	3%*	3%*	**3.7%**
3	1%	7%	4%	3%*	3%*	3%*	3%*	**3.4%**
4	3%	1%	7%	4%	3%*	3%*	3%*	**3.4%**
5	2%	3%	1%	7%	4%	3%*	3%*	**3.3%**
6	8%	2%	3%	1%	7%	4%	3%*	**4.0%**
7	10%	8%	2%	3%	1%	7%	4%	**5.0%**

3.8.3 EFOF

Newly constructed conventional resources will be afforded the initial EFOF value of zero (0%), and each year would incorporate the previous year's actual EFOF to be used in an averaging method over the number of operating years data. The initial 0% EFOF would be phased out of the calculation as historical data is available as shown in the EFOF example below.

The class average EFOF for the applicable resource type shall be applied to newly submitted conventional resources provided in the Resource Adequacy construct that have been in commercial operation (i.e. not newly constructed) when calculating their Conventional Resource Performance Adjustment for years where historical data does not yet exist when calculating the Conventional Resource Performance Adjustment up to the required number of years.

The table below shows an example on how a newly constructed natural gas resource's EFOF would be applied within the first seven years of commercial operation for the Winter Season. The EFOF values indicate the actual performance of the generating facility for each applicable operating winter year.

Operating Years	(Current Year-1) EFOF	(Current Year-2) EFOF	(Current Year-3) EFOF	(Current Year-4) EFOF	(Current Year-5) EFOF	(Current Year-6) EFOF	(Current Year-7) EFOF	Average EFOF
0	0%	---	---	---	---	---	---	0%
1	0%	---	---	---	---	---	---	0%
2	5%	0.0%	---	---	---	---	---	2.5%
3	10%	5.0%	0%	---	---	---	---	5%
4	0%	10.0%	5%	0%	---	---	---	3.75%
5	5%	0.0%	10%	5%	0%	---	---	4%
6	10%	5.0%	0%	10%	5%	0%	---	5%
7	0%	10.0%	5%	0%	10%	5%	0%	4.3%

In the event the Transmission Provider does not determine a resource's EFOF prior to the first season the resource is qualified under Attachment AA, the resource's EFOF determined by the entity shall not be adjusted for Incremental Outage Impact for the first applicable season.

3.9 Resources undergoing a primary fuel type conversion

If a resource that has been in commercial operation undergoes a primary fuel type change, the Transmission Provider will utilize historical performance values for years prior to the new in-service date following the technology or primary fuel type change unless the LRE or Generation Owner chooses to use class average or design performance values for EFORd. If the entity chooses to use updated values, the LRE or Generation Owner must notify the Transmission Provider via email no later than June 1 for the upcoming Summer Season and December 1 for the Winter Season, and the EFOF values will be set to 0% to consider the resource as newly constructed. The 0% EFOF application only applies if the LRE or Generation Owner chooses to use class average or design performance values for EFORd calculations.

4 Class average EFORd and EFOF determination

The Transmission Provider will calculate and publish a class average EFORd for the Summer Season and EFORd and EFOF for the Winter Season in accordance with Attachment AA of the SPP OATT. The resources shall be classified by technology and fuel type as identified in the Workbook, and then the EFORd or EFOF of each resource shall be weighted against all other resources in the same class for determining class average EFORd or EFOF. For combustion turbine and reciprocating internal combustion engine technology resources, entities may provide additional information related to on-site liquid fuel storage capabilities; resources which meet the criteria for this fall into a different classification for EFORd and EFOF weighted averages as stated in the following section. The weighted class average Winter Season EFOF for each class shall be determined using the EFOF from resources within the class. The class average EFOF shall be calculated prior to the application of Incremental Outage Impact. Only submitted data will be included when calculating EFORd and EFOF class averages; the 100% EFORd or EFOF assignment for data which was not submitted before the season-specific data submission window will not be considered in class average calculations for EFORd and EFOF.

$$\frac{Sum\ of\ [Net\ Generating\ Capability \times (1 - \text{EFORd})]\ from\ resources\ within\ the\ class}{Sum\ of\ Net\ Generating\ Capability\ from\ resources\ within\ the\ class}$$

The table below gives an example of one fuel type with five (5) resources, each one with a different EFORd and Net Generating Capability. Using the formula above, the weighted class average EFORd for this example fuel type would be 8.5% (741 / 810).

Resource	Net Generating Capability (MW)	EFORd	Net Generating Capability x (1-EFORd) (MW)
Resource A	100	5%	95
Resource B	10	10%	9
Resource C	200	8%	184
Resource D	350	7%	325.5
Resource E	150	15%	127.5
Total	810		741

4.1 <u>On Site Fuel Storage Determination</u>

Entities may provide additional information for Combustion Turbine and Reciprocating Internal Combustion Engine resources to calculate the availability rate for on-site fuel storage. The type of on-site fuel, initial stored capacity in runtime hours, resupply capacity in runtime hours, and resupply frequency in a 24-hour period may be submitted in the

Workbook specific to a resource. The availability rate for on-site fuel storage will be determined by calculating the on-site fuel storage capacity and resupply capacity over 48 hours using a 12-hour daily requirement. For resources to qualify for the on-site fuel storage classification, an availability rate for on-site fuel storage must be at least 100% based on the following formula:

Availability Rate for On Site Fuel Storage =

$$\frac{\frac{Initial\ Stored\ Capacity}{12} + \frac{Resupply\ Capacity\ x\ Resupply\ Frequency}{12}}{2}$$

Where:

Initial Stored Capacity = The number of hours the resource can operate solely using on-site stored fuel.

Resupply Capacity = The number of hours the resource can operate using fuel provided through a resupply event, if applicable.

Resupply Frequency = The number of times the resource is expected to receive fuel resupply in a 24-hour period following a fuel scarcity event. On-site fuel capability metrics should be submitted using the On-Site Fuel Capability form available on the SPP website. To be considered for class average designation, the completed form must be submitted by June 1 for the upcoming Summer Season and December 1 for the Winter Season. Once submitted, these metrics remain valid unless the LRE, Market Participant, or Generator Owner provides updated information to the Transmission Provider.

5.0 Verification of ACAP for Resource Specific Power Purchase Agreements or Fleet Based Agreements

Power purchase agreements from specific resources will have the resource's Conventional Resource Performance Adjustment applied from the resource supporting the agreement when the Transmission Provider verifies the Accredited Capacity of all agreements do not exceed the resource's Accredited Capacity. If there are more than one resource supporting the agreement, then the Transmission Provider will compare the total Accredited Capacity of all the identified resources to the total contracted amount of all the applicable agreements to verify the Accredited Capacity of the identified resources are not exceeded.

6.0 SPP Marketplace considerations

Market Participants, LRE, or Generator Owners of conventional Resources qualified in accordance with Attachment AA of the SPP Tariff that are registered in the SPP Marketplace should offer, at a minimum, the conventional Resource's demonstrated net generating capability into the Day-Ahead Market and the Real-Time Balancing Market, as defined in Attachment AE of the Tariff, for every hour of the applicable season, except to the extent that the Resource is unavailable due to a full outage or de-rate that is being reported using the data submission process as specified in this Business Practice 8400. Compliance with this obligation will be evaluated as needed by the SPP Market Monitoring Unit or the Transmission Provider on a non-discriminatory basis.

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