Southwest Power Pool

2025 SPP LOLE STUDY SCOPE

By SPP Resource Adequacy

January 2025

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/30/2025	SPP		SAWG Approved

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1. OVERVIEW AND OBJECTIVE

Attachment AA of the SPP Open Access Transmission Tariff (OATT) states SPP shall perform a biennial Loss of Load Expectation (LOLE) study, which investigates the expected number of days per year of available generating capacity to serve forecasted Peak Demand. Determination of the SPP Planning Reserve Margin (PRM) will be supported by the probabilistic LOLE Study, which will analyze the ability of generation to reliably serve the SPP Balancing Authority (BA) Area's forecasted Peak Demand while utilizing a Security Constrained Economic Dispatch (SCED). SPP, with input from the stakeholders, will develop the inputs and assumptions to be used for the LOLE Study. SPP will study the PRM such that the annual LOLE for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year (d/yr) The Base PRM for the Summer Season and Winter Season shall be determined using probabilistic methods in the LOLE Study to ensure the combined LOLE from the Summer Season and Winter Season does not exceed 0.1 day per year by considering factors including, but not limited to: forecasted demand and generation, load profiles, generator forced outages, load forecast uncertainty, demand response programs, variable energy resource profiles, and resulting expected unserved energy ("EUE") levels for each applicable season. Results will be compiled into a report and presented to the Supply Adequacy Working Group (SAWG), Resource and Energy Adequacy Leadership (REAL) Team, and any other appropriate working groups and committees.

Any recommendations for a change in the Base PRM will be posted as a separate document than the LOLE Study report. The Transmission Provider, with stakeholder input, will provide a recommended Base PRM value for the Summer Season and Winter Season and a recommended implementation timeline for any proposed change in the Base PRM value that considers regional available capacity and generator interconnection queue timelines to the Markets and Operations Policy Committee, Regional State Committee, and the SPP Board of Directors. Any change to the PRM will be approved through the appropriate working group and committees at SPP using the SPP Revision Request process.

2. 2023 VS 2025 STUDY DIFFERENCES

Table 1. Routine Data Update

Assumptions	2025 Study	2023 Study
Historical Wind, Solar, & Load Profiles	Years from 1980 to 2024 (Include most recent 2 years in study and re-synthesize shapes using most recent 2 years)	Years from 1980 to 2022
Cold Weather Related Outages	Temperature to outage correlation built using GADS data from years 2010-2024	Temperature to outage correlation built using GADS data from years 2010-2022
Outage data years	2017 to 2024	2015 to 2022
Physical and Economic Thermal Resource Parameters	Refresh parameters based on market data through 2024	Utilized market data through 2020

Table 2. Methodology and Assumption Changes from 2023 LOLE Study

Assumptions	2025 Study	2023 Study
Planning Years	Year 5 and Year 7 (2030 and 2032)	Year 3 and Year 6 (2026 and 2029)
Hydro Modeling	Consider hydro load obligations and additional available hydro in emergency conditions as improved modeling practices that capture hydro utilization more reflective of real-time	Historical energy limitations based on median year

3. STUDY TIMELINE

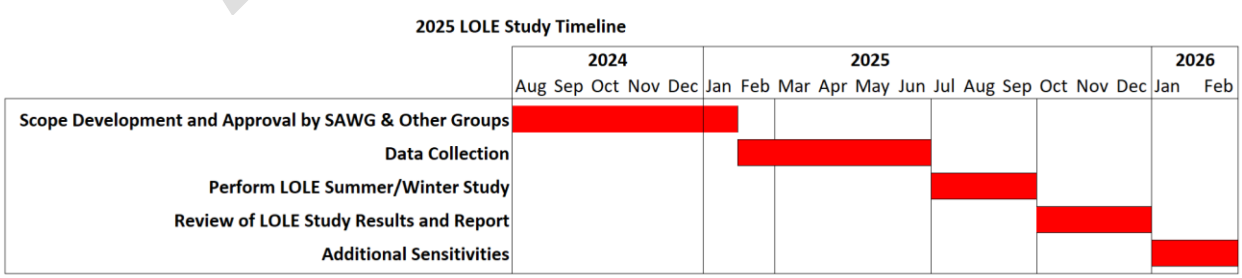

Figure 1. 2025 LOLE Study Timeline

LOLE Study Timeline

1. Scope Development and Approval by SAWG & other applicable groups
2. Data collection
3. LOLE Study performed for study years
4. LOLE Study results and report review
5. Additional sensitivities and analysis (as needed)

4. INPUT DATA

4.1. SOFTWARE

SERVM will be the software used for the 2025 LOLE Study. SERVM is a production-cost software, which performs a Security Constrained Economic Dispatch while utilizing a Monte-Carlo algorithm when varying the uncertainty of load and availability of capacity through multiple simulations.

4.2. AREA MODELING

The LOLE Study will be performed on the SPP Balancing Authority Area footprint, which includes all or parts of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Nebraska, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, and South Dakota. The SPP Balancing Authority Area footprint will be modeled as separate areas referred to as LOLE Zones (Zones) that were determined through the Zonal Formation Methodology performed for the 2019 LOLE Study. If a specific zone is found to be transmission constrained, the PRM would be impacted by the most limiting zone. The results will include how much impact the limiting zone(s) have to the PRM if any limitations exist. The 2025 LOLE Study will utilize the same zone definition as in previous LOLE Studies. The map and table below represent the Zones that will be modeled.

Zone 1	Integrated System
Zone 2	Nebraska
Zone 3	West Kansas
Zone 4	East Kansas/Missouri
Zone 5	Southwest SPP
Zone 6	Southeast SPP

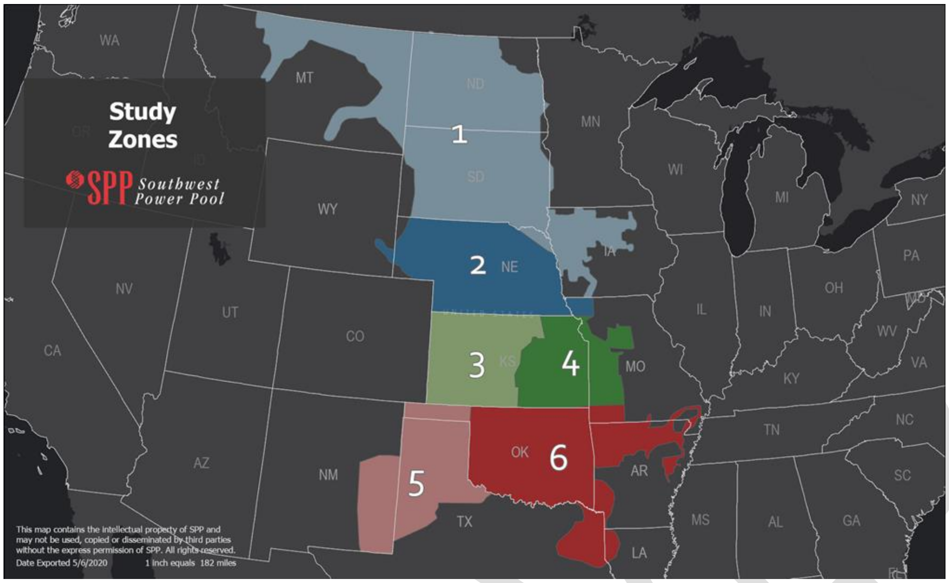

Figure 2. Geographical locations of six zones in LOLE Study

4.3. PLANNING YEARS

The 2025 LOLE Study will analyze planning years 5 (2030) and 7 (2032). Year 5 is intended to assist in the transition to the new LOLE study cadence[1] and will have a PRM recommendation. Year 7 will also have a PRM recommendation from the results of this study.

The Resource Adequacy Workbook submissions, as well as the provided feedback from entities on resource plans beyond the Workbook submissions as outlined below, will serve as the basis of resources to be considered in the LOLE Study for the applicable planning years.

Part of the additional information needed from LREs for their resource plan submitted for planning year 5 (2030) and year 7 (2032) will need to specifically document the status (in-service, planning) of those resources. For those resources in the planning phase, the LRE will state at a minimum whether the resource has an executed Generator Interconnection Agreement or alternatively submit which Generator Interconnection queue number (DISIS or other interconnection study the resources are being analyzed in).

4.4. BASE MODELS AND TOPOLOGY

The LOLE Study will utilize a pipe and bubble methodology for modeling the transmission system. The load and resources of an individual Zone will be modeled as a "bubble" representing each zone. Import capabilities and export capabilities ("pipe sizes") between Zones will be determined in accordance with the LOLE Zone Import-Export Transfer Capability Methodology.

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[1] https://spp.org/documents/73056/long%20term%20prm%20policy%20paper.pdf

For the LOLE Study, the import and export capability analysis will use the 2025 series Integrated Transmission Planning (ITP) models for system topology. This will include the Board Approved ITP NTC transmission additions along with the NREC approved JTIQ transmission buildouts. The study years will include the summer peaks for 2030 and 2032. If the ITP models for system topology do not match the study years, the closest ITP model year will be used to analyze the import and export capability. The winter PRM analysis will utilize the winter peak models for 2030 and 2032. Transmission additions and retirements are captured in the ITP models with SPP member input from the ITP process[2]. The LOLE Zone import-export methodology will consider internal and crossing interfaces and flowgates for the year 2030. The analysis will also consider the latest SPP list flowgates and interfaces.

4.5. LOAD MODELING

4.5.1. HISTORICAL WEATHER YEARS

For 2025 LOLE Study, historical SPP operational hourly load data (2019—2024) for each LOLE Zone will be collected. Based on the collected historical weather and load data, a neural network program will be used to develop relationships between weather observations with historical temperature and load used as the basis. The historical weather will consist of hourly temperature from the weather stations listed in Table 3. This methodology was also used in the previous LOLE Study[3]. Multiple 8,760 hourly load profiles will be produced for each LOLE Zone and each historical weather year dating back to 1980. The main difference from the 2023 LOLE Study is factoring in the two most recent weather years (2023 and 2024) into the analysis.

In the event that adequate data for tail event correlation is not available from the last 5 years of historical load data, more weather years will be utilized in the correlation of tail events.

Table 3. Weather Stations for Temperature

Zone	Weather Station # 1	Weather Station #2
Zone 1	Minot, ND + Williston, ND	Watertown, SD
Zone 2	Lincoln, NE	North Platte, NE
Zone 3	Dodge City, KS	Wichita, KS
Zone 4	Chanute, KS	Wichita, KS
Zone 5	Amarillo, TX	Midland, TX

[2] ITPNT process scope and ITP Manual: https://www.spp.org/engineering/transmission-planning/

[3] 2023 SPP LOLE Study Report Section 4.2: https://www.spp.org/Documents/71904/2023%20SPP%20LOLE%20Study%20Report.pdf

Zone 6	Oklahoma City, OK	Shreveport, LA

4.5.2. PEAK DEMAND

Pead demand for the respective study year will be sourced from the 2025 Resource Adequacy Workbook submissions and assigned by season. The median peak demand will be set to the forecasted peak demand. All other years' historical load shapes will be assigned the appropriate deviation amount the historical median year's peak increased to meet the forecasted peak demand. For example, if the median year has a historical peak demand of 5,000 MW and year 2012 has a historical peak demand of 5,200 MW, then the ratio for 2012 will be 1.04 (5,200 / 5,000). If the forecasted peak demand is 5,300 MW for year 2032, then the forecasted will be applied to the median year and 2012 peak will be 5,512 MW (1.04 * 5,300 MW). The median year will be determined using SPP's historical peak loads by season.

4.5.3. INTRAZONAL AND INTRASEASONAL DIVERSITY FACTOR

Diversity is considered when modeling the peak demand of each LOLE zone. The individual LREs are assigned to an LOLE Zone, in which a non-coincidental zonal peak demand is determined for each zone using the LREs' forecasted Peak Demands. Then a diversity factor is applied to that specific zone's non-coincident peak demand (from all applicable LREs within the zone) to determine the forecasted coincidental zonal peak demand. The diversity of each LOLE zone will be the average of the most recent 5 years on a seasonal basis and will be applied to the 2030 and 2032 planning years being studied. For example, if the total non-coincident peak demand from all LREs within an LOLE Zone for 2030 is 5000 MW, and that zone's average diversity was 4%, the zone's forecasted coincidental Peak Demand will be 4800 MW (5000* (1-.04)). The intra zonal diversity will be determined using the hourly load data submitted by the LREs. If needed, the zonal peak demands will be adjusted to make sure the average SPP level diversity factor over the previous 5 years is reflected appropriately for each season.

4.6. CONVENTIONAL GENERATION MODELING

4.6.1. GENERATION PORTFOLIO

Resources and net capability ratings that will be submitted in the 2025 Resource Adequacy Workbook process for planning year 2030 (Year 5) and planning year 2032 (Year 7) will be modeled in the LOLE Study. An additional data request will be sent to LREs and Generator Owners for feedback on planned generation and demand response programs for year 2030 and year 2032 and beyond. The provided feedback from entities on resource plans outside of the Workbook submissions will be modeled for the LOLE Study.

4.6.2. CONVENTIONAL RESOURCE FORCED OUTAGE MODELING

Forced outage modeling for conventional resources will consist of using the Equivalent Forced Outage Rate (EFOR) values, forced outage durations, maintenance scheduling parameters, and outage events sourced from 2017 to 2024 NERC GADS data. The most recent seven (7) years are chosen to be consistent with Performance Based Accreditation (PBA) and Effective Load Carrying Capability (ELCC) methodologies. For conventional resources that do not submit NERC GADS data, an average forced outage rate will be applied based on size, fuel type, and age of the resource.

4.6.3. INCREMENTAL COLD WEATHER OUTAGE

Incremental cold weather outage analysis from the previous LOLE study will be re-calculated to consider the most recent two years. The modeling approach will be consistent with the method used in the 2023 LOLE Study. The level of modeled incremental outages will be consistent with the level of incremental cold weather outages used in the 2023 LOLE Study. Simultaneous forced outages of multiple generators will be considered as an incremental outage application due to extreme temperatures.

4.6.4. PLANNED AND MAINTENANCE OUTAGE MODELING

Planned outages for thermal resources are modeled using the scheduled maintenance function in SERVM by switching the status of each resource to "off-line" for a specified period based on start time and duration. Once the outage duration has elapsed, the resource is placed back online in the model, unless there is an immediate outage extension that is forced or planned outage. SERVM determines the best time to schedule a maintenance outage based upon a set seasonal timeframe window. Outages will also be scheduled based on the SPP BA, not individual LOLE Zones, similar to how it was performed in the 2023 LOLE Study.

4.6.5. ECONOMIC AND PHYSICAL RESOURCE PARAMETER MODELING

Generation will be dispatched economically in the LOLE Study consistent with previous LOLE studies. Startup times, minimum downtimes, ramping capability, and other resource parameters will be honored for all generating units. This may result in certain resources with longer start up times not being able to be dispatched for situations that require units with short lead times.

The latest actual information through 2024 provided through the SPP Integrated Marketplace will be utilized, which includes Start-up Cost, Start-up Time, Ramp Rates, Min Down Time, and Min Run Time attributes. For generators where the data is not provided through the SPP Integrated Marketplace, the information will be supplemented by class average values derived from existing data.

4.6.6. HYDRO RESOURCE MODELING

Hydro, unlike thermal generation, will be dispatched according to statutory load obligations and availability of excess energy in emergency time periods. Both the historical output and the flexibility resource owners have in scheduling statutory hydro on a daily basis will be used to determine an appropriate daily output shape. The actual dispatch is assumed to be the amount needed to meet load obligations and will be modeled based on monthly obligations and consistent across all weather years. The remaining available energy above the load obligations will be modeled utilizing physical parameters to allow for SERVM to utilize the flexible remaining energy.

4.6.7. BEHIND-THE-METER GENERATION

Behind-the-meter generation reported in the 2025 Resource Adequacy Workbook submissions will be modeled as generation for the LOLE study.

4.7. WIND AND SOLAR MODELING

Solar and wind resources will be modeled with distinct 8,760 hourly profiles for each of the weather years developed for the load modeling. The modeling method will consist of all resources submitted in the 2025 Resource Adequacy Workbook consistent with the 2023 LOLE Study. An additional data request will be sent to LREs and Generator Owners for feedback on planned generation and demand response programs for year 2030 and year 2032 and beyond. Historical profiles from 2015 to 2024 will used for wind resources to generate the daily profiles for each weather years. To maintain correlation between load and wind in the different profiles, the same day will be used for each wind project being captured. The method will utilize the day that aligned best with the peak load out of all the days +/- 25 days of the source day that was available for the 2015 to 2024 period. While the process is intended to maintain correlation, further adjustments may be necessary to match historical correlations, if for instance, historical generator data begins with different commercial operation dates. If it is required, Astrapé has developed a correlation tool in which the daily profiles will be re-arranged so the historical and modeled profiles will have similar correlations. One wind profile will be modeled for each LOLE Zone at a minimum.

Solar profiles will be built using irradiance and weather data downloaded for each determined site location, as listed below, for the years from 1998 to the latest available year, from the National Renewable Energy Laboratory's (NREL) National Solar Radiation Database (NSRDB) Data Viewer. Irradiance profiles will be obtained for each of the determined solar sites. Data from the NSRDB will be placed into NREL's System Advisor Model (SAM) for each year and site to generate hourly 8760 solar profiles for both fixed and single axis tracking solar profiles. Inverter loading ("DC/AC") ratio assumptions will be 1.0 for all zones in the original creation of the shapes. An inverter loading ratio of 1.3 will be applied to all resources with no provided alternative inverter loading ratio.

Profiles for 1980 to 2014 will be selected by using the daily profiles from the day that best match the peak load out of all the days +/- 3 days of the source day for the 10-year period. Profiles for 2015 to the latest available year will be sourced directly from the normalized hourly SAM data profiles. The site profile with the nearest location to any modeled future solar facilities will be assigned to the facility. All modeled facilities will utilize the created profiles in performing SERVM simulations.

Table 4. Location of Reference Solar Stations

Coordinates (LAT/LONG)	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
Site 1	48.423, -106.395	42.819, -103.120	39.592, -101.547	39.592, -96.342	36.739, -102.283	36.639, -99.228
Site 2	47.031, -104.669	41.616, -103.857	39.328, -99.351	39.357, -94.705	36.259, -100.607	36.279, -97.952
Site 3	48.355, -103.273	42.548, -101.458	38.904, -101.178	38.944, -96.926	35.219, -102.537	35.918, -99.320
Site 4	46.605, -101.661	41.426, -101.965	38.488, -99.389	38.686, -95.238	34.813, -100.671	35.640, -98.228
Site 5	48.042, -100.214	40.583, -100.645	38.239, -101.255	38.408, -93.969	34.038, -102.511	35.254, -99.439
Site 6	46.518, -98.310	41.635, -99.795	37.899, -99.503	38.129, -97.434	33.065, -102.410	34.769, -98.333
Site 7	47.521, -97.510	42.558, -98.843	37.639, -101.299	37.849, -95.911	32.585, -103.654	34.455, -99.281
Site 8	45.549, -103.857	40.756, -99.287	37.246, -99.325	37.598, -94.172	33.606, -103.679	36.734, -96.780
Site 9	44.045, -102.105	41.985, -98.043	39.582, -97.574	37.498, -97.497	34.678, -103.679	36.239, -95.059
Site 10	45.389, -100.112	41.606, -96.723		37.185, -96.165		36.290, -93.442
Site 11	43.963, -99.985	40.477, -97.396				35.965, -96.606
Site 12	45.504, -98.399	40.380, -96.038				35.394, -94.970
Site 13	43.798, -97.599					34.928, -96.632
Site 14	42.977,-94.134					34.142, -94.632
Site 15	42.502, -95.555					33.922, -96.366

4.8. ESR MODELING

Stand-alone batteries and batteries being utilized as surplus/hybrid of a collocated resource will be modeled using the following unit specific variables:

- Max Capability – the maximum capacity the ESR can output to the system for one (1) hour.

- Storage Capability – the overall maximum capacity of the ESR. This is calculated by multiplying the Cap max by the maximum duration of the resource.
- Charge Max Capability – the maximum capacity the ESR can charge in one (1) hour.
- Cycle Efficiency – the cycle efficiency of the ESR, assumed to be 85%.
- Dispatch Method – Economic Arbitrage.

For batteries being utilized as surplus/hybrid of a collocated resource will additionally be modeled with the following facility specific variable:

- Linked Unit – the resource of which the surplus/hybrid are collocated.
- Charging Restriction – determines if restrictions of charging to the collocated resource should be enforced rather than allowing charging from the grid. This parameter will default to grid charging being allowed unless specified otherwise by the resource owner.
- Max Combined Capability – the max combined capacity output of the linked units. Unless otherwise specified, the max capability of the collocated resources will be assumed to be the maximum combined capability not to exceed the point of interconnection capacity.

4.9. DC TIE AND EXTERNAL CAPACITY MODELING

Due to the integration of the West DC Ties into SPP, where the SPP market engine will direct the dispatching levels of the West DC Ties, resource adequacy submitted capacity transactions across the West DC Tie will be modeled as hourly imports in the LOLE study.

For non-West DC Ties and external capacity transactions that are supported by firm contractual commitments in the 2025 Resource Adequacy Workbooks submissions will be modeled as hourly generators in the applicable LOLE Zone. If the transaction is a sale to an entity external to the SPP BA Area, it would be an export of capacity. If the transaction is a purchase from an entity external to the SPP BA Area, it would be an import of capacity. Forced outage rates will not be assigned to the external purchase of capacity and only firm external support will be modeled. Purchases and Sales with entities internal to the SPP BA Area will not be explicitly modeled because the selling entity's resources will be modeled internally to the applicable PRZ in the LOLE Study. External non-firm assistance will not be considered in the LOLE Study, which is consistent with previous LOLE studies.

4.10. DEMAND RESPONSE MODELING

In areas that reported controllable-capacity demand through the 2025 Resource Adequacy Workbook submissions, actual operating parameters of the Demand Response Programs will be modeled, if provided to SPP. If the owner of the Demand Response Program does not provide actual operating parameters of the program, the following parameters will be used as a default, which is consistent with the 2023 LOLE Study.

- 1 Program call per day
- 20 Program calls per season
- 1 hour minimum utilization per call
- 4 hour maximum utilization per call

4.11. CONSIDERATION OF LOLE AND EUE THRESHOLDS

Perfect generation will be removed from the model to achieve the SPP system reaching the 0.1 day per year reliability threshold. The same amount of negative generation will be added to each hour in the simulation. This method is also used in the SPP Effective Load Carrying Capability (ELCC) Studies.

4.11.1. SEASONAL BALANCE

The annual metric of 1 day in 10 years will not be exceeded between the summer (June—September) and winter (December—March) seasons. A balance of seasonal risk will be determined during the course of the study. The balance of risk will consider factors including, but not limited to, the magnitude and duration of outage events and level of EUE between each season.

4.11.2. EXPECTED UNSERVED ENERGY (EUE)

In addition to using the LOLE standard to determine the amount of capacity necessary for calculating the PRM, the metric for Expected Unserved Energy (EUE) will be evaluated. EUE refers to the average energy (MW-hours) that is expected to be unserved during loss of load events. As the SPP resource fleet continues to evolve towards a heavy penetration of energy limited (wind/solar/ESR) resources, EUE will play a larger role in the determination of capacity required. For Year 5 and Year 7 of the 2025 LOLE Study, PRM results will be given in the range of zero (0) to three (3) parts per million (PPM) EUE as well as a LOLE range up to the 0.1 d/yr annual LOLE metric. These results will assist working groups and committee discussions to determine the appropriate PRM for year 2030 and year 2032.

4.12. ADDITIONAL ASSUMPTIONS

1) Each simulation period will be from January 1 to December 31

2) The summer period is defined as June 1 to September 30
3) The winter period is defined as December 1 to March 31
4) Various trials and outage patterns will be performed to reach a convergence of 90% or greater
5) LOLE and EUE measured after full depletion of SPP operating reserves
6) Generation is dispatched using a Security Constrained Economic Dispatch algorithm based on the SPP Balancing Authority Area boundary
7) The System ELCC calculation will align with the approved methodology of the system ELCC from the 2025 ELCC study scope

5. SIMULATION STUDY PROCESS

SPP will conduct SERVM Monte-Carlo simulations by using SERVM. Resources in SPP will be randomly forced out of service during each hour of the study. Each simulation accounts for a different variation of forced outages, wind output, and load uncertainty for all hours of the year. The stop criteria for the Monte-Carlo simulation is to make the convergence factor of LOLE greater than or equal to 90% for consideration of probabilistic indices. SERVM calculates the convergence factor to determine if additional simulations are needed.

6. REPORTING AND RECOMMENDATIONS

The LOLE Study scope will be reviewed and approved by the Supply Adequacy Working Group. Once the final metric results are calculated, they will be compiled in a report, which will be presented to the appropriate working groups or committees for review. If the resulting Planning Reserve Margin (PRM) is increased as a result of Transmission Limitations between the LOLE zones, an analysis of the limitation(s) and the effect(s) on the PRM will be included as an addition to the results. Once the final report has been approved and posted, the recommendations of the Base PRM values will be presented as outlined in Attachment AA Section 4 of the SPP Tariff.