2019 Loss of Load Expectation Scope

SPP Resource Adequacy

Revision History

Date or Version Number	Author	Change Description	Comments
2/21/2019	SPP Staff	Initial Draft	

Contents

Introduction

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. The LOLE is usually measured in days/year or hours/year. The understanding is that when given in days/year, it represents a comparison between daily peak values and installed capacity. This study will be performed biennially based upon the typical industry standard metric, which is the loss of load probability of one day in ten years or 0.1 day/year.

The current SPP Planning Reserve Margin (PRM) is twelve percent (12%). If a modeled area's capacity mix is comprised of at least seventy-five percent (75%) hydro-based generation, then such entity's PRM shall be nine point eight nine percent (9.89%), as defined in the SPP Planning Criteria. Any change to the PRM will be approved through the appropriate stakeholder working group process at SPP.

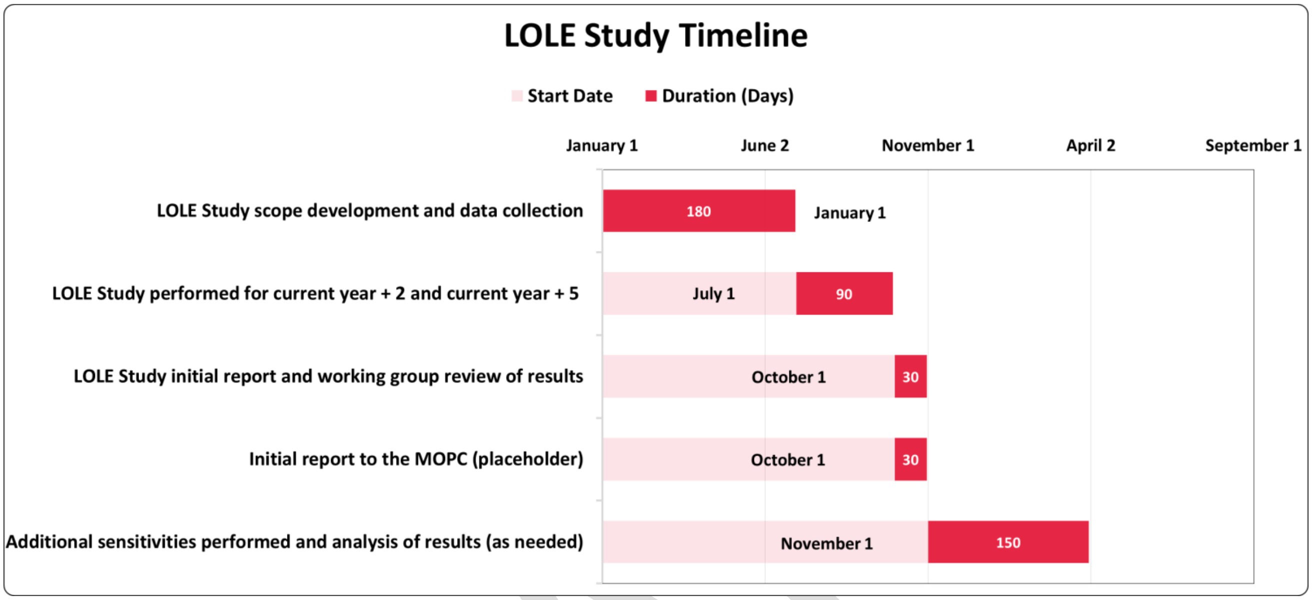
Executive Overview

Determination of the PRM will be supported by a probabilistic LOLE Study, which will analyze the ability of generation to reliably serve the SPP Balancing Authority Area's forecasted Peak Demand while utilizing a Security Constrained Economic Dispatch. 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 LOLE for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year. At a minimum, the PRM will be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year. Final metric results will be compiled into a report and presented to the Supply Adequacy Working Group.

Objective

The LOLE study provides an assessment of whether installed and proposed capacity is adequate to serve the forecasted Peak Demand while determining an appropriate PRM to maintain an LOLE of 1 day in 10 years.

Study Timeline



LOLE Study Timeline

1. LOLE Study scope development and data collection
2. LOLE Study performed for current year + 2 and current year + 5
3. LOLE Study initial report and working group review of results
4. Initial report presented to MOPC (placeholder)
5. Additional sensitivities performed and analysis of results (as needed)

Input Data

Software

SERVM will be the resource adequacy software used for the 2019 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.

Area Modeling

The LOLE Study is 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 modelled as separate areas referred to as Planning Reserve Zones (PRZs) that will be determined through the Zonal Formation Methodology. Each PRZ will be modelled as a separate area to reflect the diversity of Load Forecast Uncertainty (LFU) factors. The planning reserve margin will still be determined by the "weakest link" or most limiting zone and applied to all LREs if there is any change in the Planning Reserve Margin requirement. The map below represents the PRZs that will be modeled.

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 PRZ will be modeled as a “bubble” representing each zone. Import capabilities and export capabilities (“pipe sizes”) between PRZs will be determined in accordance with the LOLE PRZ Import-Export Transfer Capability Methodology.

For the LOLE Study, the import and export capability analysis will use the 2019 series Integrated Transmission Planning (ITP) Base Reliability (BR) models for generation, load, and system topology. The study years will include the summer peak for 2021 and 2024. Transmission additions and retirements are captured in the ITP BR models with SPP member input from the ITP process[1].

Constraints and Monitored Elements

The LOLE PRZ Import-Export methodology will take into account internal and crossing interfaces and flowgates for years 2021 and 2024. The analysis will also consider the latest SPP list flowgates and interfaces. Interfaces are key groups of transmission lines that are observed as one group between Balancing Authority regions or internal areas.

Hourly Load Profiles

Historical hourly load data from 2012 to 2018 will be used to produce 8,760 hourly load profiles for each modeled zone. The historical data is obtained through SPP operational data. FERC 714 filings will be used to complete any missing or abnormal data for each profile.

Generation Modeling

Generation data includes the following: Generation capacity, Forced Outage Rates, outage duration, maintenance schedules, and jointly owned resource information from data obtained through Ventyz or SPP Operations, modelling parameters in the ITP process, and data sourced from the Resource Adequacy Workbook.

Ratings

The maximum capacity ratings will be based on the values submitted in the Resource Adequacy Workbook for the 2019 and 2024 summer seasons. The capability testing procedure and requirements are described in SPP Planning Criteria section 7.1[2].

[1] Link to the latest ITPNT process scope and ITP Manual: https://www.spp.org/engineering/transmission-planning/
[2] https://www.spp.org/documents/33003/spp%20effective%202016%20planning%20criteria%201.pdf

Resource forced outage modeling

Forced outage modeling and economic parameters will consist of using the Equivalent Forced Outage Rate (EFOR) values, forced outage durations, and maintenance scheduling parameters provided by Astrape Consulting.

Planned 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. Previous planned outages will be taken into consideration when modeling the maintenance window for each resource. SERVM determines the best time to force a maintenance outage based upon a set seasonal timeframe window.

Economic Parameter Modeling

Generation will be dispatched economically in accordance with the data provided in the models. Startup times, minimum downtimes, and ramping capability will be honored for all generating units in accordance with the data provided for each resource. 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. Data will be sourced from actual information provided through the SPP Integrated Marketplace for Star-up Cost, Start-up Time, Ramp Rates, Min Down Time, and Min Run Time attributes. For generators where the data not provided through the SPP Integrated Marketplace, the information will be supplemented by class average values derived from existing data used in the ITP Economic Planning process or from Astrape Consulting.

Behind-the-meter generation

Behind-the-meter generation is generally netted and modeled with Peak Demand. If the behind-the-meter generation is not netted in the 2019 Resource Adequacy Workbook submissions and modeled as generation in the ITP Near Term models, then it will be modeled as generation for the LOLE study.

Wind and Solar Modeling

The model includes all wind and solar resources currently installed or proposed to be in-service in the SPP Balancing Authority Area footprint with an hourly wind generation profiles assigned to each resource. Hourly wind generation is based upon historical profiles correlated with the yearly load shapes (2012 to 2018), which are obtained through SPP Operations. The wind or solar shape is separate from the calculated accreditation value based upon current SPP Criteria section 7.1.5.3 (7). The accredited value will be used when calculating the testing reserve margin for demand adjustments.

DC Tie and External Capacity Modeling

DC tie and external capacity transactions that are supported by firm commitments will be modeled as hourly generators at the point of interconnection to SPP as a separate bubble in the system model. They are initially dispatched at the committed firm capacity amount and have a max value equivalent to the amount reserved for firm transmission service. The transactions used for both study years are obtained through the Resource Adequacy Workbook submissions and verified against transactions used in the SPP ITPNT planning process.

If the sale or purchase of capacity is between a SPP area and an outside entity, a generator is placed on the SPP entity's swing bus for the amount of the transaction. If the transaction is a sale to the outside entity, it would be an export of capacity. If the transaction is a purchase, it would be an import of capacity.

Demand Response Modeling

In areas that reported controllable-capacity demand through the 2019 Resource Adequacy Workbook submissions, equivalent thermal resources were added to the model with high fuel costs, so those resources would be dispatched last to reflect demand response operating scenarios.

Modeling Load Forecast Uncertainty

Method

SERVM allows for two options in dealing with demand uncertainty: 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user-defined uncertainty pattern and a probability distribution are both used to add uncertainty to the load values. A different load uncertainty distribution pattern will be modeled for each modeled area.

Uncertainty Components

A load model is used to define the peak-demand multipliers used to modify forecasted Peak Demand. The daily peak are selected and regressed against historical peak temperatures from 2006-2016. Excel will be used to analyze the probability distributions of temperatures observed at key weather stations throughout the SPP footprint. A forecast will then be created for both study years. Based on the forecasts, multipliers were calculated and were populated in a user defined uncertainty pattern. The user-defined uncertainty pattern allows users to provide seven monthly demand patterns. Each area has a different value for each month multiplied by seven probabilities (84 values). The load uncertainty allows for unexpected increases of demand in addition to the adjusted testing reserve margin.

Demand Adjustment

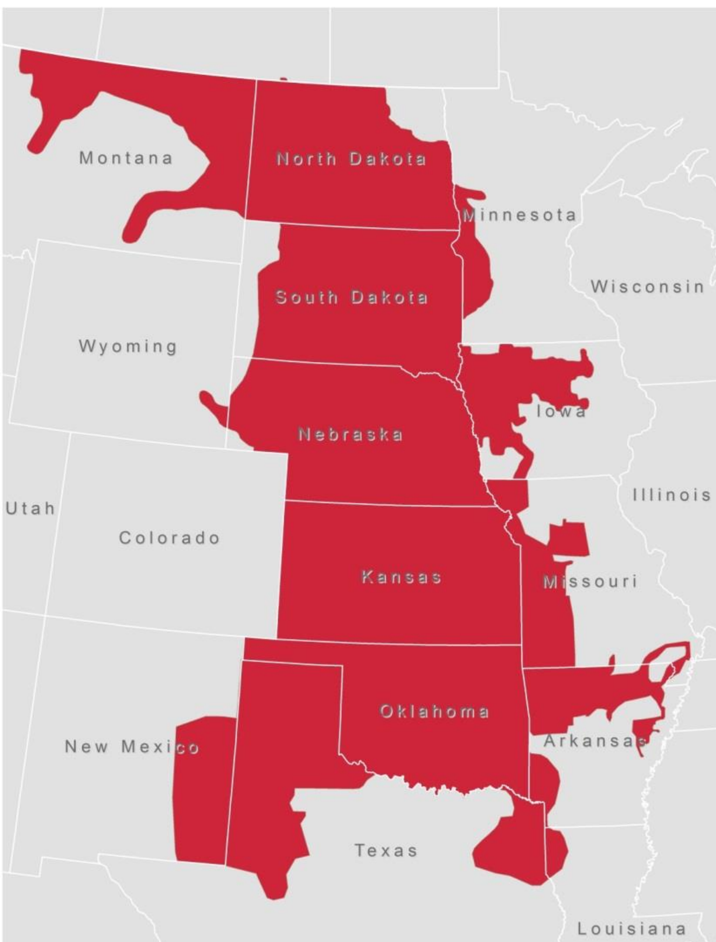
The forecasted Peak Demand shall be adjusted in SERVM scaling SPP's peak hour demand by the amount needed to meet the testing reserve margin.

Summary of Assumptions

1) Each simulation period will be from January 1 to December 31
2) The summer period is defined as June 15th – September 15th
3) At a minimum, 3000 trials per case will be run, to reach a convergence of 90% or greater
4) Only existing and planned reported generation is modeled
5) Forego SPP operating reserves
6) The forecasted Peak Demand shall be adjusted in SERVM scaling SPP's peak hour demand by the amount needed to meet the testing reserve margin.
7) Resource outages will be determined by comparing SERVM simulation outages to real time historical outages
8) Generation is dispatched using a Security Constrained Economic Dispatch algorithm based on the SPP Balancing Authority Area boundary
9) The economic commitment feature of SERVM will be applied to simulations instead of the "must run" methodology
10) Unit parameters such as ramp rate, min downtime, and startup time will be considered

Simulation and Study Process

SPP will conduct the SERVM Monte-Carlo simulation in the way 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.



Reporting

The LOLE Study scope and results 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 for review.

Additional Sensitivities

This section provides an overview of sensitivities in addition to the base assumptions for the LOLE Study.

Capacity Adjustment Sensitivity

Instead of increasing demand to the testing reserve margin level, an additional sensitivity will be performed to reduce capacity. Capacity factors from SPP operations will be used to determine the order of reducing capacity until "one day in 10 year" threshold is achieved.

"Commit All" Generator Model Comparison Sensitivity

An additional sensitivity will be performed to understand how generator attributes with economic commitment dispatch effects the PRM versus a "commit all" unit commitment reliability based model.