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Loss of Load Probability: Application to Montana

Ascend's approach to analyzing system reliability for long-term resource planning.

This memo addresses the calculation of Loss of Load Probability ("LOLP") metrics for use in long-term resource planning for NorthWestern Energy's Montana resource portfolio.

Key Takeaways and Results

- LOLP is a measure of the probability that a system's load will exceed the generation and firm power contracts available to meet that load.
- Ascend calculates the annual LOLP across the planning horizon based on the stochastic simulation of weather, load, renewable and thermal generation, and forced outages.
- LOLP can be used to determine what additional capacity might be needed to meet reliability targets. A standard industry target for loss of load is not to exceed more than one day in ten years.
- Other important metrics include Reserve Margin and Effective Load Carrying Capacity (ELCC). Reserve Margin is the percentage of expected capacity above (or below) peak load. ELCC is a measure of the capacity contribution provided by non-dispatchable resources (typically renewables).

Methodology and Inputs

LOLP is a reliability metric essential to long-term resource planning. Ascend has provided NorthWestern Energy with analysis of LOLP and other reliability metrics through the PowerSimmRA and PowerFlex platforms. The results of the reliability analysis were used to guide the long-term planning of NorthWestern's Montana portfolio.

A loss of load occurs when system load exceeds available generation. LOLP is the probability that any loss of load will occur at some point in a given year. PowerSimm's stochastic simulations capture the variability of renewable generation (whereas a deterministic approach would take the average generation, instead of creating multiple simulations with varying outputs). Figure 1 shows how average wind generation cannot capture the extreme values which have a significant impact on resource availability when discussing a system's ability to meet load.

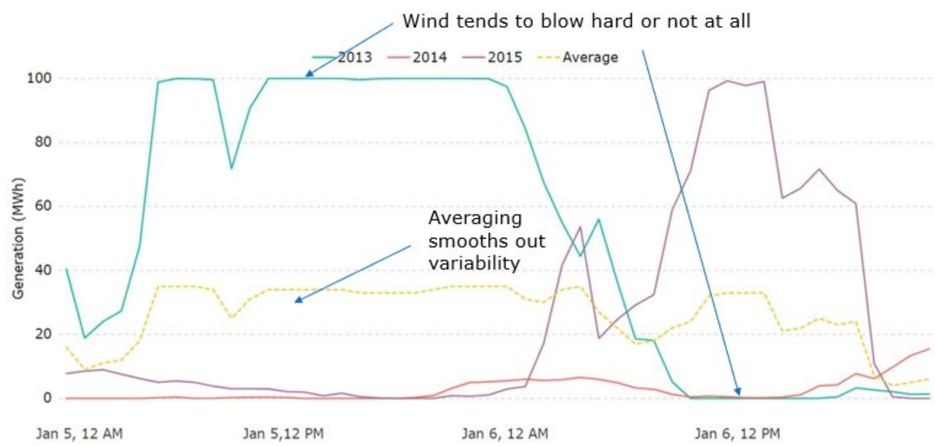

Figure 1. Averaging historical data smooths out hourly volatility, which has a significant impact on simulating the true nature of wind resources.

Load and renewable simulation results can be shown as probability distributions as shown in Figure 2. When subtracting renewable generation from load the result is a distribution of net load probabilities. Loss of load occurs where the probability distribution of net load (load minus renewable generation) exceeds thermal generation.

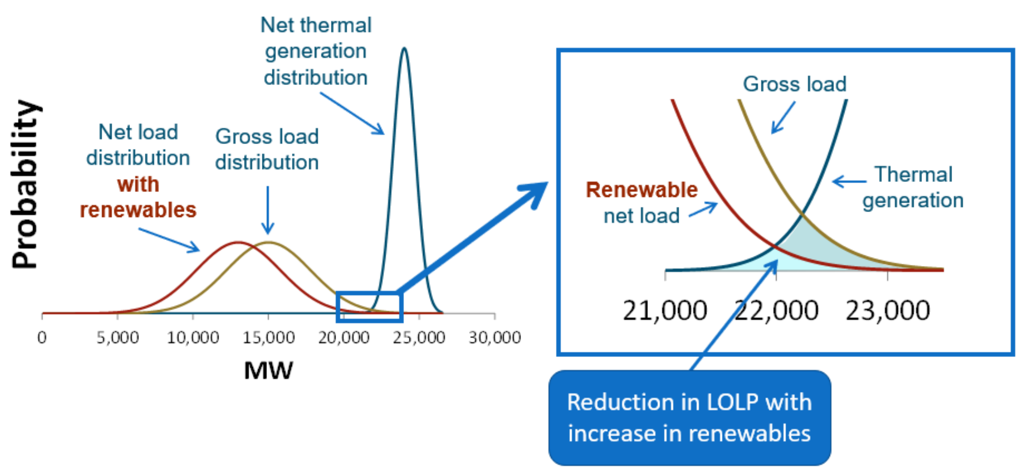

Figure 2. Hypothetical probability distributions for thermal generation, base load, and net load. Adding renewables decreases the LOLP.

Loss of Load can be expressed in a variety of ways, including the amount of capacity in megawatts (MW) short per year, or the number of hours short per year, or as a percentage of time.

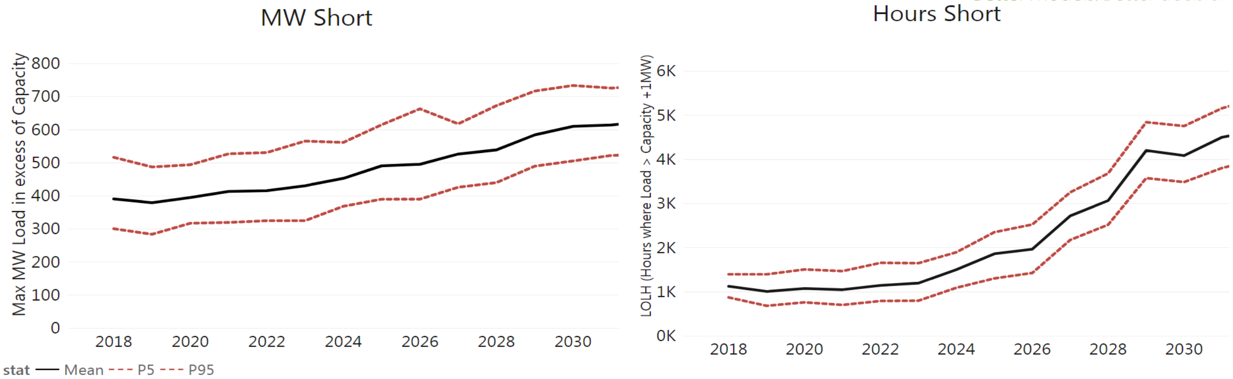

Figure 3. The above plots show two different ways to express NorthWestern's base portfolio LOLP: MW short by year and hours short by year. The red dashed lines show the 5th and 95th percentile, and the red line shows the mean.

Ascend calculates LOLP by running a PowerSimm stochastic study to simulate customer load, forced outages, and renewable (must-take) generation. These simulations are then run through PowerSimm's optimization engine to determine thermal generation capacity for each hour and each simulation throughout the study period. PowerSimmRA then combines the available generation capacity and firm power contracts for each hour and compares them to customer load requirements across simulations. As an intermediate step in calculating LOLP, the Loss of Load Hours (LOLH) is first calculated as the number of hours in a year in which customer load requirements exceed generation capacity and firm power contracts. LOLH only accounts for assets in the portfolio; it does not consider purchases on the Day-Ahead or Real-Time energy markets. LOLP is then calculated for each year and simulation by dividing LOLH by the total number of hours in the year[1]. Then, LOLH and LOLP are summarized across simulations for each year with the following statistics: mean, 5th, and 95th percentile.

The One-Day-in-Ten-Years metric (1-in-10), a standard metric used by NERC to determine system reliability, is the probability that, over a ten-year time frame, the utility will experience loss of load for a total of 24 hours[2]. An ideal portfolio will have an LOLH of 2.4 hours per year or less, such that over a ten-year time frame the total LOLH is less than or equal to 24 hours. This is equivalent to an LOLP of 0.0274%.

An additional metric that is commonly used by utilities is Reserve Margin. This is defined as the total effective installed capacity plus net firm power contract purchases minus the peak annual load, divided by the peak annual load (%).

Ascend's process for long term capacity planning is as follows:

1) Input NorthWestern's existing portfolio into PowerSimm and run a base scenario dispatch study.
2) Use PowerSimm RA to calculate LOLH/LOLP based on the base scenario simulation.

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[1] LOLP is calculated as $LOLP = \frac{LOLH}{8760}$, where $LOLH = \sum_{ij} \begin{cases} 0 \; if \; Peak_{Load_{ij}} \leq G_{ij} + R_{ij} + Pwr\_Con_{ij} \\ 1 \; if \; Peak\_Load_{ij} > G_{ij} + R_{ij} + Pwr\_Con_{ij} \end{cases}$
where *G* is simulated available thermal generation, *R* is simulated renewable generation, and *Pwr_Con* is Firm Power Contracts for each hour *i* and simulation *j* during a given year.

[2] Federal Register Volume 75, Number 207 (Wednesday, October 27, 2010).

3) Determine the additional capacity needed to maintain reliability over the study horizon.
4) Create a new planning portfolio with the added capacity based on the LOLP results.
5) Simulate a new dispatch study and validate that the LOLP is within an acceptable level.

PowerSimm's stochastic modeling provides the ability to plan to the level of risk that is required by the utility. If a utility is a true "islanded" system, it should plan to the 95th percentile. However, if the utility can import energy from the market, its risk of loss of load is mitigated compared to an isolated system. In this circumstance, Ascend recommends planning to 1-in-10 as it relates to the mean LOLP, rather than the 95th percentile of risk. This will prevent overbuilding of capacity and protect the utility from unnecessary capital investment. A utility may also plan to an even lesser built capacity if it has reliable market interactions.

Application to NorthWestern

NorthWestern's Montana portfolio currently has a negative reserve margin, meaning the installed capacity and firm contracts cannot provide enough energy to fully meet peak load demand. NorthWestern relies on day-ahead and real-time market purchases to provide roughly 20 percent of peak load as indicated in Figure 5. By 2035, nearly 45 percent of the peak load will need to be met with market purchases if no additional capacity is installed or contracted for.

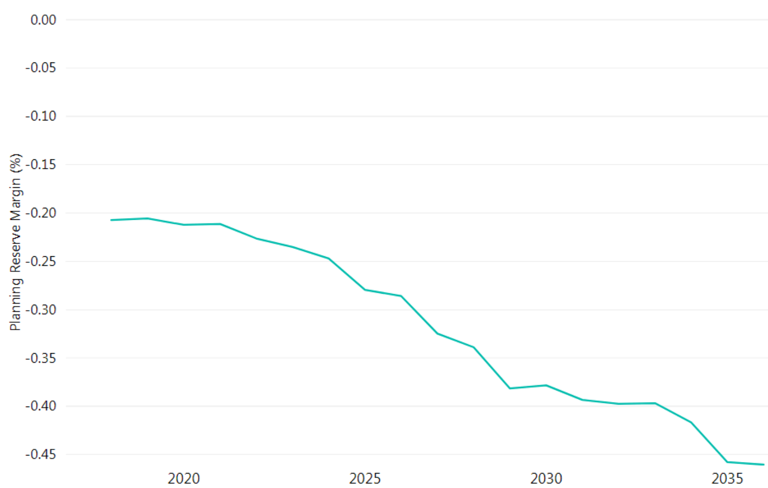

Figure 5. The above plots show Planning Reserve Margin for NorthWestern's current Montana portfolio. The system currently has a negative reserve margin that will increase negatively as load grows.

The following table indicates the Reserve Margin, LOLH, and LOLP in 2028 with various potential additions of installed or contracted capacity.

MW Additions	Reserve Margin (%)	Expected LOLH in 2028 (hours)	Expected LOLP in 2028 (%)
0	-33.89	3,068	34.93
100	-26.29	1,526	17.37
200	-18.69	581	6.62
300	-11.08	167	1.91
400	-3.48	37	0.42
450	**0.0**	**15**	**0.17**
500	4.12	5	0.06
600	11.72	0.6	0

Table 1. The table above shows the planning reserve margin, LOLH and LOLP for NorthWestern's Montana system as a function of additional MW capacity.

Planning out ten years to 2028, an additional 450 MW of capacity would be required to meet peak load with a non-negative reserve margin. If NorthWestern were to meet the 1-in-10 industry standard, it would need roughly 600 MW of additional capacity on top of its existing assets and contracts. This would put LOLH below 2.4 hours per year, the threshold for 1-in-10. Additionally, this level of additional capacity would push the Reserve Margin greater than 10%, the typical market standard.

Appendix

Forced Outages:

The inputs for forced outages (FO) include percent outage, Equivalent Forced Outage Rate (EFOR), outage mean, and outage standard deviation.

Input Item	Definition
Percent Outage (%)	Percentage of the max capacity of the plant is unavailable when an outage occurs.
EFOR (%)	Expected hours of unit failure as a percentage of the total hours in a given time period.
Outage Mean (days)	Average duration of expected forced outages.
Outage Standard Deviation (days)	Average duration of expected forced outages.

Effective Load Carrying Capacity:

The following are values for Effective Load Carrying Capacity (ELCC) used in PowerSimmRA.

Asset Type	ELCC (%)
Renewable Asset	Fifth percentile of simulated generation during the top 3% of peak load hours
Thermal Asset	1-(*EFOR*)
Firm Contract	100%

Reliability Metrics

- LOLP/LOLH:

$$LOLP = \frac{LOLH}{8760}$$

Where, $$LOLH = \sum_{ij} \begin{cases} 0 \; if \; Peak_{Load_{ij}} \leq G_{ij} + R_{ij} + Pwr\_Con_{ij} \\ 1 \; if \; Peak\_Load_{ij} > G_{ij} + R_{ij} + Pwr\_Con_{ij} \end{cases}$$

Where *G* is simulated available thermal generation, *R* is simulated renewable generation, and *Pwr_Con* is Firm Power Contracts for each hour *i* and simulation *j* during a given year. *j*. The total hours where load is not met is summed for each simulation. Statistics such as mean, 5th percentile, and 95th percentile can be calculated on the distribution of *LOLH* values for each year.

- Reserve Margin:

$$RM = \frac{(Peak\_Load - \sum(Eff\_Cap - Pwr\_Con))}{Peak\_Load}$$

Where *Eff_Cap* is Effective Installed Capacity and *Pwr_Con* is Firm Power Contracts, summed over all assets in the portfolio. *Eff_Cap is* defined as follows:

$$Eff\_Cap = Name\_Cap * ELCC$$

Where *Name_Cap* is the “nameplate” capacity of the asset, and *ELCC* is the Effective Load Carrying Capacity of the asset.

- MW Short:

  MW Short is a metric that calculates the largest gap between load and available generation resources in a given year.

$$MW_{Short} = \max(Peak\_Load_i - (G_i + R_i + Pwr\_Con_i))$$

Over all hours *i.* This maximum MW Short value is calculated for all simulations and the average, P5, and P95 statistics are presented.

Additional Reliability Metrics from NERC[3]:

- Expected Unserved Energy (EUE): EUE is the summation of the total MW short over the course of a year for each hour where load exceeds available generation resources.

$$EUE = \sum_i Peak\_Load_i - (G_i + R_i + Pwr\_Con_i)$$

Where $Peak\_Load_i > (G_i + R_i + Pwr\_Con_i)$ for each hour *i*.

- Loss of Load Expectation (LOLE): LOLE is the expected number of days in a year where load will not be met at least once in that day.

$$LOLE = \sum_d \begin{cases} 0 \; if \; LOLH_d = 0 \\ 1 \; if \; LOLH_d > 0 \end{cases}$$

For each day *d* in a year, summed over the course of a year.

[3] https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf