The 2011 Probabilistic Assessment was a pilot study performed by SPP at NERC's request to voluntarily conduct an assessment to determine reliability indices using probabilistic methods. The majority of the input data was derived from the Long Term Reliability Assessment (LTRA) data, which is provided by SPP members on an annual basis. Upon finalization of the probabilistic analysis, SPP discovered that discrepancies existed between the submitted LTRA data and portions of the data that some members provided to SPP after the analysis was completed. Due to the NERC reporting deadline, there was not adequate opportunity for stakeholders to review detailed modeling data and provide corrections.

Additionally, some SPP members have questioned the study methodology. These methodology concerns along with the input data discrepancies led to unsubstantiated results. Therefore, the 2011 Probabilistic Assessment results may not be indicative of actual study results which are normally vetted through the SPP stakeholder process.

The Probabilistic Assessment process has been revised and updated. Future assessments will include more interaction with the SPP stakeholders and further granular analysis will be provided for members whose areas show reliability concerns.

SPP Southwest Power Pool

2011 Probabilistic Assessment

11JAN12
Interregional Coordination

Southwest Power Pool

Table of Contents

Reporting

A. Reporting

1. Summary

The SPP 2011 Probabilistic Assessment is a pilot study requested by NERC under the Reliability Assessment Subcommittee (RAS). One objective of this assessment is to provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement NERC's Long-Term Reliability Assessments (LTRA). The terminology of Metrics Reporting Areas (MRA) for this report is synonymous with the reporting subregions of the LTRA. For this report Southwest Power Pool (SPP) is considered an MRA. This pilot study is based on the 2010 LTRA data, which included entities in the SPP Regional Entity footprint. Excluded from the 2010 LTRA data are all Nebraska entities. Future Probabilistic Assessments will be based on entities in the SPP Regional Transmission Organization footprint, which includes the Nebraska entities.

Another objective, which is a requirement of SPP's Criteria and not of the NERC RAS, is to assess whether the capacity margin requirement of 12% is adequate to maintain a Loss of Load Expectation (LOLE) of 1 day in 10 years.

The first objective of this report is to provide a comparison of the 2010 LTRA data and the probabilistic analysis data derived from an MRA simulation tool. SPP used GridView version 7.0, an ABB application, to perform the probabilistic analysis of the 2010 LTRA data for years 2 and 5, 2011 and 2014 respectively. Three metric results were also calculated in this study: annual Loss of Load Hours (LOLH), Expected Unserved Energy (EUE), and Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE). For the purposes of the SPP Criteria, the LOLE in days/year will be provided.

The second objective of this assessment is to validate the capacity margin requirement as listed in the SPP Criteria section 4.3.5 which states:

"SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin."

The 2011 Probabilistic Assessment is a voluntary near term pilot study requested by NERC, but there are plans for future probabilistic studies, which could become mandatory beginning in 2012. This report, upon endorsement by the Economic Studies Working Group (ESWG), will be submitted to NERC mid-January 2012. The LOLE and capacity margin assessments will continue to be performed at least on a biennial basis by SPP.

a. Identification of entities included in MRA

Entities (geographic subregions) were modeled individually. There were 21 areas modeled within the SPP RE footprint. The SPP RE footprint includes all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. For the 2011 Probabilistic Assessment the Nebraska entities (GIUD, Hastings, LES, MEAN, NPPD, OPPD) demand and capacity were not included since they were not reported in the 2010 LTRA report. Nebraska entities will be included in future Probabilistic Assessments since their reporting year began in 2011. Also Entergy demand and capacity within the AECC and CELE areas were subtracted from the totals before any analysis was performed.

MRA geographic subregions for the 2011 Probabilistic Assessment

AECC[1]	Arkansas Electric Cooperative Corporation
AEPW	American Electric Power System West
CELE[2]	Central Louisiana Electric Company, Incorporated
EMDE	Empire District Electric Company
GRDA	Grand River Dam Authority
INDN	Independence Power & Light Department
KACP	Kansas City Power and Light Company
KACY	Board of Public Utilities, Kansas City, Kansas
LAFA	City of Lafayette, Louisiana
LEPA	Louisiana Energy & Power Authority
MIDW	Midwest Energy, Incorporated
MIPU (GMO)	Missouri Public Service Company
OKGE	Oklahoma Gas and Electric Company
OMPA	Oklahoma Municipal Power Authority
SPRM	City Utilities, Springfield, Missouri
SPS	Southwestern Public Service Company
SUNC (SEPC)	Sunflower Electric Cooperative
SWPA	Southwestern Power Administration
WEPL (MKEC)	Western Plains Energy, LLC
WERE	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative

[1] Non-Entergy portion of the demand and capacity in the SPP RE footprint for AECC was included.
[2] Non-Entergy portion of the demand and capacity in the SPP RE footprint for CELE was included.

b. Seasonal capacity totals

Capacity data modeled in this assessment was derived from the 2010 LTRA submitted by SPP to NERC. The table below provides the makeup of the capacity categories and amounts used in this assessment by study year (2011, 2014). Differences in capacity values between this assessment and the 2010 SPP LTRA report are listed in this report under section 5a. For purposes of clarification, the summer season includes: April – September, and the winter season includes: January – March, and October – December.

Seasonal capacity totals

Category	2011		2014	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
Controllable capacity demand response	411	215	419	223
Intermittent and energy-limited variable resources	2,931	2,931	3,431	3,431
Traditional dispatchable capacity (Coal)	22,206	21,051	22,653	21,505
Traditional dispatchable capacity (Gas / Oil)	28,549	29,299	28,595	29,319
Traditional dispatchable capacity (Hydro)	2,637	2,639	2,625	2,599
Sales	1,029		1,022	
Purchases	1,841		1,720	
Total Capacity	56,734	56,135	57,723	57,077

c. Coincident forecast 50/50 peak seasonal demands

SPP members provided their peak seasonal forecast demand data based on individual member's forecast methodology, which may or may not be coincident forecasts. The SPP 2010 LTRA non-coincident forecasted seasonal values are listed below.

50/50 peak seasonal demands

Peak Load	2011		2014	
	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
LTRA	44,220	32,731	46,136	34,656
Simulation	43,808	32,224	45,941	32,063

d. Net Energy for Load

Net Energy for Load

Net Energy	2011	2014
	(MWh)	(MWh)
LTRA	213,464,303	223,134,126
Simulation	213,461,830	223,129,652
Difference	2,473	4,474

e. MRA metrics results

LOLH, Loss of Load Hour, is the Hourly Loss-Of-Load expectation. This metric provides the hours of resource reliability shortfall per year, which is the time in hours that the demand exceeds the capacity throughout the year. Per the SPP Criteria, generation reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years (0.1 day / year). The LOLH is measured in hours in GridView, which is the number of hours that a loss of load event occurred. This value is a summation of hourly events for a 24 hour period, which is then averaged over the number of yearly trials. GridView provides Expected Energy Not Served (EENS), which equates to Expected Unserved Energy (EUE).

Daily LOLE, Loss of Load Expectation, is the expected daily occurrences of the loss of load throughout the year.

Daily Peak LOLE, Loss of Load Expectation, is the expected occurrences of loss of load during the daily peak load hour, throughout the year.

EUE, Expected Unserved Energy, is the expected amount of megawatt-hours of load that will not be served in a given year. This is the summation of the expected amount of unserved energy during the time that the demand exceeds the capacity throughout the study year.

Normalized EUE provides a sense of how much energy, relative to the area's size, could be expected to be unserved. The calculation for normalized EUE is as follows: Normalized EUE = [EUE / (Net Energy for Load simulated)] x 1,000,000

f. Study Results

In this study, the capacity margin percentage was determined to be 22.69% for the peak hour of 2011 and 19.92% for the peak hour of 2014. The values in the table below reflect the results of the GridView LOLE simulations for both study years (2011, 2014).

MRA metrics results

All SPP entities	2011	2014
LOLE (days/year)	1.869	0
LOLH (hours/year)	2.132	0
EUE (MWh/year)	284.085	0
EUE (Normalized MWh/year)	1.331	0

12% Capacity Margin Study Results

In this study, the capacity margin percentage is decreased from 22.69% (2011) and 19.92% (2014) to 12% as a sensitivity to determine whether LOLE is within target at the required capacity margin percentage for the SPP region[3].

For 2011, the peak load was increased from 43,808 MW to 49,867 MW. The LOLH increased from 2.132 to 3.44 and the LOLE decreased from 1.869 to 1.62, which means there were less days of unserved load with the higher capacity margin, but more hours of unserved load in the days that did have unserved load. Since the SPS area was the only area that showed an LOLE, the capacity margin results are based on the SPS area.

For 2014, the peak load was increased from 45,941 MW to 50,701 MW. The LOLH and LOLE increased from 0 for both metrics to 0.16 and 0.08 respectively. Since the OMPA area showed the highest amount of LOLE, the capacity margin results are based on the OMPA area.

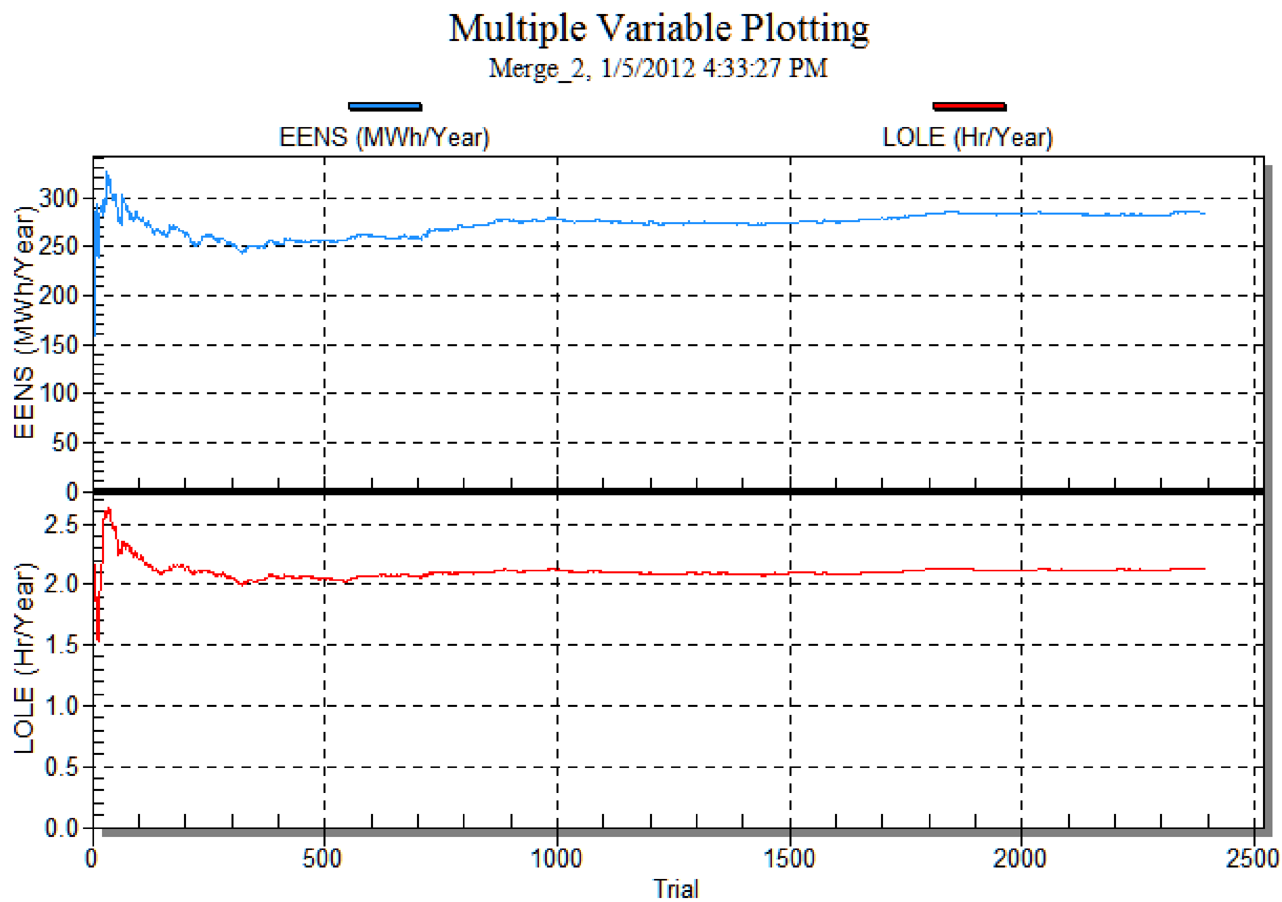
12% Capacity Margin results

All SPP entities	2011	2014
LOLE (days/year)	1.62	0.08
LOLH (hours/year)	3.44	0.16
EUE (MWh/year)	448.194	76.576
EUE (Normalized MWh/year)	2.009	0.343

[3] To decrease the 2011 capacity margin, the load and energy is increased in each modeled SPP area proportionally by 13.8%. To decrease the 2014 capacity margin, the load and energy is increased in each modeled SPP area proportionally by 10%.

2011 SPS LOLE Results

For the 2011 study, the SPS area had an LOLE of 1.869 Days/year, and an LOLH of 2.132 Hours/year. The EENS was 284.084 MWh/year. These values were calculated using 2,400 trials and the resulting convergent values are provided at the end of the simulation.

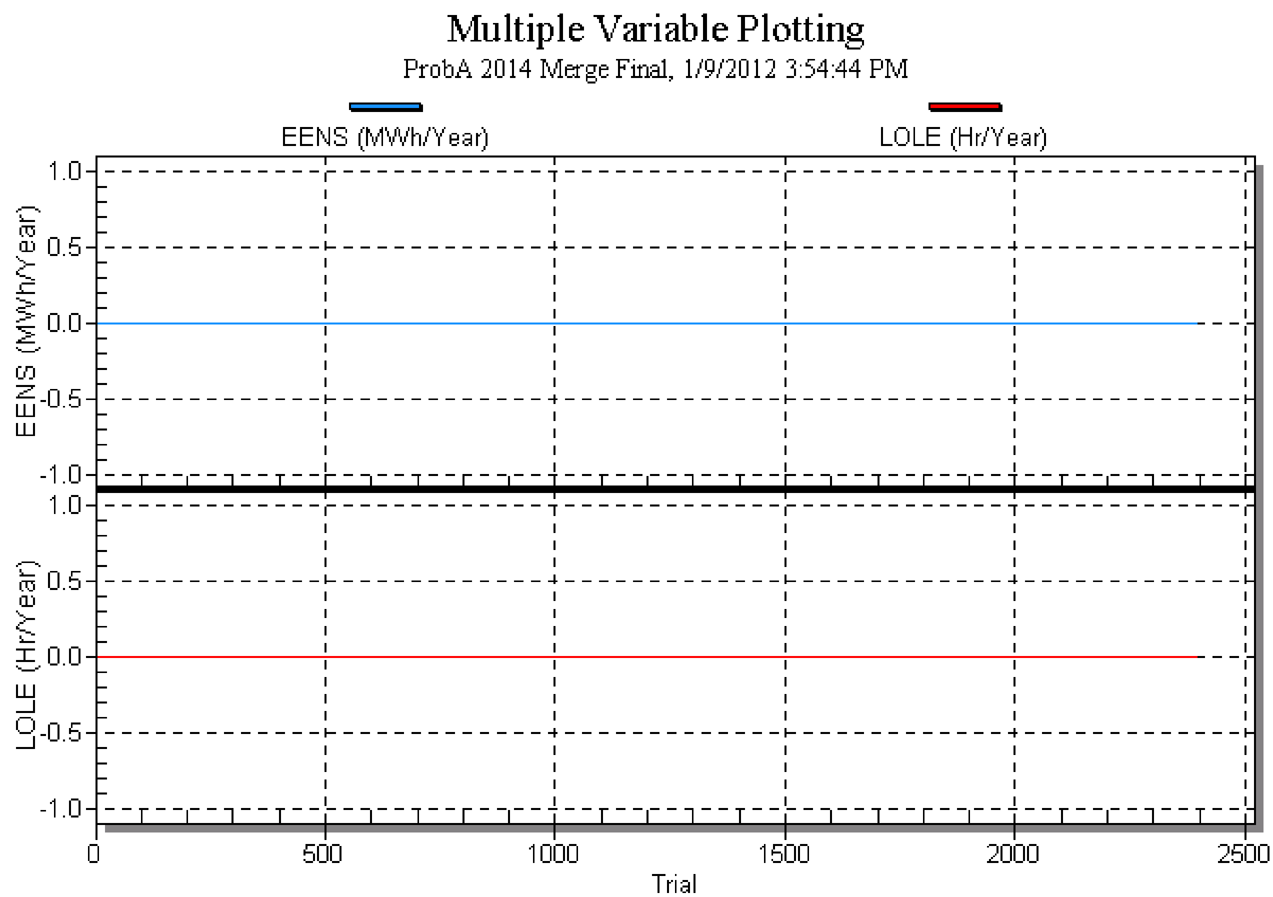


2011 SPS area study results

SPS	2011
LOLE (days/year)	1.869
LOLH (hours/year)	2.132
EUE (MWh/year)	284.084
EUE (Normalized MWh/year)	1.331

2014 SPS LOLE Results

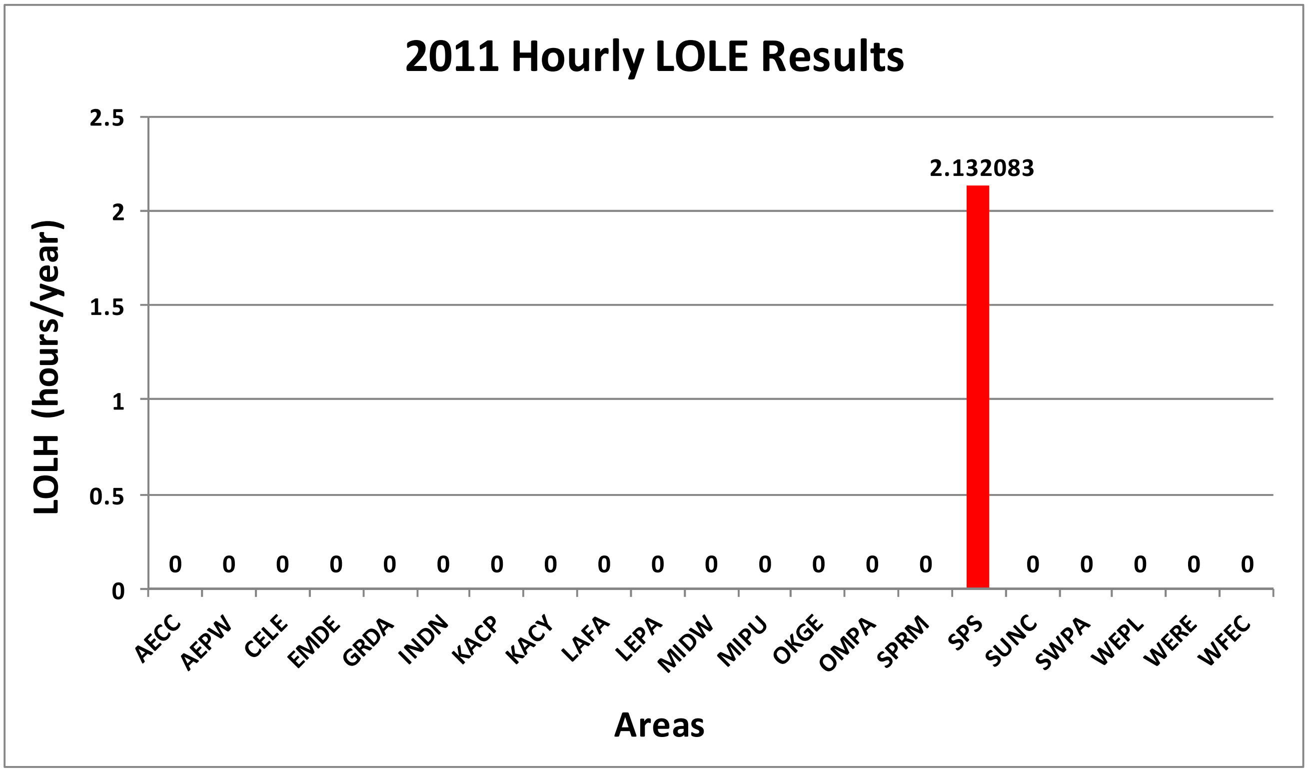
For the 2014 study, the SPS area EENS and LOLE was reduced to 0 after the inclusion of the future Transmission and Generation projects.

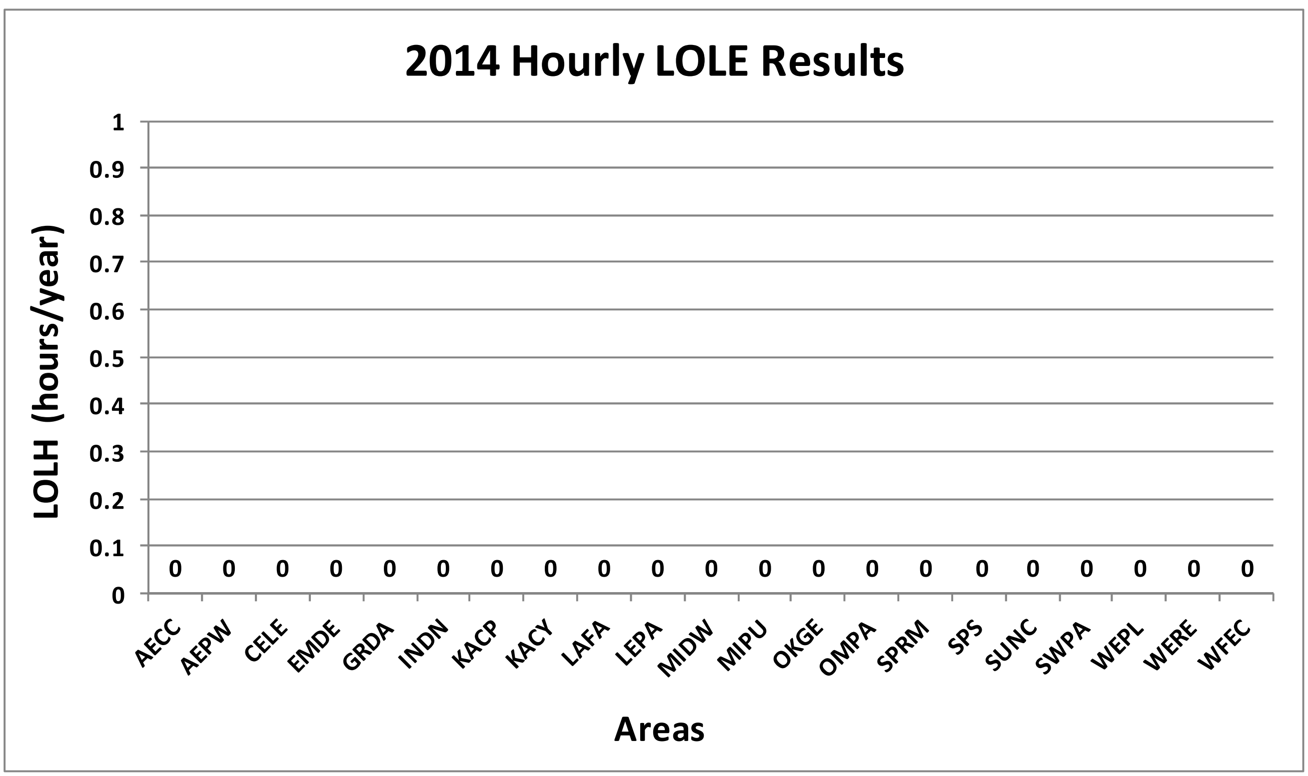


2014 SPS area study results

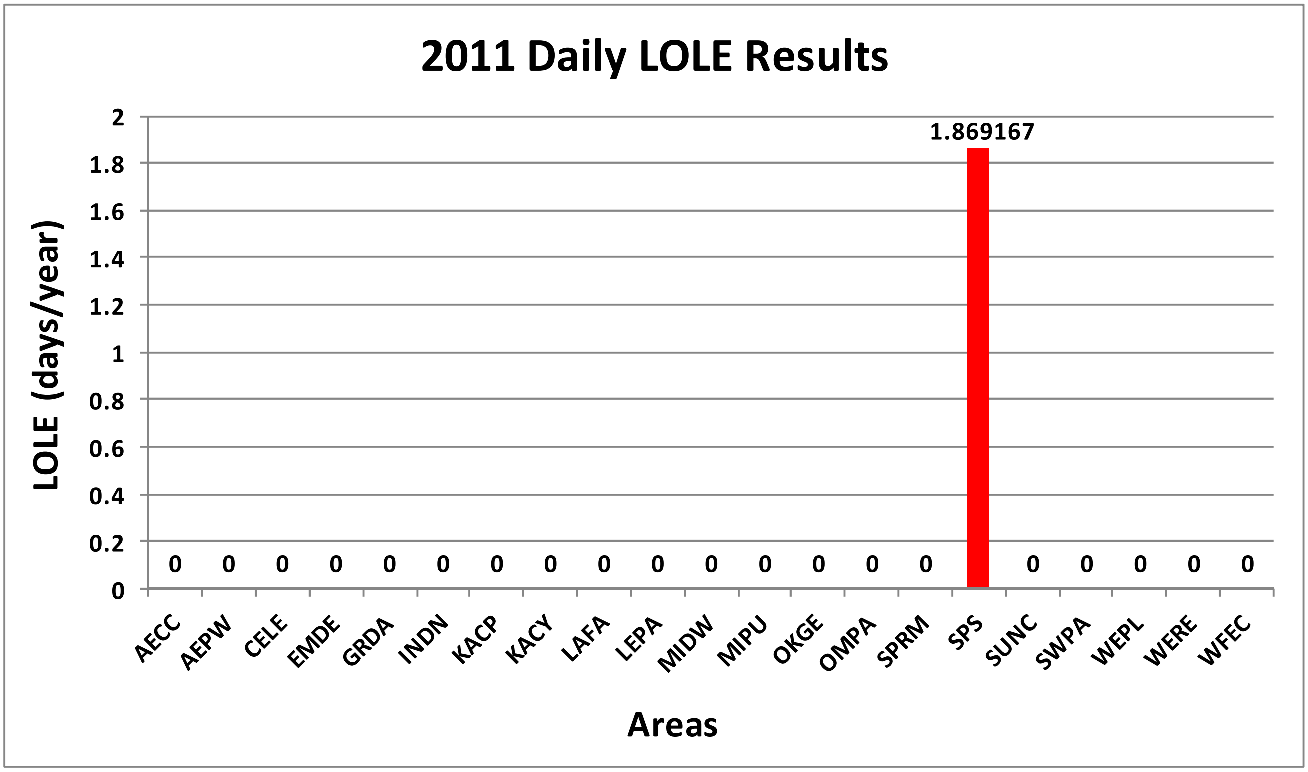
SPS	2014
LOLE (days/year)	0
LOLH (hours/year)	0
EUE (MWh/year)	0
EUE (Normalized MWh/year)	0

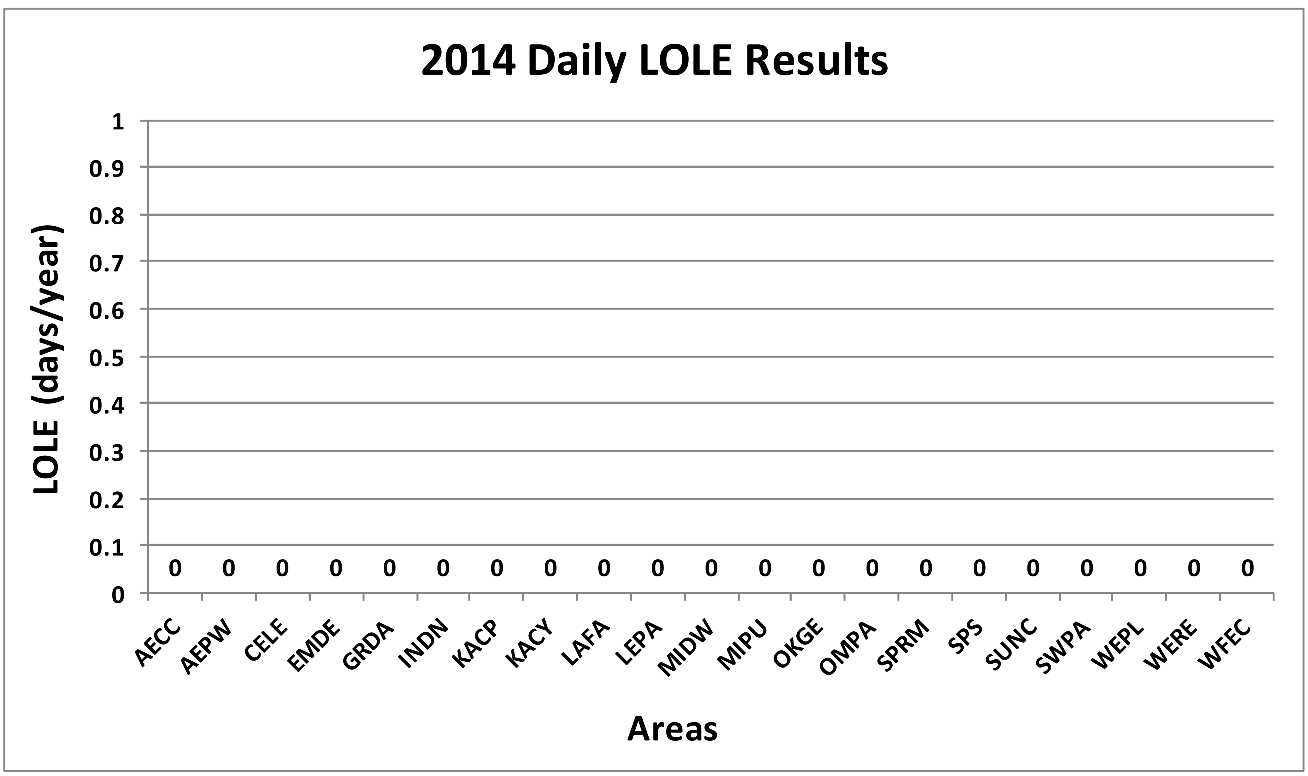
Hourly LOLH (hours/year) Results



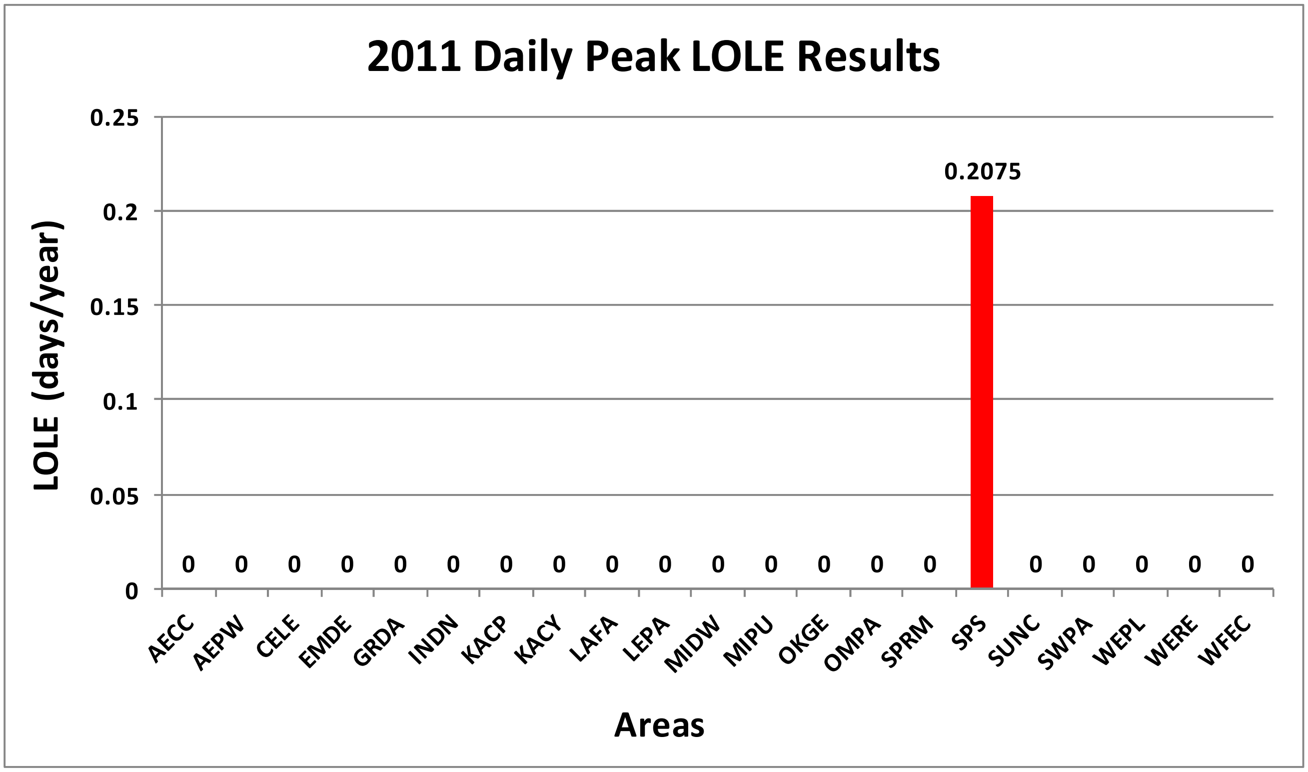


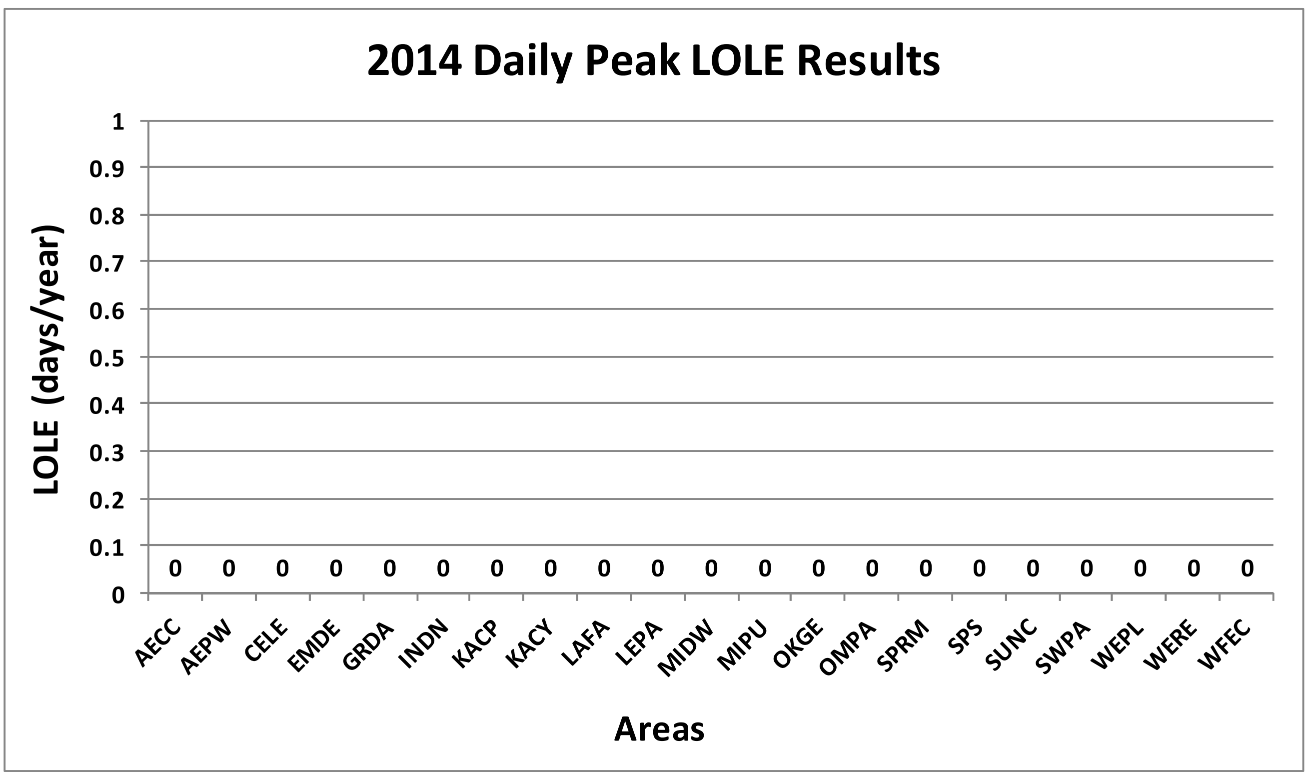
Daily LOLE (days/year) Results



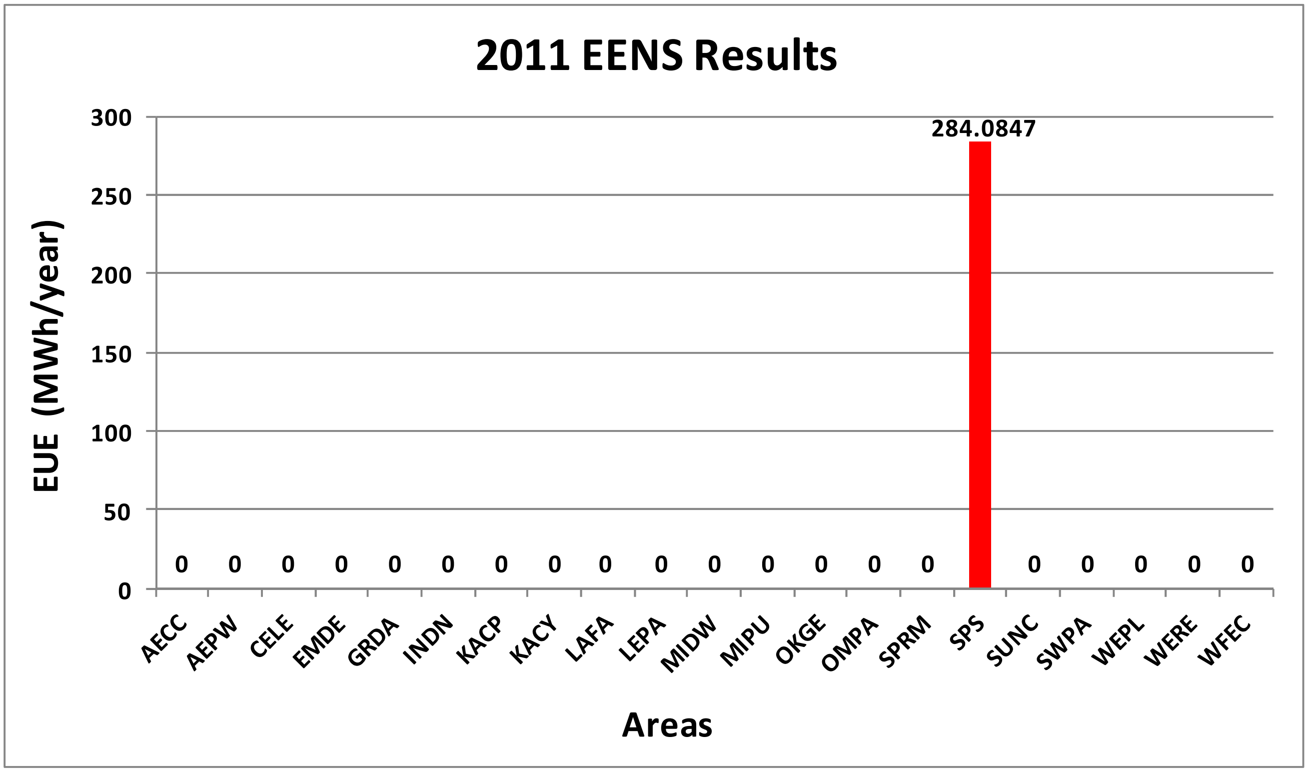


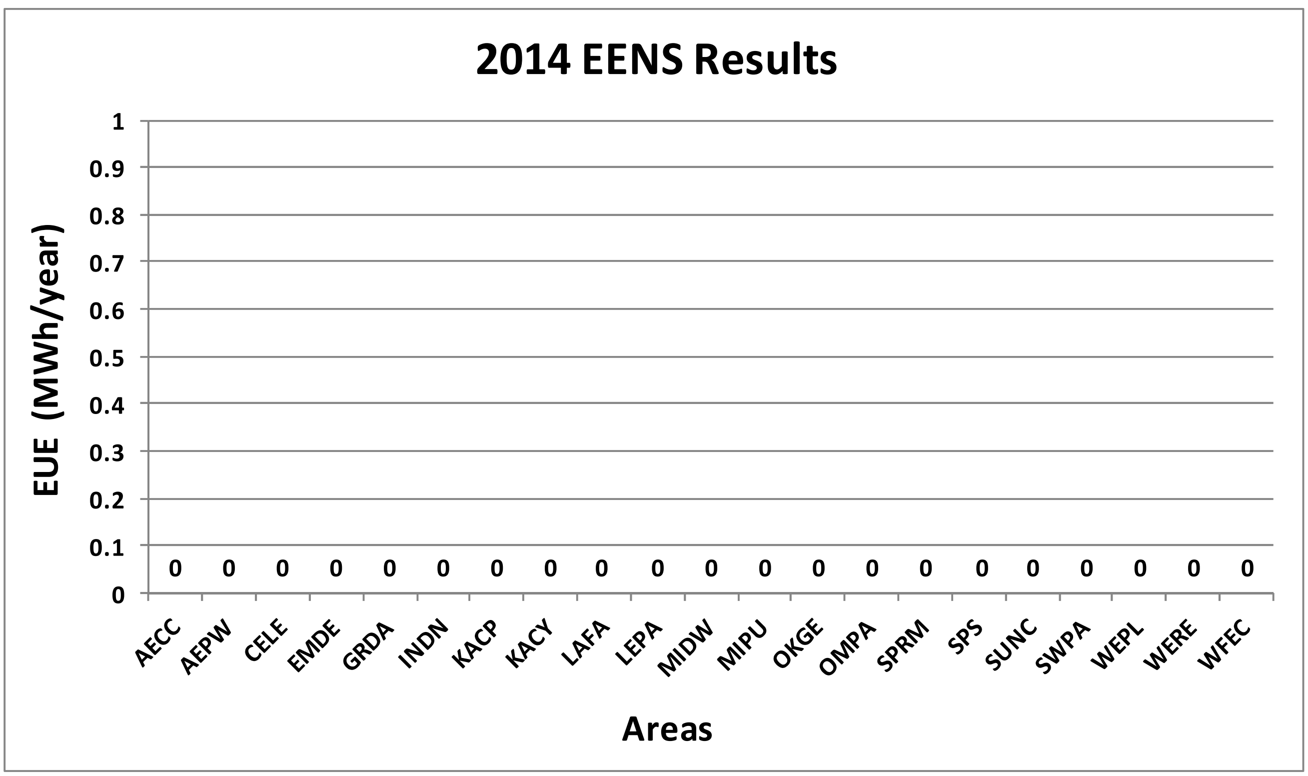
Daily Peak LOLE (days/year) Results





EENS (EUE) (MWh/year) Results





2. Software model description

a. Computational approach

GridView 7.0 was used to perform the analysis. GridView is a software application developed by ABB Inc. to simulate the economic dispatch of an electric power system while monitoring key transmission elements for each hour. GridView can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. The key advantage of using the GridView application is having the ability to model a detailed transmission system in the study region, not just a transportation model. Some other features available in this program include contingency constraints, nomograms, and emergency imports. A Monte Carlo simulation was used to perform the analysis of the SPP reliability assessment.

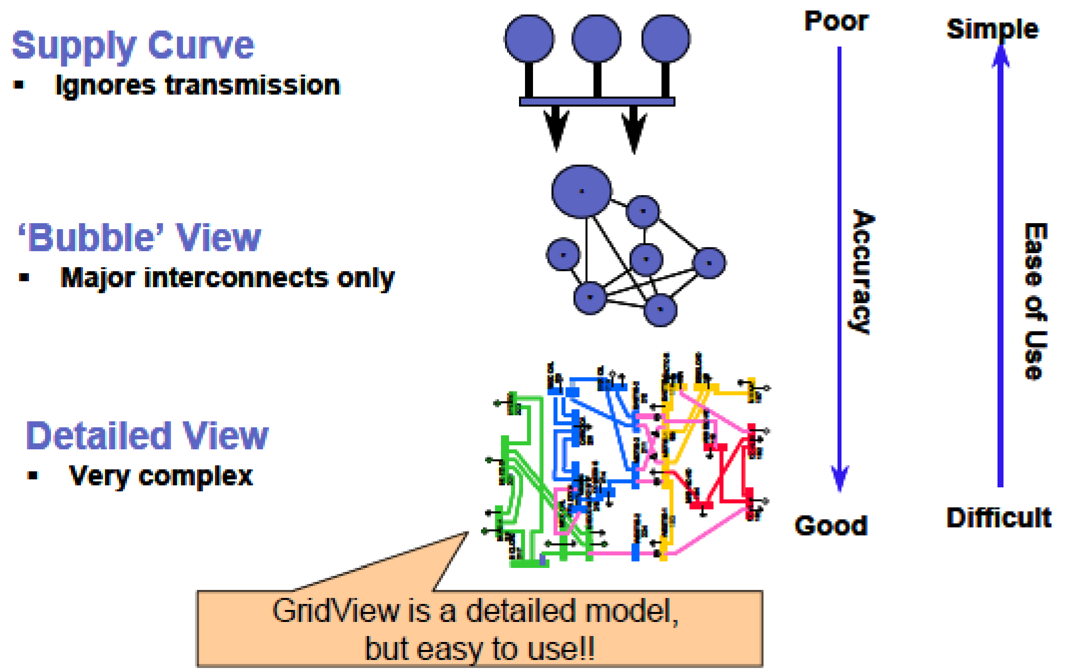


Figure 1-2 GridView Uses Very Detailed Transmission System Model

b. Algorithm usage

Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of random numbers as inputs. The goal is to determine how random variation or error affects the reliability of the system that is being modeled. Monte Carlo simulation is categorized as a sampling method because the inputs are randomly generated from probability distributions to simulate the process of sampling from an actual population. Within GridView, Monte Carlo simulation allows detailed modeling of the pre-contingency conditions and the outages of generation and/or transmission equipment and/or changes of load demands and fuel prices and/or wind generation. GridView can also model the correlation between area load demands and fuel prices. It uses probability distributions for equipment outages during a sequential mode of simulations hour by hour, and typically for a year. The selection of testing conditions is by random sampling. In order to obtain accurate risk indices, many simulations will have to be performed (2400 simulations / year for this assessment). In general, the simulations provide the loss of load reliability indices. For reliability assessment, a linear model is applied to the generation dispatch calculation for every hour in each trial in order to compute the amount of load that has to be shed in order to eliminate overload problems. The engineer performing the analysis will choose a distribution for the inputs that most closely matches data that the MRA already has, or best represents the MRA's current state of knowledge. SPP, as an MRA, calculated the error based on the last 10 year's reported annual actual vs. forecasted peak load and used those values as the load probability multiplier within GridView.

3. Demand Modeling

a. Explanation of differences between reported data and LTRA

The LTRA data includes areas (AECC[4], CELE[5] CLWL, YAZO, GIUD, Hastings, LES, MEAN, NPPD, OPPD), which were not included in the simulation since the load is not located in the SPP RE footprint. The 2008 AECC hourly load values were used with the Entergy load subtracted. Only the AECC load that is in the SPP RE footprint was used for the Probabilistic Assessment. No Entergy capacity was included in the Probabilistic Assessment.

b. Explanation of chronological load model and loads accounted for out of region

Each area has its own separate annual hourly load shape. The 2008 hourly load profile was provided by ABB for the listed entities in the MRA subregion table. SPP used 2011, and 2014 hourly peak load forecast data to modify the 2008 hourly load profiles for each entity included in this assessment. No out of region load was modeled in this study.

[4] Total AECC demand, including Entergy demand
[5] Total CELE demand, including Entergy demand

c. Explanation of how load forecast uncertainty was modeled

i. Method

GridView allows for two options in dealing with load uncertainty, 1) User defined uncertainty pattern, and 2) probability distribution. For this study, a user defined uncertainty pattern and a probability distribution was used to add uncertainty to the load shapes.

ii. Uncertainty components

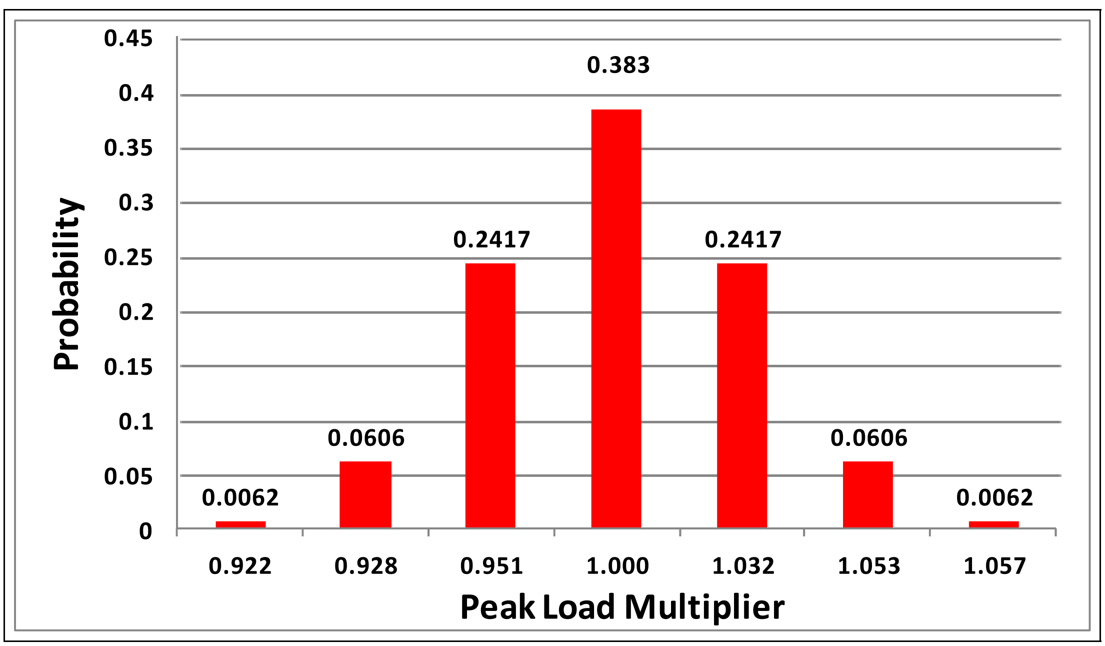
A user defined uncertainty pattern was used to define the peak load multiplier which was based on the percent error between forecasted peak loads and actual peak loads for the SPP RE footprint from the past 10 years. The user defined uncertainty pattern allows users to provide 7 monthly load patterns (each area has a different value for each pattern) with probability. The program randomly selects the load pattern at the beginning of the simulation and applies it for that trial.

iii. How the probability is incorporated

The load multiplier was applied as a normal distribution on top of the given load forecast profile. The shape would shift up, down, or remain the same depending on which multiplier was randomly chosen at the beginning of the simulation.

iv. How the MRA considered the uncertainty of different entities within the MRA

For this study 7 different load multipliers were used for each of the 7 patterns for each area. This was based on the SPP RE footprint peak load values as opposed to individual areas.



d. Explanation of how behind-the-meter generation was modeled

Behind the meter generation is netted and modeled with customer load. If the behind the meter generation is not netted, then it will be modeled as regular generation. If the behind the meter generation was not tied to its own bus, then the capacity was divided between generation units that it was associated with in the power flow model.

4. Controllable Capacity Demand Response Modeling

a. Explanation of how controllable capacity demand is modeled

SPP has controllable capacity demand in the form of Contractually Interruptible (Curtailable) demand. The areas that reported the controllable capacity demand had a load modifier applied to their shape to account for the curtailable demand.

5. Capacity Modeling

a. Differences between the MRA and LTRA capacities

Some of the LTRA capacity was subtracted from the total MRA capacity for various reasons. In one case, Entergy-owned generation units were subtracted since the Entergy demand was subtracted from the overall MRA demand. Other differences include the subtraction of demand response, units that were duplicated in the LTRA, and future units whose online dates were pushed back beyond the year 2014.

b. Determination of whether "Future, Planned" generation is "firm and deliverable

It is assumed that "Future, Planned" generation that is included in the LTRA is "firm and deliverable". Based on this assumption it is also assumed that the "Future, Planned" generation modeled in this assessment is "firm and deliverable" as well.

c. Generation additions and capacity re-ratings

New generation units were added to the GridView model and put in service based on the commission date. The new thermal and hydro units were modeled with a max capacity based on the expected on-peak summer rating reported in the LTRA. New Hourly resource units were modeled with a max capacity based on the nameplate value. Only Existing, Certain and Future, Planned units that were within the study period were modeled based on the LTRA data.

d. Explanation of how jointly owned units are modeled

Jointly owned units were modeled with the maximum capacity matching that of the value reported in the LTRA On-peak summer capacity rating. This rating is the amount that is owned by the individual area owner. Only the portion of capacity belonging to the area owner within the SPP RE footprint was modeled.

e. Capacity sales and purchases

Sales to the external region were modeled as hourly resources with a flat value shape close to the border of the importing Balancing Authority, but within the exporting Balancing Authority and tied to the highest voltage tie-line bus. The hourly resources have a negative capacity. For DC ties, 2010 actual hourly values were used to generate the hourly shape. Sales between entities within the SPP RE footprint were incorporated into the existing certain value of the LTRA and were not modeled as separate hourly resources.

Purchases from the external region were modeled as hourly resources with a flat value shape close to the border of the exporting Balancing Authority, but within the importing Balancing Authority and tied to the highest voltage tie-line bus. The hourly resources have a positive capacity. For DC ties, 2010 actual hourly values were used to generate the hourly shape. Purchases between entities within the SPP RE footprint were incorporated into the existing certain value of the LTRA and were not modeled as separate hourly resources.

f. Intermittent and energy-limited variable resources

Wind generation was modeled as an hourly resource using the 2011 SPP ITP10 Wind Siting Plan data as a reference for the wind shapes. The hourly wind shapes were developed by the National Renewable Energy Laboratory (NREL). The 2009 hourly wind shapes were imported into GridView to provide an accurate profile of the wind generation output for each hour in the year.

g. Traditional dispatchable capacity

i. Ratings

The on-peak capacity ratings are developed by the SPP member's capability testing. The capability testing procedure and requirements are described in SPP Criteria section 12.1.1[6]

ii. Forced outage modeling

Forced outage modeling within GridView consists of using the EFORd values provided from the PROMOD application, which has the unit data supplied by Ventyx. The outage period is random and the units selected are random. Up to 5 units per trial are removed from service for the entire trial.

iii. Planned outage modeling

Planned outages for thermal units were modeled by using the scheduled maintenance function in GridView to take units offline for a specified period of time based on start time, end time, and duration. Once the outage duration elapsed, the unit was placed back online in the model.

[6] http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices07-27-10.pdf

6. Transmission

a. Transmission additions and retirements

System Topology was drawn from the 2011 summer and 2013 winter Model Development Working Group (MDWG) models for the 2011 and 2014 study years respectively. Transmission additions and retirements were captured from the MDWG models that are built with the SPP members input and modeling. Transmission additions were modeled and retirements were removed from the MDWG models.

Transmission projects that were included as upgrades or modifications to the 2013 winter MDWG model were modeled so that all projects within the 2014 study year were captured.

b. MRA's transmission modeling approach

Assumptions made for both years are made in the table below:

Interface Name	Limit
COOPER_S_MAPP	±1365
SPPSPSTIES	±1134
SPSNORTH_STH_SPP	±800
SPSSPPTIES_SPP	±620

Interface limits for years 2011 and 2014 were the same even though the limits for 2014 should increase. A sensitivity study is needed to determine the interface limits for 2014. Because no such study has been performed, there was no increase in the limits.

Flowgate modeling was done in conjunction with the list of flowgates outlined in the PROMOD event file, which is sourced by the NERC book of flowgates.

7. Assistance from External Resources

a. Quantifying non-firm assistance from resources outside of the MRA's footprint

SPP does not rely on non-firm assistance from resources outside of the SPP RE footprint, consistent with the values contained in the LTRA report.

8. Definition of Loss-of-Load Event

a. MRA's definition of loss-of-load event

Loss-of-load event, as defined in this Probabilistic Assessment, is any load that is not served, or load that is greater than generation.

9. Conclusion

a. 2011 Probabilistic Assessment

Historically, the SPP-SPS PTDF based flowgate has been a source of congestion determined in previous LOLE assessments, specifically in the SPS area. This interface was monitored to limit the import into this area based on the voltage stability constraint. The SPS North-South flowgate is the internal flowgate in this area that was monitored to limit the flow from the Northern part to the Southern part of the area based on the thermal constraint. In this assessment, the SPP-SPS and SPS North-South flowgates proved to be an area of congestion, which contributed to the LOLE value.

When the capacity margin was lowered from 22.69% to 12%, the LOLE increased beyond the standard of 1 day in 10 years. This is logical because as the load increases without an increase in capacity, the expectation of load unserved should also increase.

b. 2014 Probabilistic Assessment

With the inclusion of the near-term Balanced Portfolio and Priority Transmission projects in the SPS area, along with the Wilderado Wind Farm resource, the LOLE was reduced to 0, which meets the standard of 1day in 10 years.

When the capacity margin was lowered from 19.92% to 12%, an LOLE value appeared, but is still below the standard of 1 day in 10 years.

10. Recommendation

The recommendation, based on previous LOLE studies and this assessment, is to move forward with the construction of the Woodward-Tuco 345 kV and Hitchland-Woodward 345 kV lines to reduce congestion of flow into the SPS area. The addition of Wilderado Wind Farm resource will contribute to a reduction in imports across the SPP-SPS interface. These recommendations will contribute to a decrease in LOLE.

Based on the results of this assessment, it was determined that the 2014 LOLE value meets the 1 day in 10 year requirement, therefore the SPP Criteria of 12% capacity margin is adequate.