Expected Unserved Energy and Reserve Margin Implications of Various Reliability Standards

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PREPARED FOR

Electric Reliability Council of Texas

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Contents

Executive Summary

Objective

This study was performed by Astrapé Consulting at the request of the Electric Reliability Council of Texas (ERCOT) and the Public Utility Commission of Texas (PUCT). ERCOT is considering a range of possible reliability standards at the direction of the PUCT. Each such option carries with it varying qualities that are not discussed in this study. This analysis may provide context to the ongoing work at the PUCT by identifying the reserve margins necessary to meet each standard under consideration as well as the expected unserved energy for each standard. The physical reliability standards studied include 0.1 Loss of Load Expectation (LOLE) in events per year[1]; 2.4, 4, 6, 12, and 15 Loss of Load Hours (LOLH) in hours per year; and 0.001% and 0.002% Normalized EUE (EUE in MWh / Total Demand in MWh) for the 2016 study year.

Methodology and Input Summary

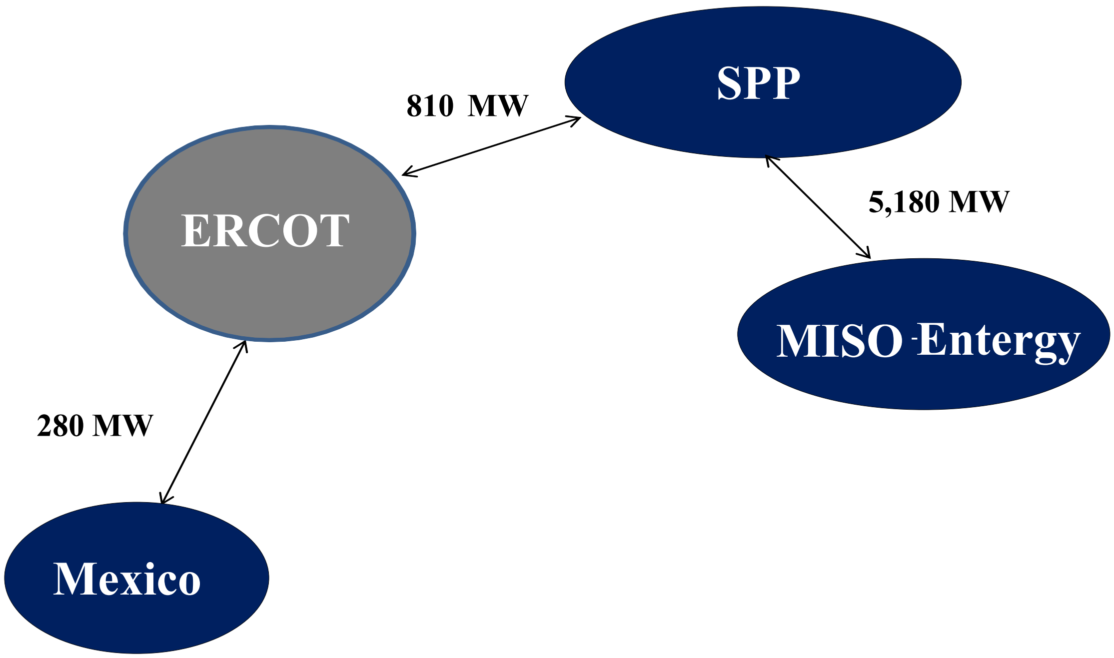
Since most reliability events are high impact, low probability events, a large number of scenarios must be considered to account for uncertainties in weather, load forecasts, and unit performance. The study used a probabilistic approach to model the uncertainty of weather, economic growth, unit availability, and transmission availability with neighboring regions for emergency tie assistance. Utilizing the Strategic Energy Risk Valuation Model (SERVM)[2], 5,500 hourly simulations were performed for 2016 at each reserve margin level to calculate physical reliability metrics for ERCOT. The 5,500 yearly simulations consisted of 11 historical weather years[3], simulated with 5 load forecast error multipliers and 100 Monte Carlo unit outage draws.[4] Each weather year was given equal probability except for 2011 which was given a 1% probability based on National Oceanic and Atmospheric Administration historical weather data. Each load forecast error multiplier was given a distinct probability of occurrence based on a review of historical economic growth uncertainty. Each Monte Carlo unit outage draw was given equal probability. For each iteration simulated, SERVM records the number of events, hours, and magnitude of all firm load shed events. A loss-of-load event in SERVM is defined as one or more consecutive hours of load shed. SERVM dispatches resources to meet load, regulation, spin, and non-spin requirements. For this assessment, it was assumed that load would be shed to maintain 500 MW of regulation and 600 MW of spinning reserve across the ERCOT region.

Figure ES1 shows the topology used for the study. The external regions of SPP, Entergy, and Mexico were all modeled as individual zones. By modeling the external regions, the benefit of weather

[1] The 0.1 Loss of Load Expectation (LOLE) in events per year represents the 1-event-in-10-year standard. This metric is also commonly referred to in the industry as the 1-day-in-10-year standard as the phrases are used interchangeably.
[2] SERVM is a state-of-the-art reliability and hourly production cost simulation tool that performs an hourly chronological economic commitment and dispatch for multiple areas using a transportation/pipeline representation. The model allows zones to share energy based on economics and subject to import and export constraints.
[3] The 11 weather years included 2002-2007 and 2009-2013. The 2008 weather year was excluded due to anomalous impacts attributable to Hurricane Ike.
[4] 11 weather years x 5 load forecast multipliers x 100 unit outage draws = 5,500 yearly simulations.

and generator outage diversity can be captured across regions but still be limited by transmission constraints. The import constraint for ERCOT from surrounding regions is modeled as a distribution with an average of 990 MW and a maximum of 1,090 MW.

Figure ES-1. Study Topology



All data inputs including load and resources are consistent with ERCOT's May 2014 Capacity and Demand Report (CDR)[5] and are included in detail in the body of the report. Price responsive demand was captured by grossing up the loads in the CDR and dispatching that block as a resource as a function of market price in the model. Load shapes, wind shapes, solar shapes, and hydro shapes were all modeled based on 11 historical weather years which provided an accurate correlation among categories for each weather year modeled. Traditional thermal generation resources were modeled with capacities, heat rate curves, startup times, minimum up times, minimum down times, and ramp rates. Forced outages were modeled for each unit with time-to-fail and time-to-repair distributions. Demand response resources were modeled with program call limits, availability constraints, and strike prices to accurately represent their dispatch and availability.

Reserve Margin Calculation

Reserve margin is defined, consistent with CDR, as the following:

- (Resources – Demand) / Demand
    - Demand is the 50/50 Annual Peak Load Forecast less demand response programs.

[5]http://www.ercot.com/content/news/presentations/2014/CapacityDemandandReserveReport-May2014.pdf.

- Coastal Wind resources are counted as 56% of nameplate capacity, Non Coastal wind resources are counted as 12% of nameplate capacity, and PV resources are counted as 100% of nameplate capacity.

- DC Ties with surrounding neighbors are counted at 643 MW.[6]

To achieve different reserve margin levels, the 50/50 load forecast was varied up and down. Load was varied rather than resources to maintain the same resource mix expected in 2016.

Results

The simulations described above were used to identify target reserve margin levels (Planning Reserve Margin) at which specific physical reliability standards would be satisfied. The table below identifies the results using the standards requested by ERCOT and the PUCT. In addition to the Planning Reserve Margin for each standard, a measure of the magnitude of the average reliability events is given in the column 'Weighted Average EUE Across All Weather Years.' The 'Planning Reserve Margin' and the 'Weighted Average EUE Across All Weather Years' columns represent the base case results which assumes 2011 weather is given a 1% probability of occurrence. Also, to provide a sense of the magnitude of reliability issues in extreme years, the final column displays the EUE from the cases that used the 2011 weather year which was the most extreme year in the sample.

Table ES-1. Summary of Results

Reliability Standard	Planning Reserve Margin	Weighted Average EUE Across All Weather Years (MWh)	2011 Weather EUE (MWh)
15-LOLH	7.50%	22,947	219,976
12-LOLH	8.14%	17,487	175,919
6- LOLH	9.97%	7,684	92,849
4- LOLH	10.96%	4,789	65,312
2.4- LOLH	12.00%	2,855	43,809
0.1 LOLE	16.75%	204	4,463
.001% EUE	11.50%	3,670	54,418
.002% EUE	10.20%	6,897	85,683

Figure ES-2 shows LOLE as a function of reserve margin in events per year. As reserve margin in ERCOT increases, LOLE decreases. The 1-event-in-10-year standard of 0.1 LOLE results in a 16.75%[7] reserve margin.

[6] Import capability from surrounding neighbors is 1080 MW, but the dependable capacity across the other side of the interfaces is assumed to be 643 MW.

[7] In the "Estimating the Economically Optimal Reserve Margin" Study performed by Astrape and *The Brattle Group* in January 2014, the LOLE at a 14.1% reserve margin was 0.1. For that study, wind capacity was given a capacity

Figure ES-2. LOLE

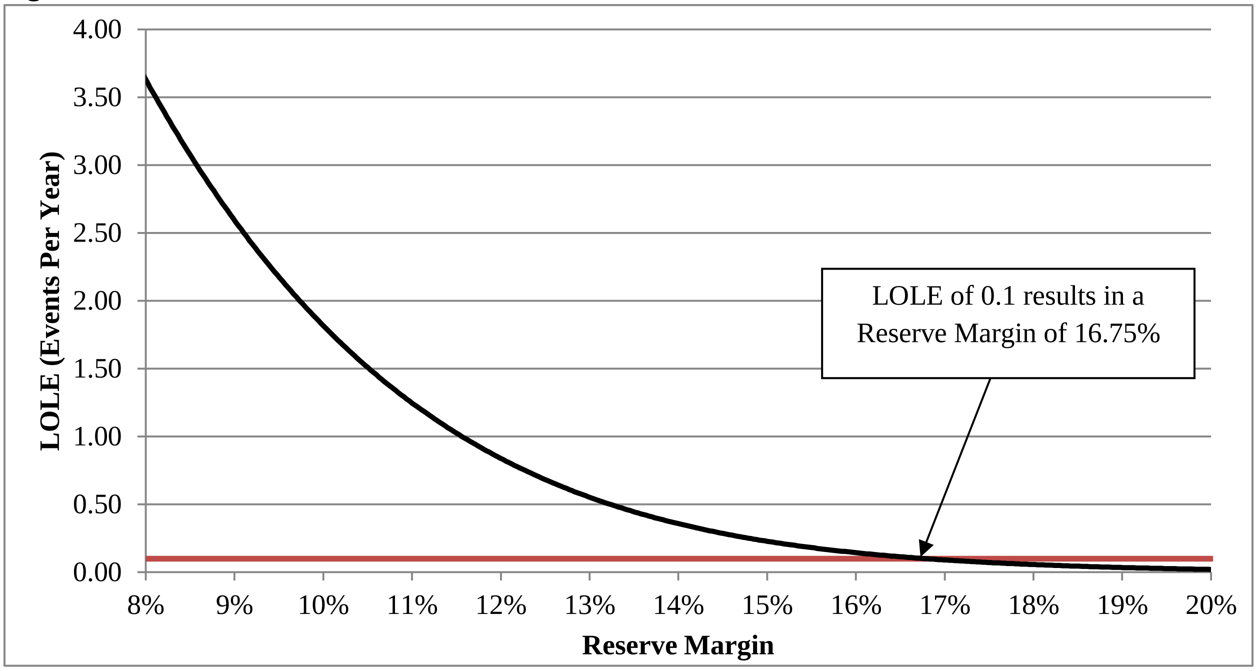
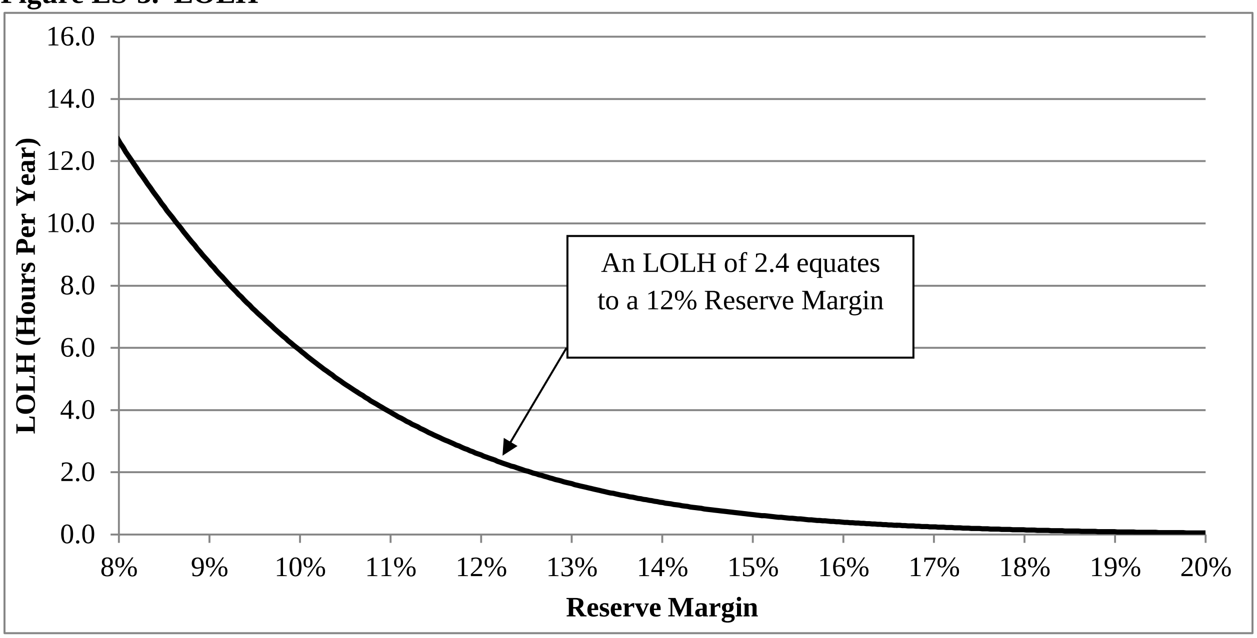


Figure ES-3 shows LOLH as a function of reserve margin. An LOLH of 2.4 hours per year equates to a 12.0% reserve margin level.

Figure ES-3. LOLH



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credit of 8.7%. With the updated capacity values for wind resources, the calculation of reserve margin increased by 2.4%, making the 16.75% 1-event-in-10-year standard reserve margin approximately in line with the 14.1% reserve margin from the previous study.

Figure ES-4 and Figure ES-5 show EUE in MWh and normalized EUE as a function of reserve margin. The reserve margin resulting in a 0.001% normalized EUE is 11.5%.

Figure ES-4. EUE

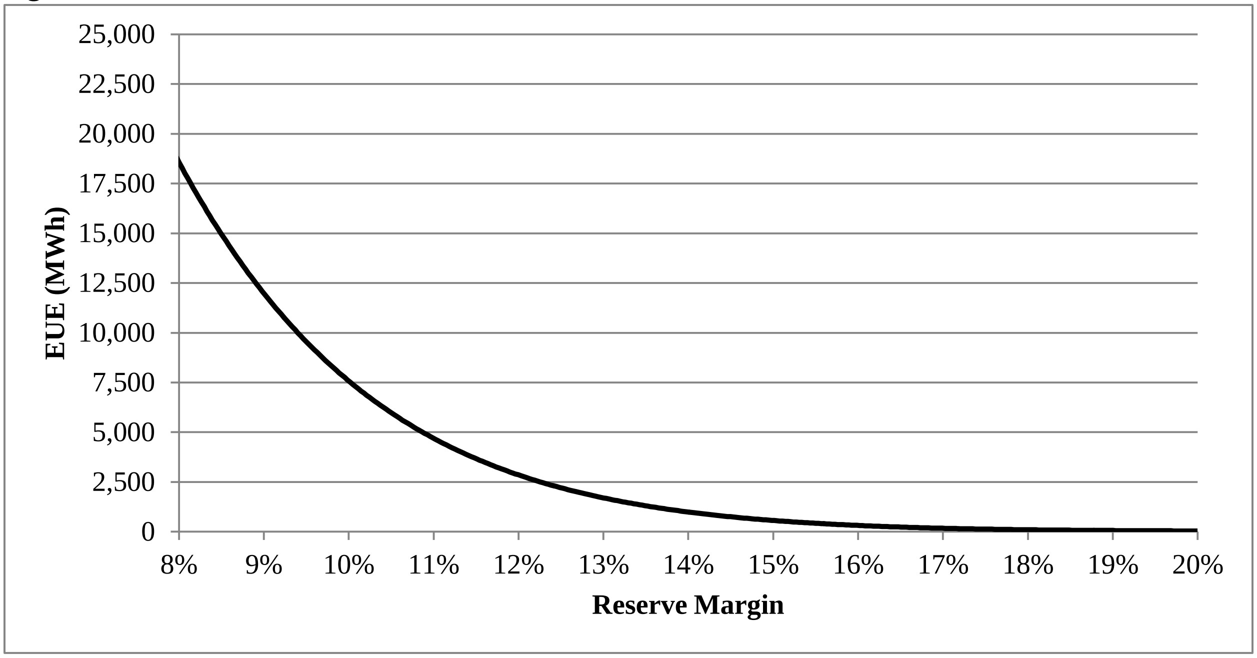


Figure ES-5. Normalized EUE

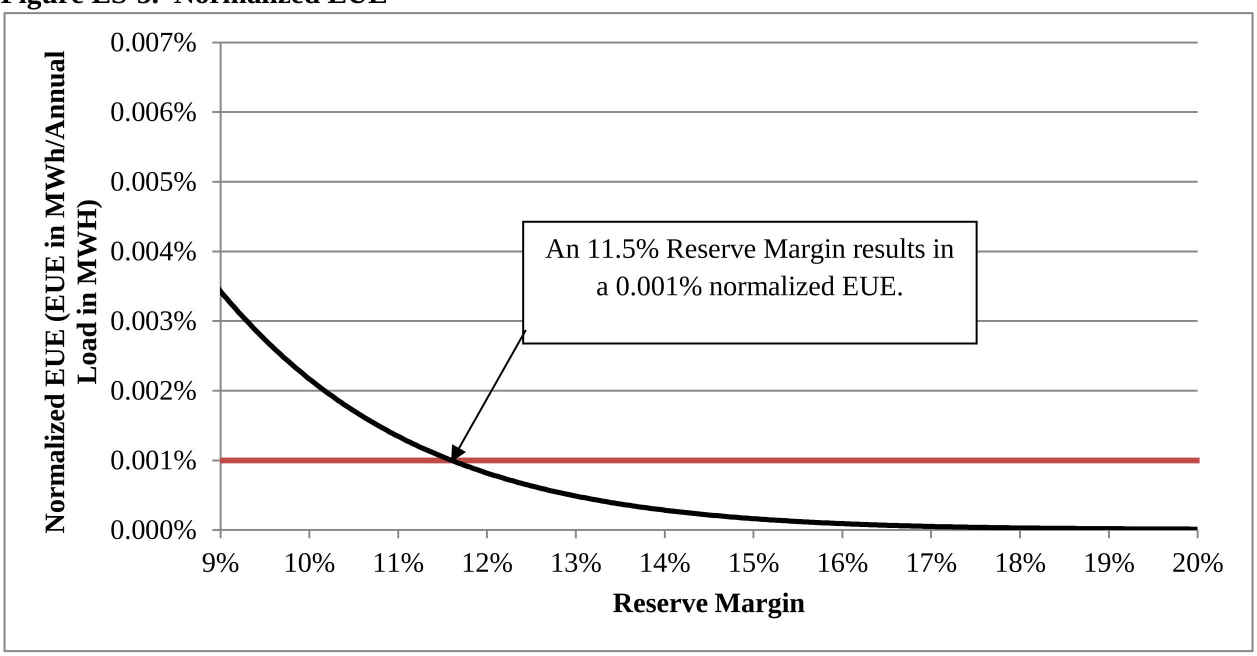
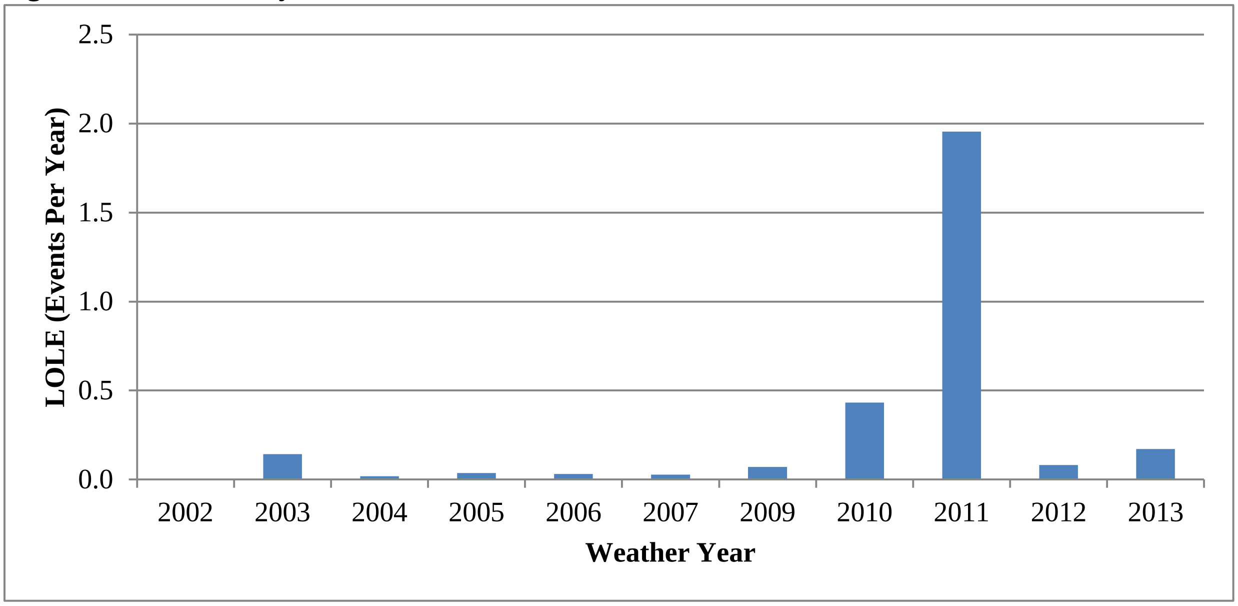


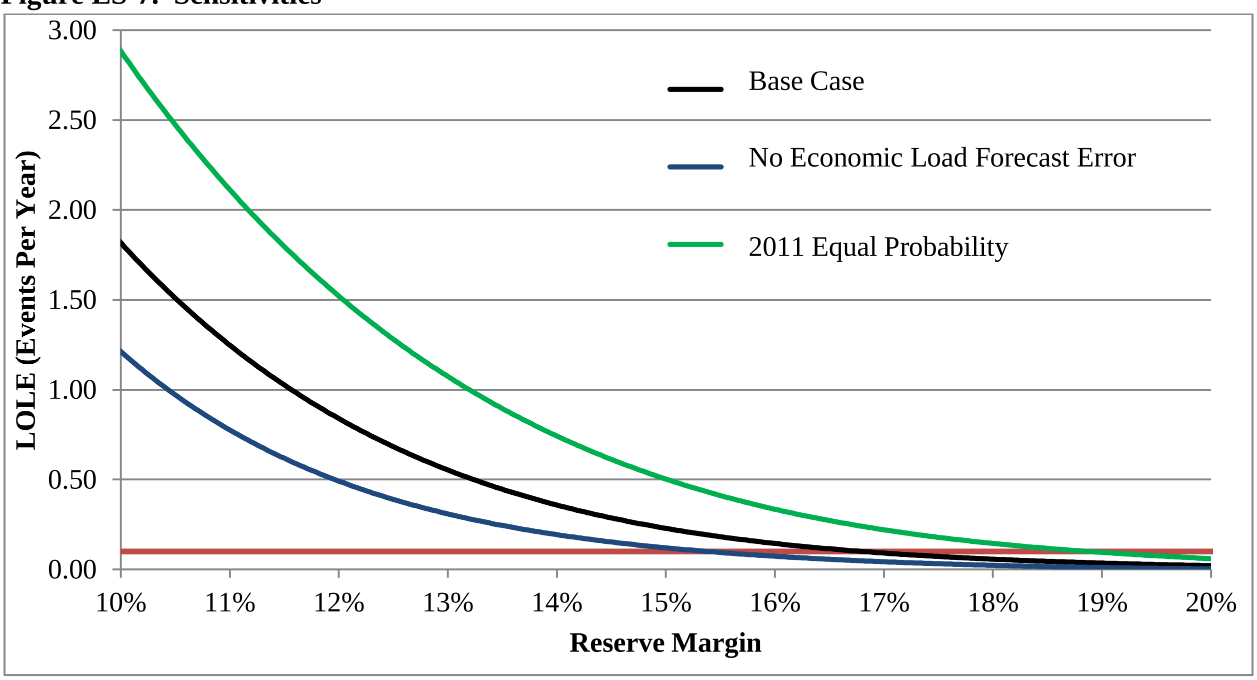
Figure ES-6 shows LOLE by weather year assuming a 16.75% reserve margin. As discussed previously, the 2011 weather year was an extreme outlier and produced the highest LOLE but was only given a 1% probability of occurrence in the study.

Figure ES-6. LOLE by Weather Year



Two additional sensitivities were performed. The first was to remove the three-year load forecast uncertainty and the second was to assume all weather years were given the same probability. The LOLE curves for those two scenarios are in Figure ES-7. The 1-event-in-10-year standard reserve margin shifts down to 15.5% if no economic load forecast error is included and increases to 18.75% if 2011 is given equal probability to the other weather years.

Figure ES-7. Sensitivities



Summary

Based on the analysis described in this report, the 1-event-in-10-year standard (0.1 LOLE) results in a 16.75% target reserve margin for the ERCOT region. If the target reserve margin were based on the less common metrics of 2.4 hours per year or 0.001% normalized EUE, the resulting reserve margins would be 12.0% or 11.5%, respectively. As shown in the sensitivity section, if the impact of load forecast error is removed, the target reserve margins which achieve the specified reliability standards shift down by approximately 1.25%. Differences between these results and previous loss-of-load studies are primarily the result of the use of new ERCOT load forecast models and revised accounting for the assumed capacity credit of wind resources.

I. List of Figures

II. List of Tables

III. Input Assumptions

A. Study Year

The Resource Adequacy Assessment was based on 2016 loads and resources.

B. Study Topology

Weather and generator outage diversity that a system has with its neighbors is an important component of understanding resource adequacy. The surrounding regions captured in the modeling included all of SPP, MISO-Entergy, and a portion of Mexico. SERVM is a multi-area model that commits and economically dispatches resources for each region, and then allows for energy to be shared on an hourly basis according to economics and subject to physical transmission constraints. Figure 1 shows the topology used for the study.

Figure 1.Study Topology

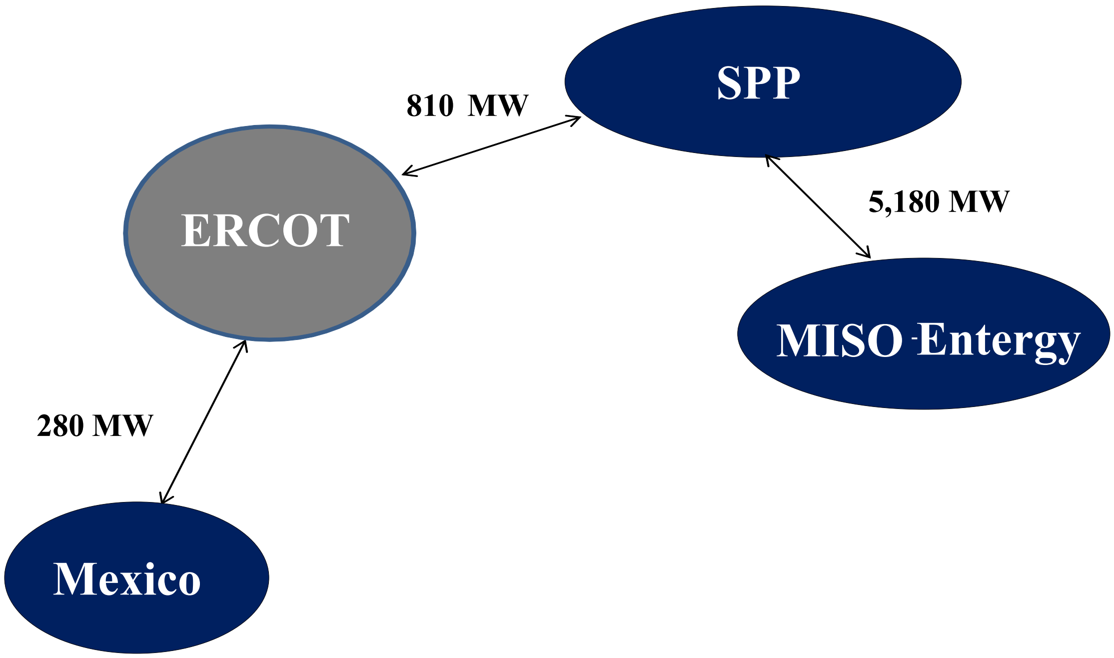
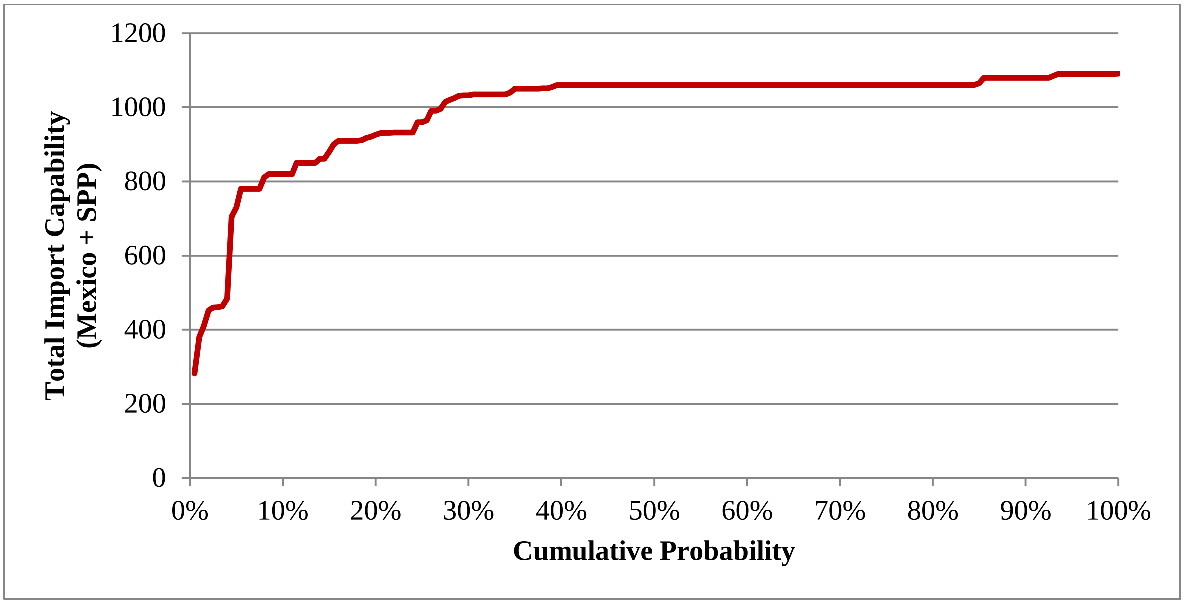


Figure 2 shows the distribution of total import capability into ERCOT from Mexico and SPP. The distribution shows that approximately 30% of the time, the total import capability is less than 1,000 MW. SERVM randomly draws from the distribution on a daily basis to assign the import capability.

Figure 2. Import Capability Distribution



C. Load Modeling

Table 1 displays the Summer and Winter Peak Loads under normal weather conditions for the ERCOT Region. These forecasts represent peak load with all price responsive demand removed. For simulation purposes, the peak hour of each load shape was grossed up by approximately 900 MW[8] to account for price responsive demand and other self-scheduled demand response programs that were captured as resources in the modeling.

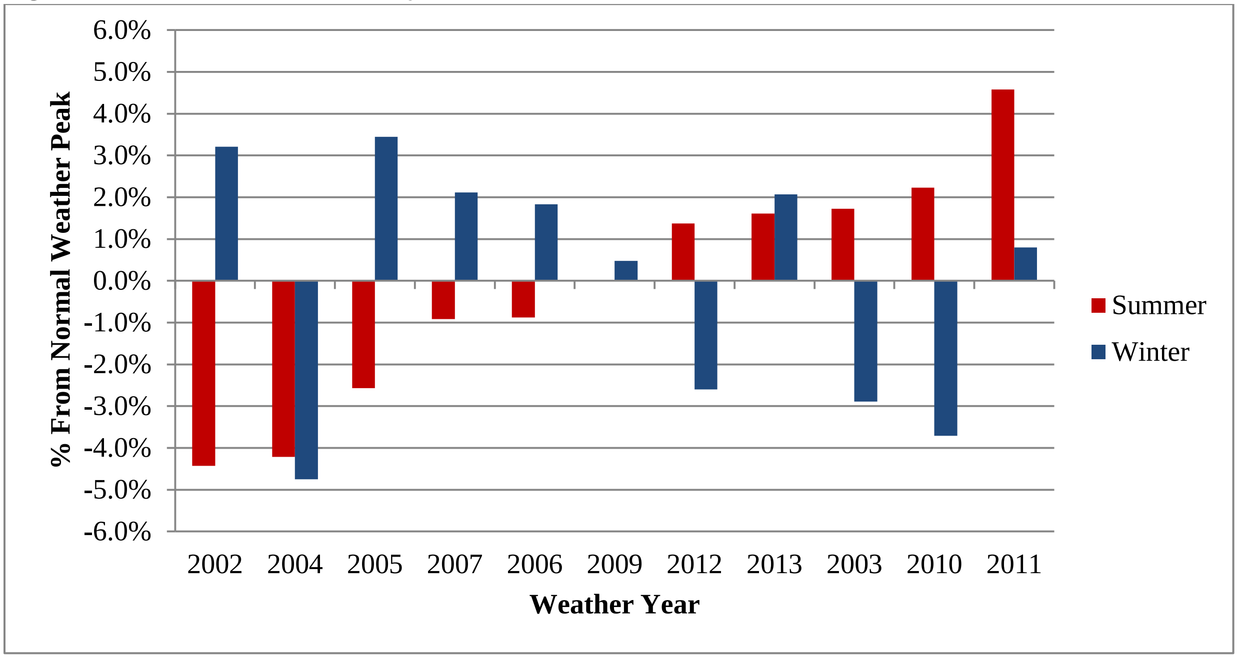
Table 1. 2016 Load Forecast

Year	Summer Peak (MW)	Winter Peak (MW)
2016	70,014	53,719

To model the effects of weather uncertainty on load, eleven synthetic load shapes were developed by ERCOT using eleven historical weather patterns. The eleven weather years used included 2002-2007 and 2009-2013. The 2008 weather year was excluded because of Hurricane Ike's anomalous impact on loads. Figure 3 shows the variance from normal weather seen in each synthetic shape (defined by the underlying historical weather year) for both the winter and summer peaks. The median of the summer peaks is forced to be equal to the forecast.

[8] The load in other hours near the peak was also increased (but by less than 900 MW) to reflect the load associated with the demand response programs.

Figure 3. Peak Load Variance by Weather Year



Note: 0% average peak conditions (normal weather).

In the most severe weather conditions, the peak could be as much as 4.6% higher than in normal weather conditions. Weather conditions in 2011 were significantly more extreme than in any other year simulated. In fact, a review of peak season weather conditions indicates that the frequency of occurrence of weather patterns experienced in 2011 is much less than other years included in the sample. Because 2011 was such an anomaly, it was assigned a 1% probability of occurrence based on National Oceanic and Atmospheric Administration historical weather data. Similar load modeling was performed for the SPP and Entergy regions. Eleven synthetic load shapes were developed using historical weather data for each external region. Table 2 shows the diversity between ERCOT and the external regions for the eleven-year period. When the entire system is peaking, there is 3.2% diversity across the entire region. When ERCOT is at its peak, SPP is on average 10% below its non-coincident (or annual) peak and Entergy is 8% below its non-coincident peak.

Table 2. Peak Load Diversity[9]

	ERCOT	SPP	ENTERGY	MEXICO	System Total
50/50 Summer Peak Load					
Non-Coincident	70,804	55,755	26,496	9,913	162,967
System Coincident	69,318	53,612	25,113	9,665	157,708
At ERCOT Peak	70,804	49,930	24,413	9,896	155,043
Load Diversity (% below non coincident peak)					
At System Coincident Peak	2.10%	3.84%	5.22%	2.50%	3.23%
At ERCOT Peak	0.00%	10.45%	7.86%	0.17%	4.86%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic component of the uncertainty of forecasting load three years in advance. The following assumptions were based on a comparison of Congressional Budget Office (CBO) GDP forecasts three years ahead with actual GDP data. The results of this comparison were fit to a normal distribution, and a standard deviation was calculated. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error. This normal distribution was broken into a discrete distribution with 5 points and their associated probabilities (shown in Table 3). The table demonstrates that 7.9% of the time, it is expected that load will be under-forecasted by 4% three years out. The SERVM model created fifty-five distinct cases consisting of each of the eleven weather years matched with each of the five load forecast error points. For example, the 2011 weather year load shape consisting of 8,760 hours was converted into 5 load shapes for simulation purposes by multiplying each hour by each of the 5 load forecast error multipliers.

Table 3. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.96	7.9%
0.98	24%
1.00	36%
1.02	24%
1.04	7.9%

[9] Loads have been grossed up for Price Responsive Demand and Self Scheduled Demand Response Resources.

E. Resources

Table 4 represents the total capacity installed for the winter and summer months.

Table 4. ERCOT Resource Summary

	2016	
CAPACITY	**Winter**	**Summer**
Capacity Installed (Nameplate)	**95,902**	**94,320**
Coal	17,367	19,161
Gas	49,066	45,888
Nuclear	5,164	4,981
PUNS	4,668	4,655
Hydro	541	541
Pumped Storage	34	34
Biomass	235	235
Wind	18,505	18,505
Solar	321	321

F. Conventional Resources

All conventional thermal resources included in the 2016 study are based on ERCOT's public "Capacity, Demand, and Reserves Report" from May 2014.[10] All conventional generators are modeled with capacities, heat rate curves, startup times, minimum up constraints, minimum down constraints, and ramp rates. SERVM commits and dispatches resources taking into account all unit constraints and co-optimizes both energy and ancillary services. All mothballed units expected to be unavailable were excluded from the study. All available switchable[11] units available to ERCOT were also included in the study. Since conventional generators are able to run their units at slightly higher outputs for short periods during capacity shortages, a synthetic emergency generation unit was modeled with capacity of 358 MW and a $500/MWh dispatch price. To model the uncertainty of the dependability of this additional capability, a response factor was applied which allowed the synthetic generator to achieve full capacity when called 50% of the time and 229 MW the other 50% of the time.

G. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events are supplied for each unit, and SERVM randomly draws from these events to simulate the unit outages. For this study, events were entered into SERVM for units with 2008-2012 GADS history. For resources without GADS data available, projections of EFOR by unit provided by ERCOT were used to create realistic event histories. The actual events are entered using the following variables:

[10] http://www.ercot.com/content/news/presentations/2014/CapacityDemandandReserveReport-May2014.pdf.
[11] Switchable units are resources that are interconnected to both ERCOT and a neighboring region.

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate: % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods if possible.

Planned Outages
Specific time periods are entered for planned outages. Typically these are performed during shoulder months.

The most important aspect of calibrating unit performance modeling in reliability studies is ensuring the simulations produce a realistic cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Figure 4 shows the distribution of outages for ERCOT based on historical modeled outages. The figure demonstrates that in any given hour, the ERCOT system can have between 0 and 7,000 MWs of its generators offline due to forced outages. The figure shows that in10% of all hours throughout the year, ERCOT has greater than 4,600 MW (~6.5% of its reserve margin) in a non-planned outage condition. This value is composed of several units that are on forced outage at the same time. The data in the figure excluded all maintenance and planned outages.

Figure 4. Conventional Resources on Forced Outage as a Percentage of Time

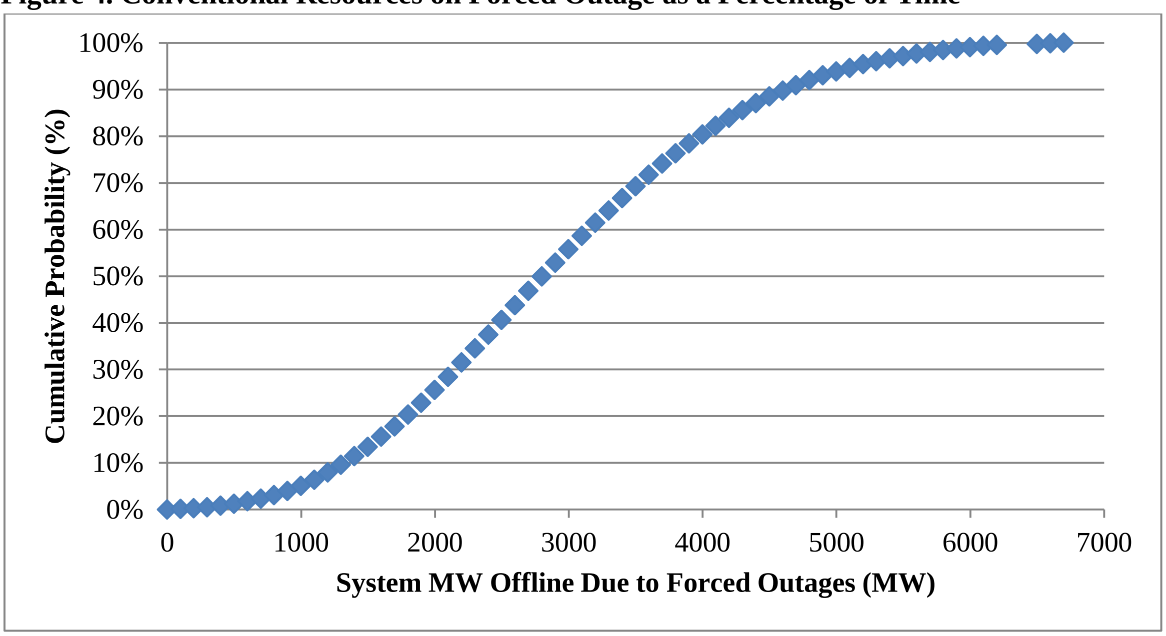


Table 5 shows the modeled class average EFOR rates. The system weighted EFOR is approximately 6.8%.

Table 5. Equivalent Forced Outage Rates by Asset Class

Unit Name	Equivalent Forced Outage Rate (%)	Mean Time-to-Fail (hours)	Mean Time-to-Repair (hours)
Nuclear	1.6%	9,352	68
Coal	5.8%	878	37
Gas Combined Cycle	5.5%	681	37
Gas Combustion Turbine	12.3%	285	40
Gas Steam Turbine	7.8%	325	27
Fleet Weighted Average EFOR		6.8%	

H. Hydro

Hydro resources for ERCOT are split into 2 categories based on analysis of historical hydro generation.

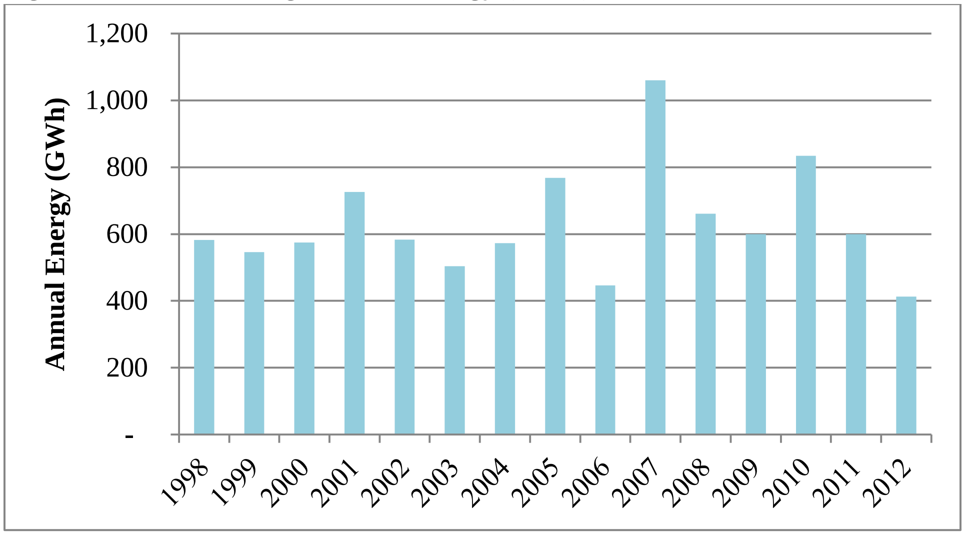
1. Scheduled Hydro: These resources represent the portion of the system hydro that is dispatched to shave the peak but also forced to meet minimum generation requirements and maximum capacity levels. A weekly hydro generation value is provided that must be fully used within the week. The hydro energies are based on eleven historical weather years to match load assumptions. The max scheduled capacity levels are based on the realized hydro dispatched in historical years.

2. Emergency Hydro: For emergency purposes, a separate energy-limited emergency hydro resource is modeled to represent the additional capability between the scheduled portion and the nameplate of the hydro system. The emergency resource can borrow energy from the peak shaving resource in times of emergency up to 4,650 MWh, which equates to approximately 20 hours. However, this type of operation forces the peak shaving resource to forfeit future energy so as to not exceed the overall monthly energy for the specific weather year.

Figure 5 shows the variability in historical hydro energy for ERCOT from 1998 – 2012, however, only 11 years (2002-2007; 2009-2013) were simulated to coincide with the load years modeled.[12]

[12] For 2013, the 2012 hydro year was repeated. Given that ERCOT has 541 MW of hydro resources, this assumption should not impact results in a meaningful way.

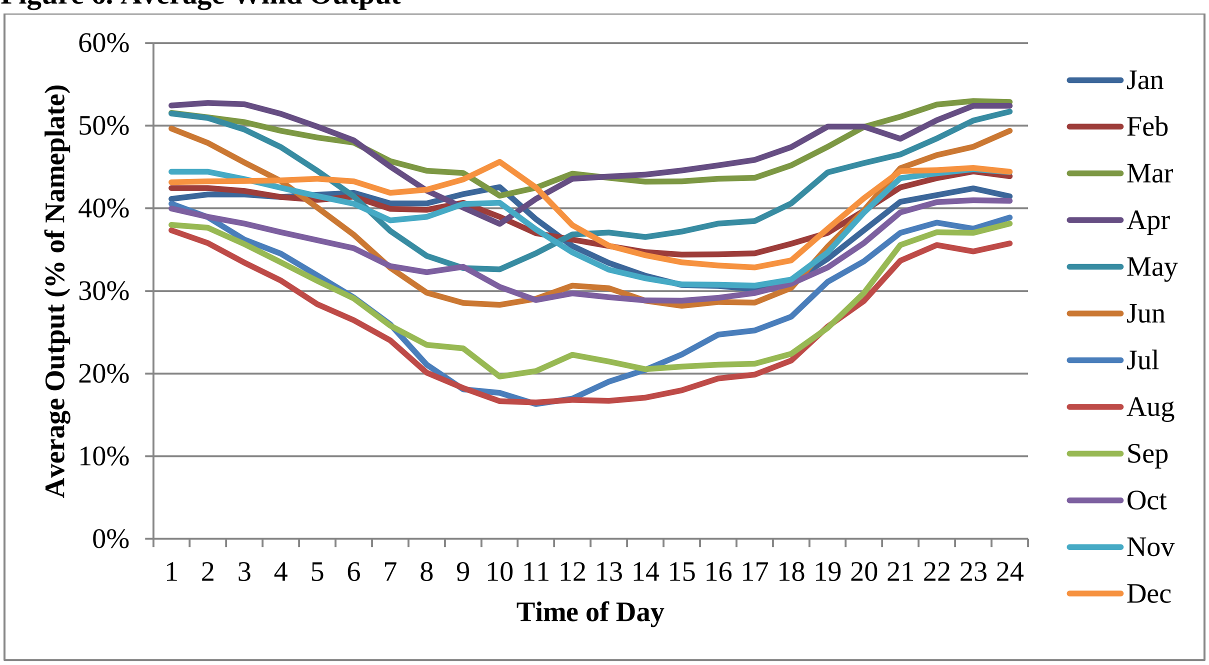
Figure 5. Peak Shaving Annual Energy (GWh)



I. Renewable Resource Modeling

The 2014 May CDR includes 18,505 MW of wind capacity in 2016. The wind was modeled with the same eleven historical weather years utilized by both load and hydro. Hourly wind shapes were developed by AWS Truepower through 2011. Because wind data was only provided through 2011, additional analysis was performed to compare 2012-2013 load years by month to previous load years. The closest match on a monthly basis considering both peak and energy was used again to represent 2012-2013 wind years. Figure 6 shows the average profile by month of the hourly wind patterns used in the simulations. For reserve margin accounting purposes, the coastal wind capacity was counted at 56% of nameplate and the non-coastal wind capacity was counted at 12%.

Figure 6. Average Wind Output



For solar resources, the 320 MW nameplate capacity was modeled in a similar fashion using the same eleven weather years mentioned previously. Similar to the wind data, the provided solar data did not cover the entire 11 year period. Solar data was only provided through 2010. To capture 2011-2013 solar shapes, additional analysis was performed to compare 2011-2013 load years by month to previous load years. The closest match on a monthly basis considering both peak and energy was used again to represent 2011-2013 solar years.[13] For reserve margin accounting, solar capacity was counted at 100% of nameplate capacity.

J. Private Use Network Modeling

Private Use Network (PUN) Resources are modeled by capturing their net output to the grid. Based on analysis of historical data and price, the net output of these resources is captured using Monte Carlo draws from the distributions shown in Table 6. For example, if the highest price across the day is between $20/MWh and $60/MWh, then the net output of PUN resources is between 2,046 MW and 5,313 MW with a 9.1% probability of drawing 5,313 MW. As the price increases, the range narrows and the peak output reaches 5,433 MW which is the maximum net output seen in historical years. This modeling method captures the variation and uncertainty provided by PUN resources to the ERCOT system.

Table 6. Private Use Network Net Output Distributions

Draw Probability	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**	**9.1%**
Price ($/MWh)	**Net Output (MW)**										
20	2,046	2,705	3,107	3,424	3,669	3,924	4,104	4,259	4,422	4,628	5,313
60	2,067	2,719	3,117	3,433	3,679	3,935	4,114	4,269	4,432	4,636	5,313
80	2,089	2,733	3,128	3,442	3,688	3,945	4,125	4,280	4,441	4,644	5,315
100	2,111	2,747	3,139	3,451	3,698	3,956	4,136	4,290	4,451	4,652	5,316
150	2,165	2,782	3,166	3,473	3,722	3,982	4,162	4,317	4,476	4,673	5,317
200	2,219	2,816	3,194	3,496	3,747	4,008	4,189	4,343	4,500	4,694	5,319
300	2,327	2,886	3,248	3,540	3,795	4,060	4,242	4,395	4,548	4,734	5,324
400	2,435	2,956	3,303	3,585	3,844	4,112	4,296	4,448	4,596	4,776	5,328
500	2,543	3,026	3,357	3,630	3,893	4,164	4,349	4,500	4,645	4,817	5,332
750	2,814	3,199	3,493	3,741	4,015	4,295	4,483	4,632	4,765	4,920	5,343
1000	3,084	3,374	3,630	3,853	4,137	4,426	4,616	4,763	4,886	5,022	5,353
1500	3,624	3,722	3,903	4,076	4,381	4,687	4,883	5,026	5,128	5,228	5,374
2000	4,070	4,165	4,175	4,300	4,625	4,948	5,150	5,288	5,369	5,395	5,433

K. Demand Response Modeling

Demand response programs are modeled as resources in the simulations with specific call limits including seasonal capability, specific availability across the day, and hours-per-year limits. Table 7 shows a

[13]For 2012 and 2013, the solar and wind shapes that were developed based on historical months were coincident with each other. For 2011, the wind shapes were based on 2011 weather shapes developed by AWS Truepower and the solar shapes were based on the closest match of previous monthly data.

breakdown of the Demand Response modeled in the study. All four of these programs are called prior to shedding firm load, in the order shown.

Table 7. Demand Response Resources

	Summer Capacity	**Call Limits**	**Call Priority**
TDSP Standard Load Management Programs	255	16 hours per year, during hours 14-20	1
Load Resources Serving as Responsive Reserve	1,231	unlimited	2
10 Min ERS	350	8 hours per season and per hourly availability intervals*; Seasons: Winter, Spring, Summer, Fall; Hourly availability intervals: week day hours 1-8 and 21-24 and weekends, week day hours 9-13, week day hours 14-16, week day hours 17-20	3
30 Min ERS	81	8 hours per season and per hourly availability intervals*; Seasons: Winter, Spring, Summer, Fall; Hourly availability intervals: week day hours 1-8 and 21-24 and weekends, week day hours 9-13, week day hours 14-16, week day hours 17-20	4

*10 min ERS and 30 Min ERS were modeled as 16 resources each representing a single season and hourly availability interval. Each resource could be dispatched 8 hours per year during its season and hourly interval.

L. Price Responsive Demand and Voluntary Load Reductions

As discussed previously, to capture price responsive demand and other voluntary load reductions, the load shapes were grossed up and the price responsive demand and voluntary load reductions were represented as resources in the modeling. Analysis based on historical data was performed to determine the amount of load gross-up as well as the relationship between these products and price. Table 8 shows the amount of load gross-up for each category during the peak hour of each load shape. The load in other hours near the peak was also increased but by less than the values in Table 8 to reflect the load associated with the demand response programs.

Table 8. Load Gross-Up Assumptions

	2016 Load Gross Up (MW)
Price Responsive Demand	691
Voluntary Load Resources	195

Table 9 shows the amount of price responsive demand simulated at different price levels. A random draw was performed on a daily basis to determine the response level similar to the Private Use Network resources. For the Voluntary Load Resources, the full 195 MW is achieved at $380/MWh.

Table 9. Price Responsive Demand Response

Cumulative Probability	5%	25.0%	50.0%	75.0%	95.0%
Price ($/MWh)	Output (MW)				
250	-	71	143	143	214
500	-	126	251	252	377
1,000	-	180	360	360	540
1,500	-	212	424	424	636
2,000	-	234	469	469	703
2,500	-	252	504	505	756
3,000	-	266	533	533	799
4,000	-	289	578	579	867
5,000	-	306	614	614	920
6,000	-	321	642	643	963
7,000	-	333	667	667	1,000
8,000	-	343	688	688	1,031
9,000	-	353	706	707	1,059

M. External Assistance Modeling

The external neighbor representation used in SERVM is modeled based on public data sources for load and fleet makeup. Table 10 shows the breakdown of capacity for each external region captured in the modeling. Each external region was modeled at its target reserve margin based on publicly available information. While it is expected that reserves maybe higher than this in the short term, the intention of the analysis is not to depend on external resources in excess of targeted reserves, since some resources may be subject to retirements or other unforeseen changes. By setting the study up this way, only weather diversity and generator outage diversity are providing reliability benefit among neighboring utilities. However, since the maximum capability for imports is only 1,080 MW, the neighbor assumptions do not substantially impact the results.

Table 10. External Regions

	SPP	MISO-Entergy	Mexico
Summer Peak Load Forecast (MW)	56,781	26,535	9,910
Target RM	13.6%	12%	15.1%
Nuclear	766	3,126	-
Biomass	422	456	-
Coal	27,511	3,331	2,600
Gas	29,500	21,128	6,895
Oil	1,531	103	1,710
Pump Storage	446	28	-
Hydro	2,346	615	-
PV	-	-	-
Wind	8,206	-	-
DR	1,336	926	200
Total Capacity*	64,514	29,714	11,405

*Assumes an 8% capacity credit for SPP wind resources.

N. Operating Reserve Requirements

SERVM dispatches resources to meet regulation, spin, and non-spin requirements. It was assumed load would be shed to maintain 500 MW of regulation and 600 MW of spinning reserves across the ERCOT region. During emergency conditions, 200 MW of regulation can be forgone. To capture this in the simulations, a 200 MW demand response resource is modeled which is called at high price thresholds before firm load is shed.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events does not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For ERCOT, Astrapé utilized eleven years of historical weather and load shapes, five economic load forecast error multipliers, and 100 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 5,500 (11weather years * 5 load forecast errors * 100 unit outage iterations = 5,500 total iterations) for each reserve margin level modeled.

A. Case Probabilities

The probabilities for each of the fifty-five cases are shown in Table 11. Due to the extreme weather seen in 2011, the 2011 weather year was only given a 1% probability while the other weather years were given equal probability of occurrence. Each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 11. Case Probabilities

Case Number	Weather Year	Weather Year Probability	Load Forecast Multiplier	Load Forecast Multiplier Probability	Case Probability
1	2002	0.099	0.96	7.90%	0.78%
2	2002	0.099	0.98	24.10%	2.39%
3	2002	0.099	1	36%	3.56%
4	2002	0.099	1.02	24.10%	2.39%
5	2002	0.099	1.04	7.90%	0.78%
6	2003	0.099	0.96	0.079	0.78%
7	2003	0.099	0.98	0.241	2.39%
8	2003	0.099	1	0.36	3.56%
9	2003	0.099	1.02	0.241	2.39%
10	2003	0.099	1.04	0.079	0.78%
11	2004	0.099	0.96	0.079	0.78%
12	2004	0.099	0.98	0.241	2.39%
13	2004	0.099	1	0.36	3.56%
14	2004	0.099	1.02	0.241	2.39%
15	2004	0.099	1.04	0.079	0.78%
16	2005	0.099	0.96	0.079	0.78%
17	2005	0.099	0.98	0.241	2.39%
18	2005	0.099	1	0.36	3.56%
19	2005	0.099	1.02	0.241	2.39%
20	2005	0.099	1.04	0.079	0.78%
21	2006	0.099	0.96	0.079	0.78%
22	2006	0.099	0.98	0.241	2.39%
23	2006	0.099	1	0.36	3.56%
24	2006	0.099	1.02	0.241	2.39%
25	2006	0.099	1.04	0.079	0.78%
26	2007	0.099	0.96	0.079	0.78%
27	2007	0.099	0.98	0.241	2.39%
28	2007	0.099	1	0.36	3.56%
29	2007	0.099	1.02	0.241	2.39%

Case Number	Weather Year	Weather Year Probability	Load Forecast Multiplier	Load Forecast Multiplier Probability	Case Probability
30	2007	0.099	1.04	0.079	0.78%
31	2009	0.099	0.96	0.079	0.78%
32	2009	0.099	0.98	0.241	2.39%
33	2009	0.099	1	0.36	3.56%
34	2009	0.099	1.02	0.241	2.39%
35	2009	0.099	1.04	0.079	0.78%
36	2010	0.099	0.96	0.079	0.78%
37	2010	0.099	0.98	0.241	2.39%
38	2010	0.099	1	0.36	3.56%
39	2010	0.099	1.02	0.241	2.39%
40	2010	0.099	1.04	0.079	0.78%
41	2011	0.01	0.96	0.079	0.08%
42	2011	0.01	0.98	0.241	0.24%
43	2011	0.01	1	0.36	0.36%
44	2011	0.01	1.02	0.241	0.24%
45	2011	0.01	1.04	0.079	0.08%
46	2012	0.099	0.96	0.079	0.78%
47	2012	0.099	0.98	0.241	2.39%
48	2012	0.099	1	0.36	3.56%
49	2012	0.099	1.02	0.241	2.39%
50	2012	0.099	1.04	0.079	0.78%
51	2013	0.099	0.96	0.079	0.78%
52	2013	0.099	0.98	0.241	2.39%
53	2013	0.099	1	0.36	3.56%
54	2013	0.099	1.02	0.241	2.39%
55	2013	0.099	1.04	0.079	0.78%
Total Percent					100%

B. Reporting Metrics

Loss of Load Expectation (LOLE) is expressed in events per year. Loss of Load Hours (LOLH) is expressed in hours per year. Expected Unserved Energy (EUE) is expressed in MWh and calculated for each of the fifty-five previously mentioned cases to develop weighted average figures. EUE as a percentage of Load is expressed in percentages.

C. Reserve Margin Definition and Calculations

For this study, reserve margin is defined as the following and a breakdown is included in Table 12:

- (Resources – Demand) / Demand
  - Demand is the 50/50 Annual Peak Load Forecast less demand response programs.
  - Coastal Wind resources are counted as 56% of nameplate capacity, Non Coastal wind resources are counted as 12% of nameplate capacity, and PV resources are counted as 100% of nameplate capacity.
  - DC Ties with surrounding neighbors are counted at 643 MW.[14]

To achieve different reserve margin levels, the 50/50 load forecast is varied up and down. This is accomplished by scaling the load shapes for each weather year to reflect the new 50/50 load forecast. Load was varied rather than resources to maintain the same resource mix expected in 2016.

Table 12. Reserve Margin Calculations

Simulation Year	**2016**
50/50 Peak Load	70,014
Demand Side Management	1,917
Net Internal Demand	**68,097**
Coal	19,161
Gas	45,888
Nuclear	4,981
Other	4,655
Hydro	446
Pumped Storage	34
Biomass	235
Wind	3,272
Solar	321
DC Ties	643
Switchable Units Removed	(300)
Total Resources	**79,336**
Reserve Margin	**16.5%**

V. Results

The simulations described above were used to identify target reserve margin levels (Planning Reserve Margin) at which specific physical reliability standards would be satisfied. Table 13 identifies the results

[14] Import capability from surrounding neighbors is 1080 MW, but the dependable capacity across the other side of the interfaces is assumed to be 643 MW.

using the standards requested by ERCOT and the PUCT. In addition to the Planning Reserve Margin for each standard, a measure of the magnitude of the average reliability events is given in the column labeled 'Weighted Average EUE Across All Weather Years'. This column represents the base case, which assumes 2011 weather has a 1% probability of occurrence. Also, to provide a sense of the magnitude of reliability issues in extreme years, the final column displays the EUE from the cases that used the 2011 weather year, which was the most extreme year in the sample.

Table 13. Summary of Results

Reliability Standard	Planning Reserve Margin	Weighted Average EUE Across All Weather Years (MWh)	2011 Weather EUE (MWh)
15-LOLH	7.50%	22,947	219,976
12-LOLH	8.14%	17,487	175,919
6- LOLH	9.97%	7,684	92,849
4- LOLH	10.96%	4,789	65,312
2.4- LOLH	12.00%	2,855	43,809
0.1 LOLE	16.75%	204	4,463
.001% EUE	11.50%	3,670	54,418
.002% EUE	10.20%	6,897	85,683

Figure 7 shows LOLE as a function of reserve margin in events per year. As reserve margin in ERCOT increases, LOLE decreases. The 1-event-in-10-year standard of 0.1 LOLE results in a 16.75% reserve margin.

Figure 7. LOLE

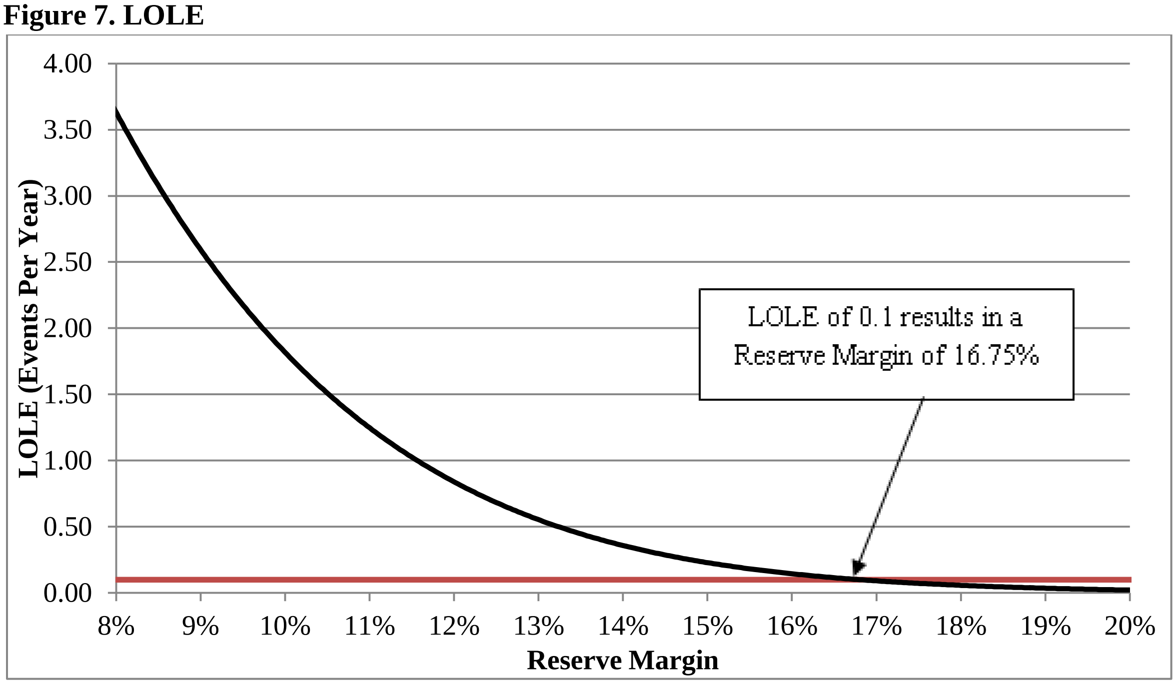


Figure 8 shows LOLH as a function of reserve margin. At the 1-event-in-10-year standard reserve margin level (LOLE = 0.1) of 16.75%, LOLH is 0.25, meaning each event lasts on average 2.5 hours. An LOLH of 2.4 hours per year equates to a 12.0% reserve margin level.

Figure 8. LOLH

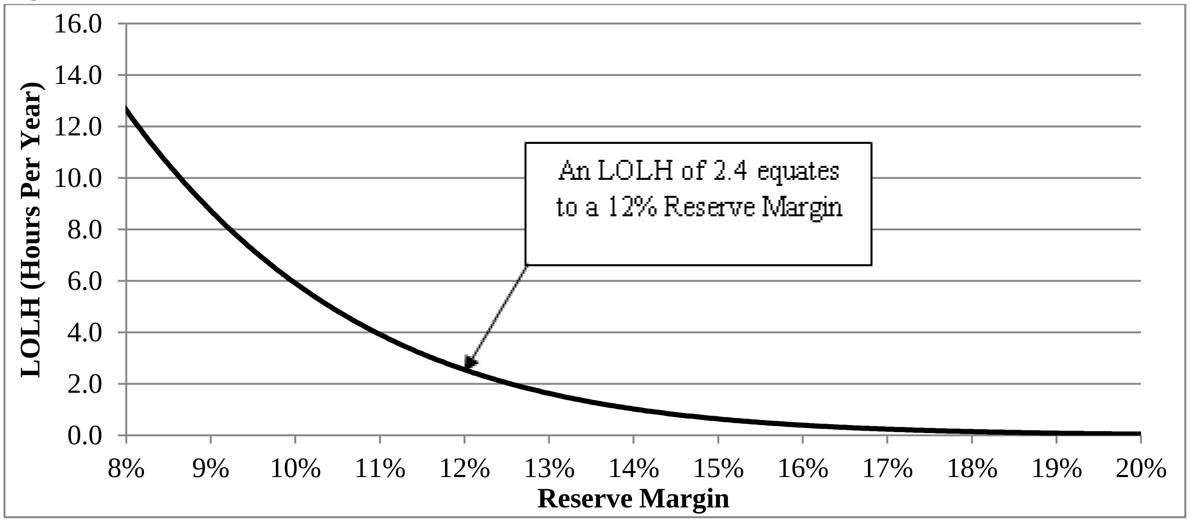


Figure 9 and Figure 10 show EUE in MWh and normalized EUE as a function of reserve margin. The reserve margin resulting in a 0.001% EUE is 11.5%.

Figure 9.EUE

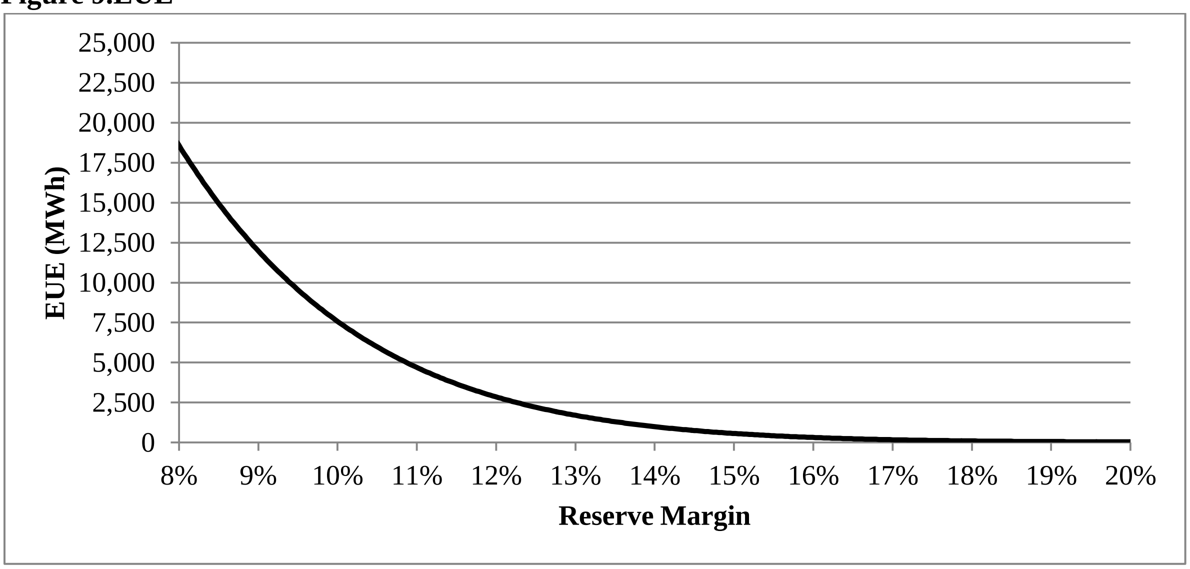


Figure 10.Normalized EUE

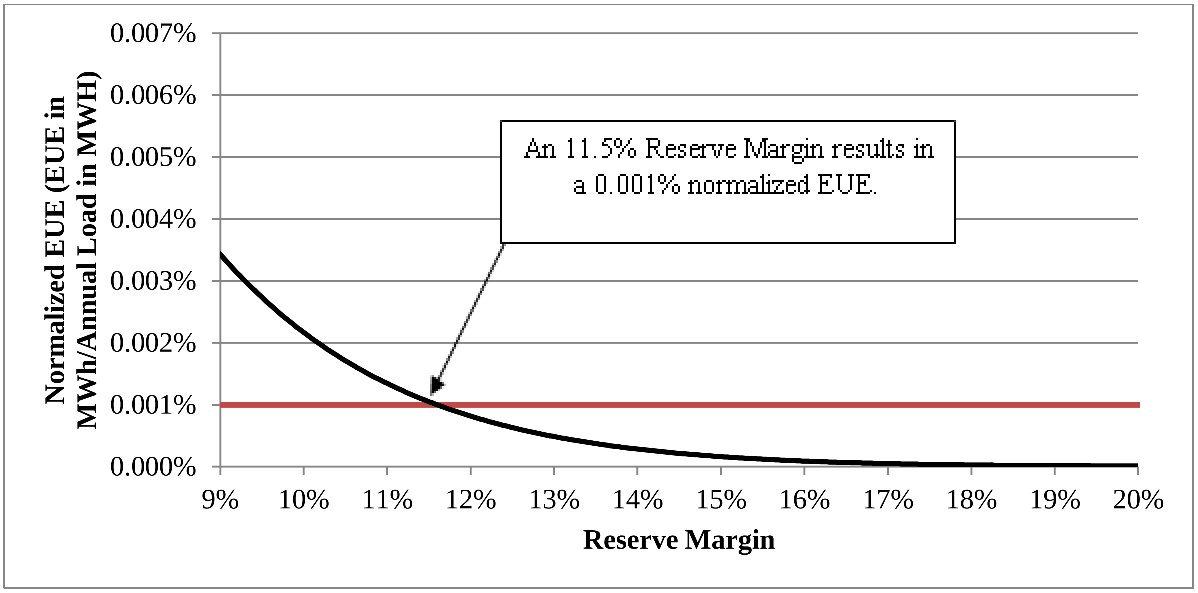


Table 14 shows the Base Case results in tabular format for each reserve margin studied.

Table 14. Summary of Base Case Results

Reserve Margin	LOLE	LOLH	EUE	Normalized EUE
%	Events Per Year	Hours Per Year	MWh	EUE in MWh/Total Load in MWh
7.6%	4.07	14.33	21,563	0.0062%
9.7%	2.00	6.57	8,569	0.0025%
11.9%	0.88	2.68	3,041	0.0009%
13.0%	0.55	1.61	1,653	0.0005%
14.2%	0.33	0.95	895	0.0003%
15.3%	0.20	0.55	493	0.0001%
16.5%	0.12	0.32	241	0.0001%
17.7%	0.06	0.17	123	0.0000%
18.9%	0.03	0.09	53	0.0000%
21.5%	0.01	0.02	13	0.0000%
24.2%	0.00	0.01	4	0.0000%

Figure 11 shows the distribution of LOLH at 16.5% reserve margin which on a weighted average basis equals 0.32 hours per year. In 90% of the scenarios simulated, the LOLH is 0.5 hours per year or less. In 95% of the cases, the LOLH is less than one hour per year.

Figure 11. Distribution of LOLH

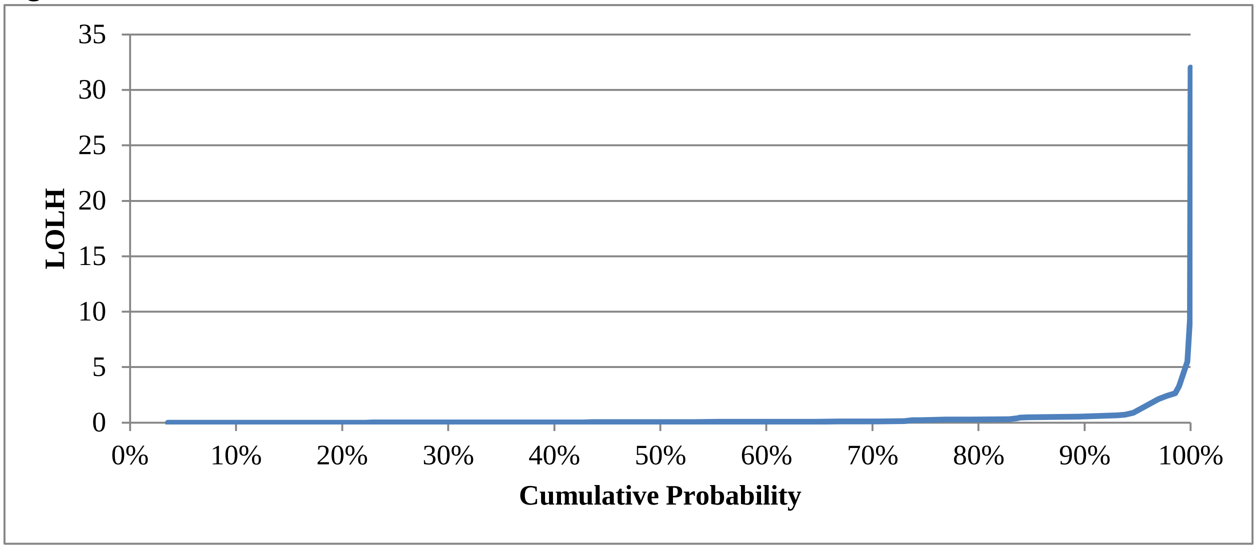
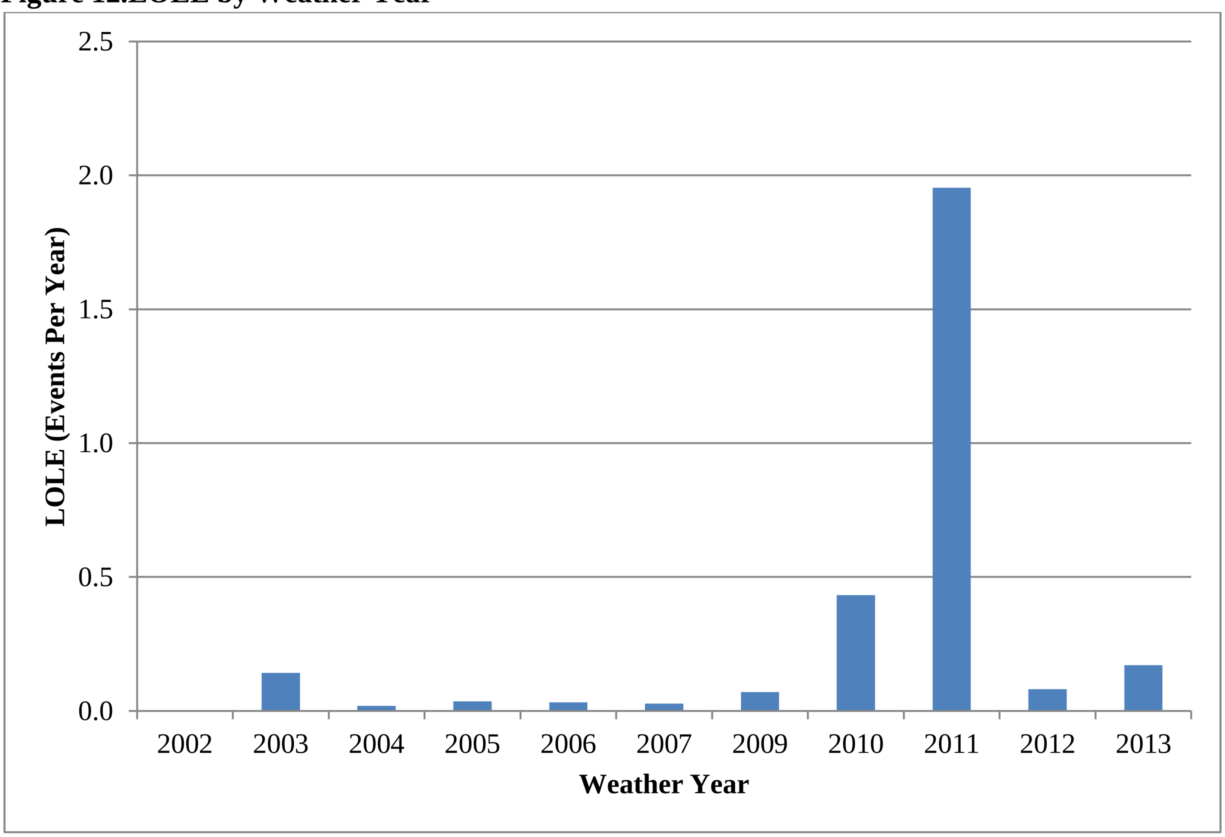


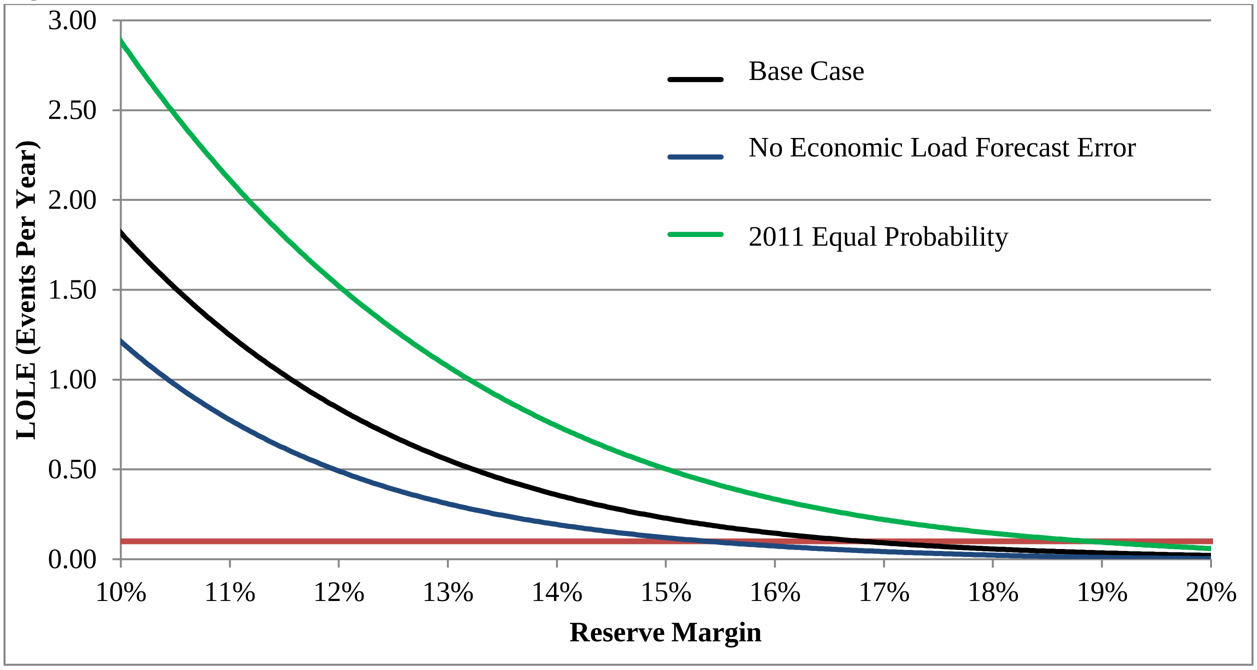
Figure 12 shows LOLE by weather year for the 16.5% reserve margin level. As discussed previously, the 2011 weather year was an anomaly and produced the highest LOLE but was only given a 1% probability of occurrence in the study.

Figure 12.LOLE by Weather Year



Two additional sensitivities were performed. The first was to remove the 3 year load forecast uncertainty and the second was to assume all weather years were equally likely. The LOLE curves for those two scenarios are shown in Figure 13. The 1-event-in-10-year standard reserve margin shifts down to 15.5% if no economic load forecast error is included and increases to 18.75% if 2011 is given equal probability to the other weather years.

Figure 13. Sensitivities



VI. Conclusions

While this analysis does not attempt to describe the various qualities associated with the range of reliability standards under consideration by the PUCT and ERCOT, the target reserve margin and EUE estimates provided in this report may inform the ongoing work done on these topics.

Based on the analysis described in this report, the 1-event-in-10-year standard (0.1 LOLE) results in a 16.75% target reserve margin for the ERCOT region. If the target reserve margin were based on the less common metrics of 2.4 hours per year or 0.001% normalized EUE, the resulting reserve margins would be 12.0% or 11.5%, respectively. As shown in the sensitivity section, if the impact of load forecast error is removed, the target reserve margins which achieve the specified reliability standards shift down by approximately 1.25%. Differences between these results and previous loss-of-load studies are primarily the result of the use of new ERCOT load forecast models and revised accounting for the assumed capacity credit of wind resources.