2012 ERCOT Loss of Load Study Assumptions and Methodology

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Executive Summary

The ERCOT 2012 Loss of Load (LOL) Study is an analysis to quantify the impact of system variability on desired reserve levels and reliability. This report documents the assumptions and methodologies used in this analysis. System volatilities such as generator outages and deratings, load forecast uncertainties, and the intermittent nature of wind were studied.

Generator full and partial outages were modeled sequentially using random draws from two exponential distributions. The Mean Time to Failure (MTTF) and Mean Time to Repair (MTTR) for each generator was used to build independent sequences of generator full and partial availabilities. For each scenario, the Monte-Carlo simulation was iterated sufficiently to achieve convergence of the reliability metrics.

Load forecast uncertainties due to weather were studied by using fifteen different load scenarios, based upon loads from 1997 through 2011. Each of these scenarios was assigned a probability of occurrence. All load scenarios were developed using Moody's base economic forecast.

Due to the inherent variability of wind powered generation on the ERCOT System, the availability of wind power generation needed to be treated differently than the availability of conventional generators in reserve margin calculations. The *Effective Load Carrying Capability* (ELCC) indicates the percentage of the total nameplate capacity of wind that can be counted towards the calculation of the reserve margin. The ELCC for two regions (West and Coastal) were evaluated by comparing the relative reliability of the installed or planned wind generation to the reliability of the planned 2014 and 2016 fleets on an annual basis. Wind profiles were developed by AWS Truepower for this study. These hourly wind profiles were developed for each wind farm for the same fifteen years as for the load profiles.

Table of Contents

List of Tables

List of Figures

1 INTRODUCTION

The objective of the Loss of Load (LOL) Study is to determine the annual Loss of Load Probability (LOLP) and related reliability metrics in accordance with North American Electric Reliability Corporation (NERC) requirements. This study has been carried out for the years 2014 and 2016.

The *ERCOT 2012 LOLP Study* evaluates the impact of system volatility on the relationship between generation reserve levels and system reliability. A power system is volatile from a resource adequacy perspective due to several primary causes: the forced outage and de-rating of generating facilities; the load forecast uncertainty related to weather; and, the intermittent nature of renewable energy sources. At the same time a power system needs to maintain an adequate level of reliability. To cope with system volatility while maintaining adequate reliability, an appropriate level of generation reserves needs to be maintained in the planning timeframe.

Historically, reserve levels have been quantified in terms of a reserve margin. The reserve margin has been defined as the *difference between nameplate installed capacity and annual peak load (of the median load profile) as a percentage of the annual peak load*. The reserve margin is compared with the target reserve margin to determine if the system, in aggregate, has sufficient generation capacity over the course of a year. The scope of this study is to assess what the appropriate (target) reserve margin level is for the ERCOT system for years 2014 and 2016.

The ERCOT system has a considerable amount of wind power resources. Due to the variation of their availability, these resources were treated differently than conventional generators in reserve margin calculations. The concept of *Effective Load Carrying Capability* (ELCC) for renewable energy sources (RES) was introduced in past studies. ELCC indicates the percentage of the total nameplate capacity of these resources that can be counted towards the calculation of the reserve margin and forms the basis for the level of RES that currently counts towards planning reserves in ERCOT. Estimating a value of the ELCC in two zones is a part of this study, and the associated ELCC methodology is thus discussed in detail.

This report is organized as follows. Chapter 2 discusses details about the input data – resources, network, and demand models. In Chapter 3, the study methodology and modeling issues are presented.

1.1 Reliability Indices

The reliability of a power system pertains to its ability to satisfy its demand under the specified operating conditions and supporting policies. For the purpose of quantifying the reliability of a power system, the following metrics apply:

- *Loss of Load Events (LOLEV):* The number of times in a year that available generation was incapable of meeting demand. In these simulations, the reduction of Operating Reserves below the minimum requirement is not considered to be a LOLEV. LOLEV provides information about the frequency of events and is measured in events/year.

- *Loss of Load Hours (LOLH):* The number of hours in a year that available generation was incapable of meeting demand. LOLH provides information about the duration of events and is measured in hrs/year. One loss-of-load event is composed of one or more consecutive loss-of-load hours.

- *Expected Unserved Energy (EUE):* The total amount of energy demand that could not be met by available generation in a year. EUE provides information about the severity of events and is measured in MWh/year.

- *Normalized EUE:* [EUE/(Net Energy for Load simulated)] x 1,000,000. This metric allows for the relative comparison of EUE between systems of different sizes.

- *Loss of Load Probability (LOLP):* The probability that in any given hour the available capacity will be less than the demand

- *Loss of Load Expectation (LOLE):* (days/year): Number of days per year (or hours per year) for which available generating capacity is insufficient to serve the daily peak demand (or the hourly demand).

A power system is considered to be adequate when it satisfies a certain reliability level. The electric power industry has generally adopted the criteria of **1 loss of load event every 10 years** (a 0.1 LOLEV per year) as this level, and this level has also been used historically for the ERCOT System.

2 DATA REQUIREMENTS

2.1 Simulation Process

Power system reliability indices can be calculated using a variety of methods. The two main approaches are analytical and simulation. Monte Carlo simulation is utilized in this study because it allows for a more comprehensive modeling of system behavior and provides a more informative set of system reliability indices. Specifically, the sequential approach of Monte Carlo simulation is used in this study. The time step of the simulations was one hour.

In order to model and simulate the system for reliability evaluation and hence calculate the reserve margin, model inputs such as generation data, load data, and wind data were required.

2.2 Resources

2.2.1 Conventional Resources

The following Generating Availability Data System (GADS) data were utilized:

- Net Maximum Capacity (NMC)
- Service Hours (SH)
- Reserve Shutdown Hours (RSH)
- Attstarts: Number of unit attempted starts
- Actstart: Number of unit actual starts
- FOH: Forced outage hours (annual)
- NFOR: Number of forced outages (# of FO)
- Scheduled Outage Hours (SOH)
- POH: De-rating hours (FORCED DERATING HOURS)
- NPFOR: Number of partial forced outages (# of DERATINGS)
- r = FOH/NFO
- D = SH/actstarts
- T = RSH/attstarts
- f = (1/r + 1/T)/(1/r+1/T + 1/D)
- fohd = f*FOH
- ford = fohd/(fohd+SH)
- fp = sh/(sh+rsh)
- fdhd = fp*POH
- fdrd = fdhd/SH

These are converted to FMTTF, FMTTR, PMTTF, and PMTTR as follows:

- FMTTR = f
- PMTTR = (POH)/NPFOR
- FMTTF = (8760-SOH)/(8760*FMTTR(1/ford-1))
- PMTTF = (8760-SH-8760*ford)/8760*PMTTR*(1/fdrd-1)

ERCOT provided the historical generator outage data used in the simulation. This was a combination of actual data received directly from the generator owners and NERC GADS data for the remaining units.

Maintenance outages were generated by ProMaxLT™, so that annual maintenance totals were met. No maintenance outages were scheduled for the summer months. Planned and maintenance outage schedules used in the simulation were kept the same for every iteration. Further, monthly capacity multipliers were applied in order to model the seasonal capacity ratings of thermal units. These capacity ratings were provided by ERCOT.

For the nuclear units at Comanche Peak and South Texas, fixed maintenance schedules were incorporated at follows:

- Comanche Peak 1
  - 2014: 10/1/2014 to 11/10/2014
  - 2016: 3/15/2016 to 4/24/2016
- Comanche Peak 2
  - 2014: 4/15/2014 to 5/25/2014
  - 2016: none
- South Texas 1
  - 2014: none
  - 2016: 10/1/2016 to 11/10/2016
- South Texas 2
  - 2014: 11/1/2014 to 12/11/2014
  - 2016: 4/15/2016 to 5/25/2016

All existing generation units, as well as future resources with a signed interconnection agreement that are expected to be in service in year 2014 and 2016, were included in the study. This also includes the units that ERCOT classifies as Reliability Must Run (RMR). Private Network Units (PUNs) were also included in the study. However, hydro generation was not included in the study.

Self-served generation and load were included in the load flow runs as fixed MW values with 100% availability. As long as the MWs of self-served generation and load are approximately the same, there is little effect on the reserve margin needed to maintain the required LOLE of 0.1 days per year.

The import capacity of the DC ties was not taken into account.

2.2.2 Renewable Energy Sources

A total nameplate capacity of 12,255 MW of wind generation was included in this study for both study years. The majority of the wind is in the Western Region (10,340 MW), with the remainder being located in the Coastal Region (1,915 MW).

Hourly wind production values were developed for ERCOT by AWS Truepower. The wind simulations were recreated using historical weather conditions. Hourly wind outputs were estimated for each wind farm, for each of the fifteen years corresponding to the load profiles (1997-2011). Thus, the wind and load are time-synchronized, providing a high level of realism.

2.3 Demand

Load forecast uncertainties due to weather were studied by running Monte Carlo simulation for various load scenarios. ERCOT prepared fifteen annual hourly chronological load profiles. The peak loads for the two study years were defined as follows:

Table 1. Peak Loads and Probabilties for Study Load Profiles

Load Profile Year (Prob%)	2014 Peak Load	2016 Peak Load	2016 Peak Load Increase	2014 Average Load	2016 Average Load	2016 Average Load Increase
1997 Load Profile (1.25%)	70,395	75,639	7.45%	43,604	46,499	6.64%
1998 Load Profile (3.57%)	72,942	78,050	7.00%	45,055	48,054	6.66%
1999 Load Profile (3.57%)	73,249	78,473	7.13%	43,601	46,496	6.64%
2000 Load Profile (3.57%)	72,423	78,047	7.77%	44,828	47,804	6.64%
2001 Load Profile (1.25%)	72,507	77,556	6.96%	43,859	46,766	6.63%
2002 Load Profile (1.25%)	71,228	76,151	6.91%	44,048	46,976	6.65%
2003 Load Profile (3.57%)	73,213	77,789	6.25%	43,850	46,766	6.65%
2004 Load Profile (1.25%)	69,972	74,807	6.91%	43,495	46,380	6.63%
2005 Load Profile (3.57%)	72,780	77,897	7.03%	44,171	47,107	6.65%
2006 Load Profile (25.0%)	74,928	80,879	7.94%	44,521	47,485	6.66%
2007 Load Profile (3.57%)	73,191	77,677	6.13%	43,678	46,575	6.63%
2008 Load Profile (3.57%)	71,771	78,355	9.17%	44,208	47,142	6.64%
2009 Load Profile (25.0%)	75,253	80,573	7.07%	44,392	47,347	6.66%
2010 Load Profile (15.0%)	75,633	82,143	8.61%	45,017	48,015	6.66%
2011 Load Profile (5.0%)	80,821	86,423	6.93%	46,694	49,795	6.64%

Please note from this table:

- The 2011 Load Profile has much higher peak loads (2014 and 2016) than the other 14 load profiles.
- The average load increase (from 2014 to 2016) is nearly identical for all 15 load profiles (approximately 6.64%).
    - The peak loads do not increase equally (from 2014 to 2016) across all 15 load profiles. The peak load increases range from 6.13% to 9.17%.

- The likely reason for the non-uniform scaling of peak loads between 2014 and 2016 is that the day-of-the-week differs between 2014 and 2016.
  - For example, when using the 2006 load/weather profile data, the peak load in 2016 occurs on Tuesday 8/17/2016 (80,879 MW). However in 2014, 8/17/2014 is a Saturday, so the load is reduced on that day.
  - Therefore, the shift in the day-of-the-week can have a direct impact on the peak loads, which in turn, is the primary driver of loss-of-load events.
- The probabilities listed in the table were applied in the calculation of reliability indices in the following way:

$$Reliability\ Index = \sum Load\ Scenario\ Probability * Reliability\ Index\ for\ that\ Scenario$$

This study did not include other Demand Response or energy efficiency programs.

3 STUDY METHODOLOGY

3.1 System Model

In this study, a realistic model of the conventional and wind generation is utilized. In this section, the maintenance and forced outage models are presented, as well as the approach used for wind generation.

3.1.1 Conventional Generation Modeling

To simulate the system, hourly generator capacity profiles are required. The net available hourly generator capacity is obtained by applying a capacity multiplier, scheduled outages and forced outages to the installed capacity of each generator. Each generator is initially assumed to be available in all the hours of the year, with the capacity for each hour set to the appropriate seasonal capacity rating for the unit. A capacity multiplier, initially set to 1.0, is applied to all units and hours. The hourly profile for a unit is then adjusted based on the scheduled outages for the unit.

All generation units in the market will periodically experience outages, which will remove them temporarily from service. In the study, outages may be the result of any number of phenomena:

- Planned full and partial maintenance outages;
- Forced outages (due to plant breakdown, including fuel supply disruptions);
- Partial forced outages

ProMaxLT™ is stochastic in nature; it uses a Monte-Carlo random outage scheduler to create full and partial outage states. The Monte-Carlo forced outage event modeling in the software allows the true impact of multiple coincident outages to be forecasted across multiple iterations of the same scenario.

An exponential distribution is used in ProMaxLT™ to randomly determine the outage and repair times for each unit. This distribution has been widely used for this purpose. Using a computer generated seed, the random number generator is used to randomly generate a number between zero and one, and the exponential distribution is then used to convert the number to an outage and repair time for each unit. Four Exponential Distributions are used: a) Full Time to Failure, b) Full Time to Repair, c) Partial Time to Failure, and d) Partial Time to Repair. As a result of this process the simulated failure and repair patterns are determined.

Separate random number generators are used for all generator elements. This ensures that outage sequences of all plants are independent. All random number sequences are chosen to be dependent on the single seed which is independent of the time clock. In that way, if the same seed is used in a repeated simulation at another time, the study can be exactly reproduced. The reference time for each unit is chosen to be at a fixed reference time in the past, so that multiple runs with different input parameters may be performed with the same outage sequence. This is an important requirement for sensitivity runs. The outages need to be sequential for the LOL events to be appropriately estimated.

3.1.2 Three State Outage Model

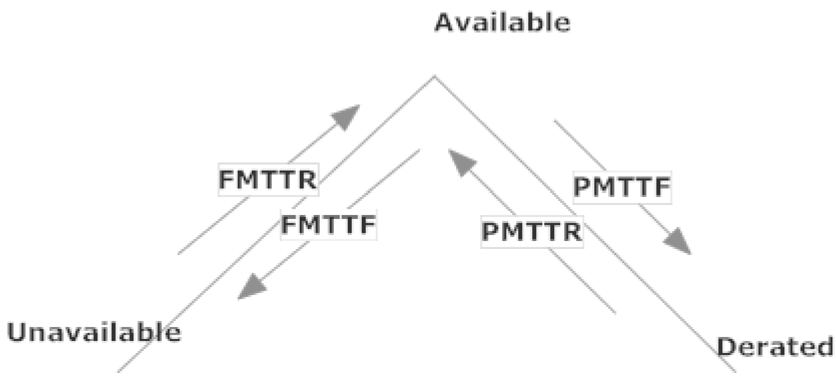

***Figure 1**. Three State Outage Model*

ProMaxLT™ utilizes a three state model for Monte-Carlo outage analysis. The three available states are:

1. Available – unit is fully available and can generate to its maximum limit
2. Derated – unit is available but at less than full capability (50% in the ERCOT studies).
3. Unavailable – Unit is off and unavailable

The transitions between these states are created by generating separate outage sequences for full and partial outages using the MTTF and MTTR values derived from the GADS data. This approach is superior to the state transition model in that it implicitly models all the possible transitions between the 3 states, and produces outage statistics that match the input GADS values.

3.1.3 Outage Modelling Using State Duration Sampling Method

ProMaxLT™ utilizes a state duration sampling method[1] for generating units where the time to outage and time to repair are generated using an exponential distribution to generate a random sequence of full and partial outages.

The full and partial failures are generated separately and then combined with each other, which will produce the required state transitions between the full, partial and off state. When using the state duration model, it is not necessary to explicitly generate the state transitions for the three state model, these are implicitly generated by the random outage sequence.

3.1.4 Modelling of Scheduled Maintenance

Planned scheduled maintenance must be entered for each unit with start date and time and end date and time.

[1] (Billinton, "Reliability Assessment of Electric Power Systems Using Monte-Carlo Methods", page 62

3.1.5 Modelling of Seasonal Outages

Seasonal outages are modelled by generating four separate full annual outage sequences for each season, using the respective outage rates for each season applied on an annual basis, but only using the sequence for the relevant season.

This process is illustrated in the figure below:

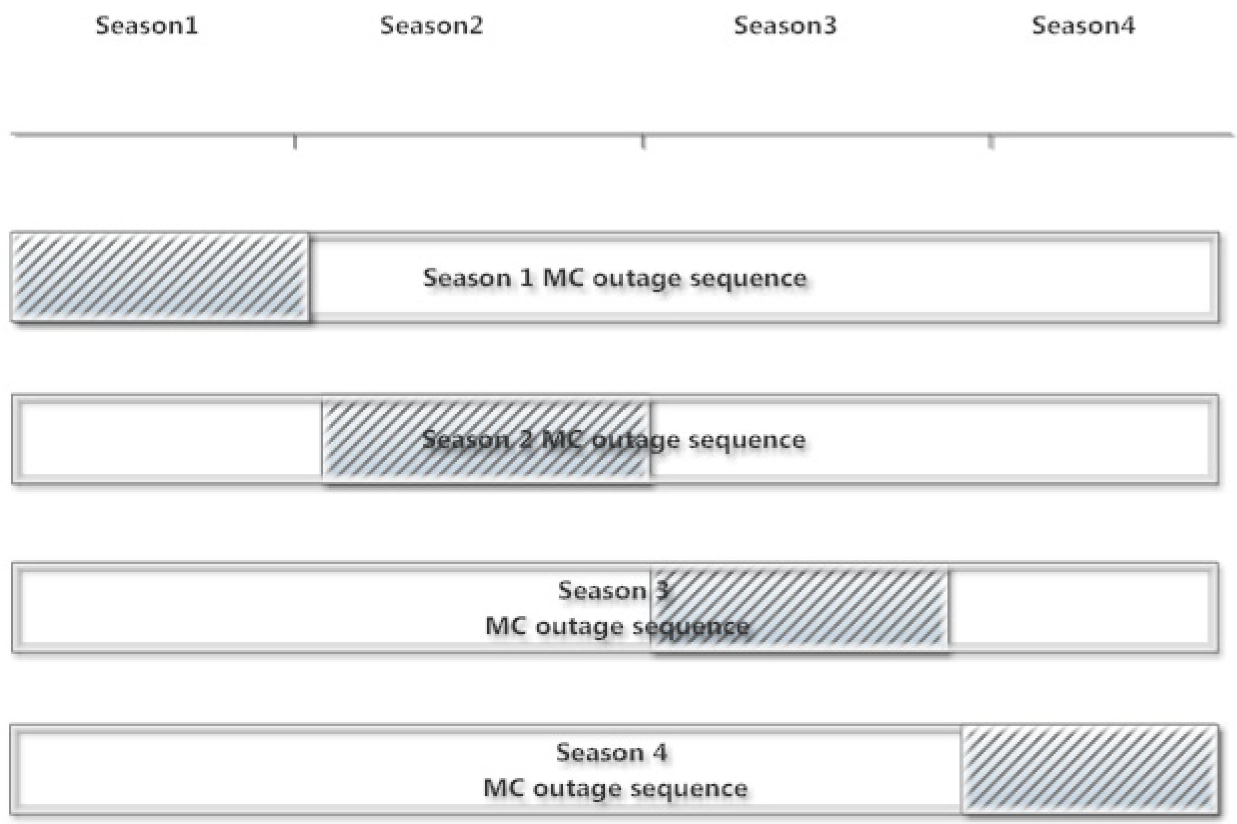

***Figure 2**. Seasonal Outage Modeling*

This means that four separate outage sequences are generated, but only the sequence for the relevant season is used in the simulations. The sequences used in the simulations are shaded in the above diagram. In this way, one can guarantee the input outage rate will match the average Monte-Carlo outage rate for the season.

3.1.6 Future Generation Capacity

Ten different generation levels were studied for 2014 and for 2016:

Table 2. Conventional Generation Capacity

Gen Level #	2014 Generation Capacity (MW)	2016 Generation Capacity (MW)
1	*76,400*	*82,660*
2	*78,471*	*84,732*
3	*80,507*	*86,809*
4	*82,535*	*88,810*
5	*84,535*	*90,810*
6	*86,535*	*92,810*
7	*88,535*	*94,810*
8	*90,535*	*96,810*
9	*92,535*	*98,332*
10	*94,535*	*100,770*

Approximately 13 GW of new generic CT generation was added for the 2014 run (14 GW for the 2016 run). This incremental generation is necessary to capture the entire range of LOLEV results for each of the 15 load profiles.

To increase capacity:

a) Use mothball (MB) units that are larger than 100 MWs (avoid non-attainment zones completely) which totals to 1,990 MW (summer rating).

   i) Valley 1 to 3 (1,069 MW summer)
   ii) Permian Basin 6 (515 MW summer)
   iii) Green Bayou 5 (406 MW summer) (MB in Dec 2011 CDR)

b) Use existing generation sites of up to 11,500 MW (increase small and medium generation unit capacities such that the existing transmission network can support increased generation capacity; this also must avoid non-attainment zones).

c) For the 93,000 MW resource case in 2014, add incremental capacity to the STP generation site of 1,670 MW. For the 99,000 MW resource case in 2016, add incremental capacity to the STP site of 2,418 MW.

To decrease capacity:

a) The entire generation fleet is derated downward. This way one can capture the tails of the LOLEV curve for applicable profiles. This may not be required for 2011 based load profiles as the LOLEV is going to be sufficiently higher than the Target Reserve Margin (1 day in 10 years).

3.1.7 Renewable Energy Source Modeling

Hourly wind profiles for 15 years were derived from wind generation patterns provided by AWS Truepower. Unique wind profiles were assigned to each wind generation facility and aggregated by zone (West and Coastal).

The wind and load for all 15 load cases are synchronized. Load profiles were based on historical load shapes (1997-2011). The MW output for each wind farm was computed based on historical weather data and weather simulations. For wind farms that did not exist in a previous year, the simulated wind patterns allow for a realistic wind output to be determined so that all simulated hours contained the same set of potential wind capacity.

3.2 Stopping Criteria

The Monte Carlo approach for reliability studies requires a large number of simulations to produce dependable reliability indices and ensure statistical significance. However, the marginal improvement in the results decreases as the number of simulations increases.

The following convergence criterion was used in these simulations:

- The standard deviation of LOLEV/square root of n (the number of iterations) should be a small fraction of the mean value of LOLEV.

3.3 Estimation of Electric Load Carrying Capability (ELCC)

Due to the inherent variability of wind generation, in financial evaluations of wind capacity, system planning, operational studies and reserve margin calculations, its availability should be treated differently than the availability of conventional generators. For this purpose, the Effective Load Carrying Capability (ELCC) methodology is commonly deployed. The ELCC indicates the percentage of the total nameplate capacity of wind that can be counted towards the calculation of the reserve margin. ProMaxLT™ was used to develop annual ELCCs for each of the two regions (West and Coastal) by comparing the relative reliability of the installed or planned wind generation to the reliability of the planned 2014 and 2016 fleets. Wind profiles developed by AWS Truepower were used in this analysis.

ECCO utilized the method developed in earlier similar ERCOT studies to determine the ELCC for the wind generation. The key steps of this methodology are:

1. For each load profile (1997-2011) and study year (2014 and 2016), a base case scenario is executed and a set of annual reliability indices calculated, including LOLEV, LOLH, and EUE, as a function of available generation capacity.
2. Another set of studies is then performed with the wind units removed from each wind zone.
3. The additional conventional generation capacity required to achieve the same level of the reliability is determined and compared to the base case. Note that the additional required generation capacity is determined in Excel using the following approach:

a) Fit a cubic-spline curve to each LOLEV vs. Generation Capacity curve. This is more accurate than simply using linear interpolation, as the spline better fits the data.

b) From this curve, determine the Generation Capacity required to achieve a 0.1 LOLEV level of reliability.

c) Compare the required generation capacity for the base case (with the wind) and for the case with the wind removed from a given region.

4. The ELCC value for the wind generation is calculated from the additional non-wind capacity, (additional conventional required capacity) / (total installed capacity of wind), expressed as a percentage.

5. For each wind region, the top 10% and bottom 10% of the 30 ELCCs are discarded, and the remaining 80% are averaged[2].

For example, assume that 50,000 MW of conventional generation capacity is required to meet the 0.1 LOLEV/year target. After removing 1,000 MW of wind capacity, 50,200 MW of conventional generation capacity is required to achieve the same reliability target. The ELCC would be (50,200-50,000)/1,000 = 20%. In other words, each MW of wind capacity delivers 0.2 MW of capacity towards meeting the reliability target.

3.4 Reliability Indices

LOLEV, which is a probability-based average, is calculated as follows,

$$LOLEV = \sum_{i=1}^{15} Probability_i \times LOLEV_i$$

The summation of the product of each load scenario probability and LOLEV for the scenario gives the study-wide LOLEV. In the above formula, i varies from 1 to 15 reflecting the fifteen annual load scenarios.

The reserve margin is calculated by,

$$Reserve\ Margin = \frac{Resources\text{-}\ Median\ Scenario\ Peak\ Load}{Median\ Scenario\ Peak\ Load}$$

where,

$$Resources = (NonWind\_Capacity + ELCC_{Coast} \times WindCapacity_{Coast} + ELCC_{West} \times WindCapacity_{West})$$

Variations in reserve margin are obtained by adjusting the non-wind generation capacity, as previously shown in Table 2. The following reliability indices were estimated for various reserve margin levels.

[2] The choice of the 10% cutoff is heuristic, but ends up having little impact on the results. Changing this percentage to 0% or even using the median ELCCs impacts the results by less than one percentage point.

- The annual Loss of Load Events (LOLEV).
- The annual Loss of Load Hours (LOLH).
- The annual Expected Unserved Energy (EUE).

4 References

[1] *2010 ERCOT Target Reserve Margin Study*, November 1, 2010. Available at ERCOT website: www.ercot.com.

[2] *NERC G&T RPM Task Force Final Report on Methodology and Metrics*, December 8, 2010. (http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf).

[3] *ERCOT Investment Incentives and Resource Adequacy*, The Brattle Group, June 1, 2012. Available at ERCOT website: www.ercot.com.