Estimating the Economically Optimal Planning Reserve Margin

Prepared on behalf of El Paso Electric Co.

May 2015

Energy+Environmental Economics

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1 Executive Summary

Target Planning Reserve Margin (tPRM)[1] is a common metric used in generation planning to determine an electric utility's resource need above typical annual peak load. As a proxy for system reliability, the tPRM is useful in informing resource decisions between detailed reliability studies.

The need for generation resources above peak load is driven by several factors. First, the tPRM is most commonly defined by using median annual peak load; thus additional generating capacity is needed to cover years in which demand eclipses this level such as during an extremely hot summer. Second, generation resources are subject to forced and planned outages and may be unavailable during some hours of the year when needed. Finally, the North American Electric Reliability Council (NERC) mandates that utilities hold operating reserves[2] for interconnection reliability purposes which must be accounted for through planning reserves.

El Paso Electric Co. (EPE) has been using a 15% tPRM standard—in line with most jurisdictions across the west and the Western Electricity Coordinating Council's (WECC) reliability assessment processes.[3] Energy and Environmental

[1] In this report we distinguish between the actual observed reserve margin and tPRM, which is the target planning reserve margin. In either case, it is defined as [(Resource Capacity/Median Peak Load) - 1] and expressed as a percentage.
[2] Operating reserves are defined as available generation resources above instantaneous system demand.
[3] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf

Economics (E3) was retained to investigate the tPRM standard for EPE and to make recommendations pertaining to its application. Our analysis **determined the societally optimal tPRM to be 15.2%** based on EPE system characteristics, NERC operating reserve requirements,[4] customer outage costs, and the cost of building and installing new capacity. We therefore do not recommend adjustments to the historical tPRM standard.

The study has also pointed to several additional conclusions:

+ Our analysis shows that deviating from the 15% tPRM by 2-3% does not substantially affect total societal cost. A PRM as low as 13% or as high as 18% will result in only a $1MM/year increase in societal costs, or 0.1% of EPE's annual revenue requirement. This is an important conclusion because it points to the need to emphasize factors in addition to PRM in making least cost resource decisions.
+ While our analysis shows that a PRM of 13% has the same expected societal costs as a PRM of 18%, the variability in annual costs is much higher at the lower PRM. This is because customer outages are infrequent but extremely costly, whereas the carrying cost of additional capacity is modest but incurred each year. Given the choice between these two scenarios, a higher PRM, and therefore less variability, is considered preferable.
+ For purposes of determining tPRM, we have not assumed imports beyond contracted external resources; however, depending on external conditions, it is possible that non-firm imports would be available to serve EPE load. Allowing for the possibility of non-firm imports, EPE system reliability would be higher than our model indicates, lowering

[4] http://www.nerc.com/files/bal-std-002-0.pdf

the tPRM. This said, for resource planning purposes, leaning on neighboring balancing authorities for non-firm capacity is not common practice and is not recommended in this report.

+ Planning reserve margin calculations typically use nameplate or summer rated capacity. For renewable resources, nameplate capacity is no longer a good approximation for resource adequacy contribution due to resource variability. Established metrics such as the effective load carrying capability (ELCC) are well suited to calculating values that can be used in the PRM calculation and is something for EPE to consider going forward.

The following report sections give background on calculating tPRM, give details specific to calculations for EPE's system, and discuss the above conclusions in greater detail.

2 Background

2.1 Planning Reserve Margin

The planning reserve margin (PRM) is defined as the percentage by which the total capacity of system resources exceeds the median peak load.[5] Surplus capacity is necessary to ensure that the supply of resources is sufficient to meet load under a variety of system conditions such as warmer than average weather (increase in load) or an unexpected generator failure (decrease in system resources). Typical PRMs can range from 10%-20% as shown in the table below.

Table 1: Planning Reserve Margins in Use by Other Jurisdictions

	PRM
PJM	15.6%[6]
NYISO	16.1%[6]
Southern Company	15.0%[6]
CAISO	15.0%[6]
FPL	20.0%[7]
ERCOT	10.2%[8]
MISO	14.8%[9]

[5] Different jurisdictions often use slight variations on this calculation, such as whether total capacity is measured as installed capacity (ICAP) or unforced capacity (UCAP), as well as whether the median (1-in-2) peak load is used or a higher percentile (1-in-10). When expressed as 1-in-X, peak load refers to the frequency that the annual peak exceeds some value.
[6] http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf
[7] http://www.fpl.com/about/ten_year/pdf/2014TYP_text.pdf
[8] ERCOT does not have an official planning reserve margin as it functions as a de-regulated market with no explicit capacity market.

SPP	13.6%[10]

A tPRM is typically determined with one of two common approaches. The first is through benchmarking to a particular engineering metric for customer reliability and the second is through economic analysis to find the point at which the marginal benefits of additional capacity matches the marginal cost of a new unit. This section provides an overview of these two approaches and explains the choice of economic analysis for the EPE system.

2.2 Engineering Approach

The tPRM can be determined by benchmarking to reliability metrics such as the expected number of outage hours per year, or the expected number of outage events per year. Many utilities across the United States use a 1-in-10 standard; though in the industry, no broad agreement exists regarding the precise definition of this metric or calculation methodology.

Common interpretations of the 1-in-10 standard includes 0.1 hour of lost load per year, 2.4 hours of lost load per year, or one loss of load event per 10 years (independent of severity or duration). We believe part of this confusion has arisen from changes in modeling methodologies enabled by increased computing capabilities.[11] In addition, recent focus on resource flexibility as a

[9] https://www.misoenergy.org/Library/Repository/Study/Seasonal%20Assessments/2014%20Summer%20Resource%20Assessment.pdf
[10] http://www.occeweb.com/News/2014/2014-08-21%20Intro%20to%20SPP%20OCC.ppt
[11] Many models initially did not perform hourly analysis when the 1-in-10 metric was established and the transition has resulted in fragmentation.

new dimension to the planning problem has raised question about the level of operational detail appropriate to stay constant with the original metrics.[12]

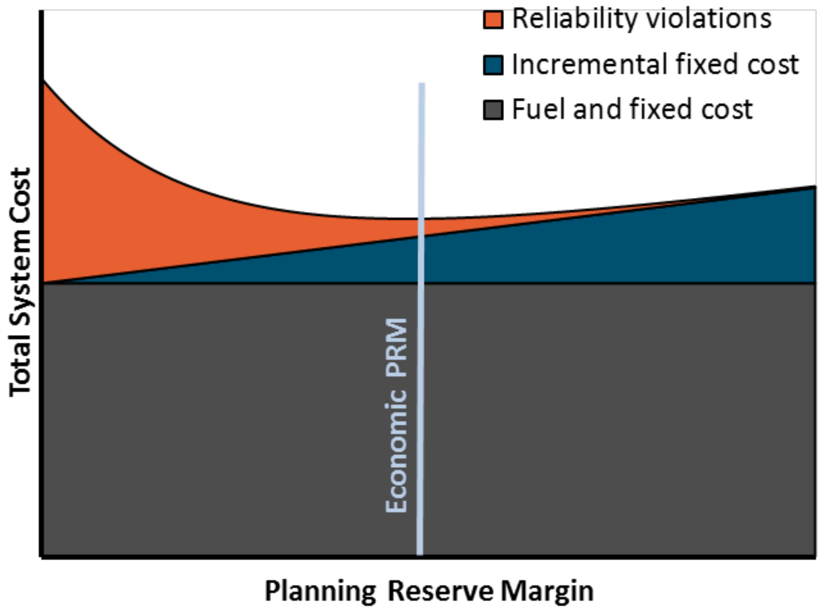
Due to these difficulties with engineering standards, we have elected to focus on the economic approach, which has less ambiguity associated with the tPRM criterion. The economic approach also has other advantages, which are detailed below.

2.3 Economic Approach

The economic approach for determining tPRM finds the level of reserves such that total system costs are minimized. System costs include both the cost of installing and maintaining a particular planning reserve margin as well as the customer outage and reliability costs associated with that planning reserve margin. In other words, an economically efficient target planning reserve margin is determined by directly comparing the cost of new capacity to the customer outage and reliability costs that are avoided by that capacity. Figure 1 illustrates this concept and how the economic tPRM is the point at which total system costs are minimized.

[12] Operational reserves are not traditionally included in loss of load probability modeling nor are any constraints regarding generator flexibility

Figure 1: Economically Optimal Reserve Margin at Lowest System Cost



This economic approach is well established in the literature[13,14,15] and is being increasingly utilized across the U.S.[16] A recent report prepared by Brattle for the Federal Energy Regulatory Commission (FERC) details much of the theory in determining an economically efficient planning reserve margin.[17] For purposes of this report, we note below the primary advantages that led to our focus on the economic method in studying El Paso Electric:

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[13] http://energy.ece.illinois.edu/GROSS/papers/1990%20Aug.pdf

[14] Sanghvi, A.P. *Measurement and Application of Customer Interruption Costs/Value of Service for Cost-Benefit Reliability Evaluation: Some Commonly Raised Issues.* Power Systems, IEEE. Vol 5, Issue 4. 1990.

[15] Afshar K., M. Ehsan, M Fotuhi-Firuzabad, N. Amjady. *Cost-Benefit Analysis and MILP for Optimal Reserve Capacity Determination in Power System*. Applied Mathematics and Computation. Vol 196, Issue 2. 2008.

[16] http://brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117

[17] http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf

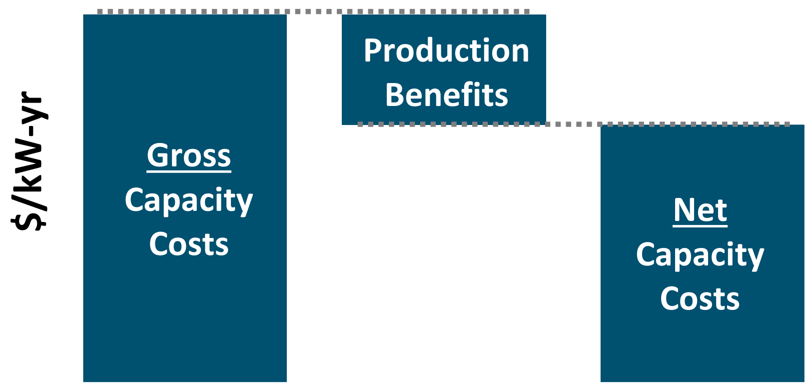
- The basic premise of the economic method, which is to plan the system to minimize cost and maximize benefits, is universally understood among stakeholders.
- The economic method avoids difficult-to-interpret metrics and instead reframes the conversation around the cost of new capacity and the value of customer service.
- Regional differences in risk preferences, new generation costs, or operational practices can be incorporated with intuitive results.
- The cost minimizing framework for planning can be extended to encompass power system flexibility or other constraints in an internally consistent way (not analyzed in this report).

2.3.1 CALCULATION STEPS

2.3.1.1 Cost of new capacity

The addition of capacity to an electric system has numerous economic impacts. In general, the largest impacts are the gross capacity and operations & maintenance costs as well as any system production cost savings (e.g. reduced expenditures on energy). The difference between these two values yields the net capacity cost which is the relevant input in determining the economically optimal target planning reserve margin. Figure 2 illustrates this below.

Figure 2: Net Capacity Cost Calculation



2.3.1.2 Reliability costs

Customer outage and reliability costs are a function of two drivers: the total quantity of outages and the value that a customer ascribes to service. The total quantity of outages is measured as 'expected unserved energy' in MWh. The value that a customer ascribes to service is the value of lost load (VOLL) measured in $/MWh. Multiplying these two values together yields total customer outage and reliability costs.

The amount of expected unserved energy (EUE) associated with a particular planning reserve margin is a function of a power system's loads and resources. Specific EPE inputs used in this analysis are listed in Section 4. Stochastically analyzing a utility's potential loads over a wide range of system conditions and combining that with a stochastic analysis of the availability of resources to meet these loads is the foundation of the EUE calculation. We have developed the Renewable Energy Capacity Planning Model (RECAP), an open-source, loss-of-load-probability model that calculates system reliability as a function of detailed inputs on load and resource. Details about RECAP methodology are available in the Technical Appendix of this report.

Expected unserved energy is also a function of many assumptions related to the protocols that system operators use in times of system stress. For instance, many systems have certain emergency procedures that they can take, such as decreasing system voltage, which can help avoid the curtailment of firm load. Additionally, expected unserved energy is sensitive to how operating reserves are utilized to meet load. Operating reserves are defined as generation that is online and ready to use in addition to resources that are being utilized to serve load. When operating reserves dip below a certain threshold, system operators are forced to curtail loads in accordance with their own protocols or NERC regulations.

The second component that feeds into customer outage and reliability costs is the value of lost load (VOLL). This metric defines how much a customer is willing to pay to avoid power outages. This value can vary substantially by customer type, season, and geographical location. For example, a small business that loses power may incur large economic losses by having to temporarily shut down, whereas a residential customer that loses power may not incur any economic losses but rather the discomfort from a lack of air conditioning or lighting. Discussion of the VOLL for EPE is taken up in Section 3.3.

3 El Paso Electric Planning Reserve Margin

Our analysis shows that the economically optimal target planning reserve margin for EPE is 15.2%. We also find that a planning reserve margin that deviates slightly from this target (2-3%) does not substantially impact total system costs due to the tradeoff between the cost of capacity and cost of customer outages.

This section details the specific inputs and assumptions used to characterize the EPE system as well the economically optimal planning reserve margin results.

3.1 EPE System Characteristics

This section describes the EPE system characteristics that we used in the analysis. As noted in the background section, customer outage and reliability costs are driven by the value of lost load and by expected unserved energy, which is a function of EPE system resources, transmission availability, and loads.

The following table describes the EPE system resources that we used in the analysis. Capacity, average forced outage rates, and average maintenance down times were also used to stochastically characterize these resources' ability to serve load.

Table 2: EPE System Resources in 2020

El Paso Electric Utility Plants	Capacity (MW)	Average Equivalent Forced Outage Rate (EFORd)[18]	Average Maintenance Down Time
Copper Unit 1	62	1.08%	2.18%
Montana Unit 1	88	1.50%	3.90%
Montana Unit 2	88	1.50%	3.90%
Montana Unit 3	88	1.50%	3.90%
Montana Unit 4	88	1.50%	3.90%
Newman 4GT1	72	4.14%	5.56%
Newman 4GT2	72	4.14%	4.72%
Newman 4ST	83	4.14%	3.70%
Newman 5GT3	70	1.02%	3.24%
Newman 5GT4	70	1.02%	2.50%
Newman 5ST	148	1.02%	6.25%
Newman Unit 1	74	1.69%	4.44%
Newman Unit 2	76	6.63%	3.52%
Newman Unit 3	97	2.15%	6.06%
Palo Verde Unit 1	211	2.20%	5.69%
Palo Verde Unit 2	211	2.20%	5.28%
Palo Verde Unit 3	211	2.20%	4.44%
Rio Grande Unit 7	46	1.29%	4.17%
Rio Grande Unit 8	142	8.21%	8.52%
Rio Grande Unit 9	87	2.57%	0.42%

Of these resources, we assumed that Palo Verde units were located behind two transmission resources (Path 47 and El Paso Import Capability [EPIC]), which further constrained its ability to serve load. The simultaneous transmission import capability of the two lines was limited to the maximum capacity of EPIC. The capacity and forced outage rates shown in the following table for both Path

[18] Based on historical outages at these locations as opposed to theoretical idealized forced outage rates

47 and EPIC are based on conversations with EPE engineers and an analysis of historical transmission availability during high load hours.

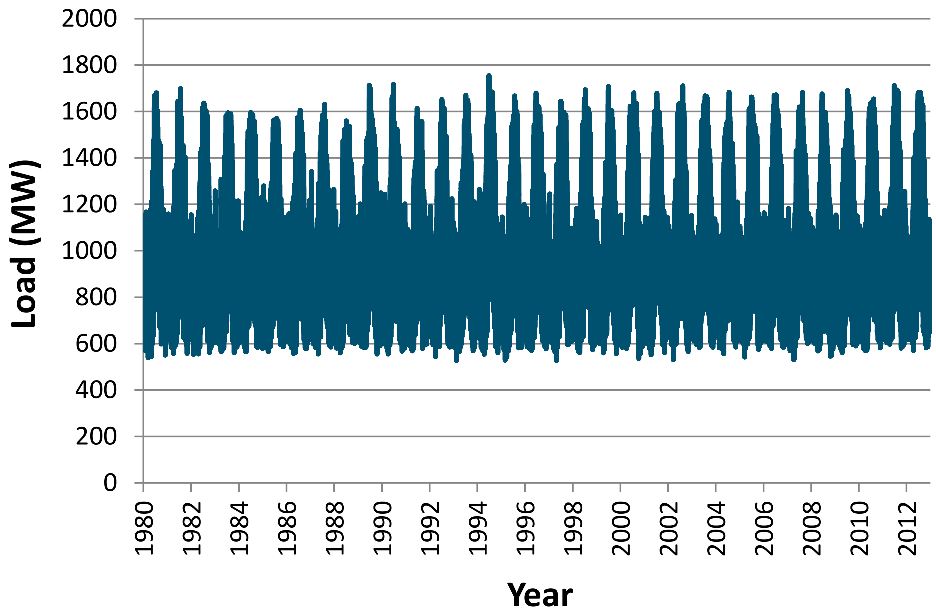
Table 3: EPE Transmission Resources

Transmission Line	Capacity (MW)	Average Equivalent Forced Outage Rate (EFORd)
Path 47	645	0.87%
EPIC	1166	4.91%

The calculation of expected unserved energy is also very dependent upon utility loads under various system conditions. The single largest factor that can affect utility load is weather. In order to capture all types of weather that might affect the El Paso area, we acquired daily temperature data from 1980 – 2012. Using a neural network regression model that matched this weather data and other factors to actual EPE loads from 2006-2012, we were able to synthetically create hourly loads for EPE for the weather years 1980 – 2012 as they would have manifested under 2012 system conditions. This rich, 33 year dataset,[19] shown below, provided the wide variety in system load conditions necessary to accurately calculate expected unserved energy.

[19] The effort to gather a large quantity of historical data was due to the specific application. A longer dataset is needed to insure robustness of results when studying power system reliability relative to other utility applications. The study team also explored the possibility of using weather data before 1980, but the data was excluded as likely underrepresenting the frequency of high load events faced by EPE in the future due to an observed upward trend in extreme weather events since 1950.

Figure 3: EPE Historical Loads (2012 Economic System Conditions)



3.2 EPE Cost of Capacity

EPE capacity costs were based on the new Montana Power Station in east El Paso. These four 88 MW simple-cycle aero-derivative combustion turbines began construction in 2014 which will continue for the next two years. EPE financial models estimate the gross capacity costs plus operations and maintenance expenses for these plants to be $77.52/kW-yr, levelized in constant real dollars.[20]

[20] This assumes a 7.35% nominal discount rate, 2% inflation, 40 year economic life. A levelization in constant real dollars was used for comparability with the customer outage costs, also assumed to be in real dollars. Both costs

Additionally, production cost modeling conducted by EPE estimates that these plants will provide $4.68/kW-yr in annual benefits due to fuel savings and market sales; subtracting the annual benefits from the levelized capacity cost results in a net capacity cost of $72.84/kW-yr.

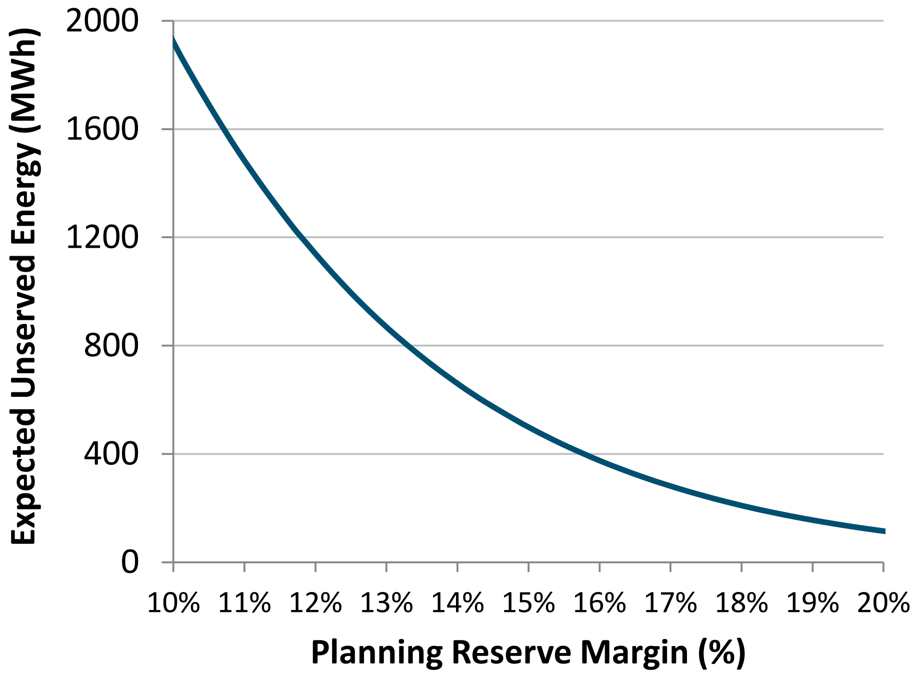
3.3 EPE Customer Outage and Reliability Costs

We calculate customer outage and reliability costs as the product between the expected unserved energy at a given planning reserve margin and the value of lost load.

Combining the probability distributions of the historical, weather-driven EPE loads and power plant and transmission line availability, we were able to calculate an output of expected unserved energy under various planning reserve margins. We have also assumed that EPE must hold 6% of load as contingency reserves in all hours due to NERC requirements, administered by WECC. Because of this, EPE is assumed to take load mitigation action such as load-shedding and/or voltage reductions as soon as available resources dip below 106% of load. The graph below shows annual expected unserved energy at various levels of planning reserve margins.

are assumed to escalate with inflation, but to stay equivalent relative to each other. Levelization in constant nominal dollars is common in other applications, yielding $99.01/kW-yr, but is not appropriate in this case.

Figure 4: Expected Unserved Energy



Estimating the value of lost load is difficult due to wide variability between customers along with other factors such as curtailment protocols. Literature suggests that appropriate values for VOLL may range between $1,000/MWh to over $2,000,000/MWh. A meta-analysis conducted by Lawrence Berkeley National Laboratory[21] on nationwide utility survey results yields the following table. Note that the dollar values are in $/MWh, thus while the marginal cost of outage decreases with duration, the overall event cost always increases with duration.

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[21] http://certs.lbl.gov/pdf/lbnl-2132e.pdf

Table 4: Value of Lost Load Estimates – LBNL

	Cost per Unserved MWh ($2014) - Summer Weekday				
Customer Type	Momentary	30 min	1 hour	4 hours	8 hours
Medium and Large C&I	$ 200,743	$ 44,648	$ 28,992	$ 21,106	$ 16,700
Small C&I	$ 2,784,424	$ 645,137	$ 432,682	$ 356,374	$ 315,089
Residential	$ 25,049	$ 5,103	$ 3,015	$ 1,508	$ 1,044

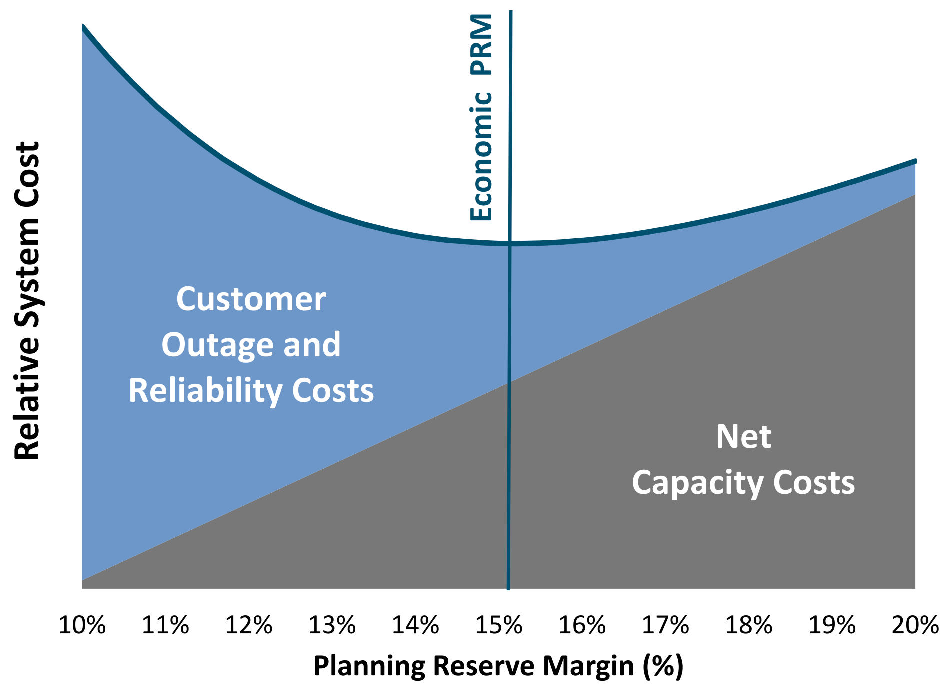
We represented the value of lost load to EPE customers at $9,000/MWh. Because this value falls in the lower end of the spectrum of LBNL's meta-analysis, we believe this to be a conservative assumption. The $9,000/MWh value is also consistent with the assumption used by The Brattle Group in its 2014 study for the Public Utility Commission of Texas (PUCT) to estimate the economically optimal reserve margin in ERCOT.[22]

3.4 EPE Optimal Target Planning Reserve Margin

Combining customer outage and reliability costs with net capacity costs at different planning reserve margins, we were able to calculate an economically optimal target planning reserve margin of 15.2%. Figure 5 illustrates that a 15.2% PRM is economically optimal because this is the point at which total system costs are minimized.

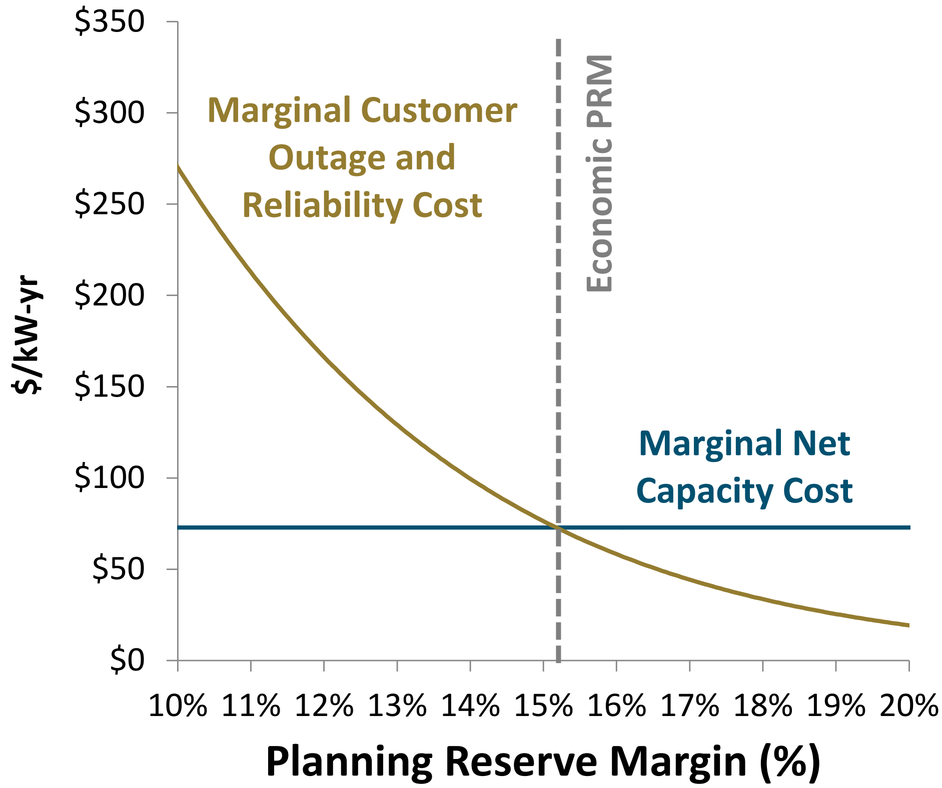
22 http://brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117

Figure 5: Economically Efficient Planning Reserve Margin – Total Cost



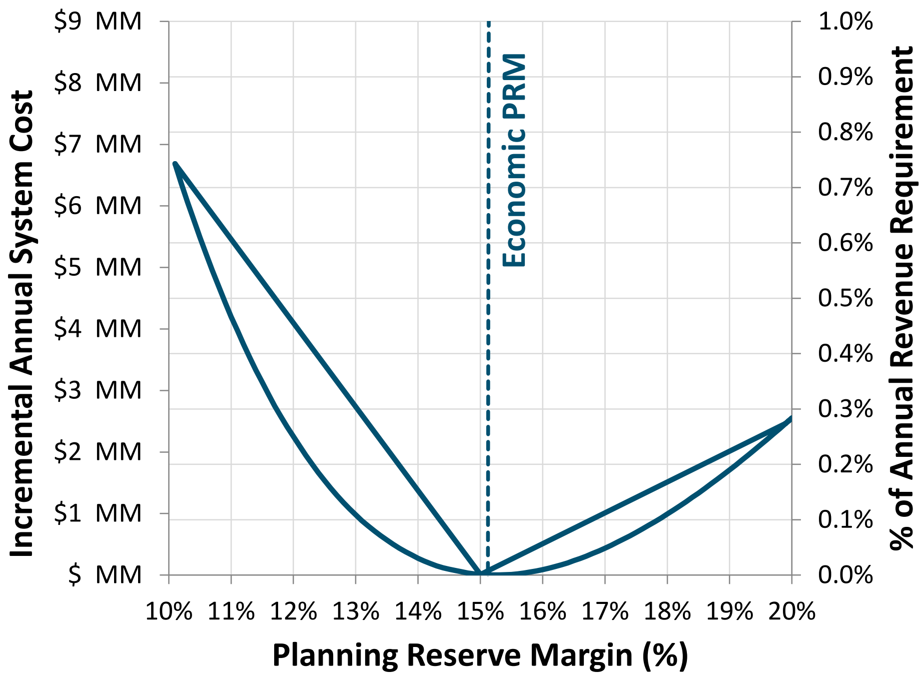
Alternatively, one can think of this optimal PRM as the point at which the *marginal* value of incremental capacity (measured as the decrease in customer outages) equals the *marginal* cost of adding additional capacity to the system. This concept is illustrated below in Figure 6. Note that this chart simply shows the slope or derivative of customer outage costs and net capacity costs shown in Figure 5.

Figure 6: Economically Efficient Planning Reserve Margin – Marginal Cost



In reality, it is not feasible for a 15.2% planning reserve margin to be realized year after year. The underlying drivers for peak load are not static and are subject to forecast error; in addition, resource expansion is subject to additional constraints and cannot be expected to match annual changes in peak load. Despite this, deviations from the 15.2% tPRM by 2-3% are shown to have a small impact on total system costs. Figure 7 shows the increase in total system cost as a function of PRM. From this graph it is clear that due to the relatively flat nature of the curve near its minimum, small deviations in planning reserve margin have a relatively small effect on total annual system cost. Although these costs are also shown as a percentage of annual revenue requirement in order to put them into context, it is important to note that the costs shown here include customer outage and reliability costs and thus are not directly comparable to costs associated with a utility revenue requirement.

Figure 7: System Cost by Planning Reserve Margin



Based on this analysis, we recommend that EPE maintain their 15% tPRM. This standard should be revisited in the future if the inflation adjusted cost of new generation or estimated customer outage costs change significantly. Additionally, with any large increase in wind or solar on the EPE system, care must be taken that this generation's contribution to resource adequacy is accurately characterized in the PRM framework.

3.4.1 COMPARISON TO OTHER JURISDICTIONS

Our analysis for the EPE economically optimal tPRM (15.2%) is higher than the results of a recent Brattle Study for ERCOT that estimates the same value at 10.2%. However, given the relative sizes of EPE and ERCOT, we believe these results to be consistent with one another. Smaller systems result in higher tPRM standards for several reasons. When ERCOT unexpectedly loses a generator, that generator comprises a much smaller fraction of total resources as compared to EPE. Therefore, EPE needs to hold a higher level of reserves in order to provide the same level of reliability. Additionally, the larger number of total generators in ERCOT provides diversity on the system and reduces the likelihood the system will face extreme generator outage events.

Many other jurisdictions around the U.S. set a tPRM based not on economics but rather using an engineering approach. Despite this, the 15.2% tPRM for El Paso fits well within the bounds of the jurisdictional tPRMs shown in Table 1 in Section 2.1.

3.4.2 SENSITIVITY CASE RESULTS

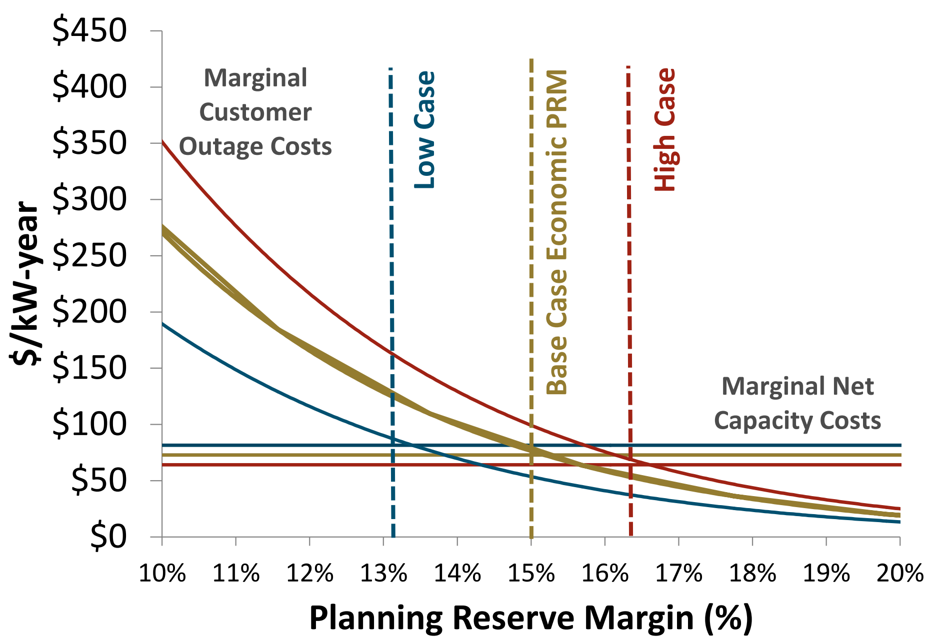
The economically optimal planning reserve margin found in our analysis is sensitive to several key input assumptions. For instance, if customers actually face higher outage costs (value of lost load) than we have assumed, it would be prudent to increase the tPRM. Conversely, if net capacity costs are actually higher than assumed, the tPRM should be decreased. We analyzed the economically optimal PRM associated with each of the following set of sensitivity assumptions as compared to the base case.

+ High tPRM Case
    - Gross Capacity Cost x 110%
    - Production Cost Benefits x 80%

    - Value of Lost Load x 130%
- Low tPRM Case
    - Gross Capacity Cost x 90%
    - Production Cost Benefits x 120%
    - Value of Lost Load x 70%

Using these sensitivity assumptions, the low tPRM case yielded a tPRM of 13.2% and the high case 16.4%, as shown in the figure below.

Figure 8: Economic PRM Sensitivity Cases



The purpose of the low and high tPRM cases was to show sensitivity to input assumptions. The adjustments themselves are arbitrary and do not reflect analysis or particular input uncertainties.

3.4.3 RISK AND VARIANCE

While our analysis shows that a PRM of 13% has the same expected societal costs as a PRM of 18%, the variability in annual costs is much higher at the lower PRM. This is because customer outages are infrequent but extremely costly, whereas the carrying cost of additional capacity is modest but incurred each year. Through time, both result in equivalent average costs, but the difference in costs for a specific year can be dramatically different, depending on whether a reliability event occurred. To the extent that utility customers are risk-averse, they will seek less variance in total annual costs and should prefer a higher PRM to a lower PRM given that the incremental annual systems costs are equal. This concept of risk aversion is well-established in the literature, although it is difficult to quantify.[23] The inherent planning difficulties associated with maintaining a tPRM will mean that EPE is often slightly over or under the target. In these cases, we recommend that EPE maintain an over-reliable system rather than under-reliable, all else being equal.

In the same vein, it is possible that risk-averse utility customers may prefer a tPRM that is higher than 15.2% to mitigate variance in annual costs, even at the expense of higher average annual system costs. However, calculating a risk-conscious economically optimal tPRM was beyond the scope of this study.

[23] http://www2.econ.iastate.edu/classes/econ642/Babcock/pratt.pdf

4 Conclusions

This study of EPE used system specific data and a standard loss of load probability model to determine the economically efficient tPRM. The optimal reserve margin was found to be 15.2%, consistent with the existing EPE target of 15%. Thus, we do not recommend changes to existing planning criterion.

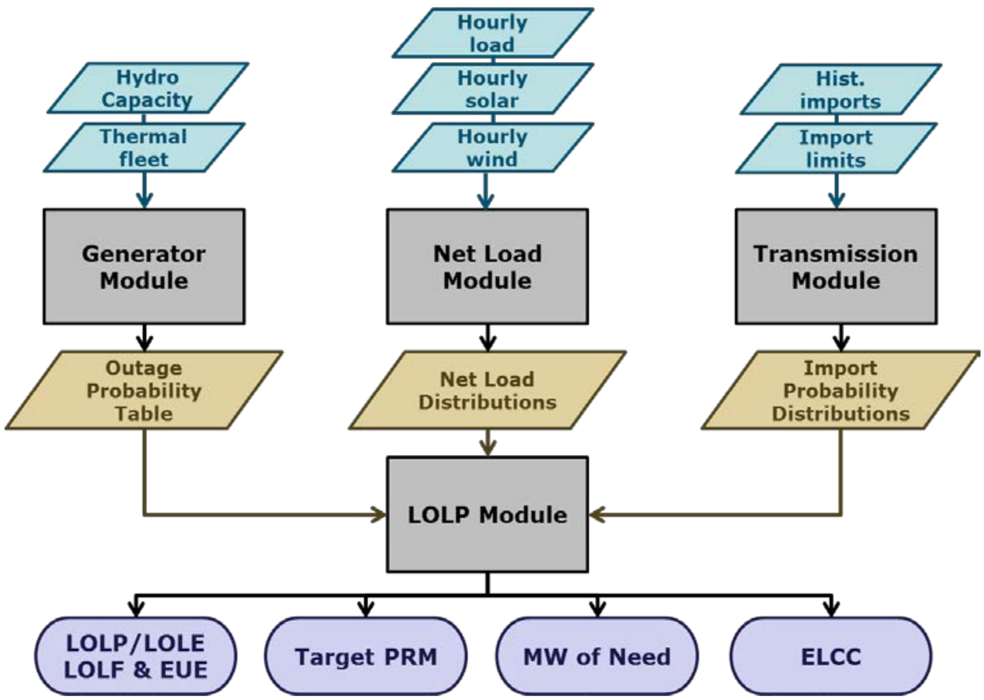
However, it is also recommended that the planning reserve margin be revisited again if 1.) The set of supply side resources changes significantly 2.) The inflation adjusted value of lost load is estimated in the future to be different than $9,000/MWh 3.) The cost of new system capacity changes significantly 4.) NERC operating rules increase or decrease operating reserve requirements during time of system emergency. In addition, if the amount of wind and solar on the EPE system increases significantly, we recommend using effective load carrying capability (ELCC) as the preferred method for measuring resource adequacy contribution within the PRM framework.

5 Technical Appendix

5.1 RECAP Methodology

The Renewable Energy Capacity Planning Model (RECAP) works by comparing probability distribution functions (PDFs) for supply and demand by month, hour, and day type (weekend, weekday) in order to find the probability that load will be greater than supply in the pertinent time slice. Relevant correlation between variables is enforced using conditional probability distributions. The model is organized into three modules, shown in Figure 9, the methods of which are summarized below.

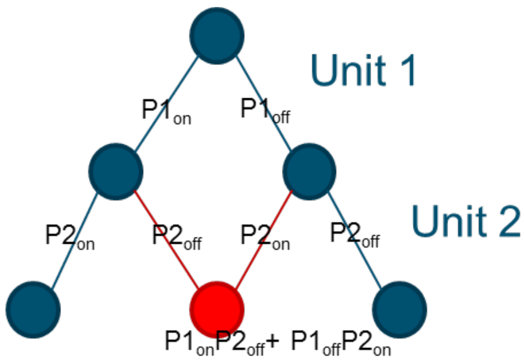
Figure 9: RECAP model flowchart



The generator module uses forced outage rates for a fleet of generators to calculate the probability of different total amounts of capacity outage. The output from this module is a capacity outage probability table, a standard output from resource adequacy models[24] illustrated in Figure 10.

[24] Billinton, R. and G. Yi (2008). "Multistate Wind Energy Conversion System Models for Adequacy Assessment of Generating Systems Incorporating Wind Energy." Energy Conversion, IEEE Transactions on 23(1): 163-170.

Figure 10: Process to create a capacity outage probability table

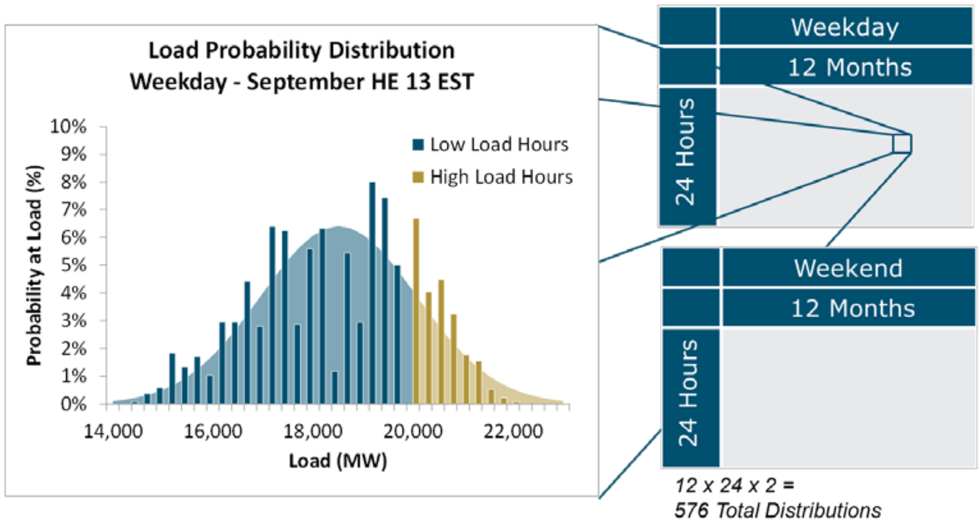


The transmission module creates import probability distributions using historical transmission outage distributions. Together with the capacity outage probability table, the import probability distributions give the probability of having different amounts of supply side resources available to a system operator.

The net load module creates a probability distribution function for net load[25]. The design was driven by the goal of making full statistical use of historical data, recognizing that often such data is not aligned through time. Gross load distributions are specific to a single month-hour-day type combination, as shown in Figure 11.

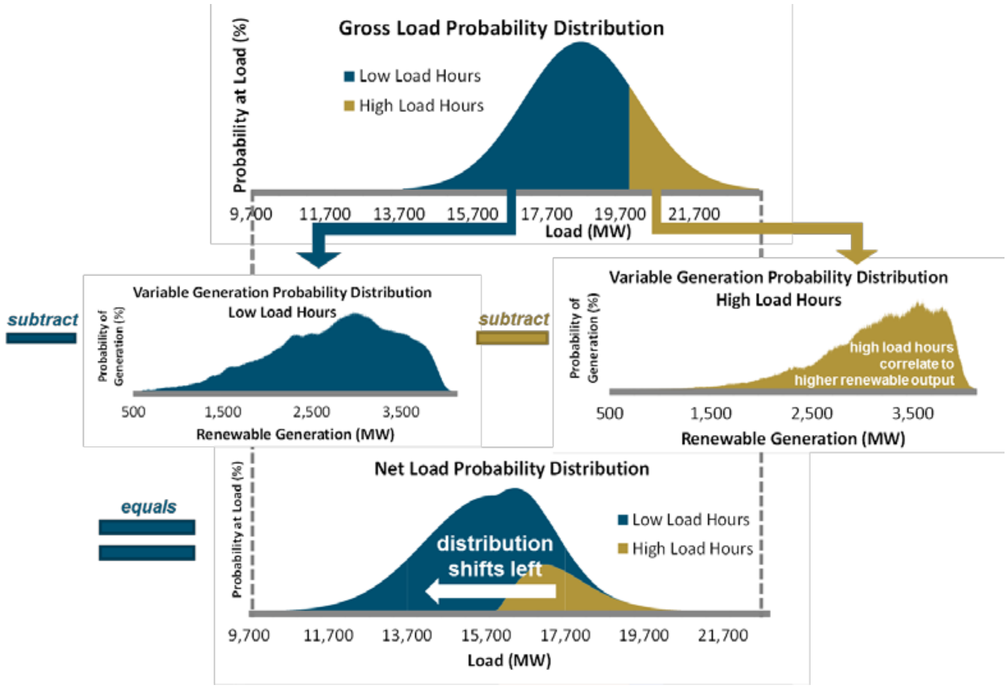
[25] Net load is gross load minus renewables, imports, run-of-river hydro, and other time sequential or energy limited variables (dispatchable hydro is modeled in the generator module). Demand response is split between the generator module and net load modules depending on the nature of the demand response program.

Figure 11: Gross load distribution



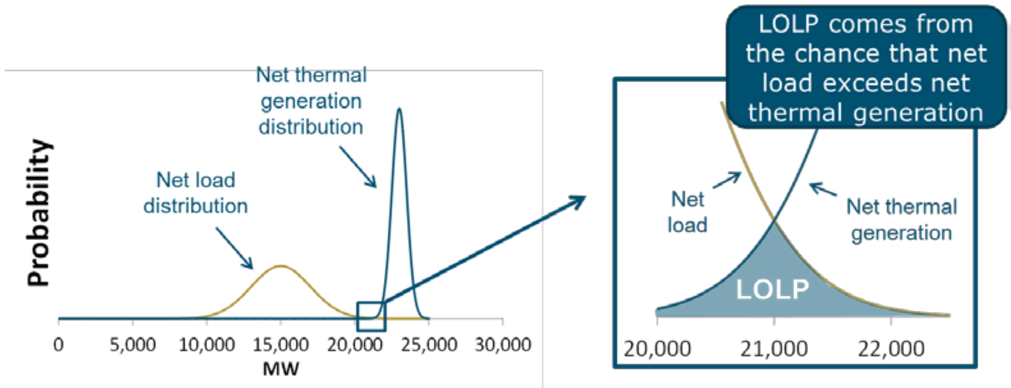
Relevant correlations between load, wind, and solar are enforced, where significant, using conditional probability distributions. Mathematically, the net load distribution function is a convolution of each of the constituent distributions. Within the RECAP Model the convolution is done a fast Fourier transform convolution algorithm. The convolution process is shown in Figure 12. The resulting net load probability distribution function is then fed into the LOLP module.

Figure 12 Net load distributions



The LOLP module combines the outputs from the net load module and generator module. Figure 13 demonstrates how this process works. The overlapping area between the generation curve and the net load demand curve is the probability of lost load for each day in that month/hour/day-type. Multiplying by the appropriate number of month/hour/day-type observations in one year and then summing across the year gives loss of load expectation, measured in hours of lost load per year. Expected Unserved Energy (EUE) is calculated by weighing each loss of load probability with the severity of each deficiency.

Figure 13 Loss of load probability module

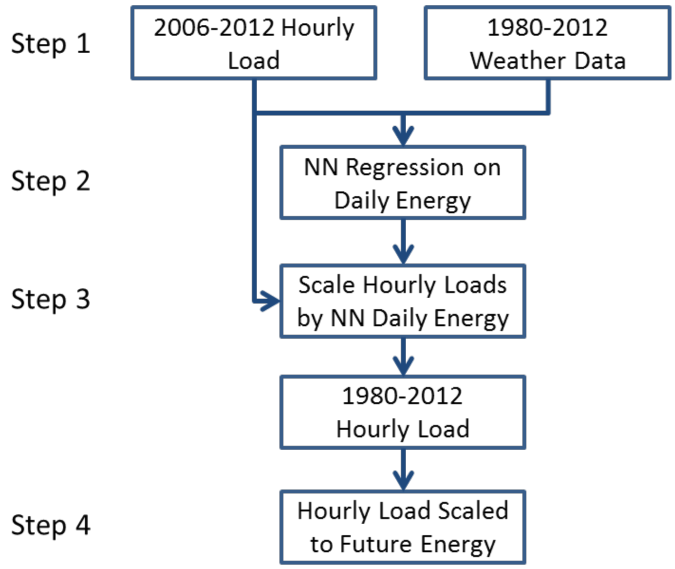


The resources are added or subtracted from the simulated power system and the resulting outage metrics are recorded, shown in Figure 4 on page 16. This result can be used directly to determine an economic target planning reserve margin. Alternatively, the outputs can be used to benchmark to engineering standards or calculate the effective load carrying capability (ELCC) for variable generation resources.

5.2 Load Regression Methodology

We use a neural network regression to take recent (2006-2012) hourly load data and extrapolate back to 1980 using historical weather data. The approach is shown in Figure 9 and each step (1-4) is described in more detail below.

Figure 14: Methodology for creating load profiles



Step 1: Hourly load data and daily weather data was gathered for the regression period.

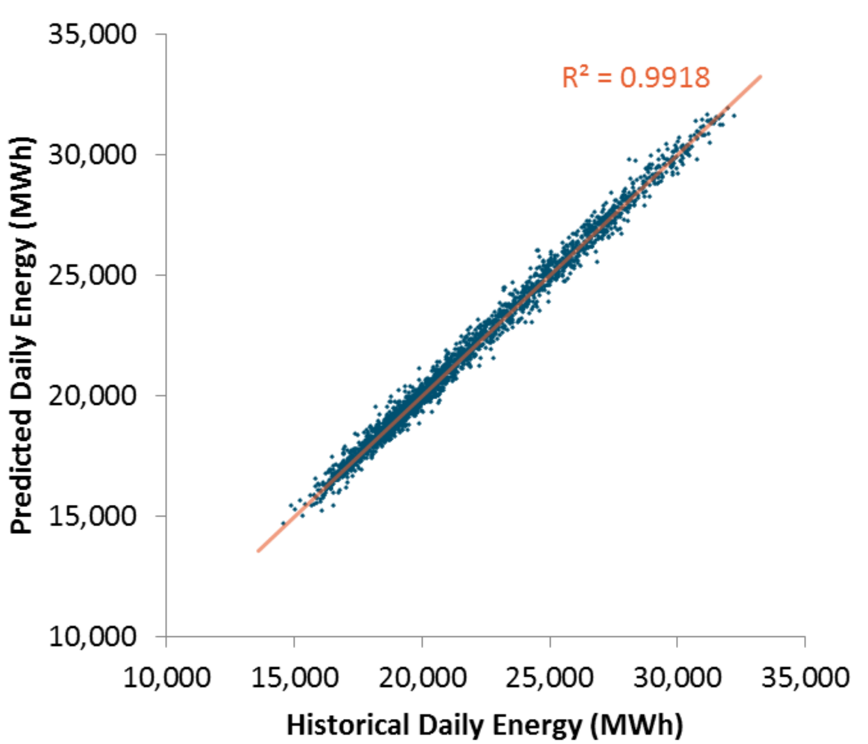
Step 2: A neural network was trained using the following explanatory variables:

Table 5: Independent variables used in regression analysis

Variable	Data Source
Daily min, max, mean temperatures with temperature lag for EPE locations	www.weathersource.com
Maximum solar azimuth	Simulated based on dates
Indicator variables including: day of week, holiday, season, economic normalization	Various

The neural network had 2 hidden layers, each with 29 nodes. Figure 10 shows a scatter plot with predicted vs. actual daily energy from 2006-2012 after the neural network had been trained.

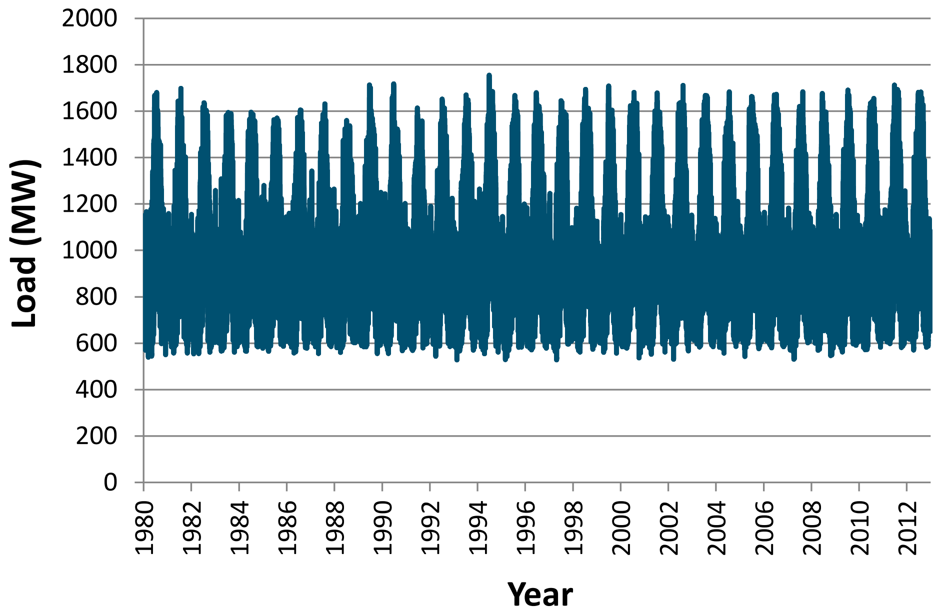
Figure 15: Comparison of actual vs. predicted daily energy 2006-2012 from the neural network regression



Step 3: A daily energy matching function is used to produce hourly load data back to 1980 from the regressed daily energy data. In the matching algorithm, years without hourly data (1980-2005) is paired with a normalized daily load shape from those years where hourly data is available (2004-2012) based on the closest match of total daily energy. Matched days are within 15 calendar days of

each other so that seasonally specific diurnal trends are preserved. In addition, weekdays and weekends are matched separately. The resulting output is shown in Figure 3.

Copy of Figure 3: EPE Historical Loads (2012 Economic System Conditions)



Step 4: The resulting 32 years of hourly load profiles are scaled to forecasted future energy and median peak load. Behind-the-meter PV is introduced as a separate profile.