Economic Equilibrium and Reliability in ERCOT

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Executive Summary

ERCOT has enjoyed a surplus of generating capacity for many years. As recently as May 2017, ERCOT's forecast of the Summer 2018 reserve margin was 18.9%, far in excess of the target planning reserve margin of 13.75% and even above the more conservative 16.75% reserve margin needed to achieve the traditional 1-in-10 years Loss-of-Load Expectation ("LOLE") standard, determined in an analysis developed for ERCOT in 2015.[1] However, ERCOT now finds itself in a situation where resource retirements and project cancellations/delays have changed the reliability landscape.

ERCOT's current target planning reserve margin was established in 2010. Since that time, ERCOT has experienced several substantial changes, including large quantities of new wind/solar additions and changes in how ERCOT counts those resources for capacity purposes. Our analysis of these changes indicates that the current target planning reserve margin of 13.75% is no longer consistent with the level of reliability it achieved at the time of its inception and that the reserve margin needed to achieve a 1-in-10 LOLE standard has risen to 17.6%.

However, we recognize that ERCOT has taken a more holistic view of planning reserve margins in recent years and may not be relying exclusively on the same reliability metrics it used to establish the current target. When the Operating Reserve Demand Curve ("ORDC") was adopted in 2014, the Brattle Group found in an analysis developed for the Public Utilities Commission of Texas (the "Commission") that it would lead to a reliability level of roughly 0.33 LOLE, or a 1-in-3-year probability of load shed, rather than the more traditional 1-in-10 standard. Although the commission may not have explicitly targeted this level of reliability, it does illustrate a general comfort level with this frequency of load shed.

Projections for Summer 2018 indicate that ERCOT's reliability level is well below any of these signposts. Given announced retirements, project delays and cancellations, and revisions to ERCOT's load forecast, ERCOT expects to enter Summer 2018 with a 9.3% reserve margin. Under the current system mix, this level of reserves produces a much higher expected frequency of load curtailments than either the traditional 1-in-10 LOLE standard or the more aggressive 1-in-3 standard known to be consistent with the ORDC at the time of its inception. Specifically, at projected Summer 2018 reserve margin levels, we would expect to see 3.1 loss-of-load events per year or about 31 times the frequency expected under the 1-in-10 standard, and 9 times the frequency expected under a more aggressive 1-in-3 standard. Further retirements or project cancellations could push the reserve margin even lower.

The cause of this dramatic shift, from a situation of oversupply to one of undersupply, is largely the result of a market structure that does not currently support the level of reliability implicitly endorsed by the Commission at the inception of the ORDC. As it is currently structured, the ORDC will lead to a long-term equilibrium with substantially more frequent load curtailments than any reasonable reliability standard would support.

A 1-in-10 reliability standard (0.1 LOLE) would require a reserve margin of 17.6% today. Even matching the level of reliability that reflected expectations at the time of the ORDC was adopted (i.e., 0.33 LOLE) would require a reserve margin of approximately 15.1%. ERCOT's current market structure, which includes the ORDC, is consistent with a long-term equilibrium reserve margin ("EERM") of 11.7%, which is consistent with an LOLE of 1.40 events per year, well in excess of either a 1-in-10 or 1-in-3 standard.

However, the current market structure is not broken; there are modest adjustments that the Commission can make to the ORDC to alleviate these threats and re-calibrate the ORDC to produce a level of reliability closer to its original intent. The Commission can authorize an incremental change to the ORDC which will alleviate much of the near-term pressure on the reserve margin. By including a Loss-of-Load Probability ("LOLP") Shift of two standard deviations (a "2.0" LOLP shift), we expect that ERCOT's EERM would increase to 15.0%, and the frequency of load

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[1] *Expected Unserved Energy and Reserve Margin Implications of Various Reliability Standards*, Astrapé Consulting, January 28, 2015. (the "Astrapé Report")

curtailments would be reduced by about 90%, from 3.1 to 0.35 events per year, a level roughly consistent with the implicit 1-in-3 standard embedded in the ORDC design at its inception. Alternatively, including a more modest LOLP Shift of one standard deviation (a "1.0" LOLP Shift) would increase the EERM to 13.1% and reduce the frequency of load curtailments to 0.8 events per year, a reduction of about 75%.

Incorporating an LOLP Shift of 2.0 or 1.0 may have other benefits as well. This incremental change to ERCOT's ORDC would tend to reduce the year-to-year volatility in generator margins, which may reduce the cost of capital for new investment. LOLP Shift values greater than zero would also tend to reduce the likelihood of binary pricing outcomes in the real-time market, making resource commitment decisions more efficient.

Finally, the costs to consumers of an LOLP shift would be modest. A 2.0 LOLP shift would raise total system costs to consumers by about $80 million per year, or roughly 0.3% of the total customer bill. Further, if consumers place a higher value on avoiding load shed than the $9,000/MWh cost embedded in the ORDC, the LOLP Shift could produce net benefits for consumers.

Introduction

ERCOT has enjoyed, for many years, a robust electric market supported by a surplus of generating capacity. Merchant investment has led to significant increases in generating capacity, resulting in persistently high reserve margins and a high level of physical reliability. This era of abundance, however, is coming to an end due to recent announcements of capacity retirements and delayed or cancelled new projects. The root cause of these announcements is a market structure that is consistent with a lower level of future reliability than ERCOT has enjoyed historically. Without recalibrating the current scarcity pricing mechanism, a system with reasonable levels of reliability is threatened.

Recent announcements of generator retirements, along with delays and cancellations of new projects, are indicative of a market that is providing inadequate compensation to the generators whose capacity provides essential system reliability. ERCOT has, in recent years, benefited from a surplus of capacity that is simply not sustainable without improvements to its market structure. This report illustrates the scope and magnitude of the threats to system reliability that ERCOT will face as soon as Summer 2018. Absent significant near-term improvements, ERCOT customers will likely face load curtailments at a rate higher than any reasonable reliability standard would allow.

There are, however, relatively straightforward adjustments to the existing scarcity pricing mechanism in ERCOT (i.e., the ORDC), which should help to alleviate these near-term threats to reliability and to restore the level of reliability implicitly targeted at the time of its adoption. These same adjustments would also improve reliability in future years by creating an environment amenable to new investment. One such proposal, incorporating a "shift" in the Loss-of-Load Probability ("LOLP") calculation of the ORDC would be a modest but materially beneficial improvement to the existing market structure, and would steer ERCOT back toward a sustainable level of reliability over the long-term.

ERCOT Needs a Higher Level of Reserves to Achieve the Same Reliability It Targeted in the Past

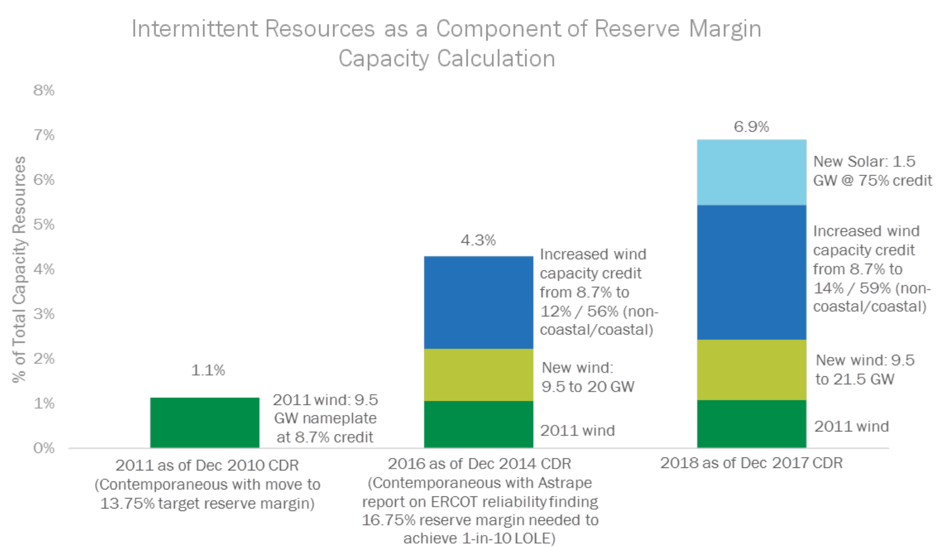
A given level of planning reserves, or reserve margin, can be translated into a particular set of reliability implications. The most familiar of these is the relationship between projected reserve margin and Loss-of-Load-Expectation ("LOLE"), which is the average number of load shed events that a system can expect to experience during a year across the full range of weather and generation outage scenarios. All else equal, the higher the expected reserve margin, the better the reliability the system can expect to experience. This improved reliability expectation will be manifested in the form of a lower LOLE and improvements in other metrics such as Loss-of-Load-Hours ("LOLH") or Expected-Unserved-Energy ("EUE").

The relationship between the level of planning reserves and physical reliability is not static over time. Electric grids, such as ERCOT, evolve over time and it is reasonable to reassess periodically whether signposts that stakeholders use to assess reliability have also shifted. At a high level, this means evaluating whether reserve margin targets continue to reflect the same level of reliability upon which they were originally based. In recent years, ERCOT has gone through a significant transformation with respect to the large-scale integration of new wind and solar resources. This structural change has major ramifications with respect to the level of physical reliability that corresponds to a given level of reserve margin. There are two primary drivers to this shift.

The first change is largely a definitional change in how the reserve margin is calculated, and not a reflection of any change in the physical system. ERCOT has adjusted the capacity credit associated with wind and solar resources known as the Effective Load Carrying Capacity ("ELCC").[2] For example, in 2010, wind resources were credited with 8.7% of their nameplate capacity for the purposes of calculating the reserve margin. Today, that figure stands at 14% for non-coastal wind resources. The change in ELCC increases the reserve margin, as calculated by ERCOT, by roughly 3%.[3] We have not performed an analysis of whether either figure is more appropriate; we simply recognize that the choice of ELCC impacts the calculated reserve margin, even if the underlying characteristics of the wind resource is unchanged. There is some intrinsic level of reliability to the system, which is independent of how one calculates the reserve margin but rather is based on the physical characteristics of the load and generation resources that make up the system, including intermittent resources such as wind and solar. For example, a system with 10 GW of peak load and 10 GW of thermal resources and 10 GW of nameplate wind capacity will produce the same level of reliability regardless of whether the wind is credited for 50% of nameplate in the reserve margin calculation (producing a 50% reserve margin) or 100% (producing a 100% reserve margin), assuming the wind resource is physically the same regardless of what credit it is given in the reserve margin calculation. But while reliability is a function of the physical system, the relationship between reliability and reserve margin, which is a function in part of the measuring scale (i.e., the ELCC for intermittent resources), will shift to the extent that the measuring scale is changed. Thus, ERCOT's changes to the ELCC of intermittent resources require that we re-calibrate the relationship between reserve margin and reliability to reflect the current scale.

The second change is a physical one and reflects the changing composition of ERCOT generation. During the last seven years, the growth in intermittent resources – both wind and solar – has been dramatic. In 2011 (based on the December 2010 Capacity Demand & Reserves Report), wind resources comprised only 1.1% of the capacity resources in ERCOT utilized in calculating the projected reserve margin for 2011. That figure now stands at 6.9% – a more than six-fold increase.

FIGURE 1: THE COMPOSITION OF ERCOT'S RESOURCES HAS CHANGED SINCE 2010



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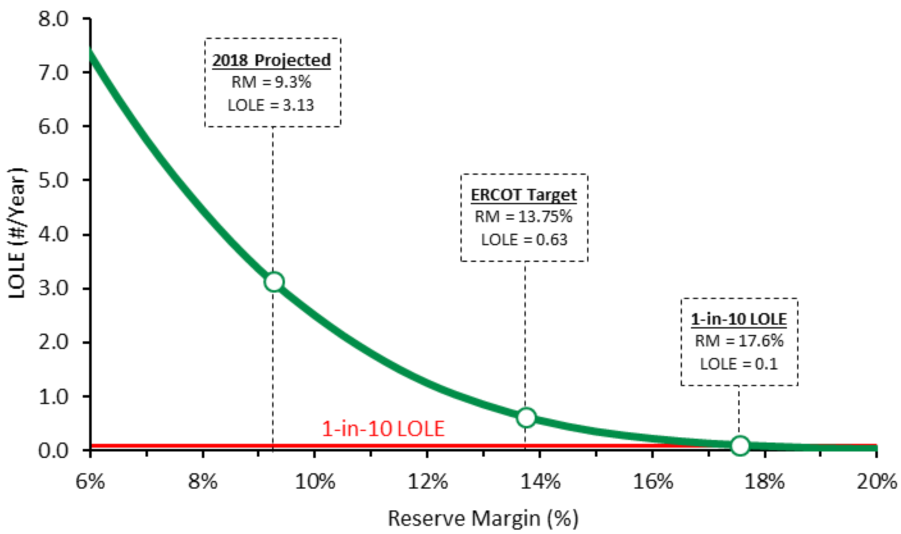
[2] The capacity credit, or Effective Load Carrying Capacity ("ELCC") is the percentage of a renewable resource's nameplate capacity that may be counted as capacity for the purpose of calculating the reserve margin.

[3] The ELCC determines the amount of nameplate capacity that may be credited for the purpose of calculating the reserve margin. All else equal, a higher ELCC value will translate to a higher reserve margin even if there is no change in the actual reliability of the system.

The reliability ramifications of both these changes are profound. NorthBridge utilized its RME™ model[4] to evaluate the reliability implications of different reserve margins in ERCOT using ERCOT's current capacity mix and ELCC values to calculate capacity while also incorporating announced capacity additions and retirements.

Our simulation modeling indicates that the reserve margin needed to achieve a given level of physical reliability has increased substantially in recent years. For example, ERCOT's current target planning reserve margin of 13.75%, which at the time of its adoption in 2010 was intended to achieve the traditional 1-in-10 LOLE (0.1 LOLE) reliability standard, can now be expected to produce 0.63 loss-of-load-events per year, or roughly 1 event per 1.5 years. Or, looking at the shift in reliability versus reserves relationship another way, the reserve margin needed to achieve the traditional 0.1 LOLE standard has risen from 13.75% to 17.6%.

FIGURE 2: LOLE ACROSS DIFFERENT RESERVE MARGINS



The increase in reserve margin needed to achieve a 1-in-10 LOLE is significant. However, it is our understanding that ERCOT may place less emphasis on that reliability metric today than it did when the 13.75% target reserve margin was established. When the Commission adopted the ORDC, it was presented with evidence by The Brattle Group that the market structure would lead to an economic equilibrium reserve margin of 11.5% and 0.33 events per year.[5] This translates into roughly a 1-in-3 LOLE standard. This is the best indication of the level of reliability stakeholders understood they could expect at the time the ORDC and its associated parameters were adopted. To achieve that same degree of reliability today, given changes over the past four years, ERCOT would need a reserve margin of 15.1%. Put another way, the 11.5% economic equilibrium reserve margin that Brattle estimated would produce 0.33 loss-of-load events per year in 2014 now produces close to 1.5 loss-of-load events per year.

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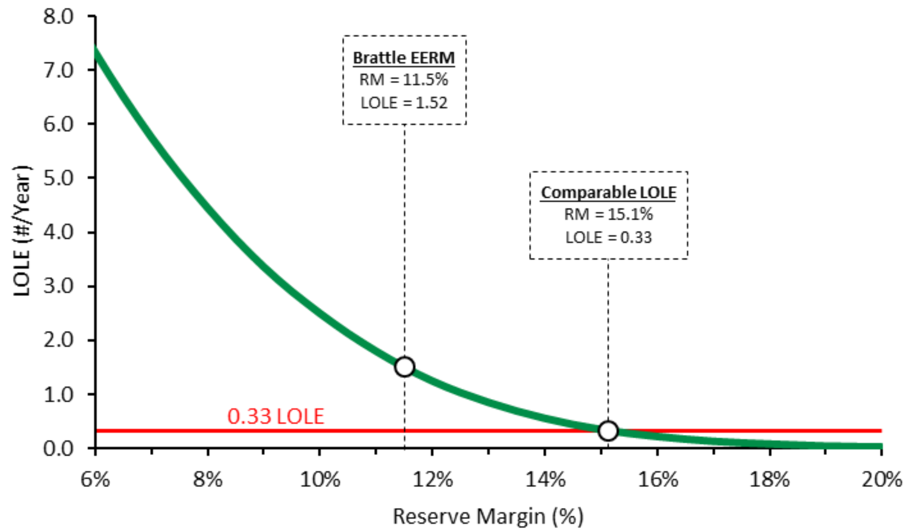
[4] Reliability and Market Equilibrium.

[5] Samuel A. Newell, Kathleen Spees, Johannes P. Pfeifenberger, Ioanna Karkatsouli (The Brattle Group), Nick Wintermantel, Kevin Carden (Astrape Consulting), *Estimating the Economically Optimal Reserve Margin in ERCOT*, Prepared for the Public Utility Commission of Texas, January 31st, 2014, Table ES-2. (the "Brattle Report")

FIGURE 3: RESERVE MARGIN TO MEET 1-IN-3 LOLE

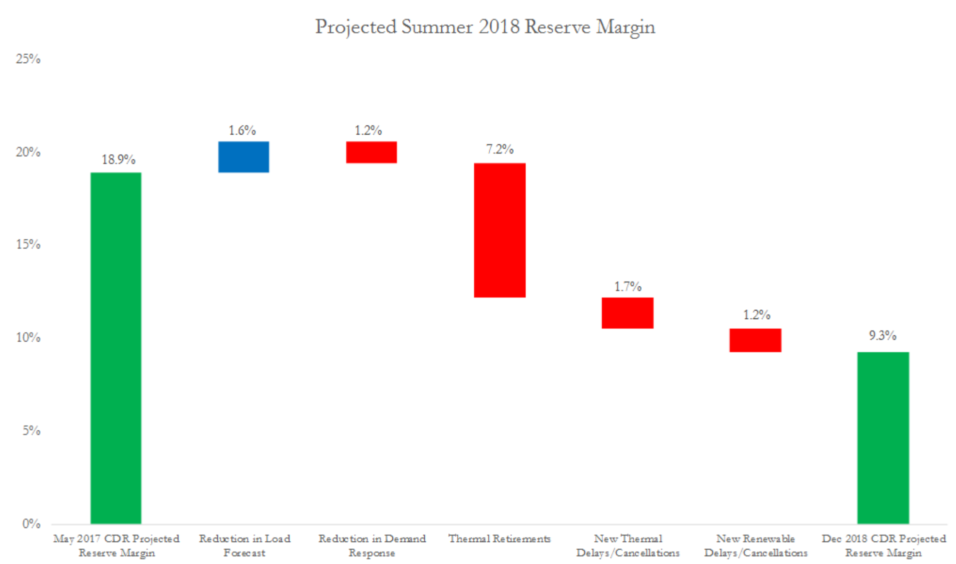


As a general matter, a given level of reserves in ERCOT today produces a less favorable reliability outcome than the same level of reserves did in years past. Across the range of potential reserve margin levels, the reserve margin needed to achieve a given level of physical reliability has risen by about 3 to 4% since 2010. The relationship between planning reserves and reliability in ERCOT's current system is a foundational element to our analysis of the reliability implications of the current near-term reserve margin outlook and energy market design in ERCOT.

Reliability for Summer 2018 is Likely to be Much Lower than in Years Past

Recent changes in the ERCOT supply mix have reduced the projected reserve margin for Summer 2018 from 18.9% (as reported in the May 2017 CDR) to 9.3% (as reported in the December 2017 CDR). Since May 2017, there have been significant retirement announcements of existing thermal resources along with delays and cancellations for new thermal and renewable resources that were originally projected to come online in time for Summer 2018. Collectively, these changes mean that approximately 7.2 GW of resources originally identified in the May 2017 CDR, and which were counted upon to meet summer peak load, are no longer expected to be available for Summer 2018. Slightly offsetting these changes, ERCOT has concurrently revised its load forecast (including demand response) for Summer 2018 downward by about 0.3 GW. The overall net effect of these changes is a reduction in the projected reserve margin for Summer 2018 to 9.3%.

FIGURE 4: CHANGES TO ERCOT SUPPLY BETWEEN MAY 2017 AND PRESENT



The reliability implications of these supply changes are significant. Not only does the removal of this supply reduce the anticipated Summer 2018 reserve margin below the level necessary to achieve an LOLE of 0.1 (i.e., 17.6%) or 0.33 (i.e., 15.1%), it reduces the reserve margin far below the 13.75% nominally targeted by ERCOT and below the reserve margin level we would expect under economic equilibrium conditions. The projected Summer 2018 reserve margin suggests real and present reliability challenges for ERCOT.

For example, given the anticipated reserve margin for Summer 2018, we would expect 3.1 loss-of-load-events spread over 10 hours. At an estimated cost of $9,000/MWh (the value of lost load used by ERCOT), these reliability events would cost ERCOT customers over $155 million.[6] In a 1-in-20 weather year, ERCOT could experience 11 loss-of-load events spread over 41 hours. The customer cost these load interruptions would be in excess of $700 million.[7]

The reserve margin for Summer 2018 could even be lower than 9.3%. In the event of further retirements, project delays, or cancellations, the capacity available in Summer 2018 could be reduced by an additional 1 GW or more. If a further 1 GW reduction in supply were to happen, the reserve margin would fall to 7.8%. At this level, ERCOT would expect more than 4.6 loss-of-load-events per year spread over more than 16 hours. In a 1-in-20 weather year, ERCOT could see over 58 hours with load interruptions.

The Current ORDC is Consistent with an Equilibrium Reserve Margin of 11.7%

In ERCOT, there is currently no direct linkage between the target reserve margin, which is set at the level needed to maintain a desired level of reliability, and the actual reserve margin, which is a function of investments in new resources and retirements of older ones. Resources in ERCOT are predominantly owned and operated by merchant

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[6] Assumes annual load of 370 TWh, 0.0046% Normalized Expected Unserved Energy ("EUE"), and VOLL of $9,000/MWh.

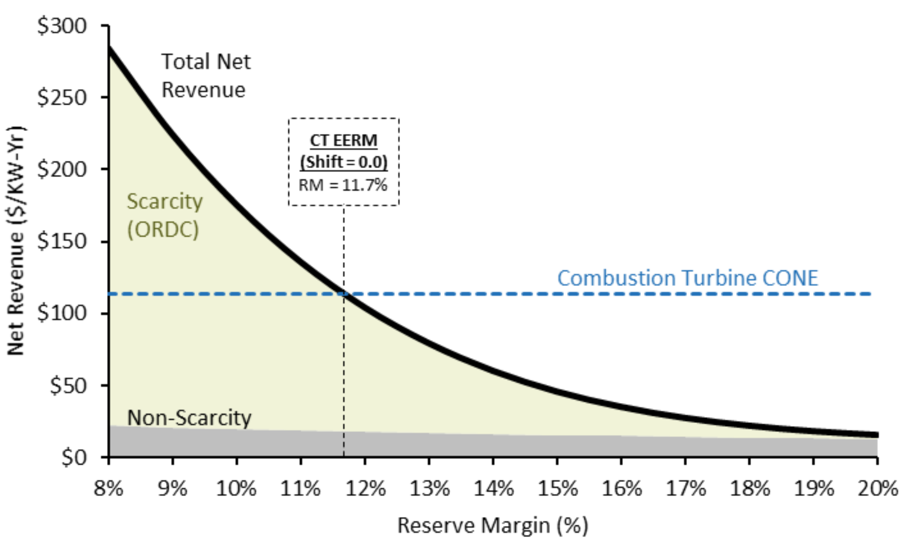
[7] Assumes annual load of 370 TWh, 0.0214% Normalized Expected Unserved Energy ("EUE"), and VOLL of $9,000/MWh.

entities, which are entirely dependent on market revenues for requisite investment returns and consequently pay close attention to the market structure. Resources may earn net revenue through both energy dispatch (as an inframarginal unit) or through the scarcity pricing mechanism, known as the ORDC.

The market is said to be in equilibrium when the expected revenue earned by a new build combustion turbine or a combined cycle unit exactly matches the revenue it requires to enter the market as a merchant generator (on a real-levelized basis). This balance occurs at a reserve margin that is both low enough that the frequency of scarcity pricing provides adequate compensation to incent new investment, but high enough that new investment earns only its required return and not more. RME™ calculates the expected net energy revenue earned by hypothetical new resources using market-based representations of energy price formation in ERCOT. The new resources we use for our analysis were combustion turbines and combined cycle units.

While both resource types would expect to earn some combination of scarcity and non-scarcity revenue at all reserve margins, at many levels the total revenue would fail to compensate investors for the cost of building and operating the resources. Therefore, we would expect the reserve margin to fall until such time that one of the two resources would become profitable. Given the current market structure in ERCOT, including the current ORDC parameters, we expect that this equilibrium will occur at roughly an 11.7% reserve margin, with a combustion turbine as the marginal resource.[8] This is the reserve margin at which a prospective combustion turbine would expect to earn total revenue adequate to provide its investors with their requisite return.[9]

FIGURE 5: ECONOMIC EQUILIBRIUM RESERVE MARGIN (CURRENT ORDC)



This economic equilibrium reserve margin is different than both the current target of 13.75% and the reserve margin needed to achieve either the traditional one-in-ten LOLE reliability standard or the more aggressive one-in-three LOLE reliability standard implied by the ORDC at the time of its adoption, and it leads to different reliability implications. Given its current market structure, ERCOT should expect to experience a level of reliability that is an

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[8] A combined cycle unit would not earn an adequate return above a reserve margin of 11.0%.

[9] "Cost of New Entry Estimates Combustion Turbine and Combined Cycle Plants in PJM", The Brattle Group, May 15, 2014. See Table 25. After-Tax WACC of 8.0%. 60% equity at 13.8%, 40% debt at 7%.

order of magnitude lower than the traditional one-in-ten standard, and also considerably lower than the level of reliability ERCOT has enjoyed in recent years.

TABLE 1: RELIABILITY METRICS UNDER EERM

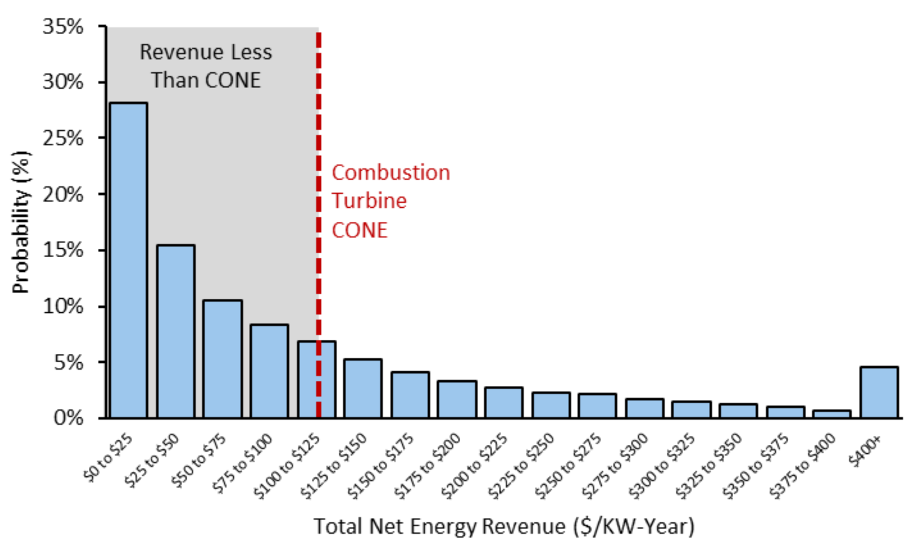
Reserve Margin	EERM (Status Quo) 11.7%	ERCOT Target 13.75%	1-in-3 LOLE 15.1%	1-in-10 LOLE 17.6%
LOLE (#/Year)	1.40	0.63	0.33	0.10
LOLH (#/Year)	4.27	1.78	0.91	0.25
Normalized Unserved Energy (%)	0.0016%	0.0006%	0.0003%	0.0001%
Loss-of-Load Hours During 1-in-20 Weather Year	20.7	10.5	5.8	1.4

At the Economic Equilibrium Reserve Margin of 11.7%, a new combustion turbine would earn adequate revenue to support its own investment, but ERCOT customers would face a high frequency of firm load shed. ERCOT would expect to see 1 to 2 loss-of-load-events each year, averaging roughly 4 hours in total. Firm load shed would become an annual occurrence. It is also important to remember that these reliability metrics represent only a "typical" year. ERCOT could expect to see more than 20 hours of load shed in a 1-in-20 weather year. In the absence of adjustments to the market design to restore previous reliability targets and, consequently, the financial compensation offered to new generators, this is the trajectory upon which ERCOT is set.

An additional point of concern is the Economic Equilibrium Reserve Margin shown above assumes that investors only care about the average or expected level of revenue in a single year and compare it to the real-levelized cost of new entry when choosing to make an investment. In reality, the revenue produced by a new resource would vary considerably from year-to-year, and the degree to which that revenue is variable could encourage or discourage new investment, even if the average level appears to be adequate.

Given the structure of the ORDC and the unpredictability of scarcity revenue, generators have a high degree of uncertainty with respect to annual revenues. At the EERM of 11.7%, a new combustion turbine would expect its earnings to fall short of its revenue requirement over 66% of the time.

FIGURE 6: DISTRIBUTION OF ANNUAL CT NET MARGIN DURING ECONOMIC EQUILIBRIUM (11.7% RM)

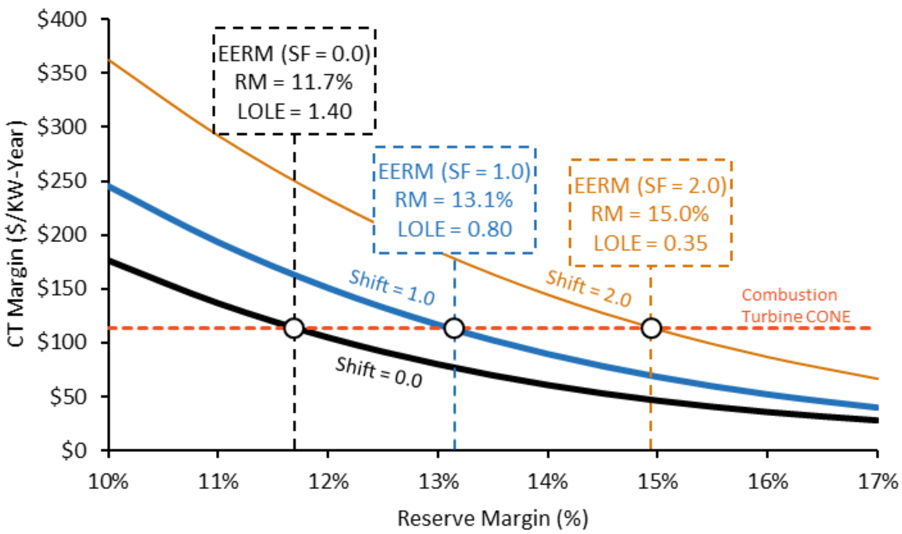


An LOLP Shift Can Improve ERCOT's System Reliability at Modest Cost

The Economic Equilibrium Reserve Margin (EERM) is the consequence of deliberate choices regarding market structure. Although the Commission does not directly control new investment and asset retirement choices, it does control elements of the market structure, in particular the design and specification of the ORDC, which may move the economic equilibrium reserve margin higher or lower.

One of the proposals before the Commission is to include an LOLP Shift in the Loss-of-Load Probability ("LOLP") input into the ORDC calculation. The details of how this change would impact price formation are somewhat technical, but the marginal effect of this change would be to improve generator compensation and ultimately the physical reliability of ERCOT. An LOLP Shift of greater than zero would improve investment returns at any given level of reserve margin and would thus lead to a higher EERM than would otherwise be achieved. The current ORDC mechanism does not include an explicit LOLP Shift. If the ORDC were modified to use an LOLP Shift of one standard deviation (a "1.0 LOLP Shift"), the EERM would improve from 11.7% to 13.1%. If the ORDC were modified to use an LOLP Shift of 2.0, the EERM would improve from 11.7% to 15.0%, which would produce roughly the same level of reliability that was expected when the ORDC was originally adopted.

FIGURE 7: IMPROVEMENT IN EERM WITH LOLP SHIFT = 1.0 AND 2.0



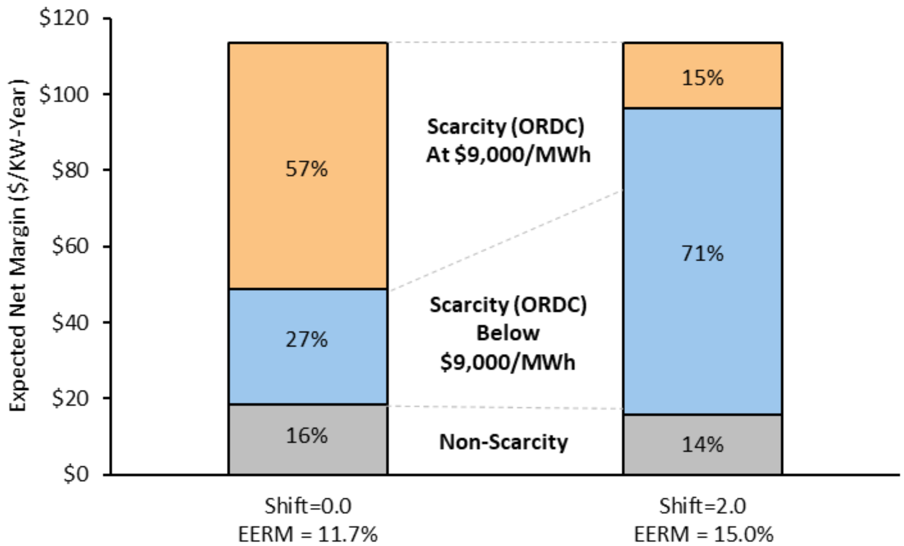
An LOLP Shift of 1.0 would result in considerably improved reliability metrics. In particular, it would nearly halve the loss-of-load event frequency and expected loss-of-load hours relative to the current design. A further increase to an LOLP shift of 2.0 would lead to a return to roughly the 0.35 LOLE expectation concurrent with the adoption of the ORDC:

TABLE 2: RELIABILITY IMPROVEMENTS WITH LOLP SHIFT = 1.0

Case	LOLP Shift = 0.0 (Current)	LOLP Shift = 1.0	LOLP Shift = 2.0
Economic Equilibrium Reserve Margin (%)	11.7%	13.1%	15.0%
LOLE (#/Year)	1.40	0.80	0.35
LOLH (#/Year)	4.27	2.34	0.97
EUE (%)	0.0016%	0.0008%	0.0003%

An LOLP Shift may also have a positive secondary effect of increasing investors' willingness to commit capital to new generation and their willingness to economically commit their units when needed. The current ORDC structure leads to highly variable generator margin even when the market is in equilibrium. Scarcity events are, intentionally and by definition, infrequent and unpredictable. If an LOLP Shift were included in the ORDC parameterization, it would have the effect of "smoothing" the inherently variable nature of ORDC revenues, making combustion turbine revenue somewhat more stable and predictable. An LOLP Shift would tend to make the ORDC adder non-zero in more hours, and would increase compensation during near-scarcity hours while leaving compensation unchanged during actual scarcity hours, meaning that generators would not be quite as reliant on rare, but extreme, hours of true scarcity pricing for their compensation.

FIGURE 8: SOURCES OF CT MARGIN IN EERM BY LOLP SHIFT



The net costs to consumers of an LOLP Shift are modest and potentially negative. If we assume that the cost to consumers of load shed is the same as the VOLL embedded in the ORDC design, an LOLP Shift of 1.0 results in incremental costs to consumers of about $25 million per year while an LOLP Shift of 2.0 results in incremental costs of $79 million per year. However, the true value of lost load experienced by consumers is not necessarily the same as the $9,000/MWh embedded in the ORDC design. Past studies have suggested that the range of uncertainty of the value of lost load is very wide, and potentially much higher than $9,000/MWh. If a higher value of lost load were attributed to consumers, the cost-benefit analysis of the LOLP shift can easily yield a net benefit to consumers through the higher economic value placed on the avoidance of load shed events with a higher economic equilibrium reserve margin. For example, with a value of lost load of $45,000 an LOLP shift of 1.0 would produce net benefits to consumers of $83 million per year, while an LOLP shift of 2.0 would produce even higher net benefits of $96 million per year.

Simulation Methodology and Inputs

NorthBridge's RME™ Model (Reliability and Market Equilibrium)

NorthBridge has developed a Monte Carlo simulation model called RME™ (Reliability and Market Equilibrium) for the purpose of measuring system reliability and estimating the EERM in ERCOT. We have designed this model to complement existing models (e.g., SERVM™ developed by Astrapé Consulting) that have been used in ERCOT to estimate system reliability metrics at different reserve margins. RME™ extends this functionality to evaluate the economic equilibrium associated with ERCOT's price formation dynamics.

RME™ incorporates the same major structural elements captured by other reliability models, such as peak demand and load variability, forced outages, and renewable output variability. It produces the same physical reliability metrics (e.g., LOLE, LOLH, and EUE) as other reliability models. Equally important, it generates physical reliability metrics quickly and robustly. Further, these metrics are in good agreement with existing models of reliability in ERCOT.

RME™'s capabilities extend beyond those of other reliability models. Rather than focusing purely on physical reliability metrics, RME™ translates physical operating conditions, such as load, unit outages, and renewable resource output, into production cost and market price outcomes. The model incorporates a statistical model of price formation in the energy market using market implied energy supply curves in ERCOT. Because it is based on, and calibrated to, observed market conditions, it captures market idiosyncrasies that fundamental dispatch models cannot. Finally, it calculates both scarcity and non-scarcity net energy revenues under different reserve margin conditions and ORDC designs.

The results produced by RME™ are intended to supplement existing models of physical reliability in ERCOT and provide insight into the economic ramifications of potential modifications to ERCOT's scarcity pricing mechanism.

Physical Reliability Under Different Reserve Margins

All measurements of physical reliability are ultimately measurements of the probability that the system may not be able to meet all of its firm load obligations. ERCOT's ability to meet firm load obligations depends on many factors including the forecasted peak demand, variability in demand, installed capacity, forced outage rates, renewable energy production and variability, and the minimum required operating reserves.

The following sections describe the methodology utilized by RME™ to simulate potential future outcomes and ultimately the likelihood, given a specified reserve margin, that ERCOT may experience reliability problems and be unable to meet all of its firm load obligations.

Definition of a Reliability Event

In the real world, a system operator's first priority is to maintain the stability of the electrical grid. As such, system operators define precise system conditions that represent levels of concern and necessitate levels of remedial actions that they would take were these conditions to appear. Operating procedures may define dozens of different conditions, each of which may constitute some degree of threat to system stability and could reasonably be described as a "reliability event".

For the purposes of simulation, RME™ defines a "reliability event" more simply. Here, a reliability event is simply a situation when, due to a combination of high load and/or low resource availability, system operators must curtail firm load. System operators would ordinarily only curtail firm load when all other options have been exhausted and when not doing so would expose the system to an unacceptable level of instability. In other words, a reliability event takes place when the total resources available are less than real-time load plus a minimum level of operating reserves.

ERCOT currently has a minimum requirement of 2,300 MW of Responsive Reserves,[10] of which at least 1,150 MW must come from physical generation.[11] These reserves exist to satisfy loss-of-resource contingencies; ERCOT must maintain these reserves at adequate levels so that a sudden resource loss does not expose the entire grid to a cascading blackout. We have chosen this benchmark as the value for minimum reserves and it represents the threshold below which ERCOT would be forced to curtail firm load, since all load-based Responsive Reserves would already have been exhausted. This means that a reliability event may be expressed algebraically as:

$$Real\ Time\ Load + 1{,}150\ MW > Total\ Resources\ Available$$

This threshold for firm load shed is actually considerably more lenient[12] than another defensible threshold, which is the value of X used in the ORDC calculation. The ORDC specifies that the value of energy and reserves rises to the Value-of-Lost-Load ("VOLL"), currently set at $9,000/MWh, when total system reserves fall below 2,000 MW. Although this is an administrative and not an engineering specification, implicit in the ORDC scarcity mechanism is the presumption that operators will curtail load (with a VOLL of $9,000/MWh) in order to preserve total reserves at or above 2,000 MW. Actual practice might differ in the details, and might include more than one condition upon which load would be curtailed. These load curtailments, would clearly be interpreted as a reliability problem. If we were to adopt 2,000 MW as the level of minimum operating reserves, metrics of physical reliability would tend to show higher likelihoods of firm load curtailment, all else equal.

Inputs and Uncertainty

The physical reliability[13] of ERCOT's electric grid is largely a function of the following categories of inputs:

- Peak system demand and hourly load,
- Thermal unit availability, and
- Variable output from renewable resources.

RME™ incorporates each of these principal components and models the ERCOT system using a sophisticated chronological Monte Carlo analysis. The following sections describe both the input assumptions used for this analysis and the simulation methodology implemented in RME™.

Simulation Flow-Diagram

Given a specified set of resources and a forecasted reserve margin, NorthBridge's RME™ model simulates thousands of hypothetical delivery years and tracks reliability metrics such as loss-of-load-events (LOLE), loss-of-

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[10] The minimum level of Responsive Reserves actually varies during the year and is often higher than 2,300 MW.

[11] ERCOT recently (on Dec. 12, 2017) approved a revision to its responsive reserve rules allowing up to 60% of Responsive Reserves to be procured from load-based resources but also establishing a minimum requirement that no fewer than 1,150 MW of responsive reserves be supplied by generation resources capable of providing primary frequency response.

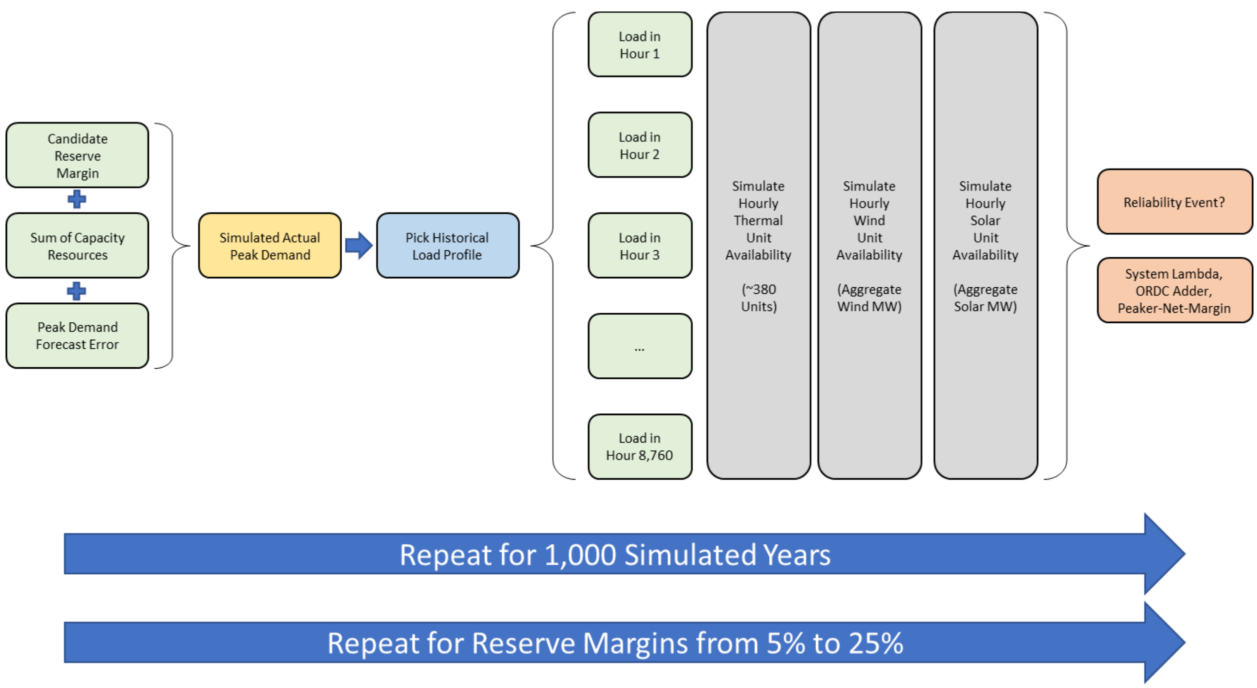
[12] Meaning that it may understate the likelihood of firm load curtailment.

[13] Physical reliability, in this report, refers to supply adequacy and the ability of supply resources to meet firm load obligations. It does not include or make reference to interruptions to firm load that may be caused by transmission or distribution-related outages.

load hours (LOLH), and expected unserved energy (EUE). In addition, the model also monitors corresponding economic outcomes such as system production costs, energy price formation, and net energy margins for hypothetical resources.

All of these metrics are first calculated in each simulated delivery year based on an hourly chronological simulation of real-time load, thermal unit outages, and renewable resource output. Next, the simulation is repeated for thousands of hypothetical delivery years, each of which exhibits a different realized peak demand outcome, simulated progressions of thermal unit outages, renewable resource output, and hourly load. This process is then repeated across different levels of forecasted reserve margin, allowing us to calculate not only the reliability of the forecasted ERCOT system, but also how that reliability might change at different reserve margins and/or market structures. The flow-diagram below illustrates the process for a single simulated delivery year:

FIGURE 9: FLOW DIAGRAM OF SIMULATION MODEL



The above diagram illustrates that the calculation of reliability metrics is fundamentally a large-scale simulation of the potential future conditions that might occur in ERCOT. The intent of this simulation is not to capture all of the fine-level engineering details of system operations. This would be an exercise in false precision. Rather, the intent is to capture the wide range of high-level factors that would contribute to shortage conditions and load shed.

Simulation of Realized Peak Demand

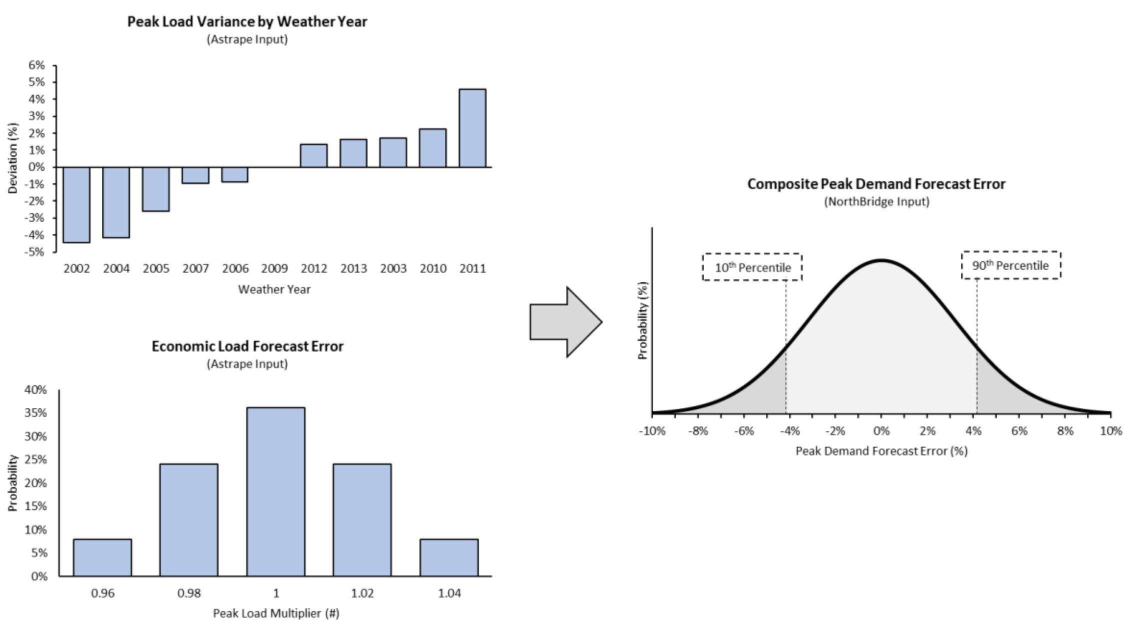
The general objective of RME™ is to evaluate the reliability ramifications of different levels of reserve margin. Therefore, the forecasted peak demand used in RME™ is not necessarily a peak demand forecast specific to a target year (e.g., the one shown in the ERCOT CDR for a specific year), but rather is simply the peak demand consistent with a specified reserve margin. The forecasted peak demand is a function of two inputs: 1) the candidate reserve margin, and 2) the sum of capacity resources in ERCOT. It is calculated as:

$$Forecast\ Peak\ Demand = \frac{Sum\ of\ Capacity\ Resources}{(1 + Reserve\ Margin)}$$

This value, however, merely represents a forecast. In a hypothetical delivery year, the actual peak demand could be higher or lower than the forecasted value by some amount, known as the forecast error. As RME™ simulates each hypothetical delivery year, it uses the forecasted peak demand as the mean or expected value[14], but then calculates a different realized, or simulated actual, peak demand for each simulated year.

The peak demand forecast error used in this analysis is based on the total peak demand forecast error implicit in the 2015 report produced by Astrapé.[15] In this report, Astrapé identifies two sources of load uncertainty. The first is weather-year uncertainty and reflects variations due to short-term effects such as weather. The second source of uncertainty is due to macroeconomic factors, such as industrial production, commercial activities, and other non-weather factors. Astrapé has quantified these components separately. RME™, however, is indifferent to the cause of the forecast error and is only concerned with the degree to which realized peak demand might differ or diverge from the forecasted value. In order to bridge the modeling approaches, we have combined Astrapé's uncertainty inputs to develop a composite measure of peak demand uncertainty.[16]

FIGURE 10: COMPOSITE PEAK DEMAND FORECAST ERROR



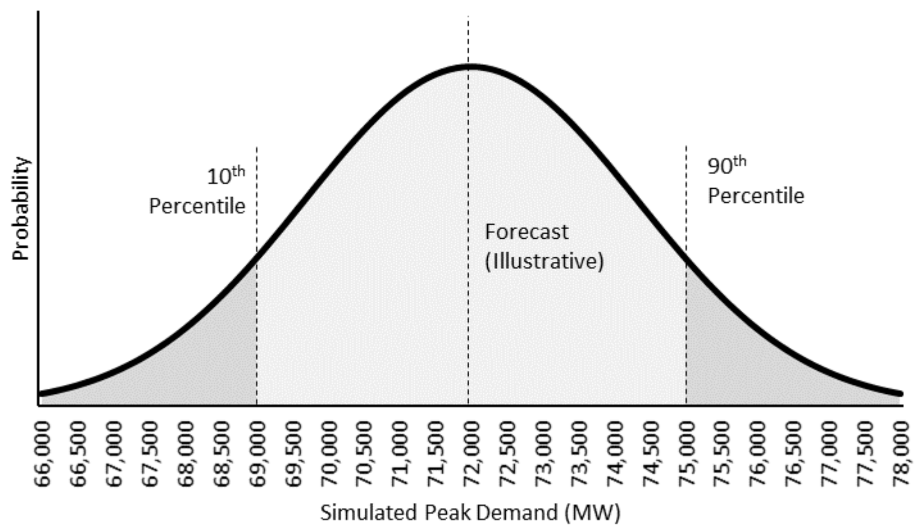
[14] RME™ treats load forecast error as symmetric. Therefore, the forecast peak demand is also the 50/50 likelihood value.

[15] *Expected Unserved Energy and Reserve Margin Implications of Various Reliability Standards*, Astrapé Consulting, January 28, 2015. (the "Astrape Report")

[16] Astrapé inputs include i) load variance by weather year, and ii) economic load forecast error. NorthBridge has developed a composite distribution of peak demand forecast error that replicates the combined variance of the two separate Astrapé inputs.

When the weather and non-weather forecast errors are summed together,[17] they produce an aggregate peak demand load forecast error of 3.23%.[18] This figure represents the degree to which the forecasted peak demand might differ from the realized value three years in the future. The distribution of outcomes implied by this forecast error is illustrated in the chart below, assuming a forecasted peak demand of 72,000 MW:

FIGURE 11: ILLUSTRATION OF SIMULATED PEAK DEMAND



Simulation of Hourly Load

While the forecasted peak demand is a critical element of reliability forecasting, it only represents a single hour. Reliability problems may arise in many hours during the year either due to high (even if not peak) load, and/or lower than expected resource availability. RME™ pairs annual simulations of realized peak demand with historical hourly load shapes, normalized to each historical year's peak demand, drawn from ERCOT historical data for the years 2002-2016. Each historical year illustrates a different load-shape and a load-factor.

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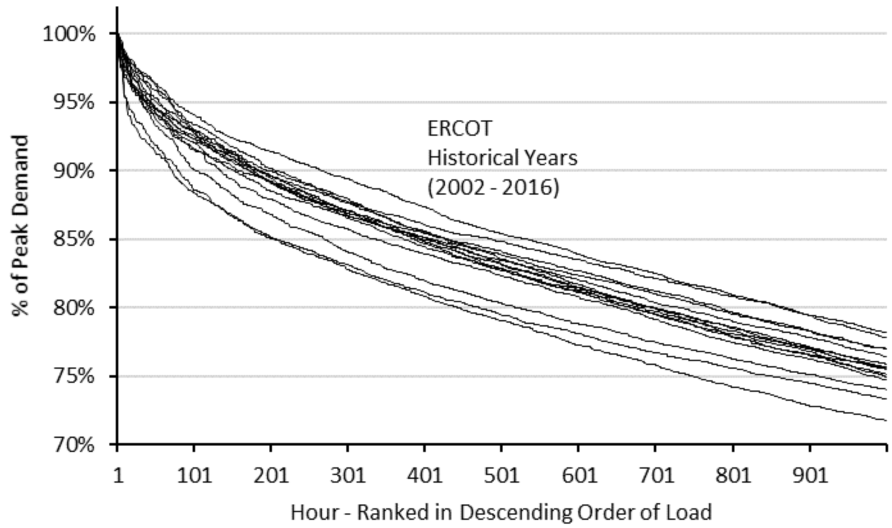
[17] It is actually the variances that are summed.

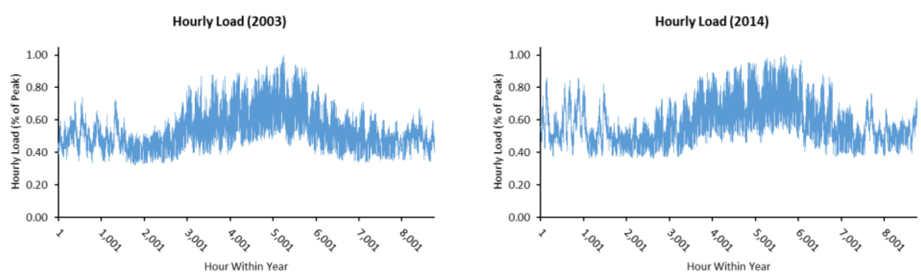
[18] This figure is the standard deviation of the peak demand forecast error and is simulated with a Gaussian distribution.

FIGURE 12: HISTORICAL LOAD SHAPES REPRESENTED IN RME™



The load duration curves shown above are ranked from highest to lowest load to illustrate that some years have load patterns with many high load hours (relative to that year's peak demand), while others are better characterized as having relatively few high load hours. RME™ is designed to simulate hourly load chronologically using the precise patterns in which historical load actually occurred. This is essential in order to measure the duration of outage events due to persistently high load, concurrent long-duration outages, or both.

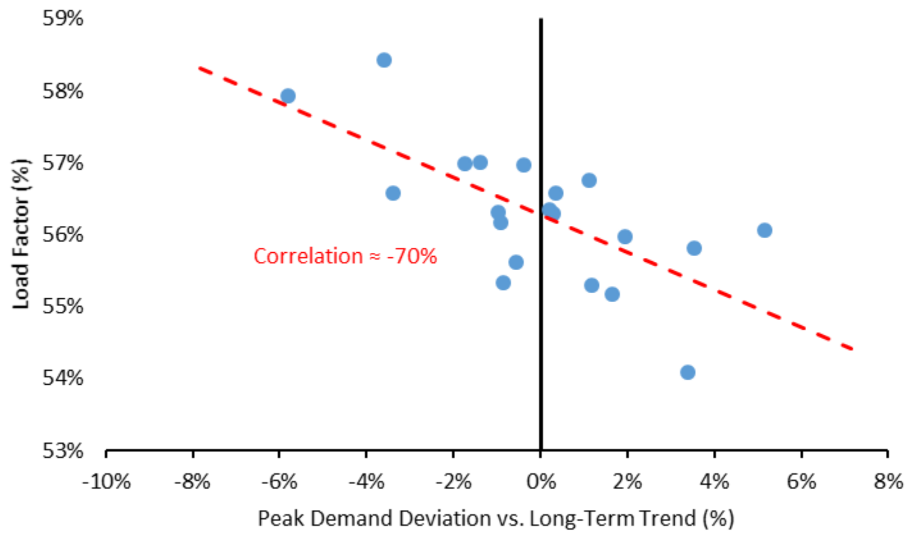
FIGURE 13: SAMPLE OF HISTORICAL CHRONOLOGICAL LOAD PATTERNS



Correlation Between Peak Demand and Load Factor

Within each simulated year, hourly loads are constructed by multiplying a simulated peak demand value by hourly historical load patterns, which are normalized to that historical year's actual peak demand. However, it is clear from historical observations that years with unexpectedly high peak demand tend to occur during years in which the overall load factor is lower than average. In other words, high peak demand is associated more with isolated load deviations within the year (i.e., a higher peak relative to average load) than with a uniform increase in load throughout the year. It would be inappropriate to assign historical weather year patterns randomly to simulated peak demand draws when there is clearly a relationship between the two.

FIGURE 14: DEVIATIONS IN PEAK DEMAND VS. LOAD FACTOR



In order to capture this relationship, RME™ incorporates a correlation between simulated peak demand and the simulated load factor of the hourly load pattern. In practice, we implement this relationship by selecting historical load profiles and peak demand values such that the correlation between the resulting peak demand and load factor is approximately -70%, which is consistent with historical observations. A higher (i.e., more positive) value for that correlation would tend to result in a higher calculated likelihood of reliability events

Variability in Intermittent Renewable Resource Output (i.e., Wind and Solar)

Reliability events in ERCOT may be driven by shortfalls in intermittent renewable output. In particular, as wind and solar become a larger component of ERCOT's capacity infrastructure, rapid fluctuations in their output may contribute to real-time shortages in the capacity available to meet firm load obligations. RME™ simulates wind production hourly based on historical observed patterns of aggregate ERCOT wind output and variability during the years 2014-16.[19] The simulation methodology captures the effects of day-to-day variations in output level during peak hours as well as diurnal patterns of renewable energy production.

At a high level, the simulation model chooses intra-day aggregate output profiles for both aggregated wind and aggregated solar that vary by season or month[20] and are grouped into decile output levels (i.e., output states). For example, for a simulated day in June, the intra-day output profile for ERCOT's aggregate wind capacity could follow one of ten hourly profiles that are derived from hourly ERCOT wind output levels during the summer months. Each one of these profiles represents a typical pattern of output as it changes throughout the day. The deciles represent groupings by on-peak output levels. The charts below illustrate the wide degree of variation in wind output depending on both season and capacity factor profile.

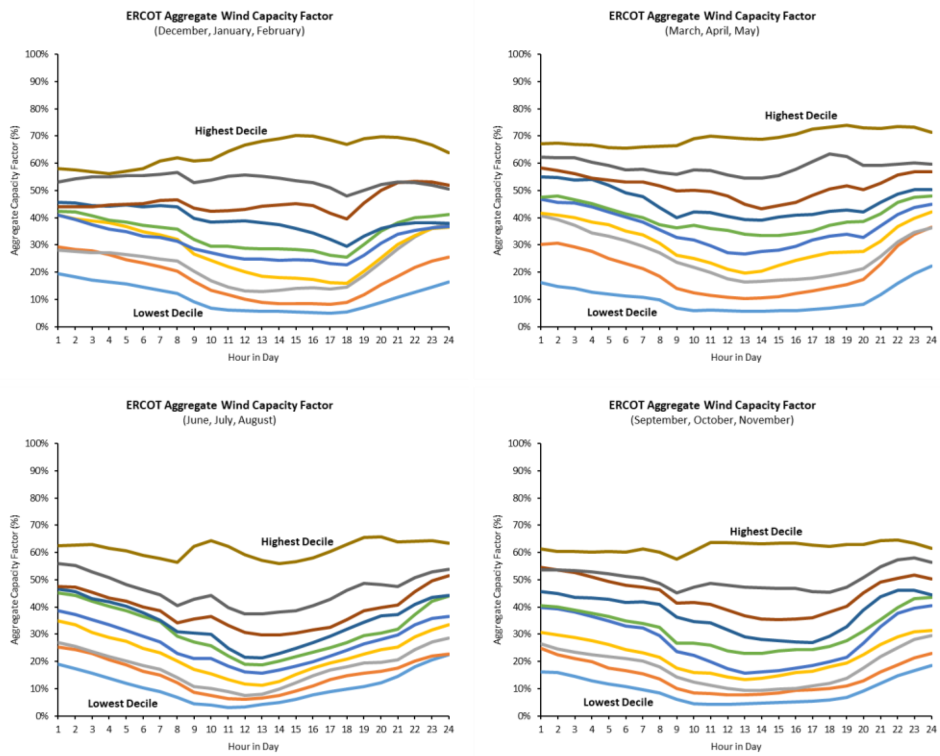
These decile profiles highlight the substantial risk inherent in relying on intermittent renewable resources to meet reliability needs. The chart showing the decile groups for the Summer months (June, July, and August) illustrate

[19] Wind production patterns were calculated as a percentage of total wind nameplate capacity during this period.

[20] Wind production is modeled with seasonal profiles. Solar production is modeled with monthly profiles.

that while the average capacity factor during super-peak hours (hours ending 11-18) may be considerable (approximately 24%), the output level in the lowest decile is only 6%.

FIGURE 15: SEASONAL INTRA-DAY WIND OUTPUT PROFILES BY DECILE



The aggregate simulated wind output in each day follows one of the season-specific decile profiles. However, the profiles are not chosen independently each day. Empirical evidence shows that wind output levels on one day are correlated with output levels on the following day. This makes intuitive sense as these output levels are a function of weather patterns. While weather clearly varies from day to day, there is some degree of linkage in weather patterns across days.

RME™ captures this linkage by using a state transition matrix in which the state (or decile) of today's wind profile is linked to potential future states on the next day. This approach allows the model to capture not only the variability in capacity factors from day to day, but also the variability in expected output levels throughout the day. If today's wind output level is high, it is more likely than not that tomorrow's level will also be high, but there is some likelihood that tomorrow's level will be low. When the model simulates output levels on each successive day, it simulates the day's state based on the prior day's state and the likelihood of transitioning to a different state. ERCOT provides substantial hourly-level data for aggregate wind output levels, allowing for a highly accurate representation of actual wind output variability that incorporates weather and outage uncertainty.

TABLE 3: WIND STATE DAILY TRANSITION MATRIX

		To State									
		1	2	3	4	5	6	7	8	9	10
From State	1	28.3%	22.3%	9.2%	13.6%	6.0%	7.6%	4.9%	3.8%	2.2%	2.2%
	2	23.6%	11.5%	14.3%	9.9%	8.2%	6.6%	7.7%	6.0%	6.6%	5.5%
	3	13.7%	9.3%	16.9%	8.7%	13.1%	12.6%	8.7%	3.8%	7.7%	5.5%
	4	7.1%	16.5%	11.5%	9.9%	8.2%	11.0%	9.3%	12.1%	8.8%	5.5%
	5	9.9%	11.0%	9.9%	11.6%	12.2%	11.0%	8.8%	14.4%	6.1%	5.0%
	6	7.1%	6.0%	8.7%	8.2%	14.2%	11.5%	10.9%	12.0%	10.9%	10.4%
	7	4.4%	7.1%	11.0%	13.2%	9.3%	11.5%	14.8%	11.0%	9.9%	7.7%
	8	5.5%	4.9%	8.2%	9.8%	7.7%	13.1%	10.9%	12.0%	20.2%	7.7%
	9	0.5%	7.7%	6.0%	9.3%	13.2%	8.2%	14.3%	11.0%	12.6%	17.0%
	10	0.5%	3.3%	3.8%	5.4%	7.6%	7.1%	9.2%	14.1%	14.7%	34.2%

While ERCOT does publish historical hourly aggregate wind output, it does not break out production between coastal and non-coastal resources, which may have significantly different production profiles. For simplicity, RME™ models all wind resources in aggregate, consistent with historical production patterns and transitions and does not separately identify coastal vs. non-coastal resources. Therefore, it is an implicit assumption in the simulation that the proportion of coastal vs. non-coastal resources will remain substantially similar to the proportion observed during the 2014-16 period.

RME™ models central station solar output in the same way it models wind output. Solar capacity is aggregated and the total ERCOT central station solar output is simulated using day-to-day state transitions and intra-day output profiles. Solar output profiles were calculated using an historical back-cast of hourly output published by ERCOT and scaled to produce an annual capacity factor of 26%.

FIGURE 16: SEASONAL INTRA-DAY SOLAR OUTPUT PROFILES BY DECILE

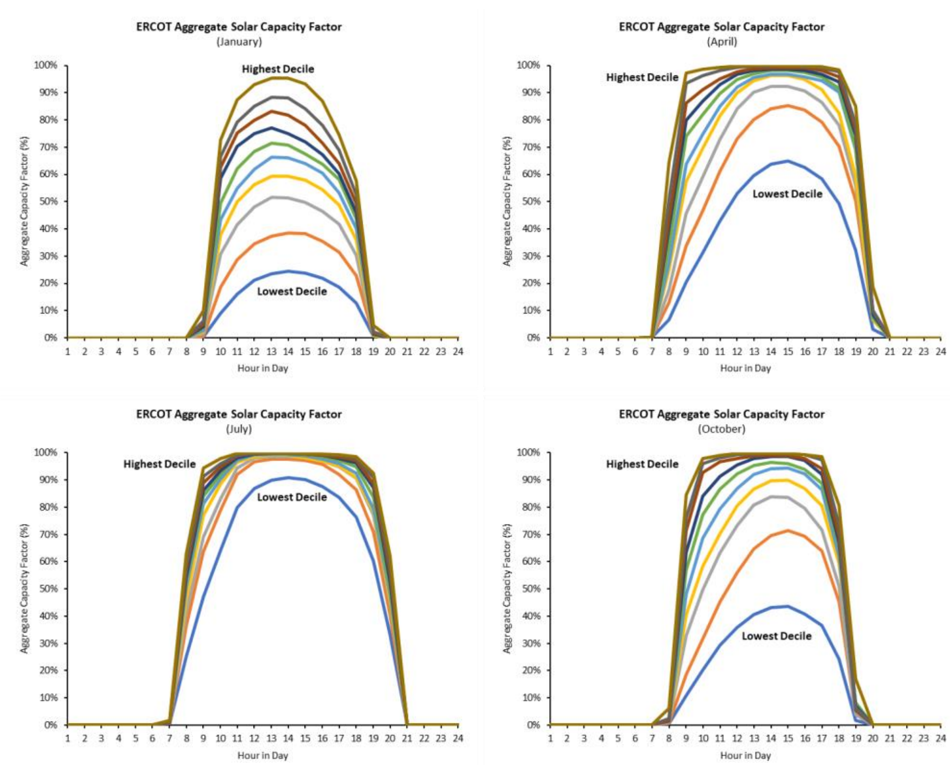


TABLE 4: SOLAR STATE DAILY TRANSITION MATRIX

		To State									
		1	2	3	4	5	6	7	8	9	10
From State	1	37.0%	21.9%	11.8%	9.1%	7.1%	5.5%	3.2%	2.0%	1.7%	0.9%
	2	23.4%	19.3%	13.0%	10.8%	9.2%	7.8%	6.5%	4.5%	3.0%	2.5%
	3	12.5%	18.7%	16.4%	13.5%	11.9%	9.6%	6.3%	4.6%	3.3%	3.0%
	4	10.7%	12.6%	15.0%	13.9%	10.8%	11.3%	8.5%	8.5%	5.3%	3.5%
	5	6.1%	9.3%	11.5%	13.5%	14.5%	11.5%	12.6%	10.2%	5.7%	5.2%
	6	4.0%	6.5%	10.2%	11.4%	12.8%	13.1%	14.1%	12.5%	9.4%	5.9%
	7	1.9%	6.1%	9.5%	10.4%	12.4%	14.7%	16.0%	11.1%	9.4%	8.6%
	8	2.6%	3.5%	6.1%	7.1%	9.9%	11.8%	12.7%	18.7%	16.3%	11.4%
	9	1.2%	1.4%	4.6%	7.6%	5.6%	9.4%	12.5%	17.7%	23.3%	16.7%
	10	0.9%	0.9%	2.0%	2.7%	5.0%	5.5%	7.6%	10.2%	22.7%	42.4%

The wind and solar output levels simulated in the model are intended to be accurate reflections of the real-world variability of renewable resources. This variability, in practice, makes the load-carrying capacity for renewable resources generally less than 100% of their nameplate capacity. In fact, ERCOT currently assigns an Effective Load Carrying Capacity ("ELCC") of 59%, 14%, and 75% to coastal wind, non-coastal wind, and solar resources, respectively, when calculating the capacity "credit" attributed to these resources. That capacity credit is used, in turn, to determine the total capacity in ERCOT for purposes of the reserve margin calculation reported in the CDR and other ERCOT reliability reports.

It is important to note, however, that while changing the ELCC value attributable to renewable resources may change the calculated reserve margin, it does not impact the actual physical reliability of the system. The ELCC follows from a probabilistic estimate of the renewable output during high load hours and not the other way around. It is possible that an incorrect value for ELCC may introduce a false equivalence between thermal and renewable generation based on their respective ability to avoid reliability events on the system.

Simulation of Thermal Unit Outages

Outages at non-intermittent (i.e., primarily thermal) capacity resources[21] were modeled stochastically both in terms of 1) the potential for a resource to experience an outage, and 2) the duration of an outage were one to occur. In order to be as consistent as possible with the 2015 Astrapé study, we have used a pool-wide forced outage rate of 6.8% and resource-specific mean-times-to-repair consistent with that study.

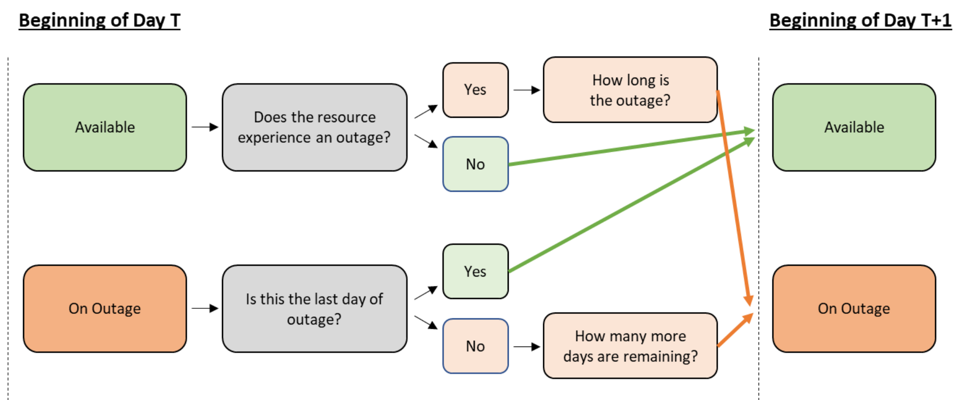
[21] We model hydro capacity in ERCOT (441 MW) as a single resource with a forced outage rate of 7.6%. The total private network capacity (3,341 MW total) is divided into 17 individual proxy units, each with a forced outage rate of 7.6%. Switchable units (2,672 MW total, net of unavailable capacity) are each modeled individually with a forced outage rate of 7.6%. The capacity contribution from non-synchronous ties (389 MW) is modeled as an individual resource with a forced outage rate of 7.6%.

TABLE 5: POOL-WIDE AND RESOURCE-SPECIFIC FORCED OUTAGE RATES AND MTTR

Resource Type	EFOR (%)	Mean Time-to-Repair (Hours)	Daily Probability of Outage (%)[22]
Nuclear	1.6%	68	0.57%
Coal	5.8%	37	3.99%
Gas and Other (aggregated)	7.6%	37	5.34%
Pool Wide	**6.8%**	**N/A**	**N/A**

The first step in the chronological simulation of unit outages is to determine, for each resource and on each day, whether the resource experiences an outage. That probability is a function of both the resource's class-specific forced outage rate and the mean duration of an outage if one were to occur. Next, if an outage occurs, RME™ determines the length of the outage by selecting a duration from a geometric distribution with a mean value equal to the generation class-specific mean time-to-repair.

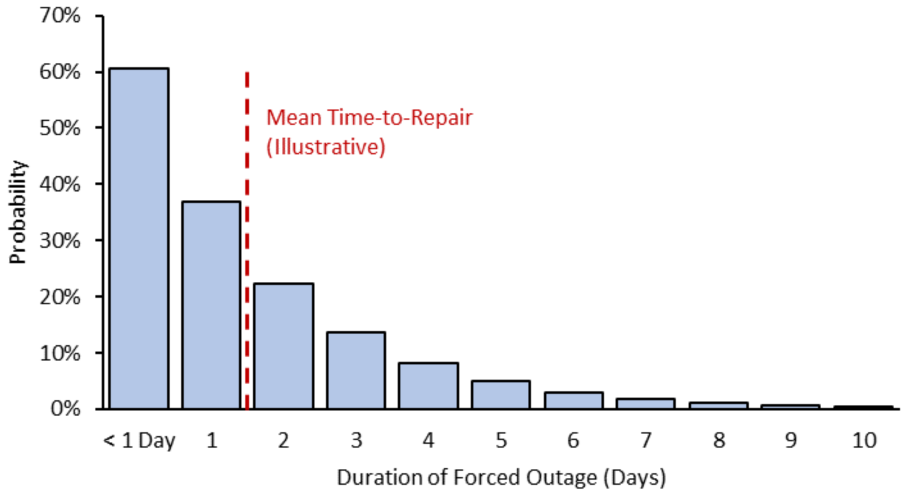
FIGURE 17: ILLUSTRATION OF CHRONOLOGICAL SIMULATION OF UNIT OUTAGES



The geometric distribution of outage durations leads to a profile where most outages are relatively short in duration, even while longer durations are still possible. This is generally consistent with the real-world experience that most outages are short in duration, but some rare outages may exceed the median or average outage length by an order of magnitude or more.

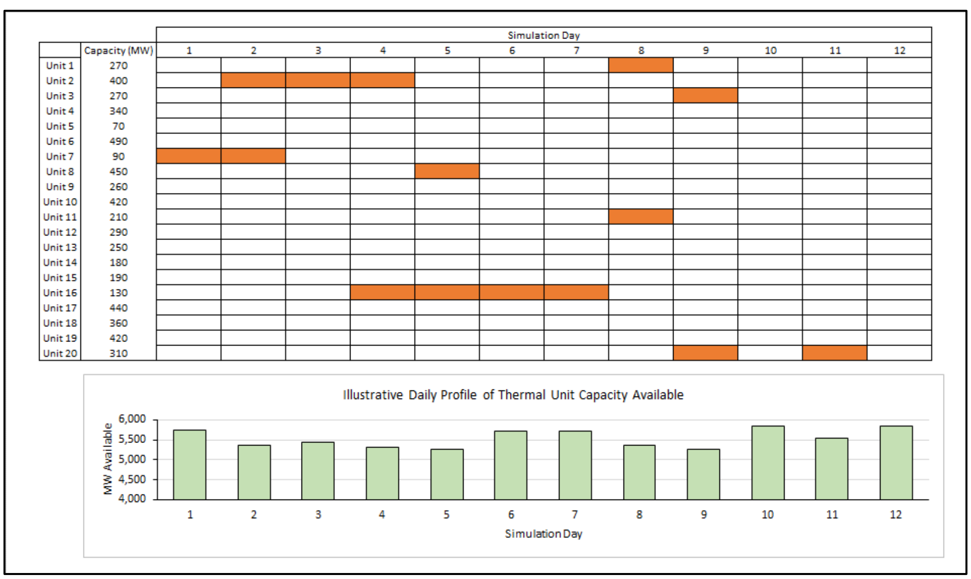
[22] The probability of an outage occurring on any given day when the unit is not currently on outage is a function of the overall forced outage rate and the duration of an outage if one were to occur (i.e., [Probability = EFOR / (Mean Duration * (1 - EFOR))]).

FIGURE 18: ILLUSTRATION OF FORCED OUTAGE DURATIONS FOR COAL UNITS



The result of these simulation steps is an hourly profile of cumulative capacity that is either online and available to meet system capacity needs, or offline and unavailable for that purpose. It is assumed that planned and maintenance outages will not occur during periods most likely to experience reliability events and are therefore not modeled explicitly. Further, RME™ assumes that during periods of scarcity, all operators will commit their units in a timely fashion. In other words, resources that are not forced out will be available to serve load.

FIGURE 19: ILLUSTRATION OF COMBINED RESOURCE OUTAGES AND POOL CAPACITY AVAILABLE

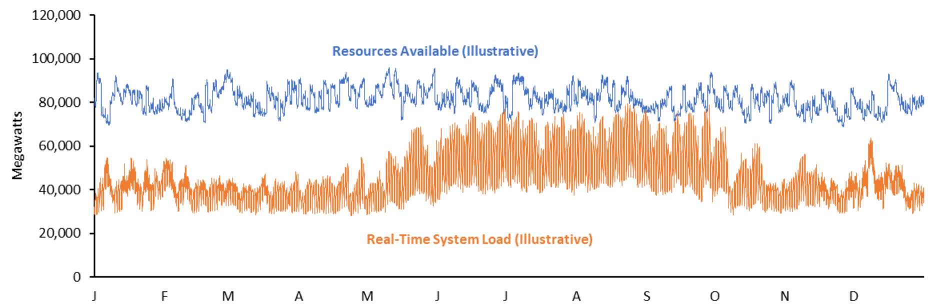


The chronological simulation of resource outages extends through 365 days for each simulated year for each of the approximately 400 non-intermittent resources in ERCOT. Outage simulations are then repeated across thousands of simulated years so that each simulated year represents a unique pattern of non-renewable resource availability.

Simulating Reliability Events

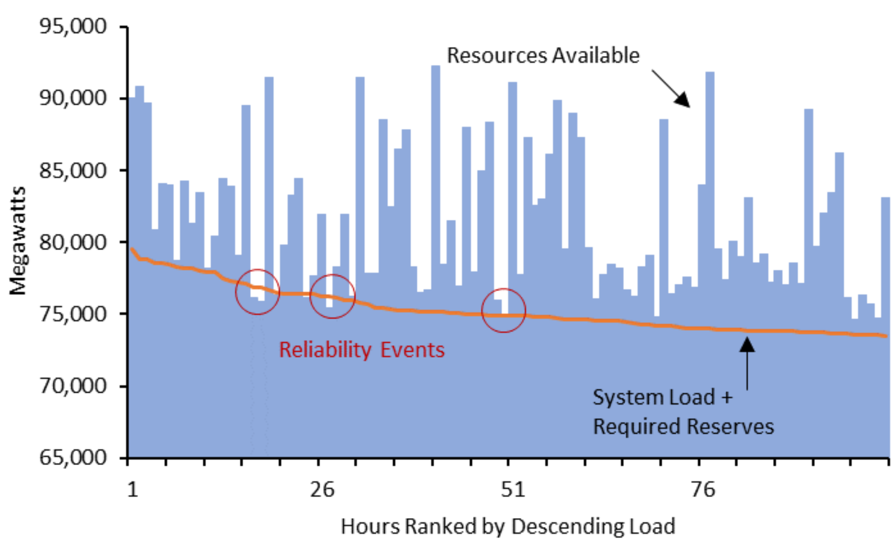
RME™ identifies reliability events, or instances where firm load shed is required, as those situations where available thermal capacity plus intermittent renewable output is less than real-time load plus minimum reserves (i.e., 1,150 MW). This can be illustrated in two ways. The first is chronological and shows the variability in resource availability and seasonal load:

FIGURE 20: CHRONOLOGICAL ILLUSTRATION OF LOAD AND AVAILABLE RESOURCES



The second illustration shows hours sorted from highest to lowest load, including minimum reserves, and overlays total resources available in each hour. This illustration easily reveals those hours in which operators would have had to curtail firm load in order to preserve system stability. What the illustration also identifies is that reliability events may occur during hours when load is well below the annual peak demand.

FIGURE 21: ILLUSTRATION OF SYSTEM LOAD + MINIMUM RESERVES VS. AVAILABLE RESOURCES



After identifying hours that require firm load shed, RME™ tracks the duration of the events in order to calculate loss-of-load-hours (LOLH) and unserved energy ("EUE"), that is, the total quantity of firm load shed in Megawatt-hours, in addition to the number of load-shed events each year (LOLE). These metrics are then averaged over thousands of simulated years to calculate mean values for LOLE, LOLH, and EUE. EUE is expressed as "Normalized EUE," that is the total MWh of firm load shed over the year as a percentage of total annual electric demand.

Reserve Margin Accounting

In keeping with current ERCOT convention, we calculate reserve margins assuming that renewable resources contribute capacity of less than 100% of their nameplate capacity:

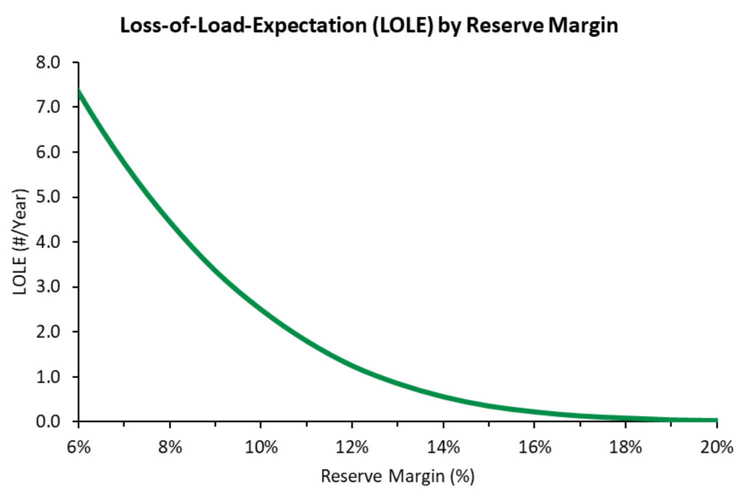
TABLE 6: ELCC FOR RENEWABLE RESOURCES

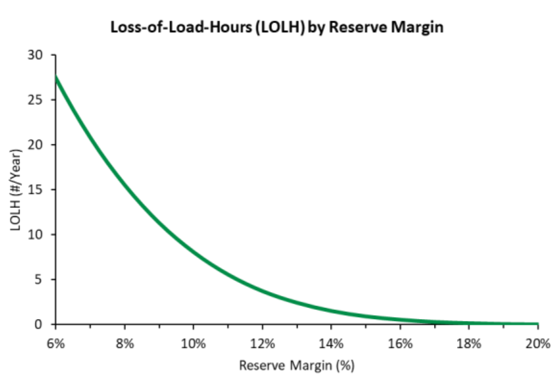
Resource Type	Effective Load Carrying Capacity (ELCC) (%)
Wind (Coastal)	59%
Wind (Non-Coastal)	14%
Solar	75%

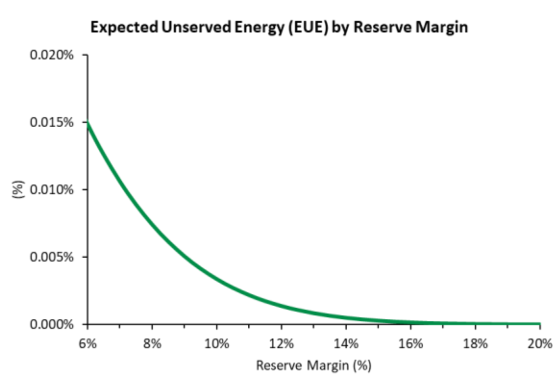
Reliability Statistics

Using the best available inputs and current projections, RME™ model produces a specific relationship between reserve margin and reliability for ERCOT:

FIGURE 22: RELIABILITY METRICS BY RESERVE MARGIN

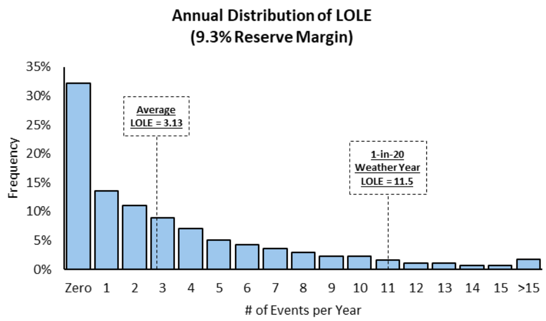


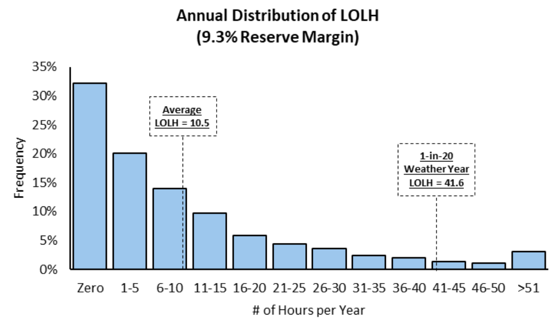




Mean or average reliability metrics only tell part of the story. In reality, fluctuations in system conditions from year to year may lead to widely varying reliability outcomes, even when entering the year at a specific projected reserve margin. Annual outcomes of reliability metrics tend to be strongly skewed to the right. Many years may exhibit few, if any reliability events. Others may exhibit many hours or days with firm load shed.

FIGURE 23: ANNUAL DISTRIBUTIONS OF LOLE AND LOLH AT 9.3% RESERVE MARGIN





Benchmarking to Astrapé (2015) Results

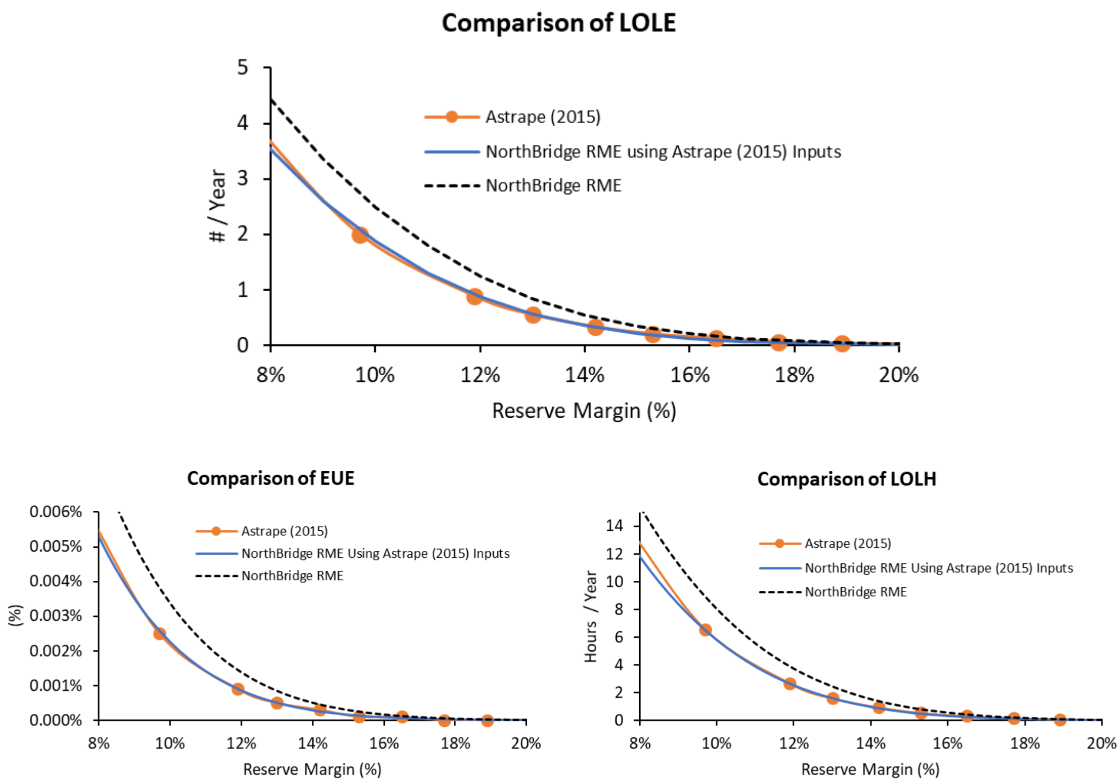
The reliability metrics produced by RME™ are intended to reflect the reality of the current ERCOT system. Because the system has changed since 2015, several inputs are substantively different than those used in the 2015 Astrapé Study. The following table identifies the most significant differences:

TABLE 7: DIFFERENCES IN ASSUMPTIONS (ASTRAPÉ VS. NORTHBRIDGE)

	Astrapé (2015)	NorthBridge RME™ (2017)	Difference
Wind Nameplate (MW)	18,505	21,516	3,011
Coastal Wind ELCC (%)	56%	59%	+3%
Non-Coastal Wind ELCC (%)	12%	14%	+2%
Wind Capacity (MW)	3,272	4,191	+919
Solar Nameplate MW	321	1,493	+1,172
Solar ELCC	100%	75%	-25%
Solar Capacity MW	321	1,120	+799
Minimum Reserves (MW)	900	1,150	+250

While it is important to use the best available and more current inputs for the current analysis, it is also important to check for consistency with prior work. When RME™ is run using inputs consistent with Astrapé's 2015 report, we arrive at similar reliability metrics. The differences in our results are largely due to updated inputs such as the increase in intermittent renewables since the Astrapé Report and the higher assumed minimum reserves.

Figure 24: Comparison of Reliability Metrics (Astrapé vs. NorthBridge)



Estimating Peaker Net Margin Impacts Under Different Reserve Margins

System resource adequacy is a function of resource availability and load. However, reliability metrics provide no direct insight into the economic viability of resources at different reserve margins. To develop this picture, we need a model of energy price formation to link load and resource conditions with both scarcity and non-scarcity prices. Ultimately, these factors contribute to the total energy margin a new combustion turbine or combined cycle unit would expect to earn.

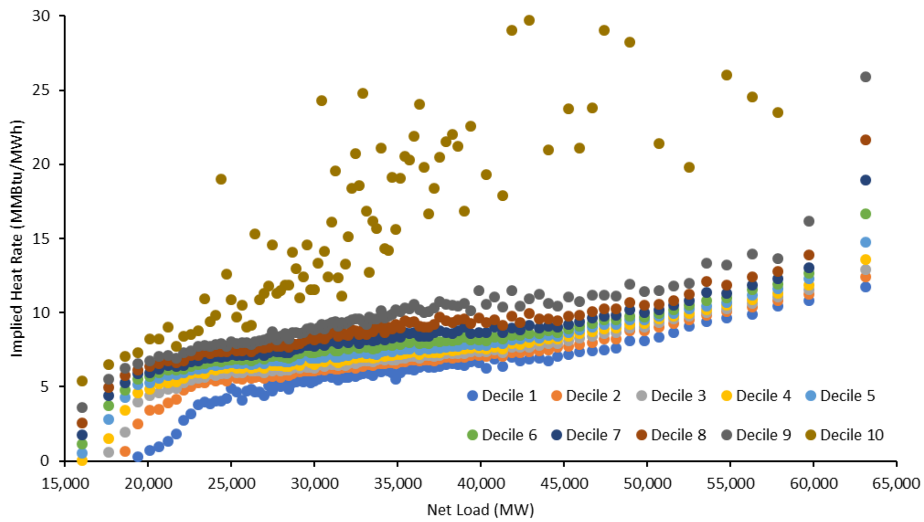
Market Implied Energy Supply Curves

Load and renewable output levels in ERCOT are clearly linked to energy price formation. It is both intuitive and demonstrable that market prices will tend to be higher during periods of higher net load (i.e., real-time system load less output from intermittent resources) because more expensive marginal resources are needed to meet system obligations. We use historical net load and market price data in ERCOT to develop an "Implied Energy Supply Curve". This implied supply curve is a direct and transparent economic representation of the underlying supply curve for energy. It accounts for resource commitment behavior and real world operational constraints in ways that fundamental dispatch models, which attempt to replicate system operations at the resource level, cannot.

The curve was developed using net load, Hub Average market prices, and Houston Ship Channel Gas prices. The curves represent actual market average heat rates (the non-ORDC component only) corresponding to different net load levels. Hourly net load in ERCOT was divided into 100 clusters, based on net load percentile. In each of these clusters, hours were again clustered by grouping them into implied heat rate deciles. Implied heat rates were then averaged within each grouping. The resulting matrix provides for ten possible market price (i.e., implied heat rate) outcomes as a function of system net load. The net load groupings and decile averages allow RME™ to reflect the shape of the actual market supply curve as well as potential variation in market price outcomes grounded in market evidence.[23]

The resulting curves illustrate the general trend that higher net load conditions tend to correspond to higher implied heat rate outcomes, but that the ultimate implied heat rate may vary considerably and may occasionally reach high levels even under moderate load conditions:

Figure 25: Market Implied Energy Supply Curves



These implied energy supply curves are used to simulate energy prices based on system conditions. For each simulated hour, RME™ calculates the net system load (i.e., total system load less renewable output). This value corresponds to one of the 100 net-load segments. Next, the simulation model picks one of the ten implied heat rate deciles in that load segment and uses that value as the market implied heat rate in that hour. Finally, the implied heat rate is multiplied by a forecasted natural gas price to calculate a simulated real-time market clearing price for energy.

[23] The implied heat rate matrix used in RME™ in this analysis has been modified from the historical data. Capacity projections for 2018 indicate that roughly 4,000 MW of uneconomic coal capacity will be deactivated. Since the energy offers associated with these MW are implicitly included in the historical data, we must make an adjustment. In those hours when the market price was in excess of $25/MWh (roughly the marginal cost of an older coal unit), we assumed that the price would have been reached at a net load level that is 4,000 MW lower than actuals.

TABLE 8: HOUSTON SHIP CHANNEL NATURAL GAS PRICE ASSUMPTIONS

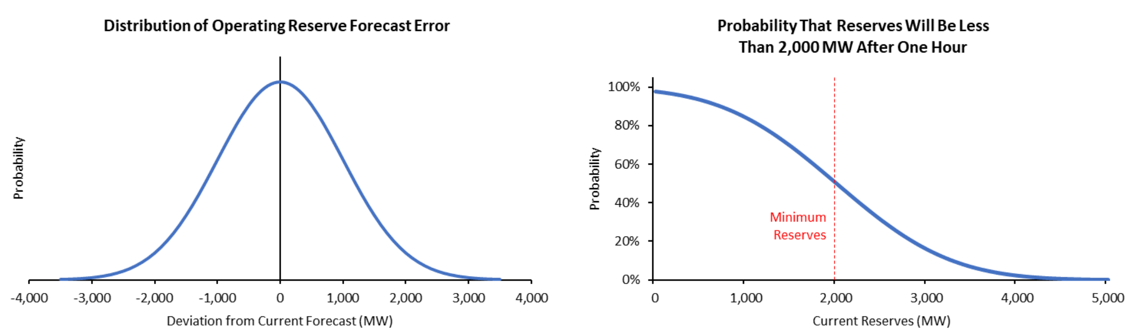
Month	$/MMBtu[24]
Jan	$2.96
Feb	$2.93
Mar	$2.89
Apr	$2.65
May	$2.64
Jun	$2.67
Jul	$2.69
Aug	$2.70
Sep	$2.70
Oct	$2.79
Nov	$2.76
Dec	$2.88
Average	**$2.77**

ORDC Scarcity Pricing Mechanism

The ORDC is designed to compensate generators for the value they add to the system by allowing the operator to avoid firm load shed events. At a high level, the mechanism pays online generators (i.e., those producing energy or contributing reserves) for the probability weighted value of the load whose curtailment they help avoid. Although the actual calculation in practice is somewhat more complex, the mechanism can be illustrated with a simple example. The price adder produced by the ORDC is the product of the value-of-lost-load (VOLL) and the probability that firm load shed may be necessary within one hour (LOLP). The value for VOLL is set administratively to $9,000 / MWh, but the calculation of the LOLP is a function of system-derived parameters.

Before calculating the ORDC adder in real-time, ERCOT calculates the historical forecast error in hour-ahead operating reserves. This calculation is repeated quarterly. To calculate the ORDC adder in each SCED interval, ERCOT identifies the amount of real-time operating reserves and calculates the probability that they might fall below a minimum threshold of 2,000 MW (X) within one hour. We can illustrate this by showing first, the probability distribution of reserve error after one hour, and second, the cumulative probability that those reserves will end the hour below the minimum threshold (as a function of current operating reserves).

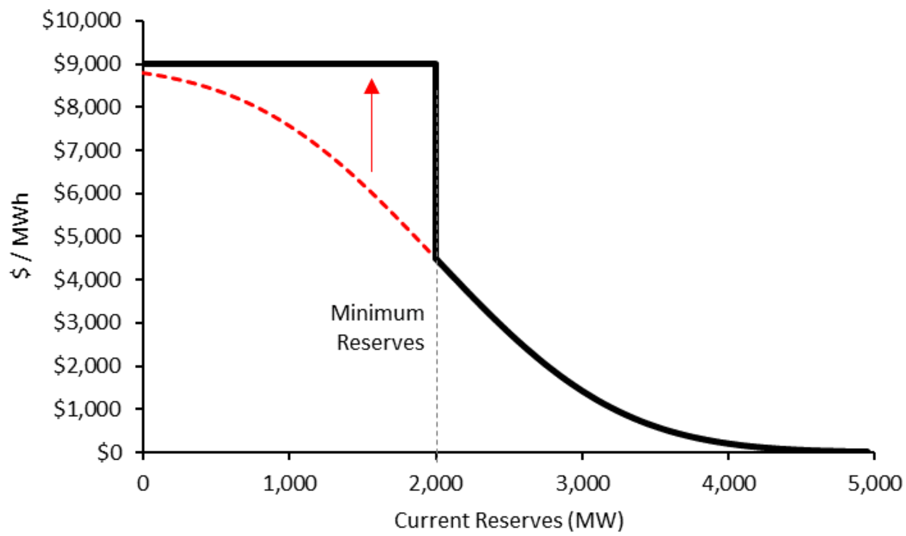
FIGURE 26: RESERVE FORECAST ERROR AND PROBABILITY OF INSUFFICIENT RESERVES



[24] Based on Henry Hub forward settlement prices on December 15, 2017 and historical Henry Hub to Houston Ship Channel basis.

Next, ERCOT calculates the customer benefit of not having their load curtailed. This is simply the VOLL multiplied by the probability that such a curtailment could occur, with one modification. In the event that the current reserves are already below the minimum reserve threshold, the probability of firm load curtailment is deemed to be 100%, which changes the shape of the curve from smooth to discontinuous:

FIGURE 27: ILLUSTRATION OF ORDC PRICE ADDER VS. OPERATING RESERVES



As the above illustration shows, the ORDC price adder is a function of available operating reserves and several parameters that determine the shape of the curve. These parameters are a function of season, time of day (both of which influence the LOLP calculation), minimum reserve level (X), and the VOLL. ERCOT updates certain ORDC parameters (e.g., μ and σ, which represent the mean and the standard deviation of the operating reserve forecast error distribution, respectively) periodically to incorporate changes in the forecast error of system reserves. Two parameters, the VOLL and X, are fixed administratively and are not changed.

RME™ simulates the ORDC adder each hour by calculating total system operating reserves, determining the ORDC parameters that match the appropriate season, time of day, and system lambda, and then determining the corresponding ORDC adder consistent the level of operating reserves and ORDC parameterization in that hour. The calculation also requires an assumption about the split between online and offline reserves.[25] RME™ uses estimates of the historical relationship between offline to total reserves to perform this calculation. Energy market prices are then calculated as the sum of the non-scarcity price and the ORDC price adder. For simplicity, RME™ is calibrated to, and calculates, Hub Average market prices.

Marginal Resource Characteristics and Net Energy Margin

Following the calculation of the market price, RME™ calculates the energy margin (that is, energy revenues less variable operating costs) that might be earned by a hypothetical new gas generator in each hour. The intent of this calculation is to determine the level of energy margin that a newly constructed resource might expect to earn.

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[25] p_{ns} = 0.5*(VOLL-System Lambda) *LOLP(60 minutes); $p_s = p_{ns}$ + 0.5*(VOLL-System Lambda)*LOLP(30 minutes)

Therefore, we must incorporate real-world assumptions about heat rate, variable operating costs, and outage rates. This is in contrast with the ERCOT concept of Peaker-Net-Margin (PNM)[26] which is a simplified administrative calculation and does not include outages or variable costs. It also assumes a heat rate of 10,000 Btu/KWh rather than one specific to a potential new resource.

The characteristics assumed for a new combustion turbine and a new combined cycle unit were taken from a report prepared by The Brattle Group for PJM in their triennial capacity demand curve review[27] and modified to be applicable to ERCOT. This report has been introduced in the current Economically Optimum Reserve Margin initiative currently underway at ERCOT. Prior estimates of the cost and characteristics of new entrant have utilized earlier versions of this same PJM report and modified the costs to adjust for differences in entry date and cost differences between PJM and ERCOT.

TABLE 9: COST AND CHARACTERISTICS OF NEW ENTRY

	Combustion Turbine	Combined Cycle
2018 Real-Levelized Gross CONE (Cost of New Entry) – PJM RTO	$117,100 / MW-Year	$159,700 / MW-Year
Cost Escalation Factor (2018 to 2021)[28]	1.0641	1.0641
2021 Real-Levelized Gross CONE (Cost of New Entry) – PJM RTO	$124,603 / MW-Year	$169,933 / MW-Year
PJM RTO to ERCOT Adjustment[29]	0.9208	0.9100
2021 Real-Levelized Gross CONE (Cost of New Entry) – ERCOT	$113,500 / MW-Year	$154,639 / MW-Year
Heat Rate (Btu / KWh)	10,297	6,791
Variable O&M	$4.27 / MWh	$2.61 / MWh

Net energy margin is calculated in each hour for each reference unit by comparing the total energy price (non-scarcity price + ORDC adder) with the hypothetical dispatch cost of each resource (fuel + variable O&M). The net energy margin is the difference between the total energy price and the dispatch cost if that value is positive. The net energy margin for the year is the sum of the hourly net energy margin. We then reduce the total net energy

[26] Peaker-Net-Margin is a concept defined administratively and is used to determine whether the system wide offer cap should be set at the higher or lower value.

[27] "Cost of New Entry Estimates Combustion Turbine and Combined Cycle Plants in PJM", The Brattle Group, May 15, 2014.

[28] Costs escalated at 2.1% per year.

[29] "Capital Cost Estimates for Utility Scale Electricity Generating Plants", U.S. Energy Information Administration, November 2015 (see Table 4). The adjustment factor is calculated as the ratio of the regional cost adjustment of Region 1 (ERCT) to Region 10 (RFCM). The ratio for the combustion turbine is 0.93 / 1.01 and the ratio for a combined cycle unit is 0.91 / 1.00.

margin by 10% to account for planned and unplanned outages.[30] For simplicity, we do not assume commitment or ramping constraints for the reference resources.

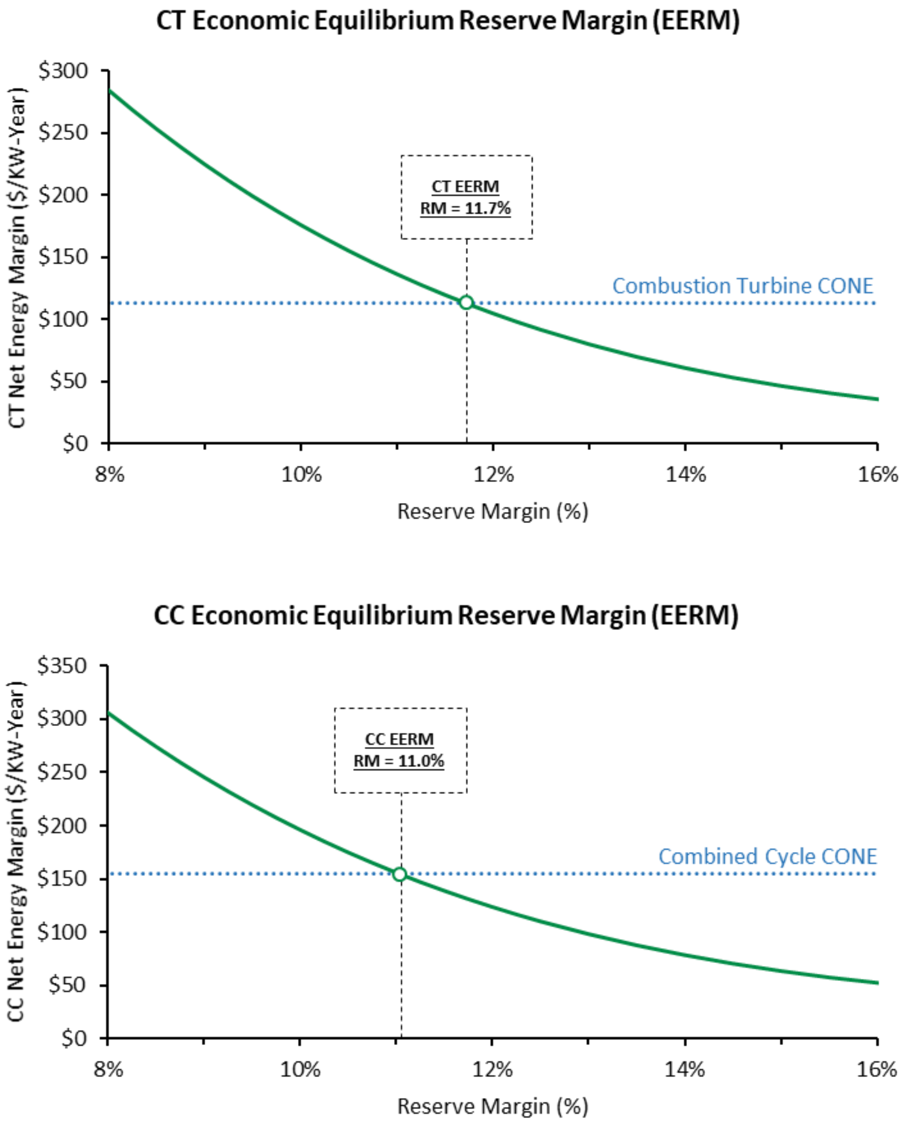
Economic Equilibrium Reserve Margin (EERM)

The EERM is the reserve margin at which a new entrant (e.g., a new combustion turbine or a new combined cycle unit) would expect to earn exactly the net revenue necessary to justify its own investment. By looking at two different resource types (e.g., a CT and a CC), we are able to identify the reserve margins that provide adequate scarcity revenue to support each new resource type. We would expect that market participants would continue to construct new capacity up to the higher of the two reserve margins. After this point, revenue expectations would be inadequate to support continued entry of either type. The EERM, therefore, is the point at which a new entrant would expect to earn exactly enough to balance out the cost of its capital and operating costs, collectively known as its Cost-of-New-Entry ("CONE").

We can determine the EERM by comparing the expected (or mean across thousands of simulated years) net energy revenue that might be earned by a new combustion turbine across different reserve margins. The point at which expected net energy revenue crosses the resource's CONE defines the EERM:

[30] A figure consistent with assumptions in the 2016 ERCOT State of the Market Report (see p. 100)

FIGURE 28: ILLUSTRATION OF EERM



The results above indicate that a new combustion turbine would to expect to earn adequate revenue until a reserve margin of 11.7%, and new entrants would continue adding capacity until that point. A combined cycle unit, on the other hand, would not earn adequate net energy revenue above a reserve margin of 11.0%. The higher of the two values, 11.7%, represents the EERM since it is the highest reserve margin that still supports the entry of new capacity.[31]

The EERM defines the reserve margin at which the expected net energy revenue matches the resource's CONE. However, this does not mean that the resource would expect to receive that net revenue each and every year. The

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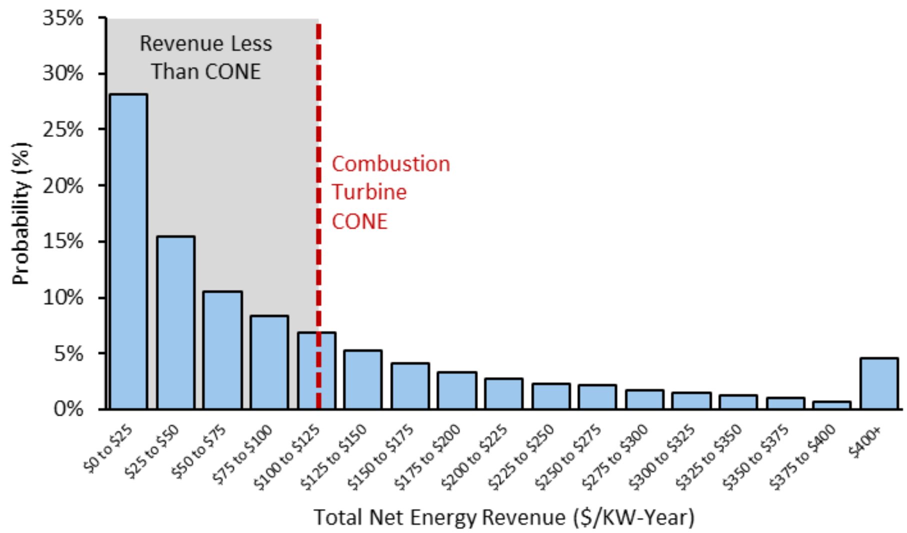
[31] The higher of the two values is the EERM because a new combustion turbine would earn an excess return at the lower reserve margin. New entry would be supported up until the point the higher reserve margin was achieved.

year-to-year variability of that revenue could be substantial, even if the average or expected net revenue matches the required amount.

Figure 29: Distribution of Annual Net Energy Revenue for New Combustion Turbine



This high level of year-to-year variability in net revenues for a marginal new entrant, even at economic equilibrium, is characteristic of an energy-only market design. The CONE values that we utilize in this analysis were originally developed for use in PJM, which unlike ERCOT, uses a capacity market to incentivize new entry which generally leads to less year-to-year variability in new entrant net revenues. If investors demand an additional risk premium for the higher variability in revenues embedded in the energy-only design, we would expect the true CONE value to be somewhat higher than the values we utilized, and the resulting estimate of the EERM to be somewhat lower.

The net energy revenue potentially earned by a new gas combustion turbine is clearly a function of the structure of the scarcity pricing mechanism (i.e., the ORDC). This mechanism explicitly links the level of real-time operating reserves to the value those reserves provide in avoiding potential shedding of firm load. That value, and thus the level of scarcity pricing, is determined by two parameters – the mean and the standard deviation of the hour-ahead operating reserve forecast error – which together are used to calculate the LOLP in that hour, which is then multiplied by VOLL minus the system lambda to set the ORDC adder, provided real-time operating reserves exceed X, or 2000 MW. If they do not, the adder is simply set at the VOLL minus the system lambda.

These parameters – the hour-ahead mean and standard deviation of hour ahead operating reserve forecast error - are calculated by ERCOT by comparing hour-ahead forecasts of operating reserves to actual real-time operating reserves. Under ERCOT's current design, both the mean and the standard deviation of the hour-ahead operating reserve forecast error are equal to fixed values differentiated by time of day and season that are updated on a quarterly basis. Together they are intended to reflect the uncertainty associated with the level of real-time reserves over the coming hour. The practical impact of these parameters is that they directly drive the frequency and level of scarcity pricing in hours where the system is approaching, but has not yet reached, true scarcity.

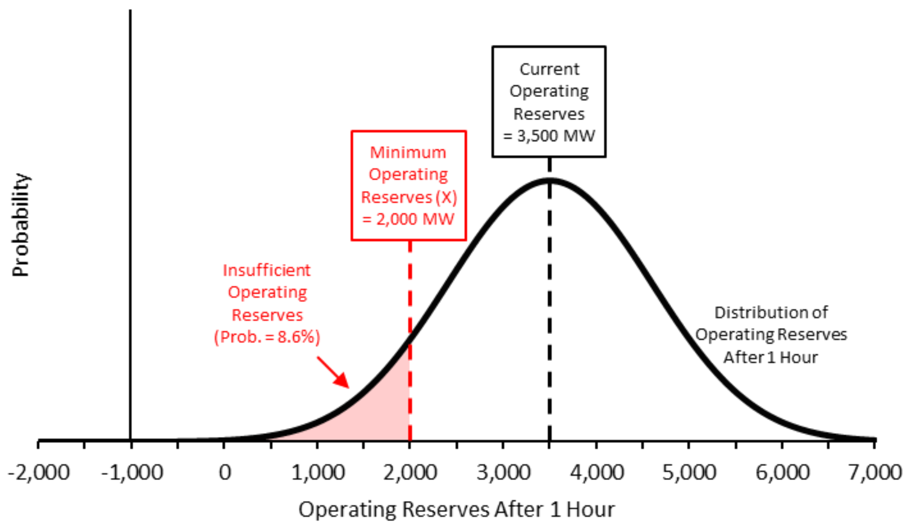
Both the net energy revenues for new gas resources and the resulting EERM could be directly influenced by adjusting either the mean or standard deviation of hour-ahead operating reserves, or by adjusting the fixed administrative components of the ORDC such as the X value or the VOLL. Hogan and Pope (2017) specifically mention the opportunity to make one such adjustment. Specifically, they describe incorporating an LOLP shift factor into the calculation of the loss-of-load-probability, which would directly lead to higher and more frequent ORDC adders during periods when operating reserves approach, but do not fall below the X value of 2,000 MW.

Impact of LOLP Shift Factor

Both market prices and the revenue a new resource would expect to earn are a function of the parameters used in the ORDC price adder calculation. Changing or adjusting the shape of the ORDC curve could result in higher price adders during periods of near-scarcity. While many possible ORDC modifications are possible, in this report we have evaluated the LOLP shift factor proposed by Hogan and Pope.

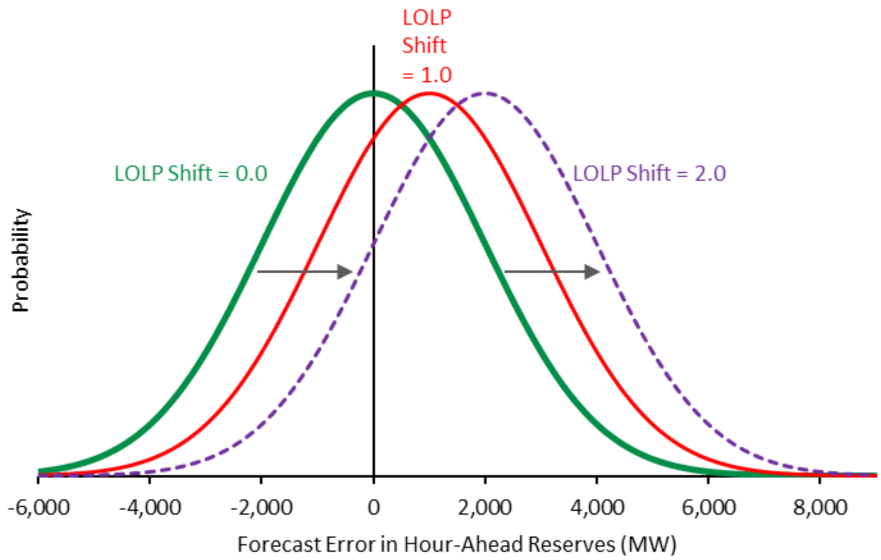
During each SCED interval, ERCOT determines the ORDC price adder by calculating the likelihood that reserves will fall below a minimum level (X) during the next hour. ERCOT does this by first estimating the potential distribution of ending hour-ahead reserves, given current real-time reserves and the distribution of reserve forecast error, and then comparing that distribution to the X value to calculate a probability (the LOLP) that reserves will fall below X in the coming hour. This calculation is illustrated below, producing an LOLP of 8.6% given current operating reserves of 3,500 MW:

FIGURE 30: ILLUSTRATION OF LOLP (SHIFT = 0.0)



This calculation is a function of the mean and standard deviation of hour ahead reserve forecast error, which together describe the normal distribution of potential hour-ahead reserves. Presently, the mean and the standard deviation are based on historical operating reserve forecast data, updated quarterly and differentiated by time of day and season. An LOLP Shift would explicitly shift the mean of the hour-ahead reserve forecast error used to calculate this likelihood:

FIGURE 31: LOLP SHIFT = 1.0 TO 2.0 (ILLUSTRATIVE)



In practical terms, the hour-ahead forecast error represents the degree to which actual operating reserves one hour in the future will be higher or lower than the current forecast. Positive values indicate that the forecast was too high (i.e., actual reserves turned out to be lower), while negative values indicate that the forecast was too low (i.e., actual reserves turned out to be higher). The LOLP Shift directly affects the calculated likelihood that reserves might fall below a minimum threshold during the next hour.[32] In particular, a positive LOLP shift implies that future operating reserves will be less than current operating reserves, which increases the likelihood that reserves will fall below the minimum allowable level. As illustrated below:

[32] It should be noted that the LOLP Shift does not change system operations. It simply changes the magnitude of the ORDC adder.

FIGURE 32: ILLUSTRATION OF LOLP (SHIFT = 1.0)

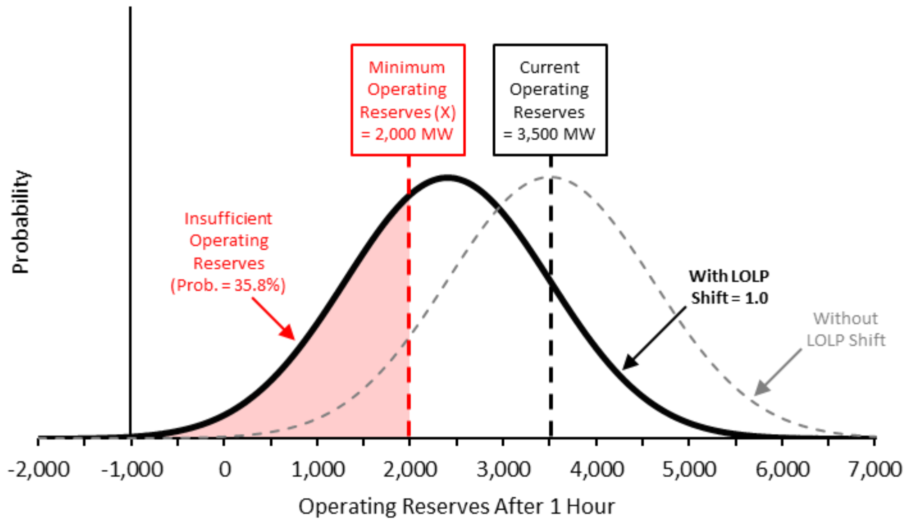
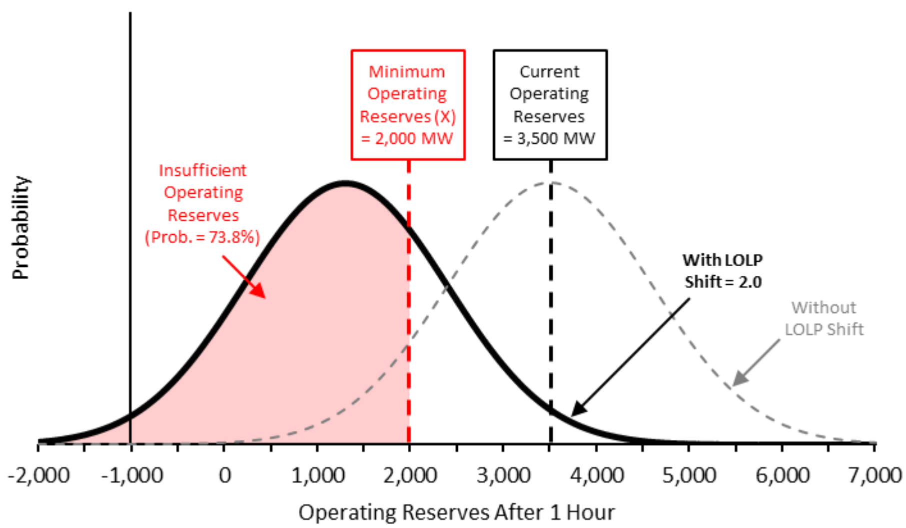
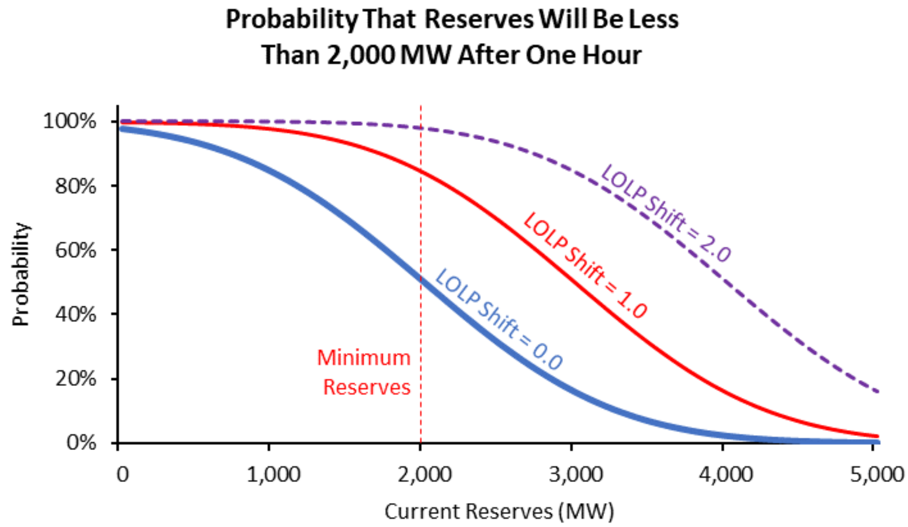


FIGURE 33: ILLUSTRATION OF LOLP (SHIFT = 2.0)



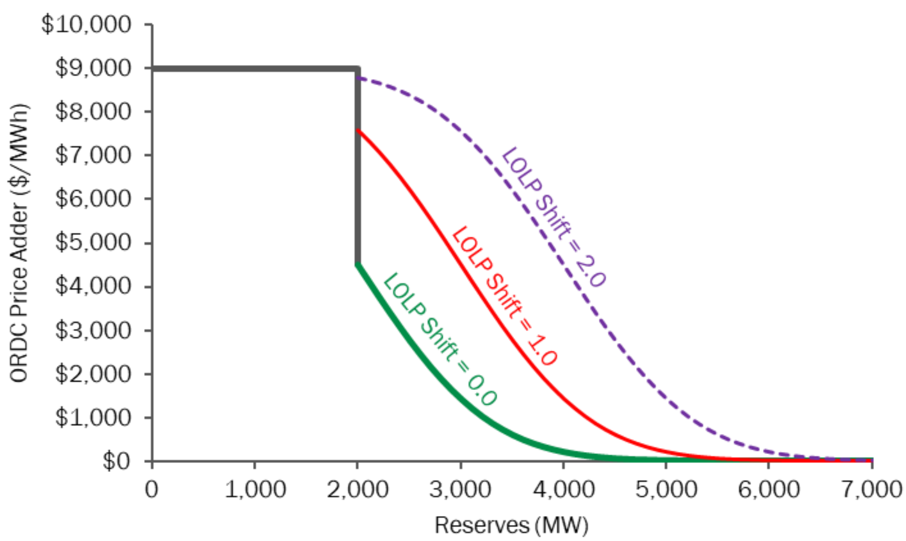
Across the range of real-time operating reserve levels, the LOLP is thus shifted upward relative to the present design:

FIGURE 34: ILLUSTRATIVE INCREASE IN LOLP WITH SHIFT = 1.0 AND 2.0



Within the ORDC construct, resources that are providing either energy or operating reserves to the system are compensated for the value of the capacity they contribute. When current reserves are above X (2,000 MW), that value is equal to the value-of-lost-load (VOLL) that they help in avoiding multiplied by the probability that such a reliability event might occur in the next hour. Therefore, any adjustment to the calculated likelihood of firm load shed over the next hour will affect the scarcity revenue paid to generators when real-time operating reserves approach, but do not fall below X. We can illustrate the resulting change to the ORDC curve during reserve levels approaching X:

FIGURE 35: ILLUSTRATIVE CHANGE IN ORDC WITH SHIFT = 1.0 AND 2.0



Using RME™, we have evaluated the impact of this proposed ORDC modification by studying a range of LOLP Shift values in the calculation of ORDC price adders. The LOLP Shift value affects market prices, resource revenues, and ultimately drives the level of the EERM.

Results and Conclusions

Current Reliability Situation

Due to changes in resource mix and the capacity credit attributed to intermittent resources in the intervening years since it was originally formulated, ERCOT's target reserve margin of 13.75% no longer achieves the NERC 1-in-10 LOLE standard upon which it was originally based. Rather, given the projected resource mix for Summer 2018, ERCOT would need a reserve margin of 17.6%[33] to achieve a level of reliability consistent with the 1-in-10 LOLE standard. This is the reserve margin that would be expected to result in roughly one firm load curtailment event every ten years.

The current ERCOT target reserve margin of 13.75% was adopted in late 2010 when intermittent resources made up about 1.1% of the capacity portfolio.[34] The composition of ERCOT's generation infrastructure has changed substantially since then and now includes a much larger percentage of intermittent resources. Further, when the figure of 13.75% was calculated, it attributed a capacity credit to wind (i.e., the ELCC) that was much smaller than the amount attributed to those resources today. An increase in the ELCC, all else equal, gives the appearance of adding physical capacity to the system and increases the calculated reserve margin. However, if no other physical changes are made to the system, physical reliability does not change. This means that the reliability metrics that were once consistent with the 13.75% reserve margin would now be consistent with a higher reserve margin.

In fact, when Astrapé was commissioned by ERCOT to study reliability metrics, their January 2015 report identified exactly this outcome. Astrapé found that the increased renewable capacity in the system, combined with a higher ELCC attributed to wind resources resulted in a reduction in reliability metrics at the same reserve margins vs. prior results. In conjunction, they found that the reserve margin needed to achieve a 1-in-10 LOLE had risen to 16.75%.

Since the Astrapé report, the share of intermittent resources in the ERCOT capacity mix has continued to rise. By 2018, based on the most recently-available information, we project that intermittent resources will account for 6.9% of the capacity resources in the reserve margin calculation,[35] roughly 6 times what they did in 2010, and roughly 50% more than they did at the time of the Astrapé report[36]:

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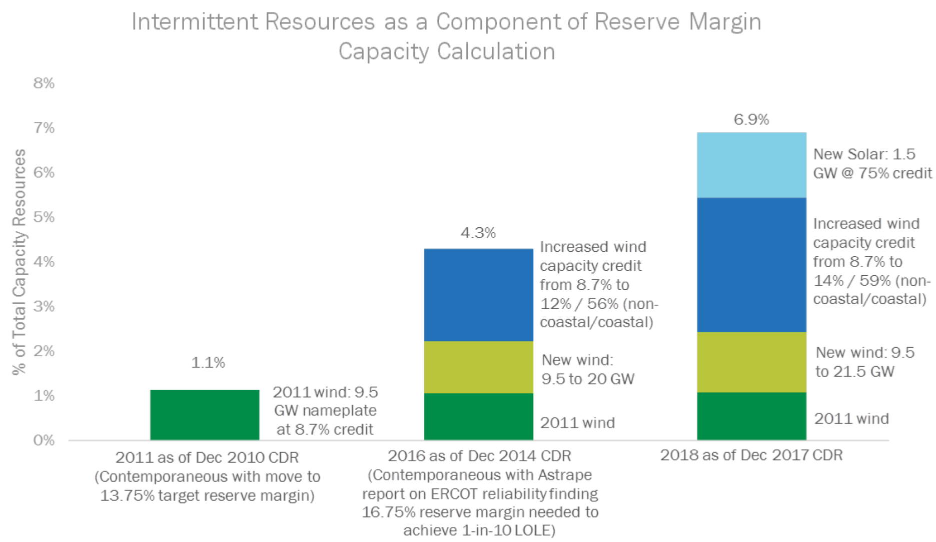
[33] Consistent with Astrapé report, figure ES-1. This figure shows that the RM that corresponds to 0.1 LOLE as of Jan 2015 was 16.75%. Because the proportion of intermittent resources in the capacity mix has increased since then, the reserve margin needed for 0.1 LOLE exceeds this value.

[34] Based on ERCOT Capacity Demand Reserves ("CDR Report") for December 2010. The Dec 2010 CDR credited wind in the aggregate with 829 MW of Effective Load Carrying Capacity ("ELCC", 8.7% multiplied by 9,529 MW of nameplate wind). This was approximately 1.1% of the total ERCOT supply portfolio of 73,656 MW at the time.

[35] Based on ERCOT December 2017 CDR Report.

[36] In the Dec 2014 CDR Report (contemporaneous with the Astrapé report) ERCOT listed 3,385 MW of existing and new build wind ELCC out of a total reported projected supply portfolio of 78,947 MW for summer 2016, or 4.3% of total supply.

FIGURE 36: SHARE OF ERCOT CAPACITY RESOURCES FROM RENEWABLE RESOURCES



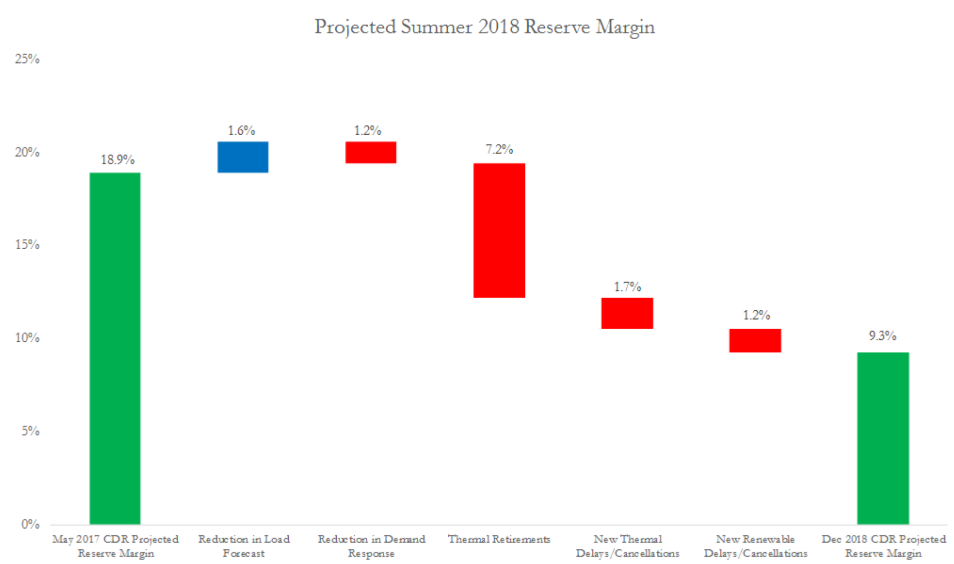
Based on this change, the reserve margin needed to achieve 1-in-10 LOLE has increased to beyond the 16.75% level found by Astrapé in 2015 to 17.6%. Further, the existing target reserve margin of 13.75% no longer achieves 0.1 LOLE, but rather currently likely achieves an LOLE of 0.63 events per year (or 1 event every 2 years, rather than 1 in 10).[37]

In addition, around the time that the ORDC was originally developed in early 2014, analysis of the ORDC design indicated that it was expected, based on the Brattle Group's analysis, to lead to an economic equilibrium reserve margin of 11.5%, which was consistent with a reliability level of 1 event per 3 years. Our analysis indicates that the reserve margin needed to achieve an effective reliability standard of 1-in-3 has risen from 11.5% in early 2014 to 15.1% today. However, ERCOT does not currently have a reserve margin of 17.6%, 15.1%, or 13.75%. Recent changes in the ERCOT supply mix have reduced the projected reserve margin for Summer 2018 from 18.9%, as reported in the December 2017 CDR, to 9.3%.

Since May 2017, there have been significant retirement announcements of existing thermal resources, along with delays and cancellations for new build thermal and renewable resources original projected to come online in time for Summer 2018. Collectively, these changes mean that approximately 7.2 GW of resources identified in the May 2017 CDR are no longer expected to be available for Summer 2018. This is partially counterbalanced by a decrease of 0.3 GW in the peak load forecast (including the effects of demand response) for summer 2018:

[37] This is consistent with Figure ES-2 in the Astrapé report (0.5 LOLE falls between 13 and 14% reserve margin)

FIGURE 37: CHANGES TO ERCOT CAPACITY MIX BETWEEN THE MAY 2017 CDR AND PRESENT



In addition, the prospects for new builds are limited within the coming years. Only 2.7 GW of additional thermal resources are projected to come online by 2019, and further delays or cancellations are possible.[38] For example, just in the past year, three large new gas facilities (Halyard Henderson, Halyard Wharton, and the PH Robinson Peakers) accounting for roughly 1,200 MW of capacity have delayed their online date from 2018 to 2019. This level of planning reserves puts ERCOT in a much tighter resource adequacy position in the near term than it has been in recent years. A reserve margin of 9.3% implies:

TABLE 10: RELIABILITY METRICS FOR SUMMER 2018 (PROJECTED)

Reserve Margin	ERCOT Target 13.75%	1-in-3 LOLE 15.1%	1-in-10 LOLE 17.6%	2018 Projected 9.3%
LOLE (#/Year)	0.63	0.33	0.10	3.13
LOLH (#/Year)	1.78	0.91	0.25	10.48
Unserved Energy (%)	0.0006%	0.0003%	0.0001%	0.0046%
Hours of Load Loss During 1-in-20 Weather Year	10.5	5.8	1.4	41.6

At the current projected reserve margin for Summer 2018, ERCOT could expect 10 hours of load curtailment spread over 3.1 events. In a 1-in-20 weather year, the expected number of hours with load curtailment would rise to nearly 42. These reliability metrics generally imply load shed frequency more than thirty times that experienced in recent years, when actual reserve margins met or exceeded the level consistent with 1-in-10 LOLE.

Further, any additional retirements or higher-than-expected load growth could drive reserve margins down even lower. For example, any combination of an additional coal unit retirement or mothball, a retirement or mothball of one or two large older gas steam units, or higher-than-expected load growth could easily cause planning reserves to fall by another 1 GW or more. A 1 GW fall in planning reserves translates into a reserve margin 7.8%, which in turn implies:

[38] Based on the December 2017 CDR.

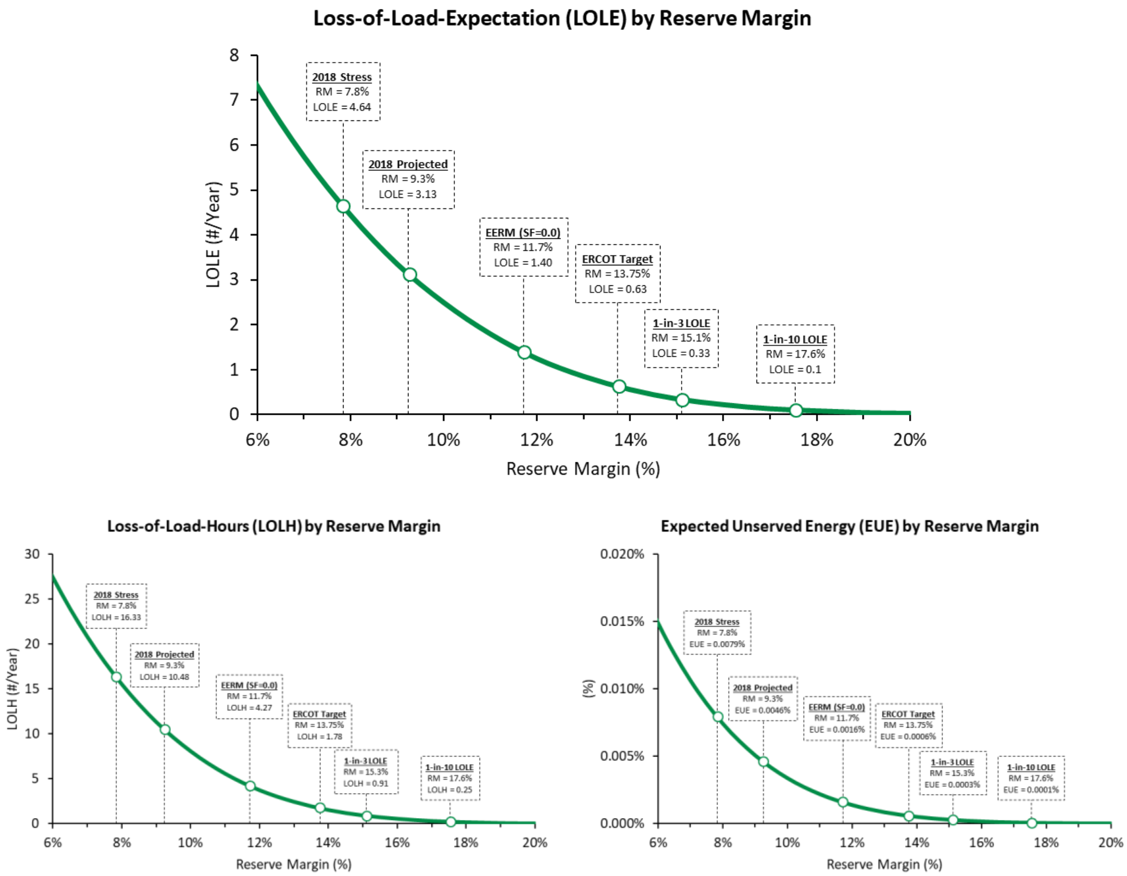
TABLE 11: RELIABILITY METRICS FOR SUMMER 2018 (STRESS)

Reserve Margin	ERCOT Target 13.75%	1-in-3 LOLE 15.1%	1-in-10 LOLE 17.6%	2018 Stress 7.8%
LOLE (#/Year)	0.63	0.33	0.10	4.64
LOLH (#/Year)	1.78	0.91	0.25	16.33
Unserved Energy (%)	0.0006%	0.0003%	0.0001%	0.0079%
Hours of Load Loss During 1-in-20 Weather Year	10.5	5.8	1.4	58.2

These reliability metrics, both for the baseline 9.3% scenario as well as a stress scenario 7.8% reserve margin are well below both the NERC 1-in-10 standard and the more aggressive 1-in-3 standard consistent with the ORDC design at its inception. In addition, these reserve margins produce reliability metrics that are less reliable than alternate more aggressive reliability targets that ERCOT has evaluated in the past and are that are utilized in some other regions. In particular, the 2015 Astrapé Report evaluated an LOLH standard of 2.4 hours per year, currently utilized the Southwest Power Pool, and a 0.001% Normalized Unserved Energy standard utilized by certain international markets as well.[39] Both the base and stress case reserve margins produce reliability metrics that fail to meet these alternative standards by a considerable margin.

[39] Astrapé Report at 4.

FIGURE 38: RELIABILITY METRICS AT VARIOUS RESERVE MARGINS

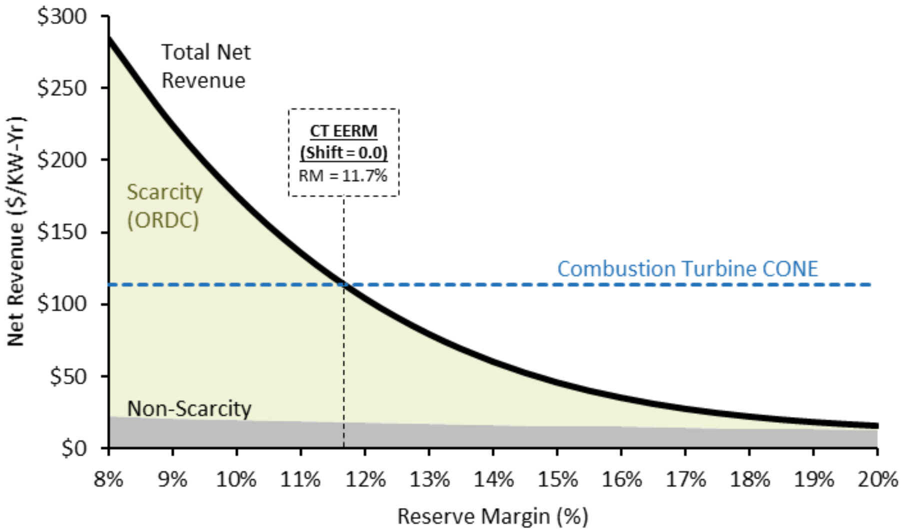


Economic Equilibrium Reserve Margin

Generation investment in ERCOT is dominated by merchant entities seeking to earn a return on their invested capital. As such, we would expect to see continued investment in new capacity until such time that the net energy revenue offered by such an investment no longer provides adequate compensation for the cost of capital and operations. In other words, we would expect the reserve margin to rise (or fall) to an equilibrium reserve margin that provides exactly the necessary amount of compensation for the cheapest form of new capacity.

RME™ indicates that with the current scarcity pricing mechanism and market structure, the new marginal resource with the most favorable economics would be a natural gas combustion turbine. That hypothetical new resource would earn differing levels of revenue at different reserve margins, but would expect to break even exactly at a reserve margin of 11.7%.

FIGURE 39: MAGNITUDE AND COMPOSITION OF NEW CT REVENUES BY RESERVE MARGIN



Given the current system mix, this EERM would expose customers in ERCOT to significant amounts of annual load curtailment even under a normal weather year.

TABLE 12: RELIABILITY METRICS FOR ECONOMIC EQUILIBRIUM (SHIFT = 0.0)

Reserve Margin	ERCOT Target 13.75%	1-in-3 LOLE 15.1%	1-in-10 LOLE 17.6%	EERM (Shift = 0.0) 11.7%
LOLE (#/Year)	0.63	0.33	0.10	1.40
LOLH (#/Year)	1.78	0.91	0.25	4.27
Unserved Energy (%)	0.0006%	0.0003%	0.0001%	0.0016%
Hours of Load Loss During 1-in-20 Weather Year	10.5	5.8	1.4	20.7

Further, the current projected Summer 2018 reserve margin of 9.3% is below the EERM we calculated using the RME™ model, which suggests that markets have "overshot" economic equilibrium. Although the EERM is the reserve margin toward which we would expect the market to move, it is not a lower bound for how low reserve margins could be in any given year. The current projection for Summer 2018 illustrates this situation, and raises the possibility that reserve margins could fall even lower in the near term. This suggests that a targeted, incremental change to the ORDC to increase the market energy revenues all market participants expect to realize from the ORDC is a prudent measure that would improve reliability in the near term by forestalling further retirements, ensuring that scheduled new builds actually come online, and driving further new builds as necessary.

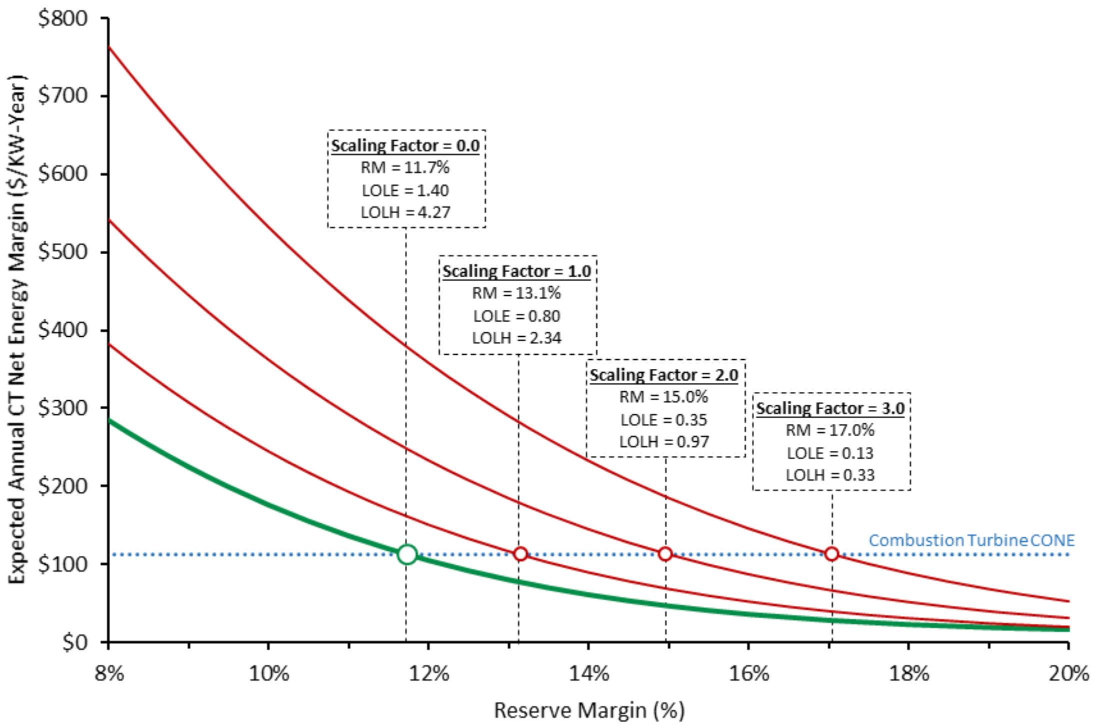
Economics of LOLP Shift

The EERM described above is a consequence of the specification of the ORDC, and particularly from the parameters used to calculate the LOLP. Different inputs to the LOLP calculation could change the expected revenue for a new entrant resource and could therefore change the equilibrium reserve margin.

One such proposed modification is to incorporate an LOLP Shift in the calculation of the ORDC price adder. This adjustment, which boosts the value of energy dispatch and operating reserves in near-scarcity conditions, would tend to increase the EERM, all else equal.

The current ORDC does not incorporate an explicit LOLP Shift. Algebraically, this is equivalent to an LOLP Shift = 0.0. As discussed above, the EERM associated with this structure is 11.7%. LOLP Shift factors of 1.0 to 3.0 have a clear impact on net energy revenues, all else equal, and lead to higher levels of EERM.

FIGURE 40: ECONOMIC EQUILIBRIUM RESERVE MARGIN BY LOLP SHIFT



An LOLP Shift Would Enhance Reliability

TABLE 13: RELIABILITY METRICS BY LOLP SHIFT

Case	Shift = 0.0	Shift = 1.0	Shift = 2.0	Shift = 3.0	1-in-3 LOLE	1-in-10 LOLE
EERM (%)	11.7%	13.1%	15.0%	17.0%	15.1%	17.6%
LOLE (#/Year)	1.40	0.80	0.35	0.13	0.33	0.1
LOLH (#/Year)	4.27	2.34	0.97	0.33	0.91	0.25
EUE (%)	0.0016%	0.0008%	0.0003%	0.0001%	0.0003%	0.0001%
Hours of Load Loss During 1-in-20 Weather Year	20.7	12.9	6.1	2.0	5.8	1.4

We estimate that an LOLP Shift of 2.0 would increase the economic equilibrium reserve margin by about <u>3.3%</u> from <u>11.7%</u> to <u>15.0%</u>. This represents a material upward shift in reliability, reducing the number of expected loss-of-load events in economic equilibrium by about 75%, from 1.4 events per year to 0.35, or slightly more than 1-in-3. Thus, an LOLP Shift of 2.0 would most approximately return the system to the level of reliability understood to be achieved by the ORDC around its inception in 2014.

Other LOLP Shift values would produce gains in the economic equilibrium reserve margin in approximate proportion to the size of the shift:

- An LOLP Shift of 1.0 would produce an increase of 1.4% (to 13.3%).
- An LOLP Shift of 3.0 would produce an increase of 5.3% (to 17.0%). An LOLP shift of 3.0 would most approximately return the system to the traditional 1-in-10 reliability standard under economic equilibrium.

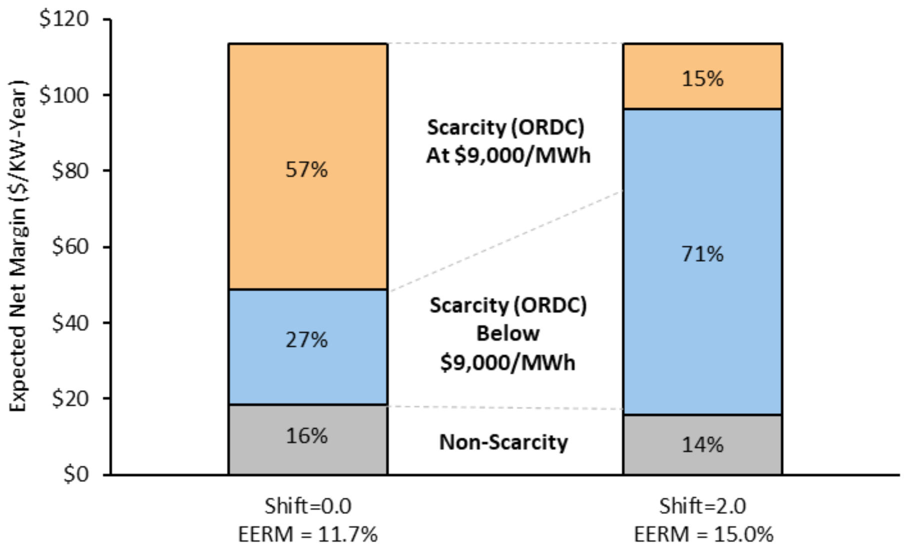
In addition to increasing the EERM that ERCOT could be expected to achieve over the long-term, an LOLP shift would have immediate near-term benefits as well, starting in Summer 2018 if implemented. As discussed above, ERCOT's projected reserve margin for Summer 2018 is 9.3%, which is below both the current EERM and the EERM achieved with any amount of LOLP Shift. Further, the risk of further deterioration in the reserve margin is very real, due to the potential for further retirements/mothballs, or further delays and cancellations of expected new entrant generators. An LOLP Shift would immediately create a stronger incentive for resources considering market exit to remain in the market, for new entrants to avoid any further delays and cancellations, for currently-mothballed resources to re-enter the market, and for retiring resources to delay or cancel their retirements. All of these potential actions would cause the reserve margin in summers 2018 and 2019 to shift faster towards the higher long-term EERM and would produce real near-term reliability value for consumers.

An LOLP Shift Would Make the ORDC More Efficient

The existing ORDC design has inefficiencies that would be ameliorated by the LOLP Shift. The current ORDC provides for scarcity pricing up to around 50% of VOLL (i.e., $4,500/MWh) up until real-time reserves fall below 2,000 MW. At this point, the ORDC jumps immediately to $9,000/MWh. This discontinuity in energy price formation leads to substantial uncertainty in short-term price forecasting because system scarcity will tend to manifest in one of two ways: either 1) scarcity turns out to be real and the energy price hits $9,000/MWh, or 2) it does not materialize, and the price is substantially lower than $4,500/MWh. This bimodal energy price outcome and price uncertainty would tend to result in less efficient market participant decision-making, all else equal.

An LOLP Shift, on the other hand, creates a smoother transition between non-scarcity pricing and true scarcity pricing.[40] An LOLP Shift thus changes the composition of energy market revenues for all resources, and particularly marginal peaking resources to be less dependent on price spikes to the full VOLL and more weighted towards lower near-scarcity pricing (i.e., where operating reserves approach, but do not fall below X). This change is illustrated below for the current design without an LOLP shift and an LOLP shift of 2.0:

FIGURE 41: SOURCES OF CT MARGIN IN ECONOMIC EQUILIBRIUM



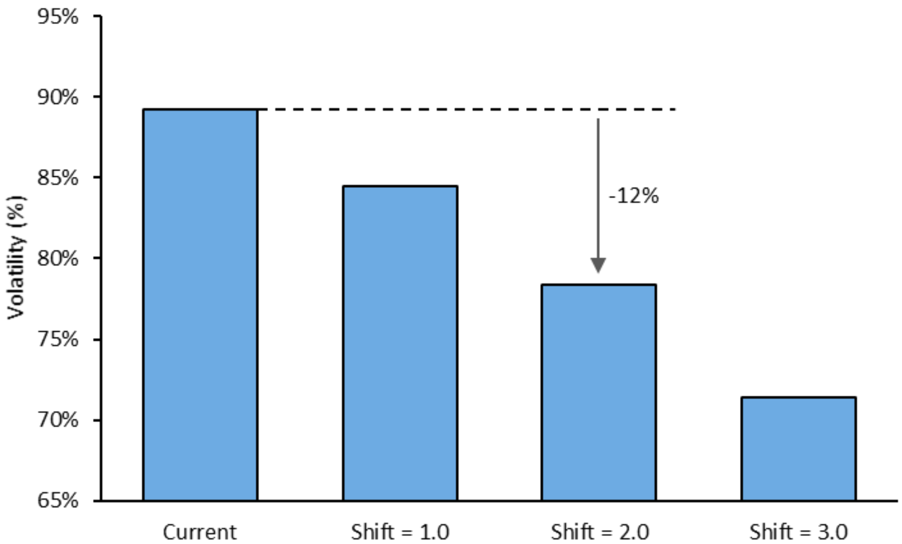
In economic equilibrium, fully 57% of a typical combustion turbine's energy margin over an entire year will come from infrequent price spikes to the full VOLL of $9,000/MWh. With an LOLP shift of 2.0, such extreme price spikes would only make up 15% of the same resources' revenue.

This revenue mix is inherently less risky from the perspective of generators evaluating whether or not to commit their units during system stress conditions and is thus likely to lead to more efficient market-based unit commitment decisions. This could result in a reduced need for the system operator to engage in out-of-market actions such as Reliability Unit Commitment ("RUCs") to ensure reliable operation of the decision.

Furthermore, in the longer-run, this more stable revenue mix leads to lower annualized net revenue volatility for merchant generators:

[40] Scarcity pricing in this context refers to situations where the ORDC price adder is non-trivial.

FIGURE 42: YEAR-TO-YEAR MARGIN VOLATILITY BY LOLP SHIFT (RESERVE MARGIN = 11.7%)



For example, an LOLP shift of 2.0 would reduce the year-to-year volatility in CT net margin by approximately 12 percent. This reduction in volatility reduces the investment risk faced by investors in new build capacity and thus ultimately likely leads to an incremental fall in the CONE for ERCOT, which in turn reduces costs for customers.

Cost to Customers of an LOLP Shift are Modest and Potentially Negative

The total cost to consumers of an LOLP Shift would be the sum of offsetting contributions from 1) the higher capital and fixed O&M costs associated with more installed capacity, 2) lower production costs, and 3) the reduced costs of loss-of-load events (i.e., load shed), which result from enhanced reliability.

The charts below illustrate the relative magnitudes of each of these cost components as the system moves from a reserve margin of 11.7% to 15.0%, and with customer values-of-lost-load[41] ranging from $9,000/MWh to $45,000/MWh. In both cases, the movement from a lower to a higher reserve margin results in higher capital and fixed O&M costs. This is the result of having more installed capacity in the system. In both cases, the production costs decline. This is the result of having more abundant resources to meet load obligations, meaning that more expensive resources will be needed less frequently to serve load. The net sum of the increase in capital cost and the reduction in production cost is an increase of $122 million/year. However, the higher reserve margin directly leads to a lower frequency of customer load curtailments, which has some offsetting value.

If customers value lost load at $9,000/MWh, which is comparable to the administratively set value used in the ORDC, the reduction in customer load curtailment would be valued at $44 million/year and the total change in system cost would be an increase of $79 million/year, or approximately 0.3% of the total customer bill in 2016.[42]

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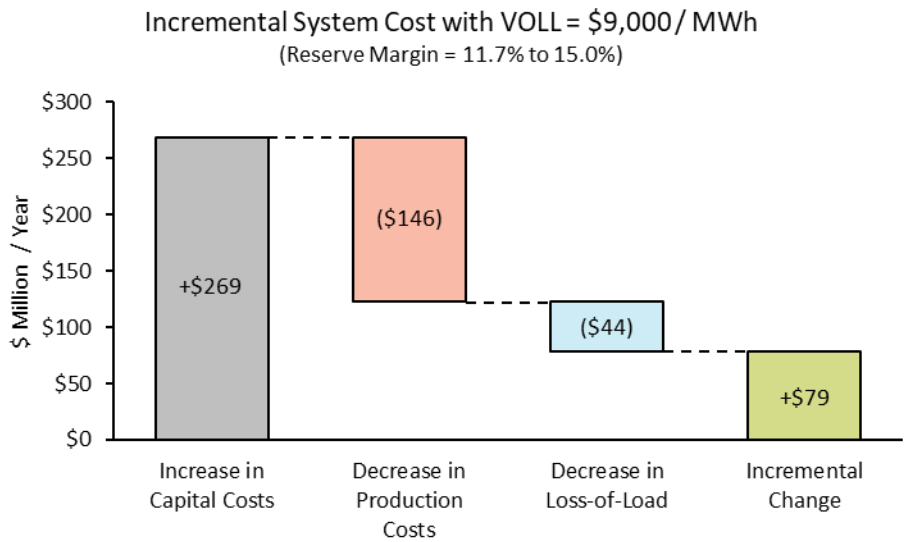
[41] We distinguish this from the VOLL value used in the ORDC, which is set administratively. The actual value that customers place on lost load may be higher or lower than the administratively set value.

[42] Based on ERCOT load of 350 TWh, and an average customer total bill in 2016 in Texas of $82.8 per MWh, as reported in the U.S. Energy Information Administration Electric Power Monthly for February 2017, Table 5.6.B.

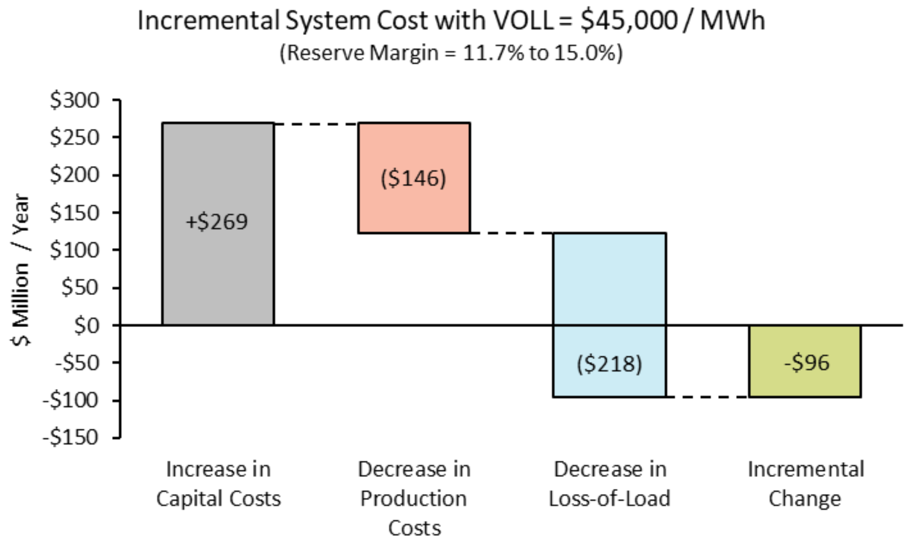
FIGURE 43: INCREMENTAL SYSTEM COSTS (LOLP SHIFT = 2.0, VOLL = $9,000/MWH)



However, the true value of lost load experienced by consumers is not necessarily the same as the $9,000/MWh embedded in the ORDC design. Past studies have suggested that the range of uncertainty of the value of lost load is very wide, and potentially much higher than $9,000/MWh. For example, the London Economics literature review commissioned by ERCOT in the ORDC proceeding concluded that a reasonable VOLL range for a developed industrial economy was between $9,000 and $45,000/MWh.[43] If a higher value of lost load were attributed to consumers, the cost-benefit analysis of the LOLP shift can easily yield a net benefit to consumers through the higher economic value placed on the avoidance of load shed events with a higher economic equilibrium reserve margin. A VOLL of $45,000/MWh shifts the change in total system cost from an increase of $79 million/year to a decrease of $96 million/year. The value gained in avoiding costly load curtailment more than offsets the net increase in other costs.

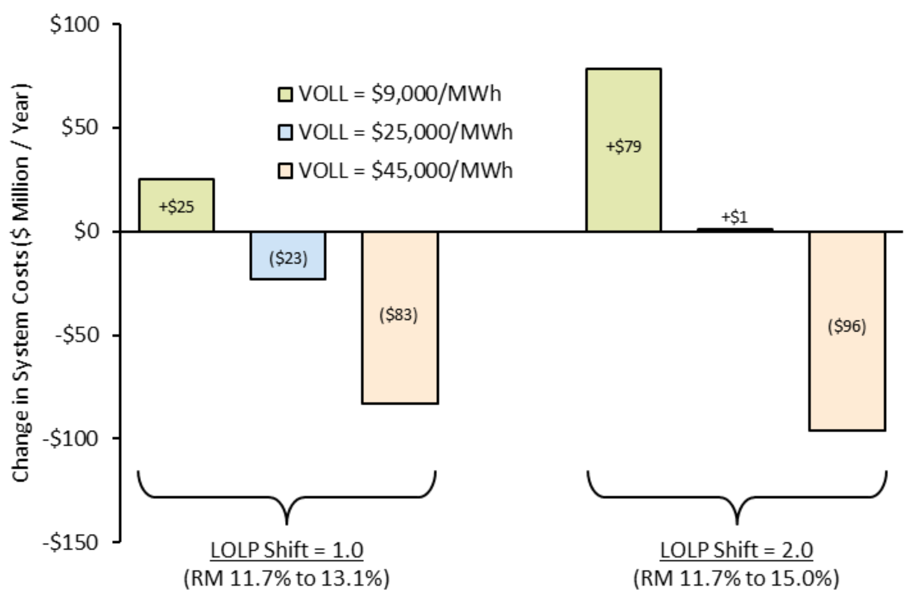
[43] *Estimating the Value of Lost Load*, *Briefing paper prepared for the Electric Reliability Council of Texas Inc.*, London Economics International LLC, June 17th, 2013, at 9.

FIGURE 44: INCREMENTAL SYSTEM COSTS (LOLP SHIFT = 2.0, VOLL = $45,000/MWH)



When all aspects of system cost are considered, incremental system costs of LOLP Shift values of 2.0 and 1.0 are likely to be quite small. After considering the wide variation in the value customers place on lost-load, it is even possible that these LOLP Shifts could even result in net customer savings:

FIGURE 45: CHANGE IN TOTAL SYSTEM COST BY LOLP SHIFT



Appendix (Detailed Results)

	Physical Reliability Metrics				Mean CT Net Energy Margin ($/KW-Year) by LOLP Shift				Mean CC Net Energy Margin ($/KW-Year) by LOLP Shift			
	RM	LOLE	LOLH	EUE	0.0	1.0	2.0	3.0	0.0	1.0	2.0	3.0
Diagnostic Reserve Margins (%)	5%	9.18	35.49	0.0205%	$543	$696	$928	$1,236	$567	$719	$951	$1,260
	6%	7.32	27.37	0.0149%	$443	$576	$783	$1,061	$465	$599	$805	$1,084
	7%	5.75	20.77	0.0107%	$357	$472	$654	$904	$379	$494	$676	$926
	8%	4.44	15.51	0.0074%	$285	$384	$542	$764	$306	$405	$564	$786
	9%	3.35	11.32	0.0051%	$225	$309	$445	$641	$245	$329	$466	$662
	10%	2.49	8.07	0.0034%	$176	$246	$362	$533	$196	$266	$382	$553
	11%	1.79	5.58	0.0022%	$136	$194	$292	$439	$156	$213	$311	$459
	12%	1.24	3.75	0.0014%	$105	$151	$233	$359	$124	$170	$252	$378
	13%	0.85	2.47	0.0009%	$80	$117	$184	$291	$98	$136	$203	$309
	14%	0.55	1.55	0.0005%	$61	$90	$144	$233	$78	$108	$162	$251
	15%	0.35	0.95	0.0003%	$46	$69	$112	$185	$63	$86	$130	$203
	16%	0.22	0.58	0.0002%	$36	$53	$87	$146	$52	$70	$104	$163
	17%	0.13	0.33	0.0001%	$28	$41	$67	$114	$44	$57	$83	$131
	18%	0.08	0.19	0.0000%	$22	$31	$51	$89	$38	$47	$67	$105
	19%	0.04	0.10	0.0000%	$19	$25	$39	$69	$34	$40	$55	$84
	20%	0.02	0.05	0.0000%	$16	$20	$31	$53	$31	$35	$46	$68
2018 (Projected)	9.3%	3.13	10.48	0.0046%	$212	$292	$424	$613	$233	$313	$444	$633
2018 (Stress)	7.8%	4.64	16.33	0.0079%	$296	$397	$560	$786	$317	$419	$581	$807
ERCOT Target	13.75%	0.63	1.78	0.0006%	$65	$97	$154	$247	$83	$115	$173	$266
LOLE = 0.1	17.6%	0.10	0.25	0.0001%	$25	$36	$58	$100	$41	$52	$74	$116
LOLE = 0.33	15.1%	0.33	0.91	0.0003%	$45	$67	$109	$181	$62	$84	$127	$198
CT EERM (Shift = 0.0)	11.7%	1.40	4.27	0.0016%	$113.5							
CT EERM (Shift = 1.0)	13.1%	0.80	2.34	0.0008%		$113.5						
CT EERM (Shift = 2.0)	15.0%	0.35	0.97	0.0003%			$113.5					
CT EERM (Shift = 3.0)	17.0%	0.13	0.33	0.0001%				$113.5				
CC EERM (Shift = 0.0)	11.0%	1.77	5.52	0.0022%					$154.6			
CC EERM (Shift = 1.0)	12.5%	1.06	3.16	0.0011%						$154.6		
CC EERM (Shift = 2.0)	14.2%	0.50	1.41	0.0005%							$154.6	
CC EERM (Shift = 3.0)	16.3%	0.19	0.51	0.0001%								$154.6