Estimating the Economically Optimal Reserve Margin in ERCOT

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PREPARED FOR

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Executive Summary

We have been asked by the Public Utility Commission of Texas (PUCT), in close coordination with the Electric Reliability Council of Texas (ERCOT), to estimate the economically optimal reserve margin for ERCOT's wholesale electric market. This study contributes to an already substantial body of technical work, regulatory proceedings, and market design revisions related to the policy framework for resource adequacy in Texas.

We provide the following new information to help the Commission and stakeholders evaluate their options for addressing the resource adequacy challenges facing Texas:

(a) An estimate of the "economically optimal" reserve margin that would minimize system costs in ERCOT;

(b) A comparison between that optimum and the "equilibrium" reserve margin that ERCOT's current energy-only market design will likely support;

(c) Estimates of the system cost and customer cost implications of mandating a higher reserve margin, such as one based on the traditional 1-in-10 loss of load event (LOLE) standard or alternative physical reliability standards;

(d) A comparison of prices, customer costs, and supplier net revenues that energy-only and capacity market design options would produce—both on average across all years and for the highest-cost years with significant scarcity events; and

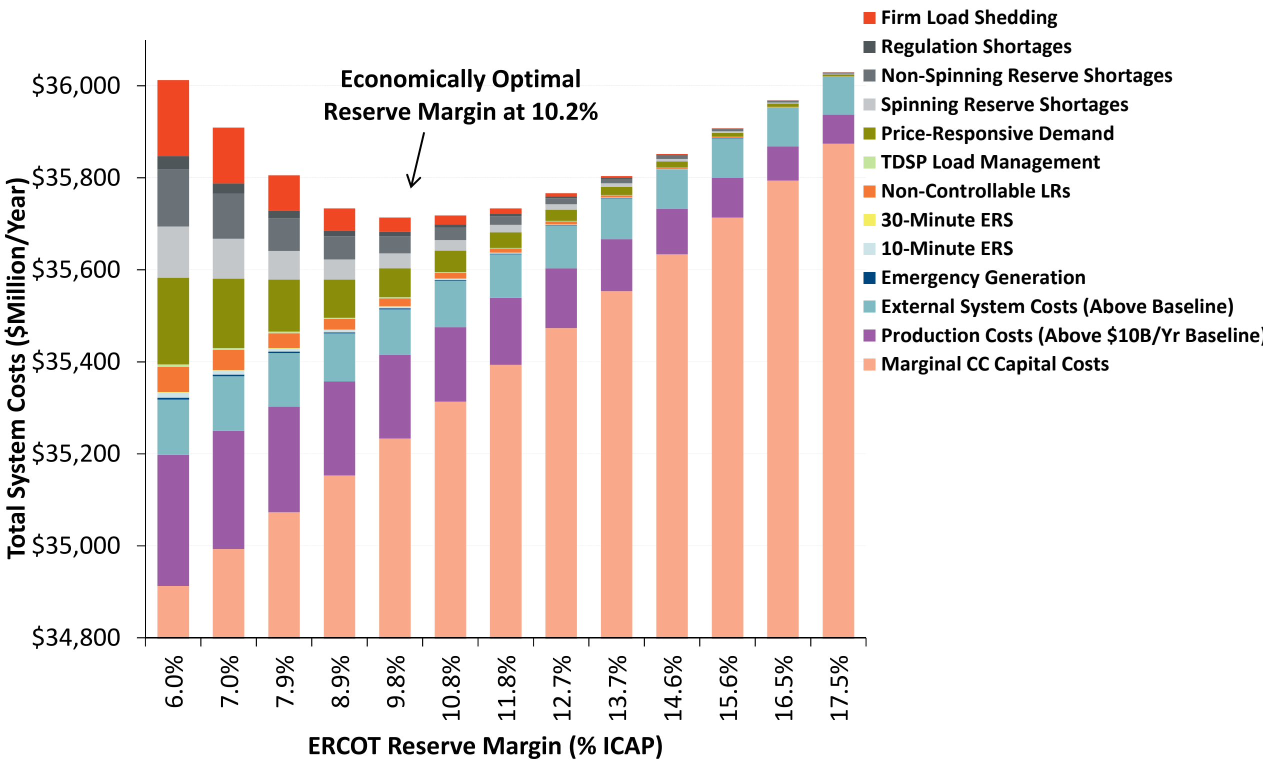
(e) The sensitivity of our reliability and economic results to a number of study assumptions.

Our analyses of viable market designs represent expected long-term average conditions at the equilibrium point where suppliers are earning adequate returns on average to support continued investment in new generation. Our results do not describe today's market conditions or the reserve margins and prices that may be realized in any of the next few years.

To undertake this analysis, we implement a series of economic and reliability modeling simulations of the ERCOT system using the Strategic Energy Risk Valuation Model (SERVM). Like other reliability modeling tools, SERVM probabilistically evaluates resource adequacy conditions by simulating ERCOT's generation outages, weather and other load uncertainty, intertie availability, demand-side resources, and other factors. Unlike other reliability modeling tools, SERVM also simulates the economic implications associated with all possible outcomes, including hourly generation dispatch, import-export dynamics, ancillary services, demand response, and individual emergency procedures. SERVM estimates hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins as a function of the planning reserve margin under a wide range of uncertainties. We simulated these uncertainties probabilistically for a Base Case, a number of sensitivity cases, and a range of planning reserve margin levels. The results for each case and simulated reserve margin level reflect the probability-weighted outcomes for 7,500 full annual simulations (for all hours of the year).

The "economically optimal" reserve margin minimizes total system costs by weighing: (1) *increasing capital costs* of building more generation plants to achieve the higher reserve margins, against (2) *decreasing scarcity-event-related costs* as higher reserve margins help to avoid load shedding, reserve shortages, demand-response calls, and other emergency event costs. Figure ES-1 summarizes these individual cost components across a range of planning reserve margins. The minimum system cost (reflecting the risk-neutral, probability-weighted-average cost of 7,500 simulations) occurs at a reserve margin of 10.2% in our Base Case. This risk-neutral, economically optimal reserve margin is substantially below the 14.1% reserve margin needed to meet the traditional 1-in-10 (0.1 LOLE) target in our Base Case simulations, meaning that the traditional 1-in-10 target is higher than economically optimal, at least before accounting for risk aversion and other considerations.

Figure ES-1
Total System Costs across Planning Reserve Margins



Notes:
Total system costs include a large baseline of total system costs that do not change across reserve margins, including $15.2B/year in transmission and distribution, $9.6B/year in fixed costs for generators other than the marginal unit, and $10B/year in production costs.

However, we also find that the total system cost curve is relatively flat near the minimum, with only modest average annual cost variation between reserve margins of 8% and 14%. For example, increasing the reserve margin from the 10.2% optimum to the 14.1% needed to meet the 1-in-10 standard, would increase total system costs by approximately $100 million per year on a long-term average basis. This compares to total ERCOT system-wide costs of more than $35 billion per year including all reliability-related costs, production costs, fleet-wide fixed costs, and transmission and distribution (T&D) costs.

Our estimates of the economically optimal reserve margin and reliability-based reserve margin targets are summarized in Table ES-1. Although the 0.1 LOLE target is the traditional metric used in Texas and most of North America, we also report reserve margins that would be needed to meet alternative reliability standards: (a) a 9.1% reserve margin would meet the 2.4 loss of load hours (LOLH) standard that the Southwest Power Pool (SPP) uses,[1] and (b) a 9.6% reserve margin would meet the a 0.001% normalized expected unserved energy (EUE) standard used in some international markets. To make the implications of the 0.001% normalized EUE standard more tangible, this means one hundred thousandth of the energy demanded each year would be shed on average due to resource inadequacy, corresponding to 0.7 events per year, each shedding about 1,700 MW for 2.8 hours on average in our ERCOT simulations. If the Commission does implement a reliability-based standard, we would recommend defining the standard in terms of normalized EUE, although not necessarily at the 0.001% level. Unlike LOLE, normalized EUE is a more robust metric in terms of its comparability across system sizes, outage durations, and outage event magnitude, as explained in a recent North American Electric Reliability Corporation (NERC) task force whitepaper.

Table ES-1
Economically Optimal and Reliability-Based Reserve Margin Targets

Reserve Margin Target	Base Case *(%)*	Sensitivity Cases *(%)*
Economically-Optimal	10.2%	9.3%-11.5%
Reliability-Based		
0.1 LOLE	14.1%	12.6%-16.1%
2.4 LOLH	9.1%	8.2%-11.1%
0.001% EUE	9.6%	8.4%-11.6%

Notes:
This reported sensitivity range reflects a subset of the sensitivities we examined in this study, reflecting the following cases: Equal 1/15 Chance of 2011 Weather, No Non-Weather Load Forecast Error, Perfect Energy Price, and Combustion Turbine as the Marginal Technology.

Table ES-1 also shows that both economically-based and reliability-based reserve margin estimates are sensitive to study assumptions, particularly those that drive the likelihood and severity of scarcity events. Two of the most important of these assumptions are the likelihood of extreme 2011 weather recurring and the magnitude of non-weather load forecast error (LFE). The economically optimal reserve margin also depends on our economic assumptions regarding the estimated capital cost of building new generation, the value of lost load (VOLL), the cost of

1 SPP's LOLH methodology yields a minimum reserve margin requirement of 12% capacity margin (13.6% reserve margin). Actual SPP reserve margins are currently much higher, however.

dispatching demand response, natural gas prices, and other factors. We show a range of results based on some of these factors in Table ES-2, and provide a more comprehensive sensitivity analysis in the body of this report.

This study also compares the long-term implications of maintaining ERCOT's current energy-only market design to those of implementing a capacity market. Under the energy-only market construct, the average reserve margin is determined solely by market forces. If reserve margins are low and prices are high, suppliers will build because they expect to earn more than their investment costs. Those newly built plants will increase the average reserve margin and thereby suppress energy prices. Suppliers will continue to build until market prices drop to an "equilibrium" level where they expect to earn an adequate return on capital, no more and no less. We estimate that the current energy-only market design will yield an equilibrium reserve margin of 11.5% under our Base Case assumptions, with a range of 9% to 13% in our sensitivity cases.

The 11.5% *equilibrium* reserve margin that the current energy-only market design is likely to achieve slightly exceeds the 10.2% risk-neutral *economically optimal* reserve margin. This important finding suggests that the current market design will support sufficient reserve margins from an economic perspective, unless political perceptions or reactions have adverse economic consequences for which we have not accounted. Some considerations of risk aversion are discussed below.

The reason the energy-only market equilibrium slightly *exceeds* the cost-minimizing economically optimal reserve margin is that the current market design occasionally yields energy prices above marginal system costs, creating additional incentives to invest that raise reserve margins somewhat above the cost-minimizing level. Specifically, this discrepancy is introduced by setting administratively-determined scarcity prices as if load would be shed (or other emergency actions taken at an equivalent cost) at an operating reserve level of X = 2,000 MW. This is above our X = 1,150 MW estimated level at which load is shed, with prior emergency actions incurring costs below the value of lost load. Under an alternative "Perfect Energy Price" case, we illustrate that the energy-only market equilibrium and economically optimal reserve margins would both be equal to 9.3% if prices were always set equal to our estimates of marginal system costs. This sensitivity case has a lower optimum reserve margin and lower total system costs because the "perfect" energy prices also result in more efficient system dispatch, with respect to high-cost price-responsive demand.

As an alternative to the current energy-only market design, the Commission could opt to mandate a higher reserve margin. This would make capacity a valuable new product because, at higher reserve margins, the market would produce lower energy market prices and lower supplier energy margins. In that case, "capacity payments" would make up the difference needed to allow suppliers to invest up to the mandated higher reserve margin. On a long-term average basis, the resulting capacity prices will equilibrate at the Net Cost of New Entry (Net CONE), which is gross CONE net of energy-market margins. This equilibrium capacity price increases with the mandated reserve margins as suppliers earn less in the energy market, such that total net revenues from capacity and energy are equal to gross CONE in equilibrium, consistent with the long-run marginal cost of supply.

At the reserve margin needed to maintain 0.1 LOLE, which is 14.1% in our Base Case, we estimate long-run equilibrium capacity prices of $39/kW-year in the Base Case and between $30–$60/kW-year in our sensitivity cases (25%–49% of total supplier net revenues). These and other metrics describing the differences between the energy-only and capacity-market designs are shown in Table ES-2.

One of the most important insights is that the net increase in customer cost under a capacity market design would be much lower than implied by our estimates of capacity prices. Although multiplying our estimated capacity price by projected peak load (plus reserve margin) suggests roughly $3.2 billion per year in capacity payments, these costs would be largely offset by a $2.8 billion reduction in annual energy-market costs, for a net customer cost increase of about $400 million relative to the energy-only market design at the 11.5% equilibrium reserve margin. This $400 million per year represents only about a 1% increase in customer rates, from about 10.1 ¢/kWh in the 11.5% energy-only equilibrium to 10.2 ¢/kWh with a 14.1% reserve margin mandate.

However, these estimates describe only long-term average prices at equilibrium. They do not describe this year or the next few years. The actual near-term price impacts of implementing a capacity market would be affected by at least two important dynamics. First, capacity prices could be temporarily lower than estimated if some low-cost capacity is available. Other regions have experienced capacity prices below Net CONE for many years due to the entry of demand response, generation uprates, and other low-cost sources of capacity. Second, even without such resources, prices would not be expected to reach equilibrium pricing until the reserve margin falls to the required reserve margin. But herein lies an important cost difference from maintaining an energy-only market. Mandating a reserve margin could cause the market to reach equilibrium as soon as reserve margins fall from their current levels to 14.1% (or whatever level is mandated), whereas the current energy-only market design may take several years to reach its 11.5% long-run equilibrium level. Under either market design, long-term equilibrium prices would be several billion dollars higher than currently-depressed wholesale prices, but a capacity requirement would cause prices to reach equilibrium prices sooner, and at a slightly higher ultimate level (*e.g.*, $400 million higher on average to support a 0.1 LOLE).

Table ES-2
Comparison of Energy-Only and Capacity Market Outcomes

		Energy-Only Market		Capacity Market at 1-in-10	
		Base Case	Sensitivity Cases	Base Case	Sensitivity Cases
Equilibrium Reserve Margin	*(%)*	11.5%	9.3%-12.9%	14.1%	12.6% - 16.1%
Realized Reliability					
Loss of Load Events	*(events/yr)*	0.33	0.27 - 0.85	0.10	0.10 - 0.10
Loss of Load Hours	*(hours/yr)*	0.86	0.68 - 2.37	0.23	0.22 - 0.23
Normalized EUE	*(% of MWh)*	0.0004%	0.0003% - 0.0013%	0.0001%	0.00008% - 0.0001%
Economics in Average Year					
Energy Price	*($/MWh)*	$58	$58 - $60	$48	$46 - $53
Capacity Price	*($/kW-yr)*	$0	$0 - $0	$39	$30 - $60
Supplier Net Revenue	*($/kW-yr)*	$122	$97 - $122	$122	$97 - $122
Average Customer Cost	*(¢/kWh)*	10.1¢	10.1¢ - 10.7¢	10.2¢	10.2¢ - 10.8¢
Total Customer Costs	*($B/Yr)*	$35.7	$35.7 - $37.8	$36.1	$36.0 - $38.3
Economics in Top 10% of Years					
Energy Price	*($/MWh)*	$99	$95 - $102	$65	$58 - $77
Capacity Price	*($/kW-yr)*	$0	$0 - $0	$76	$30 - $116
Supplier Net Revenue (Unhedged)	*($/kW-yr)*	$362	$173 - $444	$249	$152 - $302
Supplier Net Revenue (80% Hedged)	*($/kW-yr)*	$244	$119 - $259	$193	$128 - $289
Average Customer Cost (Unhedged)	*(¢/kWh)*	15.1¢	13.4¢ - 23.0¢	12.9¢	12.4¢ - 17.9¢
Average Customer Cost (80% Hedged)	*(¢/kWh)*	12.6¢	9.8¢ - 21.8¢	11.7¢	10.2¢ - 17.7¢
Total Customer Costs (Unhedged)	*($B/Yr)*	$53.6	$37.4 - $81.5	$45.7	$43.9 - $63.3
Total Customer Costs (80% Hedged)	*($B/Yr)*	$44.7	$34.6 - $77.2	$41.5	$36.2 - $62.9

Notes:
This reported sensitivity range reflects a subset of the sensitivities we examined in this study, reflecting the following cases: Equal 1/15 Chance of 2011 Weather, No Non-Weather Load Forecast Error, Perfect Energy Price, and Combustion Turbine as the Marginal Technology.

Another important difference between the energy-only and capacity market designs is the nature of the wholesale price volatility facing customers and suppliers. Increasing the system reserve margin reduces the level of energy price volatility by mitigating the impact of under-forecasting load or realizing extreme weather. We illustrate this risk mitigation effect by comparing costs during the top 10% of all years, reflecting a once-per-decade scarcity year. A customer with 80% of energy purchases hedged on a seasonal basis and with no capacity hedges would realize once-per-decade costs of 12.6 ¢/kWh (24% above average across all years) under the energy-only market, and 11.7 ¢/kWh (16% above average) under a capacity market with a 14.1% reserve margin.[2]

For suppliers, once-per-decade events affect overall economics even more than for customers, since increases in energy prices have a proportionally greater impact on suppliers' energy margins (since margins derive from the *difference* between revenues and costs that do not

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2 Without hedging, the once-per-decade scarcity year would produce spot prices of 15.1 ¢/kWh (about 50% higher than average costs) under the energy-only market or 12.9 ¢/kWh (26% above average) under the capacity market at 0.1 LOLE. Actual rates could vary more than these equilibrium estimates suggest, in part because of changes in gas prices, transmission and distribution rates, and other factors we did not vary in our analysis.

change). If a supplier is 80% hedged, the once-per-decade year would produce net revenues of \$244/kW-year (2 times CONE) in the energy-only market. In our Base Case simulations with a mandated 14.1% reserve margin, once-per-decade net revenues (including capacity payments) are reduced to \$193/kW-year (1.6 times CONE). Hence, mandating a reserve margin would reduce supplier risk. It could also slightly lower their cost of capital and thus the level of long-term average prices, although we have neither estimated nor accounted for this effect.

As noted above, we estimate that ERCOT's current energy-only market design will support average reserve margins of approximately 11.5%, slightly above our 10.2% risk-neutral economic optimum estimate. However, policymakers and stakeholders may still wish to implement a capacity market to achieve its risk mitigation, reliability, and other potential benefits. For example, a higher mandated reserve margin may be justified if policymakers and stakeholders place a greater weight on potential high-cost and low-reliability outcomes that can result from extreme weather, unexpectedly high load growth, unusual generation outages, or modelling uncertainties.

This study provides informative reference points but does not constitute a full cost-benefit analysis of energy-only and capacity market designs. A full cost-benefit analysis would need to include an explicit consideration of other quantitative and qualitative factors including: (a) cost reductions from eliminating current demand response programs and moving those resources into the capacity market; (b) potential value from a capacity market that better coordinates the timing of investment decisions, which could avoid some boom-bust effects and narrow the distribution of reserve margin outcomes, thereby further reducing the frequency and costs of shortage events; and (c) implementation, overhead, and software costs associated with moving to a capacity market design.

In considering mandating a reserve margin and implementing a capacity market, the Commission would also have to evaluate many practical implications. Mandating a reserve margin and establishing a capacity market that can efficiently meet that requirement would require extensive stakeholder discussions about alternative market design elements such as: (1) the resource adequacy requirement itself; (2) the implementation of that requirement in a capacity market, which could involve administratively defining a sloped demand curve; (3) the forward period and rules for forward and incremental auctions; (4) how to represent transmission constraints; (5) participation and verification rules for all types of resources; (6) definition of penalties and performance incentives; (7) market monitoring rules; and (8) settlement processes for both suppliers and load-serving entities. Although design decisions can benefit from other regions' past decade of experience with capacity markets, the process could take two years and would likely be contentious. In addition, initial design elements would need to be revisited and likely re-litigated over time as market conditions and reliability challenges change.

Some market participants may also suggest that implementing a capacity market would reduce the need to maintain a high energy-market price cap or administrative scarcity pricing mechanisms. We urge against this line of reasoning since efficient energy and ancillary services prices are important for maintaining operational efficiency and reliability during scarcity periods and during a large variety of operational challenges that resource adequacy does not address. Maintaining a price cap equal to the value of lost load (VOLL) during outages and prices reflective of marginal system costs in other types of scarcity events will provide efficient signals necessary for market-based responses from generators and demand response. These benefits of efficient energy and ancillary services pricing make them an essential component of the market design, whether or not a resource adequacy requirement is adopted for ERCOT.

We recognize that concurrent with the completion of our study, ERCOT has released an updated load forecast that we have not had time to incorporate and consider in our analyses. Because the updated forecast is much lower than prior forecasts, this may reduce the real or perceived urgency of addressing the resource adequacy question. In terms of the impact on our study results, we do not expect that the new forecast would change our estimates of optimal or equilibrium reserve margins substantially, since those are expressed as a percentage of peak load. However, our results could change if the new forecast methodology produces very different distributions of weather and non-weather forecast errors, or if it accounts for demand response very differently.

Regarding the urgency of the issue, that is a judgment for the Commission, ERCOT, and stakeholders. The Commission could decide not to act now or, if they see a need to change the market design in the long term to meet policy objectives, they could take advantage of the current slack to implement changes with less risk of transitional rate shocks. In any case, providing stakeholders a clear understanding of whether, how, and when the market design will change would reduce regulatory uncertainty and benefit market participants as they make business decisions over the coming years.

I. Motivation and Context

We have been asked by the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT) to estimate the economically optimal reserve margin for ERCOT's wholesale electric market. This study contributes to an already substantial body of technical work, regulatory proceedings, and market design revisions related to the policy framework for ERCOT's market design for resource adequacy.[3]

As we explained in our June 2012 study, the primary resource adequacy challenge in Texas is that the energy market is likely to support a reserve margin below what is required to meet the traditional resource adequacy target, which is based on achieving a 1-event-in-ten-years (1-in-10) loss of load event (LOLE) standard.[4] In most of North America, the planning reserve margin required to meet a 1-in-10 standard is achieved through either utility planning or capacity markets.[5] This is unlike ERCOT and other energy-only markets, which have no mechanism for ensuring a particular reserve margin. Instead, the reserve margin is the result of market forces: low reserve margins create high energy and ancillary service (A/S) prices sufficient to attract investments in new generation; those investments will continue until high reserve margins result in prices too low to support any more investment. The resulting equilibrium reserve margin may be above or below the reserve margin that would be consistent with the 1-in-10 standard, depending on market fundamentals and uncertainties such as weather.

Our probabilistic market simulations suggest that the equilibrium reserve margin supported by ERCOT's energy and A/S markets is below the reserve margin that would yield a 1-in10 LOLE standard.[6] To partially address this gap, ERCOT is implementing a number of market design changes, including increasing the price cap to $9,000/MWh and introducing a scarcity pricing mechanism.[7] While these changes will improve the efficiency of prices during scarcity events and increase the equilibrium reserve margin, our prior analyses indicate that these design changes will not be sufficient to yield a 1-in-10 LOLE outcome.

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3 For access to a comprehensive set of associated studies and regulatory proceedings, see the Resource Adequacy portion of ERCOT's website as well as the PUCT proceedings under project 40,000. See ERCOT (2014a) and PUCT (2014).

4 For additional background and information on the LOLE standard, ERCOT's resource adequacy challenge, see Newell, *et al.* (2012).

5 For a more comprehensive review of different regulated and market-based approaches to resource adequacy, see Spees, *et al.* (2013), or Pfeifenberger, *et al.* (2009)

6 See our most recent analysis of the likely equilibrium reserve margin from 2013, Newell, *et al.* (2013a).

7 ERCOT has implemented a large number of such related changes, but two of the most important are to increase the price cap to $9,000/MWh and to implement an administrative operating reserves demand curve (ORDC) for producing high administratively-set prices during scarcity events. See ERCOT (2013c).

This suggests that ERCOT's traditional 1-in-10 resource adequacy "target" is inconsistent with the energy-only market design. Reconciling this incompatibility will require the Commission to clarify its policy objectives with respect to resource adequacy and adopt a market design that best supports those objectives. The central market design choices are either: (1) to maintain the current energy-only market and accept reserve margins that are likely to fall below the current 1-in-10 target; or (2) to impose a mandatory reserve margin standard, likely through a centralized capacity market, with the reserve margin set at a level consistent with policy objectives.

The task of our present study is to provide additional information to the PUCT, ERCOT, and stakeholders as they continue to address these questions. The primary result of our study is an estimate of the economically optimal reserve margin in ERCOT, defined as the reserve margin that minimizes total system costs as illustrated in Figure 1. As Figure 1 shows, higher reserve margins are associated with the higher capital costs of building more capacity (dark blue line). This higher capital cost is offset by a reduction in the frequency and magnitude of costly reliability events (light blue line), such as load shed events, emergency events, demand-response curtailments, and the dispatch of high-cost resources. The tradeoff between increasing capital costs and decreasing reliability-related operating costs results in a U-shaped total costs curve (red line), with costs minimized at what we refer to as the "economically optimal" reserve margin.[8]

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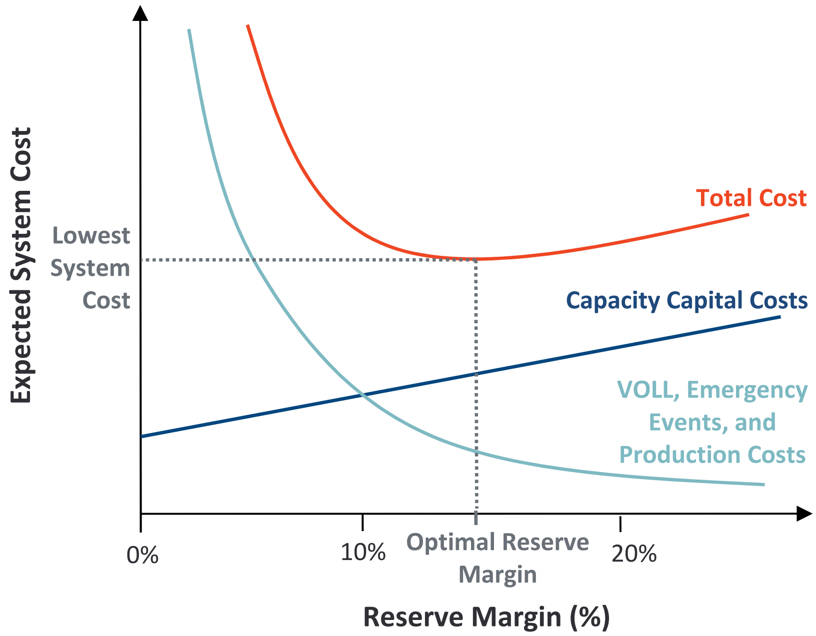
[8] In developing our approach to calculating the economically optimal reserve margin, we draw upon a large body of prior work conducted by ourselves and others, although the majority or all of this prior work was relevant in the context of regulated planning rather than restructured markets. For example, see Poland (1988), p.21; Munasinghe (1988), pp. 5–7, 12–13; and Carden, Pfeifenberger, and Wintermantel (2011).

Figure 1
"Economically Optimal" Reserve Margin at Lowest System Cost
(Illustrative Schematic, Not Simulation Results)



We conducted reliability and economic market simulations to estimate this economically optimal reserve margin in ERCOT, and to better inform the economic and reliability implications of addressing the policy questions at hand. In particular, we examined: (a) the uncertainty range of both reliability-based and economically-based reserve margin estimates; (b) the system cost and risk implications of imposing a reserve margin requirement above the level that ERCOT's energy-only market would support; (c) the energy and capacity market prices and uncertainties that would result from mandating different reserve margin levels; and (d) the implications of different levels of mandated reserve margins on supplier net revenues and total customer costs.

II. Study Assumptions and Approach

In this Section, we provide a summary of the market simulations that we use to analyze the reliability and economic implications of varying the system reserve margin and generate the results presented in Sections III and IV. Our simulation modeling approach relies on a detailed representation of the ERCOT system, including: load and weather uncertainties; the cost and performance characteristics of ERCOT's generation and demand-response resources; a representation of the ERCOT energy and ancillary services market; and a unit commitment and economic dispatch of all generation resources, demand-response resources, and the transmission interties with neighboring markets. These simulations are consistent with current projections for calendar year 2016 in terms of generation fleet, demand-response penetration, fuel prices, and energy market design.

A. SERVM Probabilistic Modeling Framework

We use the Strategic Energy Risk Valuation Model (SERVM) to estimate the economically optimal reserve margin in the ERCOT system.[9] Like other reliability modeling tools, SERVM probabilistically evaluates resource adequacy conditions by simulating generation availability, load profiles, load uncertainty, inter-regional transmission availability, and other factors. Based on these reliability simulations, SERVM estimates standard reliability metrics including loss of load events (LOLE), loss of load hours (LOLH), and expected unserved energy (EUE). Unlike other reliability modeling packages, however, SERVM also simulates economic outcomes including hourly generation dispatch, import-export dynamics, ancillary services, and individual emergency procedures. SERVM estimates hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins as a function of the planning reserve margin. These results allow us to compare these variable costs against the incremental capital costs required to achieve higher planning reserve margins.[10]

The multi-area economic and reliability simulations in SERVM include an hourly chronological economic dispatch that is subject to inter-regional transmission constraints. Each generation unit is modeled individually, characterized by its own economic and physical characteristics. Planned outages are scheduled in off-peak seasons to minimize the impact on reliability, while unplanned outages and derates occur probabilistically using historical distributions of time between failures and time to repair, as explained in Section II.C. Load, hydro, wind, and solar conditions are modeled based on profiles consistent with individual historical weather years. Dispatch limitations and limitations on annual energy output are also imposed on certain types of resources such as demand response, hydro generation, and seasonally mothballed units.

The model implements a week-ahead and then multi-hour-ahead unit commitment algorithm considering the outlook for weather and planned generation outages. In the operating day, the model runs an hourly economic dispatch of baseload, intermediate, and peaking resources, including an optimization of transmission-constrained inter-regional power flows to minimize total cost. During most hours, hourly prices reflect marginal production costs, with higher prices being realized when import constraints are binding. During emergency and other peaking conditions, SERVM simulates scarcity prices that exceed generators' marginal production costs as explained further in Section II.F below.

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9 SERVM software is a product of Astrape Consulting, co-authors of this report, see Astrape (2014)

10 Note that SERVM as a modeling tool does not endogenously estimate capital costs, which are reflected as a fixed annual cost (in $/kW-year). Total capacity costs simply increase as a function of the planning reserve margin. The question of whether a particular reserve margin is actually achievable or realistic under various market designs, including in regions with capacity markets or energy-only markets, depends on whether those markets have been constructed such that investors are able to recover their fixed costs at that reserve margin.

To examine a full range of potential economic and reliability outcomes, we implement a Monte Carlo analysis over a large number of scenarios with varying demand and supply conditions. Because reliability events occur only when system conditions reflect unusually high loads or limited supply, these simulations must capture wide distributions of possible weather, load growth, and generation performance scenarios. This study incorporates 15 weather years, 5 economic load forecast error points, and 100 draws of generating unit performance for a total of 7,500 iterations for each simulated reserve margin case, with each iteration simulating 8,760 hours for the year 2016.[11] The large number of simulations is necessary to accurately characterize from a probabilistic perspective the reliability and economic implications of varying reserve margins. A probabilistic approach is needed because the majority of reliability-related costs are associated with infrequent and sometimes extreme scarcity events. Such reliability events are typically triggered by rare circumstances that reflect a combination of extreme weather-related loads, high load-growth forecast error, and unusual combinations of generation outages.

To properly capture the magnitude and impact of reliability conditions during extreme events, a critical aspect of this modeling effort is the correct economic and operational characterization of emergency procedures. For this reason, SERVM simulates a range of emergency procedures, accounting for energy and call-hour limitations, dispatch prices, operating reserve depletion, dispatch of economic and emergency demand-response resources, and administrative scarcity pricing.[12]

B. Load Modeling

We model load as an hourly shape across the simulated year, reflecting load diversity between ERCOT and the neighboring systems. We model weather uncertainty using 15 different load shapes, consistent with 15 historical weather years and associated hydro, wind, and solar profiles as explained in Section II.C below. We also model non-weather-related load forecast error (LFE), which increase with the forward planning period. This non-weather load forecast error, which has not been reflected in prior reliability analyses of ERCOT's system, recognizes that, for example, a three-year-forward reserve margin requirement is associated with more uncertainties about market conditions during the delivery year than a one-year forward reserve margin requirement.

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11 We implement these SERVM simulations using a planning calendar with only 8760 hours even though 2016 is a leap year with 8784 hours.

12 Similar to other reliability modeling exercises, our study is focused on resource adequacy as defined by having sufficient resources to meet peak summer load. As such, we have not attempted to model other types of outage or reliability issues such as transmission and distribution outages, common mode failures related to winter weather extremes, or any potential issues related to gas pipeline constraints or delivery problems.

1. Peak Load and Regional Diversity

Table 1 summarizes the peak load for the ERCOT system and the load diversity relative to the interconnected neighboring regions. Consistent with the peak load reporting conventions used in ERCOT's capacity, demand, and reserves (CDR) report, these peak loads are reported: (a) net of anticipated load reductions from price-responsive demand (PRD) and load resources (LRs); and (b) prior to any potential reductions from transmission and distribution service provider (TDSP) load management or energy efficiency programs.[13]

Peak load for the ERCOT system was provided by ERCOT staff using a preliminary peak load estimate as of November 2013, although since that time ERCOT has updated and published a revised peak load forecast that is somewhat lower than number we use here.[14] Hourly load shapes for ERCOT were developed by ERCOT staff, and are the same load shapes used in the most recent reliability study of ERCOT's system from March 2013.[15] We independently developed external regions' peak load and load shapes based on publicly-available peak load projections, historical hourly weather profiles, and historical hourly load data.[16]

The table shows a substantial amount of load diversity between ERCOT and the neighboring systems, indicating that ERCOT may have access to substantial import quantities during shortages to the extent that sufficient intertie capability exists. For example, at the time of ERCOT's peak load, SPP load is likely to be at only 91% of its own non-coincident peak load, leaving more than 5,000 MW of excess generation available for export. However, most of these excess supplies will not be imported because ERCOT is relatively islanded, having only 800 MW of intertie capability with SPP.

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13 See ERCOT (2013a).

14 The new ERCOT Load forecast reports a year 2016 projected peak load of 70,014 MW, or 1,145 MW lower than the 71,159 MW 50/50 peak load that we use for this study. See ERCOT (2014b).

15 See ECCO (2013a and b).

16 Specifically, SPP and Entergy's 50/50 peak load forecasts are from the *2012 Long-Term Reliability Assessment*, while the Mexican states' peak load is based on an assumed 15% reserve margin above the currently-installed generation fleet, see NERC (2012) and Ventyx (2014). Load shapes in Mexico are assumed identical to those in ERCOT's South Zone, as estimated by ERCOT staff; load shapes in SPP and Entergy are based on our independently-developed statistical relationship between hourly weather and load estimated over five years of load and weather data from FERC (2013a) and NOAA (2013).

Table 1
50/50 Peak Loads and Diversity as Used in Reserve Margin Accounting
Excluding DR Gross-Up, Including TDSP Energy Efficiency

		ERCOT	SPP	Mexico	Entergy	Total
50/50 Summer Peak Load						
Non-Coincident	*(MW)*	71,159	56,781	9,910	26,535	164,385
Coincident	*(MW)*	70,106	56,080	9,484	25,766	161,436
At ERCOT Peak	*(MW)*	71,159	51,760	9,543	24,959	157,421
Load Diversity						
At Coincident Peak	*(%)*	1.48%	1.23%	4.30%	2.90%	1.79%
At ERCOT Peak	*(%)*	0.00%	8.84%	3.70%	5.94%	4.24%
Reserve Margin at Criterion						
At Non-Coincident Peak	*(%)*	n/a	13.6%	15.0%	12.0%	n/a
At ERCOT Peak	*(%)*	n/a	24.6%	19.4%	19.1%	n/a

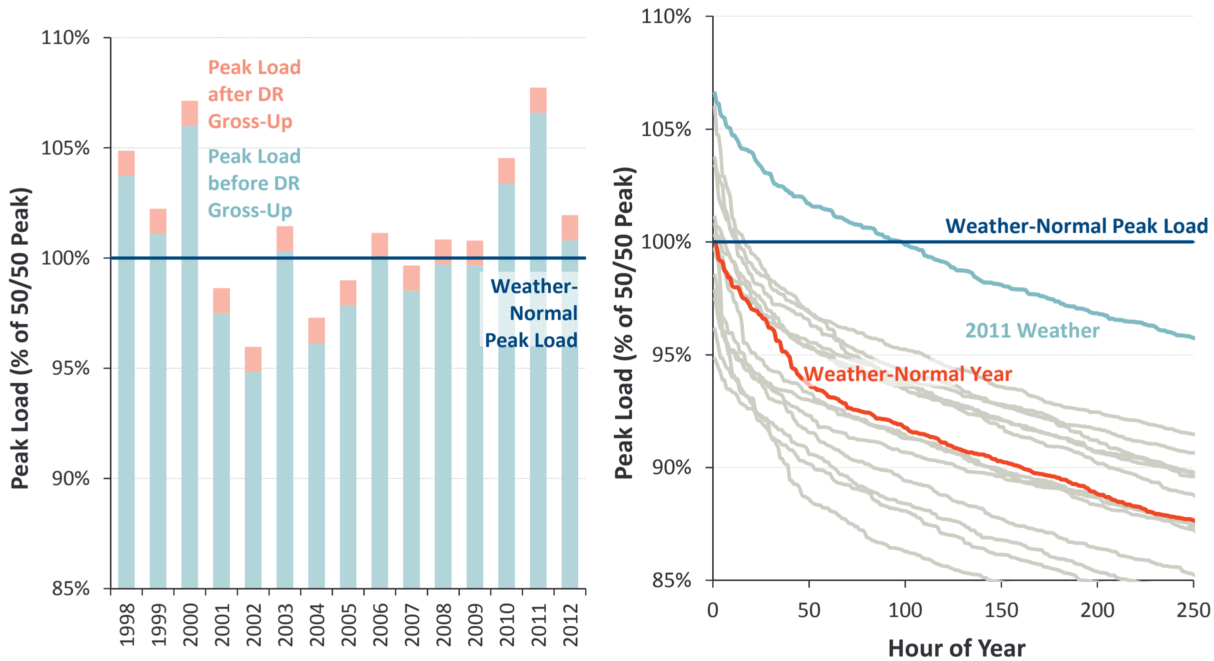
Sources and Notes:
ERCOT load shapes and 50/50 peak load for 2016 provided by ERCOT staff.
Table is consistent with peak loads used in reserve margin accounting (excluding any PRD or LR gross-up, but including TDSP Energy Efficiency Programs), see ERCOT (2013a).
SPP and Entergy peak load forecasts, demand-response capability, and reserve margin requirements from NERC 2012 Long-Term reliability assessments, see NERC (2012).
SPP and Entergy load shapes developed based on statistical relationships from five years of load data (from FERC Form 714) and 15 years of weather data, see FERC (2013a) and NOAA (2013).
Mexico load shape and forecast data were unavailable, assumed a representative 15% reserve margin above generation fleet from Ventyx and a load shape from the ERCOT South zone, see Ventyx (2014).

2. Load Shapes and Weather Years

We represent weather uncertainty by modeling 15 weather years from 1998–2012, as summarized in Figure 2. The left chart shows projected 2016 peak load relative to the weather-normal peak load before and after load gross-ups for PRD and LRs as explained further in Section II.D. The chart illustrates asymmetry in the distribution of peak loads, with the highest projected peak load (consistent with 2011 weather) at 6.6% above weather-normalized peak loads, compared to a peak load in the mildest weather year that is only 5.2% below weather-normalized peak load.

The right chart in Figure 2 shows the 2016 load duration curves for the 250 highest-load hours across all 15 weather years. The 2016 load duration curve consistent with a repeat of the extreme and extended hot summer weather in 2011 is shown as the light blue line in the chart. As shown, the entire load duration curve from 2011 weather is far above all weather years. This extreme heat was the driver of a number of emergency events and price spikes during the summer of 2011, which is described by some as a 1-in-100 weather year. As a result, the probability assigned to a repeat of 2011-type weather is a source of substantial uncertainty and an important driver of both reliability and economic results. Consistent with other ERCOT analyses, we assume a probability of 1% to the 2011 weather pattern, but also report sensitivity results for a 0% probability and equal probability (1/15 chance) that the 2011 weather pattern might recur.[17]

Figure 2
ERCOT Peak Load (Left) and Peak Load Duration Curve (Right) by Weather Year



Sources and Notes:
ERCOT load shapes for 2016 provided by ERCOT staff.
Peak loads are shown before and after gross-up for PRD and LRs (see Section II.D), load duration curves exclude any gross-ups .

3. Load Forecast Uncertainty and Forward Period

Forward-looking "planning" or "target" reserve margins differ from actually-realized reserve margins because both realized peak load and actual available resources can differ from their projected levels. Realized load will differ from projected load for two reasons. First, due to weather, because weather cannot be exactly predicted and will cause peak load to differ from the normalized-weather forecast as explained above. Second, because there are uncertainties in population growth, economic growth, efficiency rates, and other factors. These non-weather drivers of load forecast errors (LFEs) differ from weather-related LFEs because they increase with the forward planning period, while weather uncertainties will generally remain constant and be independent with the forward period.

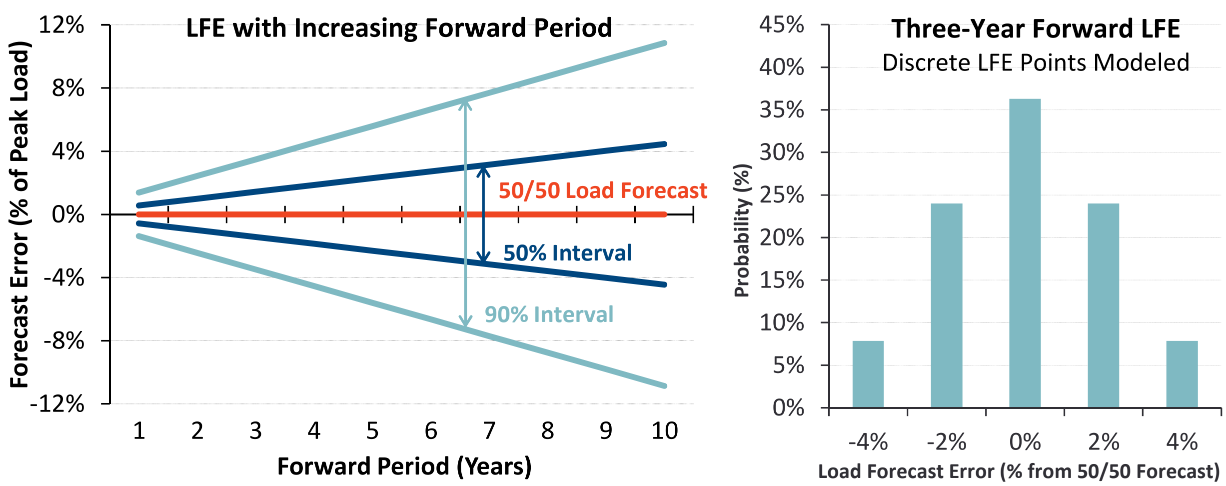
As shown in the left chart of Figure 3, we assume that a non-weather LFE is normally distributed with a standard deviation of 0.8% on a 1-year forward basis, increasing by 0.6% with each

[17] Based on a 2011 weather probability assumption provided by ERCOT staff.

additional forward year.[18] The distribution includes no bias or asymmetry in non-weather LFEs, unlike the weather-driven LFE in ERCOT, which has more upside than downside uncertainty.

For our purposes, the relevant forward period for characterizing non-weather LFEs is the period at which investment decisions must be finalized. We assume investment decisions must be finalized three years prior to delivery, consistent with the approximate construction lead time for new generation resources. This means that available supply and the expected planning reserve margin are "locked in" at three years forward, and the realized reserve margin may differ substantially as both weather and non-weather uncertainties are resolved as the delivery year approaches. The right-hand chart of Figure 3 shows the five discrete LFE points we model, equal to 0%, +/-2%, and +/-4% above and below the forecast. The largest errors are the least likely, consistent with a normal distribution. We also conduct a sensitivity analysis, examining the implications on economically optimal and reliability-based reserve margins if the forward period is varied between zero and four years forward.

Figure 3
Non-Weather Load Forecast Error



C. Generation Resources

We model the economic, availability, ancillary service capability, and dispatch characteristics of all generation units in the ERCOT fleet, using plant ratings and online status consistent with ERCOT's May 2013 CDR report. We describe here the different approaches we use for modeling conventional generation, private use networks (PUNs), and intermittent wind and solar. We also describe here the assumed cost and technical specifications of the gas combined cycle reference technology that we add or subtract to vary the system reserve margin.

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18 This assumed LFE outlook is a standard assumption that we developed in lieu of any ERCOT-specific analysis, which would require either a longer history of load forecasts in ERCOT or a new analysis developed out of ERCOT's peak load forecast, neither of which are currently available.

1. Conventional Generation Outages

A major component of reliability analyses is modeling the availability of supply resources after considering planned and forced outages. We model forced and maintenance outages of conventional generation units stochastically, with partial and full forced outages occurring probabilistically based on distributions accounting for time-to-fail, time-to-repair, startup failure rates, and partial outage derate percentages. Maintenance outages also occur stochastically, but SERVM accommodates maintenance outages with some flexibility to schedule maintenance during off-peak hours. Planned outages are differentiated from maintenance outages and are scheduled prior to each hourly simulation to occur during low demand periods in the spring and fall, such that the highest coincident planned outages occur in the lowest load days. This outage modeling approach allows SERVM to recognize some system-wide scheduling flexibility while also capturing the potential for severe shortages caused by a number of coincident unplanned outages.[19]

We develop distributions of outage parameters for time-to-fail, time-to-repair, partial outage derate percentages, startup probabilities, and startup time-to-repair from historical Generation Availability Data System (GADS) data for individual units in ERCOT's fleet, supplemented by asset class average outage rates provided by ERCOT where unit-specific data were unavailable. Table 2 summarizes fleet-wide and asset-class outage rates, including both partial and forced outages.

Table 2
Forced Outage Rates by Asset Class and Fleet Average

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

Sources and Notes:
Parameter distributions based on unit-specific GADS data and asset class average outage rates from ERCOT.

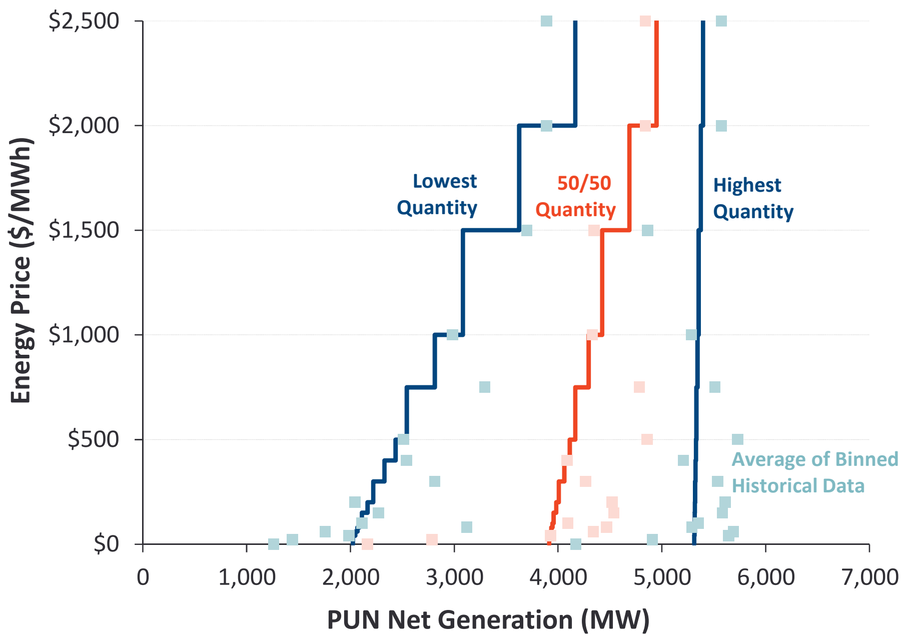
19 Capturing the possibility of such low-probability, high-impact events is an advantage of the unit-specific Monte Carlo outage modeling used in SERVM. Other production cost and reliability models typically use a simpler convolution method, resulting in a distribution of outages that may under-estimate the potential for extreme events, especially in small systems.

2. Private Use Networks

We represent generation from Private Use Networks (PUNs) in ERCOT on a net generation basis, where the net output increases with the system energy price consistent with historical data and as summarized in Figure 4. At any given price, the realized net PUN generation has a probabilistic quantity, with 11 different possible quantities of net generation within each of 15 different price bands.[20] Each of the 11 possible quantities has an equal 9.1% chance of materializing, although Figure 4 reports only the lowest, median, and highest possible quantity. We developed this probabilistic net PUN supply curve based on aggregate hourly historical net output data within each of these selected price bands. During scarcity conditions at prices $2,500 or higher, PUN output produces at least 3,900 MW of net generation with an average of 4,700 MW.

We observe a pattern of availability and price-responsiveness consistent with: (a) gross generation, much of which is fully integrated into ERCOT's economic dispatch and security constrained economic dispatch (SCED), resulting in substantial increases in the expected quantities over moderate price levels, minus (b) gross load, which introduces some probabilistic uncertainty around net generation, minus (c) some apparent load price-responsiveness, which likely contributes to some small additional increase in net PUN generation at very high prices.

Figure 4
PUN Net Generation



Sources and Notes:

Hourly net PUN generation from ERCOT, hourly prices from Ventyx (2014).

Individual data points represent summary of data in a series of data binned by price level, within each price bin, the points on the chart represent the lowest 9.1%, middle 9.1%, and top 9.1% of realized quantities in calendar year 2011.

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[20] Hourly net PUN output data gathered from ERCOT, hourly price data from Ventyx (2014).

3. Intermittent Wind and Solar

We model a total quantity of intermittent wind and solar photovoltaic resources from ERCOT's May 2013 CDR report, including the installed capacity of all existing and planned resources as of 2016.[21] This includes 15,160 MW nameplate capacity of wind and 124 MW nameplate of solar, with intermittent output based on hourly generation profiles that are specific to each weather year.

We developed our system-wide hourly wind profiles by aggregating 14 years of hourly wind shapes for individual units across the system wind shapes over 1998 to 2011, as provided by ERCOT staff.[22] Figure 5 plots the average wind output by month and time of day, showing the highest output overnight and in winter months with the lowest output in mid-day and in summer months. The overall capacity factor for wind resources is 36.9%; although we calculate reserve margins assuming an effective load-carrying capability of 8.7% consistent with the ERCOT May 2013 CDR convention.[23] As in other systems, it is likely that the estimate of wind ELCC will change over time as system conditions change or accounting conventions change. Changing this assigned ELCC would change the reserve margins that we report in our study, and would require only a simple accounting translation to adjust.

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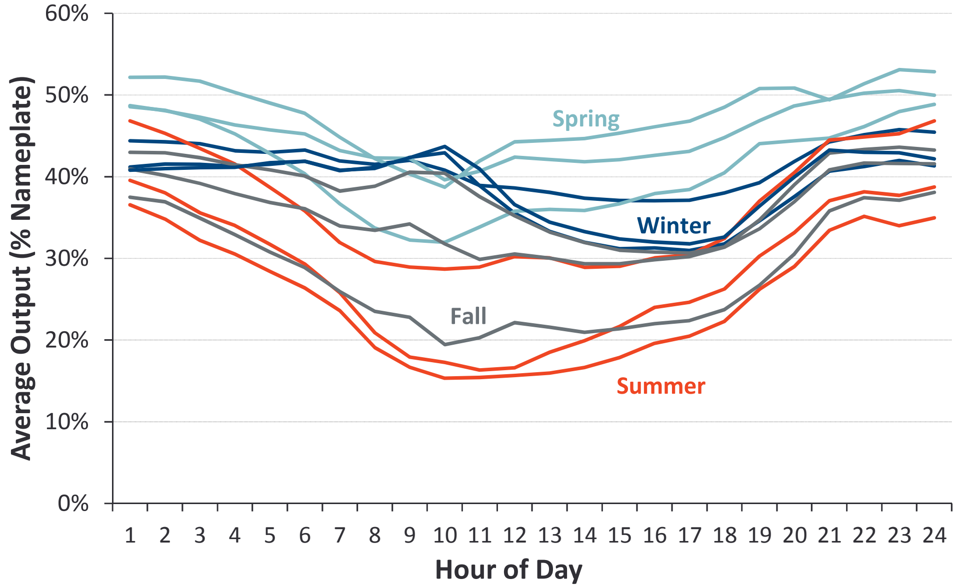
21 See ERCOT (2013a).

22 We aggregated unit-specific output profiles for all units, including traditional and coastal units. ERCOT obtained the original wind profiles through AWS True Power. Because ERCOT did not provide a profile for the year 2012, we use the 2011 wind profile to reflect 2012 as well. For new resources without an identified location, we used the fleet-average profile as aggregated from among existing resources.

23 See ERCOT (2013a), p. 31.

Figure 5
Average Wind Output by Month and Time of Day



Sources and Notes:
Average of 15 years' hourly wind profiles provided by ERCOT, originally from AWS True Power.

We similarly model hourly solar photovoltaic output based on hourly output profiles that are specific to each weather year, as aggregated from county-specific output profiles over years 1998 to 2010.[24] In aggregate, solar resources have a capacity factor of 25.4% across all years, and we assign a 100% of nameplate contribution toward the reserve margin consistent with ERCOT's CDR accounting convention.[25]

4. Hydroelectric

We include 521 MW of hydroelectric resources, consistent with ERCOT's May 2013 CDR report.[26] We characterize hydro resources using five years of hourly data over 2008–2012 provided by ERCOT, and 15 years of monthly data over 1998–2012 from FERC form 923.[27] For each month, SERVM uses two parameters for modeling hydro resources, as summarized in Figure

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24 Individual county output profiles were provided by ERCOT. Because ERCOT did not provide profiles for the years 2011 and 2012, we adopted the average hourly output profile across years for those weather years.

25 See ERCOT (2013a).

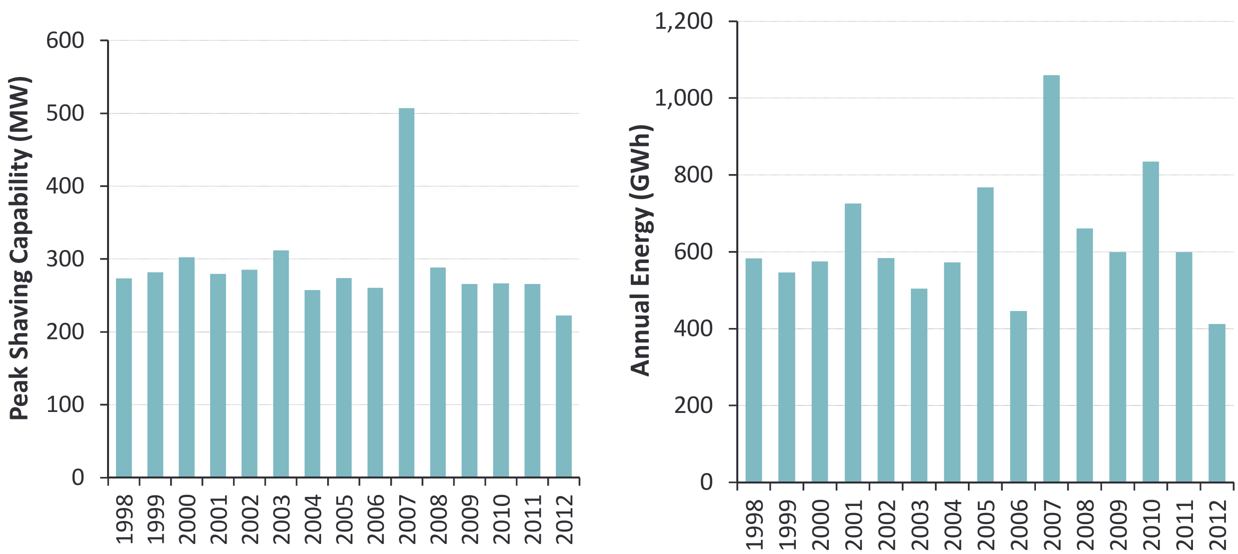
26 See ERCOT (2013a).

27 See FERC (2013b).

6: (1) *monthly total energy output*, as drawn from historical data consistent with each weather year; and (2) *daily peak shaving capability*, as estimated from historical hourly data.[28]

When developing hydro output profiles, SERVM will first schedule output up to the monthly peak shaving capability into the peak hours, but will schedule some output across all hours based on historically observed output during off-peak periods up to the total monthly output. Hydro capacity that is not generating power will contribute toward system reserves and count toward the Operating Reserve Demand Curve (ORDC) x-axis, as described in Section II.F.5.[29]

Figure 6
Hydro Peak Shaving Capability (left) and Hydro Annual Energy (right)



Sources and Notes:
Monthly and annual energy data from FERC (2013b), peak shaving capability based on five years of historical hourly data from ERCOT.

5. Marginal Resource Technology

To simulate ERCOT's system across different reserve margins, we must vary the quantity of installed generating capacity. We vary the quantity of gas combined cycle (CC) plants in our Base Case, and examine a sensitivity case where we vary the quantity of gas combustion turbines (CTs). The choice of a gas CC as the reference technology is a change from the assumptions we

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28 For years prior to 2008, we did not have hourly hydro data and instead estimated daily peak shaving capability based on a linear relationship between the two parameters.

29 This remaining hydro capacity is approximately equal to 240 MW on average, consistent with the contribution that hydrosynchronous resources contribute to ERCOT's physical responsive capacity metric as calculated according to ERCOT (2013d), Section 6.5.7.5.

used in our 2012 study, but is consistent with more recent developer announcements that indicate more CCs will be built than CTs.[30]

The costs and performance characteristics of the reference CC and CT are summarized in Table 3 and Table 4 respectively. We use the same GE 7FA technology as assumed in our 2012 study, although we have updated the cost of new entry (CONE) for escalation and cost of capital.[31] We apply 4.3% and 5.2% in cost escalation for the CT and CC respectively, consistent with a one-year delay in online date from 2015 to 2016.[32] We have also updated our estimate of the after-tax weighted-average cost of capital (ATWACC) for a merchant developer to 8.0% as summarized in Table 3. This results in an estimated CONE of $97,000/MW-yr and $122,100/MW-yr for the gas CT and CC respectively, although we also examine a sensitivity range of -10%/+25% in CONE.

Table 3
Gross Cost of New Entry

	ATWACC	Gross CONE	
		Simple Cycle	Combined Cycle
	(%/yr)	*($/MW-yr)*	*($/MW-yr)*
From 2012 Study (2015 Online Date)			
Low: Merchant ATWACC	7.6%	$90,100	$112,400
Mid: ERCOT Planning Assumption	9.6%	$105,000	$131,000
High: Developer-Reported	11.0%	$131,000	$145,000
Updated Estimate (2016 Online Date)			
Low: Base minus 10%	n/a	$87,300	$109,900
Base: Merchant ATWACC	8.0%	$97,000	$122,100
High: Base plus 25%	n/a	$121,300	$152,600

Sources and Notes:
2012 Study numbers and current numbers are adapted from a CONE study for PJM, with adjustments applied as relevant for ERCOT, see Newell, *et al.* (2012) and Spees, *et al.* (2011).
Updated estimate applies 4.3% and 5.2% escalation derived from Newell, *et al.* (2013b).

30 For example, Panda Power currently has three combined cycle stations under construction, the Lower Colorado River Authority's Ferguson Replacement project will be a combined cycle facility, and FGE Power recently announced plans to build a combined cycle project in Mitchel County.

31 See Newell, *et al.* (2012), derived from CONE numbers originally from Spees, *et al.* (2011).

32 These escalation rates are derived from a study of component-specific escalation rates as documented in Newell, *et al.* (2013b).

Table 4
Performance Characteristics

		Simple Cycle	Combined Cycle
Plant Configuration			
Turbine		GE 7FA.05	GE 7FA.05
Configuration		2 x 0	2 x 1
Heat Rate (HHV)			
Base Load			
Non-Summer	*(btu/kWh)*	10,094	6,722
Summer	*(btu/kWh)*	10,320	6,883
Max Load w/ Duct Firing			
Non-Summer	*(btu/kWh)*	n/a	6,914
Summer	*(btu/kWh)*	n/a	7,096
Installed Capacity			
Base Load			
Non-Summer	*(MW)*	418	627
Summer	*(MW)*	390	584
Max Load			
Non-Summer	*(MW)*	n/a	701
Summer	*(MW)*	n/a	656

Sources and Notes:
Technical and performance parameters from Spees, *et al.* (2011).

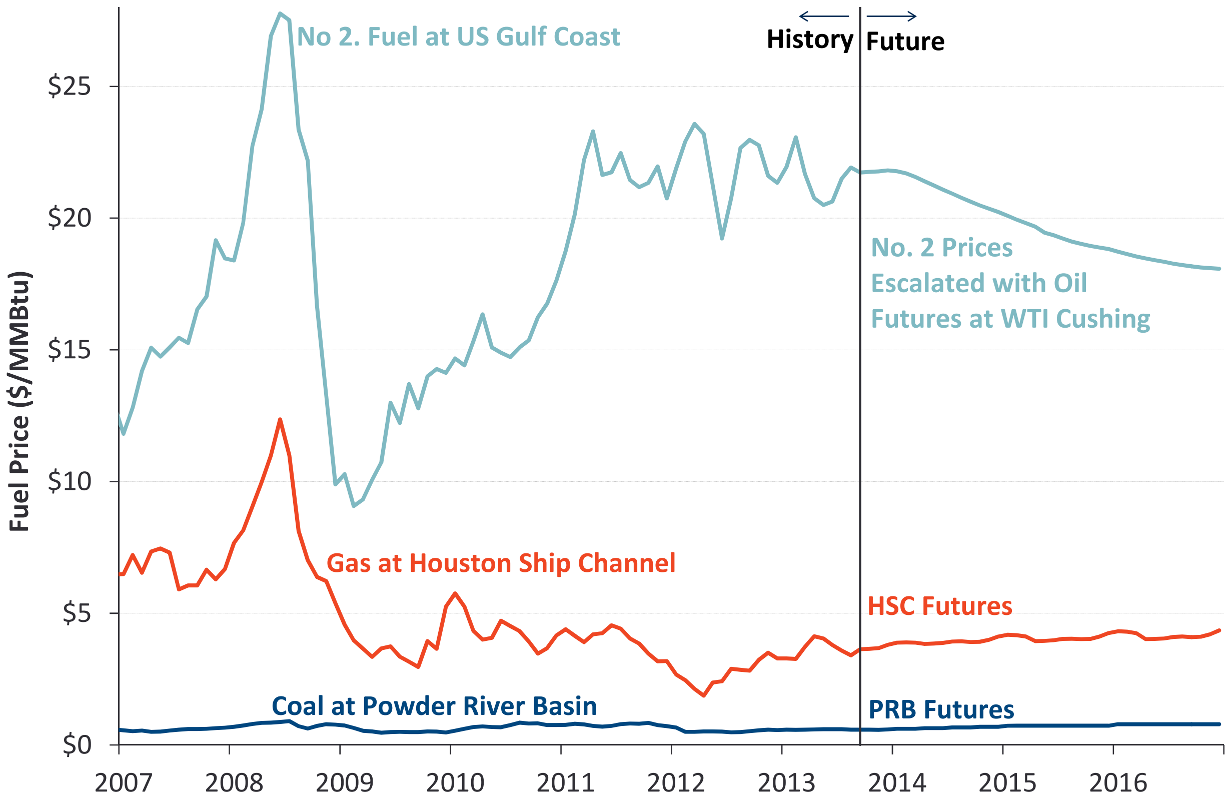
6. Fuel Prices

We estimate monthly fuel prices for gas, coal, and oil-fired plants in ERCOT and the neighboring regions using futures prices for the year 2016 and after applying a delivered fuel price basis. We use Houston Ship Channel, U.S. Gulf Coast, and Powder River Basin as the market price points for historical and futures prices as shown in Figure 7.[33] To estimate a delivered fuel price basis for each market, we calculated the historical difference between that market price point and prices as delivered to plants in that region and then escalated the delivered price basis with inflation to the year 2016.[34] This locational basis is inclusive of both market price basis as well as a delivery charge and therefore may be positive or negative overall as shown in Table 5.

33 Oil futures at WTI Cushing were used to escalate No. 2 fuel oil prices into the future due to lack of data on No. 2 futures at U.S. Gulf Coast. Data obtained from Bloomberg (2014), and SNL Energy (2014).

34 Fuel price basis varies by region by not among individual plants. Historical delivered fuel prices from Ventyx (2014).

Figure 7
Historical and Futures Prices for Gas, Coal, and No. 2 Distillate



Sources and Notes:
No. 2 prices escalated using a linear relationship with WTI Cushing and escalated with WTI futures.
Historical and futures prices from Bloomberg (2014) and SNL Energy (2014).

Table 5
Delivered Fuel Price Basis including Market Basis and Delivery Charges

	Coal above Powder River Basin *(2016$/MMBtu)*	**Gas** above Houston Ship Channel *(2016$/MMBtu)*	**No. 2 Diesel** above U.S. Gulf Coast *(2016$/MMBtu)*
ERCOT	$1.10	$0.62	$1.35
SPP	$0.93	$0.90	$0.84
Entergy	$1.24	$0.81	-$1.61

Sources and Notes:
Locational basis estimated based on delivered fuel prices relative to market price point.
Historical delivered prices from Ventyx (2014).

D. Demand-Side Resources

We account for all of the several types of demand resources in ERCOT, including explicitly modeling how they participate in the energy and ancillary services markets, whether they are triggered by price-based or emergency actions, and restrictions on availability and call hours.

1. Costs and Modeling of Demand Resources

A number of different types of demand-side resources contribute to resource adequacy in ERCOT. Table 6 summarizes these resources, explaining how we model their characteristics, their assumed marginal costs when interrupted, and how they are accounted for in the reserve margin. We developed these assumptions in close coordination with the ERCOT staff, who provided assumptions regarding the appropriate losses gross up, and the anticipated quantities of all types of demand response other than price responsive demand (PRD).

The marginal costs of these demand-side resources are highly uncertain, although the marginal costs we report in the table are in the general range that we would anticipate given the sparse data availability. Most of these resources including TDSP load management, emergency response service (ERS), and load resources (LRs) are dispatched for energy based on an emergency trigger rather than a price-based trigger consistent with marginal cost. We make the simplifying assumption that these resources are triggered in order of ascending marginal cost, and at the time when market prices are equal to their marginal curtailment cost in our Perfect Energy Price Case as explained further in Section II.F.5 below.

Two types of demand-side resources, TDSP energy efficiency (EE) and self-curtailment to avoid four coincident peak (4 CP) transmission charges are not explicitly modeled because these load reductions are already excluded from load shapes and would be realized equally across all modeled reserve margins. However, these resources are appropriately accounted for using the conventions of ERCOT's CDR report as explained further in section II.G below.

Table 6
Summary of Demand Resource Characteristics and Modeling Approach

Resource Type	Quantity Including Losses	Modeling Approach	Marginal Cost	Adjustments to ERCOT Load Shape	Reserve Margin Accounting
TDSP Programs					
Energy Efficiency	553	Not explicitly modeled.	*n/a*	None (ERCOT load shapes already reduced for TDSP EE Programs).	Load reduction. 541 MW pre-losses.
Load Management	251	Emergency trigger at EEA Level 1.	$2,450	None (ERCOT load shapes estimated assuming no LM curtailments).	Load reduction. 240 MW pre-losses.
Emergency Response Service (ERS)					
10-Minute ERS	363 MW at Peak. 496 MW Maximum.	Emergency trigger at EEA Level 2.	$3,681	None (ERCOT load shapes estimated assuming no ERS curtailments).	Load reduction. 347 MW pre-losses.
30-Minute ERS	80 MW at Peak. 133 MW Maximum.	Emergency trigger at EEA Level 1.	$1,405	None (ERCOT load shapes estimated assuming no ERS curtailments).	Load reduction. 77 MW pre-losses.
Load Resources (LRs)					
Non-Controllable LRs	1,205 MW at Peak. 1,400 MW Maximum.	Economically dispatch for RRS (most hours) or energy (few peak hours). Emergency deployment at EEA Level 2.	$2,569	Grossed up by as much as 195 MW.	1,205 MW load reduction. Remaining 195 MW will be excluded from reported peak load.
Controllable LRs	36	Self-schedule for Regulation in all hours.	*n/a*	None.	Supply Resource.
Voluntary Self-Curtailments					
4 CP Reductions	715	Not explicitly modeled (assume 4CP behavior will persist in all circumstances).	*n/a*	None (ERCOT load shapes already reduced for 4CP response).	None. Already excluded from reported peak load.
Price Responsive Demand	706	Economic self-curtailment, but with uncertain availability.	$250 - $9,000/MWh	Grossed Up.	None. Already excluded from reported peak load.

Sources and Notes:
Developed based on analyses of recent DR participation in each program and input and data from ERCOT staff. See following sections.
For 10-Minute ERS and 30-Minute ERS there is an 8-hour call limit per Contract Period. See Table 7 below.
TDSP Load Management Programs have a 16-hour call limit from June to September.

2. Emergency Response Service

Emergency Response Service (ERS) includes two types of products, 10-minute and 30-minute ERS, with the quantity of each product available changing by time of day and season as shown in Table 7. The quantity of each product by time of day and season is proportional to the quantities most recently procured over the four seasons of year 2013, with the 2016 summer peak quantity assumption provided by ERCOT.[35] We apply a losses gross-up to these ERS quantities for modeling purposes, but do not apply that gross-up when calculating the reserve margin as is the convention in the CDR report. Demand resources enrolled under ERS are dispatchable by ERCOT during emergencies, but cannot be called outside their contracted hours and cannot be called for more than eight hours total per season.[36]

Table 7
Assumed ERS Quantities Available in 2016

Contract Period	Quantity (w/o Losses)		Quantity (w/ Losses)		
	10-Min *(MW)*	30-Min *(MW)*	10-Min *(MW)*	30-Min *(MW)*	Total *(MW)*
June - September					
BH1: Weekdays 8 AM - 1 PM	475	128	496	133	629
BH2: Weekdays 1 PM - 4 PM	353	88	369	92	461
BH3: Weekdays 4 PM - 8 PM*	347	77	363	80	443
NBH: All Other Hours	387	101	404	106	510
October - January					
BH1: Weekdays 8 AM - 1 PM	453	81	472	84	557
BH2: Weekdays 1 PM - 4 PM	450	83	470	86	556
BH3: Weekdays 4 PM - 8 PM	437	82	456	86	542
NBH: All Other Hours	405	72	422	75	497
February - May					
BH1: Weekdays 8 AM - 1 PM	460	73	480	77	557
BH2: Weekdays 1 PM - 4 PM	459	73	479	77	556
BH3: Weekdays 4 PM - 8 PM	443	59	463	62	525
NBH: All Other Hours	386	41	403	43	445
Summer Peak (June-Sept, BH3)	347	77	363	80	443
Maximum at Any Time	475	128	496	133	629

Sources and Notes:
Total available ERS MW for 2016 June-Sept. BH3 provided by ERCOT staff.
ERS 10-min and 30-min MW for other contract periods scaled proportionally to summer quantity, based on availability over calendar year 2013, from ERCOT (2013e).
ERS resources have an eight-hour call limit applies to both product types and are not callable outside contracted hours, see ERCOT (2013f-g).

[35] For total ERS procurement quantities by product type and season, see ERCOT (2013e).

[36] See ERCOT (2013f–g).

3. Non-Controllable Load Resources

We model 1,400 MW of non-controllable load resources (LRs) that actively participate in the responsive reserve service (RRS) market.[37] These non-controllable LRs are separated into two dispatch blocks with different costs and dispatch characteristics as summarized in Table 8 and Figure 8. The larger 1,205 MW block of LRs self-schedule to sell RRS in all hours, but in emergency conditions ERCOT will dispatch these resources for energy during emergency conditions as explained further in Section II.F.2.

The smaller 195 MW block of resources is modeled similarly to generation that is dispatched against an energy "strike price" of $380/MWh. These resources will be scheduled for RRS service in most hours when energy prices are relatively low; but during peaking events they will act like demand response that self-curtails to avoid paying those high prices. The approximate $380/MWh strike price for these resources is based on an analysis of the realized quantities of non-controllable LRs that withdrew from the RRS market during times of high energy prices as shown in Figure 8. This modeling approach mimics typical market results in which the vast majority of hours will attract the maximum 1,400 MW of LRs in RRS, but summer peak hours will clear a lower quantity.[38]

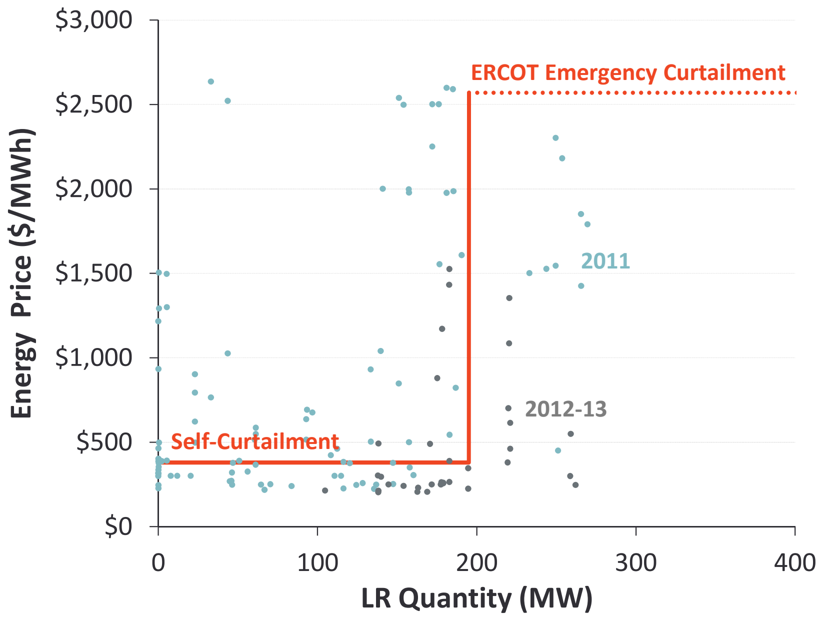
Table 8
Non-Controllable LRs Block Characteristics

Block Size *(MW)*	Cumulative Quantity *(MW)*	Marginal Cost *($/MWh)*	Energy Strike Price *($/MWh)*
195	195	$380	$380
1,205	1,400	$2,569	$9,000

[37] Currently, 1,400 MW is the maximum quantity of non-controllable LRs that are allowed to sell responsive reserve service (RRS) and is the clearing quantity in the vast majority of hours.

[38] Note that the self-curtailed LRs also contribute to resource adequacy by avoiding energy consumption during peak times similar to PRD, but also like PRD these loads are not included in ERCOT's load forecast and so are not an explicit line item in the CDR report.

Figure 8
Marginal Cost of Non-Controllable Load Resources



Sources and Notes:

Non-controllable LR Quantity on the x-axis is the quantity not clearing for RRS, and assumed to self-curtail for energy.

LR cleared and uncleared quantities from ERCOT, hourly energy prices from Ventyx (2014).

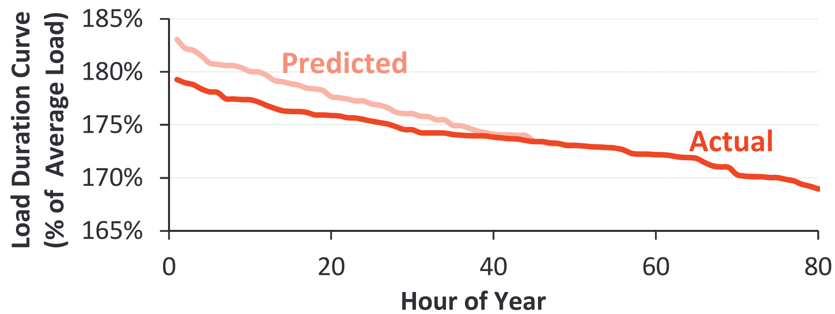
4. Price-Responsive Demand

To date there has been no comprehensive study of the likely quantity of price responsive demand (PRD) active in ERCOT, and energy price is not included as a predictive variable in ERCOT's load forecast. The quantity of PRD that currently exists is uncertain and likely to grow over the coming years as the energy market price cap increases to $9,000/MWh and as other scarcity pricing reforms result in more frequent high price events.

We estimate the approximate quantity of PRD in ERCOT by comparing realized load shapes over the top 50 hours in the 2008–2011 period to those forecast in ERCOT's load shapes over the same weather years. We observe that ERCOT's forecast of its top 50-hour load shape is "peakier" than the actual realized load shapes, likely because ERCOT's predicted load shape is not flattened by the PRD that responded to high prices. Figure 9 shows the comparison of these two peak load duration curves for the year 2011, with actual loads grossed up for curtailments in non-controllable LRs and ERS deployments. Overall, this peakier forecast load shape indicates an approximate 1% PRD penetration, although with substantial uncertainty.

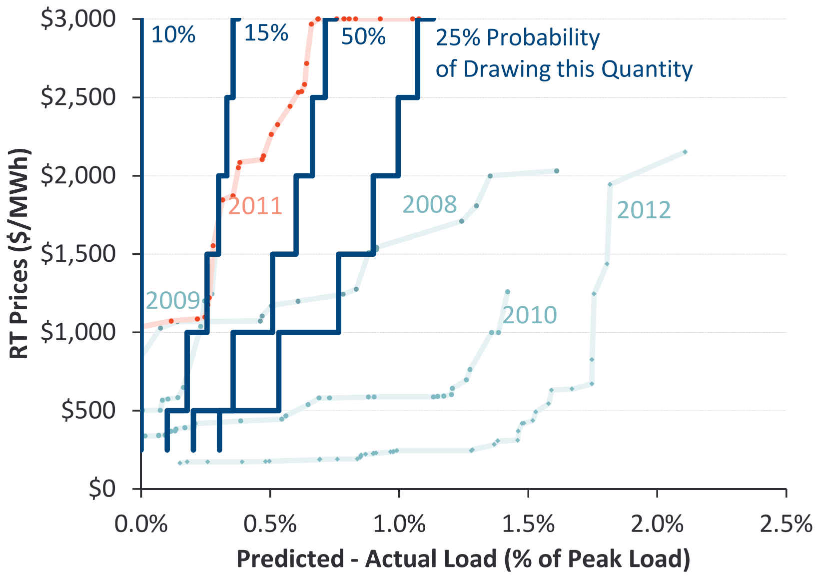
To model PRD, we first stretch the ERCOT load duration curve in the super-peak hours by up to 1% above the forecast, while maintaining the same load shape and annual energy. We then model PRD as a supply-side resource, with some uncertainty in the quantity that will be realized as shown in Figure 10. At the price cap of $9,000/MWh, we assume a 10%, 15%, 50%, and 25% chance of 0%, 0.5%, 1%, and 1.5% PRD respectively. We calculate the quantity of PRD available at price levels below the cap assuming a constant elasticity of demand. For comparison in the chart, we also show our approximate PRD supply curve compared to prices and approximate PRD quantities as implied by a comparison of predicted and actual load shapes. We stress that this analysis is a relatively rough approximation of PRD in ERCOT, and would recommend a more thorough statistical analysis of this resource, including possibly incorporating price as an explicit variable in ERCOT's various load modeling exercises.

Figure 9
Peak Load Duration Curve
2011 Weather Projected Compared to Actual



Sources and Notes:
Actual and modeled hourly load data provided by ERCOT.

Figure 10
Price Responsive Demand
Energy Supply Curve, Compared to Historical



Sources and Notes:
Actual and modeled hourly load data provided by ERCOT, actual prices from Ventyx. (2014).

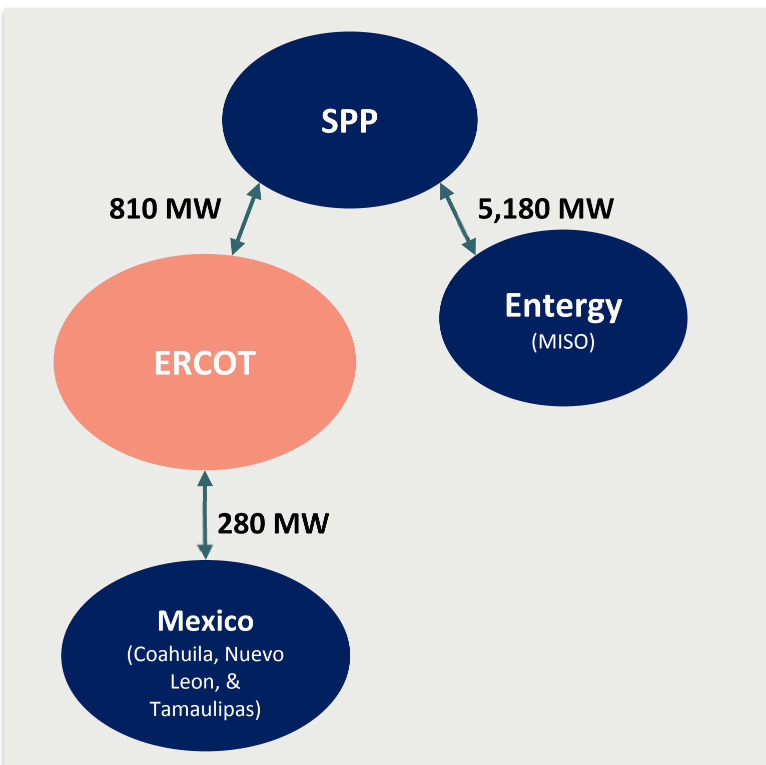
E. ERCOT AND EXTERNAL SYSTEMS' RESOURCE OVERVIEW

This section of our report provides an overview of the ERCOT fleet as summarized for individual resource types in Sections II.C and II.D above. We describe the system interconnection topology, intertie availability, ERCOT and neighboring regions' resource mixes and supply curves.

1. System Topology and Intertie Availability

We model ERCOT and the neighboring interconnected regions with the interconnection topology as shown in Figure 11. ERCOT is a relatively islanded system with only 1,090 MW of high voltage direct current (HVDC) interties; the majority of that intertie capacity is with SPP. As explained in Section II.A above, SERVM runs a multi-area economic dispatch and will schedule imports or exports from ERCOT depending on the relative cost of production compared to the neighboring systems. During peaking conditions, ERCOT will generally import power due to the high internal prices, unless imports cannot be realized. ERCOT may not be able to import during peak conditions because either: (a) the neighboring system experiences a simultaneous shortage and will prioritize meeting its own load, or (b) insufficient intertie capability exists to support the desired imports.

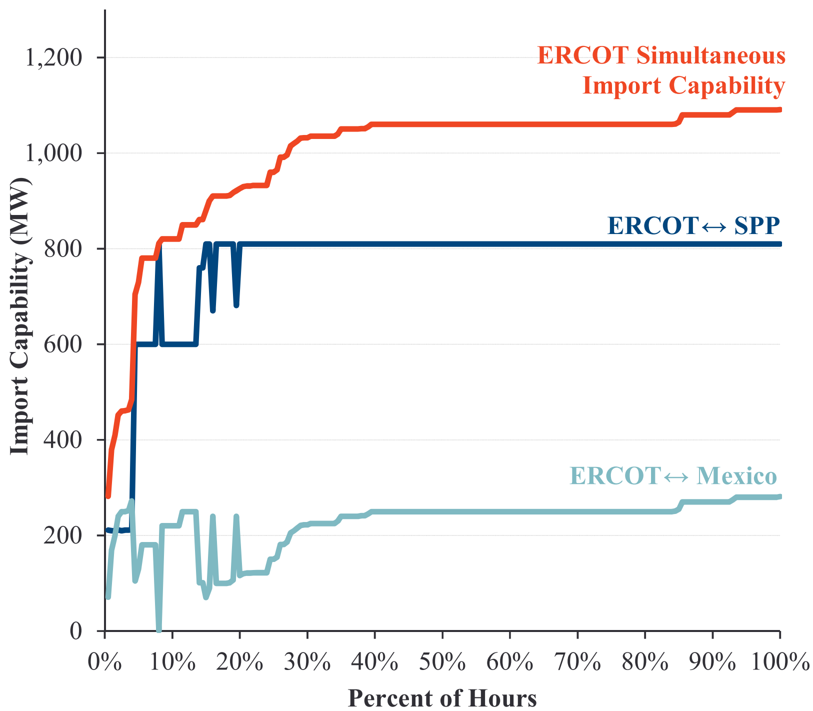
Figure 11
System Topology and Modeled Interties



Sources and Notes:
ERCOT intertie ratings from ERCOT staff, SPP-Entergy path rating from OATI (2013).

We model transmission availability according to a probability distribution that is independent of weather and other variables. Figure 12 shows the cumulative probability distribution of available transfer capability (ATC), derived from hourly ATC data from 2010–2013 across ERCOT's SPP and Mexico interfaces. The SPP-Entergy interface is similarly modeled using a probability distribution with 95% availability on average. Even if transmission is available, ERCOT may not be able to import in emergency if the external region is peaking at the same time.

Figure 12
ERCOT Intertie Capability Cumulative Distribution Function



Sources and Notes:
Based on hourly historical ATC data provided by ERCOT over 2010-13.
Export capability assumed equal to import capability in any individual draw, which is usually (but not always) the case in actual operations.

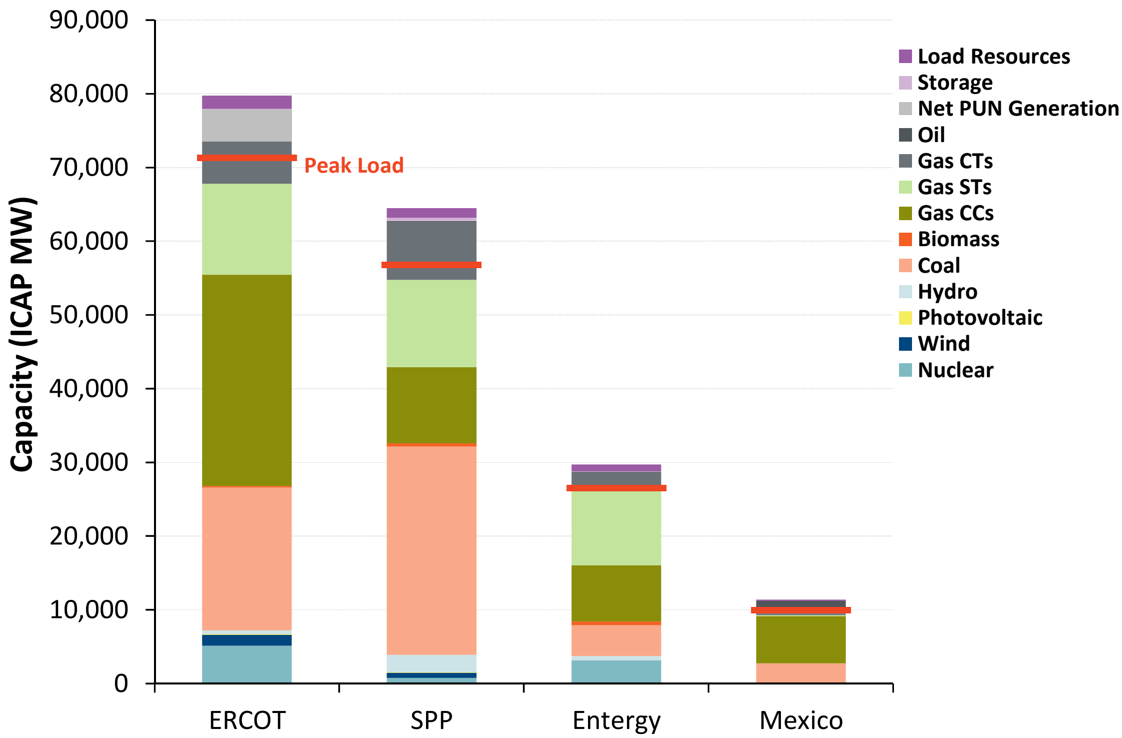
2. Resource Mix Across Reserve Margins

Figure 13 summarizes the supply resource mix that we model in ERCOT, SPP, Entergy, and Mexico. As explained above, we use ERCOT's May 2013 CDR Report as the authoritative source for documenting the ERCOT fleet, although we use the following assumptions for some special resource types:

- **Switchable Units** are included as internal resources, with the 317 MW unit that is committed off-system excluded from our model;
- **Retirements** are excluded starting in the CDR-specified year;
- **Seasonal Mothballs** are included in our model, with 1,876 MW of seasonal mothballs that are available for dispatch only in summer months, nearly all of them over May through September;
- **Permanent Mothballs** are excluded from our model; and
- **Planned New Units** are excluded.

Starting with this baseline of ERCOT resources, we conduct simulations over a range of reserve margins above and below the existing resource base. To reduce the fleet to the minimum reserve margin, we exclude all planned new resources and mothballed units (as above), and then exclude a small number of additional existing gas CCs that are similar to the reference technology described in Section II.C.5 above. To increase the fleet size, we add a single resource type (a gas CC in the Base Case) across a wide range of potential reserve margins.

Figure 13
Resource Mix for ERCOT and Neighboring Systems



Sources and Notes:
ERCOT shown at a 10% reserve margin resources reflect the May 2013 CDR Report as explained above, with the exception of adjustments related to demand-side resources as instructed by ERCOT and including or excluding resources to adjust the reserve margin as explained in Section II.G, see ERCOT (2013a)
Wind and solar reported at 8.7% and 100% of nameplate respectively, consistent with CDR, see ERCOT (2013a).
External regions' generation resource mix is from Ventyx (2014), with demand-response penetration from NERC (2012).
Total resources in external regions are adjusted such that external regions are at their target reserve margins of 13.6%, 12%, and 15% for SPP, Entergy, and Mexico respectively while maintaining the same generation resource mix, see NERC (2012).

For neighboring regions, we rely on public data sources for the fleet makeup and demand-response penetrations.[39] We model each external region *at criterion,* meaning that we treat them exactly at their respective reserve margin targets of 13.6%, 12%, and 15% for SPP, Entergy, and Mexico respectively.[40] Because these regions are currently capacity long, we adjusted their

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39 Specifically, we take external regions resource mix from Ventyx (2014) and external regions' demand-response penetrations from NERC (2012).

40 See NERC (2012).

resource base downward by removing individual units of different resource types in order to maintain the current overall resource mix.

3. Supply Curves

To provide more intuition regarding anticipated prices and intertie flows during normal conditions, we summarize the ERCOT and neighboring regions' supply curves in Figure 14. The curve reports energy dispatch costs consistent with year 2016, accounting for unit-specific heatrates, variable operations and maintenance (VOM) costs, and locational fuel prices from Section II.C.6. For ERCOT, we gathered unit-specific information representing heatrate curves, VOM, ancillary service capabilities, ramp rates, startup fuel, non-fuel startup costs, and run-time restrictions from ERCOT. For external regions, we gathered unit-specific heatrates from public data sources, supplemented by class-average characteristics similar to those in ERCOT for other unit characteristics.[41]

For all thermal resources, we model a relationship between capacity and hourly temperature which results in increased output from the fleet during colder periods. Each unit is designated a specific weather station in which the hourly temperature determines the output of the plant for that hour. By doing this, we ensure the relationships among load, thermal generation, wind, and solar across the 15 weather years that are simulated.

Overall, the regions have relatively similar supply curves that will tend to reduce the level of interchange compared to neighboring regions with very different economics. Interchange will also be limited because of ERCOT's relatively small quantity of HVDC interties, having only 810 MW of interties with SPP and 280 MW with Mexico.[42] However, some factors affecting the quantity and economic value of interchange include that: (a) SPP has more lower-cost coal that is somewhat cheaper than ERCOT-internal resources that are dominated by efficient but somewhat higher-cost gas CCs, which will lead to ERCOT being a net importer, and (b) Mexico has a substantial proportion of relatively high-cost oil-fired peaking units, which will make such imports unlikely except at high prices in shortage conditions. Further, the regions experience some amount of load diversity that will change the relative economics of supply in each region and lead to inter-regional flows.

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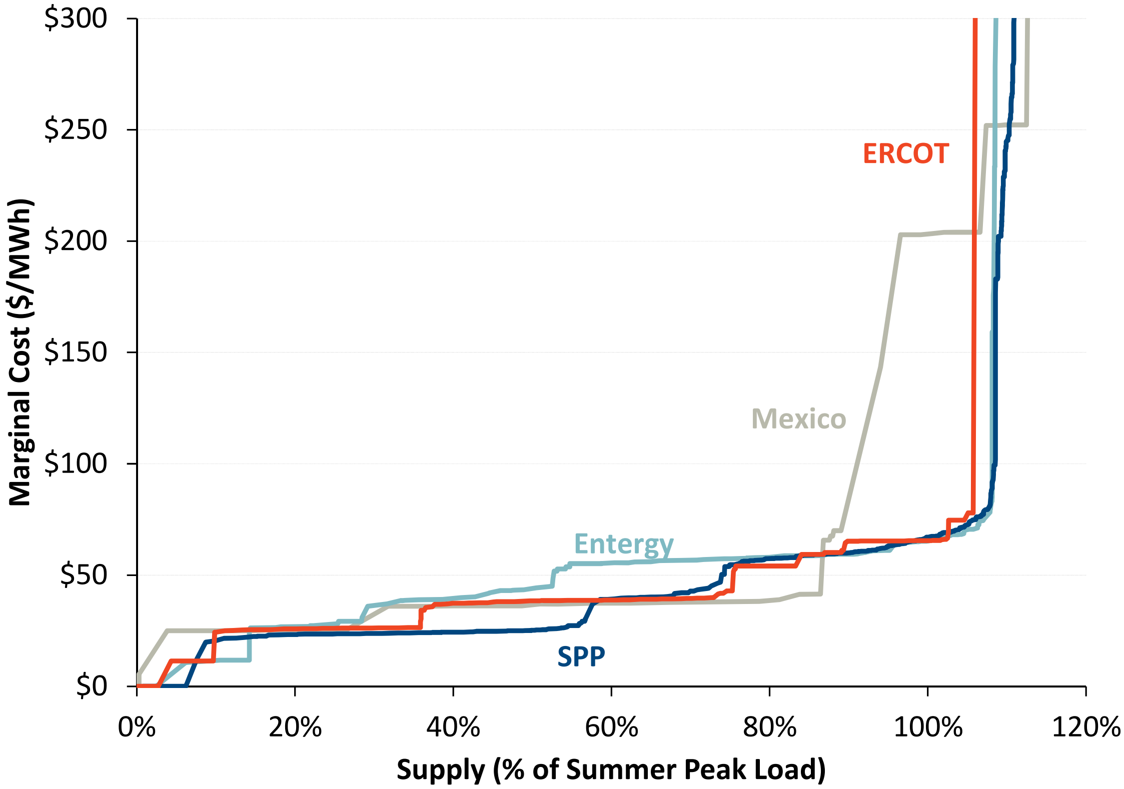
41 We gathered heatrates from Ventyx (2014).

42 Based on several years of historical hourly intertie ratings supplied by ERCOT.

Figure 14
2016 System Supply Curves



Sources and Notes:
ERCOT is shown at 10% reserve margin, with resource mix consistent with May 2013 CDR as explained in Section II.E.2, using unit-specific heat rates, VOM, and other characteristics obtained from ERCOT.
External systems resource mix from Section II.E.2, with resource attributes from Ventyx (2014).
Supply curves reflect VOM and fuel costs, with fuel prices from Section II.C.6 above.

F. Scarcity Conditions

Increasing the reserve margin provides benefits primarily by reducing the frequency and severity of high-cost emergency events. Calculating the economically optimal reserve margin requires a careful examination of the nature, frequency, and cost of each type of market-based or administrative emergency action implemented during such events.

1. Market Parameters

We develop a representation of the ERCOT market consistent for 2016 using the parameters summarized in Table 9, although we note that some of the simulated market design elements are still under revision. We assume that the administrative Value of Lost Load (VOLL) is equal to the true market VOLL and equal to the High System-Wide Offer Cap (HCAP) at $9,000/MWh.[43] We also conduct a sensitivity analysis for a reasonable range of VOLL.

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43 See PUCT (2012).

Consistent with current market rules, we tabulate the Peaker Net Margin (PNM) over the calendar year and reduce the System-Wide Offer Cap (SWOC) to the Low System-Wide Offer Cap (LCAP) of $2,000/MWh after the PNM threshold is exceeded.[44] However, we stress that this mechanism will have much less impact on the market than it has previously because the LCAP now only affects the Power Balance Penalty Curve (PBPC) and suppliers' offers, but does not affect the Operating Reserves Demand Curve (ORDC). Therefore, prices will still rise gradually to the VOLL of $9,000 in shortage conditions even after the PNM threshold is exceeded, thereby rendering the LCAP far less important. We further explain our implementation of the PBPC and ORDC in Sections II.F.4 and II.F.5 below.

Table 9
ERCOT Scarcity Pricing Parameters Assumed for 2016

Parameter	Value	Notes
Value of Lost Load	$9,000/MWh	Administrative and actual
High System-Wide Offer Cap	$9,000/MWh	Always applies to ORDC
Low System-Wide Offer Cap	$2,000/MWh	Applies only to PBPC
Peaker Net Margin Threshold	$291,000/MW-yr	3 x CT CONE

Sources and Notes:
HCAP, LCAP, and VOLL parameters consistent with scheduled increases by 2016, see PUCT (2012).
PNM threshold is set at three times CT CONE consistent with current market rules and our updated CONE estimate from Section II.C.5, but is lower than the $300,000/MW-yr value applicable for 2013, see PUCT (2012).

The offer cap and PNM parameters determine the maximum offer price for small suppliers in ERCOT's market under its monitoring and mitigation framework. However, we do not explicitly model these dynamics and instead assume that suppliers always offer into the market at price levels reflective of their marginal costs, including commitment costs.

2. Emergency Procedures and Marginal Costs

The benefits of increasing the system reserve margin accrue from reducing the frequency and severity of costly scarcity events. Therefore, estimating the economically optimal reserve margin requires careful representation of the nature, trigger order, and marginal costs realized during each type of scarcity event. Table 10 summarizes our modeling approach and assumptions under all scarcity and non-scarcity conditions depending on what type of marginal resource or administrative emergency procedure would be implemented to meet an incremental increase in demand. These marginal resources are listed in the approximate order of increasing marginal costs and emergency event scarcity, although in some cases the deployment order overlaps.

We distinguish between market-based responses to high prices in scarcity conditions and out-of-market administrative interventions triggered by emergency conditions. Among market-based

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44 See PUCT (2012).

responses, we include generation, imports, and price-responsive demand, including some very high-cost resources that will not economically deploy until prices are quite high. We also model reserve shortages that are administrative in nature, but triggered on a price basis consistent with the ORDC and PBPC as explained in the following sections.

A final category of emergency interventions encompasses out-of-market actions including ERS, LR, TDSP load management, and firm load shed deployments that are triggered for non-price reasons during emergency conditions. We implement each of these actions at a particular shortage level as indicated by the quantity of reserves capability available according to the ORDC x-axis, a measure similar to the physical responsive capacity (PRC) indicator used by ERCOT to monitor system operations. To estimate the approximate ORDC x-axis at which each action would be implemented, we reviewed ERCOT's emergency operating procedures, evaluated the PRC level coinciding with each action during historical emergency events, and vetted these assumptions with ERCOT staff.[45] These trigger levels are in line with historical emergency events, although actual emergency actions are manually implemented by the system operator based on a more complex evaluation of system conditions, including frequency and near-term load forecast.

We also describe here the marginal costs of each type of scarcity event as well as the prevailing market price during those events. In a perfectly-designed energy market, prices would always be equal to the marginal cost that would theoretically lead to optimal response to shortage events and an optimal level of investments in the market. In ERCOT, prices are reflective of marginal costs in most cases but not all. Specifically, the ORDC curve is designed based on an assumption that load would be shed at X = 2,000 MW, while our review of historical events indicates that load shedding is more likely to occur at a lower level of X = 1,150 MW. This discrepancy results in prices above marginal costs during moderate scarcity events, as discussed further in Section II.F.5 below.

[45] The PRC metric is calculated with some accounting nuances that make it a somewhat different number from the ORDC Spin x-axis, we do not consider these nuances in our modeling, for the formula for calculating PRC, see ERCOT (2013d), Section 6.5.7.5.

Table 10
Emergency Procedures and Marginal Costs

Emergency Level	Marginal Resource	Trigger	Price	Marginal System Cost
n/a	Generation	Price	Approximately $20-$250	Same
n/a	Imports	Price	Approximately $20-$250 Up to $1,000 during load shed	Same
n/a	Non-Spin Shortage	Price	Marginal Energy + Non-Spin ORDC w/ X = 2,000	Marginal Energy + Non-Spin ORDC w/ X = 1,150
n/a	Emergency Generation	Price	$500	Same
n/a	Price-Responsive Demand	Price	$250-$9000	Same
n/a	Spin Shortage	Price	Marginal Energy + Non-Spin + Spin ORDC w/ X = 2,000	Marginal Energy + Non-Spin + Spin ORDC w/ X = 1,150
n/a	Regulation Shortage	Price	Power Balance Penalty Curve	Same (Unless Capped by LCAP)
EEA 1	30-Minute ERS	Spin ORDC x-axis = 2,300 MW	$3,239 at Summer Peak (from ORDC)	$1,405
EEA 1	TDSP Load Curtailments	Spin ORDC x-axis = 1,750 MW	$9,000 (from ORDC)	$2,450
EEA 2	Load Resources in RRS	Spin ORDC x-axis = 1,700 MW	$9,000 (from ORDC)	$2,569
EEA 2	10-Minute ERS	Spin ORDC x-axis = 1,300 MW	$9,000 (from ORDC)	$3,681
EEA 3	Load Shed	Spin ORDC x-axis = 1,150 MW	VOLL = $9,000	Same

Sources and Notes:
Developed based on review of historical emergency event data, input from ERCOT staff, and ERCOT's emergency procedure manuals; see ERCOT (2013d), Section 6.5.9.4, and ERCOT (2013h), Section 4

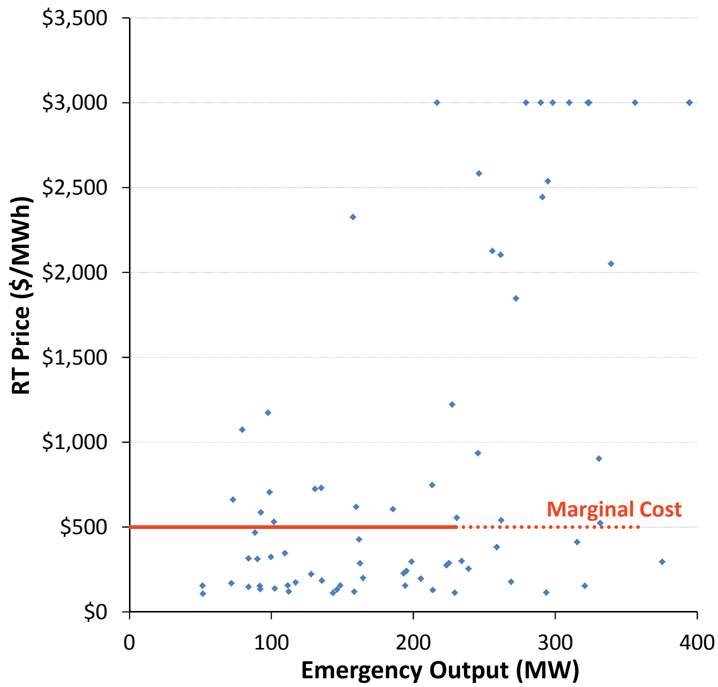
3. Emergency Generation

During severe shortage conditions, there are out-of-market instructions by ERCOT as well as strong economic incentives for suppliers to increase their power output to their emergency maximum levels for a short period of time.[46] During these conditions, suppliers can output power above their normal capacity ratings, although doing so is costly because it may impose additional maintenance costs and may put the unit at greater risk of failure.

46 CITE ERCOT procedures asking for emergency output.

To estimate the approximate quantity and cost of emergency generation, we reviewed ERCOT data on units' emergency maximum ratings as well as the actual realized output levels during high-price events in August 2011 as summarized in Figure 15. According to ERCOT's emergency maximum ratings, the aggregate ERCOT fleet should be able to produce approximately 360 MW in excess of summer CDR ratings.[47] This is approximately consistent with the quantity of output we observed historically during high-price events, although the actual realized quantity above summer CDR ratings is somewhat uncertain. To reflect this uncertainty and range of possible realized emergency generation, we model emergency generation probabilistically assuming 50% chance of realizing either 230 MW or 360 MW. We estimate the marginal cost of emergency output at approximately $500/MWh, consistent with the historical price levels at which we observed substantial output in excess of summer CDR ratings as shown in Figure 15.

Figure 15
Emergency Generation Above CDR Ratings During High-Price Events



Sources and Notes:
Unit-specific hourly generation less summer CDR ratings treated as "emergency generation" aggregated on a fleet-wide basis. Generation data from ERCOT, hourly energy prices from Ventyx (2014).

4. Power Balance Penalty Curve

The Power Balance Penalty Curve (PBPC) is an ERCOT market mechanism that introduces administrative scarcity pricing during periods of supply shortages. The PBPC is incorporated

47 This number excludes private use network resources, which we model separately as explained in Section II.C.2 above.

into the security constrained economic dispatch (SCED) software as a set of phantom generators at administratively-specified price and quantity pairs, as summarized in the blue curve in Figure 16.[48] Whenever a PBPC is dispatched for energy, it reflects a shortage of supply relative to demand in that time period that, if sustained for more than a moment, will materialize as a reduction in the quantity of regulating up capability. At the highest price, the PBPC will reach the system-wide offer cap (SWOC), which is set at the HCAP at the beginning of each calendar year but which will drop to the LCAP if the PNM threshold is exceeded as explained in Section II.F.1 above.

We similarly model the PBPC as phantom supply that may influence the realized price, and that will cause a reduction in available regulating reserves whenever called. However, we model only the first 200 MW of the curve at prices below the cap, and assume that all price points on the PBPC will increase in approximate proportion to the upcoming scheduled increases in the SWOC.[49] We also assume that the prices in the PBPC are reflective of the marginal cost incurred by going short of each quantity of regulating reserves.[50] Consistent with current market design, we assume that once the PNM threshold is exceeded, the maximum price in the PBPC will be set at the LCAP + $1/MWh or $2,001/MWh.[51] Note that even after the maximum PBPC price is reduced, ERCOT market prices may still rise to a maximum value of VOLL equal to $9,000/MWh during shortages because of the ORDC as explained in the following section.

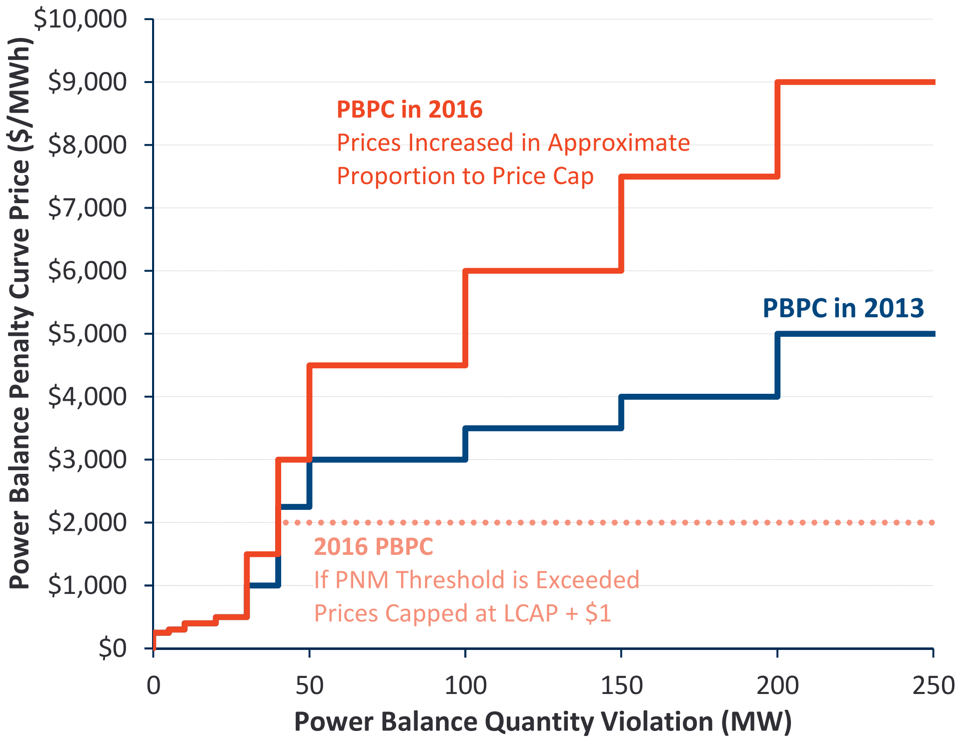
48 CITE the below ERCOT source explaining PBPC and the

49 Price points in the revised PBPC are approximately in proportion to the scheduled price cap increase between 2013 and 2016, although the exact prices are set at rounded values based on ERCOT staff input. Year 2013 PBPC numbers from ERCOT (2013b).

50 Once the PNM is exceeded and the PBPC is reduced, these prices are no longer reflective of marginal cost but are instead lower than marginal cost at regulation shortage quantities greater than 40 MW.

51 See ERCOT (2013b).

Figure 16
Power Balance Penalty Curve



Sources and Notes:
Year 2016 PBPC updated in approximate proportion to the scheduled increases in system price cap, as rounded up or down consistent with ERCOT staff guidance. 2013 PBPC numbers from ERCOT (2013b), p. 23.

5. Operating Reserves Demand Curve

The most important and influential administrative scarcity pricing mechanism in ERCOT is the recently-approved operating reserves demand curve (ORDC) that reflects the willingness to pay for spinning and non-spinning reserves in the real-time market.[52] Figure 17 illustrates our approach to implementing ORDC in our modeling, which is similar to ERCOT's implementation although with some simplifications.[53] We implement all 48 distinct ORDC curves, with different curves, four seasons, six times of day, and two types of operating reserves.[54]

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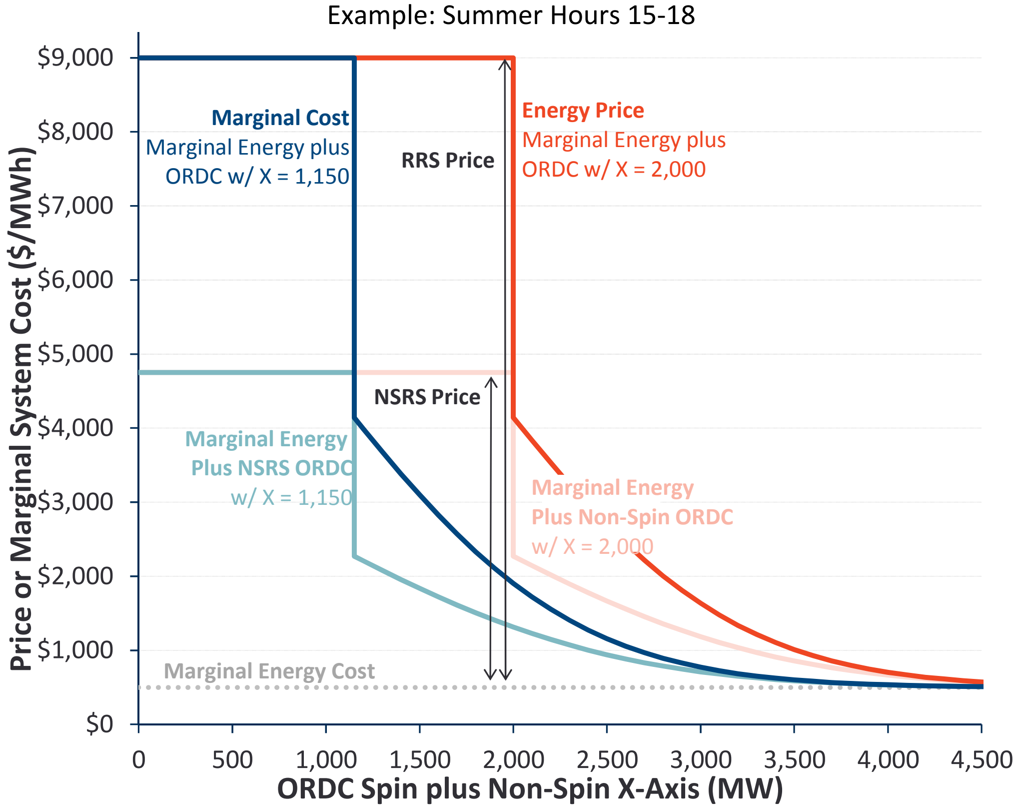
52 Note that the ORDC is not planned to be co-optimized with the energy market at this time, but the real-time spinning and non-spinning prices they produce are used to settle against the day-ahead RRS (Spin) and NSRS (Non-Spin) markets.

53 For a detailed explanation of ERCOT's ORDC implementation see their whitepaper on the methodology for calculating ORDC at ERCOT (2013c).

54 See ERCOT (2013c), p. 15.

Figure 17
Operating Reserve Demand Curves
Example: Summer Hours 15-18



Sources and Notes:
ORDC curves developed consistent with ERCOT (2013c).

The ORDC curves are calculated based on a loss of load probability (LOLP) at each quantity of reserves remaining on the system, multiplied by the value of lost load (VOLL) caused by running short of operating reserves.[55] This curve reflects the incremental cost imposed by running short of reserves and is added to the marginal energy cost to estimate the total marginal system cost and price.

The x-axis of the curve reflects the quantity of operating reserves available at a given time, where: (a) the spin ORDC includes all resources providing regulation up or RRS, suppliers that are online but dispatched below their maximum capacity, hydrosynchronous resources, non-

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[55] Note that the lost load implied by this function and caused by operating reserve shortages is additive to the lost load that we report elsewhere in this study. This is because the LOLP considered in ERCOT's ORDC curve is caused by sub-hourly changes to supply and demand that can cause short-term shortages and outages that are driven only by small quantities of operating reserves, but are not caused by an overall resource adequacy shortage, which is the type of shortage we model elsewhere in this study. For simplicity and clarity, we refer to these reserve-related load-shedding events as "reserve shortage costs" to distinguish them from the load shedding events caused by total supply shortages. We do not independently review here ERCOT's approach to calculating LOLP, but instead take this function as an accurate representation of the impacts of running short of operating reserves.

controllable load resources, and 10-minute quickstart; and (b) the spin + non-spin ORDC include all resources contributing to the spin x-axis as well as any resources providing NSRS and all 30-minute quickstart units. Table 11 provides a summary of the resources that are always available to contribute to the ORDC x-axis unless they have been dispatched for energy although the realized ORDC x-axis can be higher (if other resources are committed but not outputting at their maximum capability) or lower (during peaking conditions when some of the below resources are dispatched for energy).[56]

Table 11
Resources Always Contributing to ORDC X-Axis
Unless Dispatched for Energy

Spin X-Axis		
Controllable Load Resources	*(MW)*	36
Hydrosynchronous Resources	*(MW)*	240
10-Minute Quickstart	*(MW)*	2,283
Non-Controllable Load Resources	*(MW)*	1,400
Non-Spin X-Axis		
30-Minute Quickstart	*(MW)*	2,053
Total Spin + Non-Spin	***(MW)***	**6,012**

The red and pink curves in Figure 17 show the ORDC curves used for price-setting purposes, calculated as if ERCOT would shed load at an ORDC x-axis of X = 2,000 MW. However, as we explained in Section II.F.2 above, we assume that load shedding will actually occur at X = 1,150 MW based on our analysis of recent emergency events and consistent with the blue curves below. In other words, we model a discrepancy between marginal costs (blue) and market prices (red) that will create some inefficiency in realized market outcomes.

As in ERCOT's ORDC implementation, we calculate: (a) non-spin prices using the non-spin ORDC; (b) spin prices as the sum of the non-spin and spin ORDC; and (c) energy prices as the sum of the marginal energy production cost plus the non-spin and spin ORDC prices. However, as a simplification we do not scale the ORDC curves in proportion to VOLL minus marginal energy in each hour.[57] Instead, we treat the ORDC curves as fixed with a maximum total price adder of VOLL minus \$500, which causes prices to rise to the cap of \$9,000/MWh in shortages, because \$500 is the highest-price emergency generation resource we model. Higher-cost demand-response resources will be triggered in response to high ORDC prices and therefore prevent prices from going even higher, but do not affect the "marginal energy component" of

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56 We assume that the CC reference unit is not capable of providing either spin or non-spin from an offline position, although we assume that the CT reference unit is capable of providing non-spin from an offline position.

57 See ERCOT's implementation in ERCOT (2013c).

price-setting. We model the ORDC curves out to a maximum quantity of 8,000 MW where the prices are near zero, although they never drop all the way to zero.

These ORDC curves create an economic incentive for units to be available as spinning or non-spinning reserve, which influences suppliers' unit commitment decisions. We therefore model unit commitment in three steps: (1) a week-ahead optimal unit commitment over the fleet, with the result determining which long-lead resources will be committed;[58] (2) a four-hour ahead unit commitment (updated hourly) with an updated fleet outage schedule, with the result determining the preliminary commitment and decommitment schedules for combined cycle units; and (3) an hourly economic dispatch that dispatches online baseload units, and can commit 10-minute and 30-minute quickstart units if energy and spin prices are high enough to make it more profitable than remaining offline (similarly, if prices are not high enough these units will economically self-decommit).[59] Note that 10-minute quickstart units can earn spin payments from an offline position while 30-minute quickstart units can earn non-spin payments from an offline position. These resources will not self-commit unless doing so would result in greater energy and spin payments (net of variable and commitment costs) than would be available from an offline position. We use a similar logic to economically commit or de-commit units until the incentives provided by the ORDC are economically consistent with the quantity of resources turned on.

G. Reserve Margin Accounting

Throughout this report we use reserve margin accounting conventions consistent with those in ERCOT's CDR report, as illustrated in the example calculation in Table 12. In particular, we note that the peak load used to calculate the reserve margin is already reduced for PRD and LR self-curtailments. Peak load is then explicitly reduced for TDSP energy efficiency and load management, 10-minute and 30-minute ERS, and non-controllable LRs. On the supply side, most resources are counted toward the reserve margin at their nameplate capacity, with wind and solar counting at 8.7% and 100% of nameplate respectively, and the DC ties counting at 50% of the path ratings.

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58 Short-term resources are included in the week-ahead commitment algorithm, but their commitment schedule is not saved since it will be dynamically calculated in a shorter window. But using short-lead resources in the week-ahead commitment allows them to affect the commitment of long-lead resources.

59 These week-ahead and day-ahead commitment algorithms minimize cost subject to meeting load as well as ERCOT's administratively-determined regulation up and spinning reserve targets, with non-spinning reserve targets not considered at the unit commitment phase.

Table 12
Example Reserve Margin Calculation

Reserve Margin Component	Quantity *(MW)*
Grossed-up Peak Load	**71,159**
Peak Load from ERCOT Shapes	70,618
TDSP Energy Efficiency Programs	541
Load Reductions	**2,410**
LRs serving RRS	1,205
10-Minute ERS	347
30-Minute ERS	77
TDSP Energy Efficiency Programs	541
TDSP Curtailment Programs	240
Supply	**76,658**
Conventional Generation	69,700
Hydro	521
Wind	1,319
Solar	124
Storage	36
PUNs	4,331
50% of DC Ties	628
Reserve Margin	**11.5%**

Sources and Notes:
Reserve Margin = Supply/(Grossed-up Peak Load – Load Reductions) – 1
Peak load implemented in modeling is different from the peak load used for calculated reserve margin because the modeled load shapes exclude TDSP EE gross-ups, but include a separate gross-up for 1.5% PRD and 195 MW of additional LRs not counted in the reserve margin.
Conventional Generation includes seasonal, mothballed, and new units.
Wind and solar contribute 8.7% and 100% of nameplate respectively.

Although we use these CDR conventions to report reserve margins throughout this study, it is worth noting, given the broader context of this study, how it might make sense to revise these accounting conventions if the PUCT were to implement a mandatory reserve margin.

Whether through a centralized or bilateral capacity market, imposing a mandatory reserve margin would make capacity valuable as a new product. This would substantially increase the importance of reserve margin accounting, measurement, and verification measures. In that case, it would be important to develop a well-defined capacity product where all types of supply resources are interchangeable from a resource adequacy perspective, and include only resources committed to supply capacity in ERCOT in the reserve margin calculation. Some of the revisions that might be considered include:

- **Remove Uncommitted Supply.** Currently, there are several types of non-firm supply included in the reserve margin calculation, such as potential new builds and mothballed units. If a reserve margin mandate were implemented on a three-year forward basis, it would require that all plants currently mothballed or under development provide a firm commitment of being available in the delivery year. Without such a commitment, they would not be included in the reserve margin or earn capacity payments.

- **Revise Approach to Private Use Networks and Switchable Units.** Similarly for Private Use Networks (PUNs) and switchable units, these resources would have to commit to providing resource adequacy in ERCOT before they could be compensated or included at full value in the reserve margin calculations. For PUNs, which tend to provide a combination of generation and demand response, it may be necessary to separately and explicitly account for those networks' gross load, demand-response resources, and generation.
- **Revise Treatment of DC Ties**. Interties that contribute to resource adequacy do not constitute supply on their own. For that reason it may be beneficial to consider adopting the approach used in other capacity markets of: (a) removing DC Ties as a line item on the supply side that counts toward the reserve margin; (b) enabling importers to contribute to the reserve margin and sell capacity into ERCOT as long as they are supported by firm transmission rights; and (c) setting aside a capacity benefit margin on the interties that would not be used for firm imports but would instead be used to provide "tie benefits" or imports that are probabilistically available to contribute to resource adequacy due to load diversity with neighboring regions (and therefore reduce the required system reserve margin).
- **Move from Installed to "Unforced" Plant Capacity Accounting**. As is done in MISO, PJM, and NYISO, consider moving from installed capacity (ICAP) to unforced capacity (UCAP) accounting, which reduces each resource's capacity rating consistent with its own availability and outage rate. Similar to the effective load carrying capability (ELCC) calculation done for wind, moving to UCAP accounting would make the reserve margin contribution and economic payments for each resource more consistent with its delivered reliability value. Some special resource types such as demand response and storage might require their own ELCC studies, to determine how substantially factors such as call limits affect their reliability value as compared to generation.
- **Account for Committed Demand Response on the Supply Side**. While demand response can be accounted for on the supply or demand side, accounting in centralized auctions is a bit more transparent if all types of capacity resources are allowed to compete as supply-side resources. Interchangeable demand-response accounting also requires considering the gross-up that is appropriately applied to demand response to account for avoided line losses.

Adopting these alternative accounting conventions would have no impact on reliability, but would increase the transparency of reserve margin accounting and provide a more accurate reflection of the expected resource adequacy value of each type of resource.

III. Reliability and System Costs Results

In this Section, we summarize our primary reliability and system cost results over a range of assumed reserve margins. We report a variety of reliability metrics similar to those reported in other reliability models, as well as total system cost results including capital, production, and reliability event costs. We also report the sensitivity of these results to several modeling assumptions including the assumed reference technology, forward period, likelihood of extreme weather events, and marginal system costs.

A. System Reliability

As with other resource adequacy studies, including a recent study conducted for ERCOT, we estimate realized reliability as a function of the planning reserve margin.[60] We report here several standard reliability metrics indicating firm load shed rates as a function of reserve margin, the frequency of non-load-shed reliability events, and the sensitivity of these results to our study assumptions.

1. Physical Reliability Metrics

Traditionally, ERCOT has determined its "target" reserve margin based on the 1-in-10 standard, *i.e.*, a probability-weighted average of 0.1 loss-of-load events (LOLE) per year. We report LOLE as a function of reserve margin in Figure 18, with the dark blue line reflecting our Base Case assumptions. The Base Case results show that a 14.1% reserve margin would be required to achieve 0.1 LOLE. At that level, events would be expected to occur once per decade, each with about 1,300 MW of load being shed for 2.3 hours on average.

Figure 18 also shows the sensitivity of this result to the probability of 2011 weather recurring more frequently (left) and to the assumed multi-year forward period at which supply decisions are locked in (right). Increasing the likelihood of 2011 weather from a 1% chance to a 1-in-15 year chance (with equal weighting on all other weather years) would increase the reserve margin needed to meet the 1-in-10 standard from 14.1% to 16.1%.

The right-hand chart of Figure 18 shows the impact of assuming suppliers need less time to lock in their supply decisions, which reduces the realized non-weather load forecasting uncertainty and, therefore, the LOLE associated with a particular planning reserve margin. Reducing the forward assumed lock-in period from three years in the Base Case assumption to one year would

[60] See ECCO (2013a and b).

reduce the reserve margin needed to meet the 1-in-10 standard from 14.1% to 13.1%. For illustrative purposes, we also show that the 1-in-10 reserve margin would drop to 12.6% if it were possible to completely eliminate non-weather load forecasting errors.

Figure 18
Loss of Load Events vs. Reserve Margin
With Differing Weather Weights (Left) and Varying Forward Periods (Right)

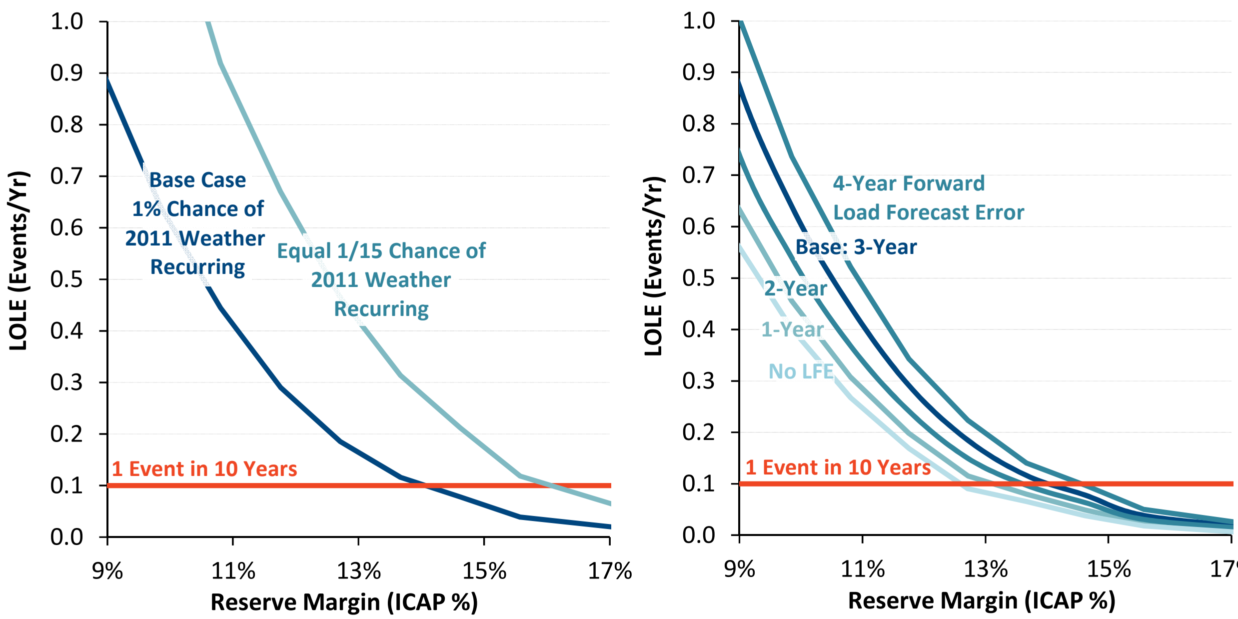

Figure 19 summarizes resource adequacy as a function of reserve margin using three different types of physical reliability metrics: (1) loss of load events (*i.e.*, LOLE) on the left; (2) loss of load hours (LOLH) in the middle; and (3) normalized expected unserved energy (normalized EUE) on the right. As discussed above, the Base Case reserve margin required to yield a 0.1 LOLE is 14.1%. If, instead, a resource adequacy requirement of one "day" in 10 years is interpreted as 24 hours per 10 years, or 2.4 hours per year, the reserve margin would only need to be 9.1%. This 2.4 hours per year interpretation of the 1-in-10 standard is currently utilized by the Southwest Power Pool.[61]

The far right panel on Figure 19 shows a third reliability metric, normalized EUE. Normalized EUE is an alternative to the 1-in-10 standard that a NERC task force recently recommended to address the limitations of traditional 1-in-10 LOLE and LOLH standards.[62] It refers to the total annual MWh of firm energy expected to be shed, divided by the total MWh of annual system load. It represents the percentage of system load that cannot be served due to supply shortages.

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61 SPP's standard corresponds to a planning reserve margin of 13.6% (equivalent to what SPP refers to as a 12%, capacity margin) although SPP's current reserve margin currently is well above that level. See SPP (2010).

62 See NERC (2010).

Some international markets already use normalized EUE to set minimum reliability thresholds or to trigger administrative interventions, although the metric may be referred to as Loss of Load Probability (LOLP) or Unserved Energy (USE). Examples of metrics equivalent to normalized EUE used in international markets include: (a) a 0.001% LOLP standard in Scandinavia; and (b) a 0.002% USE standard in Australia's National Energy Market (NEM) and South West Interconnected System (SWIS).[63] As shown in Figure 19, using a normalized EUE of 0.001 as a physical reliability standard in ERCOT would require a Base Case reserve margin of 9.6%.

We recommend adopting normalized EUE as a preferred reliability metric for setting the reliability standard because it is a more robust and meaningful measure of reliability that can be compared across systems of many sizes, load shapes, and other uncertainty factors. Such a cross-system comparison is not meaningful for either LOLE or LOLH because neither metric considers the MW size of the outage endured nor the size of the system itself. For example, a one-hour, 100 MWh outage event and a one-hour, 10,000 MWh outage event would be counted identically under the LOLE and LOLH metrics, even though the load shed amount under the second outage event is one hundred times greater in magnitude. Moreover, the 1-in-10 standard represents a higher level of reliability in a large system than in a small system because neither the LOLE nor the LOLH metric is normalized to system size.[64] This means that a 100 MWh, one-hour outage will have the same LOLE and LOLH values in a 10,000 MW and 100,000 MW power system, even though individual customers in the smaller system are ten times more likely to endure an outage. Normalized EUE avoids these shortcomings of the LOLE and LOLH metrics.

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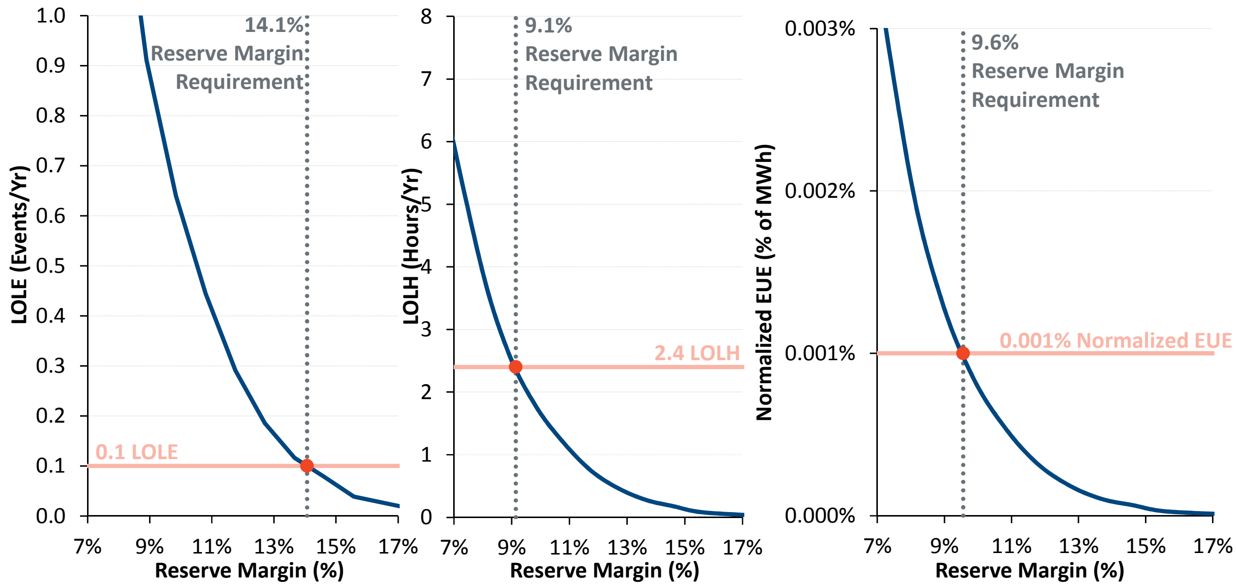
63 See Nordel (2009), p. 5; AEMC (2007), pp. 29-30, (2010), p. viii.

64 This is true as long as the one event represents a smaller proportion of total load in a large system than in a small system.

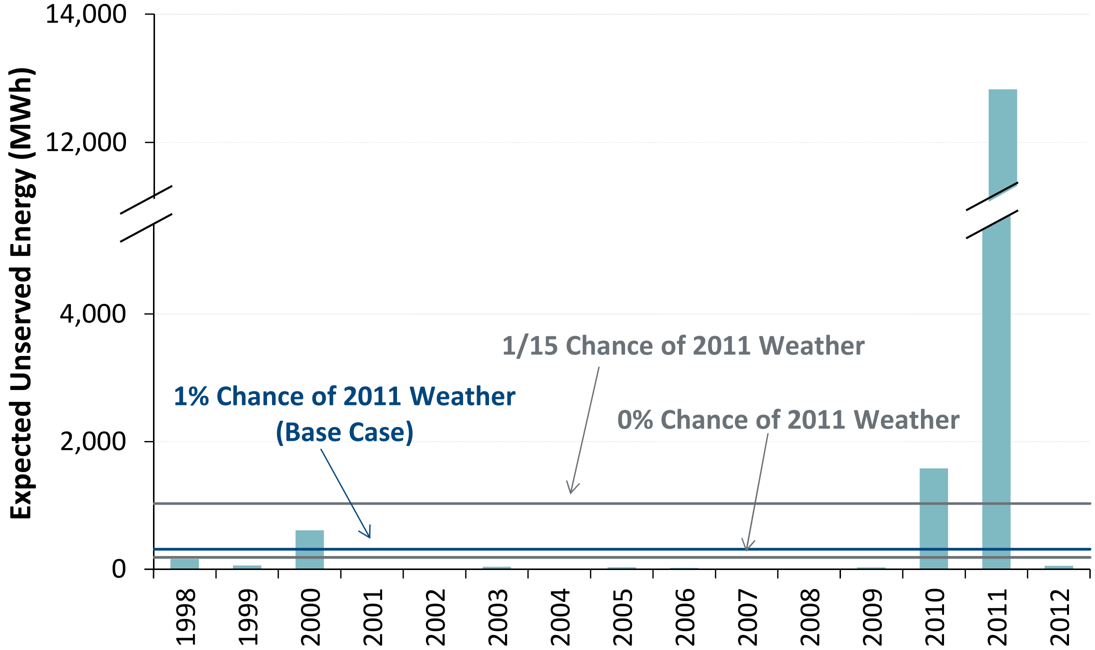
Figure 19
Reserve Margins Required to Meet Different Reliability-Based Standards



Notes:
Figure reflects reliability outcomes under our Base Case assumptions (3-Year Forward LFE, 2011 Weather at 1% Probability).

Figure 20 illustrates the sensitivity of Base Case reliability results to the assumed probability of individual weather years. The blue bars show the total MWh of annual load shed during each of the 15 weather years for the Base Case simulations at a 14.1% reserve margin (consistent with 0.1 LOLE). As illustrated, the reoccurrence of 2011 weather would lead to almost 13,000 MWh of expected involuntary curtailment of firm load, while there would be very little load being shed in 12 out of the 15 weather years. The lines in Figure 20 show the probability-weighted average of unserved energy assuming: (a) a 1% chance of 2011 weather reoccurring, as in our Base Case; (b) a zero probability of 2011 weather; and (c) the probability of 2011 weather is equal to those of the 15 other weather years. This chart highlights that assuming a higher probability of sustained weather extremes substantially increases both the reliability-based and economically-based reserve margin targets.

Figure 20
Expected Unserved Energy by Weather Year at 14.1% Reserve Margin



Notes:
Figure reflects Base Case 3-Year forward LFE assumption, but bars are based on equal 1/15 weather weight for all years.

Table 13 provides additional detail on how reliability varies with reserve margins. The left half of the table shows LOLE, LOLH, and EUE across a range of reserve margins in our simulations. As expected, these metrics show that annual outage rates decline with reserve margins. The right half of the table reports the average outage duration, size, and depth for each load-shedding event. It shows that the severity of events declines (along with the frequency) as reserve margins increase.

Table 13
Detailed Reliability Metrics across Planning Reserve Margins in Base Case

Reserve Margin (%)	Total Annual Loss of Load			Average Outage Event		
	LOLE *(events/yr)*	LOLH *(hours/yr)*	EUE *(MWh)*	Duration *(hours)*	Energy Lost *(MWh)*	Depth *(MW)*
6.0%	2.51	7.99	16,402	3.18	6,531	2,053
7.9%	1.36	4.02	7,555	2.95	5,555	1,882
8.9%	0.91	2.62	4,750	2.88	5,214	1,811
9.8%	0.64	1.77	3,020	2.76	4,719	1,709
10.8%	0.44	1.19	1,921	2.68	4,323	1,614
11.8%	0.29	0.74	1,145	2.56	3,938	1,541
12.7%	0.18	0.46	664	2.49	3,592	1,445
13.7%	0.12	0.28	370	2.38	3,186	1,339
14.6%	0.08	0.18	229	2.26	2,939	1,300
15.6%	0.04	0.08	97	2.14	2,517	1,174
17.5%	0.01	0.03	29	2.00	2,142	1,069

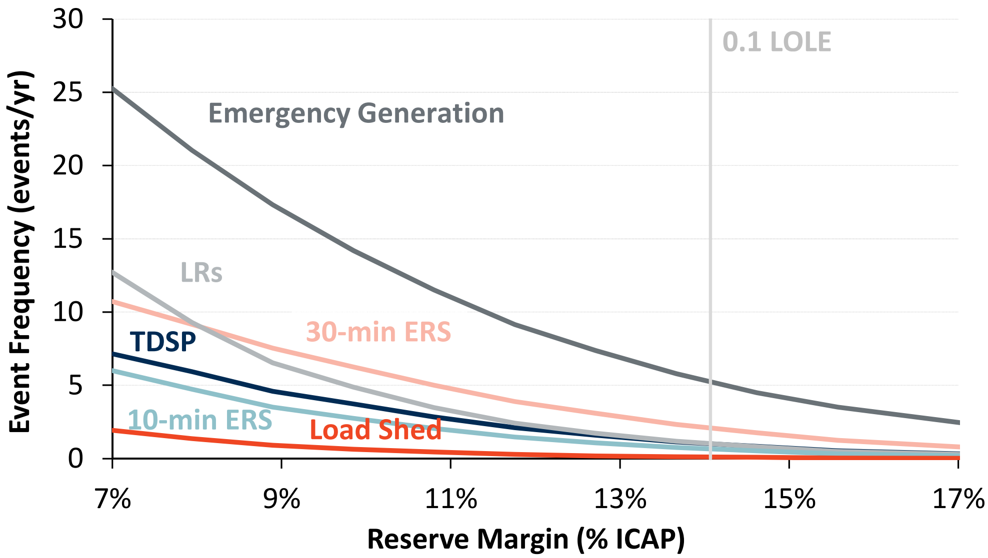
Notes:
Table reflects reliability outcomes under our Base Case assumptions (3-Year Forward LFE, 2011 Weather at 1% Probability).

2. Emergency Event Frequency

Figure 21 summarizes the frequency of six types of emergency events for the Base Case simulations as a function of the installed reserve margin. The emergency events, in increasing order of severity, are (1) the economic dispatch of emergency generation, (2) calling 30-minute ERS, (3) calling TDSP load curtailments, (4) re-dispatching LRs from RRS to energy, (5) calling 10-minute ERS and, finally, (6) shedding firm load. As shown, at the 1-in-10 reserve margin of 14.1%, emergency generation will be dispatched approximately 5 times a year on a weighted-average basis across all simulated years. At a reserve margin of 8.7%, the system faces one load shed event per year on average, most years without load shed events and some years with several. At the same 8.7% reserve margin, the various types of demand resources would have to be called from three to eight times on average each year (depending on the resource type), and emergency generation would be dispatched approximately 17 times on average each year.

All types of emergency events become more frequent at lower reserve margins, but the frequency of re-dispatching LRs from RRS to energy increases faster than ERS and TDSP calls. This is because at lower reserve margins the call-limited ERS and TDSP demand-side resources call limits more often, meaning that their reliability value diminishes and ERCOT will need to rely more heavily on other measures and resources.

Figure 21
Average Annual Frequency of Emergency Events



Notes:
Results from Base Case (3-Year Forward LFE, 2011 Weather at 1% Probability).

B. Economically Optimal Reserve Margin

The primary result from our study is an estimate of the economically optimal reserve margin that minimizes total system capital and production costs. We estimate that economic optimum to be an approximate 10.2% reserve margin under our Base Case assumptions. We also discuss the probability distribution of annual system costs across different levels of reserve margins.

1. System Cost-Minimizing Reserve Margin

Figure 22 summarizes the annual averages of total ERCOT reliability-related costs from our Base Case simulations over a range of planning reserve margins. At each reserve margin level, we show the weighted-average costs across all 7,500 annual simulations, with the individual cost line items including:

- **Marginal CC Capital Costs** are the annualized fixed costs associated with building more CC plants, at a cost of $122.1/kW-yr in the Base Case, see Section II.C.5.
- **Production Costs (Above $10 billion per year Baseline)** are total system production costs of all resources above an arbitrary baseline cost of $10 billion. We show only a portion of total system costs as an individual slice on the chart in order to avoid having production costs dwarf the magnitude of other cost components, and subtract the same $10 billion at all reserve margins shown. Production costs decrease at higher reserve margins because adding efficient new gas CCs reduces the need to dispatch higher-cost peakers.
- **External System Costs (Above Baseline)** include production and scarcity costs in neighboring regions above an arbitrary baseline, which drop by a small amount

with increasing reserve margins because ERCOT will rely less on imports from high-cost external peakers during internal scarcity events, and may also be able to export more supply during external scarcity events.[65]

- **Emergency Generation** is the price-driven dispatch of units outputting at high levels above their summer peak ratings at an assumed cost of $500/MWh, see Section II.F.3.
- **10-Minute and 30-Minute ERS** is the cost of dispatching these resources during emergency events at assumed costs of $3,681 and $1,405/MWh for 10-minute and 30-minute ERS respectively, see Section 0.
- **Non-Controllable LR** costs reflect the cost of voluntarily self-curtailed LRs at a cost of $380/MWh during high-price events, as well as the cost of administratively re-dispatching LRs from supplying RRS to supplying energy at a cost of $2,569/MWh during emergencies, see Section II.D.3.
- **TDSP Load Management** costs are incurred when ERCOT administratively orders these demand-side resources to curtail during emergencies at an assumed cost of $2,450/MWh, see Section II.F.2.
- **Price Responsive Demand** is the cost of voluntary self-curtailment among the 1% of load resources that are assumed to respond to high-price events, which are more common at lower reserve margins, see Section II.D.4.
- **Spinning and Non-Spinning Reserve Shortage** costs are calculated as the area under the ORDC curve, calculated assuming load would be shed at X = 1,150 MW, see Section II.F.5.
- **Regulation Shortage** costs are calculated according to the PBPC assuming that this curve accurately reflects the marginal cost of running short on regulating reserves, see Section II.F.4.
- **Firm Load Shedding** costs are the customer costs imposed during load-shed events at a cost at the assumed VOLL of $9,000/MWh.

At the lowest reserve margin shown in the chart, average annual reliability costs are high and are driven by the high cost of emergency generation, external system costs, and other reliability costs during scarcity conditions. As planning reserve margins increase, total reliability costs drop more quickly than the increases in capital and production costs associated with adding additional CCs. As a result, total costs drop as the reserve margin increases until the "economically optimal" quantity of capacity has been added at a reserve margin of 10.2%. After crossing this minimum cost point, the capital costs of adding more CCs exceed the benefits from reduced reliability-related costs, and so total costs increase.

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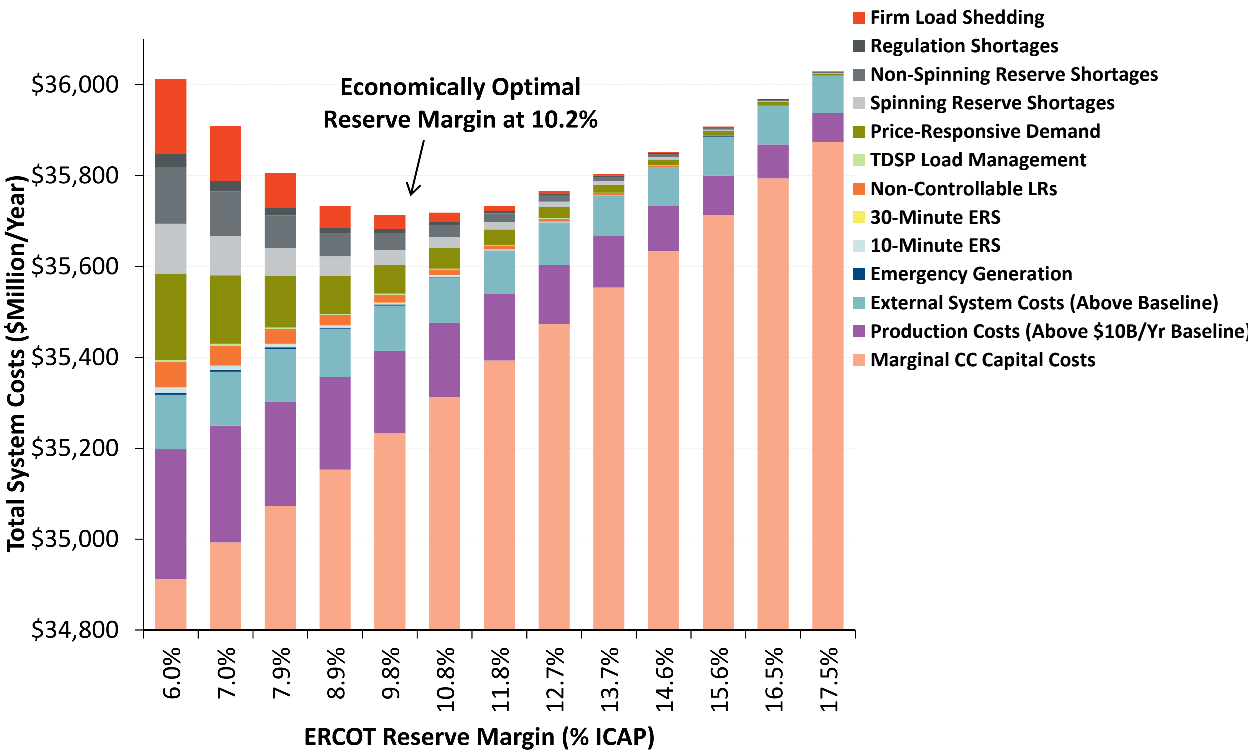
65 The baseline level of external production costs is not included in our total system cost. This differs from our reporting of ERCOT-internal production costs, for which we do include baseline costs (that do not vary with reserve margin) in order to produce a meaningful total cost estimate for the ERCOT system.

This 10.2% risk-neutral economically optimal reserve margin is substantially below the 14.1% reserve margin based on the 0.1 LOLE standard but similar to the reserve margin that would be required under the 2.4 LOLH and 0.001% normalized EUE standards.

Figure 22
Total System Costs across Planning Reserve Margins



Notes:
Total system costs include a large baseline of total system costs that do not change across reserve margins, including $15.2 B/year in transmission and distribution, $9.6 B/year in fixed costs for generators other than the marginal unit, and $10B/year in production costs.

The total cost curve shown in Figure 22 has a shape similar to that which we have observed in value-of-service studies for many other electric systems.[66] The curve is relatively flat near the minimum average cost point, indicating that expected total costs do not vary substantially between reserve margins of 8% to 14%. However, as we discuss further below, the lower end of that minimum cost range is associated with much more uncertainty in realized annual reliability costs and a much larger number of severe, high-cost reliability events. At the 14% reserve margin, a greater proportion of total annual costs is associated with the cost of adding CCs (which has less uncertainty), and a smaller proportion of the average annual costs are from uncertain, low-probability, but high-cost reliability events.

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66 For example, see Poland (1988), p.21; Munasinghe (1988), pp. 5-7 and 12-13; and Carden, Pfeifenberger, and Wintermantel (2011).

2. Exposure to Extreme Shortage Events

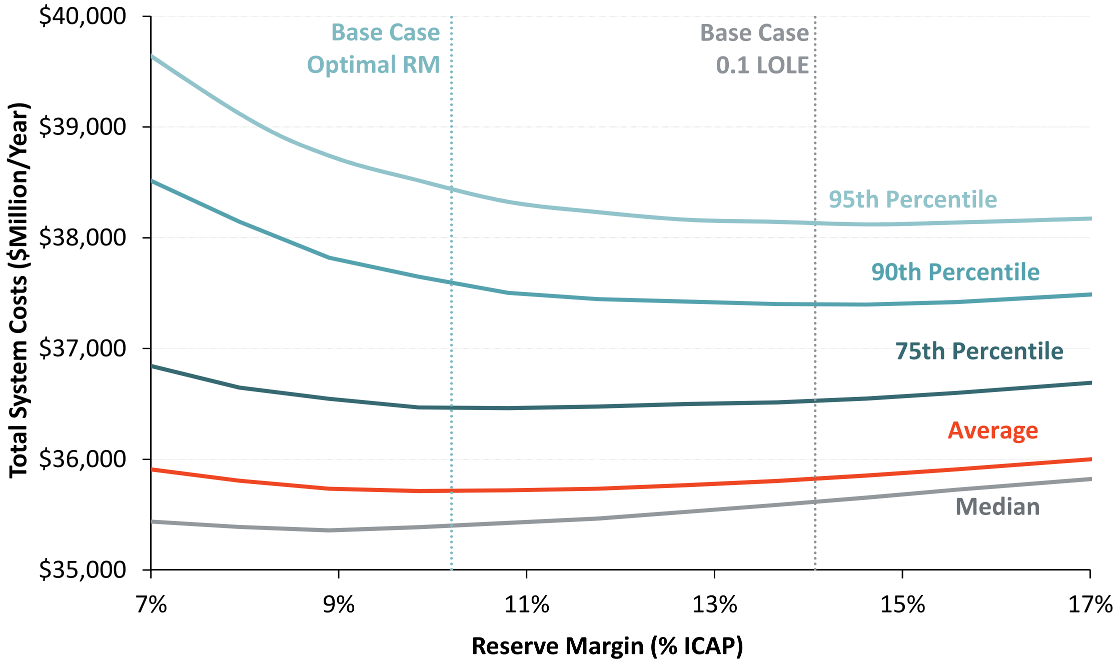
The economic results shown in the previous sections assume risk neutrality with respect to the uncertainty and volatility of reliability-related costs. This allows us to compare total costs at different reserve margins in Figure 22 simply as the probability-weighted average of annual reliability costs for all 7,500 simulation draws. However, there is substantial volatility around the average level of possible reliability cost outcomes. Most simulated years will have very modest reliability costs, while a small number of years have very high costs. These high-cost outcomes account for the majority of the weighted-average annual costs shown as the individual bars in Figure 22.

Figure 23 summarizes this risk exposure by comparing the weighted-average costs for different reserve margins (shown as the individual bars in Figure 22) to annual costs under the most costly possible outcomes, represented by the 75^{th}, 90^{th}, and 95^{th} percentiles of annual reliability costs across all 7,500 simulated scenarios. The figure shows that a substantial fraction of all reliability-related costs are concentrated in the most expensive 10% of all simulation runs for each planning reserve margin; for 10% of possible annual outcomes, the annual reliability costs are at or above the 90^{th} percentile line shown in the chart. While total average costs change by a relatively modest amount over a range of planning reserve margins, differences in planning reserve margins have a larger impact on the uncertainty in reliability costs and the likelihood of high-cost outcomes than can be encountered in any particular year.

Considering the higher cost uncertainty exposure at lower reserve margins, some planners and policymakers prefer to set planning reserve margins above the risk-neutral economic optimum. As the simulation results show, a several percentage point increase in the reserve margin would only slightly increase the average annual costs, but more significantly reduce the likelihood of experiencing very high-cost events. As we will show in later sections, this mitigating impact is modest when evaluated from a system cost perspective as we do here, but more substantial when viewed from a customer cost or supplier net revenue perspective, as we discuss in Section IV.C below.[67]

[67] This is primarily because price * quantity changes much more substantially than does production cost with small changes in quantity during scarcity events.

Figure 23
Uncertainty Range in Total Annual System Costs



Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional detail on the individual components of total system costs is available in Section III.B.1.

For example, our Base Case simulations show that the risk-neutral, economically optimal planning reserve margin is 10.2% compared to the 14.1% reserve margin needed to achieve the 0.1 LOLE standard. As Figure 22 and Figure 23 show, the increase in average annual system costs required to achieve the 14.1% planning reserve margin (rather than the 10.2% economically optimal reserve margin) is relatively modest at approximately $110 million per year.

Figure 23 also shows that this would reduce the annual system costs incurred once in a decade (*i.e.*, costs above the 90th percentile) by at least $196 million per year, and the costs incurred once in 20 years (*i.e.*, costs above the 95th percentile) by at least $313 million per year. In other words: (a) a risk-neutral policymaker would not increase reserve margins above the 10.2% risk-neutral optimum because, by definition, the expected costs would exceed expected benefits; (b) a somewhat risk-averse policymaker might prefer slightly higher reserve margins but possibly not high enough to meet 0.1 LOLE at a 14.1% reserve margin where the quantified incremental costs exceed the quantified incremental benefits by a ratio of approximately 1.5-to-one; and (c) a more risk-averse policymaker might wish to meet or even exceed the 14.1% reserve margin needed to meet 0.1 LOLE. However, this discussion addresses only the risks of high system costs. Market participants are more likely to care about risks to customer cost or supplier net revenues, which we present in Section IV.C below.

C. Sensitivity to System Conditions and Study Assumptions

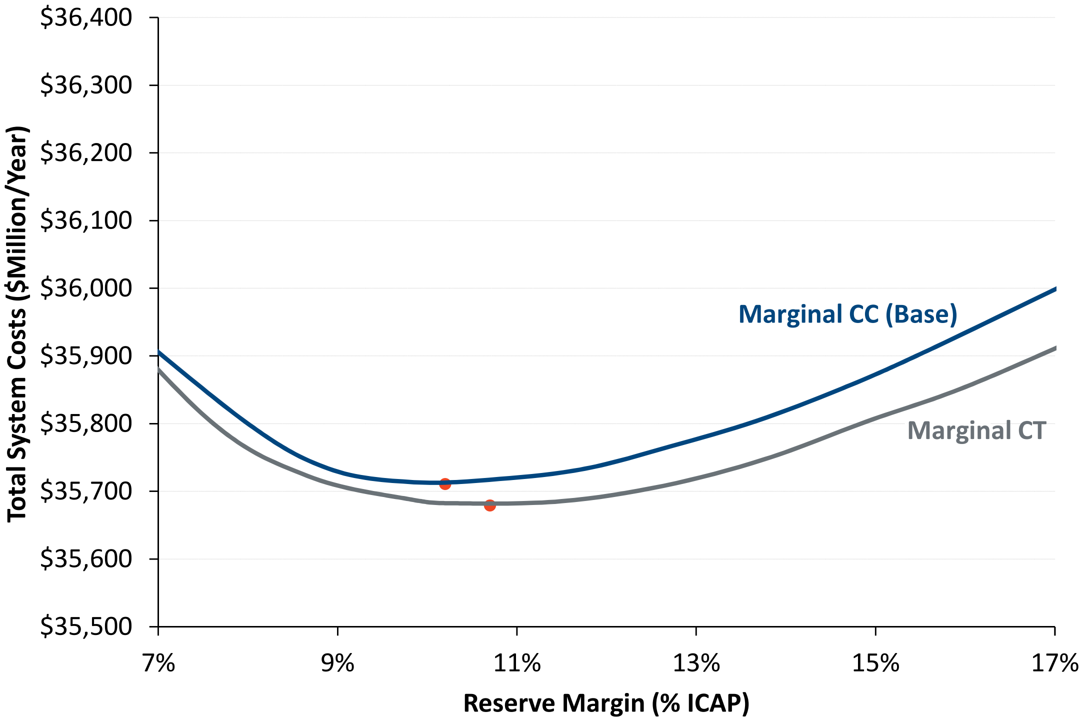
In this Section, we evaluate the sensitivity of economically optimal reserve margin estimates to a variety of alternative study assumptions. We examine the impacts of: (a) changing the assumed reference technology from a CC to a CT, (b) varying the assumed cost of building new plants, (c) varying the forward period and associated load forecast uncertainty, (d) the assumed chances of 2011 weather recurring, and (e) revising ORDC-based pricing such that prices are always equal to marginal costs.

1. Marginal Resource Technology Type and Cost of New Entry

The Base Case simulations assume that a natural-gas-fired CC is the marginal resource that will be added to increase reserve margins. In reality, it is more likely that a mix of gas CCs and gas CTs may be added over the coming years. To evaluate the impact that the CC-based assumption has on study results, Figure 24 compares the difference in total system costs for natural-gas-fired CCs and CTs as the marginal resource. The chart shows very similar impacts on total system reliability costs across the range of reserve margins for the two different resource types. The greater capital costs of the CC are approximately balanced out by the greater production cost savings, such that adding either resource type contributes approximately the same net value.

This indicates that the ERCOT system likely has a near-optimal mix of CCs and CTs in the current fleet, which may also suggest that a mix of CCs and CTs would likely be built going forward. However, the CT option is somewhat more economic overall in that it has a higher economically optimal reserve margin, at 10.7% for the CT compared to 10.2% for the CC. The total system cost implications are not very different for the two resource types, however, with the minimum CT cost point being only about $32 million/year lower than the CC minimum cost point.

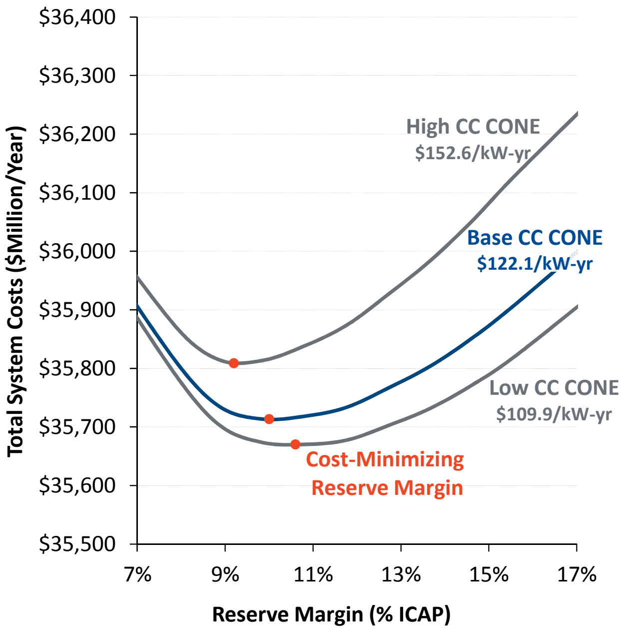
Figure 24
Total Annual System Costs with a Gas CC or CT Providing the Marginal Capacity

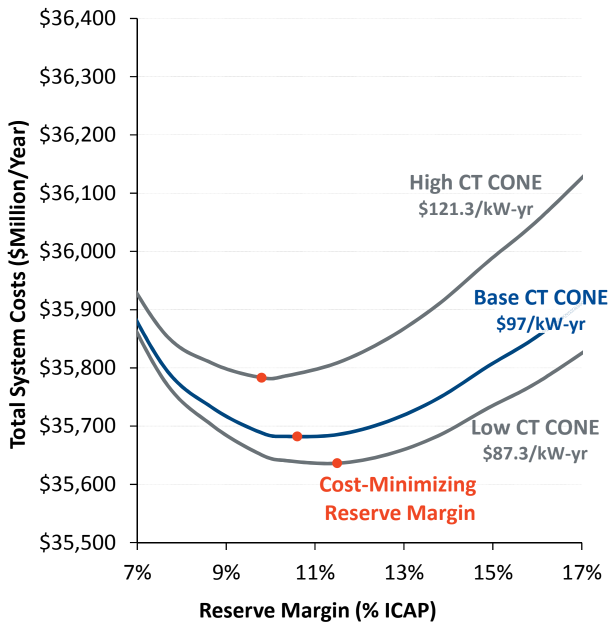


Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional details on the individual components of total system costs are available in Section III.B.1.

We also examine the impact of varying the gross CONE values of each type of marginal resource. Figure 25 shows the impact of varying gross CONE from –10% to +25% relative to our base assumption, with the CC on the left and CT on the right. Based on our experience, this range is consistent with the uncertainty range behind technology cost estimates. Increasing the assumed gross CONE value reduces the economically optimal reserve margin because the benefits of achieving higher reserve margins no longer exceed the marginal costs. Overall, the economically optimal reserve margin could vary over a range of 9.2%–11.5% depending on the assumed marginal resource type and range of gross CONE uncertainty.

Figure 25
Total Annual System Costs with Varying CC Gross CONE (left) and CT Gross CONE (right)





Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional detail on the individual components of total system costs is available in Section III.B.1.

2. Forward Period and Load Forecast Uncertainty

As explained previously, non-weather load forecasting error (LFE) increases with the forward period. This is unlike weather-related uncertainty, which is generally assumed to be constant over time. A longer forward planning period therefore results in higher load forecast uncertainty and, if resource additions cannot be modified on a shorter-term basis, a higher likelihood of reliability and scarcity events. This means that a longer forward period will also increase the reserve margin necessary to achieve any given reliability standard.

In our Base Case analysis, we assume that three years forward is the time at which all supply decisions must be locked in, which is approximately consistent with the lead time needed to construct new generation resources.[68] This lead time for constructing new resources is also the reason that PJM and ISO-NE's capacity markets rely on a three-year forward period. In traditionally-regulated regions with integrated resource planning processes subject to state

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68 Note that although the entire development timeline for most new plants is greater than three years, much of that development work, including siting and permitting, can be done without making major irreversible financial commitments. This means that the time needed for actual plant construction is most relevant when the resource investment decision is truly locked in. Developing and constructing a natural gas CC or CT takes approximately 3.25 and 2.8 years respectively, see Spees, *et al.* (2011), Appendices A.3 and B.3.

regulation, at least a portion of all planning decisions are often made on a schedule that looks more than three years forward.[69] Note, however, that most systems also have substantial flexibility to adjust their total resource portfolio on a shorter-term basis, including even a one-year forward basis. For example, there is substantial capability to adjust DR commitments, adjust retirement or retrofit decisions, delay or accelerate plant development efforts, and invest in plant upgrades on a shorter-term basis.

We examine here the implications of varying the assumed forward period on the economically optimal and reliability-based reserve margins. Generally, increasing the forward period at which supply decisions are locked in increases the economic load forecast error, which consequently increases the planning reserve margin whether the reserve margin is reliability-based or economically-based.

Figure 26 shows that increasing the forward period will increase the economically optimal planning reserve margin. The Base Case assumption of a three-year forward period is shown as a blue line while the gray lines show costs ranging from a one-year to a four-year forward planning period, as well as an illustrative case with no non-weather LFE. Total costs increase with a higher forward period because there is a greater risk of low-reliability events associated with under-forecasting load (and greater capital costs required to build sufficient capacity to avoid such events). However, if sufficient short-term resource flexibility exists to allow for a reduction of the forward planning period from three years to zero, then the risk-neutral optimal reserve margin would decrease by 1.1%, from 10.2% to 9.1%.

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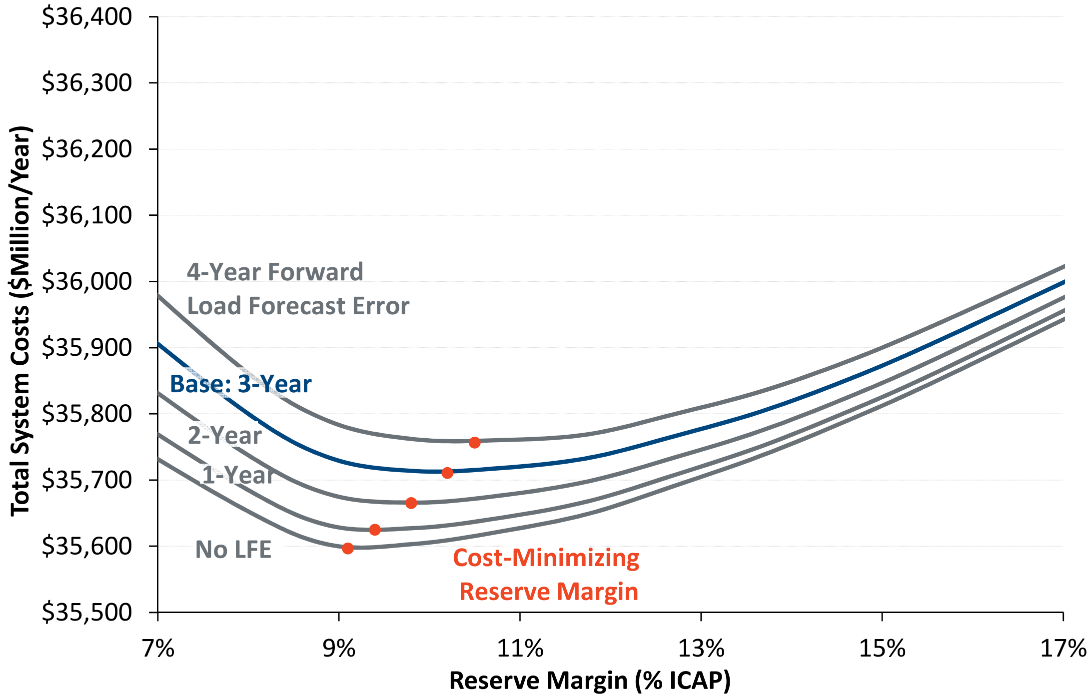
69 For example, see the discussion of the Long-Term Resource Planning processes implemented by California's investor owned utilities under the oversight of the state commission in Pfeifenberger, *et al.* (2012).

Figure 26
Total Annual System Costs with different Forward Periods for Locking in Supply Decisions



Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional detail on the individual components of total system costs is available in Section III.B.1.

The same relationship between forward period and reserve margins also holds true for reliability-based reserve margins as summarized in Table 14 for 0.1 LOLE, 2.4 LOLH, and 0.001% normalized EUE. For example, reducing the forward planning period from three years to one year reduces the 0.1 LOLE-based reserve margin by 1.0 percentage point from 14.1% to 13.1%. This would, of course, require that sufficient short-term resources exist that could be mobilized on a 12-month basis should economic growth prove greater than anticipated.[70] Such short-term resources might include additional demand response (assuming the market is not fully saturated), upgrades to existing plants (or new plants under construction), reactivations of mothballed plants, an increase in net import commitments, imports (if they are qualified to provide capacity) or the acceleration of in-service dates of new plants under development.

70 For example, assume that most resource investment decisions (*e.g.*, for existing generation) were made on a longer term basis but the final 5% of resources were not procured until one year prior to delivery. However, the actual amount of incremental resources needed on a one-year forward basis may only be 3% or as high as 7% if economic growth were higher or lower than expected in prior planning exercises.

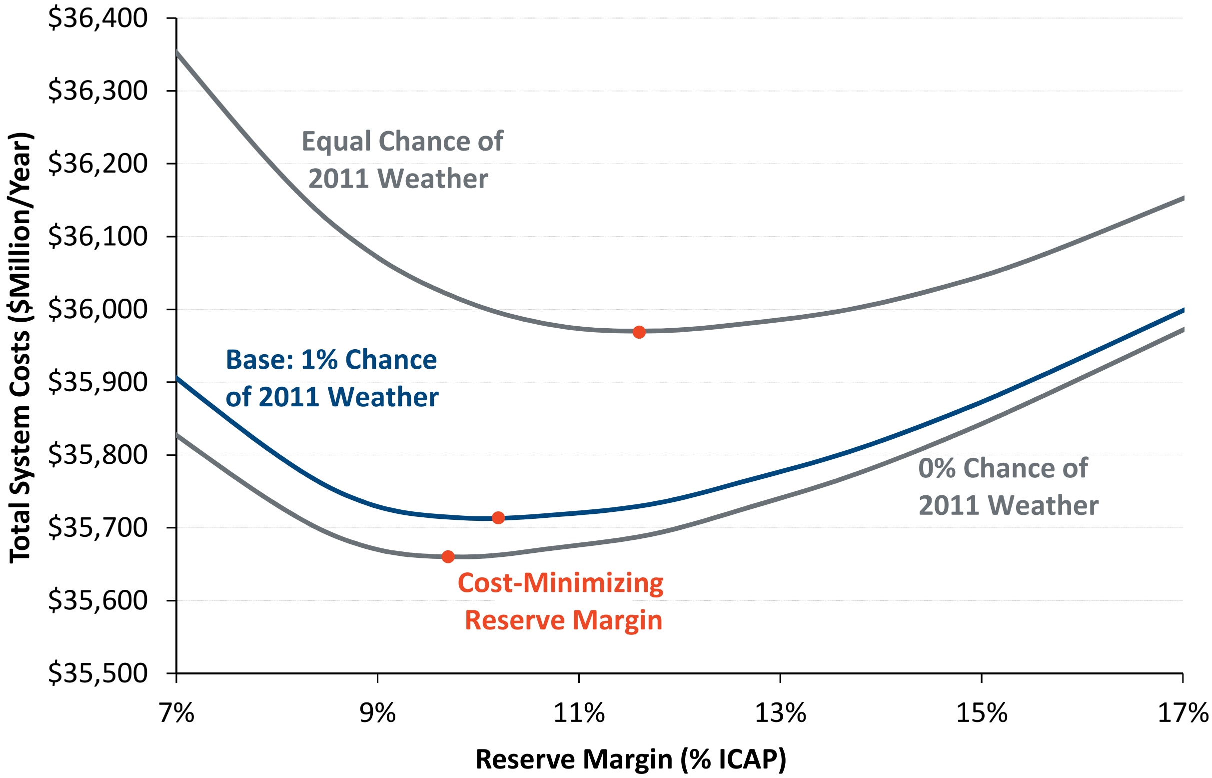
Table 14
Physical Reliability-based Reserve Margins for Varying Forward Periods

Load Forecast Error	Reliability-Based Reserve Margin		
	0.1 LOLE	2.4 LOLH	0.001% Norm. EUE
No LFE	12.6%	8.2%	8.4%
1 Year	13.1%	8.4%	8.7%
2 Years	13.6%	8.7%	9.1%
3 Years (Base)	14.1%	9.1%	9.6%
4 Years	14.6%	9.5%	9.9%

3. Probability Weighting of Weather Years

Figure 27 shows the sensitivity of our economically optimal reserve margin estimate to the likelihood of 2011 weather reoccurring. As the figure shows, the Base Case assumption of a 1% probability results in a 10.2% economically optimal reserve margin. At a zero probability, the optimal reserve margin is somewhat lower at 9.7%. However, if 2011 had a probability equal to that of the other 14 weather years (*i.e.,* a 1/15 chance), the economically optimal reserve margin would increase to 11.5%. Thus, the economically optimal reserve margin estimate may change by more than two percentage points depending on one's view of the likelihood of such extreme weather recurring.

Figure 27
Total Annual System Costs with Varying Probability of 2011 Weather Recurring



Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional detail on the individual components of total system costs is available in Section III.B.1.

4. Energy Prices Always Equal to Marginal Cost

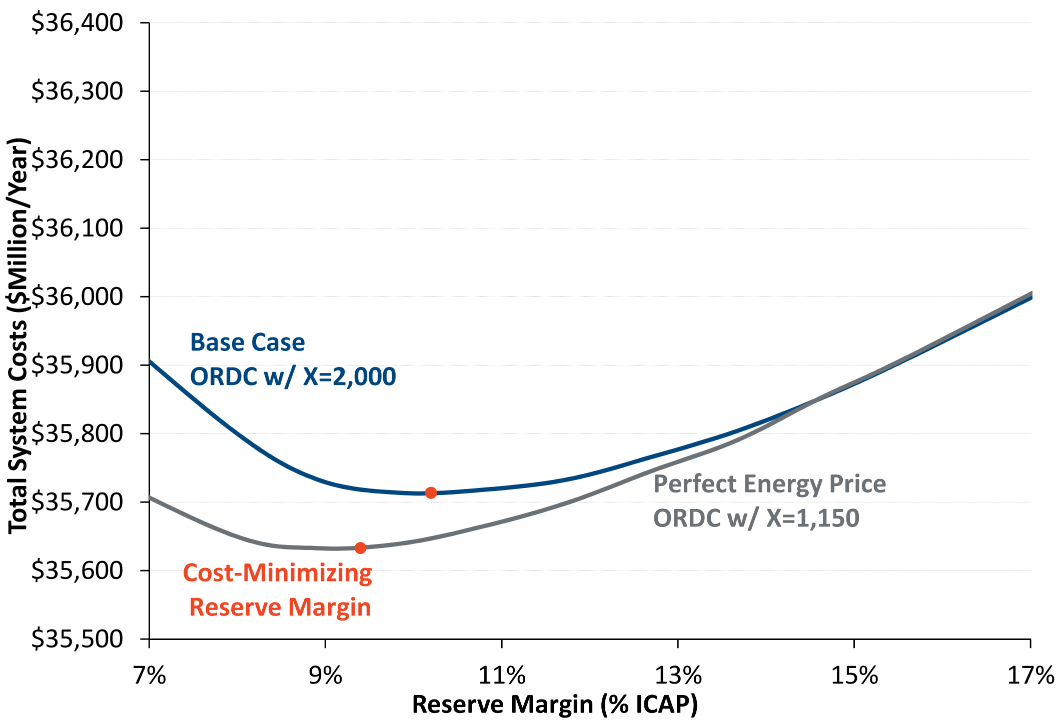
As explained in Section II.F above, our Base Case analysis simulates a complex scarcity pricing structure; the most important component of which is the administrative pricing in the ORDC curve. We implement an ORDC pricing function calculated as if load would be shed (or other emergency actions undertaken with an equivalent cost equal to the value of lost load) at an operating reserve level of X = 2,000 MW, consistent with ERCOT's proposed implementation. This creates scarcity prices that exceed marginal costs in some cases, because we assume that ERCOT will not actually shed load or otherwise incur such high costs until operating reserves are depleted to 1,150 MW. Emergency actions other than load shedding do incur costs between X=2,000 and X=1,150, but we model those actions explicitly at costs less than VOLL, as described in Section II.F.2.

To evaluate the impact of these prices in excess of marginal cost, we examine an alternative Perfect Energy Price Case, where we assume that prices are always set equal to marginal cost with the ORDC set at X = 1,150 MW for both pricing and marginal cost purposes. Another minor difference between the two cases is that we do not reduce the maximum PBPC to the

LCAP after PNM is exceeded, but instead assume that the PBPC remains at the same price that is reflective of the marginal cost of enduring regulating reserve shortages.

Figure 28 shows the difference in realized system costs in the two cases across the range of reserve margins. The chart shows that system costs would be lower under the Perfect Energy Price Case, consistent with the expectation that having perfectly efficient energy prices will result in the most efficient system dispatch and lowest overall system costs. This also reduces the economically optimal reserve margin by almost a percentage point, from 10.2% to 9.3%. The total system cost is $77 million/year lower on average at the optimum in the Perfect Energy Price Case compared to the Base Case.

Figure 28
Total Annual System Costs in Base and Perfect Energy Price Cases
(X = 2,000 MW in Base Case and X = 1,150 MW in Perfect Energy Price Case)



Notes:
Total system costs include scarcity-related and production costs (that decrease with reserve margin), generation capital costs (that increase with reserve margin), and T&D costs (which remain constant across reserve margins. Additional detail on the individual components of total system costs is available in Section III.B.1.

Table 15 summarizes the components of total system costs that contribute to the $77 million/year cost difference between the two cases. The most important factors driving the higher cost in the Base Case relative to the Perfect Energy Price Case is the increased frequency of PRD self-curtailments caused by higher prices and the increase in marginal CC capital costs incurred to achieve a higher reserve margin and avoid some of those PRD costs. Other minor contributing factors are greater imports and increased frequency of PBPC-based regulation shortages.

Some components of total system costs are actually lower in the Base Case, although not enough lower to reduce system costs overall. Those reduced costs include: (a) lower production costs, as some internal resources ramp down to provide reserves or are displaced by PRD and imports; (b) PRD calls displacing the need to make administrative calls on LRs, TDSP load curtailments, and ERS; (c) a reduction in reserve shortages; and (d) avoided load shedding, which is made possible because avoiding some administrative DR calls, as previously mentioned, reduces the likelihood of hitting their call limits and therefore necessitating load shed.

Table 15
Comparison of Total Annual System Costs in the Base and Perfect Energy Price Cases
(Base Case at 10.2% and Perfect Energy Price Case at 9.3% Reserve Margin)

Reliability-Related Cost Component	**Base Case at Economic Optimum** *($M/Yr)*	**Perfect Energy Price Case at Optimum** *($M/Yr)*	**Cost Increase: Base Case - Perfect Energy Price Case** *($M/Yr)*
Marginal CC Capital Costs	$510	$434	$76
Production Costs (Above Baseline)	$175	$196	($21)
External System Costs (Above Baseline)	$100	$91	$9
Emergency Generation	$2	$2	$0
10-Minute ERS	$3	$5	($2)
30-Minute ERS	$1	$1	($0)
Non-Controllable LRs	$15	$27	($11)
TDSP Load Management	$2	$3	($1)
Price-Responsive Demand	$57	$13	$44
Spinning Reserve Shortages	$29	$31	($2)
Non-Spinning Reserve Shortages	$34	$36	($2)
Regulation Shortages	$8	$4	$4
Firm Load Shedding	$27	$42	($15)
Transmission and Distribution	$15,160	$15,160	$0
Generation Fleet Fixed Costs	$9,593	$9,593	$0
Production Costs Baseline	$10,000	$10,000	$0
Total System Costs	**$35,716**	**$35,638**	**$77**

Notes:
Additional detail on the individual components of total system costs is available in Section III.B.1.

D. Sensitivity of Economic Reserve Margin to Study Assumptions

Our estimate of the risk-neutral economically optimal reserve margin is sensitive to a number of study assumptions as we have explained in the previous sections, and summarized in Table 16 below. As shown in the table, the economically optimal reserve margin for the most part ranges from approximately 9% to approximately 12%, depending on study assumptions that drive economic costs and the frequency of scarcity events. In addition to the drivers of scarcity that we have already discussed in prior sections, we also provide illustrative calculations in which we vary VOLL and DR costs. We estimate that halving or doubling all VOLL-related and DR-related costs would affect the economically optimal reserve margin by about +/-1.5%.

Table 16
Sensitivity of the Economically Optimal Reserve Margin to Study Assumptions

	Reserve Margin Range *(%ICAP)*	Base Assumptions	Low/High Sensitivity
Base Case	**10.2%**		
Marginal CC w/ X=2,000 MW			
Vary Load Forecast Error	9.1% - 10.5%	3 Yrs	0 Yrs - 4 Yrs
Vary CC CONE	9.2% - 10.6%	$122.1/kW-yr	$109.9 - $152.6/kW-yr
Vary 2011 Weather Weight	9.7 - 11.6%	1%	0 - 1/15
Vary VOLL and DR Costs	8.9% - 11.8%	See Section II.D.1	50% - 200% of Base Cost
Perfect Energy Price	**9.3%**		
Marginal CC w/ X=1,150 MW			
Vary Load Forecast Error	8.9% - 9.5%	3 Yrs	0 Yrs - 4 Yrs
Vary CC CONE	7.9% - 9.8%	$122.1/kW-yr	$109.9 - $152.6/kW-yr
Vary 2011 Weather Weight	9.2% - 10.6%	1%	0 - 1/15
Vary VOLL and DR Costs	7.2% - 10.8%	See Section II.D.1	50% - 200% of Base Cost
CT as Marginal Technology	**10.7%**		
Marginal CT w/ X=2,000 MW			
Vary Load Forecast Error	10% - 10.8%	3 Yrs	0 Yrs - 4 Yrs
Vary CC CONE	9.8% - 11.5%	$97/kW-yr	$87.3 - $121.3/kW-yr
Vary 2011 Weather Weight	10.3% - 11.9%	1%	0 - 1/15
Vary VOLL and DR Costs	9.0% - 12.6%	See Section II.D.1	50% - 200% of Base Cost

Notes:
VOLL and DR Sensitivities are approximate calculations not corresponding to simulation results.

IV. Comparison of Energy-Only and Capacity Market Designs

One pressing question before the Commission is whether ERCOT should maintain its current energy-only market or implement a capacity market. The essential difference is that in an energy-only market, the reserve margin and resulting reliability implications are determined by market forces. Although the Commission can estimate the likely future reserve margin and influence it by adjusting scarcity pricing provisions, the market will ultimately move toward an "equilibrium" reserve margin at which prices are just high enough to attract investments in new resources. By comparison, in a capacity market, the Commission would mandate the reserve margin consistent with its reliability, economic, and other policy objectives, and market forces would then determine the "equilibrium" capacity price that can sustain the investments needed to achieve the mandated reserve margin.

In this Section, we utilize our simulation modeling results to inform the policy question of whether to maintain the current energy-only market or move to a mandated reserve margin and capacity market design. For each of the two market designs, we evaluate the: (a) equilibrium market prices (as opposed to short-term transitional conditions that might be experienced if implemented or continued today); (b) reserve margins each design is likely to achieve; (c) year-to-year variations around equilibrium points, as well as uncertainty in the equilibria themselves; and (d) consequences for customer costs and supplier net revenues on average over many years and in extreme years. Finally, we evaluate the implications of these results for the policy questions facing the Commission in determining the best course of market design into the future.

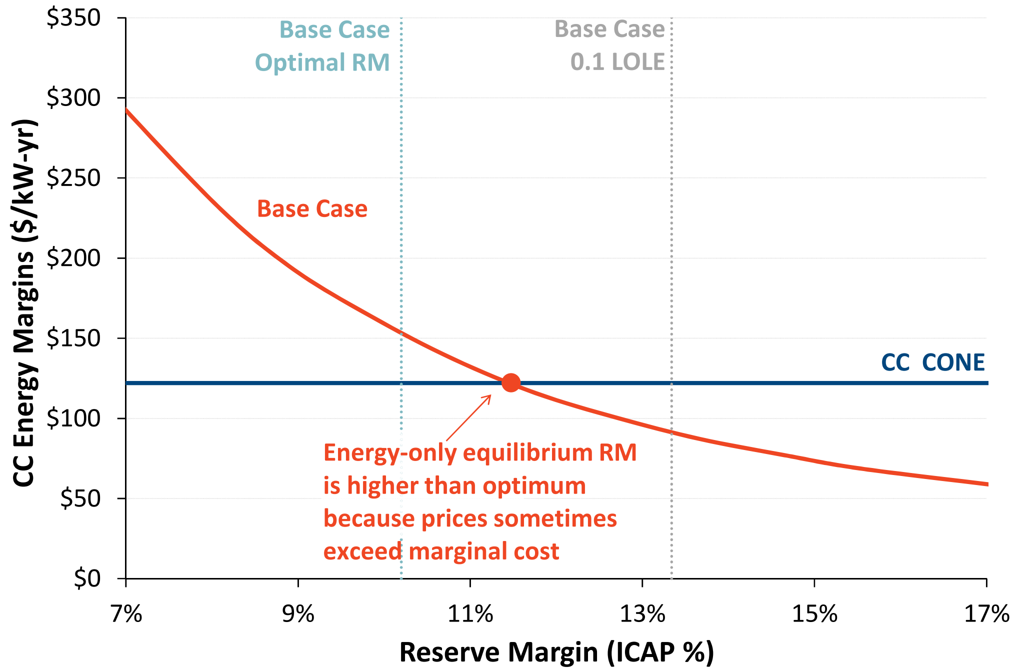
A. Energy-Only Market Results

We describe here the equilibrium conditions that we would anticipate under ERCOT's current energy-only market design by: (1) estimating the energy-only market equilibrium for our Base Case assumptions and several sensitivity cases; (2) summarizing the volatility in realized prices and net revenues across reserve margins; and (3) describing the likely year-to-year variation in realized reserve margins.

1. Equilibrium Reserve Margin

In an energy-only market, there is no mandatory reserve margin or associated reliability level. Instead, the level of generation investment and corresponding reserve margin depends on market prices. Investors build generation whenever expected future energy prices are high enough to provide an adequate return on capital. If the reserve margin is very low, frequent shortage conditions will lead to high expected prices, increased investment in new generation, and higher reserve margins. However, if the reserve margin becomes too high, prices will not be sufficient to support investment. Thus, the market will reach an equilibrium reserve margin where suppliers are recovering their investments and earn an adequate return, but no more. We illustrate such an equilibrium point in Figure 29, which we estimate at 11.5% in our Base Case. At that point, the net revenues for a new combined-cycle plant (shown in red) are just equal to its annualized capital and fixed costs at CONE (shown in blue).

Figure 29
Average Annual Energy Margins for a Combined-Cycle Plant



Notes:
Figure reflects base case assumptions, resulting in an energy-only equilibrium reserve margin of 11.5%.

We provide a comparison of this energy-only reserve margin and the associated reliability results for the Base Case and various sensitivity cases in Table 17. Our Base Case market equilibrium estimate of 11.5% is above the 10.2% economically optimal reserve margin and below the 14.1% 1-in-10 reserve margin we estimated in Section III above. This 11.5% market equilibrium exceeds the 10.2% economically optimal reserve margin because the Base Case ORDC produces energy prices that sometimes exceed marginal system cost (as explained in Section II.F) and, therefore, provides investment incentives that slightly exceed the resource's true economic value. In the alternative Perfect Energy Price Case, where prices are always equal to marginal cost, there is no such discrepancy, and the energy-only market reaches equilibrium exactly at the lower system-wide cost-minimizing reserve margin of 9.3%.

If investors have different beliefs about probability distributions around load and other factors affecting revenues or costs, the market equilibrium will differ from our estimates, as illustrated in Table 17. Changing our assumptions about the likelihood of 2011 weather recurring, the level of load forecast error, the marginal resource technology, and the ORDC scarcity pricing function results in equilibrium reserve margins ranging from 9% to 13%. The actual uncertainty could be even wider, however, when considering other variables such as natural gas price uncertainty, the cost of new entry (CONE), different beliefs about potential regulatory interventions, *etc*.

This range of equilibrium reserve margins would produce a range of reliability outcomes, which we estimate to be 0.27–0.85 LOLE, 0.68–2.37 LOLH, and 0.0003%–0.0013% normalized EUE. Thus, the energy-only market will result in an equilibrium reliability level that is below the traditional 1-in-10 LOLE standard, but at a level consistent with possible alternative reliability standards, including the 2.4 LOLH standard used in SPP and the 0.001% normalized EUE standard used in some international markets.

Table 17
Comparison of Energy-Only Equilibrium to Alternative Reserve Margin Targets

	Scenario			Reliability at Energy-Only Equilibrium		
	Economic Optimum	Energy-Only Equilibrium	0.1 LOLE	LOLE *(Events/Yr)*	LOLH *(Hours/Yr)*	Norm. EUE *(%)*
Base Case	10.2%	11.5%	14.1%	0.33	0.86	0.0004%
Equal Chance of 2011 Weather	11.5%	12.9%	16.1%	0.43	1.15	0.0005%
No Non-Weather Forecast Error	9.4%	10.8%	12.6%	0.27	0.68	0.0003%
Perfect Energy Price	9.3%	9.3%	14.3%	0.85	2.37	0.0013%
CT as the Marginal Technology	10.7%	11.6%	14.1%	0.30	0.79	0.0003%

Notes:
Reliability is slightly better in the Base Case than in the Perfect Energy Price Case because the higher prices created by ORDC attracts more price responsive demand and reduces the need to rely on call-limited administrative demand-response resources, see Section III.C.4.

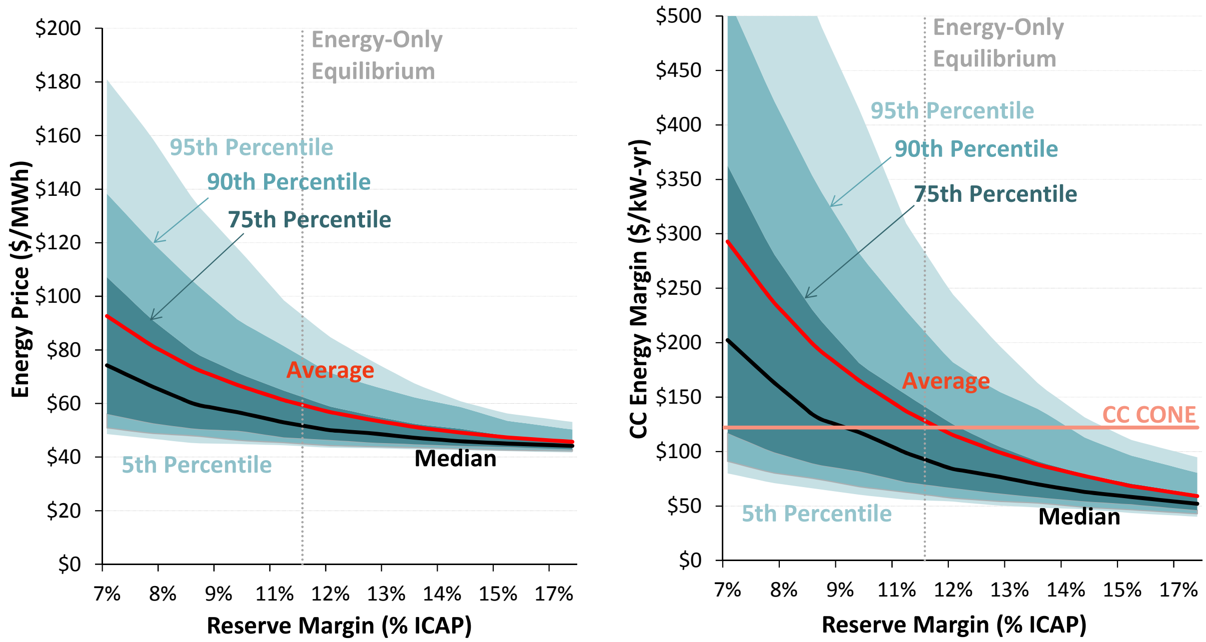
2. Volatility in Realized Prices and Energy Margins

Our estimate of the energy-only equilibrium reserve margin is strongly influenced by our assumed probability distributions for peak loads and generator outages, especially the most extreme scarcity events at the tails of those distributions. As the reserve margin declines, these tails become more likely to produce shortages, high prices, high system-wide costs, and high generator margins. We analyzed these effects by simulating the entire probability distributions for each possible reserve margin.

Figure 30 shows the resulting range of annual values for the Base Case. The upper percentile curves show that annual prices and supplier net revenues in the tails of the distribution can be much higher than the median year or the overall weighted average. This indicates that the high-cost tails have a substantial effect on the energy-only market equilibrium reserve margin.

For example, at the Base Case equilibrium reserve margin of 11.5%, we estimate that energy prices would exceed \$67.9/MWh (40% higher than the typical or "median" price) once per decade (90th percentile) and would exceed \$78.2/MWh (60% above the median price) once every two decades (95th percentile). Similarly, although supplier net revenues are at CONE on average across all years, the typical or median year has net revenues of only \$97.2/kW-year (only 80% of CONE), with net revenues exceeding CONE only once every 2.5 years. Suppliers will not be earning sufficient net revenues to recover their investment costs most of the time and will depend heavily on the net revenues realized during shortage years that would likely occur only a few times over the asset life. Assuming full exposure to spot market prices (*i.e.*, no hedging) net revenues of generating plants would exceed \$196/kW-year (1.6 times CONE) once in a decade (90th percentile) and \$263/kW-year (2.2 times CONE) once every two decades (95th percentile).

Figure 30
Uncertainty Range in Realized Load-Weighted Energy Prices (Left) and CC Energy Margins (Right)



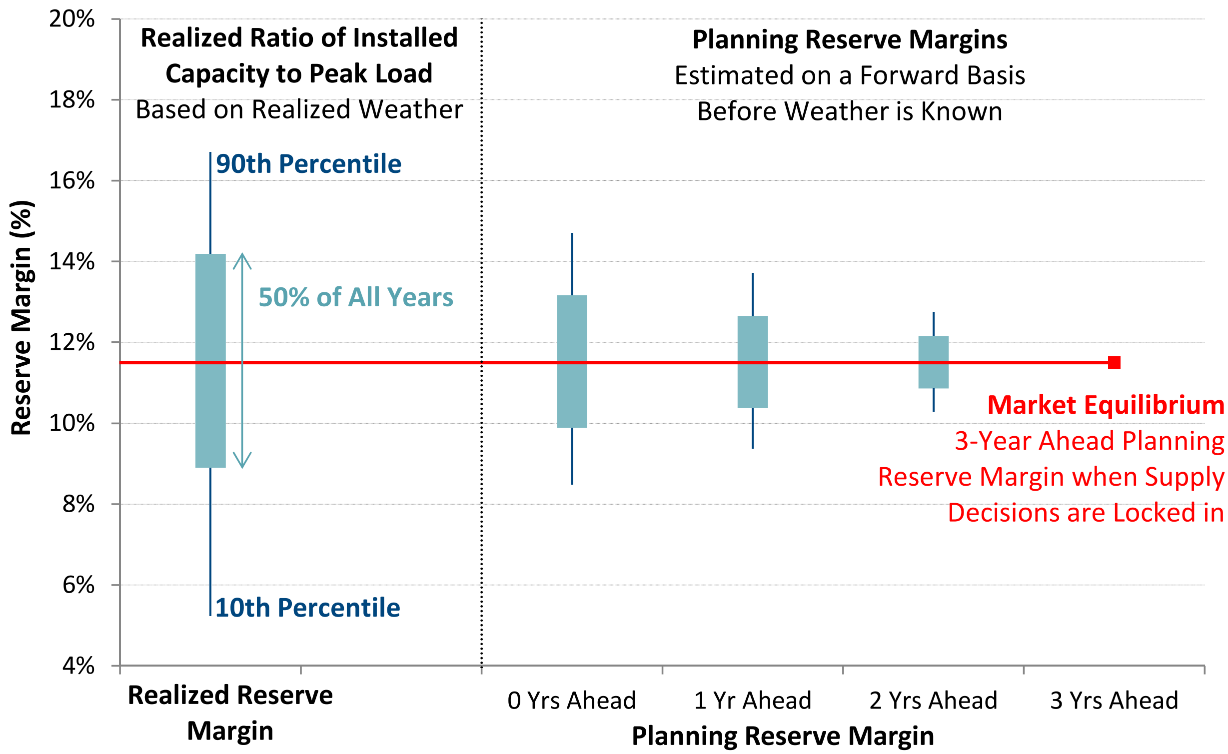
Some opponents of energy-only markets have asserted that such high spot market payoffs occur too infrequently for investors to rely on. However, this argument ignores the fact that most generators will sell their output at (*e.g.*, seasonally hedged) forward prices, not spot prices. For example, even seasonal forward prices will largely eliminate the weather-driven component of spot price uncertainty. However, even if hedged through forward contracts, suppliers will still face significant uncertainty from non-weather factors, as discussed in Section IV.C.2 below.

3. Year-to-Year Reserve Margin Variability

One of the main sources of uncertainty is load growth. Our Base Case simulations assume that the market invests to exactly meet the equilibrium planning reserve margin on a three-year forward basis. However, actual load growth will always differ from three-year expectations, resulting in a range of realized reserve margins that differ from equilibrium reserve margins. We simulate this effect based on the assumed probability distributions for non-weather forecast error as described in Section II.B.3 above. This yields the range of planning and realized reserve margins summarized in Figure 31. The three right-hand bars in the figure show *planning reserve margins* estimated on a forward basis against the weather-normalized (50/50) peak load, while the bar on the left shows the uncertainty range of *realized reserve margins* as measured after the fact, considering both realized weather and non-weather uncertainties.

The chart shows that even if the three-year-ahead planning reserve margin is exactly at the economic equilibrium of 11.5%, realized shorter-term planning reserve margins can be higher or lower as load growth uncertainty resolves itself over the next three years. As the bar second from the left shows, planning reserve margins *projected going into each summer* would thus vary around the equilibrium from 9.9%–13.2% in 50% of all years and drop below 8.5% approximately once per decade (*i.e.*, below the 10th percentile shown). Once weather-related load fluctuations are considered as well, after-the-fact *realized reserve margins* will vary even more substantially. As the bar on the very left shows, such after-the-fact realized reserve margins will drop below 5.2% approximately once per decade (*i.e.*, below the shown 10th percentile). However, realized reserve margins, particularly the lows that largely reflect realized weather extremes, should not be compared to more familiar planning reserve margin benchmarks.

Figure 31
Year-to-Year Variability in Planning and Realized Reserve Margins



Actual variability in reserve margins may differ from the three-year-forward simulation results shown in Figure 31. Our simulations do not account for the mitigating effect of short lead-time resources (such as uprates and demand response) that can exit or enter the market as expectation change between three years forward and delivery. By not simulating the effects of market exit and entry by short-term resources, our results would tend to overstate the range of realized reserve margins. However, our simulations also do not account for the countervailing effects of additional supply-side uncertainties, such as unanticipated retirements, construction delays, and lumpiness in uncoordinated new entry, which would tend to increase the variability of reserve margins; and uncertainties about modeling assumptions, anticipated fuel prices, and other factors that would further widen the distribution of realized reserve margins. Overall, we estimate that equilibrium reserve margins would range from 9% to 13%, with an additional year-to-year planning reserve margin variation of approximately 3 percentage points around that equilibrium.

B. Capacity Market Results

If ERCOT or the Commission wanted to achieve a higher or more certain reserve margin than the energy-only market would support, then a mandatory reserve margin could be imposed at a level consistent with such policy objectives. For example, a 14.1% reserve margin mandate would correspond to the traditional 1-in-10 target for our Base Case simulation results. Alternatively, the Commission could opt to specify a different LOLE (or EUE-based) target, or even opt to define a new type of reserve margin requirement based on economic cost and risk mitigation objectives.

1. Capacity Prices at Higher Reserve Margins

Mandating a higher reserve margin would make capacity valuable beyond the value obtained in the energy market. This would make additional payments available to suppliers, either through a centralized or bilateral capacity market.[71] The capacity price consistent with market conditions under any particular reserve margin mandate would be determined by market forces. In equilibrium, the average capacity price would equal the net cost of new entry (Net CONE), equal to the difference between CONE and the energy margins obtainable at the required reserve margin.

Note that these estimates describe long-term equilibrium prices. Near-term prices might be lower if the market has excess capacity or if low-cost resources (such as demand response and generation uprates) are sufficient to meet the requirement at a lower price.

Figure 32 shows how expected equilibrium capacity prices would vary with reserve margins under our Base Case assumptions. Based on our Base Case simulation results, setting a reserve margin mandate below 11.5% would produce capacity prices of zero, since suppliers would earn energy margins in excess of CONE and need no additional revenues to invest.[72] However, reserve margin mandates above the energy-only market equilibrium of 11.5% would lead to positive capacity prices. The equilibrium average capacity price would increase as reserve margins increase, since declining average energy prices would increase Net CONE. A mandate equal to the traditional 1-in-10 LOLE standard at a 14.1% reserve margin would yield an average capacity price of approximately $40/kW-year at equilibrium. These increasing reserve margins

[71] We assume for the purposes of this report that the payments would be awarded through a capacity market, but the level of capacity payments required would be the same under a range of alternative capacity payment mechanisms (although some approaches might award these over a different time schedule), as long as the approach does not involve price discrimination. For a comprehensive description of resource adequacy standards, capacity markets, and alternative market designs, see Pfeifenberger, *et al.* (2009).

[72] In reality, prices would unlikely be literally zero, but instead may be at a very low level consistent with any incremental overhead costs or penalty risks imposed by taking on a capacity obligation.

would also correspond to energy prices and energy margins lower than in the energy-only equilibrium, such that suppliers' all-in net revenues equal CONE in both cases.

Note that these estimates describe long-term equilibrium prices. Near-term prices might be lower if the market has excess capacity or if low-cost resources (such as demand response and generation uprates) are sufficient to meet the requirement at a lower price.

Figure 32
Equilibrium Capacity Prices Required to Sustain Higher Reserve Margins

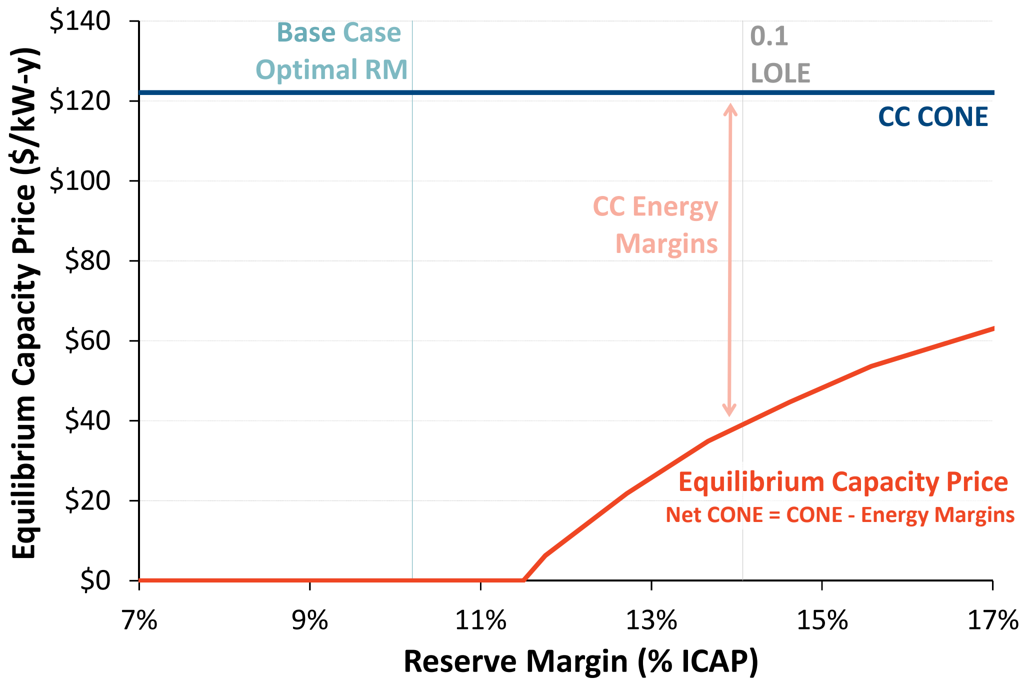
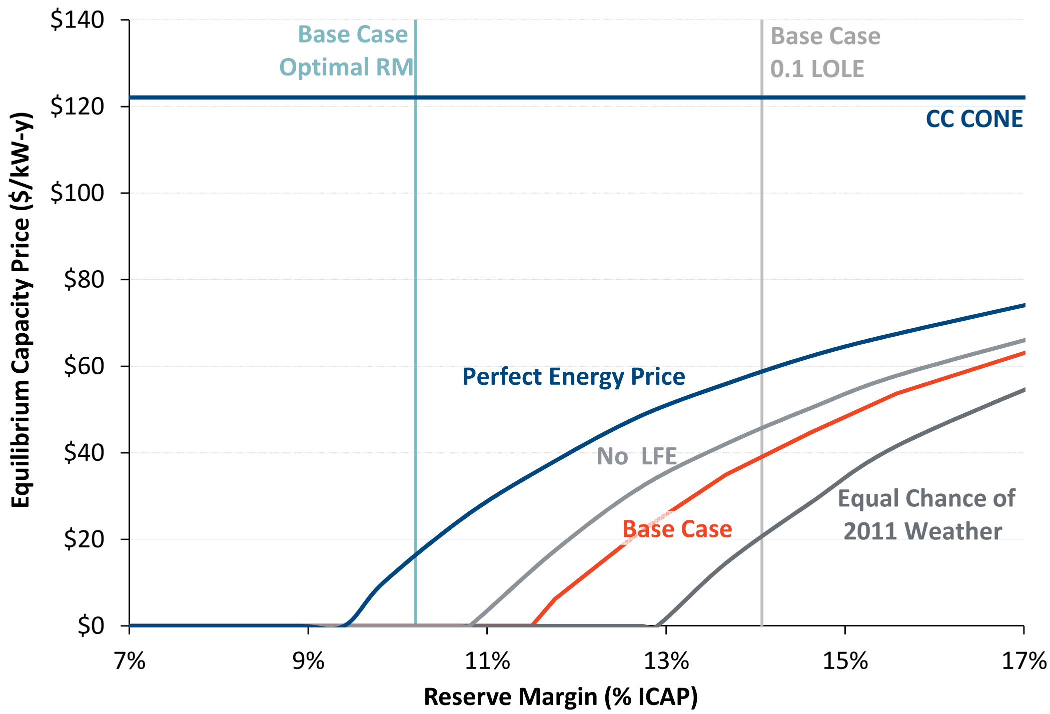


Figure 33 below shows equilibrium capacity prices for several alternative cases reflecting different study assumptions. Cases with higher energy prices and energy margins yield lower capacity prices, consistent with long-run total net revenues equal to CONE on average. At the 14.1% reserve margin needed to meet the 1-in-10 standard in the Base Case (but not in all sensitivity cases), equilibrium capacity prices would vary from approximately $20 to $60/kW-year depending on energy market design and varying with study assumptions.

Figure 33
Equilibrium Capacity Prices Under Varying Study Assumptions



2. Capacity Price Volatility

The above figures show only the equilibrium capacity prices that one would expect on average. Actual capacity prices would vary from year to year around these levels. Energy price uncertainty would be less in a market design with a higher mandated reserve margin than in an energy-only market. This is because the higher reserve margin reduces energy market volatility and average energy prices as discussed above. Although only expected future energy prices are likely to be incorporated into capacity-market supply offers (through their impact on Net CONE), capacity prices would nevertheless vary based on the supply and demand for capacity during a particular delivery year. In fact, capacity prices can be quite sensitive to even small shifts in supply and demand balances, because both supply and demand curves tend to be quite steep. This is especially true on the supply-side in capacity markets without multi-year forward procurement, which would have a near-vertical supply curve since all supply decisions have already been made and suppliers have insufficient time to respond to changes in demand.[73]

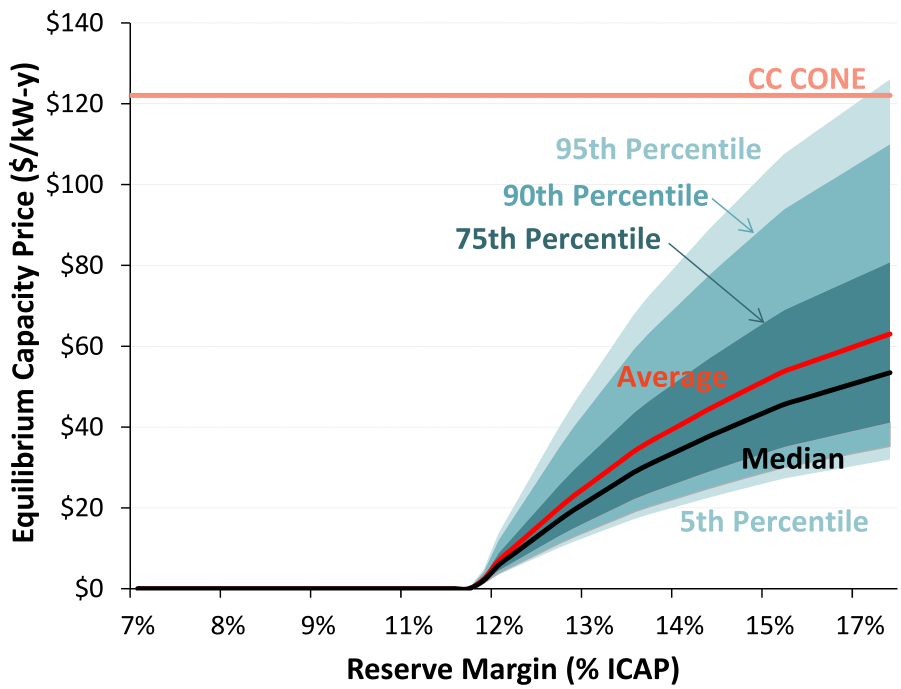
We provide indicative estimates of such variations based on Monte Carlo simulations that we conducted for another region's capacity market, consistent with realistic shocks to supply and demand, empirically-based three-year forward supply elasticities, and an assumed price cap of

[73] For a more comprehensive discussion of volatility in capacity market prices, see Spees, *et al.* (2013).

two times Net CONE (which limits volatility).[74] These indicative simulation results are shown in Figure 34. If ERCOT were to adopt a required reserve margin and a three-year forward capacity market, pricing patterns may be different, depending on its own market characteristics and market conditions.

Two of the most important factors affecting the level of volatility in a capacity market are: (1) the forward period, with longer-forward periods reducing capacity price volatility by increasing supply elasticity, and (2) the steepness of the demand curve, with a gradually sloped curve reducing capacity price volatility relative to a vertical demand curve that reflects a fixed requirement. However, it is important to note that some (but not all) factors reducing price volatility can increase quantity volatility.

Figure 34
Approximate Uncertainty Range of Three-Year Forward Capacity Prices



C. Implications for Customers and Suppliers

In this Section, we compare alternative energy-only and capacity market designs from the perspectives of customers and suppliers. On the customer side, we evaluate how energy costs and capacity costs, (if applicable) differ between the two market designs. On the supply side, we evaluate the proportion of net revenues made up from energy margins versus capacity payments,

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74 See the simulated distribution of capacity prices around Net CONE with the "Initial Candidate Demand Curve", from Newell, *et al.* (2014), p. 14.

although the total payments at equilibrium are equal to CONE in both cases. Finally, we evaluate the volatility profile of costs and revenues under either market design by looking at the once-per-decade scarcity year, and reporting the realized total costs or net revenues in that extreme event if the market participant is totally exposed to spot prices or if they are 80% hedged against extreme weather.

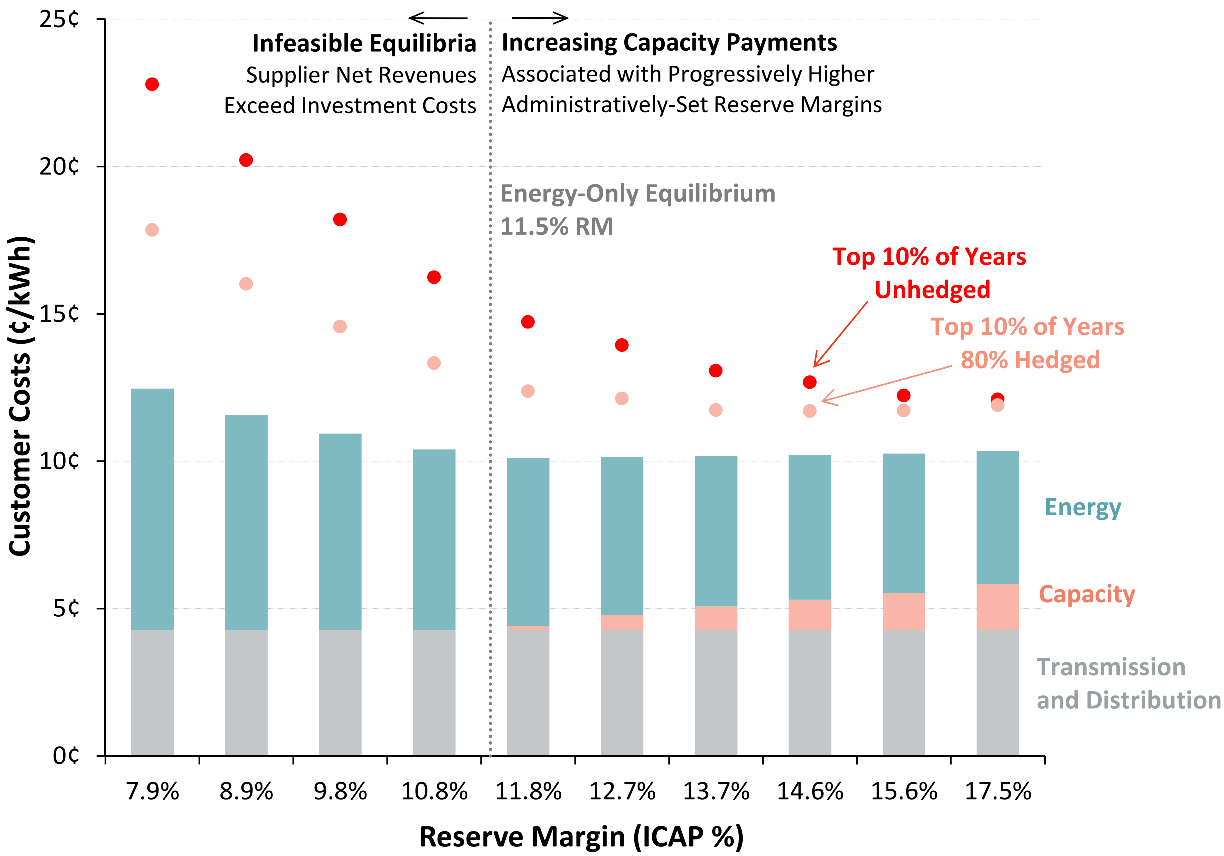
1. Total Customer Costs and Volatility

In ERCOT's competitive retail environment, the generation component of retail rates will reflect wholesale market prices, which depend on market conditions and regulatory drivers such as gas prices, realized reserve margins, and mandated planning reserve margins (if any). Very low planning reserve margins would lead to frequent price spikes and high electricity rates; very high reserve margins would depress energy prices but could only be sustained with high capacity payments in the long run. Note that the current market is not in long-run equilibrium, with reserve margins above our estimates of economically-sustainable reserve margins despite the absence of capacity payments. Suppliers are currently earning less than CONE, and customers are enjoying rates below a long-run sustainable level. By contrast, our equilibrium analysis assumes that reserve margins above the energy-only equilibrium would require capacity payments equal to Net CONE so suppliers would earn a total of CONE from the combination of capacity payments and energy margins.

To determine the reserve margin that would minimize customer costs, we calculated equilibrium energy and capacity prices (if any) from our simulations across reserve margins. The results are shown in Figure 35 with stacked bars showing the costs customers would expect to pay on average per kWh of consumption. The chart includes: (a) load-weighted-average energy costs, (b) total capacity costs, calculated as the capacity price as paid to the entire ERCOT generation and demand-response fleet at that reserve margin, and (c) an assumed transmission and distribution cost rate, which would not vary with reserve margin.

The chart provides an indication of the impact on total customer rates across all customer classes. We have not attempted to evaluate the differential cost impacts by customer class, nor for customers with very different load profiles, nor for those that have demand-response capability. In general, customers with higher load factors (flatter load profiles) will benefit less from energy price reductions at higher reserve margins, but will also incur lower capacity costs per kWh of load. Customers with some demand-response capability can further avoid incurring capacity costs by either: (a) managing load away from peak conditions that might be used to assign capacity payments, as in other RTOs with capacity markets and similar to how transmission rates are allocated on a 4 coincident peak basis; or (b) explicitly counting those demand-response capabilities on the supply side and earning capacity payments. The overall impact of increasing the reserve margin will vary among customers, and could be calculated based on individual assumed load profiles (although we have not attempted such a calculation here).

Figure 35
Total Customer Costs on Average and in Highest 10% of Years



Sources and Notes:
ERCOT Region T&D Costs of $42.8/MWh from EIA (2013), Table 55.1.

These results show that the probability-weighted average of annual customer costs are minimized at exactly the energy-only equilibrium. Customer costs would be slightly higher at either lower reserve margins or higher reserve margins. Lower reserve margins would lead to higher average energy rates, although these would not persist for many years because suppliers would earn returns in excess of CONE and therefore develop new resources in response. Higher mandated reserve margins would reduce energy prices (and therefore customer costs), but would require making capacity payments sufficient to fully compensate suppliers. This increase in capacity costs is larger than the decrease in energy costs, resulting in a net increase in total customer costs.

It is remarkable, however, to note how modest the customer cost increases are as the mandated reserve margin increases.[75] Higher mandated reserve margins with associated capacity payments

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[75] Costs increase faster on the left side of the curve at low reserve margins, but this observation can be misleading since reserve margins below the 11.5% energy-only market equilibrium would not be expected to occur on a 3-year forward basis. It is possible that 0-year forward reserve margins will

Continued on next page

would cost customers only slightly more than the energy-only equilibrium. For example, the 14.1% reserve margin needed to maintain a 0.1 LOLE standard would cost customers only 0.1 ¢/kWh more on average than the energy-only market at an 11.5% reserve margin in the long-run equilibrium. That represents an increase in average customer bills of only about 1%. This is because the higher reserve margins reduce average annual energy prices, and the competitive market sets capacity prices such that suppliers earn no more than CONE in total, no matter how high the reserve margin requirement.

On an ERCOT-wide basis, raising the reserve margin from 11.5% to 14.1% would cost customers approximately $400 million per year at equilibrium market conditions (from a $2.8 billion reduction in energy costs offset by a $3.2 billion increase in capacity costs). However, these estimates describe only long-term average prices at equilibrium. They do not describe this year or the next few years. The actual near-term price impacts of implementing a capacity market would be affected by at least two important dynamics. First, capacity prices could be temporarily lower than estimated if some low-cost capacity is available. Other regions have experienced capacity prices below Net CONE for many years due to the entry of demand response, generation uprates, and other low-cost sources of capacity. Second, even without such resources, prices would not be expected to reach equilibrium pricing until the reserve margin falls to the required reserve margin. But herein lies an important cost difference from maintaining an energy-only market. Mandating a reserve margin could cause the market to reach equilibrium as soon as reserve margins fall from their current levels to 14.1% (or whatever level is mandated), whereas the current energy-only market design may take several years to reach its 11.5% long-run equilibrium level. Under either market design, long-term equilibrium prices would be several billion dollars higher than currently-depressed wholesale prices, but a capacity requirement would cause prices to reach equilibrium prices sooner, and at a slightly higher ultimate level (*e.g.*, $400 million higher on average to support a 0.1 LOLE).

Customers care about long-term average rates as well as year-to-year variability and uncertainty. At a given planning reserve margin, wholesale spot prices for energy fluctuate because of variations in load and generation availability (as well as gas price changes, which we have not evaluated in this study). Capacity prices will also fluctuate with supply and demand conditions, as explained in Section IV.B.2 above. The combined effect of energy and capacity price uncertainty is reflected in the red dots in Figure 35, representing the average of retail prices for the highest 10% of years, reflecting a once-per-decade scarcity year. As reserve margins increase, this variability declines because the largest factor driving it is volatility in energy prices, which make up a large portion of total customer costs. Volatility from uncertain capacity prices increases with reserve margins, but this effect is less important since capacity costs are a relatively smaller portion of total customer costs and because we assume that capacity prices are capped at 2 times CONE.

Continued from previous page

occur, *e.g.*, if load grows faster than expected, but this possibility is accounted for in the cost and reliability distribution we show for the 3-year forward reserve margin of 11.5%.

Most customers are not fully exposed to these spot price fluctuations, however, and are at least partially hedged through fixed-price retail contracts and other arrangements. Hedging practices vary by customer class and retail supplier. To illustrate the risk-mitigation effect of such hedging, we assume that the average retail service will hedge 80% of weather-related price risk (*e.g.*, through seasonal forward contracts), but that the retailer will not hedge sufficiently far forward to avoid any non-weather uncertainties such as load forecast error. We also assume that customers would not be hedged against capacity price volatility, since we assume capacity prices would be determined in three-year forward auctions and subsequently incorporated into retail rates.

The results of this risk-mitigation analysis are shown in Figure 35 as pink dots, representing the average annual customer rates during the highest 10% of all years. It shows that hedging protects customers from the weather-driven extremes in energy spot prices that can occur at low reserve margins. Hedging also reduces customer rate variability at higher reserve margins, but not as much.

However, even when hedging practices are considered, customer rate variability will still decline with increasing reserve margin. For example, the once-per-decade scarcity year would produce prices of 15.1 ¢/kWh (about 50% more than average costs) under the energy-only market or 12.9 ¢/kWh (26% above average) under the capacity market at 0.1 LOLE. However, in either case much of this once-per-decade volatility can be mitigated through hedging; a customer with 80% of energy purchases hedged on a seasonal basis and no capacity hedges would realize once-per-decade costs of 12.6 ¢/kWh (24% above average) under the energy-only market or 11.7 ¢/kWh (16% above average) under the capacity market.

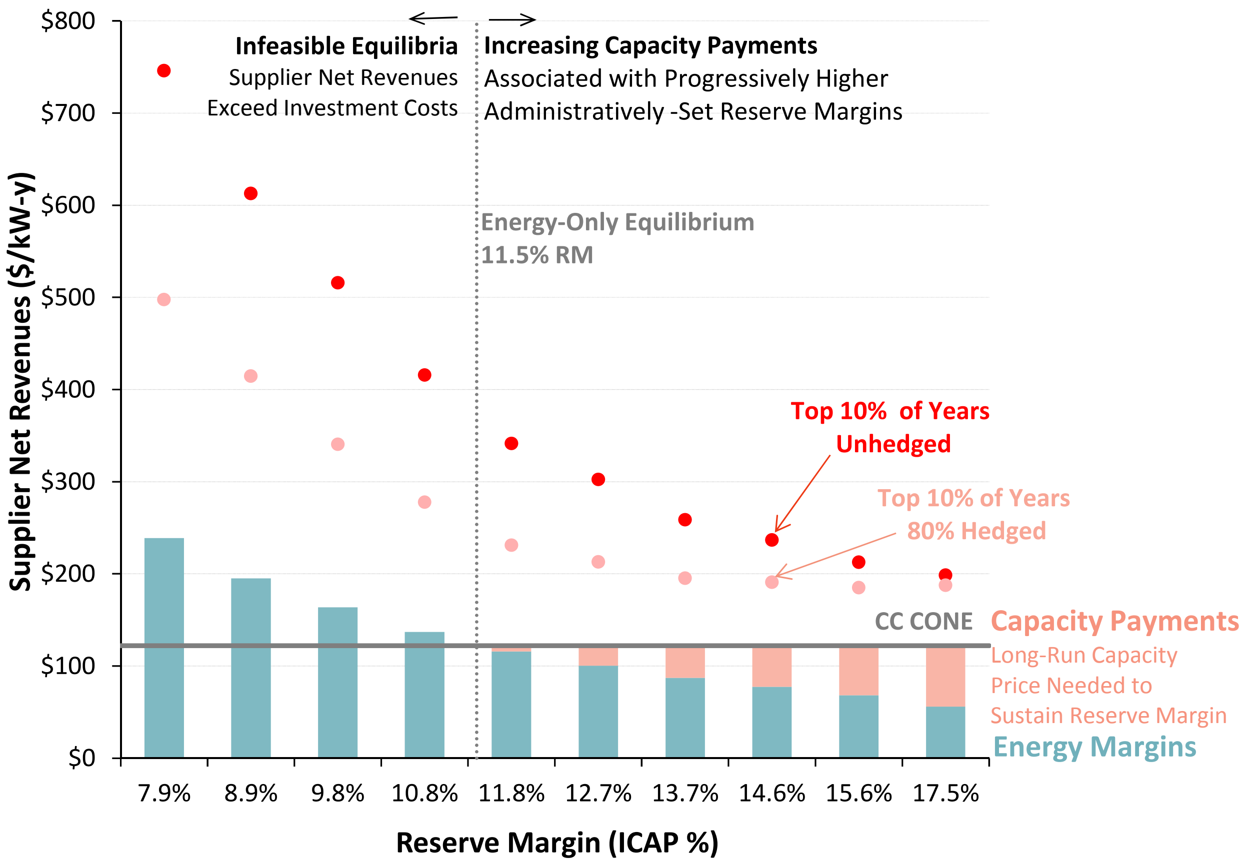
2. Supplier Net Revenues and Volatility

Suppliers earn CONE under equilibrium market conditions under either a capacity market or an energy-only market design, consistent with the incentives necessary to attract investments in a deregulated electricity market. Reserve margins below the 11.5% energy-only equilibrium show higher net revenues, but such conditions cannot persist because suppliers would earn margins above CONE and invest in new resources until the reserve margin reached 11.5% and net revenues dropped to CONE on average. Mandating reserve margins higher than 11.5% would yield increasingly higher capacity prices to compensate for declining energy margins, as shown in Figure 36. The individual components of the chart correspond to the customer cost chart shown above, with the same assumptions about hedging against spot market uncertainty.

While supplier net revenues are equal across all reserve margins (above the minimum feasible equilibrium at 11.5%), the proportion of those net revenues from the energy market declines while those from the capacity market increase. For the gas CC reflected in the chart, capacity payments increase from 0% of net revenues at the 11.5% energy-only equilibrium, up to 32% of net revenues at the 14.1% reserve margin consistent with 1-in-10. The proportion of total revenues from the capacity market would also vary by resource type, with baseload resources earning most of their net revenues out of the energy market, while demand response and peakers would earn most revenues out of the capacity market. The increasing importance of capacity payments to overall investment incentives at higher reserve margins highlights the importance of carefully designing the capacity market so it produces efficient prices consistent with market conditions.[76]

Figure 36

Supplier Net Revenues on Average and in Highest 10% of Years



Similar to customers, suppliers experience more revenue volatility at lower reserve margins. We illustrate these volatility impacts in Figure 36 by reporting net revenues in the once-per-decade scarcity year if the supplier is totally exposed to spot energy and capacity prices (red dots) and, alternatively, assuming hedging practices that eliminate approximately 80% of weather risks (pink dots).[77]

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[76] We document best practices and pitfalls to avoid in capacity market design in Spees, *et al.* (2013) and Pfeifenberger, *et al.* (2013).

[77] See Section IV.C.1 for an explanation of how we implement the 80% seasonal energy hedging assumption; see Section IV.B.2 for an explanation of how we estimate approximate capacity price volatility.

Because net revenues reflect the *difference* between prices and costs, supplier net revenues are more volatile than customer rates. Similarly, the mitigating impacts of hedging and increasing reserve margins are also greater for suppliers than they are for customers. For example, the once-per-decade scarcity year would produce supplier net revenues of $228/kW-year (1.9 times CONE) in the energy-only market or $184/kW-year (1.5 times CONE) with a capacity market at 0.1 LOLE. If the supplier is 80% hedged, the once-per-decade year would produce net revenues of $211/kW-year (1.7 times CONE) in the energy-only market or $172/kW-year (1.4 times CONE) with a capacity market.

This reduced volatility at higher mandated reserve margins has implications for investor risk and, as a likely result, suppliers' cost of capital. Since electricity markets tend to be pro-cyclical (*i.e.*, earnings increase when the overall economy expands and decrease in a poor economy), non-weather-related price risk is partly non-diversifiable and affects investors' costs of capital and therefore CONE. We have not quantified this effect, and so cannot evaluate its potential magnitude. However, as an illustrative example calculation, if a higher reserve margin requirement reduced investors' cost of capital by, say, 10 basis points, CONE and all-in prices would decrease slightly, by less than 1%. Hence, imposing higher reserve margin requirements could at least marginally reduce the cost of capital and the market price for capacity, although we have not attempted to quantify this effect and do not account for it in our analysis.

In addition, it is again important to note that Figure 36 represents supplier margins only under equilibrium conditions. It does not account for possible transitional effects. Imposing a required reserve margin could cause prices to climb from current levels toward equilibrium faster than they would otherwise.

V. Policy Implications

The PUCT, ERCOT, and stakeholders have been addressing resource adequacy concerns since 2011, when extreme weather made the likely implications of a declining reserve margin trend more tangible. Since then, the Commission held numerous workshops and sponsored several studies aimed at addressing various aspects of the problem.[78] The Commission has acted to strengthen energy price signals by raising the price cap, implementing the ORDC, and other reforms. Additional market design changes remain under discussion, including the possible implementation of a mandatory reserve margin and an associated capacity market. These debates have attracted considerable political interest. Meanwhile, suppliers have responded, at least partially, to the increase in anticipated incentives by developing new plants.[79]

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78 For access to a comprehensive set of associated studies and regulatory proceedings, see the Resource Adequacy portion of ERCOT's website as well as the PUCT proceedings under project 40,000. See ERCOT (2014a) and PUCT (2014).

79 For example, Panda Power currently has three combined cycle stations under construction.

Another significant development affecting the outlook for resource adequacy is ERCOT's recent load forecast update, based on a revised load forecasting methodology.[80] Under the new approach, ERCOT is now projecting substantially lower load growth compared to recent years. If that forecast is accurate and no major retirements or project cancellations occur, ERCOT could enjoy robust reserve margins for several years. That revised outlook may reduce the real or perceived urgency of addressing resource adequacy concerns.

However, even if the immediacy of the concern is postponed for an intermediate number of years, these issues highlight a complex set of difficult policy questions that must be answered for the long term, including:

1. What reserve margin and supporting market design would be best for Texas?
2. What are the practical implications of maintaining the current energy-only market design?
3. What would be the practical implications of introducing a resource adequacy requirement and capacity market?
4. How would these conclusions change with market conditions, and what study extensions or updates might be warranted?

We discuss here how our study results help to inform these policy questions as the Commission, ERCOT, and stakeholders evaluate the most appropriate course for ERCOT's market design for resource adequacy.

1. What Reserve Margin and Supporting Market Design Would Be Best for Texas?

As we have explained previously, the most appropriate reserve margin and market design for Texas depend on the policy objectives for resource adequacy that have yet to be fully articulated. If economic efficiency is the only policy objective, then maintaining the energy-only market design is likely the most appropriate course of action. As we have stated elsewhere and illustrated through our Perfect Energy Price Case, a perfectly efficient energy-only market will attract the economically optimal level of supply investments. In fact, our simulations indicate that the current energy-only market design will sustain a reserve margin of approximately 11.5%, which is 1.3 percentage points above the risk-neutral, economically optimum level of approximately 10.2%, because the ORDC curve will sometimes produce prices in excess of marginal system cost.

However, the Commission must weigh multiple, sometimes conflicting, policy objectives that might potentially be best supported by a mandatory reserve margin requirement, as implemented in a well-designed capacity market. Specifically, implementing a capacity market would reduce the risks associated with potential low-reliability and high-cost events, providing net benefits

80 See ERCOT (2014b).

overall from a risk-averse (rather than risk-neutral) perspective. Only by carefully examining the reliability, economic, and other policy implications of increasing reserve margins can the Commission determine the market design that will best serve the state of Texas.

If policymakers and stakeholders place a greater weight on the potential high-cost and low-reliability outcomes that can result from extreme weather, unexpectedly high load growth, unusual generation outages, or modelling uncertainties, then a higher mandated reserve margin could be justified. For example, at the 11.5% energy-only equilibrium in the Base Case, the LOLE would be about 0.3 events per year, which would result in an average of about one load shedding event due to inadequate installed generation capacity every three to four years. Each such event would shed about 1,600 MW of load (approximately 2% of peak load) for about 2.6 hours. At an assumed VOLL of $9,000/MWh, the implied cost of these load-shed events is approximately $40 million. This economic value is already incorporated as one of the components of our analysis and reflected in the 10.2% risk-neutral, economically optimal reserve margin, but the cost of such "blackout" events may appear to be much higher from a public, political, and regulatory policy perspective.

Strong aversion to load shed events is difficult to assess from an economic perspective. However, potentially strong risk aversion preferences are suggested by the level of press attention and public reaction that follows rolling blackout events. A higher mandated reserve margin would reduce the risk of such events. It would also pre-empt the possible regulatory and legislative interventions in ERCOT's power market that might follow such an event, the prospect of which increases perceived regulatory risk by suppliers and reduces their incentive to invest in an energy-only market.

A high level of risk aversion to load shed or extreme high price events may justify the additional cost of a maintaining a high reserve margin. One of the most interesting findings from this study is the slow rate at which total system costs and average customer costs would likely increase with higher reserve margins. Because the increased expense associated with capacity payments is partially offset by reduced energy market prices and reduced costs of reliability events, the net cost increase associated with mandating reserve margins above the energy-only equilibrium is just slightly higher on a long-term average basis. For example, our simulation results suggest that the net increase in the average system-wide costs of increasing the reserve margin from 11.5% to 14.1% would be in the order of $100 million per year. If risk aversion to load shed events is very high, these costs may be justified to support a higher reserve margin.

Some market participants have suggested the possibility of implementing a capacity market with a reserve margin mandate set at the risk-neutral, economic optimum; another option would be to increase that reserve margin slightly to reflect some level of risk aversion. At the risk-neutral optimum, this would mean imposing a 10.2% minimum reserve margin requirement, which is below the likely energy-only market equilibrium of 11.5% (a relationship that may not have been anticipated by the market participants suggesting this possibility). While this approach would not increase the average planning reserve margin, it still has theoretical merit. Implementing a 10.2% or 11.5% reserve margin would not increase system costs compared to an energy-only market at the same reserve margin, but would still provide some of the benefits of a capacity market, including: (a) reducing the risk of and high costs of low-reliability outcomes under which reserve margins fall below the mandated reserve margin; (b) providing transparency that would help rationalize supply and demand outlooks on a three-year forward basis, thereby reducing the likelihood of boom-bust cycles; (c) providing a more stable price signal for maintaining the chosen reserve margin; and (d) creating a competitive centralized auction within which all types of supply, including demand response, can compete and possibly improve the overall efficiency of investment decisions in the fleet.

However, implementing mandated reserve margins and an associated capacity market will add considerable complexity to ERCOT's current energy market design. This complexity may not be justified if the current design already sustains an equilibrium reserve margin of 11.5%, which is above our 10.2% estimate of the risk-neutral, economically optimal reserve margin. Costs also include having to design, implement, and administer a complex new market with many administrative determinations that will have significant economic consequences and are likely to be litigated.

2. What Are the Practical Implications of Maintaining the Current Energy-Only Market Design?

Maintaining the current energy-only market would avoid the complexity of introducing major new market design elements. The Commission and ERCOT would continue with their various ongoing initiatives to enhance ERCOT's existing energy and ancillary service markets to support reliable operations with maximal economic efficiency. In particular, we recommend continuing efforts to enable the economic and efficient participation of demand-response resources. The Commission might consider further assessing whether there are ways to further improve the ability of demand response to participate efficiently in the energy and ancillary services markets.

However, it may be beneficial to codify the overarching market design principles to discourage future interventions in the market whenever prices spike or rare reliability events occur, recognizing that such outcomes are an inherent component of the chosen energy-only market design. Without such regulatory assurances, potential investors may discount the expected revenues that could be realized under these shortage conditions. Articulating more clearly the principles and expectations supporting the current design may reduce this regulatory uncertainty and help attract the needed investments in the energy-only market.

3. What Would Be the Practical Implications of Introducing a Resource Adequacy Requirement and Capacity Market?

Establishing a resource adequacy requirement and a capacity market would be a major market design effort. It would require extensive stakeholder discussions about market design details, including the determination of a number of administrative parameters. Design elements that would have to be addressed include: (1) the resource adequacy requirement itself, which could be based on various economic or reliability standards as discussed in this report; (2) the implementation of that requirement in a capacity market, which could involve administratively defining a sloped demand curve; (3) the forward period and rules for forward and incremental auctions; (4) whether and how to represent transmission constraints; (5) participation and verification rules for all types of resources; (6) definition of penalties and performance incentives; (7) market monitoring protocols to preventing the exercise of market power by suppliers or manipulation by buyers; and (8) settlement processes and rules for both suppliers and load-serving entities.

Regions that have implemented capacity markets have spent years developing these design elements and have been adjusting them periodically, often in a litigation setting. Many of these design elements also become politically charged, particularly if policymakers believe customer costs have increased inefficiently. ERCOT and the Commission would face similar challenges if they adopted a capacity market, although it could learn from the other regions' experiences. They could avoid some of the other regions' complications, such as multi-state jurisdictions and interactions with FERC oversight.

One challenge is the transition period when first implementing a capacity market. Specifically, mandating a higher reserve margin could cause a significant increase in total customer costs over the next few years relative to the energy-only course, with these near-term cost increases exceeding the long-run equilibrium cost differential that we have estimated in this study. Short-term cost increases would be driven by the fact that the ERCOT system as it stands may have only a small excess relative to the capacity market equilibrium reserve margin (meaning that equilibrium price levels may be reached very soon). Meanwhile the current reserve margin exceeds the energy-only equilibrium reserve margin by several percentage points, and so energy-only market prices may not reach higher long-run sustainable levels for several more years. Other transitional challenges include phasing in procurement of capacity to achieve a three- or four-year forward procurement, addressing legacy contracts and resources, and specifying the resource adequacy values of different resource types, including intermittent resources, uncommitted supply, and interties with neighboring markets.

Another concern about implementing a resource adequacy requirement and an associated capacity market is that it would introduce significant complexity without directly addressing all aspects of reliability. The resource adequacy discussion is focused on ensuring that installed generation capacity is sufficient to meet load at summer peak. But this is only one aspect of system reliability and does not address the much more frequent distribution system-related outages. Even from a system reliability perspective, gas supply disruptions or widespread freezing and drought conditions can disable supply and lead to customer outages despite adequate levels of installed reserve margins. Outages may also result from inadequate ramping capability for meeting rapid changes in load and wind generation, and other operational challenges. The ORDC design already addresses some of these challenges by providing incentive to invest slightly beyond the risk-neutral, economically optimal level of installed capacity and operational performance.

4. How Would These Conclusions Change with Market Conditions, and What Study Extensions or Updates Might Be Warranted?

The quantitative analysis presented in this study is based on many data inputs, simulations to approximate projected system characteristics, assumed market conditions, and market rules expected for 2016. If the PUCT were to mandate a particular reserve margin based on the analysis presented in this study, it would be necessary to update the analysis as system conditions, market conditions, and market rules change in the future. For example, a new load forecast with a wider (or narrower) distribution of possible load-growth outcomes could increase (or decrease) the estimated energy-only equilibrium and the optimal reserve margins. A higher (or lower) gas price forecast could similarly increase (or decrease) the reserve margin results. Any change in accounting for the resource adequacy value of transmission ties with neighboring markets, wind power plant, or demand response would also change the level of specified reserve margins.

We recognize that concurrent with the completion of our study, ERCOT has released an updated load forecast that we have not had time to incorporate and consider in our analyses. Because the updated forecast is much lower than prior forecasts, this may reduce the real or perceived urgency of addressing the resource adequacy question. In terms of the impact on our study results, we do not expect that the new forecast would change our estimates of optimal or equilibrium reserve margins substantially, since those are expressed as a percentage of peak load. However, our results could change if the new forecast methodology produces very different distributions of weather and non-weather forecast errors, or if it accounts for demand response very differently.

Regarding the urgency of the issue, that is a judgment for the Commission, ERCOT, and stakeholders. The Commission could decide not to act now or, if they see a need to change the market design in the long term to meet policy objectives, they could take advantage of the current slack to implement changes with less risk of transitional rate shocks. In any case, providing stakeholders a clear understanding of whether, how, and when the market design will change would reduce regulatory uncertainty and benefit market participants as they make business decisions over the coming years.

List of Acronyms

1-in-10	1-Day-In-Ten-Years, which can refer to either 1 load shed event in 10 years or 24 hours of load shedding in 10 years
4 CP	Four Coincident Peak
A/S	Ancillary Service
ATC	Available Transfer Capability
ATWACC	After-Tax Weighted-Average Cost of Capital
Btu	British Thermal Unit
CC	Combined Cycle
CDR	Capacity, Demand, and Reserves
CONE	Cost of New Entry
CT	Combustion Turbine
DC	Direct Current
DR	Demand Response
EE	Energy Efficiency
EEA	Energy Emergency Alert
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generation Availability Data System
HCAP	High System-Wide Offer Cap
HHV	Higher Heating Value

HVDC	High Voltage Direct Current
ICAP	Installed Capacity
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt hour
LCAP	Low System-Wide Offer Cap
LFE	Load Forecast Error
LOLE	Loss of Load Event
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LR	Load Resource
MISO	Midcontinent Independent System Operator
MMBtu	One Million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NSRS	Non-Spinning Reserve Service
NYISO	New York Independent System Operator
ORDC	Operating Reserve Demand Curve
PBPC	Power Balance Penalty Curve
PNM	Peaker Net Margin
PRC	Physical Responsive Capability
PRD	Price-Responsive Demand
PUCT	Public Utility Commission of Texas

PUN	Private Use Network
RM	Reserve Margin
RRS	Responsive Reserve Service
RT	Real-Time
SCED	Security Constrained Economic Dispatch
SERVM	Strategic Energy Risk Valuation Model
SPP	Southwest Power Pool
ST	Steam Turbine
SWOC	System-Wide Offer Cap
T&D	Transmission and Distribution
TDSP	Transmission and Distribution Service Provider
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance

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