The Brattle Group

ERCOT Investment Incentives and Resource Adequacy

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Electric Reliability Council of Texas

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EXECUTIVE SUMMARY

The Electric Reliability Council of Texas's (ERCOT's) energy-only market has worked well for many years to support efficient operations and to attract sufficient generation investment to maintain resource adequacy. Now, despite reserve margins declining with load growth and retirements, investment appears to have stalled. Many projects have been postponed or cancelled and no major new generation projects are starting construction. As a result, ERCOT projects that reserve margins will fall to 9.8% by 2014, substantially below its current reliability target of 13.75%. Reserve margins will decline even further thereafter unless new resources are added. Generation investors state that a lack of long-term contracting with buyers, low market heat rates, and low gas prices in ERCOT's energy-only market make for a uniquely challenging investment environment.

In response to these concerns, the Public Utility Commission of Texas (PUCT) has implemented a number of actions to ensure stronger price signals to add generation when market conditions become tight. The PUCT has enabled prices to reach the current $3,000/MWh offer cap under a broader set of scarcity conditions and is considering raising offer caps to as high as $9,000/MWh, among other measures. Following the PUCT's initiatives, forward prices have increased and more than 2,000 MW of relatively low-cost capacity additions have been announced, including uprates and reactivations of mothballed units. The critical question remains whether the recent and proposed reforms will be adequate and what other measures might be necessary to attract sufficient investment.

To inform the Commission's and ERCOT's actions, ERCOT commissioned *The Brattle Group* to address three questions:

1. **Investors and their Investment Criteria**. Identify, describe, and rank the relevant factors that influence investment decisions made by the development and financial community related to new capacity additions, capacity retirements, and repowering projects in ERCOT.
2. **Market Outlook for Investment and Resource Adequacy**. Evaluate the current drivers from both a wholesale and retail perspective that influence resource investment decisions in the ERCOT market.
3. **Evaluation of Policy Options**. Provide suggestions for ways to enhance favorable investment outcomes for long-term resource adequacy in ERCOT.

Our approach to addressing these questions and our findings are summarized as follows:

Investors and their Investment Criteria

To understand the factors affecting suppliers' willingness to invest, we interviewed a broad spectrum of generation developers and lenders and analyzed relevant financial indicators, as described in Section II. We found that investors are generally cautious after a history of investment losses. However, many could and would invest in ERCOT if revenue levels were expected to be adequate to earn a return on the investment that is commensurate with perceived risks.

The lack of long-term power purchase agreements (PPAs) in Texas's retail choice environment generally leaves much of the investment risk with investors, similar to other retail restructured markets. A number of generators also stated that the ERCOT's energy-only market design is more volatile, harder to model, and riskier overall than energy-and-capacity markets (though they acknowledged that generator revenues in ERCOT are more stable than spot prices, since most power is sold at least several months forward at prices that average out weather and other unexpected effects). Some also worried that energy-only markets can lead to extreme outcomes that might induce future regulators to intervene in the market. However, they expressed that the current Commission has demonstrated a strong commitment to markets and regulatory certainty. Overall, we believe that ERCOT's energy-only market may be only marginally riskier than energy-and-capacity markets, a view consistent with the statements of a subset of merchant investors. Both types of markets place much more risk on investors than do regulated environments without retail choice.

Considering these risk factors, some generation developers state that they will require projected returns exceeding the 9.6% after-tax weighted-average cost of capital (ATWACC) assumed by ERCOT.[1] Large, diversified investors with hedging options and the ability to finance plants on their balance sheet might be able to invest at lower returns. We estimate an ATWACC as low as 7.6% for efficiently hedged and diversified merchant generation investments.

Risk tolerances and revenue needs vary considerably by type of investor. To underwrite project-finance loans with no upside opportunities, lenders must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error. Larger borrowers can partially diversify project-specific risks and can borrow more cost-efficiently against a larger corporate balance sheet. Such investors may be able and willing to weather some bad years for a few good years as long as the discounted expected value is high enough. These are likely to be the most robust investors in a market with high price volatility. Smaller, undiversified borrowers relying on high leverage through project-specific, non-recourse debt financing with little equity, however, might ultimately be uncompetitive and pushed out of the market unless they can secure long-term PPAs with public power or other entities.

Market Outlook for Investment and Resource Adequacy

In Sections III and IV, we examine whether new and proposed rules are likely to produce prices that are high enough often enough to attract sufficient investment. Our approach includes: (1) assessing ERCOT's market and operational processes to understand how new and proposed rules will affect scarcity prices; (2) analyzing forward curves; (3) conducting economic simulation modeling to project future prices, including the frequency of scarcity prices; and (4) comparing projected energy margins to capital costs and investors' cost of capital. We conduct this analysis for a broad range of potential planning reserve margins, showing how suppliers' energy margins will increase as reserve margins fall and the market becomes tighter, or decrease as reserve margins rise. The key question is whether market prices will be high enough to support entry at an acceptably high reserve margin and associated reliability level. We address this question in the context of several major uncertainties that investors face.

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[1] See PUCT (2012b), Item Number 87, p. 1. We note that ERCOT's ATWACC estimate was developed a year ago and that the cost of capital has decreased since then, as we discuss further in Section II.D.3.

We find that generators' energy margins have been low because of low gas prices and low market heat rates, except during rare price spikes. Market heat rates have been low because an efficient generating fleet and new wind generation form a very low and flat supply curve. However, current and proposed market rule changes will increase the frequency and level of scarcity prices. Forward curves have risen correspondingly, but they are still not high enough to support investment in new generation, notwithstanding recent success in attracting relatively low-cost plant reactivations and uprates.

Our simulation analysis finds that the Commission's proposals to further raise the offer cap would stimulate greater investment, but investment would still fall short of what is needed to meet ERCOT's current reliability target of "one load-shed event in 10 years," at least under current market conditions and demand response penetration. Scarcity prices would be too infrequent to support the target because if reserve margins are high enough to make load shedding very rare, scarcity pricing events would also be quite rare. This is compounded by the long "tails" of the load distribution, including rare, extreme extended heat waves such as the one in 2011. Having high enough reserves to limit load shedding even under even such challenging conditions would eliminate scarcity in most years.

We estimate that the current market design and the $3,000 offer cap would achieve a reserve margin of only 6% on a long-term average basis under current market conditions. If the offer cap is increased to $9,000, a reserve margin of approximately 10% could be achieved without reducing the frequency of scarcity prices below the level needed to support investment. This is approximately five percentage points less than the 15.25% reserve margin we estimate would be needed to achieve ERCOT's reliability target. Our 15.25% estimate is higher than ERCOT's current 13.75% reliability target because we assumed a 1-in-15 chance of extreme 2011 weather occurring, whereas ERCOT's target reserve margin study could not account for 2011 weather because it had not been experienced at the time. On average, the 10% reserve margin achieved with a $9,000 offer cap would result in approximately one load-shed event *per year* with an expected duration of two-and-a-half hours, and thirteen such events in a year with a heat wave as severe as the one in 2011. In years with less extreme weather than 2011, however, load shedding would be expected to occur less than once in ten years.

Reserve margins would differ on a year-to-year basis due to the lead times required to respond to supply shocks, such as simultaneous environmentally-driven generation retirements. Moreover, even our long-term average estimates are highly uncertain due to underlying uncertainties about market conditions, weather, regulatory risk, and investors' perceptions of these risks. The range of uncertainties we analyzed could result in average reserve margins that fall between one and seven percentage points below the 1-in-10 target reserve margin on average. For example, with only a 1-in-100 chance of extreme 2011 weather, the reserve margin achieved with a $9,000 offer cap would fall only three percentage points below the reserve margin needed to achieve the reliability target and load shedding would be expected only once every three years on average.

An important qualification to these simulation results is that they assume only the current level of demand response (DR). If several thousand megawatts (MW) of price-responsive demand were added, those resources could prevent involuntary load shedding and set prices at customers' willingness to pay, thereby increasing reliability and softening (but not eliminating) price spikes. With this much demand response, ERCOT's energy-only market design could support the current bulk power reliability target under a $9,000 price cap. However, achieving such a high demand response penetration would take years, not months, as we explain further in Section V.B.

Evaluation of Policy Options

Our finding that the energy-only market will not dependably support ERCOT's current reliability target until sufficient demand response penetration is achieved suggests that either the market design needs to be adjusted or the reliability objectives have to be revised. We present a broad analysis of policy options, preceded by a discussion of reliability objectives.

The "1-in-10" reliability standard has been used in the industry for decades, but has rarely been evaluated from an economic perspective, as we explain in Section VI. ERCOT's "1 load-shed event in 10 years" interpretation of the 1-in-10 standard is more stringent than the "1 outage day in 10 years" interpretation used in the Southwest Power Pool (SPP). Other regions use entirely different approaches based on the economic value of reliability. We also note that distribution outages cause customers to lose power 100 times more often than do generation resource shortages, suggesting that the 1-in-10 target could be too high. Even if reserve margins fall to a 10% equilibrium reserve margin, load shedding would occur approximately two-and-a-half hours per year, averaging only three minutes per customer; this compares to an average of a few *hundred* minutes per customer per year from distribution outages. Moreover, critical loads that are not behind a single distribution feeder may enjoy even less exposure to power outages, assuming load shedding protocols are designed properly. We therefore recommend that the PUCT and ERCOT evaluate their resource adequacy objectives in the context of delivered reliability, load shedding protocols, and informed by an analysis of marginal costs and benefits. We recommend determining the *desirable* reserve margin target and, separately, a *minimum acceptable* reserve margin needed to avoid extremely adverse consequences under worst-plausible weather and outage conditions.

This report does not recommend a specific course of action because the best path forward depends on policy objectives, which only stakeholders, regulators, and other policymakers can assess. To inform the choice among policy options, we describe five available options and present the advantages and disadvantages of each in Section VI:

1. Energy-only with market-based reserve margin;
2. Energy-only with adders to support a target reserve margin;
3. Energy-only with backstop procurement at minimum acceptable reliability;
4. Mandatory resource adequacy requirement for load serving entities (LSEs); and
5. Resource adequacy requirement with a centralized forward capacity market.

The evaluation criteria assessed for each option include both the reliability implications of letting the market determine the level of reliability and the market implications of having regulators determine the level of reliability. We also assess economic efficiency, compatibility with investment, regulatory stability, and the extent and complexity of necessary market design changes. Table 1 summarizes our evaluation of these policy options.

Table 1
Comparison of Policy Options

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes	Comments
1. Energy- Only with Market-Based Reserve Margin	Market	Market	High in short-run; Lower in long-run w/ more DR	High	May be highest in long-run	Easy	- Depends on substantial DR participating to set prices at willingness-to-pay; ERCOT does not yet have much DR
2. Energy-Only With Adders to Support a Target Reserve Margin	Regulated	Market	Medium	High	Lower	Easy	- Not a reliable way to meet target - Adders are administratively determined
3. Energy- Only with Backstop Procurement at Minimum Acceptable Reliability	Regulated (when backstop imposed)	Regulator (when backstop imposed)	Low	High	Lower	Easy	- Attractive as an infrequent last resort, but long-term reliance is inefficient, non-market based, and slippery-slope
4. Mandatory Resource Adequacy Requirement for LSEs	Regulated	Market	Low (with sufficient deficiency penalty)	Med-High	Medium (due to regulatory parameters)	Medium	- Well-defined system and local requirements and resource qualification support bilateral trading of fungible credits, and competition - Cannot be a forward requirement - Flexibility: DR is like opting out; customers not behind a single distribution feeder could pay for higher reserves and reliability
5. Resource Adequacy Requirement with Centralized Forward Capacity Market	Regulated	Market	Low	Med-High (slightly less than #4)	Medium (due to regulatory parameters)	Major	- Working well in PJM - Forward construct can efficiently respond to retirements and meet needs with sufficient lead time - Transparency valuable to market participants and market monitor - Many administrative determinations

"Energy-only with market-based reserve margins" is theoretically the most efficient option because it allows customers to choose the level of supply based on prices and their value of avoiding curtailment, without having to pay for costly reserves they may not want. It also provides strong incentives for resources to be available when they are needed most. We believe that energy-only, perhaps with rare backstop procurement of short-term resources as needed to support a very minimal reserve margin, might be the most aligned with the Commission's demonstrated philosophy to let the market work. However, this would require managing public expectations about reliability implications and the potential for periodic high spot prices. Energy-only will deliver less reliability than the current target until more price-responsive demand is developed.

If the Commission and ERCOT want to maintain a higher level of reliability, the four other options we present differ in their effectiveness, efficiency, and complexity. Price adders or backstop procurement may seem appealing because they require the least modification to the existing design in the short term. However, price adders will not dependably achieve any particular reserve margin. The backstop procurement option introduces market inefficiencies and could threaten the viability of market-based investments unless it is used very sparingly to maintain only a minimum-acceptable level of reserves that is well below the "desirable" target. If policymakers decide that a higher target reserve margin must be met every year, imposing a resource adequacy requirement on LSEs is the most market-based, efficient option. Implementing such a reserve margin requirement through a forward capacity market could further increase forward competition, price transparency, and efficient investments, but these markets are quite complex and increase the importance of administrative parameters such as the load forecast.

Recommendations

Our primary recommendations are that the PUCT and ERCOT: (1) evaluate and define resource adequacy objectives for the bulk power system; and then (2) choose a policy path to meet those objectives, informed by the advantages and disadvantages of each option we have identified. We recommend defining the long-term resource adequacy framework expeditiously. Committing to a definitive course of action will resolve regulatory uncertainty and support investment. However, we urge caution about implementing major changes too quickly or without sufficient analytical support or stakeholder consideration. Complex market design changes will likely take more than a year to implement, and market participants need to be allowed ample time to prepare for the implementation of any changes.

The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments. However, we anticipate that more low-cost resources will enter the market before 2014 than are currently reported in ERCOT's Report on the Capacity, Demand and Reserves (CDR) Report, yielding reserve margins that are at least somewhat above the 9.8% currently projected.[2] If the 2014 planning reserve margin outlook fails to improve sufficiently to meet a minimum acceptable level of reliability before new generation can be added, the PUCT and ERCOT could consider soliciting additional Emergency Response Service resources as a short-term solution. However, we stress that such a backstop mechanism should be implemented with great restraint to avoid introducing a perpetual dependence on backstops or displacing market-based resources that would otherwise be developed.

In addition, and regardless of the overarching policy path selected by the Commission, we recommend enhancing several design elements to make the ERCOT market more reliable and efficient, as discussed in Section V: (1) increase the offer cap from the current $3,000 to $9,000, or a similarly high level consistent with the average value of lost load (VOLL) in ERCOT, but impose this price cap only in extreme scarcity events when load must be shed; (2) for pricing during shortage conditions when load shedding is not yet necessary, institute an administrative scarcity pricing function that starts at a much lower level, such as $500/MWh when first deploying responsive reserves, and then increase gradually, reaching $9,000 or VOLL only when

[2] ERCOT (2012n).

actually shedding load; (3) increase the Peaker Net Margin threshold to approximately $300/kW-year or a similar multiple of the cost of new entry (CONE), and increase the low system offer cap to a lever greater than the strike price of most price-responsive demand in Texas; (4) enable demand response to play a larger role in efficient price formation during shortage conditions by introducing a more gradually-increasing scarcity pricing function (as stated above) so loads can respond to a more stable continuum of high prices, by enabling load reductions to participate directly in the real-time market, and by preventing price reversal caused by reliability deployments; (5) adjust scarcity pricing mechanisms to ensure they provide *locational* scarcity pricing signals when appropriate; (6) avoid mechanisms that trigger scarcity prices during non-scarcity conditions; (7) address pricing inefficiencies related to unit commitment but without over-correcting; (8) clarify offer mitigation rules; (9) revisit provisions to ensure that retail electric providers (REPs) can cover their positions as reserve margins tighten and price caps increase; and (10) continue to demonstrate regulatory commitment and stability. We recommend considering these ten suggestions no matter which resource adequacy framework the Commission and ERCOT select.

I. BACKGROUND

The Electric Reliability Council of Texas (ERCOT) engaged *The Brattle Group* to analyze the ability of its energy-only market to attract and retain sufficient resources to reliably power Texas. This study comes two years before reserve margins are projected to fall significantly below target levels. Concerns that wholesale prices have been too low to attract the needed investments led to a number of ongoing wholesale market reforms by ERCOT, the Public Utility Commission of Texas (PUCT), and stakeholders. This study is intended to support and inform that ongoing effort.

A. STUDY MOTIVATION AND APPROACH

1. Motivation

Since deregulation, ERCOT's energy-only market has successfully attracted substantial investment without the need for regulatory intervention to maintain resource adequacy. In the early 2000s, investors added more than 20,000 MW of efficient gas-fired combined-cycle (CC) plants. Toward the middle of the decade, investors began developing approximately 4,000 MW of coal plants that are now online or about to come online. Additionally, more than 9,000 MW of wind capacity was developed over the past half-decade. Now, however, no other major new generation is under construction.[3] The handful of permitted projects that were planned to begin construction has been postponed.[4] Developers state that prices are not high enough to support new generation, due to the combination of low gas prices, an efficient fleet, and the recent influx of wind generation.

With few new resources and expected load growth, ERCOT is projecting a planning reserve margin of only 9.8% by 2014, compared to a reliability target of 13.75%.[5] Thereafter, further load growth and potential environmentally-driven retirements would push reserves even lower unless new resources come online.

The prospect of declining reserve margins concerns ERCOT and the PUCT, particularly after experiencing supply shortages in 2011. The year 2011 presented extreme weather conditions, including very cold weather in February that disabled generation and froze some gas delivery equipment, leading to 8 hours of load shedding.[6] Extraordinarily hot weather in August pushed the system into shortages that required emergency actions, while drought conditions threatened to derate or disable capacity.[7] These events occurred when the planning reserve margin was

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[3] See ERCOT (2011f), p. 16, Total Future Non-Wind Resources. We exclude Sandy Creek, which completed construction but experienced an accident during testing in 2011. See further discussion in Section III.D.

[4] See ERCOT (2011b), p. 6. Pondera King Power Project, Las Brisas Energy Center, and Coleto Creek Unit 2 have delayed their commercial operations dates.

[5] See ERCOT (2012n), p. 7.

[6] See Potomac Economics (2011a), p. 5.

[7] See ERCOT (2012c) and ERCOT (2012h).

14%, which suggests vulnerability if the reserve margin were to fall to the much lower projected levels.[8]

In this context, stakeholders and policy makers are concerned about the current lack of construction and the possibility that price signals may not be sufficient to attract needed investments, even as the reserve margin outlook becomes tighter. The PUCT and ERCOT have implemented a number of measures to address these concerns, and they are considering several additional proposed enhancements. They sponsored this study to provide an analytical and objective foundation to help ensure that ongoing reforms will be adequate and efficient.

2. Approach

To inform ERCOT's and the PUCT's efforts, we analyze three aspects of attracting investment and maintaining resource adequacy in ERCOT, consistent with ERCOT's request for proposals (RFP) for this study:

1. **Investors and their Investment Criteria**. The RFP required that we "*identify, describe, and rank the relevant factors that influence investment decisions by the development and financial community related to new capacity additions, capacity retirements, and repowering projects in ERCOT.*"[9] We review financial indicators and report our findings from interviews with numerous generation developers and lenders. Section II characterizes the spectrum of investors and their investment criteria, and provides an estimate of the returns they will require to build new generation in ERCOT.
2. **Market Outlook for Investment and Resource Adequacy**. The RFP required that we "*evaluate the current drivers from both a wholesale and retail perspective that influence resource investment decisions in the ERCOT market.*" We examine whether new and proposed rules are likely to produce prices that are high enough often enough to attract sufficient investment. Our approach includes: (1) assessing market and operational processes to understand how the new and proposed rules will affect scarcity prices; (2) analyzing forward curves; (3) conducting economic simulation modeling to project future prices, including the frequency of scarcity prices; and (4) comparing projected energy margins to capital costs and investors' cost of capital. We conduct this analysis for a broad range of potential planning reserve margins, showing how suppliers' energy margins will increase as reserve margins fall and the market becomes tighter, or decrease as reserve margins rise. The key question is whether returns on investment will be high enough to support entry at an acceptable reserve margin and reliability level. We address this question in the context of several major uncertainties that investors face. Sections III and IV summarize our analysis of the current and long-term market outlook for investment, respectively.

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[8] The CDR report released in June 2011reported the planning reserve margin at 17.5% for the Summer of 2011, however, ERCOT advised the PUCT during its February 2012 Open Meeting that the Summer 2011 CDR reserve margin would have been 14% based on a revised analysis subject to the: (1) application of the hotter "normal" weather profile being used post 2011 to produce the peak load forecast; (2) use of actual peak net generation from private-use networks, rather than survey results; and (3) improved tracking of the expected availability of new generation, see ERCOT (2011b) and (2012d).

[9] See ERCOT (2012g), Section 2.3.

3. **Design Recommendations and Policy Options**. The RFP required that we "*provide suggestions for ways to enhance favorable investment outcomes for long-term resource adequacy in ERCOT.*" We evaluate options for improving the efficiency and effectiveness of ERCOT's market design for resource adequacy. In Section V, we present an analysis of market design improvements that we recommend pursuing regardless of overall policy objectives. These refinements to the wholesale market design, many of which are already under review within ERCOT or PUCT initiatives, would increase the efficiency of market signals and enhance resource adequacy. In Section VI, we present a broader analysis of policy options, starting with a question of objectives: should regulators determine the level of reliability instead of the market and, if so, what level of reliability is optimal and what level is minimally acceptable? We then describe five market constructs for meeting those objectives, and evaluate each option's advantages, disadvantages, and implementation issues.

In conducting this analysis of resource adequacy in ERCOT, we examine major concerns identified by regulators, generators, load representatives, and market observers in public comments and private interviews.

B. ERCOT ENERGY-ONLY MARKET DESIGN

Between 1996 and 2002, the Texas legislature and the PUCT restructured the electricity system to create the competitive wholesale and retail markets that exist today.[10] ERCOT has made a number of enhancements to its market since inception, including transitioning to a nodal market in late 2010, and increasing the system-wide offer cap.[11] However, the core principals have not changed. ERCOT is an "energy-only" market in which both operations and investment are driven primarily by energy price signals.

ERCOT's design as an energy-only market distinguishes it from all other regions in the U.S. Other U.S. markets maintain a minimum reserve margin through regulated planning, resource adequacy requirements, or capacity markets. These other markets support investment through either long-term contracts or market-based payments that recognize suppliers' contributions to resource adequacy.[12] In ERCOT and other energy-only markets such as those in Alberta, Australia, and Nord Pool, realized reserve margins are the aggregate outcome of private investment decisions based on wholesale prices. ERCOT does have a target reliability standard of "1 loss of load event in 10 years" that currently translates into a 13.75% reserve margin, but this target is not enforced through any specific requirements or market structures.[13] ERCOT's realized reserve margin may be higher or lower than this target.

Spot prices in energy-only markets are characterized by moderate prices most of the time and occasional severe price spikes during shortage conditions. Price spikes are essential to a well-functioning energy-only market because they signal resource shortages and provide revenues that can attract new investments. Few suppliers would be able to recover their capital costs and

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[10] See ERCOT (2012e); Kiesling and Kleit (2009).

[11] See ERCOT (2012e); Potomac Economics (2011a), p. 15.

[12] For a more comprehensive discussion of various market design approaches to resource adequacy, see Pfeifenberger, Spees, and Schumacher (2009).

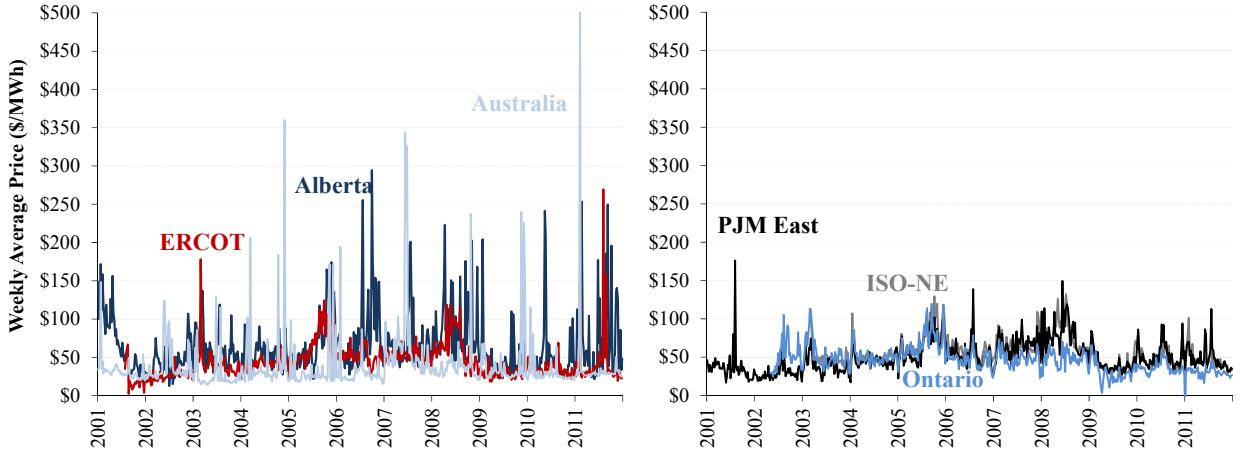
[13] See ERCOT (2010a).

justify a new investment without these price spikes, except under the fortuitous condition in which new generation has substantially lower operating costs than existing price-setting generation (which was the case in ERCOT at times in the past decade, as discussed below).

Some energy-only markets set price caps at a high level tied to customers' value of lost load (VOLL), which is approximately $3,000 – $12,000.[14] A high VOLL-based price cap is a theoretically efficient market price during load-shed events because it reflects the price that customers would have been willing to pay to avoid curtailment.[15] ERCOT does not currently base its $3,000 offer cap on a VOLL estimate but has historically maintained a higher price cap than other non-energy only markets.

Similar price spikes may be avoided in most markets with a resource adequacy standard, because those markets' high reserve margins reduce the likelihood of scarcity events. In addition, those markets generally apply lower price caps when scarcity occurs. However, over the past few years, and particularly since a Federal Energy Regulatory Commission (FERC) mandate in Order 719, even non-energy-only markets have begun to revise their scarcity pricing mechanisms to allow for more efficient high prices during shortage events.[16] The different character of prices in these markets is highlighted in Figure 1. The figure shows that energy-only markets such as ERCOT, Australia, and Alberta periodically produce much higher prices than those markets with resource adequacy standards such as PJM, ISO-NE, and Ontario.

Figure 1
Prices in Energy Only Markets (Left) and Markets with a Reliability Requirement (Right)



Sources and Notes:

Weekly average prices from Ventyx (2012); Weekly average prices for Australia from AEMO (2012).

Historical prices shown for ERCOT are at the North Hub; Australia prices are at New South Wales; PJM prices are at the Eastern Hub; and ISO-NE prices are at the System Hub.

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[14] For example, Australia's National Energy Market has a VOLL-based price cap of $12,500 AUD ($12,200 USD), see AEMC (2009). Estimates of VOLL range widely by study and especially by customer segment, at $1,500 – $3,000/MWh for residential, $10,000 – $50,000/MWh for commercial, and $10,000 – $80,000/MWh for industrial loads according to a MISO survey conducted in 2005, see MISO (2006). Exchange rate assumed is USD/AUD = $1.02 from Bloomberg (2012).

[15] Note that this high price should also make customers indifferent as to whether they were actually curtailed or stayed online but were required to pay a high price.

[16] See FERC (2008), and, for example, PJM (2010).

The cyclical periods of high prices or low reliability that characterize energy-only markets can also make them susceptible to regulatory intervention, depending on the political context. Political pressures may arise in response to price shocks even if *average* customer costs are no higher than all-in costs in markets with resource adequacy standards.[17] If public officials were to succumb to the pressure and intervene in the market (*e.g.*, by changing the rules or sponsoring out-of-market supplies), they would not only depress in-market investment but also undermine investor confidence generally. Resisting political pressures to intervene is essential if an energy-only market is to attract investment. Over the past decade, regulators in ERCOT have demonstrated a sustained commitment to market principles, leading at least two analysts to rank the Texas regulatory environment as more favorable for investment than most other states.[18] However, at least one agency does not rank the PUCT as attractive for investors, noting a less constructive, higher-risk regulatory climate from an investor viewpoint.[19]

In addition to its energy and ancillary services (A/S) markets, ERCOT also maintains two non-market reliability mechanisms that support resource adequacy. One is the Emergency Response Service (ERS), formerly known as Emergency Interruptible Load Service (EILS). ERS is a demand curtailment program in which approximately 350 MW of medium-large commercial and industrial (C&I) customers earn a capacity payment to be callable as a last resort during system emergencies.[20] The other non-market reliability mechanism is ERCOT's option to sign reliability-must-run (RMR) contracts to induce mothballed generation to reactivate or remain online.[21] Many market commentators have rightly observed that these mechanisms deviate from a true "energy-only" market because they use non-market mechanisms to attract sufficient capacity for resource adequacy purposes.

Similar out-of-market reliability mechanisms are common in many energy-only and other markets to safeguard reliability, even though they invariably introduce tensions with market efficiency.[22] Resources supported by out-of-market means such as RMR contracts can depress efficient wholesale prices when they are dispatched, and in the worst extremes can supplant in-market investments. The potential for such outcomes is a concern that ERCOT has addressed by requiring RMR generation to offer its energy at the system-wide offer cap.[23] We examine this topic further in Sections V.A and VI.B.3.

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[17] For example, a recent high-price period in Alberta initiated by an unexpected plant retirement caused a wave of unfavorable press articles and consumer complaints, even though average long-term rates remained below the Canadian average according to an industry-sponsored study, see London Economics (2011), p. 25. However, regulators have resisted pressures to intervene, and reaffirmed their commitment to the energy-only design.

[18] See UBS (2012), p. 2; TCPA (2011).

[19] See SNL (2012).

[20] See ERCOT (2012a).

[21] See ERCOT (2012k), Section 3.14.1.

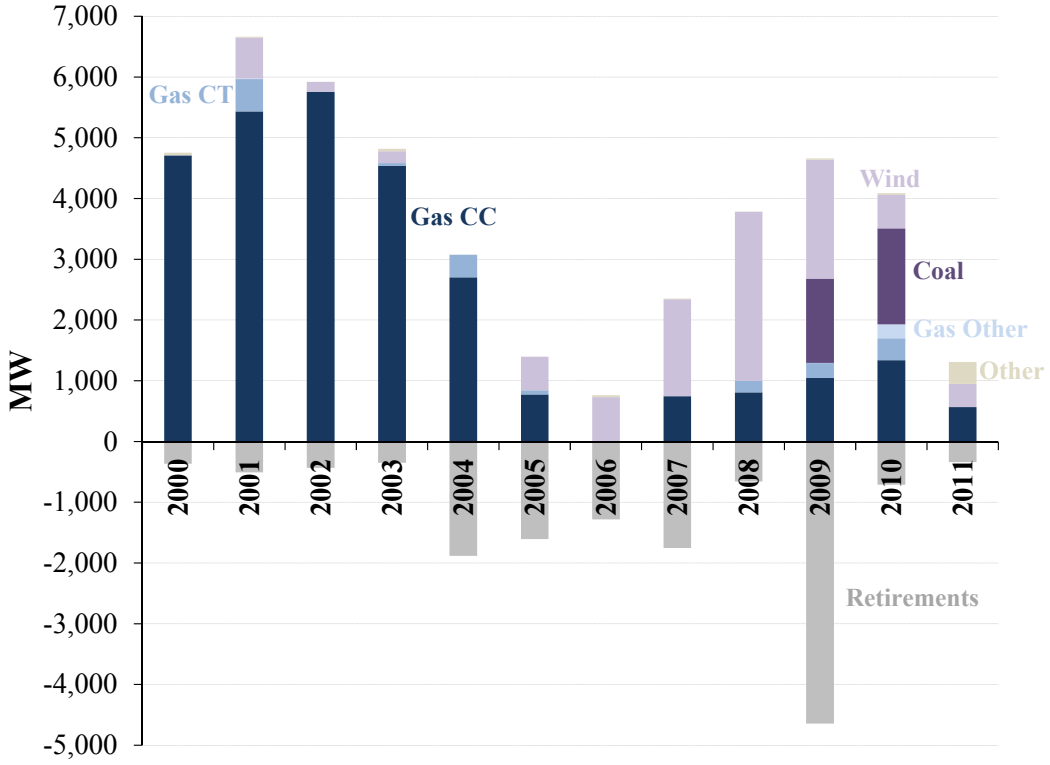
[22] Some type of RMR or other reliability backstop mechanism exists in almost all markets, but the frequency with which these mechanisms are implemented and the corresponding level of inefficiency that they introduce varies widely. For a few examples, see Pfeifenberger, Spees, and Schumacher (2009), Section IV.

[23] See ERCOT (2012f), NPRR442, approved 5/15/2012.

C. Investment Track Record since Market Implementation

Since ERCOT deregulated its wholesale electricity market, it has attracted substantial quantities of investment as shown in Figure 2. The first and largest wave of investment started before the beginning of the decade. Between 2000 and 2005, more than 20,000 MW of gas-fired CCs came online. Investors sought to capitalize on new opportunities brought by deregulation and the efficient new generation technology. New combined cycles appeared economic because energy prices were often set by less efficient older units.[24] However, in Texas as in many other regions, the investment boom led to excess capacity and lower prices, causing many of these investors to lose money.

Figure 2
Historical Investment and Retirement Activity in ERCOT



Sources and Notes:
Wind investments reported at nameplate capacity.
Total quantities may not exactly match those reported in ERCOT sources because we rely on a separate data source for unit capacities, see Ventyx (2012).

Toward the middle of the decade as gas prices rose, solid fuels became more economic. Investors began developing nearly 4,000 MW of coal plants. Approximately 3,000 MW are already online, and the 925 MW Sandy Creek Energy Station is scheduled to come online in

[24] See Kiesling and Kleit (2009), p. 100.

2013 due to construction delays.[25,26] In addition, the new 100 MW wood-fired Nacogdoches Station is scheduled to come online later this year.[27]

In the second half of the decade, developers brought more than 9,000 MW of wind generation online, supported by high gas prices as well as state and federal policies. In 1999, the PUCT had instituted Electric Substantive Rule 25.173, *Goal for Renewable Energy*, which established a renewable portfolio standard (RPS), a renewable energy credit (REC) trading program, and renewable energy purchase requirements for competitive retailers in Texas.[28] In 2005, Texas updated the RPS, increasing the renewable-energy mandate to 5,880 MW by 2015 and a target of 10,000 MW by 2025.[29] Other states' renewable portfolio standards have also contributed to wind investments in ERCOT because developers can benefit from the superior wind resources in Texas while selling RECs into other states that allow external resources to qualify.[30]

The federal production tax credit (PTC) is another major driver of wind development in ERCOT and elsewhere. The PTC is a $22/MWh tax credit for electricity generated by qualified renewable resources.[31] The PTC was originally enacted in 1992 with a planned expiration date in 1999. It has since been extended several times, most recently in February 2009, when it was extended to include wind resources that are completed and in-service by the end of 2012.[32] Political efforts are underway to extend the credit again, but it is unclear whether these will succeed.[33]

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[25] The 3,000 MW already online includes the 785 MW JK Spruce plant, the 1,616 MW Oak Grove Station, and the 570 MW Sandow 5 unit, see Ventyx (2012).

[26] See ERCOT (2012n), p. 19.

[27] See ERCOT (2011f), p. 16.

[28] See PUCT (1999).

[29] See Texas State Legislature (2005).

[30] Many wind assets developed in Texas may be able to sell renewable energy credits to meet other states' RPS standards. See RPS program descriptions at DSIRE (2012a).

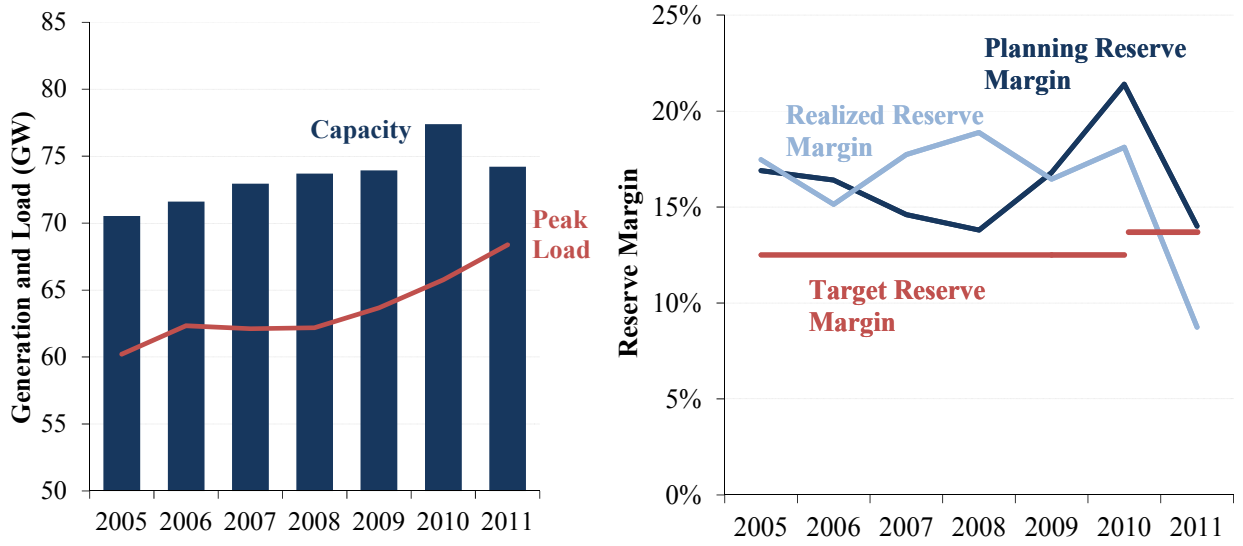
[31] See DSIRE (2012b).

[32] See Internal Revenue Code (2012), Section D.1.

[33] See American Renewable Energy Production Tax Credit Extension Act (2011).

The energy-only market was able to attract sufficient market-based investments to maintain resource adequacy over the past decade, as Figure 3 shows. The left chart shows that net capacity additions kept pace with substantial load growth even in the face of moderate retirements; the right chart shows that planning and realized reserve margins were always above the reliability target except under the extreme load conditions in 2011.

Figure 3
ERCOT Capacity and Load Growth (Left) and Reserve Margins (Right)



Sources and Notes:

Capacity includes generation and load resources from ERCOT's 2005 – 2011 CDR Reports. Year 2011 data account for revisions from the original CDR, see ERCOT (2012d).

Peak load is from ERCOT's 2012 Long-Term Demand and Energy Forecast, see ERCOT (2012b), p. 2.

Planning reserve margins are based on peak load expected with normal weather, from ERCOT's CDR reports.

"Realized reserve margins" are calculated based on actual peak load rather than the weather-normalized forecast. In a year such as 2011, with severe weather and an actual peak load much higher than forecast, the realized reserve margin was lower than the planning reserve margin.

The target reserve margin increased from 12.5% to 13.75% for years starting 2011, see ERCOT (2011g), p. 27.

D. Recent Market Conditions

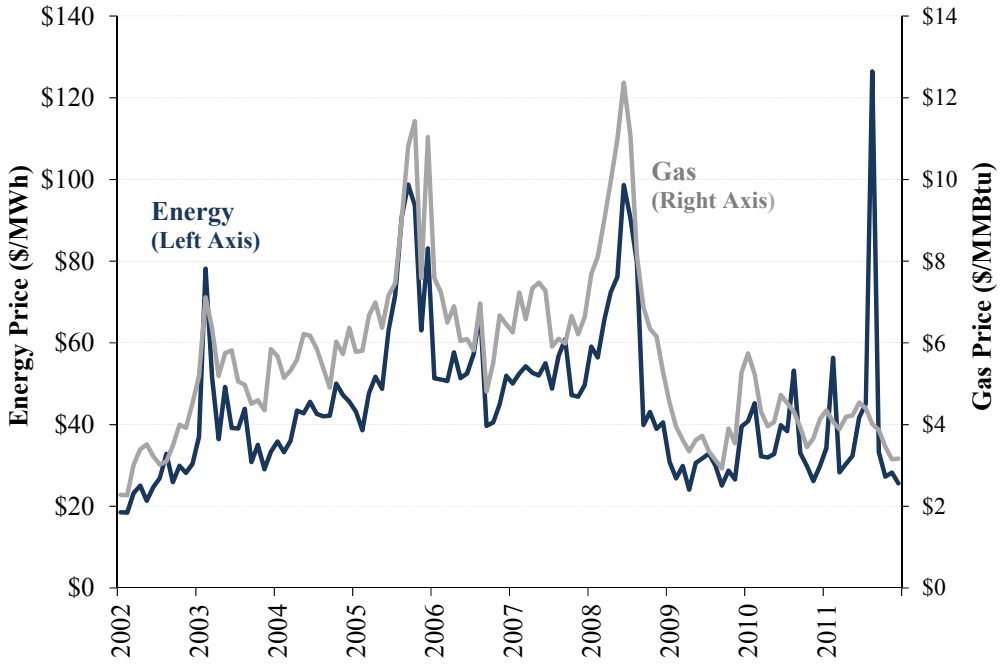
Although ERCOT has maintained sufficient reserve margins since deregulation, recent market conditions raise resource adequacy concerns. Existing generators will face retirement pressures from new environmental rules at a time when operating margins are already depressed by low electric prices. ERCOT's low electric prices are driven primarily by low natural gas prices and by the composition of ERCOT's generation fleet including a large number of efficient combined cycles and growing wind supply. We describe these challenges and the impact they have had on generator energy margins.

1. Low Gas Prices

The price of natural gas directly affects the production cost and offer prices of gas generators in the wholesale electricity market. Because natural gas-fired generators are the price-setting

suppliers in most hours, the price of natural gas strongly affects the market-clearing price for electricity.[34] Figure 4 shows recent North Hub electricity prices and Houston Ship Channel gas prices, demonstrating the close relationship between natural gas and electricity prices.

Figure 4
Monthly ERCOT Gas and Energy Prices



Sources and Notes:
Electricity prices for North Hub from Ventyx (2012).
Gas prices for Houston Ship Channel from Platts (2012).

More recently, rapid increases in shale gas production and the economic downturn have depressed natural gas and electricity prices.[35] Over 2009 – 2011, average Houston Ship Channel prices dropped to $4.01/MMBtu, from an average of $6.27/MMBtu in 2002 through 2008. Coincident with falling natural gas prices, electric prices have also decreased to $36/MWh in 2009 through 2011, from an average of $49/MWh over 2002 – 2008. Given the changed fundamentals of the natural gas industry due to shale gas development, low gas prices are expected to continue for the foreseeable future and are reflected in low futures prices, as discussed in Section III.

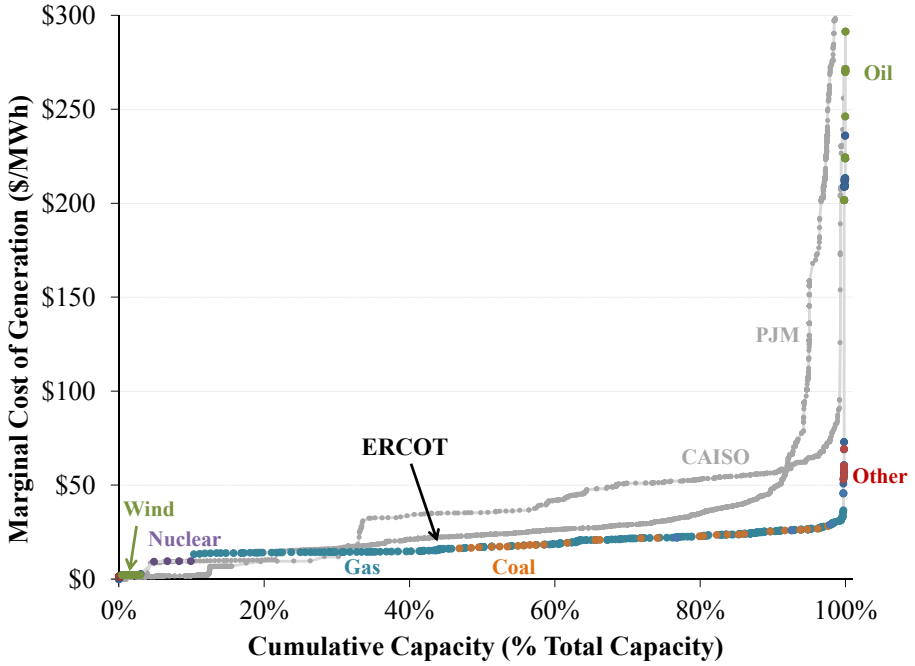
[34] For example, in 2007 – 2010 in the Houston Zone, gas generation was marginal in more than 70% of hours in almost all months, and was marginal in more than 90% of hours in some months. See Potomac Economics (2011c), p. 10.

[35] See, for example, Saur and Wallace (2011).

2. Fleet Makeup and Supply Stack

With more than 20,000 MW of new, efficient combined-cycle generation, as well as low-cost coal, wind, and nuclear generation, much of ERCOT's fleet has uniformly low marginal costs compared to other regions' fleets. Figure 5 shows the marginal cost of ERCOT's supply stack compared to PJM and CAISO. In ERCOT, the low marginal costs of much of the supply stack cause low prices in most hours, with the sharp increase at the end of the stack leading to severe price spikes only when generation supplies are almost completely exhausted.

Figure 5
ERCOT Supply Stack vs. Other Markets



Sources and Notes:

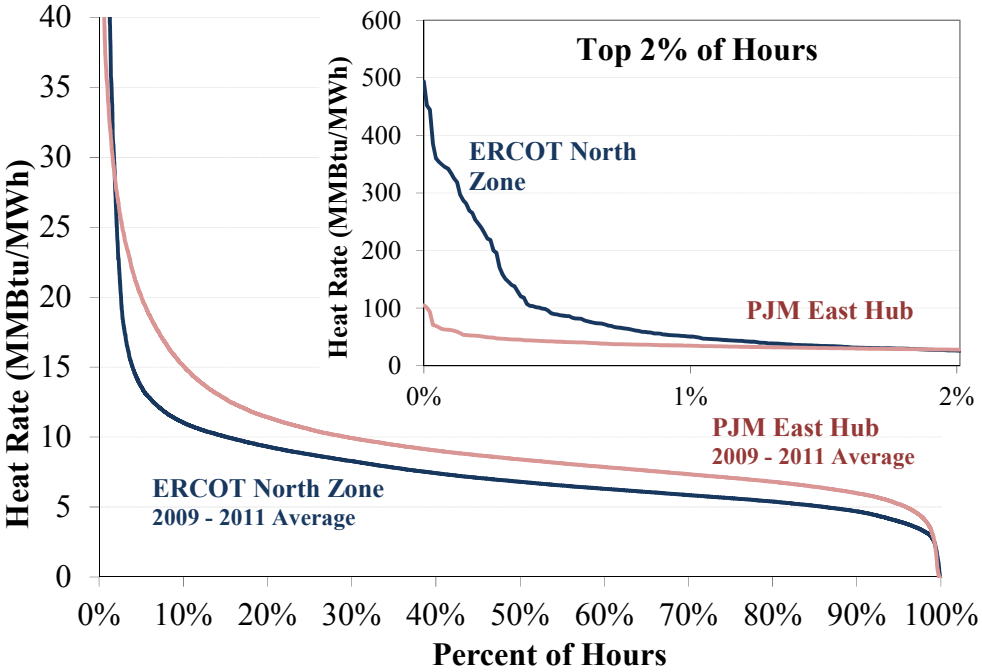
Individual plants' marginal costs obtained from Ventyx (2012).

To calculate plant marginal costs, Ventyx estimates VOM, fuel, and emissions prices. To calculate fuel costs, Ventyx estimates coal prices based on the last 3 months' delivered cost, natural gas prices based on 5/10/2012 spot prices via Intercontinental Exchange, and petroleum prices based on the 4/2012 ENERFAX price.

Imports are not accounted for. Wind is derated to 20% of installed capacity.

The impact of ERCOT's distinctly "hockey-stick" shaped supply stack on market prices is highlighted in Figure 6. The figure compares market heat rate duration curves in ERCOT's North Zone to those in PJM East.[36] Heat rates in ERCOT are lower across almost the entire duration curve due to its efficient fleet and flat supply stack, whereas heat rates in the top one percent of hours are substantially higher due to the sharp bend in ERCOT's supply stack, its higher price cap, and its scarcity pricing mechanisms. As a result, ERCOT's generators face low energy prices and margins under normal conditions and earn a disproportionate share of their total revenue in super-peak hours. The extremely high prices during super-peak hours (up to $3,000 in some hours) is illustrated by the spike in the monthly average price to over $120/MWh during the heat wave of August 2011, as shown in Figure 4 above.

Figure 6
ERCOT vs. PJM Market Heat Rate Duration Curves from 2009 - 2011



Sources and Notes:

Shows market heat rates, calculated as hourly energy price divided by daily gas price; each year's 8,760 hours are sorted from highest to lowest; the three years' duration curves are averaged into a single curve.

Energy Prices at PJM East Hub and ERCOT North Zone from Ventyx (2012).

Gas prices are at Transco Zone 6 Non-NY for PJM and Houston Ship Channel for ERCOT, from Platts (2012).

3. The Impacts of Wind Penetration

Because wind is an intermittent resource, it provides little resource adequacy value. ERCOT currently discounts the installed capacity of wind by 91.3% to establish its capacity value in its reserve margin accounting.[37] While not contributing substantially to resource adequacy, wind generation does have a substantial impact on the energy market because it enters the supply stack

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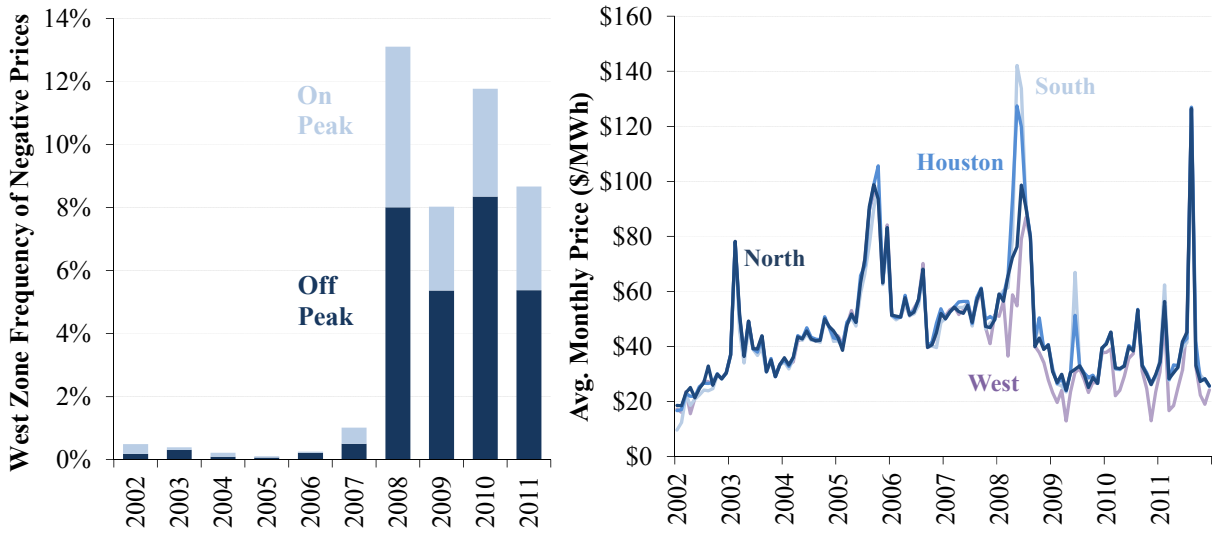
[36] The figure shows hourly market heat rates calculated as the hourly electric price divided by the daily gas price; this measure can be thought of as the electric price after normalizing for changes in gas prices.

[37] See ERCOT (2011f), p. 3.

at zero or negative-priced offers. Wind generators may offer their output at negative values if not generating would forego PTC value or REC payments.[38]

Wind generation puts downward pressure on energy prices in all parts of ERCOT whenever the wind blows. However, the effect is greatest in the West Zone, where more than 70% of ERCOT's wind capacity is located.[39] In the West Zone, wind generation has caused negative prices in many off-peak periods when wind generation was high, zonal load was low, and transmission capacity was insufficient to export the excess. The left panel of Figure 7 shows the growing incidence of negative prices in the West Zone as the amount of wind generation increased there.[40] Negative prices have largely been confined to the ERCOT's West Zone, while the other 3 zones have not had more than 0.4% of hours with negative prices.[41] Wind growth has therefore depressed West Zone prices relative to the other zones, as shown in the right panel of Figure 7.[42]

Figure 7
Frequency of Negative Prices in the West Zone (Left) and Average Prices by Zone (Right)



Source:
Hourly zonal real-time prices from Ventyx (2012).

Owners and investors in non-wind generation have expressed concern about the energy market impacts of the PUCT's Competitive Renewable Energy Zones (CREZ) Transmission Program.[43] The CREZ project is primarily designed to move electricity generated by wind and other renewable resources from remote parts of Texas (*i.e.*, West Texas and the Texas Panhandle) to the more heavily-populated areas of Texas (*e.g.*, Austin, Dallas-Fort Worth, and San Antonio). This transmission expansion will also increase Texas's ability to build more wind generation, but

38 See Potomac Economics (2009), p. xxxii.
39 See ERCOT (2011f), pp. 14-16.
40 For a further discussion of the impact of wind generation on prices in the West Zone, see Potomac Economics (2009), pp. iv, xxxi–xxxii, and 87–90.
41 See Ventyx (2012).
42 See Potomac Economics (2009), p. iv.
43 See PUCT (2010).

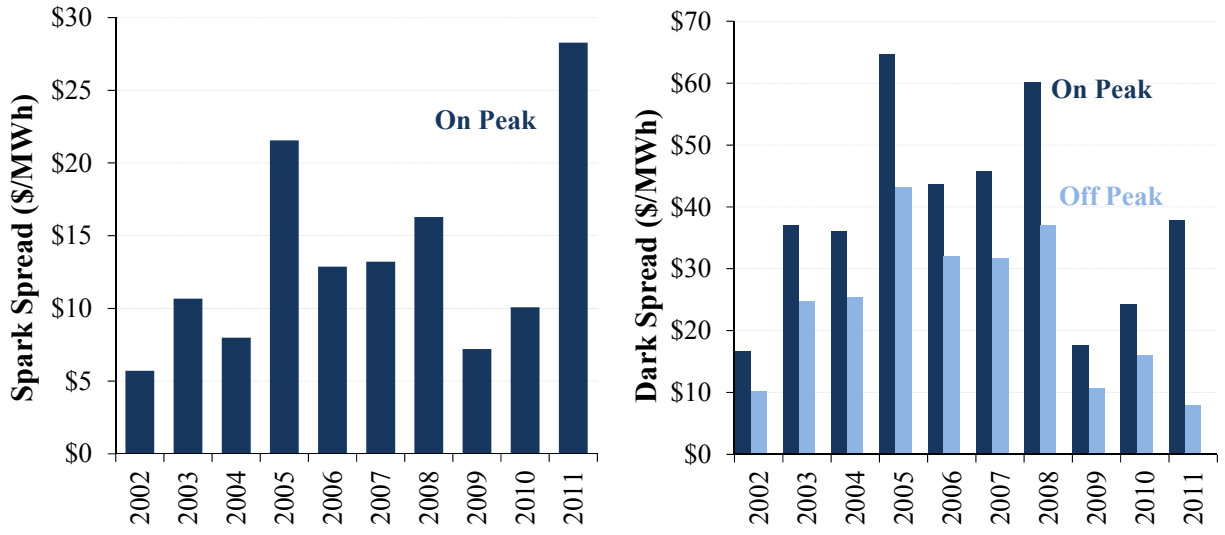
may in the future erode non-wind generator economics more by depressing energy prices in the other three zones.

In addition, large wind penetration levels can introduce a variety of operational challenges, as the system operator must develop wind forecasting capability and operate the power grid with a highly intermittent generation resource. The risk of sudden reductions in wind output increases the need for operating reserves. Unexpectedly high wind output during low load periods can also create operational challenges by creating over-generation conditions when baseload generators are operating at minimum output, and the system operator must order further involuntary generation reductions or shutdowns. These operational challenges are the subject of an ongoing market design effort by ERCOT and stakeholders to address increasing wind penetration in the near term and longer term.

4. Historical Generator Returns

The combination of ERCOT's efficient supply stack, low gas prices, and high wind penetration has greatly reduced the operating margins of existing and potential new generators. Figure 8 shows trends in spark and dark spreads since 2002, indicating the approximate per-MWh profitability of a continuously-operating gas CC or coal unit, respectively.[44] Spark spreads declined in 2009 and 2010, then increased in 2011 because of price spikes caused by extreme weather and scarcity conditions. Similarly, dark spreads have declined sharply since 2008, with the exception of 2011.

Figure 8
ERCOT On-Peak Spark Spreads (Left) and Dark Spreads (Right)



Sources and Notes:

Hourly energy prices from Ventyx (2012).

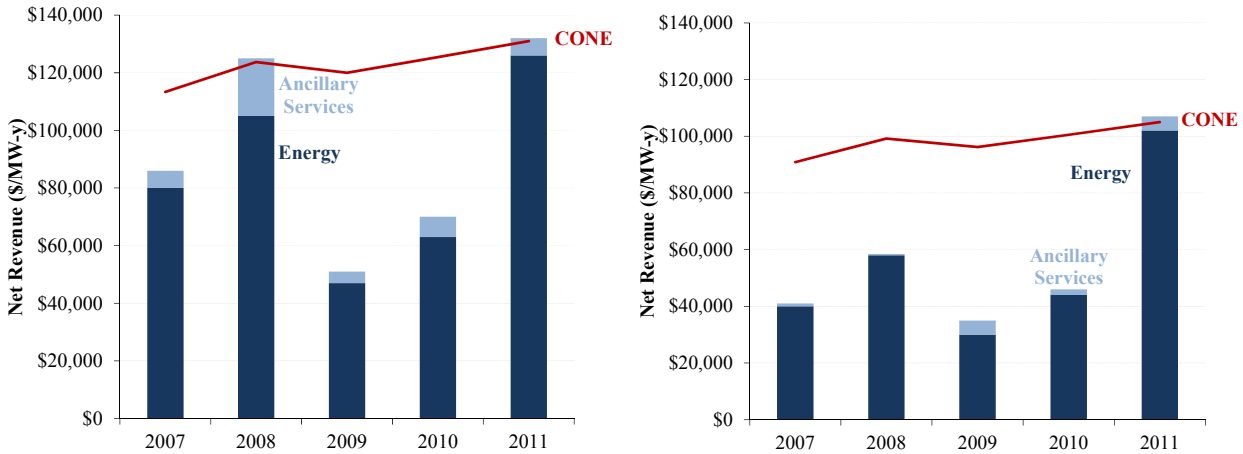
Gas and coal prices from Ventyx (2012). Gas prices at Houston Ship Channel, coal prices as reported by Ventyx on average across ERCOT's coal units.

Spark spreads calculated based on a 7,000 Btu/kWh heat rate. Dark spreads calculated based on a 9,500 Btu/kWh heat rate.

[44] Spark and dark spreads show the difference between power prices and fuel costs. On-peak spark spreads show the difference between the electricity price and fuel price for a unit with a 7,000 Btu/kWh heat rate. Similarly, dark spreads fuel prices are based on coal prices at a 9,500 heat rate.

Figure 9 shows the historical energy margins for simple-cycle combustion turbine (CT) and combined-cycle units. Both technologies have been uneconomic relative to their levelized investment costs since 2007, with the exception of 2008 and 2011 for CCs, and 2011 for CTs. Even though the extreme weather and shortage events of 2011 approximately doubled the profitability of CCs and CTs relative to previous years, these technologies still earned only marginally more than their annualized revenue requirements. Suppliers would have to expect returns at 2011 levels on average in every year in order to invest; therefore, it appears that recent market conditions have been insufficient to attract new generation.

Figure 9
ERCOT Combined Cycle (Left) and Simple Cycle (Right) Energy Margins



Sources and Notes:

"CONE" is a Brattle estimated CONE based on an overnight cost of $667/kW and a 9.6% ATWACC. CONE is deflated by Handy Whitman (2011). See Section II below for discussion of estimated CONE.

Net revenue estimates are from the Independent Market Monitor, see Potomac Economics (2011c).

E. Current Resource Adequacy Concerns

Investors' basic requirement is that they can expect future revenues to be high enough, often enough, to cover the costs of building a plant, including a return on capital commensurate with risk. Because the wholesale market conditions in ERCOT have not been favorable due to the fleet makeup and low electric prices, investment appears to have stalled. This lack of investment threatens resource adequacy in the near future.

1. Recent and Projected Shortages

Since deregulation, ERCOT has maintained sufficient levels of investment and reserve margins. However, reserve margins are deteriorating due to retirements and relatively low new entry, combined with rapid, economically-driven load growth at an average rate of 2.3% a year since 2002.[45] By 2011, the planning reserve margin was 14%, and system reliability was stressed by weather conditions at or beyond the range of possibilities that had been considered when establishing target reserve margins.

[45] *Brattle* calculated average load growth for 2002 – 2011, data from Ventyx (2012).

On February 2, 2011, ERCOT experienced extreme cold weather, causing a record winter peak demand of 56,493 MW, and the loss of numerous generating facilities used to help meet demand. Cold ambient temperatures combined with high winds caused problems with plant control systems and caused 82 generating units representing more than 8,000 MW to go offline, or never come online.[46] Additionally, some gas units were derated due to fuel availability problems.[47] The combination of record demand and unit outages caused ERCOT to shed up to 4,000 MW of load across an 8-hour period.[48]

In addition to the cold snap in February, ERCOT experienced unusually hot weather in 2011. Average June – August temperatures were the hottest recorded by the National Weather Service since recordkeeping began in 1895.[49] The August heat wave led to the use of energy emergency procedures 6 times and 19 hours of prices at the $3,000 price cap, although no load shedding was needed.[50] With the extreme weather in August, the realized reserve margin was only 9%, compared to the 14% reserve margin that would have been realized under normal weather conditions.

As 2011 has shown, reliability outcomes in Texas depend heavily on the weather. ERCOT estimates that a 13.75% reserve margin is needed to maintain the "1 loss-of-load event in 10 years" reliability target.[51] However, this target was established in 2010, before considering the possibility of outlier weather events as extreme as those witnessed in 2011. ERCOT is currently updating its target reserve margin based on updated weather data which includes 2011.

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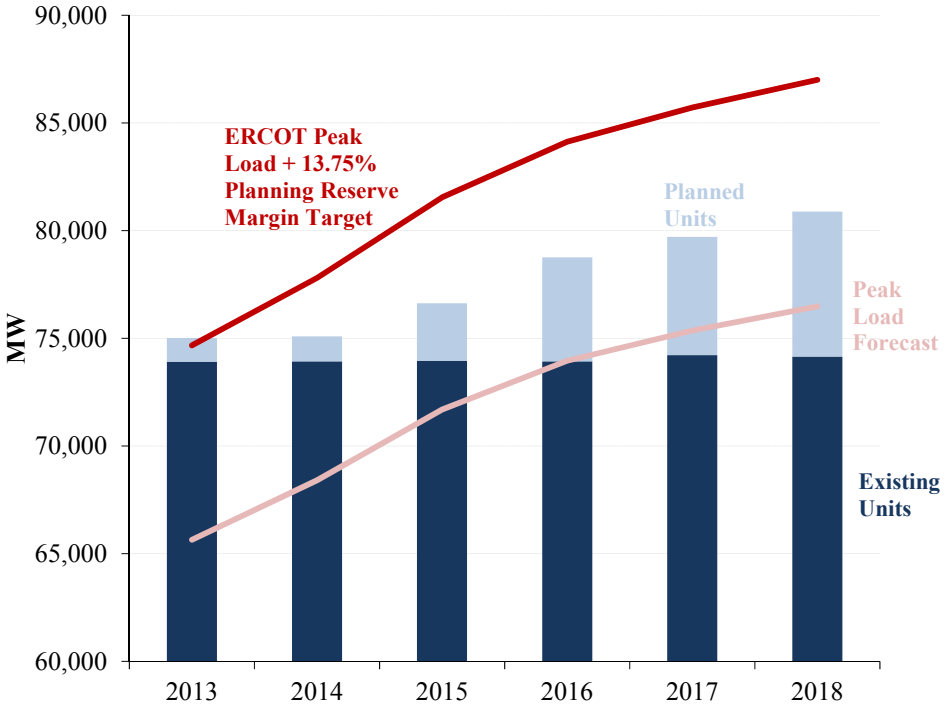
46 See ERCOT (2012b).
47 See ERCOT (2011a).
48 See Potomac Economics (2011a).
49 See ERCOT (2012f).
50 See ERCOT (2012c), Ventyx (2012).
51 See ERCOT (2010a).

As shown in Figure 10, projected planning reserve margins are headed for a low 9.8% by 2014, even if no incremental generation retirements occur.[52] Thereafter, load growth and potential retirements could depress reserve margins much further if new capacity is not added.

Figure 10
Projected Load Growth, Reserve Margin Target, and Capacity Additions



Sources and Notes:

ERCOT does not currently project any retirements in its CDR Report as reflected here, although it has identified some units at risk to retirement in future years as discussed in Section I.E.2, see ERCOT (2012n).

2. Potential Impacts of Environmental Regulations

Several impending environmental regulations will further challenge resource adequacy in ERCOT. ERCOT has analyzed the impact of four different potential rules, including the: (1) Cross-State Air Pollution Rule (CSAPR); (2) Mercury and Air Toxics Standards (MATS); (3) Clean Water Act (CWA) – Section 316(b); and (4) Coal Combustion Residuals Disposal Regulations.

Cross-State Air Pollution Rule — When the EPA finalized CSAPR in July 2011, it included Texas although the state was not included in the earlier proposed rules.[53] The rule was to be implemented within five months, by January 2012. However, on December 30, 2011,

[52] See ERCOT (2012n).
[53] See Environmental Protection Agency (2011a).

the U.S District Court of Appeals stayed CSAPR.[54] The Court is currently hearing oral arguments and is expected to make a decision as early as June or July 2012.[55]

CSAPR is being implemented in order to address the interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).[56] Under CSAPR, generating units in Texas would be regulated for annual emissions of SO_2 and NO_X, as well as emissions of NO_X during the peak season. Each unit will be awarded a set allocation of emissions allowances. At the end of the calendar year, resource owners must turn in one allowance for each ton of emissions or be subjected to penalties. Interstate allowance trading will be allowed among states in the same group, but if any one state exceeds its awarded allowances plus a variability limit, then suppliers contributing to the excess will face a penalty. Compliance would likely require a combination of allowance purchases, reduced unit output, the use of low-sulfur fuel, or capital-intensive retrofits.

Mercury and Air Toxics Standards — The EPA finalized the Mercury and Air Toxics Standards rule in December 2011, requiring coal and oil-fired power plants to reduce emission rates of mercury, acid gases, and non-mercury metals below specific limits by April 2015.[57] In addition to the three-year statutory requirement, the EPA allows a potential 1-year extension of the deadline if approved by state permitting agencies, and a further 1-year extension under the circumstances where a power plant would need to continue operations in order to maintain reliability.[58] The MATS rule will require coal plants to install various combinations of controls depending on the unit's existing controls, boiler type, type of coal used, and economic factors. The control equipment needed to comply with MATS may include wet or dry flue gas desulfurization (FGD), selective catalytic reduction (SCR), fabric filter (or baghouse), dry sorbent injection (DSI), or activated carbon injection (ACI).[59]

Clean Water Act 316(b) — Section 316(b) of the Clean Water Act requires that cooling-water intake structures utilize best available technology, and that these structures minimize adverse environmental impacts to fish populations.[60] The EPA announced proposed revisions to the requirements for cooling-water intake structures for existing facilities on March 28, 2011.[61] These regulations are designed to reduce fish entrainment and impingement caused by the use of cooling water by industrial facilities and electric generation plants. While the proposed regulations provide for flexibility and development of site-specific solutions, the strictest implementation of these revised regulations could require that closed-loop cooling tower systems be installed at all

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54 See United States Court of Appeals (2011).
55 See Power Magazine (2012).
56 See Environmental Protection Agency (2011a).
57 The compliance deadline is 60 days plus 3 years from the date of publication in the *Federal Register*, which was February 16, 2012. See *Federal Register* (2012), p. 9407.
58 EPA states that it expects that few or no reliability exceptions of this type will be needed, see EPA (2011b).
59 See Celebi, *et al.* (2012), p. 7
60 See EPA (2011c).
61 See EPA (2011d).

existing facilities that currently utilize once-through cooling.[62] A final rule will be issued by July 27, 2012.[63]

Coal Combustion Residuals Disposal Regulations — Under section 3001(b)(3)(A)(i) of the Resource Conservation and Recovery Act (RCRA) (known as the Bevill exclusion), ash products generated from the combustion of coal are excluded from the handling and disposal requirements in the Act pending a determination from the EPA that such requirements are justified.[64] In 1993 and 2000, the EPA determined that regulation of ash from coal combustion under RCRA was not justified.[65] However, in June 2010, the EPA issued a new proposal to address the risks associated with coal ash disposal by either reversing its earlier Bevill regulatory determinations and classifying coal ash as a "special waste," or maintaining its previous Bevill determinations, but issuing national minimum criteria regarding the proper disposal of coal ash waste. In either case, the EPA proposal would limit ash disposal options and require additional monitoring of ash disposal facilities. The EPA proposal could also limit options for the beneficial use of coal ash products.[66]

To evaluate the impact of each regulation, ERCOT reviewed published studies of the nation-wide impacts, and met with environmental experts from several ERCOT generators. ERCOT then developed scenarios based on likely compliance requirements and future market conditions. Units that ERCOT did not project to earn sufficient market returns to justify the cost of a controls upgrade were assumed to retire. These retirement decisions were based solely on market economics; ERCOT did not consider any reliability-based reserve margin requirement and did not consider whether any generation expansion might materialize.

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62 See ERCOT (2011c), p. 2.
63 See EPA (2011d).
64 See EPA (2000), p. 2.
65 See EPA (2000b).
66 See EPA (2010).

Table 2 shows the results of ERCOT's evaluation on the impact of CSAPR under three different scenarios. ERCOT could expect to lose 1,200 – 1,400 MW during peak summer months.

Table 2
Environmental Impacts of CSAPR

Scenario		Capacity Reductions		
		Fall *(MW)*	Spring *(MW)*	Summer *(MW)*
Low	Based on compliance plans from resource owners	3,000	3,000	1,200-1,400
Mid	Based on compliance plans + additional maintenance of coal due to daily dispatch	5,000	3,000	1,200-1,400
High	Based on compliance, additional maintenance, and limited imported low-sulfur coal	6,000	3,000	1,200-1,400

Source:
ERCOT (2011e).
Assumed rule implementation by January 2012.

Table 3 shows the retirement impacts of MATS, CWA 316(b), and the Coal Ash regulations. Given ERCOT's relatively small number of coal units that would require major controls upgrades for MATS, it will be much easier for Texas to comply than other parts of the country such as MISO and PJM. ERCOT projects 1,200 MW of coal retirements in the base scenario. Among gas capacity, ERCOT deems that no units are at risk unless the EPA imposes a once-through cooling mandate, in which case nearly 10,000 MW of gas-fired capacity will likely retire. These retirements are from old gas steam units that are less efficient and less flexible than quick-start gas-fired generation. Many of these older units are nearing the end of their economic lives and any requirement to upgrade will likely cause retirement.

Table 3
Combined Environmental Impacts
(Includes MATS, CWA 316(b), and CCR Regulations)

Scenario	w/o Closed-Loop Requirement		w/ Closed-Loop Requirement	
	Coal-Fired Retirements *(MW)*	Gas-Fired Retirements *(MW)*	Coal-Fired Retirements *(MW)*	Gas-Fired Retirements *(MW)*
Base Case	0	0	1,200	9,800
High Gas Price	0	0	0	9,800
$25/ton Carbon Price	4,400	0	5,600	9,800
High Gas Price w/Carbon Price	0	0	0	9,800

Sources and Notes:
ERCOT (2011c).
Assumes the retirements listed in the tables occur by 2016.
Base case gas price is $5.1/MMBtu, high gas price is $8/MMBtu.
This study also included the Clean Air Transport Rule, which was the proposed version of CSAPR at the time. However, the study found no incremental impacts from CATR on ERCOT because it only included Texas in the peak season NO_X program, see ERCOT (2011e), p. 1.

F. RECENT AND ONGOING EFFORTS TO ADDRESS RESOURCE ADEQUACY

In response to emergency conditions faced in 2011 and projections that reserve margins will fall below the target level by 2014, the PUCT convened Project 37897 to address resource adequacy challenges and scarcity pricing.[67] Since then, ERCOT, the PUCT, and stakeholders have worked through a number of important efforts to analyze resource adequacy challenges and implement market reforms. To date, key approved reforms include the following measures that will prevent price suppression from administrative reliability interventions, or otherwise work to increase prices during scarcity conditions:

- Implementing a price floor at the System Wide Offer Cap for energy deployed from Responsive Reserves and Regulation Up;[68]
- Implementing a price floor at the System Wide Offer Cap for energy deployed from Reliability Unit Commitment (RUC) and RMR units operating between their low sustained limit (LSL) and high sustained limit (HSL);[69]
- Implementing a price floor for deployments of Non-Spinning Reserves, including a floor of $120/MWh for Online Non-Spin, and $180/MWh for Offline Non-Spin;[70]
- Expanding Responsive Reserves by 500 MW with a corresponding reduction in non-spin;[71] and
- Expanding Emergency Interruptible Load Service (EILS) into Emergency Response Service (ERS).[72]

Resource adequacy challenges are also the subject of ongoing market design efforts by the PUCT and ERCOT. Several additional reforms are in progress or under consideration, including:

- Raising the System Wide Offer Cap, possibly as high as $9,000/MWh, with corresponding increases to the Low System Wide Offer Cap and Peaker Net Margin Threshold;[73]
- Raising the high end of the Power Balance Penalty Curve and adjusting its slope and width;[74]
- Eliminating price distortions caused by deployments of load resources;[75]
- Eliminating price distortions caused by 0-LSL energy from ONRUC, RMR, quick-start, and offline non-spin resources;[76]
- Initiating an ERS Demand Response Pilot, and Load Management Initiatives;
- Posting non-binding near real-time forward prices; and
- Sponsoring this study to analyze the resource adequacy challenge.

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67 See PUCT (2012b).
68 See ERCOT (2012f), NPRR427.
69 See ERCOT (2012f), NPRR435 and NPRR442.
70 See ERCOT (2012f), NPRR428.
71 See ERCOT (2012f), NPRR434.
72 See ERCOT (2012f), NPRR451.
73 See, for example, PUCT (2012a), Item Number 106.
74 See PUCT (2012a), Item Number 125.
75 See ERCOT (2012f), NPRR444.
76 See ERCOT (2012f), NPRR444.

We further discuss the implications of these recent and potential changes where relevant in the remainder of this study. In particular, we examine the implications of recently-implemented and proposed changes on generator margins in Section IV and discuss the efficiency of individual market design elements further in Section V.

II. GENERATION INVESTMENT CRITERIA BY INVESTOR CLASS

To understand the factors affecting investors' willingness to invest in ERCOT, we interviewed a broad spectrum of generation developers and lenders and analyzed relevant financial indicators. We found that investors are generally cautious after a history of investment losses but that many could and would invest in ERCOT if revenue levels were expected to be adequate to earn a return commensurate with risks.

The lack of long-term PPAs in Texas's retail choice environment means that investment risks usually remain with suppliers rather than buyers. This places more risk on investors in restructured markets than in regulated markets where long-term PPAs are standard. A number of generators also state that the wholesale energy-only market design is riskier than other restructured markets where capacity payments are a major revenue stream. However, investors also noted that revenues in ERCOT are more stable than spot prices, since they sell most power at least a few months forward at prices that average out short-term risks such as weather effects. Overall, we believe that the energy-only markets are somewhat riskier and harder to model from a revenue-forecast perspective than capacity markets.

Investors also worry that energy-only markets can lead to extreme outcomes that might induce future regulators to intervene in the market even though they expressed that the current Commission has demonstrated its commitment to markets and regulatory certainty. Considering all of these factors, at least some investors state that they may require returns exceeding the 9.6% after-tax weighted-average cost of capital (ATWACC) assumed by ERCOT last year.[77] Large, diversified investors with hedging options and the ability to finance plants on their balance sheets might be able to accept lower returns on incremental investments in ERCOT, perhaps closer to our current ATWACC estimate of 7.6% for merchant project investments. We also note that some investors believe the ATWACC required for projects in ERCOT is higher than for merchant projects in other locations.

Revenue requirements and risk tolerances vary considerably by type of investor. Lenders of project-finance loans with no upside opportunities must be confident that the borrowing entity will have sufficiently stable net revenues to cover the total amount borrowed with ample margin for error. Larger borrowers can partially diversify project-specific risks and borrow more cost-efficiently against their corporate balance sheet while also absorbing equity risks. Such investors may be able and willing to weather some bad years for a few good years as long as the discounted expected value is high enough. These are likely to be the most robust type of

[77] See PUCT (2012a), Item Number 87, p. 1.; Note that this estimate is a year old, and required rates of return have decreased since then. The ATWACC is defined as the capital-structure weighted average of: (1) the cost of equity; and (2) the after tax cost of debt (*i.e.*, the cost of debt multiplied by one minus the marginal tax rate). See Brealey, *et al.* (2011), p. 216.

investors in a market with high price volatility. Smaller, undiversified borrowers, particularly those relying on high leverage through project-specific, non-recourse debt financing with little equity, might be pushed out of the market unless they can secure PPAs with public power entities.

A. Classes of Generation Investors

Several classes of generation investors are active in ERCOT, with each investor class differing in size, preferred financing model, financial profile, and risk tolerance. In this section, we describe: (1) investment criteria considered by various types of entities that may be involved in new generation investments; (2) the market share of generation owners and investors currently active in ERCOT; and (3) the varying ability of different classes of investors to move ahead with new investment projects in ERCOT, based on their risk exposure, diversification level, and credit ratings.

1. Classes and Criteria of Entities Involved in Generation Development

A number of different types of entities can be directly involved in developing and building new power plants. We will refer loosely to "generation developers" as a group, but note that it is important to understand that each type of entity has a different role and investment considerations:

Unaffiliated Generation Developers — The power industry has a large number of small companies that actively scout for power generation development opportunities. These developers are generally small enterprises without substantial equity or assets to diversify against. To move ahead with an attractive generation investment opportunity, an unaffiliated developer will need to secure financial commitments from major equity investors and lenders. They also need to secure a long-term contract with a buyer to reduce investment risk. Once such a generation project is developed, it is often sold to a variety of companies who own and operate power plants.

Privately-Held Independent Power Producers (IPPs) — Privately-held IPPs span a broad range from smaller, less diversified generation companies to larger, more diversified interests including for example: (a) Topaz, which currently has 2,000 MW generation investment in ERCOT; (b) Panda Power Funds, which is proposing 2,000 MW of new generation in ERCOT and has developed other projects elsewhere in the past; and (c) Tenaska, which has developed almost 3,000 MW in ERCOT and 9,000 MW of generation nationally and internationally.[78]

Publicly-Held IPPs — There are a number of publicly-traded merchant generation companies that currently do or may in the future invest in ERCOT, including: (a) companies that primarily invest in merchant generation, such as NRG and Calpine; (b) merchant affiliates of regulated utilities located in other regions, such as Exelon; or (c) merchant generation investors who are highly diversified or have primary interests in industries other than power, such as Hess. These investors vary widely in size, credit ratings, and diversification, and not all investors from among these types currently have

[78] Tenaska also participates in marketing of gas, power and biofuels, and provides risk management and fuel procurement. For asset information see Topaz (2012); Panda Power Funds (2012); Tenaska (2012).

interests in ERCOT. Many merchant generation companies, such as NRG and Exelon, have partially vertically integrated into retail services to hedge a portion of their generation output as discussed below.[79]

Municipalities and Cooperatives — Municipalities and cooperatives are directly owned by their customers and, as a result, are driven directly by the interests of end users. These entities do not require the same return on investment as merchant investors, because the costs of a generation investment are borne by their end-user customers regardless of prevailing market conditions. These entities engage in long-term planning for power supply and may directly invest in new generation projects or may sign long-term contracts to buy power from other generation owners When signing a long-term PPA, munis and coops take on the risk that a particular generation project may ultimately become uneconomic; these PPAs therefore reduce investment risks to the merchant PPA counterparty. However, munis and coops will face pressure from members to restructure if any investments turn out to be out-of-the-money.

Partially Reintegrated REPs — Unlike munis and coops, REPs are generally unwilling to sign long-term PPAs that would support generation investments. However, there are some large REPs, such as Direct Energy, that have a strategy to hedge a portion of their retail positions with direct ownership in generation assets. These partially-reintegrated entities may purchase existing assets to attain their desired hedging position. As discussed above, there are also many publicly-held merchant generators that hedge their generation position through a retail position in ERCOT as is the case with NRG and its REP subsidiary Reliant.[80]

Large Customers — There are a small number of end-user customers that are large enough to invest in generation assets for self-supply. The majority of these investments would be in small on-site generation with a special economic situation, including cogeneration opportunities and backup power.

Lenders — Large financial institutions provide the project-specific debt used to finance new investments. As discussed further in Section 0 below, the size and terms of any loan will depend on the risk of the investment it supports as well as the equity position and financial health of the company making the investment.

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[79] For further discussion of partial vertical integration trends, see Pfeifenberger and Newell (2011).

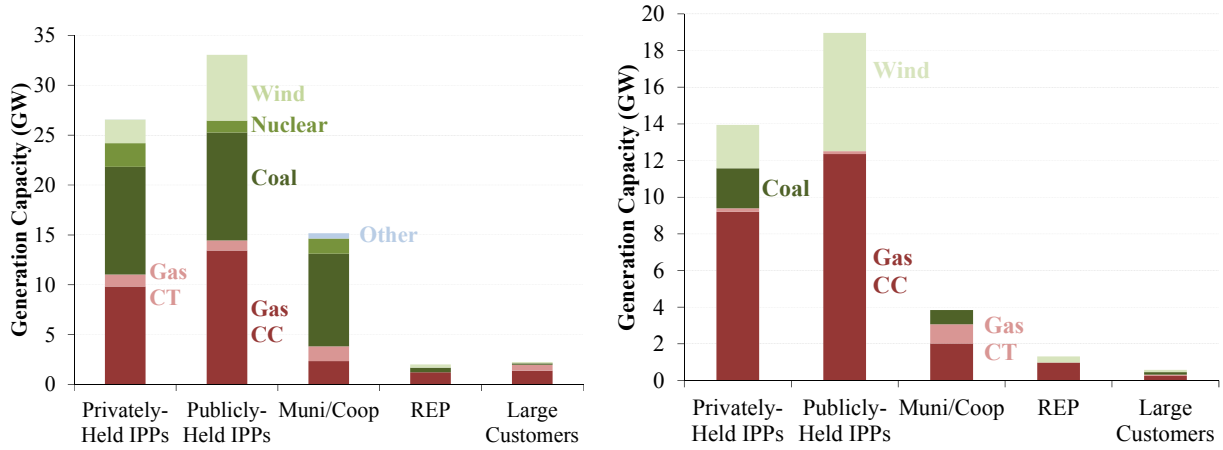
[80] See Reliant (2012).

2. Market Share of Current ERCOT Asset Owners

To illustrate the relative importance of each investor class in ERCOT, we summarize the current asset holdings by ownership for new generation investments since 2000 and for the entire fleet in Figure 11. Since 2000, ERCOT has attracted roughly 34,000 MW of new generation investments.[81]

The largest market share and recent investments in ERCOT are from privately-held IPPs such as Tenaska and Topaz, and from publicly-held IPPs such as Calpine and NextEra. About 10% of new generation investments have come from municipalities and cooperatives. While municipalities and cooperatives have an important role in enabling some investments, their relatively small market share means that resource adequacy in ERCOT will ultimately depend on IPPs developing assets based on market returns.

Figure 11
Total Generation Installed (Left) and Built Since 2000 (Right) by Investor Class



Sources and Notes:
All capacity reported at summer nameplate rating, from Ventyx (2012).
Ownership categorized based on the identity of the primary owner.

[81] Roughly 10,000 MW of the investment since 2000 was wind generation as shown in Figure 11.

Table **4** summarizes the current asset holdings of all of the largest generating entities in ERCOT, including total generation and generation built since 2000. IPPs account for the largest share of the market: the largest is Luminant, owning approximately 17% of the total fleet in ERCOT, the majority of which are coal plants.[82] NRG has the second largest portfolio, with approximately 14%. Calpine and NextEra Energy are smaller in terms of total generation, but are the two companies that have made the largest investments since 2000. In ERCOT, munis and coops such as CPS, Lower Colorado River Authority, Austin Energy, and Brazos have the largest market share and recent investment activity. Munis and coops own less generation than their 25% combined share of ERCOT load because much of their supply is contracted. As shown, REPs (not counting merchant generators who vertically integrated into retail supply) and large customers make up a small portion of ERCOT generation investment.

Table 4
Total ERCOT Generation Assets by Investor Class and Company

	Total Fleet		Since 2000	
	MW	%	MW	%
Privately- Held IPPs	**18,444**	**23%**	**6,613**	**17%**
Luminant	13,682	17%	2,186	6%
Tenaska Inc	2,901	4%	2,901	7%
Topaz	1,861	2%	1,526	4%
Publicly- Held IPPs	**28,003**	**35%**	**13,480**	**35%**
NRG Energy Inc	10,896	14%	483	1%
Calpine Corp	4,985	6%	4,571	12%
NextEra Energy Inc	5,204	7%	5,061	13%
International Power (GDF Suez)	3,893	5%	2,508	6%
Exelon Corp	3,026	4%	857	2%
Muni/Coop	**12,886**	**16%**	**3,441**	**9%**
CPS Energy	5,829	7%	1,607	4%
Lower Colorado River Authority	3,067	4%	694	2%
Austin Energy	2,546	3%	575	1%
Brazos Electric Power Coop	1,445	2%	565	1%
REP	**2,014**	**3%**	**1,318**	**3%**
Direct Energy	1,227	2%	988	3%
AEP	787	1%	330	1%
Large Customers	**1,774**	**2%**	**394**	**1%**
Dow Chemical	1,033	1%	100	0%
Formosa Plastics Corp	740	1%	294	1%

Sources and Notes:
Capacity reported at summer nameplate rating, from Ventyx (2012).
Percentages for each category will be more than the individual companies because not all companies are included in the above table.

[82] Luminant is currently a privately-owned subsidiary of Energy Future Holding Corporation. EFH acquired Luminant in 2007 with a private-equity acquisition of Kohlberg Kravis Roberts & Co. TPG and Goldman Sachs Capital Partners. EFH also owns TXU Energy and Oncor. See Energy Futures Holdings Corporation (2012).

3. Ability to Finance Investments by Investor Class

In addition to characterizing ERCOT investors in terms of their qualitative differences and market shares, we separately categorize these companies based on their relative ability and willingness to make new generation investments in ERCOT. The ability and willingness of investors to make these investments relates principally to their projected returns (which depend on the market prices they all face) and ability to absorb or diversify risk.

Table 5 ranks these investor types in order of their ability to absorb risk. Generally, a company's willingness and ability to invest in ERCOT has more to do with their size, diversification, and credit quality as discussed below than their ownership type as discussed above. Organized by their ability to manage risk, these investor classes include:

Self-Suppliers — Self-suppliers, such as municipalities, cooperatives, and a select number of large customers, are positioned differently from other generation investors. Retail power consumers are simultaneously constituents or member-owners of the generation entity, with an alignment of economic interests. Public power entities have their own load and usually build or contract far in advance to cover it, consistent with a long-term resource plan. While these entities consider the same market dynamics of price levels and volatility that affect other investors, they are not subject to the same risks because even uneconomic investment costs may be recovered from their retail customers. This protection against losses enables public power entities to enjoy lower financing costs than merchant investors. Public power entities may also enable PPA counterparties to achieve lower financing costs by taking on the risk that the investment may become uneconomic.

Diversified IPPs with Investment-Grade Credit Ratings — These investors are large national or international entities with diversified portfolios, nearly all of them publicly-held companies such as Exelon, NextEra, GDF Suez, and Hess. Such diversified entities have substantial, but not infinite, ability to absorb cash flow timing and volatility challenges posed by individual project investments. Investment-grade credit ratings also provide the ability to borrow on a corporate or balance sheet basis on terms more favorable than those available under project-specific, non-recourse financing.

Diversified IPPs with Below-Investment-Grade (or No) Credit Ratings — Companies in this category include some large publicly-held merchant generation companies and private equity firms with diverse asset portfolios. Their diversification makes them reasonably well-positioned to meet the challenges associated with cash flow volatility of individual plant investments. Their portfolios enable them to issue corporate debt, but their lower credit ratings mean that they face higher interest rates on bank loans and public bonds. Companies in this category may have low credit ratings due to a poor company outlook, but in some cases the companies may intentionally manage to a sub-investment grade credit rating in order to optimize equity returns. In the latter case, the companies may boost equity returns by taking on large amounts of debt. This debt will, in turn, necessarily translate into a lower credit rating and higher required returns regardless of other indicators of financial well-being.

Undiversified IPPs — Undiversified investors are typically privately-held project development or acquisition companies with narrow asset portfolios and insufficient

critical mass to attract public-market debt or equity financing. The equity portion of these undiversified companies is typically funded by private equity firms, while the debt portion typically requires non-recourse or "project" financing, as further discussed in Section 0 below. Though some cash flow timing and volatility risks can be managed through third-party hedges and insurance, to make sufficient debt financing possible, these undiversified investors are more reliant on long-term PPAs than any of the other investor classes. They are therefore likely to be excluded from the market if long-term PPAs are unavailable.

Table 5
Investors' Investment Criteria from Most Able to Least Able to Absorb Risk

Type of Investor	Investment Criteria
Self-Suppliers Municipalities and Cooperatives (Including their Long-Term PPA Counterparties) Select Large Customers	– **Long-Term Planning —** Interests driven by end-use customers who are the ultimate owners. Self-suppliers will own or contract for long-term supplies to meet projected demand. – **Prices and Volatility —** Will plan for lowest long-term costs and preventing price volatility, but will recover investment costs from ratepayers even if a project becomes uneconomic with changing market conditions.
Diversified IPPs with Investment-Grade Credit Publicly-Held IPPs	– **Expected Price Levels —** Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Can diversify against larger portfolio. – **Debt Financing** — Able to borrow against balance sheet (but will often prefer project financing with a long-term PPA, if available). – **Regulatory Uncertainty —** Concern that upside could be curtailed through regulatory change or intervention.
Diversified IPPs with Below Investment-Grade Credit Publicly-Held IPPs Privately-Held IPPs	– **Expected Price Levels —** Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Can diversify against portfolio. – **Debt Financing** — May or may not be able to borrow against balance sheet; ability to invest may depend on securing project financing supported by long-term PPA. – **Regulatory Uncertainty —** Concern that upside could be curtailed through regulatory change or intervention.
Undiversified IPPs Unaffiliated Developers	– **Expected Price Levels —** Must project returns commensurate with risk. Cautious due to history of investment losses. – **Market Price Volatility** — Limited portfolio to diversify against. – **Debt financing** — Only able to invest under project financing model supported by steady and certain cash flow, which could be achieved through long-term PPAs or long-term hedges with power marketers, but these are both difficult to secure. With less risk shifting, required returns can exceed those of other investor classes, thereby possibly precluding investment. – **Regulatory Uncertainty —** Concern that upside could be curtailed through regulatory change or intervention.

Most Able to Absorb Risk ↑ ↓ **Least Able to Absorb Risk**

Table 6 summarizes the size, debt characteristics, and credit ratings of a number of important investors in ERCOT. As previously explained, municipalities and cooperatives usually have

strong credit ratings, given their ability to pass risk through to customers. This puts them in a favorable position to invest even if they are small relative to other investors. Some large customers also have favorable credit ratings that could enable them to invest in self-supply, but it is likely that their interest will be limited to a small number of specific cogeneration or backup power opportunities.

Table 6
Investors' Balance Sheets and Credit Quality

	Assets *($B)*	Debt *(%)*	Equity *(%)*	Project Debt *(%)*	S&P Rating
Self-Suppliers					
Municipalities and Cooperatives					
CPS (City of San Antonio)	$10	60%	40%	n/a	AA
Brazos	$2.7	83%	17%	n/a	A-
Austin Energy	n/a	n/a	n/a	n/a	A+
Large Customers					
Dow Chemical	$69	48%	52%	7%	BBB
Publically Held IPPs					
Utility Affiliates					
Exelon	$55	48%	52%	n/a	BBB-
International Power (GDF Suez)	$62	40%	60%	>10%	BBB-
NextEra	$57	59%	41%	26%	A-
Merchant Generators					
NRG	$27	56%	44%	18%	BB-
Calpine	$17	71%	29%	16%	B+
Privately Held IPPs					
Luminant (EFH)	$44	128%	-28%	n/a	CCC
Tenaska	$2.8	49%	51%	n/a	n/a

Sources and Notes:
Investor information from Bloomberg (2012).
Debt and equity percentages calculated based on "capitalization" (except for Tenaska which is based on "total assets").
The majority of International Power's transactions in North America are supported by its parent company, GDF Suez, which has assets of $267 Billion, a debt/equity ratio of 41/59%, and whose current S&P rating is A.
Data for CPS is for the year ending 1/31/2011.
Data for Brazos is for 2010.
Rating for Austin Energy is the rating of its electric utility system revenue bonds.
For additional credit rating explanations see S&P (2012).

IPP affiliates of regulated utilities can sometimes also benefit from the higher credit ratings of their parent companies (which reflect a mix of regulated and IPP operations). Pure merchant generation companies often have below investment-grade credit ratings, although, as noted earlier, this may be intentional to optimize equity returns. Finally, private equity firms cover a range of sizes and credit ratings although these entities are usually not required to publicly report their financial information. In particular, the large Energy Future Holdings (EFH), which owns Luminant, TXU, and Oncor, has a very poor credit rating caused by a $45 billion leveraged buyout that it has not been able to recover since its coal fleet's energy margins fell along with the

drop in natural gas prices.[83] Overall, there are a number of entities that are well-positioned to make additional generation investments in ERCOT as long as anticipated returns are commensurate with their risk and financing costs.

B. DEBT FINANCING MODELS FOR POWER PLANT INVESTMENTS

There are two general debt financing models used to develop power plants: (1) project financing, and (2) balance sheet financing. For many years IPPs have built generating plants using project financing with revenues stabilized through long-term PPAs. In the presence of long-term PPAs, project financing has been attractive to developers because it limits investor risk, allows greater debt leverage, and therefore reduces financing costs.

In recent years, however, declining market prices and the expansion of retail competition have reduced the number of buyers willing to sign long-term PPAs to support new generation plants. Further, since the financial crisis, power marketers have been reluctant to sell long-term hedges (*e.g.*, 10 years) that could otherwise be used to support project-specific debt. These changes have reduced project financing opportunities. As a result, generation development has been shifting toward balance sheet financing and a greater reliance on equity investment.

In this context it is important to understand that lenders have first claim on cash flows (and, if necessary, liquidation value) for the purpose of repaying principal and interest. Lenders have no stake in the residual value of the investment after their principal is repaid, nor any claim to project "upside" in the event of asset appreciation. Leveraging equity investments with debt conserves equity investors' funds and increases their returns, along with their financial risks. Lenders bear less risk than equity investors, making the required return on debt less than the required return on equity. However, with no upside potential, lenders require that their first claim be substantially insulated from default risk and therefore impose corresponding requirements on borrowers.

1. Project Financing

Project financing refers to the use of project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a power plant. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual power plant. This means if the project becomes insolvent, the creditors will be unable to recover their investment from any other entity than the project itself. Non-recourse debt is riskier for the lender and consequently more expensive than corporate debt secured through a guarantee associated with the more diversified revenues and assets of a larger parent company.

While usually more expensive than corporate debt, non-recourse debt is still attractive to developers because: (1) it is often the only form of debt financing available for small generation developers; (2) it may be less expensive than corporate debt for companies with below-investment grade ratings; (3) it limits the equity investor's risk to the value of the equity originally invested in case the project proves to be a bad investment; and (4) the leverage project financing provides is attractive to many equity investors who prefer the higher-risk, higher-return investment options it creates.

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[83] See Lattman (2012).

Because lenders, unlike equity investors, generally have no possibility of earning "upside" beyond the stipulated debt interest rate, they must apply conservative criteria in a project finance credit evaluation. Generation developers can only secure project financing if lenders are highly confident that cash flows from the plant will be sufficient to repay principal plus interest. The most important factor that can provide this confidence is a long-term PPA to sell power at a known revenue stream. Having a PPA reduces project risk to the owner and lender by shifting market risks to the buyer. With a PPA, even relatively small entities with limited borrowing capacity may be able to build a plant through project financing. Without a PPA, the share of a project that lenders are willing to support through project financing drops substantially. For example, some projects supported by PPAs are able to employ non-recourse debt for 70% or more of total project capital. Conversely, the higher volatility and uncertainty in projected cash flows of projects without PPAs may reduce the portion that can be financed with non-recourse debt to 30% or less of total project capital. By shifting most of the project risk to a long-term buyer, project financing with a PPA will reduce financing costs and the overall cost of building a new plant.

2. Balance Sheet Financing

In addition to project finance, some larger and diversified developers are able to use "balance sheet" financing for power projects. Balance sheet financing employs debt backed by the repayment obligation of the project owner itself, which may have significant, diverse resources and assets beyond the individual project. Corporate debt provides creditors much greater certainty because repayment is no longer solely reliant on the success of any one project but is instead tied to the solvency of a large, diversified company. Corporate debt backing means that the loan will not go into default due to transitory periods of cash flow shortfall that may result from merchant project operations in volatile markets. Therefore, balance sheet financing will tend to increase the amount of debt financing effectively available to a given project without a PPA, *e.g.*, to 50% or 60%.

Balance sheet financing requires an investor with sufficient scale and diversity to provide this security to the lender. This will exclude a number of smaller investors and project developers from a market with few or no PPAs available. Finally, balance sheet financing is not cost-free to investors. Rather, when a company increases its corporate debt through issuing bonds or taking on large bank loans, it reduces its financial flexibility and risks lowering its credit rating because it will have more debt on its balance sheet.

C. Capital Market Conditions

The ability to make investments in ERCOT is driven not only by expected market revenues, but also by overall debt and equity market conditions. The cost of financing depends on the state of the debt and equity markets, which have changed substantially over the past ten years. We outline the state of both debt and equity markets for potential investors in ERCOT.

1. Debt Markets

In the wake of the worldwide financial crisis starting in 2008, financing costs for corporate debt in the U.S. shot up. Corporate debt rates have since dropped back to pre-crisis levels, but the

spread to treasuries remains wider than before 2008 due to the ongoing European sovereign debt crisis, low demand for high-risk securities, and new regulatory capital requirements on financial market participants.[84] The project-financing sector has also been adversely affected by the reduction in availability of long-term contracts, with numerous financial institutions refocusing on financing renewable generation investments (which frequently have long term PPAs) or ceasing power industry lending altogether.[85]

Treasury rates and the London Interbank Offering Rate (LIBOR) are now at historic lows, reflecting current policies of the Federal Reserve and investors' continued "flight to safety." However, the cost of debt for power project investors has not dropped as far. Figure 12 shows that even though yields on 20-year Treasury bonds are low relative to pre-crisis levels, yields on corporate bonds are relatively unchanged. We show 20-year BB utility bonds as a rough proxy for borrowing costs facing power projects because this credit rating is in line with the credit rating of some potential ERCOT investors. The spread between BB utility bonds and Treasuries increased after 2006 when it was approximately 2%, escalated dramatically up to 8% during the financial crisis, and has since dropped to current levels in the 3-4% range. While below the spreads experienced during the 2008 financial crisis, today's spreads are as high as they were immediately prior to the crisis. Borrowing spreads have not dropped further due to lower demand for corporate bonds relative to higher-rated securities and the more stringent regulatory standards imposed on financial institutions (*e.g.*, capital requirements).[86]

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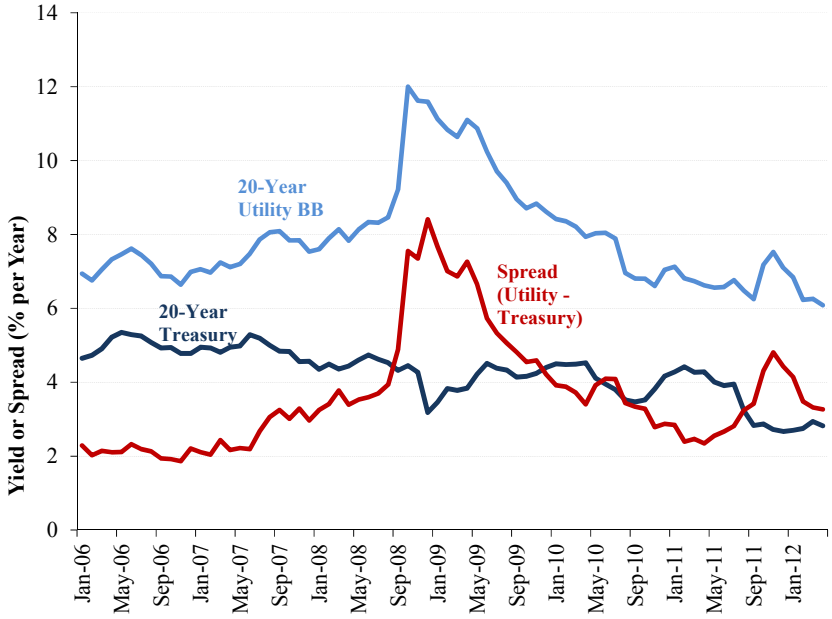
[84] See Krishnan (2012).
[85] See, for example, Wigglesworth and Dombey (2012).
[86] See, for example, Lonski (2012).

Figure 12
Spread Between 20-Year Utility BB Bonds and 20-Year Treasury Notes



Sources and Notes:
Yield is the annual return that a bond-holder will earn.
Spread is the difference in yield between 20-Year Utility BB Bonds and 20-Year Treasuries.
Bloomberg (2012).

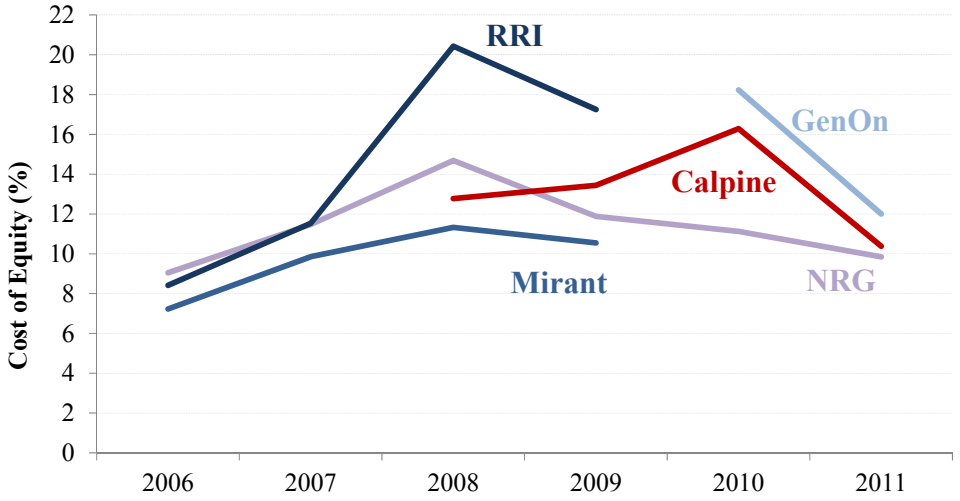
Additionally, while in the pre-crisis era it was typical for project-financed plants to be structured with maturities in excess of 15 years, lenders' interest in such long maturities has waned in recent years, and is now strictly bounded by PPA and or hedge availability.

2. Public Equity Markets

The cost of equity has returned to levels similar to those before the financial crisis and lower than a year ago. A readily visible indicator of this reduction is the estimated cost of equity for publicly-held IPPs. For example, Figure 13 shows the cost of equity for NRG, Calpine, and GenOn (including its predecessor companies RRI and Mirant).[87] While each company has a number of idiosyncratic issues that have affected its cost of capital, we see that overall for the group, the cost of equity reached the mid-teens in 2008 during the financial crisis. Now, these companies' equity costs have receded to pre-crisis levels of approximately 10% to 12%, thereby improving the prospects for investments in ERCOT.[88]

[87] As estimated by Bloomberg (2012).
[88] The companies' share prices and price-to-earnings ratios, however, have been held down by current and expected low energy margins, see, for example, Dow Jones (2012).

Figure 13
Estimated Cost of Equity for Calpine and NRG



Sources and Notes:

Cost of equity estimated by Bloomberg by using the capital asset pricing model with the current risk-free rate, standard beta estimates, and the most recent market risk premium provided by Ibbotson.

RRI and Mirant merged to form GenOn in 2010, see GenOn (2010).

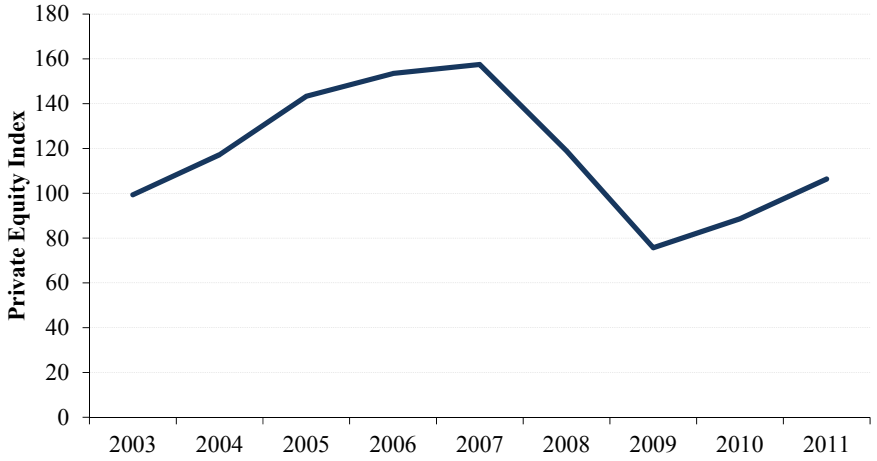
Data from Bloomberg (2012), as of May 15, 2012.

3. Private Equity

Similar to these trends in public equity markets, investment interest from private equity firms has started to recover since the financial crisis in 2008, albeit less robustly than for public shareholders The Private Equity Growth Capital Council, a private equity trade organization, reported approximately $120 billion in private equity investment volume over the four quarters ending in March 2012, up from approximately $55 billion in 2010, and down from approximately $220 billion in 2006.[89] Private equity investments in electric generation have been relatively prolific, and some in the industry now observe an excess of investor interest relative to the number of attractive investment opportunities.[90] Figure 14 shows a private equity index that tracks the health of the private equity sector incorporating measures such as private equity deal volume, equity contributions, private equity fundraising, and exit volumes. The index shows that although investment dropped steeply after the financial crisis, it has been recovering since 2009.

[89] See Private Equity Growth Capital Council (2012), p. 2.
[90] See Power Intelligence (2011).

Figure 14
Private Equity Index



Source:
Private Equity Growth Capital Council (2012).

Private equity investors are generally oriented to higher risks and returns than are public shareholders and may therefore have greater sensitivity to debt availability. This means that the current anemic state of debt markets may be the greatest challenge for private equity investments.

D. Implications for Generation Investment in ERCOT

1. Ability to Finance Plants without Long-Term Contracts

The ERCOT portion of Texas transitioned from a cost-of-service regulated market to a deregulated market over 1996 to 2002.[91] This is important for resource adequacy, because retail market design affects LSEs' willingness to sign long-term contracts with generators. In regulated markets, the vertically-integrated utility has a long-term obligation to serve load and will procure supply in a portfolio that includes direct ownership and long-term contracts. Municipalities and cooperatives in Texas, which account for approximately 25% of ERCOT load, will plan supplies in this way and so are likely to support some generation development through ownership or long-term contracts.[92]

However, in the restructured retail space covering 75% of ERCOT load represented by approximately 179 REPs, customers are no longer bound to a specific REP and may switch suppliers at any time, subject to contractual terms.[93] Small retail customers typically sign contracts with a particular REP for up to a year or occasionally two; the largest commercial and industrial (C&I) customers typically sign contracts with 1- to 5-year durations. Without captive load, REPs in Texas similarly limit most of their procurement to less than 3 years, and only to the extent they have promised fixed rates to their customers (as opposed to indexed rates). Signing longer-term supply contracts would put the REP at risk of having above-market

[91] Kiesling and Kleit (2009), pp. 28–36.
[92] See ERCOT (2012i), p. 6.
[93] See ERCOT (2012c), p. 15.

purchase contracts with no offsetting sales positions. Consequently, most new generation developments in ERCOT will not be able to obtain the revenue certainty of a long-term PPA. While generation developers can procure a long-term hedge from a bank or power marketer, banks told us that since the financial crisis they have generally been unwilling to offer hedges longer than 5 years. Developers, therefore, must absorb more of the investment risk.

While all investors would prefer to have the security of a long-term buyer, the lack of long-term PPAs does not mean that generation projects cannot be built in ERCOT. It may be difficult or impossible for small, undiversified developers to debt finance their projects without a PPA, but projects can still be financed by larger, diversified IPPs that use balance sheet financing. For these reasons, investments in ERCOT will incur higher financing costs than regions with regulated retail markets, and many smaller, undiversified investors may be precluded from ERCOT's market.

2. Impact of Market and Regulatory Structure on Financeability

There is a fundamental difference in the financing and investment conditions between: (1) regulated regions, where customers bear the risks of potentially uneconomic investments; and (2) restructured markets, where suppliers take on these risks. Regulated systems use integrated planning with cost recovery to support investments; the integrated utility procuring the needed supplies through either direct investments or through long-term contracts with IPPs. Shifting risks to customers makes investing in regulated markets an attractive option for IPPs if they are able to find a long-term contracting opportunity; this also enables them to reduce their financing costs. Municipalities and cooperatives in Texas operate under this regulated model, as do state-regulated utilities throughout SPP, most of WECC, most of MISO, and the Southeastern Electric Reliability Council (SERC).

Restructured markets, on the other hand, use market-based mechanisms to attract investments, thereby placing the risk of uneconomic investment decisions on suppliers. Because long-term contracts are generally unavailable in restructured markets, suppliers bear substantially higher risks and financing costs than in regulated systems. Among restructured markets, there are a range of market designs for providing investment incentives to suppliers, from energy-only markets such as in Texas and Alberta, to forward capacity markets as in PJM and ISO-NE.[94]

Many generators in ERCOT stated in our interviews that the energy-only market is excessively volatile and uncertain, and that they would prefer that ERCOT adopt a structure with more forward price certainty, such as a forward capacity market. Interestingly, in our recent review of PJM's forward capacity market, we heard many similar concerns about capacity price volatility and uncertainty.[95] A number of PJM suppliers proposed to extend the forward period of the capacity market, or extend the capacity market into long-term products reminiscent of long-term PPAs or a regulated planning construct. After considering these market participants' arguments and analyzing the overall volatility in returns in both energy-only and capacity markets for a number of clients, our view is that energy-only markets are somewhat more volatile, uncertain, and difficult to model than capacity markets and will likely require somewhat higher projected

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[94] For a comprehensive discussion of this range of market designs for resource adequacy, see Pfeifenberger, Spees, and Schumacher (2009).

[95] See Pfeifenberger, Newell, Spees, *et al.* (2011).

returns to attract investment. This view is also consistent with some of the ERCOT generators who have investment experience in both PJM and ERCOT.

Capacity markets will tend to reduce some year-to-year price volatility, largely because: (1) a portion of capital recovery is independent of power prices and weather, rather than to more-volatile realized conditions; and (2) forward capacity markets impose reliability requirements that will tend to keep the market at a more stable reserve margin and will therefore partially stabilize energy market prices. However, because both well-functioning capacity and energy-only markets tie investor returns to underlying market conditions, they place much greater risks on suppliers than do regulated market structures.

3. Estimated Cost of Capital and Range of Potential Investment Hurdle Rates

When making an investment in ERCOT, debt and equity investors will consider the minimum required return, called the cost of capital, needed to make the investment worthwhile. The project's cost of capital is the opportunity cost for a marginal investor—the rate of return that capital could be expected to earn with an alternative, equally risky investment. Because investment risks differ, investors will have a different required return for each type of project they consider. For example, an investor will have a relatively low cost of capital for a project built in ERCOT with a long-term PPA that provides a stable revenue stream. Alternatively, investors will face greater risk, and require a higher cost of capital, for a project fully exposed to market risks.

Most investments are financed by some combination of debt and equity. Generally, the riskier the investment, the less debt financing is available as a percentage of total capital. While established financial theory posits that the cost of capital of an incremental investment is independent of the capital structure of a particular asset, in practice the cost of capital is estimated by observing the proportions of debt and equity in a project or company and calculating the weighted-average cost of capital, typically on an after-tax basis.[96] Additionally, a number of smaller investors may also apply investment "hurdle rates" that exceed the cost of capital because of their greater sensitivity to volatility and more limited ability to diversify risks. While no data are publicly available on the hurdle rates for smaller, undiversified investors, they and their private equity partners have anecdotally reported higher required investment returns. Ultimately, however, such players may find it difficult to compete with larger companies who can manage and diversify risks more cost-effectively.

We estimated the after-tax weighted-average cost of capital (ATWACC) for a merchant generation project as we did in a recent study for PJM and as summarized in Table 7. We first calculated the ATWACC for a sample group of publicly-traded merchant generation companies using the capital asset pricing model and recent market data.[97] Then we added 40 basis points to the value-weighted average across companies consistent with our PJM study.[98] That adder

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[96] See Brealey, *et al.* (2011), pp. 472-488.

[97] See Spees, *et al.* (2011), pp 35-41.

[98] For fairness opinions that ranged from 7.1% to 12.0% see Cohen and Gordon (2010a), p. 7; Mirant and RRI (2010), p. 42; Cohen and Gordon (2010b), p. 7; Mirant and RRI (2010), p. 48; Dynegy (2010), p. 48; FirstEnergy Corp. and Allegheny Energy (2010), p. 85; FirstEnergy and Allegheny (2010), p. 84; and Duke (2011), p. 102.

brought our PJM estimate closer to the middle of a range of ATWACC estimates from equity analysts rendering the reviewed fairness opinions for merger and acquisition transactions in PJM. It was also intended to reflect the business risk of a merchant investment in PJM compared to the more diversified and partially hedged portfolio of the larger companies for which we calculated an ATWACC. Consistent with financial market conditions that have lowered financing costs since we estimated the cost of capital for PJM a year ago, the result of our updated ATWACC estimate for a merchant generation project is 7.6%.

Table 7
ATWACC Estimates for a Portfolio of Merchant Generation Companies

	Cost of Equity *(%)* [1]	Cost of Debt *(%)* [2]	Debt-to Equity Ratio [3]	Tax Rate *(%)* [4]	ATWACC *(%)* [5]
Value-Weighted Portfolio Average	10.69%	7.68%	58/42	40%	7.2%
Estimated Merchant Project Parameters	**10.80%**	**7.68%**	**50/50**	**40%**	**7.6%**

Sources and Notes:
Data source is Bloomberg (2012) as of 4/2012.
Estimated merchant ATWACC represents the value-weighted portfolio average of Calpine, Mirant, RRI, and NRG. We added 40 basis points to the portfolio average, as explained above.
[1] Risk free rate for U.S. Treasuries plus a risk premium, defined as the portfolio beta multiplied by the market premium, see Brealey, *et al.* (2011), p. 193.
[2] Each company in the portfolio's bond yield, weighted by its 5-year average long-term debt
[3] Each company in the portfolio's 5-year average debt-to-equity ratio, weighted by market capitalization
[4] See KPMG (2010), p. 26.
[5] [1] x [3] + [2] x [3] x (1 – [4]), see Brealey, *et al.* (2011), p. 216.

However, some ERCOT investors we interviewed suggested that a significantly higher cost of capital may be appropriate for ERCOT due to the greater pricing uncertainty of an energy-only market. For these reasons, we also report two higher estimates. First, we considered the 9.6% ATWACC assumption that ERCOT used for long-term planning a year ago, although cost-of-capital estimates have declined since ERCOT developed its estimate.[99] To be consistent with ERCOT's assumptions and generators' filings with the PUCT, we use this as our "base case" hurdle rate for our analysis in Sections III and IV.[100] Second, through our investor interviews, we found that at least some investors claim that the investment hurdle rate for merchant generation investments in ERCOT is even higher. We therefore also provide a "high" estimate for investment hurdle rates of 11% based on these investors' statements. Table 8 summarizes these three estimates.

[99] See ERCOT (2012p).
[100] See PUCT (2012a), Item Number 87, p. 1 and ERCOT (2012p).

Table 8
Range of Investor After-Tax Hurdle Rate Estimates

Low	7.6%	2012 average for publicly held IPPs (NRG, Calpine, RRI, and Mirant)
Mid	9.6%	2011 ERCOT Long-Term Planning assumption
High	11.0%	Based on generator investor interviews

Sources and Notes:
Mirant and RRI merged in December 2010 to form GenOn. Our analysis spans the time period before and after the merger, prior to which RRI and Mirant are tracked as separate companies and after which our reported results reflect the performance of the merged company.

4. Estimated Cost of New Entry

We estimated the cost of new entry for new gas CT and CC plants based on our recent CONE study for PJM.[101] That study identified the most efficient configuration for simple-cycle and combined-cycle gas-fired plants and included a bottom-up estimate of the cost of building and operating such plants. For the purposes of the present study, we assume that the appropriate reference technologies in ERCOT are similar to those in PJM, including: (a) a 390 MW CT plant with 2 7FA.05 turbines and a 10,300 Btu/kWh heat rate; and (b) a 656 MW, 2x1 CC plant with 7FA.05 turbines, a 7,000 Btu/kWh heat rate, and duct firing.

We adjusted our overnight capital cost estimates to account for locational cost differences between Illinois and Texas using locational cost inflation factors that R.W. Beck developed in its study for the U.S. Energy and Information Administration (EIA).[102] Texas has a lower cost index than Illinois due to factors including labor productivity and rates, taxes, delivery charges, and weather-related construction interruptions. We did not adjust for differences in electrical network upgrade costs allocated to the developer. Table 9 summarizes our resulting CC and CT capital cost estimates for ERCOT.

Table 9
Gas CT and CC Capital Cost Estimates

	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*
June 1, 2015 Online Date (2015$)				
CT Capital Cost	$260.0	390	$667.4	$15.2
CC Capital Cost	$523.6	656	$798.2	$16.0

Sources and Notes:
See Spees, *et al.* (2011) and EIA (2010).

To determine the expected annual revenues that a merchant generator in ERCOT would require on an investment, we levelized these capital and FOM costs over a 20-year economic plant life after considering the financing costs of that investment. Such levelized costs are often the basis

[101] See Spees, *et al.* (2011).
[102] See EIA (2010).

for the contract price in long-term power purchase agreements, which may be structured as annual payments that are constant over the contract duration, or as annual payments that increase over time.

We estimate the annual CONE using a "level-real" cost recovery path, which reflects levelized payments that are constant in inflation-adjusted real terms, representing an implied assumption that net market returns will increase with an estimated 2.5% annual inflation rate.[103]

Table 10 shows the resulting range of CT and CC CONE estimates in ERCOT based on the range of financing cost estimates from Section II.D.3 above. We use this range of CONE estimates to evaluate the attractiveness of incremental investments in ERCOT compared to potential project revenues in Sections III and IV.

Table 10
Range of Level-Real Cost of New Entry Estimates

		Low	Mid	High
ATWACC	*(%)*	7.6%	9.6%	11.0%
CT Cost of New Entry	*($/MW-y)*	$90,100	$105,000	$116,000
CC Cost of New Entry	*($/MW-y)*	$112,400	$131,000	$145,000

III. CURRENT MARKET OUTLOOK

This section analyzes current market activity to assess progress in attracting new investment in ERCOT. We focus on trends in futures prices, stakeholder perceptions of the current market, and recent developments in resource additions.

A. TRENDS IN FUTURES PRICES

Futures prices provide valuable insights into market participants' expectations about future market conditions and about their willingness to place bets today based on those expectations. Figure 15 shows recent spot prices and futures prices for natural gas and on-peak energy. Gas prices increase only moderately from current lows to about $4/MMBtu for delivery in 2014, remaining far below prices from 2008 and earlier. Annual average on-peak energy futures also increase from $36/MWh in 2012 to about $47/MWh for delivery in 2014, with most of the increase occurring in July and August when hot weather can cause spot prices to spike. The market appears to be anticipating such spikes to increase between 2012 and 2014 as projected reserve margins tighten. However, the market does not appear to be anticipating price spikes as severe as in August 2011, when unusually extreme weather caused real-time prices to reach the $3,000/MWh cap in 19 hours and raised the monthly on-peak average price to more than $200.[104] Outside of the summer months, on-peak energy futures remain below $40/MWh.

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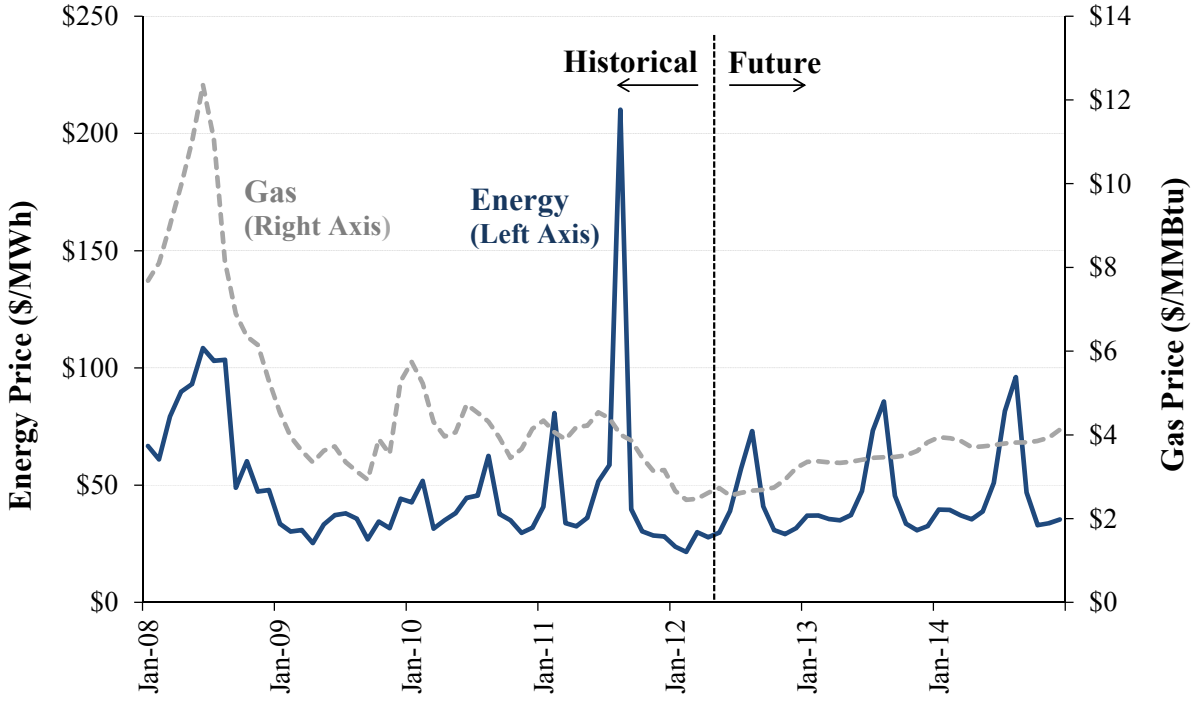
[103] See Spees, *et al.* (2011), Section VI.A. for inflation discussion and Section VII.C. for levelization discussion.

[104] Ventyx (2012).

Figure 15
Monthly Gas and On-Peak Energy Prices



Sources and Notes:
On-peak power at ERCOT North Hub; Gas at Houston Ship Channel.
Historic gas and power prices from Ventyx (2012).
Futures prices shown as of 5/25/2012. Power futures from Platts (2012); gas futures from Ventyx (2012).

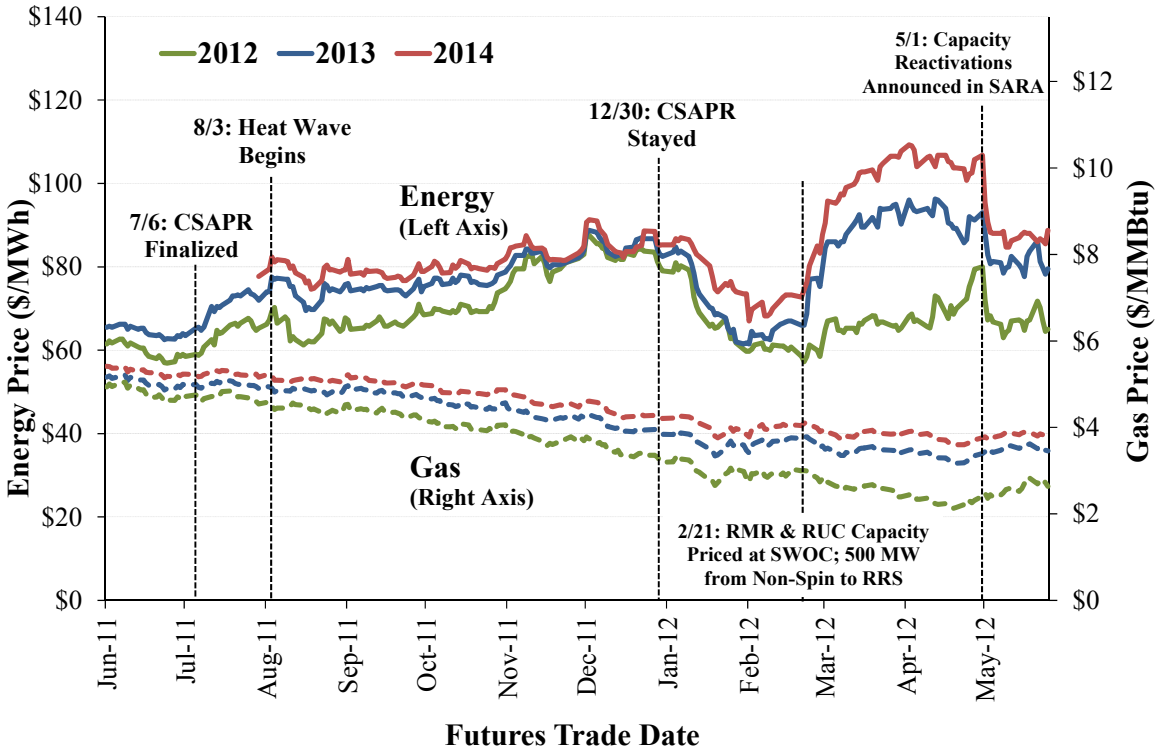
Figure 16 focuses on futures prices for just July and August delivery. By showing futures prices on the y-axis and the trade date on the x-axis, the figure illustrates how market participants' valuations of the same future product evolved over time. Prices for energy futures generally increased even as gas futures decreased. For example, power futures for delivery in July and August 2013 (in solid blue) traded at $66/MWh in June 2011, but increased to $80/MWh by May 2012, while gas futures for July and August 2013 delivery (in dashed blue) fell from $5.2/MMBtu to $3.5/MMBtu.

In order to remove the effect of gas prices and isolate the effect of anticipated market tightness on power prices, Figure 17 shows implied market heat rates. Implied market heat rates are calculated as the power price divided by the gas price. The result is that implied market heat rates increased even more than energy prices.

We believe implied market heat rates increased because the resource adequacy challenge facing ERCOT became more apparent, and because the PUCT and ERCOT enacted reforms that will increase the likelihood and magnitude of scarcity pricing. Futures market heat rates were stable in June 2011; then began to increase following the finalization of CSAPR in July and the heat wave and scarcity prices in August. We heard from market participants that witnessing sustained high prices without regulatory intervention substantially increased market confidence. Market heat rates increased throughout Autumn as the PUCT considered market reforms to better reflect scarcity, fell in January following the stay of CSAPR, and then rose steeply following the PUCT's approval of several market reforms in late February. Market heat rates fell in early

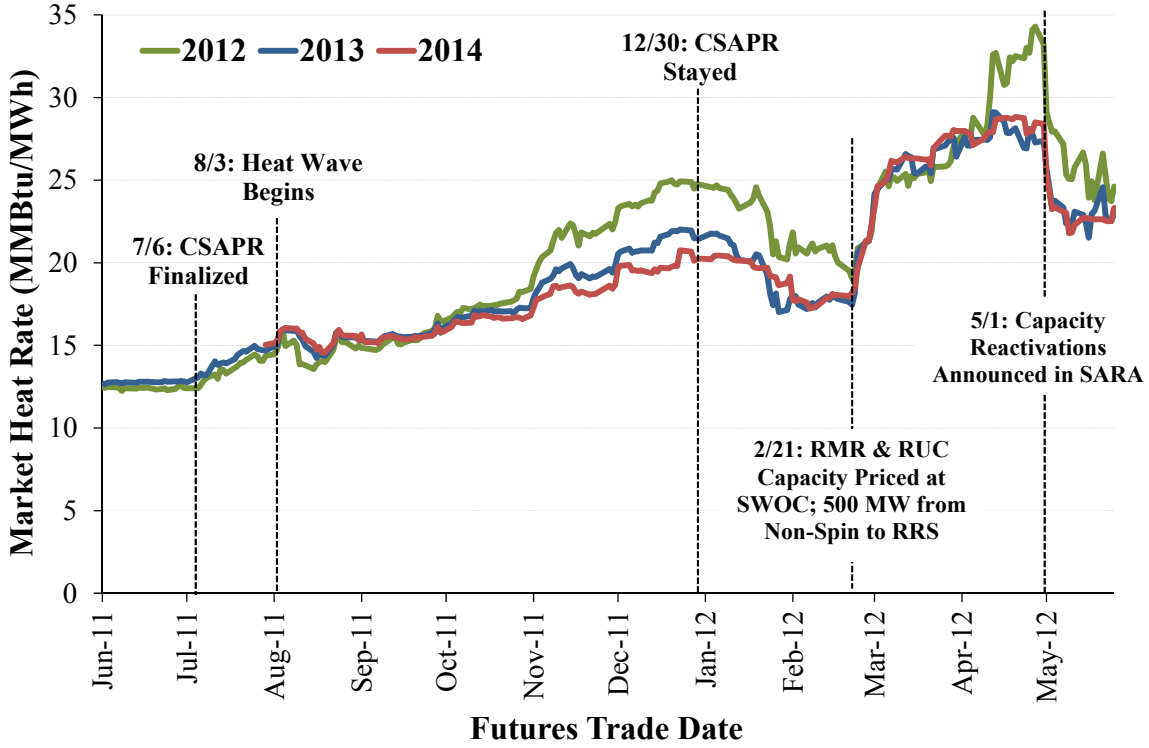
May, and some market participants attributed this to the announcement of capacity reactivations in the Seasonal Assessment of Resource Adequacy (SARA), as discussed further in Section III.D. Overall, expected heat rates for peak summer periods have nearly doubled since ERCOT's resource adequacy challenge emerged in summer 2011.

Figure 16
Futures Prices for July-August Delivery of Gas and On-Peak Energy Futures



Sources and Notes:
On-peak energy at ERCOT North Hub, from Ventyx (2012). Gas at Houston Ship Channel from Platts (2012).

Figure 17
Implied Market Heat Rates for July–August Delivery



Sources and Notes:

Market heat rate calculated as electric price divided by gas price.
On-peak power at ERCOT North Hub, from Ventyx (2012); gas at Houston Ship Channel, Platts (2012).

B. Comparison of Futures Prices to CONE

Increasing futures prices indicate an improving environment for investment but do not necessarily mean that prices will be high enough to attract new power plants. We use two approaches to evaluate whether futures prices indicate that market participants believe market prices will be high enough to support investment in new gas-fired combined-cycle (CC) power plants.[105] First, we use a simplified approach similar to that used by generation representatives in a recent PUCT filing in which they estimated a generic CC's annual energy margins based on futures prices.[106] We multiply monthly on-peak and off-peak spark spreads for a CC with a heat rate of 7 MMBtu/MWh by the number of on-peak and off-peak hours each month.[107] This approach indicates that a CC would earn $97/kW-year based on 2013 forward prices, and $95/kW-year based on 2014 prices.[108] These margins are below the levelized cost of new entry (CONE), which we estimate to be $112-145/kW-year, as calculated in Section II.D.4.

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[105] Estimating whether futures prices support investment in a CT would require forward prices for super-peak products, for which we do not have visibility.

[106] See Group of Competitive Texas Generators (2012). Their approach assumed a constant $4/MMBtu gas price and did not consider off-peak futures, as well as other minor differences.

[107] Negative spark spreads are excluded. Based on 4,100 on-peak hours and 4,660 off-peak hours per year.

[108] Based on futures traded 5/25/2012.

Second, we estimate energy margins using a virtual dispatch against hourly prices consistent with futures. This more sophisticated approach reflects the additional market value introduced by price variations throughout the day and month that will result in greater margins for a plant that can operate during profitable hours and shut down during unprofitable hours. We also account for the negative impact of operating constraints and costs not captured in the simplified spark spread estimate described above.

To add a realistic amount of hourly price volatility around average monthly on-peak and off-peak futures, we apply heat rate shapes observed in the real-time market over 2008-2011, and in the 2011 day-ahead market (while maintaining consistency with futures prices on an on-peak and off-peak monthly-average basis). We then estimate a generic CC's energy margins using a virtual dispatch against the hourly prices, accounting for: (a) startup and ramping costs; (b) minimum up and down time constraints; (c) variable operations and maintenance costs; (d) forced and planned outages; and (e) minimum load, baseload, and maximum load with duct firing operating modes. Table 11 shows the energy margins and capacity factors estimated with each of the five modeled price shapes.

This approach indicates that a CC may be expected to earn approximately $91/kW-year based on 2013 futures, and $93/kW-year based on 2014 futures. These energy margins are slightly lower than those estimated without accounting for price volatility or operational characteristics, and are still below CONE. Overall, it appears that there is a substantial gap between market expectations about future energy prices and the prices needed to attract new combined-cycle power plants. At these levels, we would not expect market participants to invest in generic new combined-cycle capacity in ERCOT at least through 2014.

Table 11
CC Energy Margins Based on Virtual Dispatch

	2013 Futures		2014 Futures	
Virtual Dispatch Price Shape	Energy Margins *($/kW-y)*	Capacity Factor *(%)*	Energy Margins *($/kW-y)*	Capacity Factor *(%)*
2011 DA	85	67%	91	59%
2011 RT	94	53%	101	46%
2010 RT	92	56%	98	51%
2009 RT	95	59%	102	56%
2008 RT	97	61%	104	58%
Average	**93**	**59%**	**99**	**54%**

Sources and Notes:
Calculated based on futures with a trade date of 5/25/2012.
Platts (2012) and Ventyx (2012).

C. Stakeholder Perceptions of the Futures Market

In our interviews, we asked market participants to share their perceptions of the forward market in ERCOT. Potential generation investors emphasized that the two- to three-year horizon of futures prices is not long enough to support investment in an asset with a lead time of three years and an operating life of several decades. They stated that futures prices are, however, a helpful indicator showing that prices are not yet high enough to support new investment, a statement that is consistent with our own analysis. They also claimed that, while recent market reforms are a step in the right direction, future scarcity pricing conditions may be too rare and unpredictable to support investment. We note however, that these statements must be taken in context and that the true test of generators' willingness to invest will be whether they actually move ahead with projects once prices are consistent with CONE.

Some generators commented that 2013 and 2014 futures are probably underpriced relative to what actual spot prices will be. They observed that despite expectations of a lower reserve margin and a tighter market, Summer 2013 and 2014 forward heat rates are not higher than 2012 heat rates, as shown in Figure 17. A discount in futures prices could be introduced because REPs generally focus their hedging activities only on the upcoming Summer, leaving very few buyers for futures in later years. Further, the futures market may not fully reflect new rules whose implications for prices are difficult to model.

Stakeholders also stated that liquidity in futures markets is currently low, especially for super-peak products. We have heard this anecdotally but do not have data to support or refute this claim. We suspect that current regulatory uncertainty may be reducing liquidity, as both buyers and sellers are reluctant to enter transactions while the PUCT deliberates important market reforms. Some stakeholders blamed the low liquidity on high price caps, but we expect that high price caps could actually increase liquidity for peaking products as REPs become more motivated to take fully hedged positions and avoid excess exposure to extreme prices. We believe that concerns about forward markets will diminish over time as uncertainties resolve and market participants' hedging strategies adapt.

D. Observed Developments in Resource Investment

While futures prices are likely not high enough to support new greenfield generation investment, price increases expected from market reforms and declining reserve margins have attracted some low-cost, short lead-time investments such as uprates and reactivations of mothballed units. For example, generation owners have already reactivated or announced the reactivation of nearly 2,000 MW of mothballed capacity for Summer 2012.[109] Additionally, in April, Calpine announced two combined-cycle expansions totaling 520 MW.[110] Notably, these combined-cycle expansions cost less than $550/kW, giving them a substantial economic advantage over a new combined-cycle plant at approximately $800/kW.[111] The economic advantage of Calpine's two uprates is further enhanced by associated plant-wide efficiency improvements of 5% and 17% respectively that effectively lower the relative cost of the uprates even further. Based on generation owners' comments in our interviews, we expect additional low-cost uprates and

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[109] See ERCOT (2012m) and (2012t).
[110] See Calpine (2012).
[111] See Calpine (2012). CC overnight cost from Section II.D.4 above.

reactivations to come online before 2014. These owners, however, may be reluctant to announce investment plans while the PUCT is actively considering whether to increase price parameters in response to an expected capacity shortfall. Beyond these reactivations and expansions, no major units are currently under construction.[112] Furthermore, several permitted projects which were expected to have already begun construction are now on hold and will not be completed until 2015 at the earliest.[113]

IV. LONG-TERM RESOURCE ADEQUACY OUTLOOK

This section describes how we estimate the "economic equilibrium" reserve margins that ERCOT's market structure is likely to achieve under current and proposed price caps. Our primary finding is that increasing the price cap to $9,000 will attract more investment, but ERCOT is still likely to fall substantially short of its current reliability target until several thousand megawatts of additional demand response are able to prevent load shedding without eliminating scarcity prices. In addition, we anticipate substantial uncertainty and year-to-year variability in the reserve margin that the current market structure will achieve.

A. METHODOLOGY

We estimate an "economic equilibrium planning reserve margin" at which generation developers would be willing to invest, using the following methodology. First, we simulate the energy margins that a new GE 7FA simple-cycle CT would earn over a range of planning reserve margins.[114] Next, we compare these energy margins to the levelized cost of new entry (CONE) that a new plant must expect to earn on average over many years to attract investment, as estimated in Section II.D.4 above. Finally, we identify the highest planning reserve margin at which energy margins exceed CONE. This represents the economic equilibrium reserve margin that the energy-only market is likely to produce on a long-term average basis.

We use outputs from ERCOT's Loss of Load Expectation (LOLE) Model to estimate the frequency of involuntary load shedding and high-priced scarcity events at each potential planning reserve margin. We estimate generators' net revenues over a range of reserve margin as a sum of three components: (1) energy margins earned during scarcity events, based on the frequency of scarcity events indicated by the LOLE model; (2) non-scarcity margins, which are a function of both reserve margins and gas prices; and (3) adders to non-scarcity margins that we expect from recently-implemented market rules, based on ERCOT's recent backcasting analyses.

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[112] See ERCOT (2011f), p. 16, Total Future Non-Wind Resources. We exclude Sandy Creek 1, which completed construction but experienced an accident during testing in 2011.

[113] See ERCOT (2011b), p. 6. Pondera King Power Project, Las Brisas Energy Center, and Coleto Creek Unit 2 have delayed their commercial operations dates.

[114] We focus on a simple-cycle combustion turbine rather than a combined-cycle for simplicity, although we estimate that both would be economic in equilibrium. Specifically, we focus on a GE7FA-based simple-cycle combustion turbine, which has a large turbine with significant economies of scale compared to aeroderivative models, and a much lower cost per kW.

1. Generator Energy Margins During Scarcity Conditions

ERCOT's Loss of Load Expectation Model. We rely on ERCOT's LOLE model to project the frequency of load-shedding events and scarcity events that will trigger scarcity prices. This model estimates the frequency of scarcity events when extreme weather-driven load and high generation outages coincide. Probability distributions of load and generation, including the tails of those distributions, drive the simulated frequency of scarcity events. ERCOT provided simulations using several different weather-driven load profiles (each 8,760 hours), with thousands of random draws on generation outages for each load profile. A primary output is the frequency of load-shed events (when total supply is insufficient to meet demand) expected at a given planning reserve margin, which ERCOT usually uses to identify the reserve margin that achieves the reliability target. However, it is similarly useful to us for estimating the frequency of various levels of scarcity prior to load shedding. We incorporate load shedding and other metrics that we translate into scarcity pricing events (as described below) over several model runs representing a large range of planning reserve margins.

To support our study, ERCOT's planning department provided simulation results using the same modeling assumptions and input data used to develop their most recent LOLE study in 2010.[115] ERCOT staff made only one update to the LOLE model for the purposes of our study, modeling fifteen years of weather data from 1997 to 2011, rather than modeling five representative weather years selected from 1996 to 2010. Importantly, this update allows the LOLE model to account for the extreme conditions experienced in 2011. After including 2011 weather data, a 15.25% planning reserve margin is needed to achieve the "one loss of load event in ten years" (0.1 LOLE) reliability target, which is greater than ERCOT's currently approved 13.75% target. Because ERCOT is in the process of implementing several model enhancements regarding wind generation and unit availability, and because the reliability estimate is highly sensitive to assumptions regarding weather weights (as explained further below), the results we report here will not exactly match those that will be reported in ERCOT's forthcoming updated LOLE study. Our estimated reserve margin needed to achieve the 0.1 LOLE target should not be interpreted as the new target for ERCOT.[116]

The choice of weather-years and the probability weights assigned to each year strongly affect the model results. We used 15 historical weather profiles spanning 1997 to 2011 and weighted each equally with a 1-in-15 chance of occurring (sensitivity analyses using different weights are presented later). Figure 15 shows the 2012 peak load estimate consistent with each of these 15 weather profiles as well as the 15-year average and the normal weather peak load estimate.[117] The peak load estimate based on 2011 weather is substantially higher than the peak load based on other years because 2011 weather was so unusually extreme. The extreme loads lead to more frequent scarcity events that would not exist in more typical weather years.

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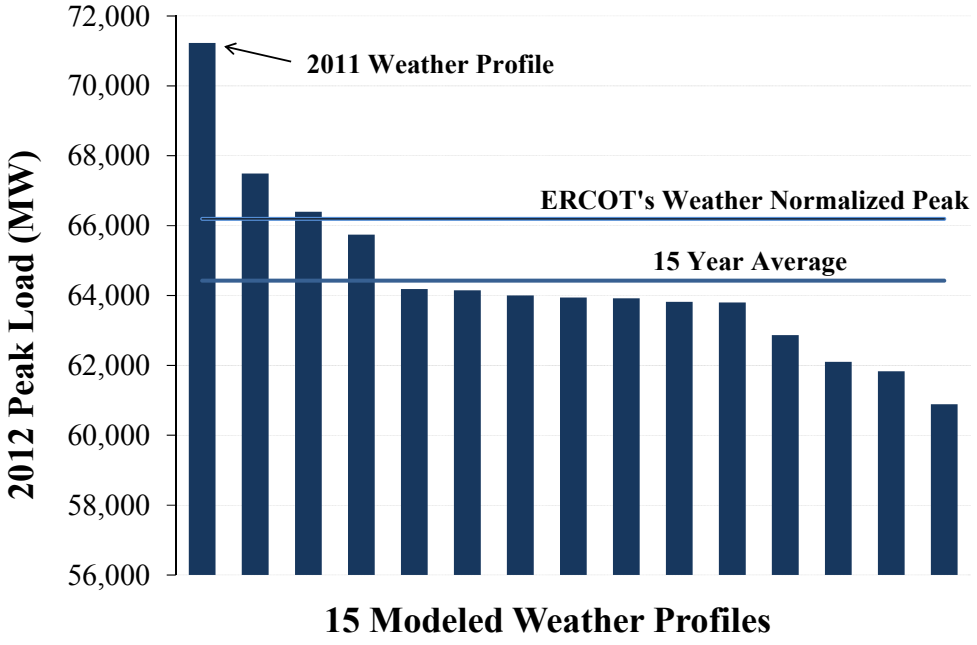
[115] See ERCOT (2010a).

[116] Furthermore, comparisons of our results to prior LOLE studies also must consider the following factors that have changed: the introduction of extreme 2011 weather; our recognition of 1,700 MW load over-forecast error during super-peak periods which reduces the incidence of load shedding and scarcity events; and ERCOT's new (higher) weather normalization methodology which increases weather-normalized load and therefore increases the amount of capacity implied by any given planning reserve margin.

[117] All loads modeled represent a 2012-sized economy in ERCOT. This one-year analysis is useful for our long-term equilibrium model because, although load would be higher in future years, we expect the relationship between reserve margin and scarcity events to remain approximately constant.

Figure 18
2012 Peak Load Estimate Under 15 Weather Profiles



Sources and Notes:
Data provided by ERCOT (2012a).
Consistent with load estimates under weather uncertainty provided in the *ERCOT Planning 2012 Long-Term Demand and Energy Forecast*, see ERCOT (2011h), p. 12.
ERCOT's current weather normalization methodology places its weather-normalized peak for 2012 substantially above the mean and median peak loads corresponding to the last 15 years' weather profiles imposed on a 2012 economy.

We translated the LOLE model outputs into scarcity prices in two steps. First, we recorded the frequency of hours in which the residual capacity falls below several levels of residual supply at each planning reserve margin analyzed. Second, we translated residual supply metrics into scarcity prices that are consistent with ERCOT's operations and its current and proposed scarcity pricing rules.

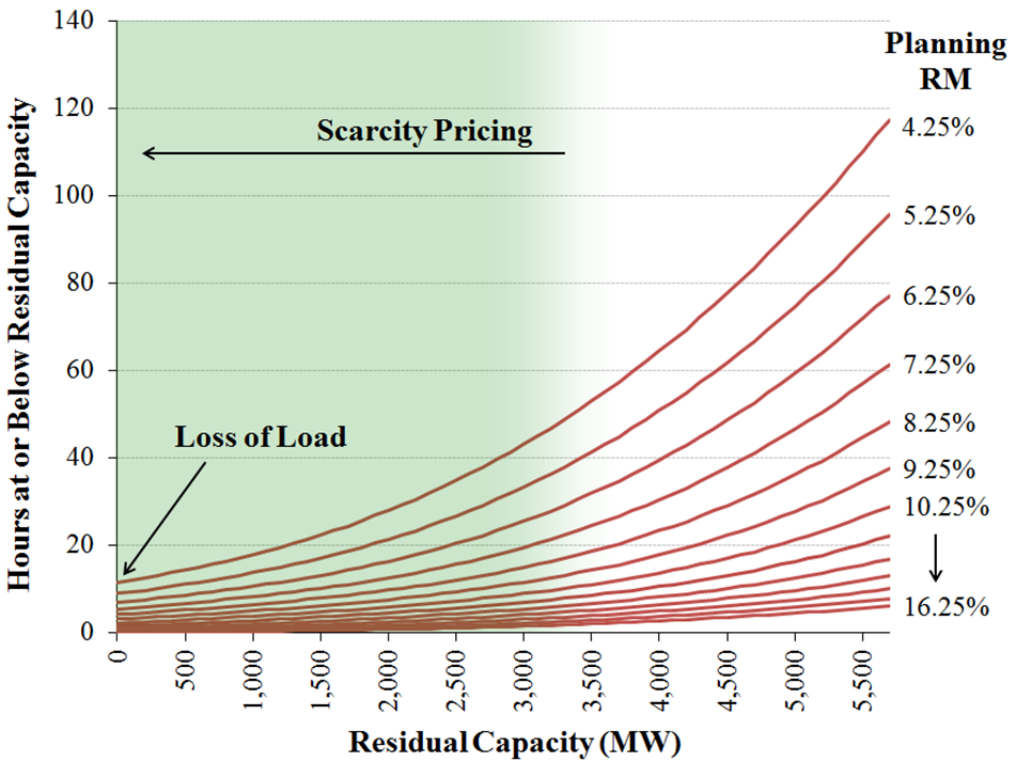
Frequency of low residual capacity. In each load hour and generation outage draw, the LOLE model calculates the residual capacity. For our purposes, we treat "residual capacity" as all available generation and controllable load response resources that ERCOT has not deployed, but could deploy to avoid shedding load. We record whenever residual capacity falls below certain low levels, at every 500 MW increment below 5,700 MW.[118] In interpreting the results, however, we adjust for demand elasticity during scarcity that is likely to occur in reality but is not accounted for by the LOLE model. Large industrial customers exposed to real-time prices are likely to reduce their consumption when prices spike, customers with four coincident peak (4CP) rate structures are likely to reduce consumption when they anticipate a 4CP interval, and the public may respond to emergency conservation appeals. Therefore, under scarcity

[118] Increments smaller than 500 MW are interpolated.

conditions, we adjusted the load downward, and therefore adjusted residual capacity upward. Our adjustment was 1,700 MW based on the observed error of ERCOT's load forecasting model at the 2011 peak load, when prices reached the $3,000/MWh cap, loads were likely anticipating a 4CP interval, and conservation appeals were in effect. This adjustment not only makes sense but also improved the calibration of our model, with scarcity event frequencies under 2011 weather and a 14% planning reserve margin close to those observed in 2011 under similar conditions.[119] However, the effects of this assumption on our analysis are tested in the sensitivity analyses presented in Section IV.

Figure 19 shows the projected number of hours with low residual capacity at varying planning reserve margins, averaged across the 15 modeled weather profiles. For example, at a 4.25% planning reserve margin, the LOLE model projects 120 hours with residual capacity less than 5,700 MW and 15 hours with zero residual capacity (*i.e.*, load shedding).[120] As expected, the frequency of load shedding and severe shortage events increases with lower planning reserve margins.

Figure 19
ERCOT's Loss of Load Expectation Model Projections



Sources and Notes:

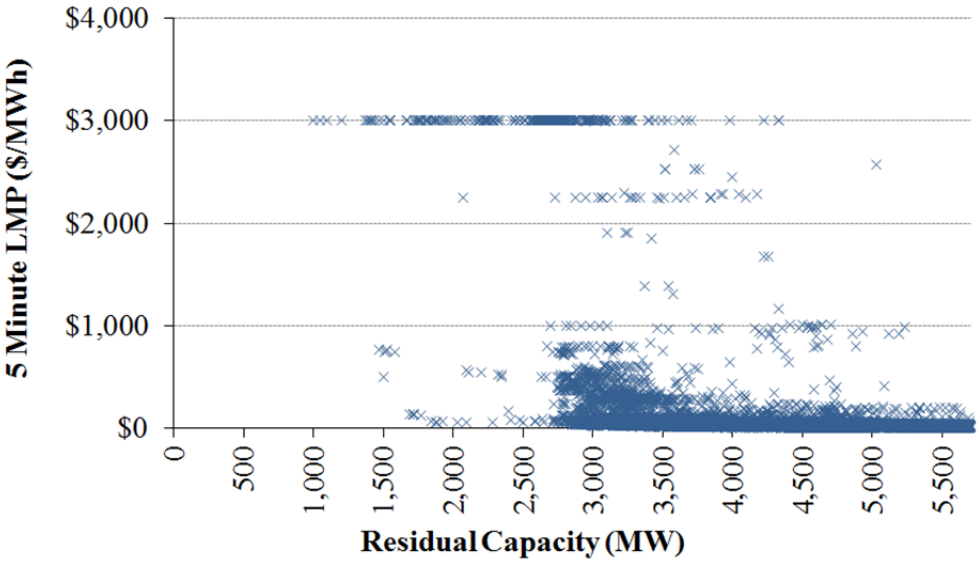
Data provided by ERCOT (2012a), adjusted to account for demand elasticity during scarcity.

[119] In fact, a comparison against actual 2011 data showed that this adjustment is likely an under-correction.

[120] The frequency of these scarcity events varies among the 15 weather profiles; the plot shows the average frequency among these profiles.

Translation of Low Residual Capacity into Scarcity Prices. To translate low residual capacity levels into estimates of scarcity pricing, we first examine the relationship between residual capacity and scarcity pricing observed in 2011. In 2011, scarcity pricing rarely occurred when residual capacity was high, and scarcity prices were triggered with increasing frequency as residual capacity declined, as shown in Figure 20.

Figure 20
2011 Pricing and Residual Capacity Patterns



Sources and Notes:

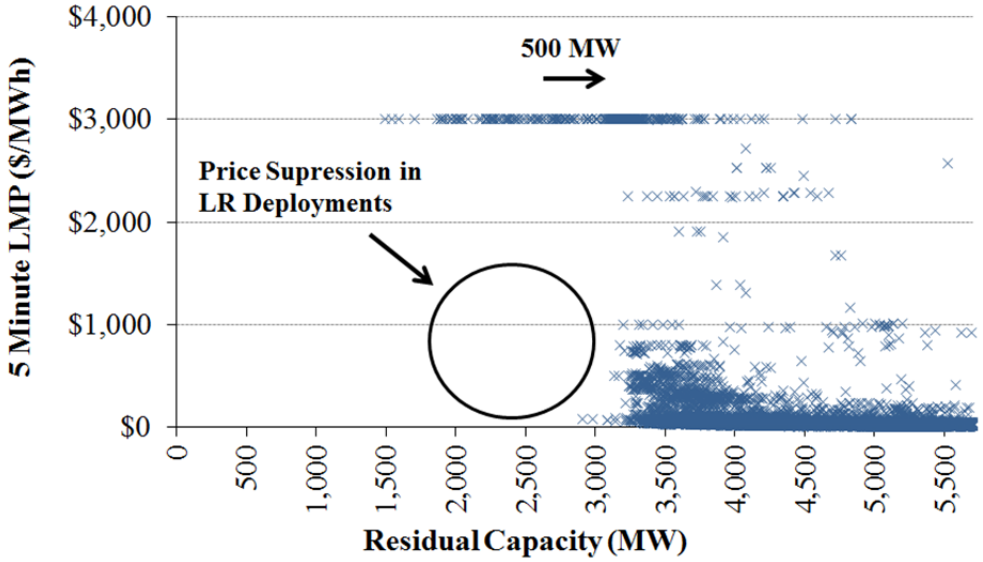
Data provided by ERCOT (2012a).

Residual capacity is calculated as Physical Responsive Capability + undeployed EILS, which is consistent with total residual capacity when all units are committed and transmission constraints are relaxed. This calculation was calibrated to check for consistency between historical data and comparable LOLE model results, and was validated by ERCOT staff to ensure consistent accounting of various resources.

We then adjusted the scarcity pricing patterns observed in 2011 to account for two reforms which will impact scarcity pricing in the future. The first reform is a 500 MW increase in responsive reserve capacity.[121] This will have the effect of triggering scarcity pricing earlier, when residual capacity is 500 MW higher, since the increase in responsive reserves will reduce the capacity available at prices below the system-wide offer cap and will essentially "widen the warning track" of scarcity pricing before load is shed. This effect is shown as a 500 MW shift to the right in Figure 21. The second reform is the proposed elimination of price suppression during load resource deployments.[122] There were several intervals observed in 2011 with very low residual capacity but with prices far below scarcity levels due to price suppression from the deployment of load resources. For example, many such intervals are apparent in the bottom-left corner of Figure 20, where prices remained below $1,000/MWh at a residual capacity of less than 2,500 MW. The effect of eliminating price suppression in these intervals is shown in the empty circle in Figure 21.

[121] See ERCOT (2012f), NPRR434, approved 02/21/2012.
[122] See ERCOT (2012f), NPRR444, pending with urgent status.

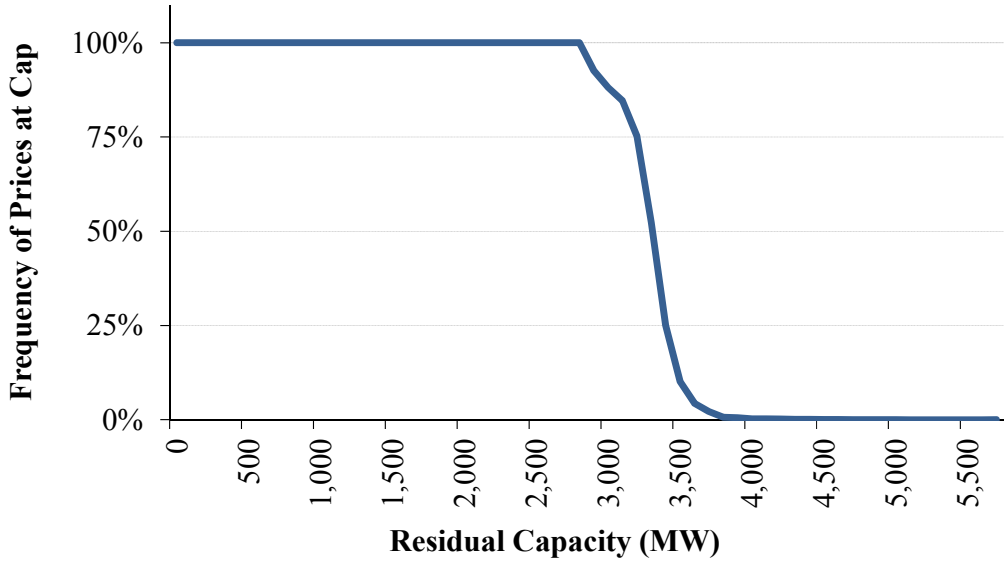
Figure 21
Impact of Reforms on Scarcity Pricing



Sources and Notes:
Data provided by ERCOT (2012a). *Brattle* Analysis.

After accounting for these reforms, we determined the frequency of prices at the system-wide offer cap for each residual capacity level, as shown in Figure 22. We then applied these frequencies to the outputs of the LOLE model to estimate the expected frequency of scarcity pricing. For example, with 3,500 MW of residual capacity, 8% of intervals have prices at the cap. Therefore, for each hour that the LOLE model projects a residual capacity of 3,500 MW, we apply an 8% chance that the price will be at the cap. (We used the same methodology to estimate the frequency of prices at various levels below the cap, down to $500/MWh).

Figure 22
Frequency of Prices at the Cap



Sources and Notes:
Data provided by ERCOT (2012a). *Brattle* Analysis.

Next, we account for the fact that generators would not be able to profit from all scarcity pricing intervals due to outages and operating constraints which can prevent them from capturing transient price spikes. We discount projected scarcity margins based on the generation patterns of actual combustion turbines in 2011 to calculate scarcity margins.

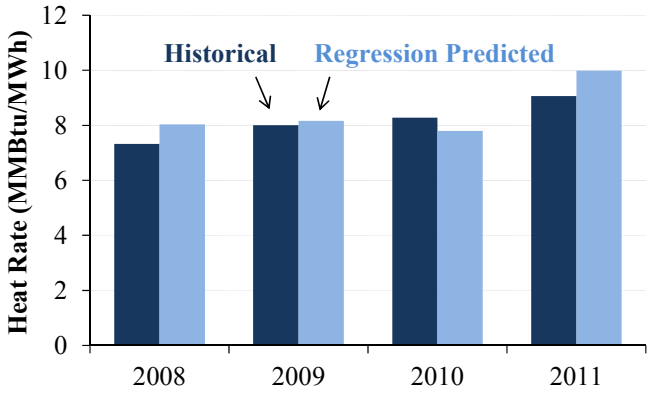
Finally, based on simulated residual capacity levels, our translation of residual capacity into prices, and our estimate of the fraction of such prices that a combustion turbine could capture, we estimate the energy margins a combustion turbine would earn. We do so at each planning reserve margin and each weather profile modeled in the LOLE model. We also calculate the *average* energy margins that a combustion turbine would earn over each of the 15 weather years.

2. Non-Scarcity Margins

The second component of our estimated energy margins is the margin a combustion turbine would earn during non-scarcity periods, when energy prices are less than $500.[123] We estimated non-scarcity margins using a regression analysis of historical data and applying the results to our forward-looking analysis at each potential reserve margin.

Our regression analysis relates hourly market heat rates to hourly reserve margins based on actual market data from 2008 through 2011. Hourly market heat rates are given by the ERCOT North real-time price divided by the daily natural gas price at the Houston Ship Channel. Hourly reserve margins are defined as the total installed capacity (each year) less the capacity unavailable due to outages each hour, divided by the actual hourly load net of wind generation.[124] We estimated this relationship using a segmented regression by partitioning the historical data based on the hourly reserve margin, and then estimating coefficients separately within each segment. This approach is a standard method,[125] and it allowed us to identify a steeper relationship between the market heat rate and reserve margins as reserve margins tighten. Figure 23 shows the result of the regression, comparing the average non-scarcity market heat rate predicted by the regression against actual historical averages.

Figure 23
Average Non-Scarcity Market Heat Rate



[123] We define non-scarcity margins as margins earned from prices less than $500. Margins earned at prices above this are defined as scarcity margins. For example, in an hour with a price of $3,000, we attribute $2,500 to scarcity margins, and $500 to non-scarcity margins. This avoids potential double-counting.

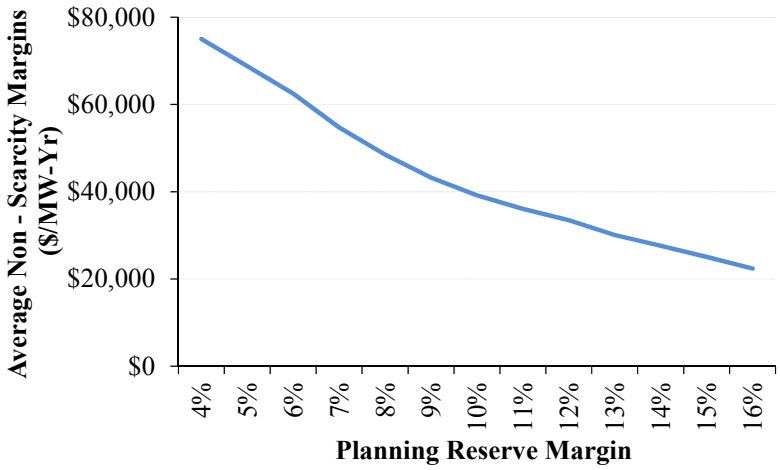
[124] ERCOT provided the hourly data on unit outages. Load data sourced from Ventyx (2012).

[125] See, for example, Boogert and Dupont (2008).

We then applied the results of the regression analysis to estimate energy margins going forward. We estimated market heat rates for each planning reserve margin and weather profile by applying the regression coefficients to hourly reserve margins (*i.e.*, total capacity less historical monthly average outage profiles, divided by forecast load net of wind generation). Based on these projected hourly market heat rates, we calculated energy margins based on a virtual dispatch against the hourly market heat rate, and a gas price of $3.5/MMBtu, which is the average forward price for 2013 delivery of natural gas at the Houston Ship Channel.[126] We accounted for start-up and variable operating and maintenance (VOM) costs.

Figure 24 shows the results of this projection at varying reserve margins, averaged across the 15 weather profiles. To account for the degree of uncertainty inherent in this type of projection, as well as uncertainty regarding future gas prices, Section IV.B.4 will present sensitivity analyses examining the effect of different non-scarcity margins on reliability outcomes.

Figure 24
Estimated Non-Scarcity Margins a CT Would Earn



3. Adders to Non-Scarcity Margins from New Rules

The third component of energy margins we estimated is "adders to non-scarcity margins from recently-implemented market rules." The impact of the recently approved ONRUC & non-spin price floors is not captured in historical non-scarcity margins, nor can it be estimated with the LOLE model because deployments of these resources are triggered by ramping and unit commitment issues, not true capacity shortages.

Non-Spin Price Floors — An ERCOT backcast analysis of 2011 estimated the impact of the non-spin price floors at less than $2,000 MW-year.[127] We assume a GE7FA-based combustion turbine would capture this amount every year, in addition to the scarcity and non-scarcity margins calculated above.

ONRUC Price Floor — We project margins for a GE7FA-based simple-cycle combustion turbine, which has a large turbine and is not as flexible as aeroderivative turbines. We

[126] Ventyx (2012). Futures traded 5/25/2012.
[127] ERCOT (2012j).

therefore assume they do not capture the RUC floor impact due to its brevity and unexpectedness. It is quite possible that this assumption is incorrect, and that a GE7FA combustion turbine would in fact capture some or all of the price floor impact. We find that assuming it would capture the price floor impact estimated by ERCOT's 2011 backcast analysis does not significantly affect the results of our simulations.

Based on the Independent Market Monitor's net revenue estimates, CC plants earned $20,000 – $30,000/MW-year more than combustion turbines from 2009 through 2011.[128] The difference in margins is similar to the difference in levelized cost of new entry between a CC and a CT, about $26,000/MW-year.[129]. A substantial rise in gas prices above 2009 – 2011 levels could improve the relative economics of a CC, as illustrated by CCs' revenue advantage of more than $50,000 MW-year during the high gas prices of 2008. However, both types of plants are likely to be economic in a long-term equilibrium.

[128] Potomac Economics (2012), and Potomac Economics (2011c).

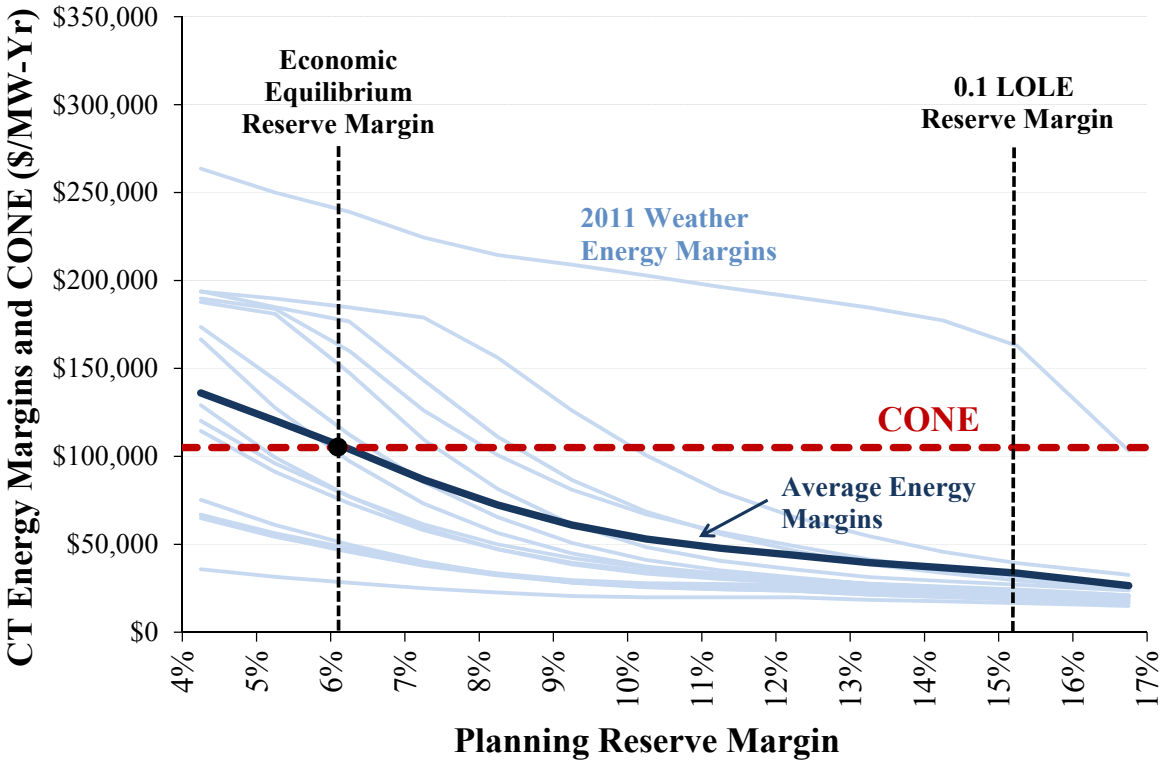
[129] Estimated CC CONE is $131,000 MW-Yr, estimated CT CONE is $105,000 MW-Yr. See calculations in Section II.D.4.

B. Estimated Reserve Margins this Market will Support

1. Economic Equilibrium Reserve Margins at Current Price Caps

To determine the economic equilibrium planning reserve margin, we combine scarcity, non-scarcity, and additional margins to estimate total energy margins, and then compare these to CONE. Figure 25 plots this comparison, with energy margins estimated under current price caps consisting of a $3,000/MWh High Cap (HCAP), a $500/MWh Low Cap (LCAP), and a $175,000/MW-year Peaker Net Margin (PNM) threshold which triggers the LCAP. At each planning reserve margin, the figure shows total energy margins for each of the 15 weather profiles (in light blue), average energy margins across the 15 profiles (in dark blue), and CONE (in red). Energy margins are greater at lower planning reserve margins, and are consistently greater than average with the extreme weather of 2011.

Figure 25
Economic Equilibrium with Current Price Caps



The economic equilibrium is the highest planning reserve margin at which total energy margins exceed CONE. With current price caps, the projected economic equilibrium planning reserve margin is 6.1%, which is more than 9 percentage points short of the 15.25% planning reserve margin needed to achieve the 0.1 LOLE target, assuming each of the past 15 years' weather patterns are equally likely. At this equilibrium planning reserve margin of 6.1%, ERCOT is projected to experience 2.2 loss-of-load events, 7.0 loss-of-load hours, and 35 hours with prices at the cap, on an annual average basis. In a worst-case year with the extreme weather of 2011, 27 loss-of-load events, 92 loss-of-load hours, and 248 hours with prices at the cap are projected. This extreme possibility strongly affects the average even though it is only assigned a 1-in-15 probability. In fact, across the fourteen weather profiles excluding 2011, only 0.5 loss-of-load events and 0.9 loss-of-load hours are projected on average.

2. Economic Equilibrium Reserve Margins at Higher Price Caps

Higher price caps increase generators' margins during scarcity intervals and therefore reduce the number of intervals needed to provide sufficient energy margins to support investment. We examine the impact of three sets of increased price caps on the economic equilibrium and long-run resource adequacy.[130] These price caps represent the range of proposals recently put forth by the PUCT and are summarized in Table 12.

Table 12
Range of Price Caps and PNM Thresholds

Scenario	HCAP	LCAP	PNM Threshold
	($/MWh)	*($/MWh)*	*($/MW-y)*
Current	$3,000	$500	$175,000
Mid	$4,500	$2,000	$262,500
High	$6,000	$3,000	$300,000
Highest	$9,000	$4,500	$300,000

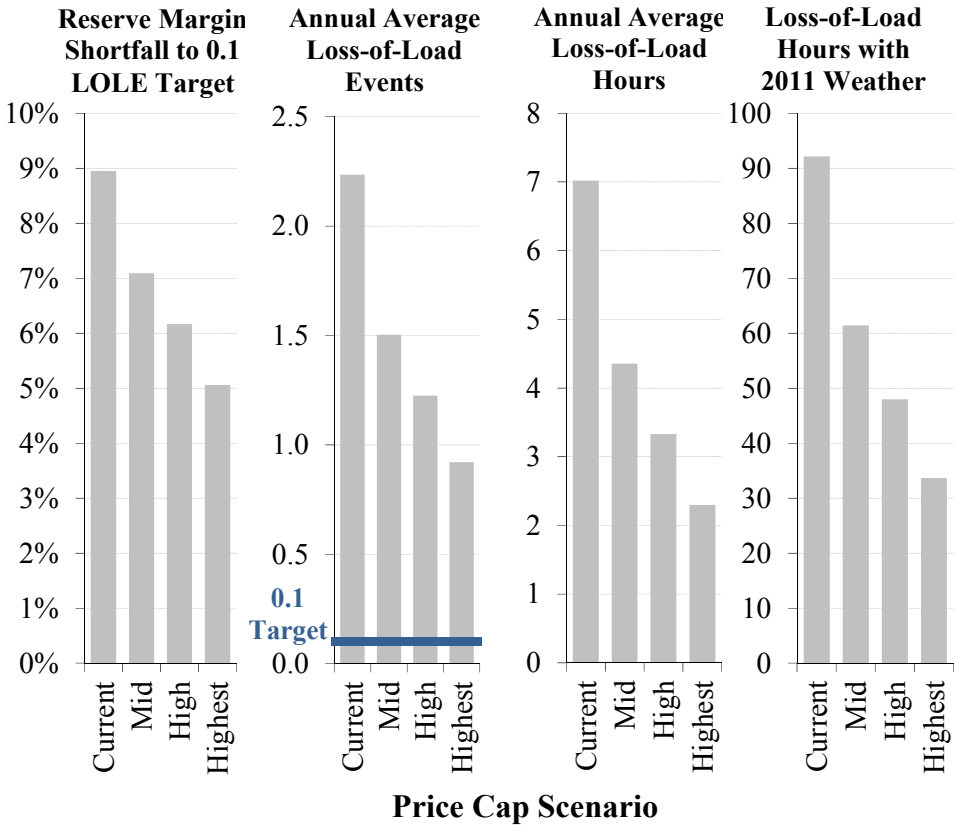
Figure 26 presents our estimates of long-run reliability achieved at the economic equilibrium with these price cap scenarios. Our key finding is that all scenarios fall short of the 0.1 LOLE target reserve margin. Even with the highest price caps, ERCOT is projected to experience an annual average of 0.9 loss-of-load events, and is exposed to the risk of experiencing more than 30 loss-of-load hours under extreme 2011 weather conditions.[131] We leave it to the regulators and stakeholders to determine whether such reliability outcomes would be adequate. Section VI.A of this report provides a framework for thinking about reliability objectives.

We also examine the impact of the PNM threshold and LCAP by simulating a variation of the highest price cap scenario without these caps. At equilibrium, this scenario is projected to achieve an annual average of 0.6 LOLE rather than the 0.9 LOLE achieved under the standard highest price cap scenario. We caution, however, that investors may be reluctant to trust that future regulators will not interfere with the prolonged high spot pricing patterns that would have to be allowed to prevail in order to support this improved reliability outcome, as discussed in Section VI.

[130] Our analysis of higher price caps does not account for potential changes in market behavior, exercise of market power, or additional demand response during scarcity.

[131] With the highest price caps, an average of 0.04 loss-of-load events and 0.06 loss-of-load hours are projected on average across the fourteen non-2011 weather profiles.

Figure 26
Reliability at the Economic Equilibrium with Higher Price Caps



3. Reliability and the Frequency of Scarcity Pricing Conditions

Generation in ERCOT currently faces low non-scarcity margins due to a flat supply curve and low gas prices, as discussed in Section I. Without capacity payments, potential investors therefore require a moderate number of scarcity pricing hours on average to recover the costs of a new plant. For example, if a combustion turbine earns non-scarcity margins of $30,000/MW-year and has a levelized CONE of $105,000/MW-year, eight hours of scarcity pricing are needed to support investment even with a price cap of $9,000/MWh.

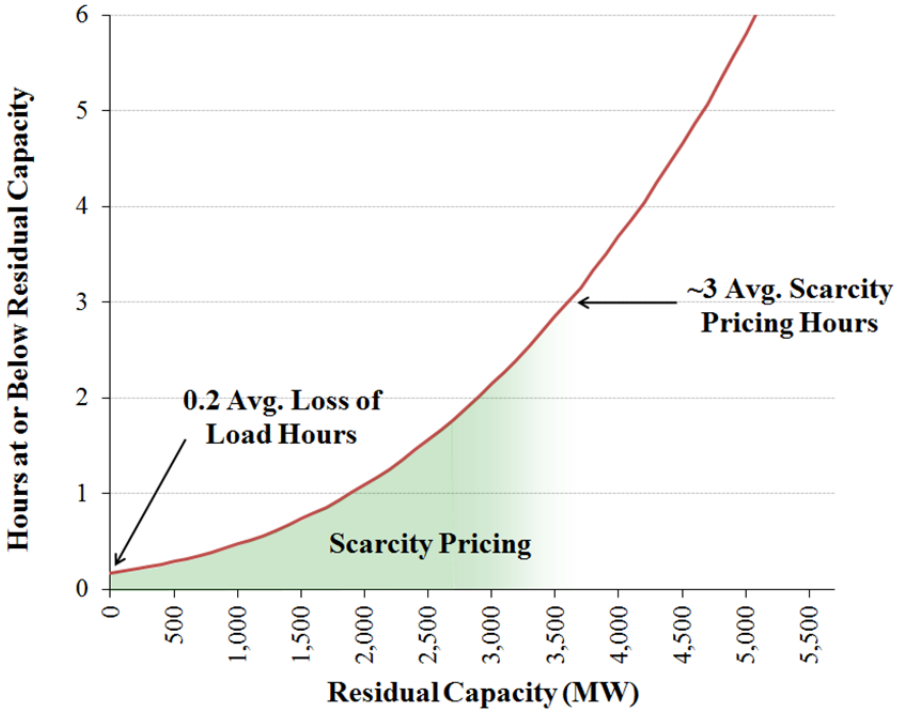
Such reliance on scarcity pricing to ensure long-term reliability presents a challenge simply because higher planning reserve margins increase reliability but also decrease the frequency of scarcity pricing. The shortfall between the economic equilibruim and the 1-in-10 LOLE target planning reserve margin we projected largely reflects the fact that very few scarcity pricing hours are likely to occur if the planning reserve margin is high enough to achieve the 1-in-10 LOLE target. In other words, the high reserve margin needed for reliability eliminates the very scarcity that is required for recovering investment costs.

Figure 27 illustrates this fundamental challenge. It shows the expected annual frequency (in red) of low residual capacity levels at the 15.25% planning reserve margin which achieves the 1-in-10 LOLE target. At this reserve margin, there is an average of 0.2 loss-of-load hours, as shown by

the expected frequency of 0 MW residual capacity. For simplicity, we show expected scarcity pricing intervals (in green) occurring at residual capacity levels lower than 3,500 MW.[132] Based on this, only about 3 hours of scarcity pricing are expected on average, substantially less than the number of scarcity hours per year that would support generation investment.

Thus, it is very difficult to achieve a 1-in-10 reliability target through scarcity pricing unless large amounts of demand response are able to avoid load shedding without eliminating scarcity prices. The expected reserve margin shortfall would decrease if price caps were increased even higher than $9,000, but the magnitude of the shortfall would be uncertain on average and year-to-year, as we show in the next section. In addition, we heard from many stakeholders that much higher caps might create prohibitively higher credit requirements.

Figure 27
Illustration of Reliability vs. Scarcity Pricing



Sources and Notes:
Data provided by ERCOT (2012a), adjusted to account for demand elasticity during scarcity. Average of 1997 – 2011 weather at a 15.25% reserve margin.

4. Sensitivity to Weather, Regulatory, Cost, and Modeling Uncertainties

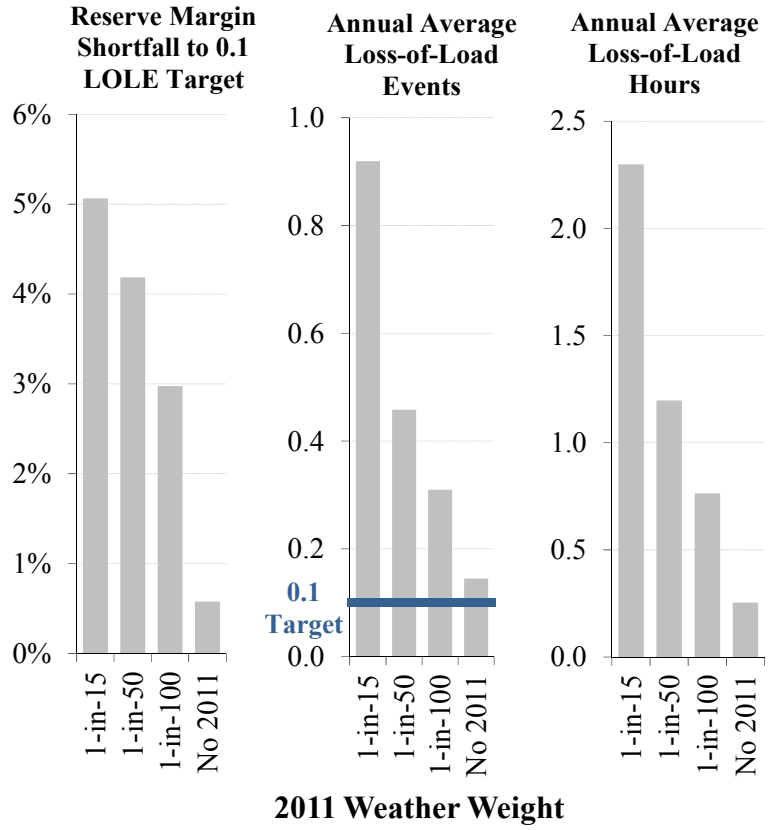
The analysis presented above involves numerous assumptions and modeling techniques. Reasonable analysts could differ in their assumptions and approach and arrive at different results. More importantly, *investors*' beliefs and willingness to place bets could differ from our analysis, and their decisions ultimately determine the level of investment. To test the sensitivity of our estimated "equilibrium reserve margin" and reliability outcomes to reasonable variation in assumptions, we analyzed the following five different cases:

[132] Section IV.A.1 describes the relationship between residual capacity and scarcity pricing in more detail.

Variation in Weather Distribution. While extreme weather is a major driver of scarcity margins and loss of load, its frequency is highly uncertain. To highlight the impact of extreme weather, we projected the economic equilibrium with various likelihoods of 2011 weather, ranging from 1-in-15 to zero.[133] Note that the base case described above is based on a 1-in-15 chance of 2011 weather, using a simple average of the 1997 – 2011 profiles.

Figure 28 presents estimates of reliability at the economic equilibrium with these weather distributions under the $9,000 offer cap scenario. As already presented above, the equilibrium reserve margin achieved assuming the base case weather distribution would result in 0.9 loss-of-load events per year on average. However, under an alternative assumption that 2011 weather will never occur again, the equilibrium reserve margin would very nearly achieve the 0.1 LOLE target. This highlights that the extreme events at the tails of the weather distribution are a major reason why reliance on scarcity prices in unlikely to achieve ERCOT's current reliability objectives. If it were not for these extremes, an energy-only market with high price caps would have a much better chance of achieving the current objectives.

Figure 28
Reliability at the Economic Equilibrium with a Range of Weather Distribution
Under the Highest Price Cap Scenario



[133] Our projections under varying weather distributions account for the impact of weather on both reliability and generators' scarcity margins. For example, a projection based on a zero chance of 2011 weather would have lower scarcity margins than the base case, as well as a lower loss of load frequency.

Investors' Weather Expectations Differ from Actual. Estimating the likelihood of extreme weather is highly speculative, and any disconnect between investor expectations and actual weather conditions will substantially affect the economic equilibrium. The base case assumes investors' weather expectations are perfectly accurate—meaning that they expect a 1-in-15 chance of 2011 weather and this is exactly what materializes on a long-run average basis. We examine a sensitivity where investors are overly optimistic and expect a 1-in-5 chance of 2011 weather, but it materializes at a 1-in-15 rate. This case would increase reliability at the economic equilibrium because generators would invest expecting that they would frequently earn the substantial scarcity margins caused by extreme weather, but ERCOT would not actually suffer frequent extreme weather and its associated reliability problems. We also examine a sensitivity where investors are pessimistic and expect a 1-in-100 chance of 2011 weather, but it materializes at a 1-in-15 rate. This case would decrease reliability at the economic equilibrium. Our goal in presenting these sensitivities is not to suggest that investors' expectations of extreme weather will be persistently optimistic or pessimistic, but rather is to illustrate how sensitive ERCOT's long-term reliability is to these highly speculative judgments.

Regulatory Uncertainty. Generators may discount any expectations of high scarcity margins earned under high price caps if they fear that the future regulators will reinstate lower caps. To illustrate the impact of such uncertainty, we conducted a sensitivity analysis in which investors expect future regulators will reduce price caps to $1,000 in 5 years. This future regulatory uncertainty may partially undermine the current Commission's ability to attract generation and improve reliability by increasing price caps. Even if the current Commission signals a firm commitment to letting the market work, it is difficult for them to guarantee that future commissions and legislatures would not reduce price caps in response to extreme outcomes.

Variation in Cost of New Entry (CONE). Variation in investors' cost of capital and the construction cost of generation affects the levelized cost of new entry, which will in turn affect the economic equilibrium. We determine the economic equilibrium assuming a High CT CONE of $116,000/MW-year (based on an 11% cost of capital), and a Low CT CONE of $90,100/MW-year (based on a 7.6% cost of capital). The Base CT CONE is $105,000/MW-year, with a 9.6% cost of capital to be consistent with ERCOT assumptions.[134]

Variation in Non-Scarcity Margins. Variation in non-scarcity margins could be caused by a change in gas prices, fleet composition, and also uncertainty surrounding our projections based on recent historical data. We therefore included one sensitivity analysis with 40% higher non-scarcity margins, and another with 40% lower scarcity margins than the base case.

Other Modeling Uncertainties. Both scarcity pricing and load shedding are highly uncertain, not only because they are stochastic, which we accounted for in our modeling, but also because of several factors which are difficult to model accurately or at all, including: the possibility of common mode failures; the correlation between outages, load and wind generation; the variation in operational practices; the imperfect calibration of our forward-looking model based on a limited set of past conditions; the adjustments for demand elasticity not modeled explicitly; and the uncertainty about how actual investors would model this problem. We test two cases designed to reflect a broad range of modeling uncertainties.

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[134] See Section II.D for more detail on CONE and cost of capital calculations.

High Equilibrium Modeling Parameters: (1) Scarcity pricing is triggered at residual capacity levels 500 MW higher than estimated based on 2011 patterns and new rules; (2) An additional 1000MW of demand elasticity prior to load shed reduces loss-of-load frequency but does not depress prices.

Low Equilibrium Modeling Parameters: (1) Scarcity pricing is triggered at residual capacity levels 500 MW lower than estimated based on 2011 patterns and new rules; (2) Load is shed when 500 MW of residual capacity remain available.

The results of these five sensitivities are shown in Table 13 and Table 14.

Table 13
Economic Equilibrium Sensitivity to Uncertainties
Under The Highest Price Cap Scenario

Sensitivity	Annual Average Loss-of-Load Events	Annual Average Loss-of-Load Hours	Loss-of-Load Hours with 2011 Weather	Reserve Margin Shortfall to 0.1 LOLE Target
Base Case	0.9	2.3	34	(5.1%)
Variation in weather distribution	0.1 - 0.9	0.3 - 2.3	NA - 56	(0.6%) - (5.1%)
Investors overly optimistic or pessimistic about weather	0.2 - 1.4	0.3 - 3.9	4 - 56	(0.8%) - (6.7%)
Price caps reduced to $1,000 after 5 years (Regulatory Uncertainty)	1.4	4.1	58	(6.9%)
Low CONE - High CONE	0.7 - 1.0	1.7 - 2.7	25 - 39	(4.3%) - (5.5%)
Variation in non-scarcity margins	0.7 - 1.1	1.7 - 2.9	25 - 43	(4.3%) - (5.8%)
Range of other modeling uncertainties	0.4 - 1.3	0.9 - 3.5	13 - 50	(2.8%) - (6.3%)

Table 14
Economic Equilibrium Sensitivity to Uncertainties
Differences Shown Relative to the Base Case

Sensitivity	Annual Average Loss-of-Load Events	Annual Average Loss-of-Load Hours	Loss-of-Load Hours with 2011 Weather	Reserve Margin Shortfall to 0.1 LOLE Target
Base Case	0.9	2.3	34	(5.1%)
Variation in weather distribution	(0.8) - 0	(2.0) - 0	NA - 22	(4.5%) - 0%
Investors overly optimistic or pessimistic about weather	(0.7) - 0.5	(2.0) - 1.6	(30) - 22	(4.3%) - 1.6%
Price caps reduced to $1,000 after 5 years (Regulatory Uncertainty)	0.5	1.8	24	1.8%
Low CONE - High CONE	(0.2) - 0.1	(0.6) - 0.4	(9) - 5	(0.8%) - 0.4%
Variation in non-scarcity margins	(0.2) - 0.2	(0.6) - 0.6	(9) - 9	(0.8%) - 0.7%
Range of other modeling uncertainties	(0.5) - 0.4	(1.4) - 1.2	(21) - 16	(2.3%) - 1.2%

5. Impact of Additional Demand Response Penetration

'Price-setting' demand response which can set market prices or support price formation at high levels corresponding to its willingness-to-pay can play a very beneficial role in the energy market. It can also support resource adequacy by reducing the loss-of-load frequency while preserving the high energy prices which support generation investment. Demand response that curtails at lower prices, however, partially erodes the high prices needed to support generation investment, and therefore greater quantities are needed to achieve the same beneficial impact on resource adequacy.

We assessed the impact of additional demand response (ERS and LR are already modeled in our base case projections) that could set market prices by applying the curtailment price of the demand response to the residual capacity levels where the demand response would set prices. As listed in Table 15, 3,600 – 5,600 MW of price-setting demand response could achieve ERCOT's 1-in-10 LOLE reliability target at the economic equilibrium under the highest price cap scenario, depending on the curtailment price of the demand response.

Table 15
Amount of Price-Setting DR Needed
to Achieve 0.1 LOLE Target at Equilibrium
Under The Highest Price Cap Scenario

Curtailment Price of Price-Setting DR *($/MWh)*	Price-Setting DR Quantity *(MW)*
$4,500	3,600
$3,000	4,300
$1,500	5,600

Achieving so much DR that can set or support prices at these levels will require a major increase in DR development as well as wholesale market design changes, as discussed in Section V.B.

C. IMPLICATIONS FOR RESOURCE ADEQUACY

Administrative scarcity pricing is unlikely to achieve ERCOT's 1-in-10 reliability target, even with aggressive increases in scarcity pricing parameters. Further, the level of long-run reliability achieved by adjusting scarcity pricing parameters is highly sensitive to uncertainties regarding weather, plant costs, fuel prices, modeling assumptions, and investors' expectations of weather and regulatory stability. Moreover, the reserve margin in any particular year could diverge substantially from the long-run equilibrium, for example following the retirement of a large unit.

Many lower cost resources, such as reactivations and uprates, will enter before new greenfield generation, as we have seen recently. There is a limited supply, however, of these low cost resources, and durable, long-run resource adequacy will only be achieved under a market construct which supports new entry.

Our analysis shows that major increases in the penetration of demand response resources that can set prices could support ERCOT's 1-in-10 LOLE target when combined with increased price caps. However, DR penetration on the scale needed is likely multiple years away, as explained in Section V.B.

V. REVIEW OF ENERGY MARKET DESIGN ELEMENTS

This section focuses on the economic efficiency of ERCOT's wholesale energy prices. Ideally, during most hours, energy prices should be at or near the locational marginal system production cost, including variable operating costs, start-up and shut-down costs, opportunity costs, and performance risks. When there is insufficient supply to meet load and maintain the full amount of operating reserves, prices should still reflect marginal system costs, but the marginal cost should also account for the possibility of shedding load. When supplies become insufficient to serve all load, prices should be set at customers' willingness to pay as they economically ration scarce supplies. We first examine the efficiency of a number of wholesale pricing mechanisms, and then address how to facilitate greater *demand response* participation in efficient price formation.

The market design elements we examine in this section will affect not only prices and system operations, but also investment signals. However, achieving fully efficient wholesale price signals will not necessarily support any particular reserve margin target. In Section VI below, we describe high-level policy options for supporting resource adequacy targets, including some options that deviate from the design ideals we discuss in this section.

A. WHOLESALE PRICING MECHANISMS

In this section we examine the efficiency of ERCOT's *wholesale pricing* rules and proposed reforms regarding: (1) the accuracy of energy and A/S prices during normal conditions; (2) the accuracy of prices during scarcity conditions; (3) the impact of the Peaker Net Margin threshold and the low system offer cap; (4) the locational scarcity pricing mechanisms; and (5) the market power mitigation rules.

1. Accuracy of Prices during Normal Conditions

Most of the time, the ERCOT market will be in normal operating conditions that are not affected by capacity shortages. Even during normal system conditions, there may be short-term supply scarcity related to ramping constraints, unit commitment, or under-forecasted load. For our purposes, however, we do not characterize these transient scarcity events as representing scarcity conditions, because they are just as likely to occur whether or not the market has excess capacity resources. For our purposes, we define "scarcity conditions" as those hours when administrative interventions are required in response to capacity shortages, and where a contributing cause of the capacity shortage is a low planning or realized reserve margin.

Although prices during normal conditions are not directly related to capacity shortages, they do influence long-term resource adequacy. Energy and A/S margins that generators earn during non-scarcity conditions will contribute to their return on capital and will therefore affect suppliers' willingness to invest. For this reason, any systematic overpricing or underpricing during normal conditions could adversely affect investment signals and resource adequacy. We examine three aspects of price-setting during normal conditions that may be improved: (a) pricing inefficiencies introduced through unit commitment processes, which may tend to suppress prices overall; (b) pricing inefficiencies related to imperfect coordination between energy and A/S prices, which may suppress or inflate prices; and (c) new pricing mechanisms that could inefficiently increase prices to "scarcity" levels during non-scarcity conditions.

a. Price Inefficiencies Related to Unit Commitment, including RUCs

Prices during normal market conditions are conceptually easy to set if unit commitment decisions can be ignored, because one can economically dispatch the lowest-cost resources first until supply is sufficient to meet demand. In this simplified case, the efficient price is just the marginal production cost from the highest-cost resources dispatched to satisfy load, transmission, or operational constraints.

However, supply discontinuities related to unit commitment complicate price formation. Unit commitment determines which resources to turn on over a multi-period timeframe to minimize system costs, including startup costs, operating costs, and minimum load costs. Economic dispatch determines which units operate at a given instant considering only those units that are already committed, and the energy price generally reflects the incremental offer of the last unit dispatched without regard to startup or minimum load costs. This leads to an inconsistency in

which costs are considered between unit commitment processes used to determine start-up and shut-down schedules, and economic dispatch processes used to determine short-term output and market prices. These inconsistencies can create small, systematic underpricing effects and can therefore necessitate uplift payments for units that are committed but that do not earn enough energy margins to cover their startup or minimum load costs. In 2011, Day-Ahead make whole uplift payments were less than $0.01 per MWh of load, and RUC uplift payments were $0.05 per MWh of load.[135]

Although these underpricing effects can be caused by "in-market" resources that are committed in the day-ahead market, market participants have been particularly concerned about price-suppression impacts on the real-time market from units that ERCOT commits out-of-market, through its Reliability Unit Commitment (RUC) process.[136] The RUC process is intended to commit incremental generation on a day-ahead or hour-ahead basis to meet projected load and operating reserve requirements and support local reliability.[137] We understand that nearly all RUCs are committed through the hour-ahead, not day-ahead process; RUC units may be committed to replace units that trip offline, support local reliability, support upcoming ramp requirements, or meet other system operating constraints.

Whenever RUC units require uplift payments, this indicates that market prices were artificially low over that dispatch period. However, ERCOT recently implemented the first part of a solution to prevent RUC units from suppressing prices by releasing RUC-dispatched generation (above minimum load) as available to SCED only at the offer cap. An urgent-priority NPRR will also address the "0-LSL" issue, which refers to price suppression from RUC and some other types of units operating at minimum generation.[138] The NPRR proposes to conduct one SCED run that accounts for the minimum generation constraint on these RUCs and other units for dispatch purposes, and a separate SCED run that relaxes this constraint for market pricing purposes.[139] However, we believe these solutions are inefficient, especially in combination.

RUC units that do not receive uplift payments are not depressing prices below a competitive level because these units would have opted to run on an in-market basis had they had perfect foresight of market prices. For RUC units that would require uplift payments, a more appropriate approach to preventing price suppression would be to inflate their incremental cost offer by an amount that more closely reflects their commitment costs or estimated uplift payments. Raising a RUC unit's offer to the system-wide offer cap is more than necessary. Some market participants claim that any generation by these units below the cap depresses prices, since the market did not elicit their output. We disagree because if there were an hour-ahead market, the unit would presumably have entered in-market.

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135 See ERCOT (2012a). RUC uplift payments are net of RUC clawback charges.

136 The day-ahead market includes a unit commitment process followed by a day-ahead dispatch and pricing process. This day-ahead unit commitment process is separate from any subsequent day-ahead RUC that ERCOT may require. However, units committed in the day-ahead market that fail to earn sufficient revenues based on day-ahead prices and dispatch will also receive an uplift payments, see ERCOT (2012s).

137 See ERCOT (2010j).

138 These types of administrative commitments include RUC units, ERCOT commitment of RMR units, and Offline Non-Spin, as well as quickstart generation dispatch by SCED. See ERCOT (2012f), NPRR444.

139 The NPRR also includes a provision to add load curtailed from load resources and ERS in the pricing run. See ERCOT (2012f), NPRR444.

The one exception is RUCs committed for local reliability reasons. If they are not dispatched above LSL, they need uplift payments. The price depressing effect of their minimum load output should be mitigated if it is very significant. However, we are cautious of solutions involving separate SCED runs for dispatch and price-setting because this approach will result in some plants being dispatched in a way that deviates from what pricing signals would support.

Starting after implementation in June 2012, Phase 1 of ERCOT's "Look-Ahead SCED" initiative could potentially reduce the number of RUC units required, by providing a 40- to 50-minute forward indicative price. Forward indicative prices will be informative to suppliers that are self-committing generation and to demand-side participants interested in efficiently reducing their load.[140] However, these self-commitment actions would not be coordinated by ERCOT. In future phases of Look-Ahead SCED, ERCOT may better coordinate these actions by explicitly integrating unit commitment considerations into the process, although the details of these options have not yet been developed.

On a longer-term basis, we recommend addressing similar commitment-related price suppression impacts whenever ERCOT or stakeholders identify a particular issue as introducing substantial uplift payments. For example, it may be desirable to create a mechanism for enabling block-loaded resources to set day-ahead and real-time energy prices.[141] There are also more ambitious options for incorporating commitment costs and other discontinuities into dispatch and pricing software, such as moving toward convex hull pricing.[142] However, such options could be very expensive to implement and should only be pursued if simpler fixes are insufficient and the benefits can be shown to exceed the associated software upgrade costs. The ideal result of any future pricing enhancements would be that suppliers self-dispatching against these prices with perfect foresight would exactly match the least-cost system result. Like other markets, ERCOT can make steps toward this ideal, but likely will not fully be able to achieve it.

b. Co-Optimizing Energy and Ancillary Services

In its day-ahead market, ERCOT already fully co-optimizes market clearing and price-setting between its energy and A/S markets. As a longer-term component of its broad Look-Ahead SCED initiative, ERCOT and stakeholders have also considered the option of co-optimizing energy and A/S in real-time markets as is done in NYISO.[143] This revised design would readjust which suppliers are providing energy and A/S services at any given time in response to real-time system conditions and changing economics. This proposal is in its early stages and no specific design construct has been developed, but it would be an improvement that could increase price

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140 See ERCOT (2012f), NPRR444.

141 Block loaded resources have minimum generation equal to maximum generation and so have no variable output range over which to calculate the marginal cost of incrementally more power. For any interval when a block-loaded resource is the highest-cost unit dispatched, the market will end up being underpriced without such a change and the block-loaded resource will require uplift payments.

142 The convex hull pricing approach is mathematically complex and requires substantial software upgrades, but represents a best practice approach to minimizing uplift requirements and imperfect price incentives. Convex hull pricing replaces a blocky and discontinuous supply curve with a smoother incremental cost curve that can be used to set more efficient and stable prices. We do not attempt to fully explain this approach here, which is conceptually and mathematically complex with many variations. Instead we refer readers to Gribik (2009).

143 See ERCOT (2012q), p. 6.

and operational efficiency. This design improvement would result in better-behaved, smoother pricing, least-cost dispatch and higher operating reliability. However, it would also involve a major and potentially costly software change and so should only be pursued after careful consideration of the costs and benefits.

c. Avoiding Mechanisms for "Scarcity" Prices during Non-Scarcity Conditions

In addition to pricing revisions that will increase the efficiency of wholesale prices, some mechanisms may inefficiently increase prices to "scarcity" levels even when resources are plentiful. We recommend avoiding such changes because they would increase prices in a way that is unrelated to an underlying need for new investments.

The recent 500 MW increase in the RRS requirement is an example of a change that could inefficiently introduce scarcity prices during non-scarcity conditions.[144] This increase in operating reserves does not necessarily reflect an operational system need, and will therefore unnecessarily increase system operating costs all of the time whether there is a scarcity event or not (*i.e.*, with more capacity spinning than operationally needed for 8,760 hours per year). This will increase prices and returns to suppliers as intended, but will unfortunately also inefficiently increase customer costs. We recommend that operating reserves requirements instead be determined based on analysis of contingency risks, ramping needs, wind balancing requirements, load balancing requirements, or other operating considerations.

The new RUC mechanism described above also is likely to introduce scarcity prices during non-scarcity events. This mechanism will add RUC units to the SCED pricing run at the offer cap of $3,000/MWh. The likely result is that prices may be driven to very high levels during high-ramp or under-forecast conditions. These ramping and forecasting considerations represent real system operating needs, but are not related to resource adequacy or the realized reserve margin. High-price events caused by this RUC mechanism will be just as likely to occur with a 30% reserve margin as with a 10% reserve margin. We do recognize, however, that the old RUC mechanism inefficiently suppressed prices by failing to incorporate commitment costs into pricing. Balancing these concerns, we recommend a different approach to preventing price suppression from RUC units using approaches similar to those discussed in Section V.A.1.a above.

2. Accuracy of Prices during Scarcity Conditions

During scarcity conditions, as during normal conditions, the efficient market price will reflect the marginal system cost of power. Ideally, it would be best to rely on high-priced DR curtailment bids (or offers, if DR is included on the supply side) to set prices in scarcity conditions, as discussed in Section V.B. However, without substantial DR resources, it is difficult to determine the marginal system cost during scarcity events because typical dispatch and price-setting mechanisms are not sufficient to bring supply and demand into balance. Instead, out-of-market actions must be implemented, including deploying operating reserves, relaxing transmission constraints, deploying backstop resources, or shedding firm load. These out-of-market actions

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[144] However, the "Energy-only with adders" policy option described in Section VI.B.2 could include increased operating reserve requirements and other elements to support resource adequacy through elevated prices.

can sometimes inappropriately suppress market prices when high prices are most needed, although ERCOT and the PUCT have already changed market rules to prevent price suppression in many cases.

If market-based supply offers and demand bids cannot be used to determine the marginal cost of power during scarcity events, then the price must be administratively determined. Marginal system cost is difficult to calculate during scarcity, but would include, among other things, the system risks introduced by operating with low reserves and customer costs incurred during load-shed events. We examine here various components of ERCOT's scarcity pricing mechanisms, including: (a) the "small fish swim free" rule's relationship to scarcity pricing; (b) the price cap and high system offer cap; and (c) administrative scarcity pricing mechanisms.

a. Small Fish Swim Free Mitigation Rule

In its original scarcity pricing framework, the PUCT developed a construct that relied on the "small fish swim free" mitigation rule to produce high prices during shortage conditions. Under this mechanism, small suppliers with less than 5% market share are always allowed to offer into the wholesale market at high prices up to the offer cap.[145] The offer cap would usually be the High System Offer Cap (HCAP), which is currently $3,000/MWh.[146]

This framework was intended to strike a balance between allowing wholesale prices to reach high levels during scarcity conditions and limiting the potential for exercise of market power during non-scarcity conditions. During normal conditions when the efficient market-clearing price is low, these small suppliers would rationally offer close to their marginal cost to ensure that they would clear. However, during scarcity conditions small suppliers would become pivotal and could still clear even if they offered at high prices. They could create high scarcity prices only during true shortage conditions.

Unfortunately, the small fish swim free approach has not proven to be a reliable scarcity pricing mechanism. The most important problem is that small suppliers may incorrectly predict scarcity conditions, thereby inefficiently pricing themselves out of the market during non-scarcity conditions or under-bidding during shortages. The risk of inadvertently pricing out of the market is a substantial burden to place on small suppliers. The market monitor has examined historical prices during shortage events and noted that "relying exclusively upon the submission of high-priced offers by market participants was generally not a reliable means of producing efficient scarcity prices."[147] Another unfortunate result of this mechanism is that small suppliers who offer their generation at very high prices face the risk of public reprisal, as occurred in 2008 when a small supplier's above-cost offers were featured in a *Wall Street Journal* article that drew comparisons to the California Electricity Crisis.[148] Finally, the mechanism is not functionally tied to any measure of the severity of a scarcity event, and so is likely to produce similarly high prices during moderate and severe events.

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[145] See PUCT (1999).

[146] The offer cap would drop to the Low System Offer Cap if the PNM threshold were exceeded as discussed further in Section V.A.2.b below. To date, the PNM threshold has never been reached, see ERCOT (2012j).

[147] See Potomac Economics (2011b), p. 54.

[148] See Smith (2008).

Overall, it appears that this mechanism has failed to introduce sufficiently high prices reflective of scarcity conditions to meet long-term resource adequacy needs. While it does not appear that this mechanism must be revised, it does appear that ERCOT will require supplemental mechanisms to produce needed scarcity premiums. We believe that this observation is consistent with the observations and recent market design activities of the PUCT, ERCOT, and stakeholders.

b. Price Cap and High System Offer Cap

ERCOT's high system offer cap (HCAP) is set to $3,000/MWh; while ERCOT does not have any enforced price cap, it would be unusual for prices to rise above the offer cap.[149] Commissioners of the PUCT have stated plans to further increase the offer cap to possibly $4,500 to $9,000/MWh, motivated by concerns that the current cap is too low to attract a desired level of investment.[150] Neither the current offer cap nor the proposed offer cap increases are based on an analysis of customers' VOLL or an analysis of the price cap needed to sustain investments.

We recommend creating a locational marginal price (LMP) cap set at the average customer VOLL, which would also impose a maximum limit on other parameters such as the offer caps and the Power Balance Penalty Curve (PBPC) shadow price. This is the efficient price level during severe scarcity conditions when ERCOT must enact involuntary load shedding, because this is the price that the average customer would have been willing to pay to avoid curtailment. A VOLL-based price cap approximates what the demand curve would have been had customers been actively bidding to avoid curtailment. Setting the price cap at VOLL is supported by a rich theoretical literature demonstrating the economic efficiency of this approach.[151]

Determining an accurate estimate of VOLL is difficult, however, and could range from a few thousand to tens of thousands of dollars depending on customer class. For example, in its 2006 review of VOLL studies, MISO found that VOLL ranged from $1,500-$3,000/MWh for residential, $10,000-$50,000/MWh for commercial, and $10,000-$80,000/MWh for industrial customers.[152] Ultimately, MISO decided to set its price cap at the low end of $3,000/MWh, consistent with residential VOLL estimates.[153] As another example, Australia's National Energy Market (NEM) price cap is at a VOLL of $12,500/MWh AUD ($12,200 USD), with the parameter subject to periodic study and updating.[154] The VOLL estimate appropriate in ERCOT is likely in the same range as VOLL estimates elsewhere, but a study would need to be conducted to estimate the number accurately. In particular, the study would have to consider: (1) the VOLL of different classes of customers; (2) the likely ratio of load shed events that would be imposed on each customer class, including considering that utility protocols may result in more load shedding for residential rather than large C&I customers; and (3) that certain very high-VOLL customers should be excluded from the analysis because they will already have

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149 Some nodal prices may rise above the offer cap if, for example, the penalty factor on a certain system constraint had a very high shadow price.
150 See, for example, PUCT (2012a), Item Number 106.
151 See Hogan (2005), pp. 9-11; and Joskow and Tirole (2004) p. 14.
152 See MISO (2006).
153 See MISO (2012a), Section 5.
154 See AEMO (2012). Exchange rate assumed is USD/AUD = $1.02 from Bloomberg (2012).

invested in backup generation or dual distribution feeds and will therefore not experience a full outage even during a load shed event.

Another way to set the price cap would be to derive it, along with other administrative scarcity pricing parameters, based on an estimate of the price levels needed to attract a desired level of investment. We more fully examine this option under Section VI.B.2 below, although we do not recommend this as a dependable way to achieve a particular reserve margin.

Finally, we recommend creating a functional distinction among: (1) ERCOT's price cap, which is currently undefined, meaning that prices may exceed the offer cap depending on transmission constraints; (2) the high, low, and other offer caps created for market mitigation purposes and implementing the small fish rule; and (3) administrative scarcity pricing thresholds used to set prices during scarcity events. Each of these mechanisms has a different purpose, and so they should not be forced to have identical values in all cases. The purpose of imposing a price cap at VOLL is to prevent LMPs from exceeding customers' willingness to pay to avoid outages during load-shed events.[155] The high and low offer caps used under the small fish swim free rule might be set to a separate, lower level based on PUCT and market monitor analyses of market power mitigation concerns. Administrative scarcity pricing thresholds might be set to different levels as discussed in the next Section.

Increasing the offer and price caps would introduce some risks associated with potential defaults. We have not analyzed all of the credit requirements, qualifications, and other provisions that might be required to ensure that market participants are able to cover their day-ahead and forward bilateral positions without defaulting. However, we are concerned that as reserve margins tighten and offer caps increase, an unscrupulous REP with little to lose might find ways to exploit asymmetric risk exposures, if any exist. Such a REP could under-hedge in order to make money in the likely event that realized spot prices are lower than forward prices, while ignoring the risk that spot prices could spike to levels they cannot pay in the unlikely event of 2011-like weather. Instead of paying the cost of such an extreme event, they could simply default and exit the retail electric business, and ERCOT's other customers would have to pay. Given risks such as these, we recommend that the PUCT revisit its credit and qualification provisions for REPs, as we understand ERCOT is already doing for settlements under their purview.

c. Administrative Price-Setting during Scarcity Events

There are three key objectives when developing price-setting mechanisms during scarcity events: (1) ensuring that administrative reliability interventions do not artificially suppress prices during scarcity events; (2) incorporating DR into price-setting as much as possible as discussed in Section V.B.4 below; and (3) developing administrative price-setting mechanisms that will accurately reflect marginal system costs.

Price suppression during administrative reliability interventions is a risk in any market because these interventions make incremental supplies available for dispatch. If those actions add supply at a low offer price (or reduce demand), then the typical result will be to reduce prices just when

[155] Note that in the absence of a price cap, increasing the offer cap to $9,000/MWh means that actual realized prices could exceed $9,000/MWh and the VOLL at specific nodes, depending on system constraints.

very high prices are most needed. Over recent months, ERCOT has implemented, or is developing, corrective measures to prevent this outcome from reliability interventions including RMR units' dispatch, deploying responsive reserves for energy, and Online and Offline Non-Spin deployments.[156] However, there are a few types of reliability interventions that could suppress market prices but have not yet been addressed. We recommend that ERCOT develop protections to prevent price suppression from these actions, including during: (1) Emergency Response Service (ERS) and Load Resource (LR) deployments, which a current NPRR is intended to address; (2) calling on emergency imports; (3) relaxing internal transmission constraints; and (4) any other type of reliability intervention that stakeholders or ERCOT may identify in the future.[157] Additionally, we recommend that ERCOT periodically examine price outcomes during all scarcity-related reliability events to confirm that no unexpected low prices occurred during those events.

Setting prices at an *efficient* level during these scarcity events is just as important as ensuring that prices are not inadvertently suppressed. To date the price corrections that ERCOT and PUCT have pursued have been tied to the objectives of preventing price suppression or attracting new investments. For this reason, some interventions including depleting regulation reserves at an initial price of $200/MWh may be underpriced relative to their system cost impact, while other interventions such as deploying responsive reserves only at $3,000/MWh even for the first MW deployed may be overpriced.

We recommend developing price correction mechanisms that tie all administrative pricing mechanisms to the marginal system costs of these interventions. Table 16 summarizes the principles that could be used to set efficient prices during each type of scarcity event and compares these pricing mechanisms with those that are currently in place. For example, if ERCOT can avoid shedding load by making an administrative off-system power purchase at $600, then we would recommend setting the price to $600 during that intervention. As another example, it may be possible to estimate the marginal system costs of operating with reduced levels of reserves by accounting for the increased system contingency risks and loss of load probability (LOLP) introduced by operating with lower reserves. Depleting operating reserves will increase the likelihood of load shedding from contingencies and so introduces a greater risk to customers as the scarcity event becomes more severe. For that reason, the efficient price during these events will also increase with the severity of the event and ultimately reach VOLL when load must be shed. Note that setting prices to VOLL when there are still enough operating reserves to operate reliably could result in customers' unnecessarily reducing high-value uses of power.[158]

A gradual approach to administrative scarcity pricing will result in a continuum of high-price outcomes related to the severity of each scarcity event. Under current rules with most scarcity interventions priced at the cap of $3,000, prices can jump back and forth between $200 and $3,000. A more continuous scarcity pricing approach will better-enable price-responsive

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[156] See ERCOT (2012f), NPRR442, NPRR427, and NPRR428.

[157] ERS and LR resources were formerly referred to as "EILS" and "LaaR," respectively. For the current NPRR 444 regarding re-pricing for these resource deployments, see ERCOT (2012f), NPRR444.

[158] If the PUCT opted to move ahead with an approach to adjust price parameters to achieve a particular reserve margin, it may introduce this type of inefficient load shedding in order to achieve that desired reserve margin objective. We discuss this issue further in Section VI.B.2 below.

demand to contribute to price formation even if it is not incorporated into SCED. For example, a customer valuing energy at $1,500 can reduce consumption if the price rises above $1,500 without causing prices to plummet back to non-scarcity levels. Graduated scarcity pricing will also serve as a guide to ensure that the lowest-cost reliability interventions are implemented first before costlier measures.

The concept of introducing scarcity prices gradually is already implied by the PBPC, which starts at $200/MWh and increases to the offer cap over 50 MW. The 50 MW range of the PBPC is based on the quantity of regulating reserves that can be deployed for energy before substantial reliability concerns arise. A new PUCT proposal to implement a more gradual PBPC over 200 MW is a move in the right direction and would require RRS deployments to make up the required energy.[159] We recommend something simple and gradual, such as stretching the entire scarcity pricing curve from $500 when first depleting operating reserves, then increasing to $9,000 or some similar VOLL-based level when close to shedding load. The shape of the increasing curve could be a simple linear function or a more complex function approximating the shape of system cost increases as operating reserves are deployed. As an alternative, if not all reliability interventions can be incorporated into one scarcity pricing function, these interventions could be treated as re-priced units in SCED similar to the current treatment of non-spin, RMR, and other types of reliability interventions. However, these re-priced units would have increasing marginal cost curves that approximate the smoothed scarcity pricing function.

[159] See PUCT (2012a), Item Number 125.

Table 16 summarizes how the marginal system costs of any one reliability intervention might be calculated to inform the shape of the scarcity pricing function. We recommend that all types of reliability interventions be incorporated into this scarcity pricing curve, which will extend the graduated scarcity pricing effects over a wider range of MW from low-cost interventions to high-cost interventions.

Table 16
Administrative Scarcity Pricing Mechanisms
(As Currently Implemented and Under Potential Marginal System Cost Mechanisms)

Scarcity Intervention	Current Pricing Mechanism	Potential Marginal Cost-Based Pricing Mechanism
Emergency Imports	- Reduces demand, suppresses prices	- Purchase price of emergency power
Call RRS	- Gen: Add to SCED at $3,000/MWh - Load: Reduces demand, which can reverse prices. Reform under consideration to add LR back to the demand for settlement.	- Estimate marginal system cost of operating at low reserves, including LOLP * VOLL, or some proxy thereof that varies with megawatts
Relax Transmission Constraints	- Shadow price caps for relaxing constraints - Some constraints not passed to SCED	- Estimate marginal LOLP impact, plus - O&M cost impact on transmission elements
Call Reg-Up for Energy (Not for Balancing)	- 0-50 MW used for PBPC at $200-$3,000 - Rest added to SCED at $3,000/MWh	- Estimate marginal LOLP impact, plus - Cost of reduced load balancing efficiency
Call RMR	- Add to SCED at $3,000/MWh	- Ideally, market would exclude RMRs (never entirely possible due to transmission security concerns) - If called, marginal cost is total availability payments divided by expected number of call-hours
Call ERS	- Reduces demand and can suppress prices. Reform under consideration	- Ideally, a pure energy-only market would exclude ERS - If kept, marginal cost could be estimated based on total payments divided by expected number of call-hours
Load Shed	- SWCAP of $3,000 ($500 if PNM exceeded) - Increased high & low caps under consideration	- Price at VOLL - Study end users to estimate average VOLL in Texas (possibly ~$10,000/MWh)

3. Level of Peaker Net Margin Threshold and Low System Offer Cap

The Peaker Net Margin (PNM) threshold and low system offer cap (LCAP) are a combined mechanism intended to prevent extreme, excessively high prices in any one year. ERCOT calculates the accumulated PNM over each calendar year as the operating margins of a gas CT with a heat rate of 10 MMBtu/MWh.[160] ERCOT's estimate of such a unit's operating margins excludes variable operating and maintenance (VOM) costs, start-up and shut-down costs,

[160] See ERCOT (2012k), Section 4.4.11.
See also, PUCT (1999).

emissions costs, and imperfect dispatch. If the PNM over the year increases above the threshold of $175/kW-year, then the offer cap is reduced from the $3,000 HCAP to the LCAP.[161] This lower LCAP is the greater of: (a) $500/MWh; or (b) the theoretical operating cost of a gas-fired unit with a heat rate of 50 MMBtu/MWh. In light of recent resource adequacy concerns about the ability of the market to attract sufficient investments, commissioners and stakeholders have proposed increasing the PNM threshold and LCAP as a means of achieving a more favorable overall investment environment.

The PNM threshold is ultimately a regulated safety valve to prevent extreme one-year results, meaning that the parameter has no one "correct" level that can be derived from economic principles. However there are a number of considerations to incorporate into the determination of PNM threshold:

- First, it makes sense to set the PNM threshold as some multiple of the cost of building a new peaking plant, in order to relate it to the overall investment returns suppliers may expect to earn. If CONE is the average net revenue needed over many years to attract investments, then the PNM threshold can be considered an approximate soft cap on returns that will be allowed in any given year. The PNM is an imperfect measure because actual peaking generators' are able to earn only 60-85% of PNM due to imperfect dispatch and various operating costs.[162] Further, it is a "soft" cap because generators will continue to earn some incremental returns at a reduced rate even after the PNM threshold is exceeded.
- Second, it is important to consider the frequency and magnitude of price spikes.[163] For example, if substantial scarcity is expected only once every five years and energy margins in non-scarcity years are only half of CONE, then the returns and PNM in the scarcity year would need to be approximately three times CONE to attract investment. There is only limited value to such a simplified formula, however, if prices become extremely high extremely infrequently. For example, if prices were very low in most years but high enough for a generator to earn 10 times CONE once every ten years, we would expect very few investments. The difficulty of modeling severe outlier outcomes and the risk of potential political interventions would likely cause most suppliers to discount the potential for such high prices. If suppliers do not expect such extreme pricing events to be allowed to persist, discounting these events through an administrative rule such as PNM (rather than ad hoc interventions) makes prices more predictable.
- Finally, regulators should consider the public's tolerance for withstanding years with extremely high prices, with the average wholesale price being a relevant metric for

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[161] Id.

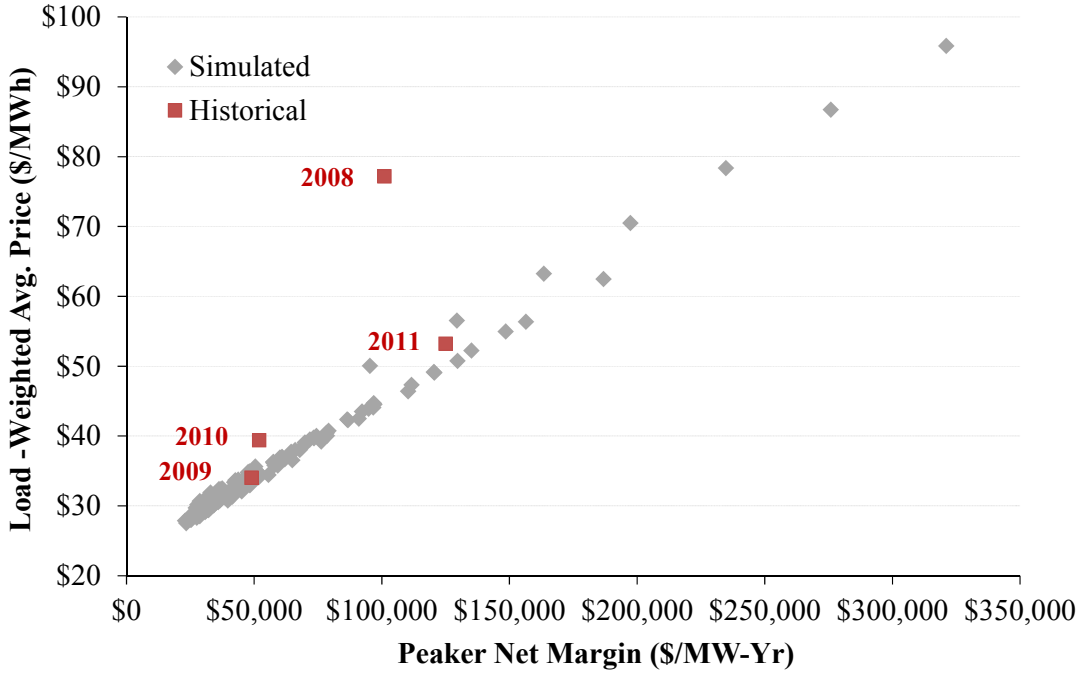
[162] Calculated based on 2008-2011 net revenue estimates from Potomac Economics (2011c) and (2012). For PNM data, see ERCOT (2012j).

[163] Although suppliers generally sell most of their power on a forward basis, these forwards will reflect the market's expectations of spot market price spikes adjusted for risk. Therefore, spot prices need to be allowed to rise to levels sufficient to support investment. Forwards will also incorporate the expected impact of PNM in preventing certain very high-price outcomes in the real-time market. For these reasons and for simplicity, we discuss the impacts of PNM only on real-time prices and presume that the effects will translate to generator returns regardless of their hedging strategies.

determining whether customers will demand political intervention.[164] Figure 29 below shows the relationship between PNM and the average wholesale energy price in recent years, based on the simulation methodology used in Section IV above.[165] For example, if the public is intolerant of prices that rise to twice the average level, this would indicate an appropriate PNM threshold of $300/kW-year or approximately three times CONE.

Overall, we stress that there is no "correct" level for the PNM threshold. In fact, the stability and predictability of the parameter over a number of years may be more important than the exact level. After considering all of these factors, we would recommend a PNM threshold in the range of $250-350/kW-year that increases in some predictable way over time, commensurate with the increasing costs of construction. For example, the PNM threshold may be set at a specific multiple of CONE and inflated annually according to a standard index such as Handy-Whitman.[166]

Figure 29
Peaker Net Margin vs. Average Annual Wholesale Price



Sources and Notes:
Historical data from ERCOT (2012j) and Potomac Economics (2011c).
Simulated results based on methodology outlined in Section IV, with a high cap of $3,000/MWh and no PNM threshold. Some results with a PNM greater than $350/kW-year are not shown.

The LCAP is a related parameter because it is the offer cap imposed after the PNM has been exceeded. The purpose of the LCAP is to assist in preventing excessively high prices on a

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164 We note that this metric is one indicator of potential customer concern, but is not perfect for a number of reasons including that: (1) much of retail customers' load is hedged on a forward basis and not exposed to spot prices; (2) it may be monthly rather than annual extremes in bills that would cause most consumer or REP concerns; and (3) wholesale prices are only a portion of customer bills and so do not translate proportionally.

165 The simulation reflected includes all 15 weather year profiles as described in Section IV.

166 See Handy-Whitman (2011).

continuous basis over the year, so it makes intuitive sense to keep this cap at a relatively low level as long as it does not introduce excessively inefficient price distortions. For example, an LCAP of only $100/MWh would introduce excessive inefficiencies because it would preclude a large number of peaking generators from being dispatched. The current LCAP of $500 (or higher in high fuel price circumstances) may be reasonable if one considers only a generation market and ignores the potential for demand response. We would recommend increasing this LCAP to a higher level if any generation resources in the fleet have a marginal cost (including opportunity costs) above the cap. Further, as demand response grows in Texas, it will be important to raise the LCAP to a level that ensures that most load reductions would be achieved at prices below the LCAP. Determining this level could be informed by an econometric study to evaluate the level of demand reductions achieved at various price levels. We further discuss how such a study could be conducted in Section V.B.4.c below.

4. Locational Scarcity Pricing

Resource adequacy can be a regional or sub-regional concern, depending on the nature of transmission constraints. Even if the overall RTO has sufficient generation supplies, this does not necessarily mean that all locations will achieve the reliability target because the system may have: (1) load pockets within which there is insufficient local generation or import capability to meet peak demands; or (2) generation pockets with excess supply but insufficient export capability to meet peak demands in other locations.

In markets with resource adequacy requirements, locational reliability concerns are directly defined and addressed, for example, through local capacity requirements within load pockets.[167] In energy-only markets, it is more difficult to address locational resource adequacy concerns so directly, particularly in ERCOT, the first nodal energy-only market. Other energy-only markets have relied solely on system-wide prices as in Alberta or on zonal prices as in Australia.[168] In a nodal energy-only market, it will be a challenge to achieve an effective scarcity pricing mechanism that is: (1) location-specific enough that it will attract investments to where incremental generation is most needed; and (2) not so focused on a small number of nodes that a more regional or sub-regional resource adequacy need fails to be reflected in the broader price. The IMM highlighted this challenge in the 2008 State of the Market Report, which cautioned that the move to nodal pricing could focus scarcity pricing into too-small clusters of nodes.[169]

To date, ERCOT's scarcity pricing mechanisms have not been developed in a way that explicitly considers the potential for locational resource adequacy concerns as opposed to system-wide resource adequacy concerns. We recommend assessing the need to revise these mechanisms for locational relevance. While a number of approaches could be used to achieve this result, one option would be to revise administrative scarcity pricing mechanisms around new "A/S Regions" that may or may not coincide with ERCOT's current Load Zones. The mechanisms could be conceptually similar to the Reserve Zone approach implemented by MISO that expresses: (1)

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[167] See Pfeifenberger, Spees, and Schumacher (2009), Section VII.B.3.
[168] See AEMO (2010), and AESO (2011).
[169] See Potomac Economics (2009), pp. 83-87.

system-wide scarcity prices when depleting system-wide reserves; and (2) scarcity prices specific to that Reserve Zone when reserves drop below that location's requirement.[170]

Implementing this type of concept in ERCOT might require the RTO to:

Define A/S Regions — We recommend that in its LOLE study or transmission planning processes, ERCOT evaluate whether there are load pockets or generation pockets relevant for resource adequacy. Load pockets would be identified as regions within which LOLE is concentrated due to import constraints; generation pockets would be defined as regions with excess supply that is generally unavailable to the rest of the system during peaking conditions. While this question has not previously been analyzed in ERCOT, it appears that the Houston Load Zone is a candidate for evaluation as a potential load pocket relevant for locational resource adequacy; however, we note that such load or generation pockets would be defined based on transmission topology and would not necessarily coincide with a current Load Zone. For the purposes of our discussion here, we presume that the boundaries of these load and generation pockets would be equally relevant for defining new boundaries in the A/S markets and so we term these locations as "A/S Regions."[171] To the extent that no such A/S Regions are needed now or are expected within the coming years, we would not recommend pursuing any of the other following mechanisms at this time. However, if locational resource adequacy concerns are identified, then we recommend refining scarcity pricing mechanisms in a way that ensures that locational scarcity will be reflected in realized prices in those defined regions.

Define A/S Penalty Curve by A/S Region — All supply resources in SCED, including the virtual resource represented by the PBPC, must be assigned to a specific node. The current PBPC is defined at the reference bus, meaning that it has a distributed "location" across all load nodes. This also means that scarcity pricing outcomes related to the PBPC will be tied to system-wide but not location-specific scarcity conditions. However, locational scarcity may be better reflected if each identified A/S Region had its own A/S Penalty Curve that affected prices only at the group of nodes defined within that region. However, system-wide shortages could still be reflected in scarcity prices driven by the system-wide PBPC.

Evaluate Each Administrative Scarcity Mechanism for Locational Relevance — Several of the scarcity pricing mechanisms developed by ERCOT rely on administratively re-pricing certain types of resources and adding them into SCED, including RMR, RRS, Non-Spin, and RUC resources. Because each of these resources represents a real generation unit, they are all tied to a specific node and may have the effect of increasing prices in that location but not in others, depending on transmission constraints. It is not clear whether or under what circumstances these mechanisms are likely to introduce scarcity pricing signals where they are most needed. We recommend individually evaluating each mechanism for this purpose. For example, if a load pocket exhibits incremental A/S needs or requires an RMR for capacity, then we would recommend that any scarcity

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[170] See MISO (2012a), Sections 3.3, 5.1.1, and 5.2.

[171] To the extent that it is more appropriate to define A/S market boundaries separately or differently from load and generation pockets relevant for resource adequacy, the mechanisms we propose here would have to be revised at least to some extent.

pricing related to those associated resources' deployments be developed in a way that impacts all nodes in that A/S Region. Deploying these resources would only impact RTO-wide node prices in the case of an ERCOT-wide shortage.

Align Load Settlements by A/S Region — Customer prices are defined based on Load Zone prices, which could create an economic disconnect for sub-zonal load pockets. This means that potential price-responsive demand within these small regions may go undeveloped due to uneconomically low load prices there; similarly, too much price-responsive demand might be incented outside the load pocket where it is not helpful for resolving the transmission constraints. To the extent that such sub-zonal resource adequacy zones exist, we would recommend re-defining Load Zones and settlement according to the boundaries of that A/S Region. This would create the most efficient price for price-responsive loads to respond to for resource adequacy purposes.

Align Real-Time Mitigation Procedures with A/S Regions — Under certain circumstances, ERCOT's real-time mitigation procedures could prevent locational scarcity prices from materializing. For example, high offer prices in SCED from small fish, or administratively-priced RMR, RRS, Non-Spin, or RUC units could be re-priced down to marginal cost if those resources are behind a "non-competitive" constraint.[172] We suspect that in many cases these mitigation procedures would not result in underpricing relative to locational resource adequacy needs because these units may still set locational scarcity prices to the extent that they are behind "competitive" constraints. However, we do recommend that ERCOT examine the extent to which the definitions of competitive and non-competitive constraints could prevent locational scarcity prices from materializing.

More generally, as ERCOT's scarcity mechanisms are refined or revised, we recommend that they be developed in a way that explicitly considers how well they will perform to reflect both locational and system-wide resource adequacy shortages.

5. Offer Monitoring and Mitigation Rules

There are two levels of market monitoring and mitigation affecting market prices in ERCOT. The first is the well-defined mitigation construct that ERCOT enforces in its real-time market to prevent suppliers that are behind non-competitive constraints from artificially inflating prices in small, constrained locations.[173] ERCOT does not impose any type of mitigation procedures in its day-ahead market.

The second level of market monitoring and mitigation is implemented by the IMM under PUCT mandate, which is governed by three general principles set out by the PUCT: (1) that "small fish" with less than 5% market share will be allowed to offer energy at any price up to the offer cap; (2) that larger entities may not offer their power at levels that are "substantially above its marginal cost"; and (3) that generators who wish to confirm that their approach to offering into the market is not in violation can request that the PUCT, with IMM input, approve a voluntary

[172] See ERCOT (2012r), Section 6.5.7.3.
[173] See ERCOT (2012r), Section 6.5.7.

mitigation plan for compliance.[174] The extent to which market participants have completed the process of having a voluntary mitigation plan approved is not public.

In our interviews, a number of suppliers proposed relaxing or clarifying these offer mitigation rules. In terms of clarifying the rules that the IMM will enforce, market participants have expressed uncertainty about what constitutes offer prices that are "substantially above marginal cost" as indicated in the PUCT Substantive Rule. While it may not be possible to strictly define this principle in all circumstances, we do agree that it would benefit suppliers to have a better understanding of how the IMM will generally interpret and enforce it. For example, publishing a document outlining monitoring and mitigation guidelines similar to the one published by Alberta's Market Surveillance Administrator would better inform suppliers' current activities and voluntary mitigation plan proposals.[175] Some of the specific questions that such a guideline could address include: (1) whether marginal cost should be interpreted as short-run or long-run; (2) what constitutes "substantially above" marginal cost and is it situation-specific; (3) whether the IMM will monitor or mitigate based on offer prices in the day-ahead market, or whether it considers this market entirely voluntary as it is treated under ERCOT's protocols; and (4) how suppliers can reflect in their marginal cost calculations various types of opportunity costs (*e.g.*, those related to environmental constraints that limit annual run-hours, self-imposed operating constraints intended to postpone maintenance cycle limits, or fuel-related opportunity costs).

In terms of potentially relaxing the PUCT Substantive Rules regarding monitoring and mitigation, the primary rationale would be to allow market participants to increase offer prices as a means of providing needed investment signals to the market. While there are a number of options for relaxing these rules, the approach would be to enable larger market participants to exercise their market power to a greater but still limited extent. This would increase prices and market returns. We also note that this type of limited, measured approach to market mitigation has worked effectively in Alberta's energy-only market to help attract enough merchant generation to sustain resource adequacy over the past decade.[176] Similarly, more permissive mitigation approaches are applied in European energy-only markets and in the conduct and impact mitigation approaches applied by the MISO and NYISO.[177] A somewhat relaxed monitoring and mitigation construct could contribute to restoring price signals without requiring any substantial market design changes.

There are two important drawbacks to relaxing market monitoring and mitigation rules. First, it invites offers that may deviate substantially from short-run marginal cost, which could introduce pricing and dispatch inefficiencies under some circumstances—although dispatch inefficiencies will also result if opportunity costs cannot be reflected in suppliers' bids. Second, and possibly more importantly, there is no clear way to determine how much the mitigation rules would need to be relaxed to achieve any particular desired level of investment. Given these drawbacks, we recommend relaxing mitigation rules but recognize that doing so may not be the most effective or direct way to restore investment signals, as we discuss further in Section VI below.

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[174] See PUCT (1999), 25.505c-e.
[175] See Market Surveillance Administrator (2011).
[176] See Pfeifenberger and Spees (2011).
[177] See Reitzes, *et al.* (2007)

B. FACILITATING DEMAND RESPONSE

In this section, we address how to facilitate greater demand response participation in efficient price formation, including: (1) a discussion of the importance of demand response in electricity markets; (2) the current level of demand response penetration in ERCOT compared to the estimated potential; (3) the wholesale factors affecting demand response development; and (4) how to efficiently accommodate demand response in wholesale markets so that it can support both reliability and efficient price formation.

1. The Importance of Demand Response in Electricity Markets

Electricity wholesale markets are more volatile than most commodity markets because they have neither storage capability nor sufficient short-term demand elasticity to moderate consumption during shortages. Most customers are on fixed rates and have no incentive to use less when spot prices are high, even on the hottest day of the year. When demand exceeds available supply, real-time prices rise to the offer cap, and system operators initiate involuntary load shedding. Therefore, load's traditional inelasticity creates reliability challenges without a large generation reserve margin. It is also economically inefficient, with some high-value end-uses being curtailed involuntarily while other relatively low-value uses continue.

In contrast, if a portion of demand is exposed and responsive to real-time prices, involuntary load shedding may be avoided. Demand response can thus reduce the amount of generation reserves needed to maintain a given level of reliability. Moreover, demand response can enable energy-only markets to support sufficient generation investment to reliably serve the residual load. Because demand response tends to occur at strike prices exceeding the offers of generation, its participation in the market can yield relatively high clearing prices, but only if it is able to set the price at its strike price. Realizing a continuum of high prices related to demand reductions at varying levels of scarcity would create a more robust and predictable distribution of peaking prices. This translates into a more stable revenue stream for generators than reliance on rare excursions to a high price cap. Achieving more DR participation would also displace some generation investments, but would achieve the same level of reliability. Our "High DR" simulations presented in Section IV demonstrate this effect.

Achieving this ideal requires widespread demand response and market structures that enable loads to contribute to efficient price formation. However, the ERCOT market is only part way toward that ideal. The ERCOT market has some demand response, although substantially less than the likely economic potential, and it is largely unable to contribute to efficient price formation. Nor is the reliability value of all types of DR fully recognized in ERCOT's loss-of-load studies used to set the target reserve margin.

2. Demand Response Penetration in ERCOT versus Estimated Potential

There are many forms of demand response in ERCOT: some is administered by ERCOT, some by the transmission and distribution service providers (TDSPs), and some by the load serving entities (LSEs); some is triggered by under-frequency and emergency conditions (which generally coincide with very high prices); and some is triggered by high prices directly. In this section, we quantify the current penetration of demand response in ERCOT in terms of peak load reductions, and we compare it to the achievable potential.

a. Current Demand Response Penetration

ERCOT currently administers two DR programs: (1) the Load Resources program (previously known as "LaaR"), where large customers with loads that are controllable via telemetry and under-frequency relays can provide up to 1,400 MW of responsive reserves on a day-ahead basis and can be deployed for energy in system emergencies;[178] and (2) the Emergency Response Service (ERS) program, where approximately 365 MW of medium-large commercial and industrial (C&I) customers are paid a capacity payment to be callable as a last resort in system emergencies.[179] ERCOT also allows price-sensitive demand bids in its day-ahead market. In fact large quantities of day-ahead demand bid as price-responsive, but it appears that most of these bids reflect load-side hedging rather than price-responsive load, *i.e.*, LSEs will defer some purchases to real-time if day-ahead prices become too high. ERCOT does not admit load reductions to offer and be paid as energy supply in either the day-ahead or real-time markets as in the FERC-regulated ISOs.[180]

The TDSPs pay for approximately 310 MW of load to be curtailable in emergencies as part of their "energy efficiency" programs.[181] The TDSPs also stimulate some peak load reduction through their four coincident peak (4CP) rate structures, which charge municipally-owned utilities, electric cooperatives, and large customers for transmission based on their metered load during the highest system load intervals in each of the four summer months (June through September). ERCOT does not directly observe the quantity of peak load reductions associated with 4CP rates, but a 2007 survey of LSEs indicates that it results in about 223 MW of load reductions.[182] Other analyses have found higher levels of response (600 MW or more) although an empirical analysis has not been conducted.

Price-based demand response is currently provided only by LSEs, but not through ERCOT. REPs and public power entities can create incentives for price-based DR by providing lower rates to customers who use less or curtail when spot prices are highest. We understand from our interviews with REPs that many large industrial customers are on "block-and-index" pricing, where all consumption above a certain amount is exposed to real-time prices. We also understand that few smaller customers are exposed to prices or engaged in any type of demand response.

Unfortunately, the extent of price-response programs is difficult to quantify exactly because pricing arrangements are a private contractual matter between REPs and their customers. Price-based load reductions were likely a major contributor to the 1,700 MW ERCOT load forecasting error in 2011 when prices reached $3,000/MWh. (The error may also be attributable in part to

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[178] Although 2,500 MW are registered to participate as Load Resources, much less has been available at any given time. In the summer, as little as 850-900 MW participates during peak conditions, when registered Load Resources seek to preserve their ability to respond to high prices, to reduce their metered load during 4CP intervals, and to reduce their likelihood of being curtailed. ERCOT has not yet hit the 1,400 MW LR procurement ceiling since the ceiling was raised in April along with the PUCT's expansion of the RRS requirement, see ERCOT (2012a).

[179] See ERCOT (2012a).

[180] See Newell and Hajos (2010), p. 9.

[181] See ERCOT (2012a).

[182] See ERCOT (2007), pp. 18-19. The survey of LSEs did not account for 4CP load reductions that were triggered in response to signals from third parties or undertaken unilaterally by customers.

4CP response, voluntary public response to conservation appeals, and load forecast model error.) Other estimates indicate less price responsive demand. ERCOT's 2007 survey identified only 431 MW of curtailable load on real-time pricing.[183] Another study of industrial customers' 2002–2005 consumption found very little responsiveness to wholesale price signals.[184] We believe that quantifying price-responsive demand in ERCOT is an important area for further study.

Based on the above, we estimate the total quantity of peak load reductions from demand response in ERCOT to be approximately 1,600 MW in various registered ERCOT and TDSP programs. We also attribute approximately 1,000 MW of ERCOT's 2011 load forecasting error to customers' responses to high prices and 4CP rate structures. Including both registered and price-based load reductions, we estimate a total demand response penetration of approximately 4% of peak load.[185]

b. Comparison to Demand Response Potential Estimates

We estimate a total achievable potential of 8-15% of peak load reductions, which implies that DR penetration could grow by another of 4-11% of peak load. Our sense is that the potential is much closer to the high end of this range, given how few small customers are yet engaged and how much more valuable demand response will become as generation reserve margins become tighter and offer caps rise.

This 8-15% total potential estimate is based on a review of recent studies estimating the possible peak demand reduction achievable in Texas through expanded DR activities. The first study, FERC's 2009 *National Assessment of Demand Response Potential*, was led by *Brattle* staff and is the only study to develop a bottom-up DR potential estimate for each state.[186] It estimates DR potential by 2019 under three scenarios representing different program adoption rates. The second study is ACEEE's 2007 *Potential for Energy Efficiency, Demand Response and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*.[187] It estimates the potential impact of all cost-effective DR by 2023.

Basic assumptions behind the scenarios in these studies include:

ACEEE "Economic Potential" — Residential and commercial participation in direct load control are 43% and 36%, respectively; with expanded industrial participation in the Load Resources program.

FERC "Expanded Business as Usual" — Existing programs are expanded to national "best practices" levels of enrollment, with roughly 25% of residential and industrial customers and 5% of commercial customers enrolled in DR programs.

FERC "Achievable Participation" — Dynamic pricing and load control technologies are deployed on an opt-out basis, with roughly 75% of customers participating.

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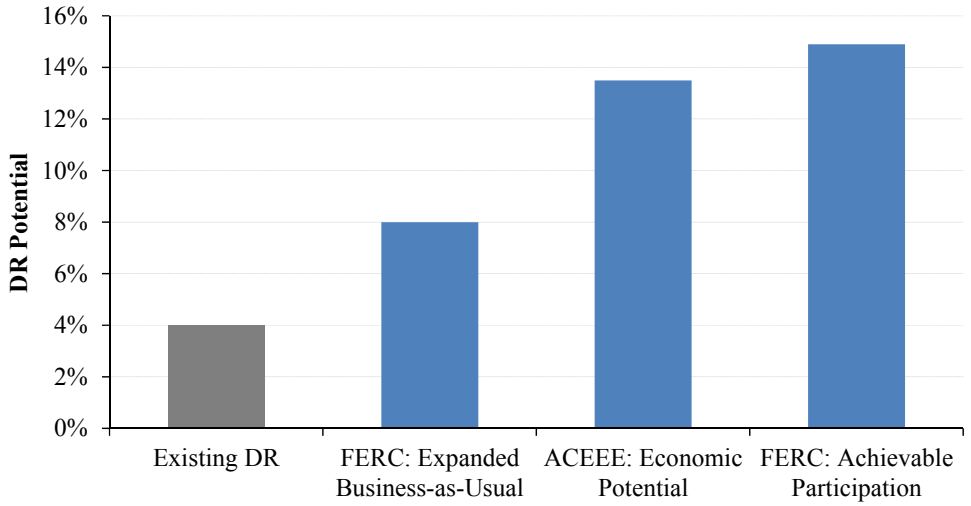
183 See ERCOT (2007), p. 12.
184 See Zarnikau and Hallet (2008).
185 The 1,600 MW of registered DR includes 900 MW LR, 365 MW ERS, and 310 MW in TDSP programs. Total penetration percentage calculated from 68,379 MW 2011 peak load; see ERCOT (2012h), p. 3.
186 FERC (2009).
187 Elliot, *et al.* (2007).

FERC "Full Participation" — Dynamic pricing and load control are deployed on a mandatory basis; we did not include this scenario in our analysis because we do not consider it plausible over a ten-year horizon, and because a mandatory deployment under a default tariff would not be possible under current regulations.

Figure 30 shows the range of DR potential estimates of 8%-15% peak load reductions from the two studies, relative to the current penetration of approximately 5%.

Figure 30
ERCOT DR Peak Demand Reduction Potential



Sources and Notes:
Existing DR estimated by *Brattle* to include large industrial price response.
ACEEE Economic Potential is adjusted from the figure in ACEEE report to include only DR potential and exclude impacts from other sources.

Some parts of the country are closer to meeting their potential, such as in PJM, where DR can reduce peak load by 10%.[188] We and others attribute that success primarily to the attractiveness of capacity payments to third-party curtailment service providers (CSPs), who are able to aggregate customers' load reduction capabilities and sell them into PJM's capacity market. In fact, over the nine delivery years since the capacity market was implemented, PJM's DR penetration has increased from 1% of peak load in 2006/07 up to 10% for 2015/16.[189]

c. Opportunity Areas for Achieving Greater Penetration

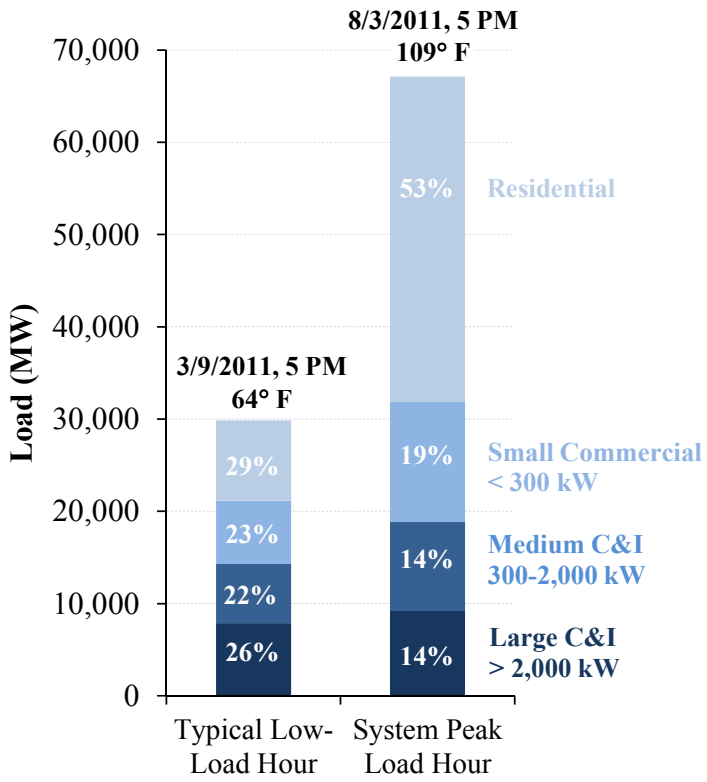
Current penetration and achievable potential vary by customer segment, as do the types of opportunities most suitable for each. We examine large C&I customers, medium-large C&I customers, and residential and small commercial customers. The most important DR opportunities are those that are achievable during summer peak load conditions, although some less substantial cost savings would also be available during other parts of the year. Figure 31

[188] Based on 15,755 MW of cleared demand resources in the 2015/16 Base Residual Auction, see PJM (2012a), p. 11. The PJM 2015/16 peak load forecast is 163,168 MW, see PJM (2012b), p. 4.

[189] Based on 1,200 MW of Active Load Management in 2006/2007, see PJM (2012a), p. 12. The PJM 2006 peak load was 145,951 MW, see PJM (2007), p. 56.

shows that residential and small commercial customers accounted for 72% of load during the 2011 system peak, even though they made up only 52% of load during low-load conditions. Residential and small commercial customers show very high loads during peaking conditions relative to their average load. By comparison, large C&I customers show a peak load that is only marginally above off-peak loads.

Figure 31
Peak and Off-Peak Load by Customer Segment



Source:
Based on ERCOT data, ERCOT (2012a).
Reported temperatures are from Dallas.
Customer class breakdown is for competitive choice areas.

Largest Commercial and Industrial

The largest customers with peak loads greater than a few MW are already quite engaged in programs to exercise their operating flexibility to manage their substantial energy costs. We heard in our interviews that large C&I customers who have any flexibility are already responding to wholesale prices, managing 4CP load to reduce T&D charges, and providing some LR and ERS in ERCOT programs.

Given their active participation, the potential for engaging additional large C&I *customers* may be limited, but the magnitude of their load reductions may increase in response to higher prices. The most interesting incremental opportunity with large customers is to enhance their role in price formation, by entering them directly into SCED at a strike price, as we discuss further below. Because Load Resource providers are already controllable with telemetry, they are the best candidates to participate in SCED and set real-time prices.

Medium Commercial and Industrial

Most customers below a few MW of peak demand do not spend enough on energy to have developed sophisticated load management practices. They usually do not have their own energy management staff, although they may engage consultants or their REPs for this purpose. We understand from our interviews with REPs that this segment is not yet fully engaged in dynamic pricing or curtailable rates. So far, they have done little to reduce peak demand because super-peak prices have not been high enough to generate widespread interest among customers for whom energy is a small percentage of their total costs. The REPs we interviewed expressed growing interest as their exposure to higher price caps increases, but they cautioned that penetration will be slow.

Customers with peak loads exceeding 300 kW may be attractive targets for CSPs if they have the opportunity to aggregate their load reductions and sell them as wholesale capacity supply. In fact, this is the segment that has provided most of the 450 MW of ERS to date. Other ISOs with capacity payments have elicited substantially more DR and done so in a way that forces the DR to compete with generation for providing both capacity and energy. While we believe that ERCOT could similarly procure substantially more DR through its ERS program, we caution against this avenue because of its out-of-market nature, as we discuss in Section VI.

Residential and Small Commercial

As Figure 31 above shows, small customers account for more than 70% of peak load, and they currently provide little demand response, especially in the retail-choice areas of the ERCOT region. Large numbers of small customers are inherently difficult to engage for DR because the potential savings are relatively small compared to recruitment, equipment, setup, and ongoing management costs. Mass market penetration will be slow and possibly never very deep due to limited interest and lack of economies of scale. However, penetration can be much higher than zero, and the PUCT has laid the groundwork for willing customers to engage.

The TDSPs will soon complete the deployment of the Advanced Metering Infrastructure (AMI) in all investor-owned utility territories, achieving capabilities beyond all other states.[190] This AMI will enable REPs to offer time-varying and dynamic rate options to the mass market, but it is unclear how many customers will enroll in dynamic rates. There is limited empirical evidence on adoption rates, since dynamic tariffs are just being rolled out to residential customers in places like California, Maryland, and Washington, DC.[191] However, post pilot surveys find very high satisfaction levels among participants.[192] Recent pilots around the world have consistently shown that customers will reduce peak demand when faced with a higher peak price or a rebate for load curtailment, even without installing any enabling equipment such as smart thermostats. Peak load reductions generally range from 5% to 10% for time-of-use rates, and from 10% to 30% for rates with stronger peak price signals.[193]

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[190] See PUCT (2011).

[191] For example, Pepco is in the process determining the details of its residential dynamic pricing rollout with Maryland stakeholders; see MD PSC (2012). Also, PG&E has begun offering dynamic pricing on a voluntary basis to all eligible residential customers; see PG&E (2012).

[192] See Faruqui (2009).

[193] See Faruqui and Palmer (2012), and Faruqui and Sergici (2009).

Additional enabling equipment, such as smart thermostats, switches on pool pumps, and other controls dramatically increase residential customers' ability to respond. However, these advanced controls may cost $300 per customer[194] and may not be cost-effective in many cases. Even if they are cost effective, many customers may not want to front the cost, and neither will REPs if customers do not sign a multi-year contract. Yet there are a number of ways enabling equipment could develop. Perhaps some REPs will decide to offer equipment at a discount for a two-year plan, like a cell phone, or perhaps TDSPs could play a role in providing equipment and installation services paid for by participating customers via on-bill financing.

3. Wholesale Factors Affecting DR Development

There are a number of aspects of the wholesale market that affect the ability of LSEs and CSPs to develop incremental DR resources. We examine some of those factors here, including: (1) the level of the price cap, with higher prices creating more incentives to increase DR; and (2) the structure of wholesale DR products.

a. Impact of Price Cap on DR Development

We expect that the Commission's plan to raise the price cap will incent REPs and customers to develop more DR to hedge their exposure and reduce the cost to serve. For example, with $9,000 scarcity prices, the value of DR is three times as high as when scarcity prices reach only $3,000. As reserve margins tighten and the expected frequency of price spikes increases, the value of peak reductions will further increase.

b. Impact of Wholesale Product Structure on DR Development

In the Eastern RTOs, CSPs have developed the majority of new DR by selling aggregated emergency call options into capacity markets. The CSPs there depend on capacity payments to provide a revenue stream even in years without emergencies. A pure energy-only market with very high price caps may be less conducive to CSP participation if they cannot sell capacity. They can only sell energy, and only if the RTO allows their load reductions to be counted as supply, as contemplated in some ERCOT and stakeholder proposals. Even that might not attract CSPs if they can earn revenues only in the rare event that high scarcity pricing occurs.[195] REPs can much more easily monetize the *expected* value of DR if physical hedging through curtailments allows them to manage their exposure with less financial hedging. In our interviews, REPs expressed cautious interest in this strategy, but our impression is that few REPs are yet implementing such options. We expect them to implement these options more as price caps increase and reserve margins tighten. Overall, it is still unclear whether capacity payments are needed to stimulate large quantities of demand response development, but it seems likely that such payments would accelerate development.

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[194] Estimates based on stakeholder interviews.

[195] However, even an energy-only market could support annual compensation for CSPs at the *expected* value of their ability to call load reductions (like a capacity payment). CSPs could sell high priced call options to other market participants if the ISO facilitated such transactions by recognizing load reductions (if the strike price is reached and load reductions are realized) as energy supply in real-time.

ERCOT has used capacity payments to attract approximately 450 MW of emergency DR through the ERS program, formerly referred to as EILS.[196] We find that this program has had onerous qualification and performance requirements, the relief of which could attract substantially more DR capacity. ERCOT recently improved the program by imposing less stringent availability requirements, lowering minimum size limits (from 1 MW to 100 kW, enabling many more medium-sized C&I customers), enabling behind-the-meter generation, and redefining limits on the number of calls.[197] If ERCOT wants to expand ERS further to support reliability, it should consider further reforms to the product definition, including: (1) 2-hour curtailment notification, which should be sufficient for resource adequacy purposes;[198] (2) better-defined limits to the number of call hours, which would help providers understand their risks; and (3) an increase to the number of call hours so that the product remains useful in an extended heat wave. Similar reforms could also apply to DR products qualified to sell capacity if the PUCT pursued a policy of imposing resource adequacy requirements on LSEs. While we believe there is substantial potential to achieve more DR participation through expanding the ERS program, we caution against this option due to its out-of-market nature and potential to cannibalize DR that could have developed on an in-market basis.

In one area of DR-related market structure, ERCOT is ahead of most other ISOs. Its Load Resources program, consisting primarily of industrial customers, provides up to 1,400 MW of responsive reserves that can respond quickly to emergencies via under-frequency relays or through 10-minute load reductions in response to ERCOT dispatch. This provides a valuable reliability service and also a source of revenue that has supported DR development. Responsive reserves, like capacity-based products, are an attractive opportunity for DR because they receive steady revenues while being deployed only very infrequently. A good market structure provides multiple revenue opportunities, allows DR to compete on a level playing field with generators to provide the same services, and allows each resource to find its highest-value combination of uses.

4. Efficiently Incorporating DR in Wholesale Markets

Even if a substantial quantity of price-responsive load were to develop in ERCOT, this does not mean that it will be easily or automatically incorporated into the wholesale market. To achieve the most efficient wholesale price outcomes, these resources would need to be accommodated and accounted for in wholesale operations.

a. Demand Response Participation in Energy Price Formation

For demand response to contribute to efficient energy price formation, it must be able to help set the energy clearing price at a strike price equal to its willingness-to-pay for energy (or its strike price for being curtailed). Achieving this simple goal is relatively straightforward in the day-ahead energy markets: LSEs can enter price-responsive demand bids reflecting arrangements they may have with their customers to manage loads under extreme market conditions. Day-ahead participation should efficiently accommodate many DR resources by allowing them to

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[196] See ERCOT (2010b).
[197] See ERCOT (2012l).
[198] ERCOT is currently planning a pilot program to all ERS with 30-minute notification times instead of the current 10-minute requirement.

plan for lower consumption in real-time. However, the day-ahead market will not accommodate DR resources with strike prices at or near the price cap. Load reductions with strike prices at or near the cap would not likely be triggered by day-ahead prices, which tend to be less volatile than real-time prices. They may be triggered in real-time when unexpected shortages occur, but only if they can respond on a real-time basis, preferably within SCED. Incorporating DR into real-time markets is much more challenging than day-ahead.[199]

Demand response is not yet able to express price-sensitive bids or offers in SCED. Even if ERCOT enhanced SCED to accommodate DR bids or offers, it would be a challenge to incorporate these resources due to a lack of telemetry, nodal dispatch and settlement, block loading, and notification lead times. If all of these requirements were imposed on DR resources to qualify for participation in SCED, many end users may not bother to participate after considering the setup costs and any consequences for not performing when dispatched. They may prefer to respond voluntarily to prices, even if participating in SCED would allow them to better optimize their operations against prices.

It is important to consider that even loads that merely respond to prices can potentially help set prices at efficient levels without participating in SCED. They could theoretically help set prices by using more energy when the price is below their willingness-to-pay and less when the price is above. However, the current shape of the supply curve and the scarcity pricing function is so "hockey-stick" shaped that prices move too quickly from low levels to the cap and back for loads to respond quickly enough to guide the market toward equilibrium somewhere in middle on the power balance penalty curve. The resulting prices can be quite unstable, even when ERCOT is deploying its ERS and LR resources. Each of these emergency deployments could potentially reverse the price to non-scarcity levels.

Enabling large amounts of DR to contribute to efficient price formation in real-time will require significant changes in market design. We examine four complementary channels that would increase the chance of success:

1. Enabling some DR to participate in SCED so it can set prices directly, and perhaps enabling all emergency DR to set prices at their individual strike prices during reserve shortage conditions, as in PJM;[200]
2. Providing timely, *ex-ante* pricing information that enables price-responsive demand to adjust its consumption downward when prices are above the strike price and upward when prices fall below the strike price;[201]
3. Fostering a wide and gradually-increasing scarcity pricing function as discussed in Section V.A.2 above, so DR that is not in SCED can respond to prices without depressing prices to levels far below their willingness-to-pay; and

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[199] To our knowledge, price-sensitive demand bids are not yet accommodated in any RTO real-time energy market due to technical and communication infrastructure challenges. See for example, PJM (2012c), p. 32.

[200] See PJM (2010).

[201] This is included in NPRR 351 (Look-Ahead SCED).

4. Never deploying emergency DR at a zero price (which is the effect if the load is simply dropped), but instead at its strike price, which should be set at or near the price cap if the DR is supported by capacity payments not available to generators.[202]

These measures would help improve DR participation in real-time markets to engage demand resources that are most available on a just-in-time basis or that have very high strike prices. Other demand resources are already efficiently accommodated through the day-ahead energy market. We more fully describe these options below.

Demand Response in SCED

ERCOT already has an ongoing "Load in SCED" effort that aims to incorporate DR into SCED as supply-side offers on load reductions.[203] This effort encompasses a number of initiatives to allow load reductions to be committed and dispatched when economic, and to set prices when marginal. Some of the key design questions ERCOT and its stakeholders will have to resolve are:

Supply-Side Offers vs. Demand-Side Bids — The industry's current focus is on supply-side offers, which have the advantage of recognizing load reductions provided by third-party CSPs who do not own any load. However, validating cleared quantities requires defining a hypothetical "baseline" below which load reductions are measured. Baselines are inherently awkward to define, as experience in other ISOs has demonstrated.[204] ERCOT can benefit from other ISOs' successes and failures, as well as its own experience in validating reductions in its ERS program, but no perfect method exists. It would be simpler to accommodate only price-sensitive demand bids from LSEs. Given the healthy retail competition in ERCOT, it may be less important to accommodate CSPs than in other jurisdictions. It may be that the most appropriate role for a CSP in an energy-only market is as a subcontractor to an LSE.

Qualification Criteria — The most rigorous but narrow approach would treat load like generation. Load offers would have to have real-time telemetry, nodal dispatch and settlement, and probably continuous controllability. ERCOT is also considering allowing aggregated resources (not at a single node) and virtual telemetry. However, the FERC has just approved a scarcity pricing proposal in PJM that allows demand resources to set prices during scarcity conditions even if it does not meet the normal criteria.[205] ERCOT should consider adopting similar provisions in order to substantially expand participation and enable load to set prices during scarcity, at a slight cost to operational efficiency.

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[202] This is proposed in NPRR 444, as discussed further above.

[203] Load in SCED is an effort between ERCOT staff and the Demand Side Working Group (DSDWG), subordinate to the Wholesale Market Subcommittee, and the Market Enhancement Task Force (METF). The focus of the DSWG is the enhancement of ERCOT Market Systems to support the development and implementation of Demand Response products. The METF is concerned with the design of Real Time Dispatch (RTD) and Commitment (RTC) upgrades to ERCOT Market Systems that incorporate Demand Response products into the Day-Ahead Market and the Real Time Market through Security Constrained Economic Dispatch and Commitment. See ERCOT (2011d).

[204] See, for example, Radford (2011), and Newell and Hajos (2011), p. 9.

[205] The will be required to submit other operational data in lieu of telemetered data. See FERC (2012).

Compensation and Funding — If supply offers clear, they would have to be paid a market price. The Demand Side Working Group (DSWG) has already identified that the economically efficient payment is "LMP-G" since the customer that has reduced its load by a unit is also saving "G," the generation component of their retail rate. Hence, the customer earns LMP in total, which is the efficient level.[206] Such payments could be funded by the residual load, either within the same LSE, zone, or pool. Such side payments are unnecessary if DR participation is limited to demand-side bids.

However, even if Load in SCED is implemented, it will not necessarily attract many participants other than those who are already providing ancillary services. Participation in SCED enables precise optimization of energy consumption and cost, but it could require meeting costly qualification criteria, create additional implementation difficulties, or result in penalties for deviating from dispatch instructions. Our understanding is that a zonal version of Load in SCED, called "Balancing Up Load," failed to attract participants for these reasons, among others. Other ISOs may have more direct participation due to the widespread participation of CSPs, who do not own load and need to be paid by the RTO for any capacity or energy they provide. There may be options for forcing more load into SCED however. For example, if ERCOT opts to impose resource adequacy requirements on LSEs in a way that explicitly recognizes demand response, it could require that all providers submit strike prices for use in SCED.

Facilitating Efficient "Passive" Responsiveness to Prices

For price-sensitive customers to respond efficiently to prices, they need visibility into current and likely future prices. ERCOT's current plan to provide an indicative price before each interval will help inform customer consumption decisions to the extent such indicators are fairly accurate. However, that price is not binding and it may change, particularly if many loads decide to respond (the surprise could be lessened if prices were incorporated in the load forecasting model, as discussed below). Prices are particularly unstable at the edge of scarcity conditions because there is no width to the power balance penalty curve, and the rest of the scarcity price schedule is flat at the price cap. A mere 50 MW change in load caused prices to jump from low non-scarcity prices to the price cap. Therefore, any shift in system conditions can move prices from one extreme to the other, no matter what any price-responsive load does. There is little chance for a price-responsive customer with a $1,500/MWh strike price to adjust its load until the price settles smoothly at $1,500.

An obvious solution is to revise the scarcity pricing curve to be more gradual. This would be more efficient, since the marginal system cost when deploying one MW of responsive reserves is less than the marginal system cost when shedding load (nor would a true energy-only market, in which scarcity prices are set by load willingness-to-pay, experience such bimodal pricing). Ideally, the width of the sloped part of the curve would be more than the approximately 1,000 to 2,000 MW typical hourly change in system load in the several hours when loads are at or near their daily and annual peak. This would allow respondents to see a few intervals of intermediate prices and adjust their consumption accordingly. Therefore, we recommend tilting the entire scarcity pricing curve by releasing responsive reserves and other administrative interventions to

[206] For a more complete discussion of why "LMP-G" is the efficient payment for wholesale DR reductions, see Newell, Spees, and Hanser (2010).

SCED at a range of prices as discussed in Section V.A.1.c above. The curve could start at $500 and increase according to a scarcity pricing function up to a price cap based on the value of lost load (*e.g.*, $9,000/MWh) when shedding load.

It must be noted, however, that a more gradually sloped scarcity pricing curve would reduce generators' energy margins and therefore lead to a lower economic equilibrium planning reserve margin. Our simulations indicate that at the highest price caps, a gradually sloped scarcity pricing curve beginning at $500/MWh and rising linearly to the price cap just before shedding load would reduce the equilibrium planning reserve margin by roughly two percentage points relative to the current scarcity pricing function, which triggers full scarcity pricing almost immediately with very little slope.

Avoid Price Reversal

Currently, when LR or ERS is deployed, the resulting load reduction can reverse prices to non-scarcity levels or prevent high prices from ever occurring. All of the design enhancements discussed above could help limit this price reversal. Load Resources and ERS could be deployed as price-responsive demand bids incorporated into SCED. Alternately, if they are deployed as supply offers, their potential load reduction would have to be added back to the demand for establishing the settlement price.

b. Resource Adequacy Credits for Demand Response

In the event that the PUCT and ERCOT choose to impose resource adequacy requirements on LSEs, ERS would transform such that the participating DR resources would compete with generation to provide resource adequacy. DR would not have the same qualification criteria and performance requirements as generation, since it has very different characteristics. However, the qualification criteria and performance requirements would have to be defined in such a way that all competing products provide the same resource adequacy value at the margin. For example, at high reserve margins, DR can provide the same resource adequacy value as generation even if the number of calls is low. As DR penetration increases and generation reserve margins become tighter, DR is likely to be needed more often, and so the number of call hours the system operator is allowed must increase if DR is to be as valuable as generation.

As a simpler alternative, but one that does not admit CSPs, DR could be used to reduce a REPs resource requirement. REPs would be obligated to procure reserves only for their "firm" load , not for "non-firm" load.

c. Accounting for Price-Responsive Demand in Load Forecasts

ERCOT uses different load forecast models for different timescales of operation, including using: (1) a long-term load forecast to determine the amount of resources needed to meet the 1-in-10 reliability target; (2) a short-term forecast to make sure it has enough capacity committed on a day-ahead and hour-ahead basis; and (3) a very short-term forecast for its real-time dispatch. None of these forecasts account for price-responsive demand, except in partial and indirect ways. As a result, ERCOT's load forecasts tend to be conservatively high during periods when prices rise to extreme levels.

Accounting for price-responsive demand in load forecasts requires adding a price variable to the load forecasting model so the model can "learn" that when prices reach very high levels, load is

lower than it otherwise would be under similar time and weather conditions. The planning model would also need to incorporate price by adjusting load downward during hours in which load would be shed and prices would be at the cap. We performed a similar step in our analysis of scarcity pricing and load shedding for this study, as discussed in Section IV above; we added 1,700 MW of additional supply during scarcity and load-shed conditions based on observed errors in the load forecast model during scarcity conditions in 2011.

VI. REVIEW OF POLICY OPTIONS FOR RESOURCE ADEQUACY

This section discusses resource adequacy objectives and an array of market design options that the PUCT and ERCOT could pursue to achieve those objectives. We discuss the advantages and disadvantages of each option, although we do not recommend any one over the others because the best path depends on the policy objectives.

A. RESOURCE ADEQUACY OBJECTIVES

Before pursuing any major market redesign efforts, we recommend that the PUCT and ERCOT first clarify the fundamental design objectives of ERCOT's resource adequacy construct. More specifically, we recommend considering the following questions:

1. Is the current 1-event-in-10-years (1-in-10) reliability standard yielding the appropriate and efficient resource adequacy target around which to design the ERCOT wholesale power market?
2. Should regulators determine the reliability target, or should the reliability level be determined solely by market forces?
3. Even if the target reliability level is to be determined by market forces rather than an administrative determination, do regulators wish to impose a backstop constraint preventing very low reliability outcomes?

Answering these questions will help regulators determine which of several policy paths to pursue, achieve a more efficient outcome, and reduce regulatory uncertainties for market participants.

1. Appropriateness and Efficiency of the 1-in-10 Reliability Target

Consistent with industry practice, ERCOT's reliability target for the bulk power system is based on LOLE, or the frequency of expected firm load shed events caused by supply shortages. For decades, the utility industry has used a 1-day-in-10-years bulk power standard for setting target reserve margins and capacity requirements.[207] While the origin of the 1-in-10 metric is unclear, references to the standard appear as early as the 1940s.[208] Usually, utilities and system operators offer no justification for the reasonableness of 1-in-10 other than that it is the industry standard

[207] For a discussion of the 1-in-10 standard and alternatives, see Carden, Wintermantel, and Pfeifenberger (2011).

[208] See Calabrese (1950).

or that it is consistent with NERC guidelines.[209] Because customers rarely complain about bulk power reliability under the 1-in-10 standard and system operators and policymakers generally are not faulted if they adhere to long-term industry practices, few question 1-in-10 as an appropriate standard.

It is also helpful to understand that the 1-in-10 standard is not applied uniformly throughout the industry. For example, ERCOT and many other system operators interpret the 1-day-in-10-years standard as "1 outage event in 10 years," while other system operators such as SPP interpret the 1-day-in-10-years standard as "24 outage hours in 10 years." While the two interpretations sound semantically similar, the level of reliability they impose differs significantly. As shown in a recent case study of a 40,000 MW power system, the former definition requires a 14.5% reserve margin, while the latter requires only 10%.[210] Finally, some regions, including TVA, SERC, and WECC, do not use the 1-in-10 standard at all to set planning reserve margins, instead using a different approach or leaving this task to their member utilities.[211] For example, utilities within SERC and TVA have determined planning reserves based on explicit benefit-cost analyses of the economically optimal reserve margin. A recent NRRI whitepaper explains how these studies can be conducted.[212]

The 1-in-10 standard is also poorly-defined with respect to the events it describes. For example, the "1 event in 10 years" standard that ERCOT and many other regions use is independent of the size or duration of outage events. Small load-shed events are given the same priority as widespread, large events. For example, two 2 MW events in 10 years with a duration of 1-hour each would not be acceptable, whereas one 3,000 MW event lasting 10-hours would still meet the standard. A better-defined metric would recognize that the latter case represents poorer reliability because it requires 7,500 times more MWh to be shed. Moreover, because outage events tend to affect a larger proportion of total load in smaller power systems, 1-in-10 does not provide the same level of reliability for customers in differently-sized power systems. These concerns led the NERC Generation and Transmission Planning Models Task Force to adopt the better-defined metric of *normalized* Expected Unserved Energy (EUE), which is the MWh of load shed divided by the total load if there had been no shedding.[213]

Another important consideration is the role of bulk power reliability in the context of overall customer reliability. In ERCOT, the 1-in-10 resource adequacy target implies average outages of less than 1 minute per year per customer.[214] This compares to average annual customer outages

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[209] Some industry participants may believe that the 1-in-10 standard is a NERC requirement, but it is our understanding that this is not quite the case. In many NERC Regional Entities, non-binding guidelines reference the 1-in-10 standard or require a study of reliability, although the actual mandated reliability levels are determined by the utilities or RTOs themselves under state or FERC oversight. Some NERC entities, such as SERC, do not rely on the 1-in-10 standard as a guideline, see NERC (2008).

[210] See Carden, Wintermantel, and Pfeifenberger (2011).

[211] See NERC (2008).

[212] See Carden, Wintermantel, and Pfeifenberger (2011).

[213] See NERC (2010).

[214] Based on an average 2-hour, 1,500 MW outage event every 10 years in a 65,000 MW system. The 2-hour outage translates to 12 minutes of outages per year, while each individual customer would have only a 2% chance of being curtailed during those outages because only 1,500 of 65,000 MW will be shed. This results in approximately 0.3 minutes of load shed per customer per year with these assumed outage characteristics.

well in excess of 100 minutes due to outages caused by disturbances on the distribution system (and on the transmission system to a lesser extent). During severe storm events, annual outage durations can reach several hundred to several thousand minutes per customer, as shown in Table 17.

Table 17
Average Annual Minutes of Power Outage per Customer

	2008 *(min)*	2009 *(min)*	2010 *(min)*	2011 *(min)*
Centerpoint	8,690	136	111	170
Oncor	344	260	246	237
AEP Central	943	165	2	306
TNMP	47	1	41	54
Entergy	10,480	195	3	219

Source:
Data aggregated by ERCOT from utilities' Annual Service Quality Reports, see PUCT (2012a).

For these reasons, the value of maintaining a high resource adequacy standard needs to be evaluated carefully in the context of distribution- and transmission-related outages, which have a much greater impact on customer reliability. Creating market structures that further increase resource adequacy may prove to be less cost-effective than investments to improve distribution reliability.

Despite these considerations, little empirical work has been done in the industry to quantify the economics of the 1-in-10 criterion to confirm that it reasonably balances the tradeoffs between the economic value of reliability and the system capital costs imposed. Nor have the economics of the 1-in-10 target been evaluated in ERCOT specifically. We recommend that ERCOT, the PUCT, and stakeholders re-evaluate the target in terms of its overall value, policy objectives, risk, and cost-effectiveness before re-designing the electricity market in an attempt to achieve that target.

Such an economic evaluation of bulk system reliability should take into account all economic and risk mitigation benefits of increased planning reserve margins, including reduced cost of outages considering customers' VOLL, the reduced costs of emergency power purchases, and a reduced incidence of extremely high-cost outcomes during unusual market conditions.[215] Note also that VOLL varies widely by customer types, with residential customers generally having the lowest outage-related costs (often less than $5,000/MWh) and commercial and certain industrial customers the highest (often exceeding $10,000/MWh). A load-weighted average VOLL for the system is sometimes used in these evaluations. However, if load-shed events can be targeted to customers with the lowest VOLL, then the optimal resource adequacy target will be lower. We discuss options to let consumers differentiate reliability in Section VI.B.

[215] See Carden, Wintermantel, and Pfeifenberger (2011).

2. Regulator-Determined versus Market-Determined Reliability

Another important question is whether the PUCT and ERCOT should determine the desired level of bulk power reliability, or whether the reliability level should be determined solely through market forces. All other U.S. regulators have determined that reliability standards should be mandated, except to the extent that demand response allows customers to self-select a lower level of firm service. In those markets, bulk power reliability is treated as a public good with administratively-imposed standards, not unlike many other standards such as ambient air quality standards or car safety standards. Even in markets with administratively-determined reliability targets or mandates, there are a variety of market-based approaches for achieving these reliability outcomes. We examine several options of this type in Sections VI.B.2-5.

Allowing market forces to determine the level of resource adequacy is one of the chief theoretical advantages of the textbook energy-only market construct.[216] Under this theoretical design, there is no such thing as "involuntary" load shed because wholesale prices are allowed to rise high enough that eventually sufficient voluntary curtailments will bring supply and demand into balance. The resulting reserve margins and bulk power reliability levels therefore represent the most efficient outcome, based on customers' own expression of the value of reliability. However, as discussed in Section V.B above, this construct is most effective with a substantial level of DR penetration that has not yet been achieved in ERCOT. If and when sufficient DR penetration is achieved, market-determined reliability levels have a clear advantage over administratively-determined reliability outcomes. In the absence of substantial DR penetration, even a market-based approach to determining bulk power reliability must still rely on administrative approximations of efficient prices during scarcity conditions, as discussed in Section V.A.2 above and Section VI.B.1 below.

3. Reliability Target versus Minimum Acceptable Reliability

A final policy question is whether, aside from a target or optimal level of reliability, the PUCT and ERCOT also wish to separately identify a lower "minimum acceptable" level of reliability. For example, market outcomes may be allowed to vary from year to year around an economically optimal target. However, there may be a reserve margins level below which potential reliability outcomes would be unacceptable to customers and policy makers. It might be appropriate to define such a minimum resource adequacy level based on the total amount of load shedding that could occur under worst-case weather, such as that which occurred in 2011.

B. Policy Options

In this section we evaluate five distinct policy options for approaching resource adequacy in ERCOT:

1. Energy-Only with Market-Based Reserve Margin
2. Energy-Only with Adders to Support a Target Reserve Margin
3. Energy-Only with Backstop Procurement at Minimum Acceptable Reliability
4. Mandatory Resource Adequacy Requirement for LSEs
5. Resource Adequacy Requirement with Centralized Forward Capacity Market

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[216] See Pfeifenberger, Spees, and Schumacher (2009), Section IV.

For each option, we describe the concept, advantages and disadvantages, and implementation considerations, considering the following criteria:

- The reliability implications of letting the market determine the level of resource adequacy,
- The market implications of having regulators determine the level of resource adequacy,
- How well it supports investment,
- Economic efficiency,
- Implementation complexity, and
- Regulatory stability.

None of the identified options is perfect or easy to implement because all require tradeoffs among reliability, market efficiency, system costs, and implementation complexity. We outline these tradeoffs to inform the policymakers' decisions.

1. Energy-Only with Market-Based Reserve Margin

Concept: In a pure energy-only market, the market determines the reserve margin based on energy prices alone. There is no regulatory imposition of a planning reserve margin requirement, nor are there out-of-market interventions to support target reserves or adjust energy prices. Energy prices are usually set by marginal generation offers. When all generation resources are fully utilized, the price rises until price-responsive demand curtails itself voluntarily and the market clears at load's marginal willingness to pay for power. The price can rise to very high levels or reach an administratively-determined cap at VOLL if involuntary curtailments are required. A price cap may be used as a safeguard when there is insufficient price-responsive demand to economically ration the scarce power.

Note that ERCOT is not currently a pure energy-only market because of backstop mechanisms such as ERS and RMR contracts, as well as administratively-determined scarcity pricing adders meant to support a higher reserve margin. Other energy-only markets around the world also have insufficient DR penetration and impose backstop reliability measures, although the level of reliance on out-of-market interventions is relatively low in some energy-only markets such as Alberta and Australia.[217]

Advantages: In theory, a pure energy-only market achieves the economically optimum reserve margin because customers choose the level of supply based on their willingness to pay for power during shortages. Customers who value firm supply less do not pay for costly reserves they do not want. In addition, prices always reflect market fundamentals, allowing supply and demand to optimize both short-term operational decisions and long-term investments. Scarcity prices in energy-only markets provide strong incentives to be available when resources are needed the most.

In contrast, with administratively-imposed resource adequacy requirements, all customers have to pay for the same level of planning reserves even if they do not value bulk power reliability, although demand response programs allow at least some customers to opt for lower reliability for a portion of their load. However, incentives for resources to be available during shortages may

[217] See PJM (2009), Section IV.B. See also Pfeifenberger and Spees (2011).

not be ideal because the marginal "price" affecting generator availability and demand response may be driven by administratively-defined capacity performance obligations and penalty structures. Shortage prices and incentives in those markets tend to remain below the higher levels that would be efficient during extreme events, although FERC Order 719 has resulted in most RTOs at least partially addressing this concern.[218]

Disadvantages: Unless there is a large amount of demand that will curtail voluntarily and help set scarcity prices at high levels, involuntary curtailment in an energy-only market may occur more often than customers, regulators, and policymakers find acceptable. Further, spot prices can be highly volatile especially during extreme weather, which can worry regulators and policymakers even if most loads have limited exposure to real-time prices. A pure energy-only construct works best at high DR penetration levels, as we have discussed in Section V, but unfortunately this level of DR participation is yet to be achieved in ERCOT.[219] In the absence of substantial DR participation, an energy-only market must rely on administrative approximations to achieve efficient prices during scarcity conditions. Such administrative estimates in any market construct can introduce inefficiencies because they are subject to error and revision. Finally, the potential for very high price spikes imposes a greater need for market participants to develop more sophisticated hedging techniques and may require ERCOT and the PUCT to impose additional credit requirements to guard against defaults by market participants.

Implementation Considerations: For energy-only markets to be efficient and avoid excessive involuntary load-shedding, a significant amount of demand has to respond to prices. As our ERCOT market simulations demonstrate, several thousand megawatts of load would have to be willing to respond and set prices at several thousand dollars per MW to provide the price and investment signals needed to achieve the 1-in-10 resource adequacy target. This is more challenging than it sounds because ERCOT demand response penetration is currently low and increasing DR penetration is likely to proceed slowly. Moreover, most load is not ideally suited to set prices, although Section V above describes measures that would enable DR to set prices more often. These measures should be pursued and progress monitored.

The other requirement for a workable energy-only market is that regulators and policymakers must be committed to tolerating price spikes and even rare, involuntary load shedding. Investors have to trust that not only the current regulators, but also future regulators will not intervene in a way that undermines their investments. Some of the investors we interviewed fear that future regulators would be tempted to intervene in inherently volatile energy-only markets, thereby undermining investment incentives. Perhaps this concern could be alleviated through education to manage the public's expectations about bulk power reliability and the potential for price spikes and rare load shed events. If taken within the context of the broader economics and value

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[218] See FERC (2008).

[219] Many customers simply want reliable power and are not interested in optimizing their electricity usage against prices, *e.g.*, because the cost differences are too small relative to the bother of actively managing their load or choosing automated protocols. We believe there is a large amount of latent DR capability that will slowly develop in response to price signals while making use of advanced metering infrastructure. However, it would be premature to say exactly how much, and how successful ERCOT can be in enabling much of the DR to help set prices at willingness-to-pay rather than depress prices to non-scarcity levels (*e.g.*, if when customers who value power at $1,500 see prices reach $3,000 their dropping load could cause prices to fall to $100 if the supply curve is very steep).

of reliability, it will be helpful to show that certain levels of infrequent load shedding and occasional price spikes are part of an efficient power market and are no cause for concern. However, this does not mean that public perceptions of such events, when they occur, would not result in unfavorable press or political responses.

2. Energy-Only with Adders to Support a Target Reserve Margin

Concept: If an energy-only market design is the public policy choice, but reserve margin outcomes are expected to be lower than acceptable, market rule changes could increase prices to support additional investments. The PUCT appears to have been pursuing this strategy in recent rule changes.[220] Such actions have not only increased the rewards for resource owners and investors, but have also signaled to the market that the Commission is committed to supporting a healthy investment climate.

As we show in Section IV, however, none of the Commission's existing proposals would likely support a target reserve margin consistent with the 1-in-10 criterion, unless much more price-setting DR were to participate in the market. If the Commission wishes to achieve a 1-in-10 reliability level, it could continue to revise market rules to further increase prices and stimulate investment by: (1) further increasing the high system offer cap, the low system offer cap, or the PNM threshold; (2) expanding the responsive reserve requirement, which would in effect structurally withhold more generation capacity and increase prices; (3) relaxing market power mitigation rules; (4) considering an LMP adder, as some stakeholders have suggested; or (5) introducing various types of capacity or availability payments as a separate, explicit revenue stream as has been done in Spain and a number of Latin American countries.[221] There are an infinite number of possibilities, so we focus on the ones stakeholders mentioned the most.

Advantages: The main advantage of this option is that it could attract more investment and achieve higher reliability without a major market redesign. Moreover, most of these options introduce incremental price signals that generally increase with scarcity, meaning that price signals will help attract and retain the most economic generation resources. We have seen that the Commission's recent actions combined with shrinking reserve margins have already attracted more than 2,000 MW of relatively low-cost generation uprates and reactivations.

Disadvantages: The main disadvantage of further increasing scarcity pricing parameters is that it does not reliably achieve a particular reserve margin. As our analysis in Section IV shows, uncertainties about investors' beliefs and other modeling uncertainties could easily result in a 6 percentage point range of expected equilibrium reserve margins, with even more uncertainty in any particular year. A second major concern is that this approach requires prices to be set at levels deviating from marginal system costs in many hours, possibly resulting in inefficient energy or ancillary service dispatch incentives. Third, the risk of very high price events raises the cost of doing business through higher credit requirements and the need to hedge more. Many

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[220] For example, through its recent 500 MW expansion of the responsive reserve requirement to widen the applicability of the price cap to conditions that are only near scarcity. Similarly, its plan to increase the price cap (applicable as soon as responsive reserves begin to be depleted) have been aimed more at attracting investment than tuning prices to reflect system marginal costs. See Section V for additional discussion of these topics.

[221] For additional discussion of capacity and availability payment mechanisms, see Pfeifenberger, Spees, and Schumacher (2009), Section V.

market participants that were supportive of the Commission's actions so far were wary of the prospect of raising caps much higher. Fourth, investors discount for regulatory risk, and the perceived risk of future interventions increases as the price caps and PNM thresholds rise. Investors are wary of investing based on the chance of occasional extreme price spikes that might appear excessive to future regulators. And fifth, to design scarcity pricing around achieving a particular reserve margin, the PUCT or ERCOT would need to conduct extensive modeling to establish the parameters and refine them as market conditions change. Such administrative simulations and estimates will invariably introduce some amount of error and inefficiency into market outcomes, yielding reserve margins that may be either too high or too low.

In addition to these disadvantages, some of the various options for introducing price adders raise different, unique concerns:

- Increasing the high offer cap beyond the current $3,000 level is generally advisable, as we discuss further in Section V. However, based on our simulations, it appears that to achieve the target reserve margin could require increasing the cap to a level far above VOLL, which would lead to market inefficiencies unless demand response increases to avoid such excessively high prices above VOLL. We see less risk for market inefficiency associated with increasing the low system offer cap or the PNM threshold, however, as long as the market monitor and PUCT gain comfort from the implications for market mitigation and overall customer cost variability discussed in Section V.
- Further increasing the responsive reserves requirement to trigger high prices more often has a substantial disadvantage in that it is operationally inefficient, since it requires holding more operating reserves than needed. That additional capacity must be on and spinning every day of the year, not just on the day that happens to experience scarcity. Such operational inefficiency might not be acceptable to load representatives and future policymakers, increasing the possibility of future intervention to reverse the requirement.
- As discussed in Section V, one option for increasing returns would be to partially relax market mitigation rules administered by the IMM. By allowing prices to move above short-run marginal costs toward long-run marginal costs, a less stringent approach to market mitigation (such as those employed in Alberta, MISO, and NYISO) will increase investment signals. However its impact on market participants' bidding behavior and market prices is highly uncertain, which makes it an ineffective tool if the objective is to achieve a specific target reserve margin. Making market mitigation too permissive could also introduce concerns about excessive profit-taking and operational inefficiency that would have to be addressed to avoid interventions by future regulators. Regardless, we do recommend clarifying monitoring and mitigation rules to explicitly allow offers to appropriately reflect commitment costs and opportunity costs, both of which could incrementally contribute to investment signals.
- Introducing LMP adders in every hour or in a subset of hours does not necessarily reward marginal capacity resources (which may have very high strike prices) as much as it rewards existing baseload generation. This would therefore distort investment signals and yield a suboptimal mix of peaking and baseload resources.
- Introducing availability or capacity payments would reward suppliers for having installed capacity whether it was running or not in any particular hour. Making payments based on availability rather than output would directly and equally reward all types of capacity

suppliers for contributing to resource adequacy. The level of these payments could even be related to the reserve margin to reward suppliers more when reserve margins are low as is done in Spain.[222] However, once such a capacity-based payment is introduced, it is more efficient to determine the level of these payments using market mechanisms (as described under Options 4 and 5 below) rather than based on administrative determinations that could deviate from underlying market conditions.

The primary problem with these approaches is that, given significant uncertainties, adjusting administrative price parameters would introduce market inefficiencies without dependably delivering the target reserve margin. If a certain reserve margin is desired, there are other market-based approaches that would achieve it more directly, as discussed under Options 4 and 5 below.

Implementation Considerations: If the PUCT and ERCOT opt to further boost pricing parameters in an attempt to achieve a target reserve margin, they should consider increasing the pricing parameters based on market simulations similar to those described in Section IV above. These pricing parameters would have to be refined over time as market conditions change and as DR penetration increases. However, because substantial uncertainty surrounds the reserve margin that might be achieved over the long-term (and even much more so the short term due to supply shocks and resource development lead-times) the Commission could consider implementing this approach in concert with backstop procurement, as in Option 3.

3. Energy-Only with Backstop Procurement at Minimum Acceptable Reliability

Concept: Energy-only markets do not provide assurance that a target reserve margin will be achieved on average. Moreover, reserve margins can vary from year to year, especially when changes in economic conditions and generation additions or retirements suddenly alter the amount of capacity available. If the potential for occasional, low reliability outcomes under Options 1 or 2 above is a concern, then regulators could impose a backstop procurement provision that is triggered when anticipated reserve margins fall below a minimum threshold. Capacity levels would be allowed to vary from year-to-year above and below the *target* reserve margin, but would not be allowed to drop below the *minimum* acceptable reserve margin. Such a "minimum acceptable" reserve margin would have to be far enough below the target to allow for market-based outcomes to prevail in most years, as discussed in Section VI.A.3.

ERCOT has already engaged in backstop procurement to reactivate mothballed capacity under RMR agreements and procure emergency demand resources through its ERS program.[223] Those resources enjoy capacity payments that other resources do not receive. Stakeholders praised the Commission's resolve to prevent RMRs from depressing energy prices and undermining energy-market-based investment. After the recent rule change, ERCOT now dispatches out-of-market RMR units only as a last resort with offers at the price cap, and any energy margins earned by

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[222] Note that the Spanish construct has a number of other administrative qualifications on which resources earn what level of capacity payment that we would not recommend adopting, including awarding payments only to new resources and not to existing resources. For additional discussion of capacity and availability payment mechanisms, see Pfeifenberger, Spees, and Schumacher (2009), Section V.

[223] For example, ERCOT signed two RMR contracts in 2011 from NRG Energy and Garland Power, see ERCOT (2011i). ERCOT also procured all their emergency demand resources on August 4, 2011, see ERCOT (2012a) and (2011j).

these resources will be used to offset their capacity payments.[224] There is now an outstanding NPRR to similarly ensure that prices are not suppressed whenever ERS is deployed as a last resort.[225]

One stakeholder complaint about ERCOT's implementation of backstop procurement came from Non-Opt-in Entities (NOIEs) without retail choice, who argued that the high energy costs should not be allocated to LSEs that have procured sufficient resources to cover the reserve margin target. Exempting LSEs with sufficient resources from the costs of procuring backstop resources seems efficient and appropriate, but LSEs wishing to avoid these charges would have to submit documentation of their resource balance under some defined process.

Advantages: Backstop procurement is especially attractive for withstanding short-term supply shocks that catch the market by surprise. These targeted procurements can address unacceptable shortfalls without requiring major market redesign. Further, it is likely that a large amount of backstop resources could be procured on a short-term basis. Emergency demand response is especially promising. For example, curtailment service providers serving the medium-large C&I segment would likely respond to a solicitation for DR capacity, particularly if the terms were refined to suit more participants, as suggested in Section V. Low-cost reactivations of mothballed capacity and plant uprates are also candidates for backstop procurement, but most of these should prefer to operate in-market, and several have already announced plans to return to service to take advantage of changing market conditions. Intertie uprates to neighboring regions such as SPP or Mexico are another alternative, to the extent that the neighboring region is projected to be sufficiently long on capacity to provide a meaningful contribution to resource adequacy, such upgrades are cost-effective relative to other capacity supplies, and no mechanisms exist to attract intertie upgrades on a merchant basis.[226] Some have also suggested that new combustion turbines could be procured through such a backstop mechanism, but this would be a more problematic option, as we discuss below.

Disadvantages: The disadvantages of the backstop procurement option are substantial. First, protecting the energy market from distortions requires that backstop resources be dispatched only as a last resort, *e.g.*, at the price cap. This is operationally inefficient and also prevents emergency DR from evolving into price-based DR. Second, if regulators solicit specific types of capacity, their choices may not reflect the least-cost options that would be procured in a market environment. And most importantly, reliance on backstop procurement could potentially lead to a long-term outcome where new capacity will enter only with RMR contracts, representing a failure of the energy-only market construct.

Dispatching backstop resources only as a last resort is necessary to protect the energy market from artificial price suppression, but it is inefficient in several ways. First, backstop resources will not be dispatched even when the real-time price rises to many times their dispatch costs, requiring more costly generators to run and possibly inducing consumers to reduce relatively high-value loads. Second, it could inhibit the development of DR into a price-responsive

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[224] See ERCOT (2012s), Section 5.7.5.

[225] See ERCOT (2012f), NPRR 444.

[226] In fact, most other RTOs do have mechanisms for rewarding merchant intertie upgrades such as the Neptune Line between PJM and NYISO and Cross-Sound Cable between ISO-NE and NYISO. See Neptune (2012) and Cross-Sound Cable (2012).

resource that would be critical to supporting the energy-only market design in the long-run. This is because DR resources providing ERS must maintain their baseline consumption, and so cannot become price responsive.

Backstop procurement can be costly because it relies on administrative procurement decisions instead of allowing market forces to identify least-cost options. Regulators may have the best intentions to minimize costs, but by making backstop decisions outside of a market environment they may easily select sub-optimal resources. The all-in costs of different types of resources are difficult to compare because non-price terms can vary greatly and may depend on market conditions. For example, DR has limited dispatch duration whereas most generation does not; some options are more reliable than others, and some resources would be able to operate for many more years than others. Ultimately, customers will pay the consequences of any inadvertently uneconomic administrative choices, and potentially for many years in the case of new resources.

The risk of suboptimal backstop procurement could be reduced by holding a capacity auction in which all resource types can compete to provide the backstop supplies. However, this would exclude existing capacity, thereby preventing efficient tradeoffs between maintaining or retrofitting existing supply and investing in new resources. The prospect of backstop procurement with above-market payments may also create incentives to mothball marginal generating capacity in the hopes of winning a backstop payment. These factors could make it difficult for ERCOT or the PUCT to distinguish between resources that would or would not have opted to operate even without a backstop payment. These problems could be avoided by a non-discriminatory auction for both existing and new capacity, or by implementing a resource adequacy construct in which all resource types would be able to compete, as described under Options 4 and 5.

There are particular risks involved in procuring new generating plants using out-of-market backstop mechanisms.[227] First, compared to emergency DR, new generation is more capital-intensive, is longer-lived, and has lower variable costs. This increases the cost of poor procurement decisions and increases the inefficiency of limiting dispatch only during events that would require load shedding. Some stakeholders have proposed that a backstop generating resource could count its energy-market payments to "buy out" its non-market status. However, this possibility seems unlikely, since energy margins will be small if scarcity events are rare. Second, the need to procure new generating units through backstop procurement is a strong indication of market failure, particularly if backstops are needed more than infrequently (in response to rare, unexpected supply shocks). The Ontario market was originally intended to procure only a portion of its new supplies through regulated contracts for new resources while attracting merchant investments for most new entry. Instead, this goal has essentially devolved into a re-regulated market in which new generation cannot be built without obtaining a long-term contract from the planning authority.[228]

Implementation Considerations: If the PUCT and ERCOT opt to use backstop procurement to prevent reserve margins from falling below a minimum threshold, they should consider limiting procurement to demand resources (including behind-the-meter emergency generation). This

[227] See, for example, Schwertner and Seidlits (2012).
[228] See, for example, PJM (2009).

strategy would amount to paying some loads to provide last-resort voluntary curtailment to avoid involuntarily curtailment for higher-value loads. Capacity payments for emergency response are a natural way to attract DR resources, many of which prefer receiving compensation for selling an *option* to curtail rarely, rather than participating frequently in the energy market. Load resources tend to have a high strike price and would be less impaired than generation by the last-resort-only dispatch provisions that must apply to out-of-market resources. The inclusion of generation in backup procurement would likely be more inefficient and more disruptive of in-market decisions, as described above.

We do not know exactly how much emergency DR could be procured or if there would always be enough to maintain the minimum acceptable reserve margin. We suspect roughly 5,000 MW would be available if ERCOT could procure as much as New England as a percentage of load; and roughly 7,000 MW might be available if ERCOT could procure as much as PJM as a percentage of load.[229,230] Maximizing participation could involve adjusting or replacing ERS to: (1) increase notification times from 10 minutes to two hours; (2) increase and better define the maximum number of call hours; (3) focus performance requirements around summer peaks when resource deficiencies are more likely; and (4) revisit the availability rules to ensure that they are not unnecessarily stringent.

However, as appealing as procuring a large quantity of backstop DR may sound, we would also be concerned about the potential for crowding out or "cannibalizing" market-based demand response. An aggressive emergency DR procurement program could lure away high-quality demand resources that might otherwise provide responsive reserves or participate in the energy market at lower strike prices. Taking such resources out of the energy and ancillary service markets could substantially inhibit progress toward a pure energy-only end state of the market. It could prevent the market from determining scarcity prices based on willingness-to-pay, and setting energy prices at a range of levels, rather than along an ill-behaved hockey stick pricing function. It creates barriers to letting the market ultimately determine an efficient level of resource investment. Finally, cannibalized DR resources would not incrementally improve reliability because these resources would have been curtailed prior to firm load shedding in any case.

Perhaps some of the crowding-out problem could be reduced by awarding load resources capacity payments *in addition* to the responsive reserve payments they receive. This would reduce the capacity payments that load resources would require to provide emergency service. Further, loads that want to respond to energy prices at strike prices below the offer cap could be

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[229] 10% DR penetration percentage in PJM based on 15,755 MW of cleared demand resources in the 2015/16 Base Residual Auction, see PJM (2012a), p. 11. The PJM 2015/16 peak load forecast is 163,168 MW, see PJM (2012b), p. 4. DR penetration percentage of 7% in New England is based on 2,002 MW of cleared Real-Time and Real-Time Emergency Generation resources in the 2015 FCA6, see ISO-NE (2012a). The ISO-NE 2015 peak load forecast is 29,380 MW, see ISO-NE (2012b).

[230] Note that these quantities would be inclusive of all types of DR simultaneously available in ERCOT, and so procuring the entire quantity for backstops may cannibalize some other types of DR currently employed in the ancillary service market or in TDSP programs. Also note that load characteristics are different in ERCOT than in these other markets, with greater potential in the mass market due to high penetration of central A/C, pool pumps, and AMI. There are also different amounts of flexibility from a very different industrial base. We have heard that most industrial operating flexibility is already being leveraged to manage energy costs and transmission cost allocation, see additional discussion in Section V.B above.

allowed to do so without surrendering any energy margins even though they also receive out-of-market capacity payments.

All or nearly all of these problems associated with backstops could be eliminated if the reserve margin were supported solely with *in-market* capacity payments that were available to all resources. The following two policy options rely on competitive markets to meet administratively-determined resource adequacy requirements.

4. Mandatory Resource Adequacy Requirement for LSEs

Concept: If the PUCT determines that the reliability provided by an energy-only market is unacceptably low, it could explicitly impose resource adequacy requirements on LSEs, including locational minimums for LSEs in load pockets. The resource adequacy requirement itself would be determined administratively based on reliability studies, as in Option 2. However, LSEs would be required to buy or self-supply enough capacity to meet their peak load plus the mandated reserve margin or else face a penalty. Placing the resource adequacy requirement on LSEs would require them to buy or build capacity, while suppliers would compete to sell the needed capacity supplies. In fact, all types of resources (existing and new fossil generation, demand response, storage, solar, wind, *etc.*) would have to compete to meet the demand expressed by LSEs. ERCOT could facilitate an efficient bilateral market for capacity by qualifying resources into a standard, tradable resource adequacy product.[231]

Advantages: The advantages of this approach over other approaches to achieve a target reserve margin are that: (1) it achieves the target reserve margin more dependably than price-adder approaches; (2) it uses non-discriminatory market mechanisms to meet the requirement, unlike backstop procurement, and therefore allows all resources to compete to achieve the least-cost solution that self-adjusts as market conditions change; (3) since all resources compete in the same market, no out-of-market procurement is needed, which means no resources would be excluded from energy or A/S markets; (4) it allows for differentiated reliability among controllable customers; and (5) the revenue stream investors would receive from selling capacity may be slightly more stable and predictable than that provided by the energy-only market, although there are still no long-term price guarantees.

Imposing explicit requirements on LSEs would achieve a given resource adequacy target more dependably than an energy-only market with price adders. The penalty imposed on LSEs that do not comply enforces the reserve margin. If the penalty is set at, say 1.5 times the cost of new capacity, LSEs will be motivated to procure capacity instead of paying the penalty. They will also procure at least some capacity forward to reduce their exposure to being caught short, but competitive retailers will likely procure most capacity closer to the delivery period. Suppliers will know that if the market is short, bilateral prices for capacity will climb, which provides incentives to build and maintain sufficient capacity in aggregate.

Using such market mechanisms allows all resources to compete to achieve the least-cost solution and also self-adjusts as market conditions change. Competitors include existing capacity, existing capacity considering retrofits, uprates, demand response, new merchant generation of

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[231] Similar to the tradable Planning Resource Credit introduced in MISO, see Section IV.A.2 of Newell, Spees, and Hajos (2010).

various technologies at brownfield and greenfield sites, new cogeneration capacity, generation at the ERCOT border that might be able to sell into either market, imports over interties, storage, wind, solar, *etc*.[232] There are undoubtedly many low-cost resources that might never emerge absent such competitive procurement processes. Most observers of the PJM capacity market (which also allows all resource types to compete to meet capacity needs, although in a centralized forward capacity market similar to Option 5 below) have been surprised by the mix of resources winning the auctions.[233] PJM's auctions have cleared at relatively low prices because large amounts of demand response, uprates, and increased net imports obviated the need for more expensive new generation for many years. In the most recent auction, substantial quantities of new merchant generation has now entered, but at lower costs than some industry analysts expected.[234]

The price of capacity in the bilateral market would presumably reflect the "missing money" of the marginal resource. In other words, the price of capacity will cover the payments, beyond what is available through the energy market, that are needed to recover the marginal resource's fixed costs and a required investment return. Because the price is market-based, the mechanism automatically adjusts as market conditions change. The cost of meeting the requirement may even decline to zero if energy margins increase or market fundamentals result in excess supply. In this case the market would essentially revert to an energy-only market with a non-binding constraint at the target reliability margin.

This construct also creates opportunities for differentiating reliability across customers. Customers could self-select lower reliability levels by supplying DR to meet the reserve margin requirement. It might also be possible, albeit substantially more complex, to allow customers to opt for higher reliability by procuring more capacity than needed to meet the requirement, as discussed below.

Disadvantages: The primary disadvantage of imposing resource adequacy requirements on LSEs is that the approach is complicated, incurs substantial implementation costs, and requires a number of new design elements to be introduced. Implementation would also involve numerous administrative judgments and parameters. By far the most important administrative parameter is the planning reserve margin itself, but this parameter would underpin the market under all options except the pure energy-only market under Option 1. A disadvantage relative to Option 5 is that the requirement cannot be imposed on a forward basis, due to the stranded cost risk that would be imposed on REPs in ERCOT's retail choice environment. If not for this limitation, imposing the resource adequacy on a multi-year forward basis would provide a more certain resource outlook and facilitate more timely recognition and replacement of retiring capacity.

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[232] Note that the resource adequacy and capacity value will vary by the type of capacity, with wind and solar providing far less capacity value than their nameplate ratings, as already recognized within ERCOT's CDR reports.

[233] See Pfeifenberger, Newell, *et al.* (2011).

[234] While 2015/16 cleared below the administrative Net CONE in all regions for the annual capacity product, it still cleared almost 5 GW of new generation. Not all of that new generation was built on a merchant basis however, with three new generation plants with an approximate combined capacity of 2,000 MW being supported through out-of-market contracts in Maryland and New Jersey, see PJM (2012a) and Cordner (2012b).

Implementation Considerations: If the PUCT and ERCOT opt to impose resource adequacy requirements on LSEs, it would be valuable to incorporate in its market design the lessons learned from the experience in other regions. CAISO, SPP, and MISO have all implemented resource adequacy requirements without centralized capacity markets. The essential elements of enforcing resource adequacy requirements on LSEs in any market include:

Reliability Target — Definition of a reliability target, such as the 1-in-10 standard or alternative based on estimates of the economic optimum.

System Wide and Locational Resource Adequacy Requirements — Determination of both system-wide and locational planning reserve margins needed to meet that target, ideally denoted on an "unforced capacity" (UCAP) basis that accounts for the different value of resources with high and low availability.

Requirement Allocations — Allocation of the resource adequacy requirements to individual LSEs based on system-peak-load contributions during peak hours.

Qualification Procedures — Resource measurement, verification, and qualification for the UCAP-equivalent value of all capacity resources including existing and new fossil generation, intermittent renewables, storage, and various types of demand resources. In particular, a number of options exist for appropriately accounting for DR on the supply side of the market (which enables competitive independent curtailment service providers) or on the demand side (which reduces participating LSEs' procurement requirements).

Enforcement Mechanisms — LSE procurement monitoring with non-compliance penalties. The penalty would have to be sufficiently high to ensure compliance.

Monitoring and Mitigation — Market power monitoring and mitigation rules, especially in load pockets, although such monitoring is typically quite difficult in markets that are primarily bilateral.

In addition, there are also a number of optional design elements that could provide additional value, including enabling a more robust bilateral market for meeting resource adequacy standards:

Standard Capacity Product — ERCOT could facilitate a more liquid bilateral market for capacity by defining, qualifying, and tracking standard, tradable locational resource credits, as MISO does.[235]

Voluntary Auctions — ERCOT could administer auctions that are voluntary to both LSEs and suppliers, through which LSEs may procure a portion of their requirements either on a forward basis or on a near-term basis right before delivery. NYISO conducts similar voluntary strip and spot auctions prior to its mandatory spot auction, while MISO conducts a voluntary auction immediately prior to delivery.[236,237]

Differentiated Reliability — Direct transmission customers and those with dual distribution feeders could potentially procure more reserves than the system-wide requirement. To implement differentiated reliability, ERCOT would need to track individual customers'

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[235] See Section IV.A.2 of Newell, Spees, and Hajos (2010).
[236] See NYISO (2011) and NYISO (2012).
[237] See MISO (2012b).

reserve margins (through LSEs) and with TDSPs recognizing each customer's reserve margin. Customers procuring power with the lowest planning reserve margin level would be shed first, but only until their effective reserve margin was the same as the customers with the next higher planning reserve margin, at which point both customer groups would be subject to curtailments. ERCOT would need to develop systems to generate these differentiated curtailment instructions in real-time. The feasibility and costs have not been assessed, and this concept has not yet been implemented in other market areas (although direct transmission customers may already be spared from load-shedding protocols under the current protocols).

5. Resource Adequacy Requirement with Centralized Forward Capacity Market

Concept: ERCOT would hold an auction in which it procures forward capacity obligations on behalf of all load 3 to 4 years prior to delivery. During the delivery year, the cost of that procurement would be allocated to LSEs. LSEs would be able to hedge against capacity auction costs through self-supply or bilateral forward contracting. Incremental auctions would also be needed to facilitate economic adjustment to new information and manage supply- and demand-side risks between the time of the initial auction and delivery.

Advantages: Centralized forward capacity markets have all the advantages of imposing a resource adequacy on LSEs through a bilateral market. Centralized forward capacity markets also offer additional advantages: (1) multi-year forward procurement is enabled without creating stranded cost risk for REPs who do not have captive load; (2) forward procurement allows early visibility into potential environmental retirements and fosters competition among existing generation, new generation, uprates, imports, and DR; (3) a three- or four-year forward procurement period may not provide long-term price certainty for investors, but it substantially improves transparency and predictability; and (4) centralized auctions are easier to monitor and mitigate for market power than are bilateral markets or strictly voluntary capacity auctions.

Disadvantages: Several of the disadvantages applicable to Option 4 also apply to centralized forward capacity auctions, including their complexity, implementation costs, transitional design risks, and the importance of often-controversial administrative parameters. In particular, the administrative uncertainty in the load forecast and resource adequacy requirement increases with the forward period, which increases the chances of over- or under-procurement.

In addition to these real but surmountable disadvantages, capacity markets tend to face a substantial amount of unwarranted skepticism and criticism. In particular, while we have observed that generation investors in ERCOT, particularly those that have experience in capacity markets, look favorably on this option, capacity markets appear to be unpopular among regulators and other stakeholders. To partly address these concerns, we address four prevalent myths about capacity markets:

Myth 1: Capacity Markets Cost More than Energy-Only Markets. It is not correct that capacity payments increase all-in customer costs. Capacity payments only replace the "missing money" that results from high mandated reserve margins depressing energy market prices (by lowering market heat rates and avoiding scarcity prices). In capacity markets as well as energy-only markets, the all-in "price" paid by customers must be sufficient to support investment in new generation. It is even conceivable that such all-in prices could be lower with a capacity market, if it reduces revenue volatility and

regulatory risk, thereby lowering investors' cost of capital. Claims by some loads and eastern commissioners that capacity market prices are "too high" are contradicted by the evidence. Prices have generally been below the level needed to support new generation in the long run, due to competitive low-cost entry from DR, uprates, and imports. Prices in PJM and its load pockets are consistent with transmission constraints and supply-demand fundamentals.[238] The only reason that resource adequacy requirements might cost more than energy-only is that mandating *additional* investment (*e.g.*, to achieve a 15% planning reserve margin instead of, say, 10% in an energy-only market) forces customers to support the incremental quantity of supply.

Myth 2: Capacity Markets Overpay DR. Capacity markets will not overpay DR if qualifications, performance obligations, and penalties are defined such that one MW of DR provides as much incremental reliability value as one MW of generation. The rules are generally quite involved and controversial, but mistakes can be avoided by following best practices and lessons-learned from various RTOs' experiences. As the amount of DR in the market increases, the number of likely calls increases. As PJM approached DR penetration equal to 10% of total resource needs, it introduced three tiers of DR products, depending on how often a resource could be called. Only the highest-value DR with unlimited calls competes directly with generation for the same payments, while lower-value DR receives a lower price.[239] The fact that a generator provides more energy value than DR is already accounted for in its ability to offer capacity at lower cost (a competitive offer is the avoidable going-forward fixed cost minus expected energy margins and ancillary service revenues) and earn higher margins at a given capacity price. In reality, DR is a valuable addition to the resource mix with relatively low fixed costs that has helped lower the overall cost (and price) of meeting resource adequacy requirements.

Myth 3: Capacity Markets Overpay Existing Generation. Several northeastern state commissions have expressed concern that old generating plants with high emissions receive the same capacity payments as new generation under RPM. These concerns overlook the fact that energy-only markets similarly pay old and new resources the same price to reward their equal contribution to providing power when resources become scarce. Trying to differentiate either energy or capacity payments based on a unit's age or environmental characteristics would be inconsistent with a market approach in which all resources sell the same product. Paying new generation higher prices would lead to higher costs, for example when new plants are more expensive than retrofitting existing plants. Regarding the fact that existing units can be dirtier than new units, these differences may already be recognized in the energy market, to the extent that polluters must pay for emission allowances. Capacity markets also allow suppliers to include the fixed and variable costs of complying with environmental regulations in their capacity offers, meaning that the market can evaluate efficient investment tradeoffs for meeting environmental standards such as MATS. However, some critics seem to expect capacity markets to solve environmental problems that have not been defined by state and federal governments.

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[238] See Pfeifenberger, Newell, *et al.* (2011).
[239] See PJM (2011).

Myth 4: Capacity Markets Do Not Attract New Generation. Critics of PJM claim that capacity markets do not work because they have not attracted new generation. It is true that little new merchant generation has been built in PJM, but that is because capacity markets *do* work. All locations in PJM have had sufficient capacity for a number of years, with incremental low-cost additions from DR, uprates, and imports that were cheaper than new generation. New generation was not needed or economic, a truth the market revealed despite some regulators' belief to the contrary. Now that some parts of PJM are becoming tighter due to load growth, retirements, and near saturation of DR, new merchant generation is entering. In the most recent PJM capacity auction, nearly 5 GW of new generation cleared, with much of the incremental supply from merchant generators.[240] Among the cleared new merchant generation, LS Power recently broke ground on its 650 MW merchant CC project in New Jersey, and Calpine cleared its 309 MW merchant CC project in Delaware.[241]

Implementation Considerations: Most of the implementation issues with capacity markets are identical to those identified under Option 4 "Imposing Resource Adequacy Requirements on LSEs." However, several additional key elements that would need to be addressed include: (1) the design of the demand curve for resources (*i.e.*, vertical or sloped); (2) incremental auctions; (3) different monitoring and mitigation measures; (4) additional qualification procedures for resources that are not yet online; and (5) auction-clearing mechanics. If pursuing such an option, we would recommend a deep review of the lessons learned from already-implemented markets in PJM, ISO-NE, and NYISO.

[240] Approximately 2 GW were from out-of-market state contracts in New Jersey and Maryland, see Cordner (2012b), and PJM (2012a).

[241] See Cordner (2012a) and Marrin (2012).

C. Summary of Advantages and Disadvantages

Table 18 provides a summary comparison of the five policy options we examined in Section VI.B above, while Table 19 summarizes their various advantages and disadvantages.

Table 18
Comparison of Policy Options

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes	Comments
1. Energy- Only with Market-Based Reserve Margin	Market	Market	High in short-run; Lower in long-run w/ more DR	High	May be highest in long-run	Easy	- Depends on substantial DR participating to set prices at willingness-to-pay; ERCOT does not yet have much DR
2. Energy-Only With Adders to Support a Target Reserve Margin	Regulated	Market	Medium	High	Lower	Easy	- Not a reliable way to meet target - Adders are administratively determined
3. Energy- Only with Backstop Procurement at Minimum Acceptable Reliability	Regulated (when backstop imposed)	Regulator (when backstop imposed)	Low	High	Lower	Easy	- Attractive as an infrequent last resort, but long-term reliance is inefficient, non-market based, and slippery-slope
4. Mandatory Resource Adequacy Requirement for LSEs	Regulated	Market	Low (with sufficient deficiency penalty)	Med-High	Medium (due to regulatory parameters)	Medium	- Well-defined system and local requirements and resource qualification support bilateral trading of fungible credits, and competition - Cannot be a forward requirement - Flexibility: DR is like opting out; customers not behind a single distribution feeder could pay for higher reserves and reliability
5. Resource Adequacy Requirement with Centralized Forward Capacity Market	Regulated	Market	Low	Med-High (slightly less than #4)	Medium (due to regulatory parameters)	Major	- Working well in PJM - Forward construct can efficiently respond to retirements and meet needs with sufficient lead time - Transparency valuable to market participants and market monitor - Many administrative determinations

Table 19
Advantages and Disadvantages of Policy Options

Option	Advantages	Disadvantages
1. Energy- Only with Market-Based Reserve Margin	- Theoretically most efficient - Performance incentives concentrated during greatest need - High prices likely to stimulate DR - Controllable loads can pay for and enjoy their own reserve margins	- Works best with a high penetration of price-setting DR not yet achieved in ERCOT - Without sufficient price-setting DR, difficult to accurately reflect marginal cost in scarcity - Without sufficient DR, energy-only is susceptible to low reliability, price spikes and future regulatory intervention - Reliability especially vulnerable when simultaneous environmental retirements occur
2. Energy-Only with Adders to Support a Target Reserve Margin	- Can increase prices to close gap to achieve target reliability in expectation	- Reliability not guaranteed - Adders introduce inefficiencies - Greater reliance on administrative parameters (and must adjust parameters as market conditions change)
3. Energy-Only with Backstop Procurement at Minimum Acceptable Reliability	- Can protect against extreme low reliability events (e.g. large simultaneous environmentally-driven retirements)	- Risk of becoming dependent on backstops during many or most years (indicating market failure) - If DR and mothball resources are depleted only option left is procurement of new gen, undermining ability to attract competitive entry
4. Mandatory Resource Adequacy Requirement for LSEs	- Guarantee reserve margin system-wide and locally - Market-based approach to meeting mandated reserve margin, with all supply types competing - Avoids out-of-market resources.	- Substantial new design elements needed - Increased importance of administrative parameters (e.g., RA requirement) - Requirement can't be forward w/retail choice
5. Resource Adequacy Requirement with Centralized Forward Capacity Market	- Transparent prices - Forward market can rationalize retirement and new build decisions - Can draw on lessons from other ISOs	- Major market redesign - Many administrative determinations and complexity - Seems politically unpopular in ERCOT

VII. RECOMMENDATIONS

Based on our findings in this study, our primary recommendations are that the PUCT and ERCOT: (1) evaluate and define resource adequacy objectives for the bulk power system; and then (2) choose a policy path to meet those objectives, informed by the advantages and disadvantages of each option we have identified. We recommend defining the long-term resource adequacy framework expeditiously. Committing to a definitive course of action will resolve regulatory uncertainty and support investment. However, we caution not to implement major changes too quickly or without sufficient analytical support or stakeholder consideration. Complex market design changes will likely take more than a year to implement, and market participants need to be allowed ample time to prepare for the implementation of any changes.

The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments. However, we anticipate that more low-cost resources will enter the market before 2014 than are currently reported in ERCOT's Report on the Capacity, Demand and Reserves (CDR) Report, yielding reserve margins that are at least somewhat above the 9.8% currently projected.[242] If the 2014 planning reserve margin outlook fails to improve sufficiently to meet a minimum acceptable level of reliability before new generation can be added, the PUCT and ERCOT could consider soliciting additional Emergency Response Service resources as a short-term solution. However, we stress that such a backstop mechanism should be implemented with great restraint to avoid introducing a perpetual dependence on backstops or displacing market-based resources that would otherwise be developed.

In addition, and regardless of the overarching policy path selected by the Commission, we recommend enhancing several design elements to make the ERCOT market more reliable and efficient, as discussed in Section V: (1) increase the offer cap from the current $3,000 to $9,000, or a similarly high level consistent with the average value of lost load (VOLL) in ERCOT, but impose this price cap only in extreme scarcity events when load must be shed; (2) for pricing during shortage conditions when load shedding is not yet necessary, institute an administrative scarcity pricing function that starts at a much lower level, such as $500/MWh when first deploying responsive reserves, and then increase gradually, reaching $9,000 or VOLL only when actually shedding load; (3) increase the Peaker Net Margin threshold to approximately $300/kW-year or a similar multiple of the cost of new entry (CONE), and increase the low system offer cap to a lever greater than the strike price of most price-responsive demand in Texas; (4) enable demand response to play a larger role in efficient price formation during shortage conditions by introducing a more gradually-increasing scarcity pricing function (as stated above) so loads can respond to a more stable continuum of high prices, by enabling load reductions to participate directly in the real-time market, and by preventing price reversal caused by reliability deployments; (5) adjust scarcity pricing mechanisms to ensure they provide *locational* scarcity pricing signals when appropriate; (6) avoid mechanisms that trigger scarcity prices during non-scarcity conditions; (7) address pricing inefficiencies related to unit commitment but without over-correcting; (8) clarify offer mitigation rules; (9) revisit provisions to ensure that retail electric providers (REPs) can cover their positions as reserve margins tighten and price caps increase; and (10) continue to demonstrate regulatory commitment and stability.

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[242] ERCOT (2012n).

We recommend considering these ten suggestions no matter which resource adequacy framework the Commission and ERCOT select.

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LIST OF ACRONYMS

ACEEE	American Council for an Energy-Efficient Economy
ACI	Activated Carbon Injection
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
ATWACC	After-Tax Weighted-Average Cost Of Capital
AUD	Australian Dollars
Btu	British Thermal Unit
C&I	Commercial & Industrial
CAISO	California Independent System Operator
CC	Combined Cycle
CCR	Coal Combustion Residuals
CDR	Capacity, Demand, and Reserves
CONE	Cost of New Entry
CREZ	Competitive Renewable Energy Zones
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment Service Provider
CT	Combustion Turbine
CWA	Clean Water Act
DR	Demand Response
DSI	Dry Sorbent Injection
EFORd	Equivalent Forced Outage Rate
EGU	Electric Generating Unit
EILS	Emergency Interruptible Load Service
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FSL	Firm Service Level

HCAP	High System Offer Cap
HSL	High Sustained Limit
ICAP	Installed Capacity
IMM	Independent Market Monitor
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
LCAP	Low System Offer Cap
LIBOR	London Interbank Offering Rate
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LR	Load Resource
LSE	Load Serving Entity
LSL	Low Sustained Limit
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MISO	Midwest Independent System Operator
MMBtu	1,000,000 Btu
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NO_X	Nitrogen Oxides
NPRR	Nodal Protocol Revision Request
NYISO	New York ISO
PBPC	Power Balance Penalty Curve
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PNM	Peaker Net Margin
PPA	Power Purchase Agreement
PRC	Planning Resource Credit
PRD	Price Responsive Demand

PTC	Production Tax Credit
PUCT	Public Utility Commission of Texas
PUN	Private Use Network
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
REP	Retail Electric Provider
RFP	Request for Proposal
RMR	Reliability Must Run
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SCED	Security Constrained Economic Dispatch
SCR	Selective Catalytic Reduction
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
T&D	Transmission and Distribution
TDSP	Transmission and Distribution Service Provider
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VOM	Variable Operating and Maintenance
WECC	Western Electricity Coordinating Council