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

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

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

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

[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.

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'

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.

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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

We have not analyzed all of the credit requirements, qualification requirements, and other provisions needed 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, some unscrupulous REPs with little to lose may be tempted to exploit asymmetric risk exposures, if such exist. They could under-hedge in order to make money in the likely event that realized spot prices are lower than forward prices, while taking a risk that spot prices spike to levels they cannot pay in the unlikely event of 2011-like weather. They would simply default and exit the retail electric business, but ERCOT's other customers would have to pay. Given risks such as these, we recommend that the PUC revisits its credit and qualification provisions.

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

141