PROJECT NO. 40480

COMMISSION PROCEEDING REGARDING POLICY OPTIONS ON RESOURCE ADEQUACY	**§ § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

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COMMENTS OF CPS ENERGY

CPS Energy[1] appreciates the opportunity to participate in this project and the July 27, 2012 workshop at which the Public Utility Commission (Commission or PUC) will discuss The Brattle Group "ERCOT Investment Incentives and Resource Adequacy" (the Report) filed by the Electric Reliability Council of Texas (ERCOT) on June 1, 2012 in Project No. 40268, *Rulemaking to Amend PUC Subst. R. §25.505, Relating to Resource Adequacy in the Electric Reliability Council of Texas (ERCOT) Power Region.*

The Report raises issues that, if adopted, would restructure the ERCOT market, and CPS Energy urges the Commission to undertake any consideration of market changes with care and deliberation, allowing interested parties to ask questions, provide input, and offer recommended revisions at the workshop and at additional meetings that CPS Energy recommends follow the workshop.

Having stated its position regarding issues of import in Project No. 40268[2], CPS Energy raises the following questions about the Report:

1. The Brattle Group uses a $9,000/MWh offer cap throughout the Report (*e.g.*, p. 1, p. 3, p. 6). What change(s), if any, would be necessary to the conclusions or recommendations in the Report because the Commission adopted a $4,500/MWh offer cap instead of the $9,000/MWh offer cap?

[1] CPS Energy™ is the trade name of City Public Service of San Antonio, acting by and through the City Public Service Board.

[2] CPS Energy filed initial comments in Project No. 40268 on June 15, 2012, and reply comments on June 29, 2012.

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2. The Report makes numerous recommendations, as shown on the attached entitled Exhibit A – Recommendations, The Brattle Group "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012. CPS Energy suggests that it would be helpful to have input from both ERCOT and the Independent Market Monitor (IMM) regarding each of The Brattle Group recommendations enumerated on Exhibit A to help guide a broader discussion of these issues.

CPS Energy appreciates the opportunity to ask the above questions and looks forward to the July 27, 2012 workshop. It also urges that the Commission plan for additional meetings following the workshop at which the Commission, ERCOT, market participants, and interested parties can understand positions and develop solutions that will make the ERCOT market a more workable, competitive market.

Respectfully submitted,
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EXHIBIT A – Recommendations The Brattle Group
"ERCOT Investment Incentives and Resource Adequacy"
June 1, 2012

In the page numbers below, the first number is the original page number of The Brattle Group "ERCOT Investment Incentives and Resource Adequacy" (the Report), and the second number is the page number of the filed page. CPS Energy added the bold-faced language to establish that the text is a recommendation from The Brattle Group; footnotes are omitted.

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We therefore **recommend** that the PUCT and ERCOT evaluate their resource adequacy objectives in the context of delivered reliability, load shedding protocols, and informed by an analysis of marginal costs and benefits. We **recommend** determining the *desirable* reserve margin target and, separately, a *minimum acceptable* reserve margin needed to avoid extremely adverse consequences under worst plausible weather and outage conditions.

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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.

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

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On a longer-term basis, we **recommend** addressing similar commitment-related price suppression impacts whenever ERCOT or stakeholders identify a particular issue as introducing substantial uplift payments. For example, it may be desirable to create a mechanism for enabling block-loaded resources to set day-ahead and real-time energy

prices. There are also more ambitious options for incorporating commitment costs and other discontinuities into dispatch and pricing software, such as moving toward convex hull pricing. However, such options could be very expensive to implement and should only be pursued if simpler fixes are insufficient and the benefits can be shown to exceed the associated software upgrade costs. The ideal result of any future pricing enhancements would be that suppliers self-dispatching against these prices with perfect foresight would exactly match the least-cost system result. Like other markets, ERCOT can make steps toward this ideal, but likely will not fully be able to achieve it.

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

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

The new RUC mechanism described above also is likely to introduce scarcity prices during nonscarcity events. This mechanism will add RUC units to the SCED pricing run at the offer cap of $3,000/MWh. The likely result is that prices may be driven to very high levels during high-ramp or under-forecast conditions. These ramping and forecasting considerations represent real system operating needs, but are not related to resource adequacy or the realized reserve margin.

High-price events caused by this RUC mechanism will be just as likely to occur with a 30% reserve margin as with a 10% reserve margin. We do recognize, however, that the old RUC mechanism inefficiently suppressed prices by failing to incorporate commitment costs into pricing. Balancing these concerns, we **recommend** a different approach to preventing price-suppression from RUC units using approaches similar to those discussed in Section V.A.1.a above.

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We **recommend** creating a locational marginal price (LMP) cap set at the average customer VOLL, which would also impose a maximum limit on other parameters such as the offer caps and the Power Balance Penalty Curve (PBPC) shadow price. This is the efficient price level during severe scarcity conditions when ERCOT must enact involuntary load shedding, because this is the price that the average customer would have been willing to pay to avoid curtailment.

A VOLL-based price cap approximates what the demand curve would have been had customers been actively bidding to avoid curtailment. Setting the price cap at VOLL is supported by a rich theoretical literature demonstrating the economic efficiency of this approach.

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

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

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

Page 78-79/74-85
Price suppression during administrative reliability interventions is a risk in any market because these interventions make incremental supplies available for dispatch. If those actions add supply at a low offer price (or reduce demand), then the typical result will be to reduce prices just when very high prices are most needed. Over recent months, ERCOT has implemented, or is developing, corrective measures to prevent this outcome from reliability interventions including RMR units' dispatch, deploying responsive reserves for energy, and Online and Offline Non-Spin deployments. However, there are a few types of reliability interventions that could suppress market prices but have not yet been addressed. We **recommend** that ERCOT develop protections to prevent price suppression from these actions, including during: (1) Emergency Response Service (ERS) and Load Resource (LR) deployments, which a current NPRR is intended to address; (2) calling on emergency imports; (3) relaxing internal transmission constraints; and (4) any other type of reliability intervention that stakeholders or ERCOT may identify in the future. Additionally, we **recommend** that ERCOT periodically examine price outcomes during all scarcity-related reliability events to confirm that no unexpected low prices occurred during those events.

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We **recommend** developing price correction mechanisms that tie all administrative pricing mechanisms to the marginal system costs of these interventions. Table 16 summarizes the

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

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

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

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

Page 83-84/89-90
The LCAP is a related parameter because it is the offer cap imposed after the PNM has been exceeded. The purpose of the LCAP is to assist in preventing excessively high prices on a continuous basis over the year, so it makes intuitive sense to keep this cap at a relatively low level as long as it does not introduce excessively inefficient price distortions. For

example, an LCAP of only $100/MWh would introduce excessive inefficiencies because it would preclude a large number of peaking generators from being dispatched. The current LCAP of $500 (or higher in high fuel price circumstances) may be reasonable if one considers only a generation market and ignores the potential for demand response. We would **recommend** increasing this LCAP to a higher level if any generation resources in the fleet have a marginal cost (including opportunity costs) above the cap. Further, as demand response grows in Texas, it will be important to raise the LCAP to a level that ensures that most load reductions would be achieved at prices below the LCAP. Determining this level could be informed by an econometric study to evaluate the level of demand reductions achieved at various price levels. We further discuss how such a study could be conducted in Section V.B.4.c below.

Page 84-86/90-92
To date, ERCOT's scarcity pricing mechanisms have not been developed in a way that explicitly considers the potential for locational resource adequacy concerns as opposed to system-wide resource adequacy concerns. We **recommend** assessing the need to revise these mechanisms for locational relevance. While a number of approaches could be used to achieve this result, one option would be to revise administrative scarcity pricing mechanisms around new "A/S Regions" that may or may not coincide with ERCOT's current Load Zones. The mechanisms could be conceptually similar to the Reserve Zone approach implemented by MISO that expresses: (1) system-wide scarcity prices when depleting system-wide reserves; and (2) scarcity prices specific to that Reserve Zone when reserves drop below that location's requirement.

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

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

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

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

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

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

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

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

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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 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.

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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.

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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.

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

- 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.

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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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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.

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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. 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.

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