The Brattle Group

Resource Adequacy in ERCOT: 'Composite' Policy Options

Prepared for:

The Public Utility Commission of Texas

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October 25, 2012

Contents

Background

The Commission has not yet established a minimum acceptable reserve margin, but the current energy-only market design will not attract enough investment to meet the current "target" reserve margin and reliability objectives

Stakeholders have submitted many thoughtful market design proposals to better meet reliability objectives

We have developed two options for achieving higher reserve margins than an energy-only market, each based on a composite of stakeholders' proposals

This presentation describes and evaluates those options

Market Design Options (at a High Level)

Pure Energy-Only	Energy-Only with Administrative Support	Resource Adequacy Requirement and Capacity Market
No change in design; Reserve margin would fall to unprecedented low levels (until high penetration of DR)	Is it possible to maintain the energy prices of an energy-only market and yet achieve the reliability of a RA requirement? Many proposals with varying viability	Effective in maintaining current reliability, but complicated, as other regions demonstrate

Agenda Today:

Not discussed in this presentation	*Today, we present the "best-of" the proposals, focused on:* • *Expanding DR* • *Limited administrative withholding thru op. reserve*	*Today, we present a "TX Capacity Market" that is simpler and could work well here.*

Considerations for Designing A 'Texas Solution' to the RA Challenge

Texas is different from other regions, and <u>any</u> solution must recognize the following key differences that stakeholders have emphasized:

- Different regulatory structure
  - One-state RTO under PUCT jurisdiction
  - Retail access with strongest retail competition
  - Pro-market
- Different energy market design
  - Recognizes scarcity with very high energy prices
- Different fundamentals
  - High load growth
  - Hot climate and high AC Loads
  - Low energy prices when not in scarcity
  - Robust transmission system

However, Texas can benefit from lessons learned in other markets

Options Should be Evaluated Against Policy Objectives and Risks of Unintended Consequences

Reliability

- Is there a desired level and a minimum acceptable level?
- Or is more just marginally better, subject to trade-offs?

Economic Efficiency and Cost

- Higher reliability generally costs slightly more
- Market-based competition tends to reduce costs

Regulatory Stability and Investor Risk

- Depends on market design
- Affects both cost and long-term viability

Implementation Complexity

- Market design risks
- Initial implementation and ongoing maintenance costs
- Risk of delay
- Relevant experience from other regions

Composite Option #1
Energy-Only Market with Support for DR

Composite Option #1

Energy-Only with Support for DR

Concepts	Major Design Elements
Maintain the pricing of an energy-only market (including frequent scarcity at low equilibrium RM) but aim for the reliability of a higher resource adequacy requirement	Continue with scarcity pricing reforms
Promote DR to support reliability without suppressing energy prices (due to high strike price) and displacing investment	DR-only capacity market and other options for supporting DR in all customer segments
Operating-reserve-based administrative withholding can support higher energy prices and greater investment but large amount can create regulatory instability	Increase operating reserves as needed to move reserves toward target, per EDF/GDF proposals
Backstop procurement of generation would undermine energy prices or create regulatory instability if withheld	No procurement of backstop generation

Energy Only Design Elements: Support for DR

Why Provide Extra Support for DR?

DR resources could provide additional resource adequacy without displacing generation investment, since it has a high strike price

Substantial DR growth would be needed quickly to maintain the target margin

- By 2015, a significant shortfall is projected relative to current 13.75% target
- By 2016 and beyond, we expect that more than 3,500 MW of additional DR is needed to meet the current reliability target

The energy market alone will not develop DR soon enough to maintain a reserve margin above the target

- Market conditions are not yet tight enough to attract great interest
- Current programs limit participation
- The economics for making small customers curtailable are difficult

Aggressive support for DR will speed up its development and could possibly achieve an ideal "energy-only endstate with active demand side" while avoiding a near-term reliability lapse

The next few slides address how to grow DR in each customer segment

The Residential DR Opportunity

Currently, residential customers (53% of peak load) provide very little DR

- AMI opens possibilities for dynamic pricing
- *Curtailability* would require direct controls on AC compressors, pool pumps, water heaters
- So far, REPs have not installed such controls because controls are expensive (very roughly, $300/residence)
- So far, there have been very limited opportunities to capture the value; no “capacity” value and not enough value in the energy market

Experience in other regions shows that customers are willing to participate with

- Creative marketing
- Free control equipment
- Participation incentives
- Reasonable terms, *e.g.*, dispatchable by ERCOT in emergencies up to 10 times per year for up to 4 hours per call; some event opt-out provisions

Energy Only Design Elements: Support for DR

Three Broad Ways to Grow Residential DR

Administer Through TDUs

- Equipment determined administratively and recovered through the transmission and distribution utility (TDU) ratebase
- Customer incentive determined administratively
- At least initially, use “deemed value” of kW/customer instead of detailed measurement and verifications (M&V)
- May facilitate faster development because ~no risk for the provider
- But not market-based, limited to approved types of equipment, lose innovation and expertise of REP/DR providers

Fund Equipment Through TDUs; Incentive through Capacity Auction

- Equipment determined administratively and recovered through TDU ratebase
- Customer incentive provided by REP/DR provider based on their price and commitments in the auction
- Benefit from expertise of DR providers, but innovation is limited because of limits on approved types of equipment

DR Capacity Auctions

- Equipment and customer incentive are offered by REP/DR provider based on prices and commitments in the auction
- Market-based approach allows for most innovation, competition, and procurement of least-cost resources
- BUT: Risks to REP/DR provider of taking on capacity supply obligation, finding customers, and recovering equipment costs may make them conservative and slow development rates
- Explore auction rules to reduce risk

Simpler & Possibly Faster ⟷ More Market-Based & More Innovation

Energy Only Design Elements: Support for DR

A Capacity Auction to Attract Larger DR

REPs and CSPs working with larger C&I customers may or may not participate in the same auction as for small customers

Need to define products and performance obligations

- For C&I customers, set baselines using lessons learned from other ISOs
- Avoid rewarding reductions that would occur anyway, e.g., baseline ≤ peak load contribution
- Consider distinguishing “limited” from “unlimited” DR products

Need to design an auction

- Annual auction determines single market-clearing capacity price
- Need to define demand and price caps

Relationship to other DR products

- ERCOT’s “ERS” program subsumed; TDU “energy efficiency” DR programs could also be subsumed
- Load Resources still provide responsive reserves and could receive capacity payments in addition
- Consider not qualifying 4CP load management and price management if they occur anyway without a capacity payment and are already in the load forecast; alternative is to let them count but then paying more without gaining reliability

Risks

- A DR-only capacity market is discriminatory and therefore less efficient
- Need to address many of the same complicated issues is in a broader capacity market
- Payments may be needed for many years

Who pays to support DR: Spread equally across all load, not based on net short

Energy Only Design Elements: Support for DR

Energy Price Formation is Critical with More DR

Preventing Price Reversal

- "Price reversal" refers to when demand response deployment causes prices to fall below the strike price of the resource
- It is critical to prevent price reversal during DR deployments or else generation investment will be reduced
- Price reversal is a particular concern when operators call (and hold) a large block of DR during an emergency; may be less problematic when individual loads reduce at a variety of strike prices below the cap
- This can be solved by administratively setting the price at the cap as long as emergency DR resources are deployed

Enabling Efficient DR Participation and Price Formation Below the Cap

- Implementing a gradually sloped demand curve will help demand set prices approximately at willingness-to-pay
- ERCOT should also evaluate the benefits and costs of implementing an Hour-Ahead Market (HAM) and "Loads in SCED"
- Note: if a large amount of new DR has a low strike price, more MW will be needed to achieve reliability objectives (see pp. 70-71 of our Report)

Why Increase Operating Reserves?

Projected DR growth may not be sufficient to meet target reserve margin; even if DR growth is *projected* to be sufficient, actual growth may lag and trigger low reserve margins

If **this possibility of low reserve margins is unacceptable, then increasing the quantity of operating reserves can support a higher level of generation investment by making scarcity pricing more frequent**

- Implementation is easy

Key Risks

- Future regulators may be temped to release excess operating reserves at low prices, particularly if reserve margins turn out to be adequate, or under extended high-priced conditions
- Higher amounts of withholding have higher regulatory risks
- This risk could undermine market investment, or at least increase the "risk premium" and therefore market prices

How to Increase Operating Reserves?

When?

- To attract incremental generation investment, a firm commitment to increase operating reserves by a certain amount would be needed 2-3 years in advance. So this commitment would need to be made by spring 2013 to attract resources for 2015.

How Much?

- The quantity would be based on projected load and resources, and the estimated incremental investment impact of increasing operating reserves
- But determining the right quantity is NOT straightforward
  - If the only new supply were available combustion turbines (at Net CONE), you would need to withhold the target reserve margin minus the "equilibrium energy-only reserve margin" estimated for current rules/market conditions/DR penetration; this amount changes as market conditions change
  - If some supply is available at lower cost, less is needed; and other adjustments

What Type of Operating Reserves, and At What Prices?

- Something that is not spinning all the time (inefficient), such as non-spin or limit the extra reserves to peak hours, as in EDF's proposal
- For 1 MW of increased operating reserves to expand the economic equilibrium reserve margin by 1 MW, need to deploy the reserves only at the price cap
- But it is more efficient to deploy such reserves before depleting more valuable responsive reserves and regulation. Therefore, deploy the new reserves at a range of intermediate prices, and move the higher value reserves from our "proxy demand" schedule to the cap.

Energy Only Design Elements

No Procurement of Backstop Generation

Backstop Procurement Can Be Inefficient

- Regulators can make inefficient investment decisions
- Withholding backstop generation from the energy market is operationally inefficient

Backstop Procurement Significantly Increases Regulatory Risk

- Future regulators may be temped to release backstop generation to the market
- This risk may undermine in-market investment, more so as procurement increases
- In worst case, could deter all market entry and devolve into regulated planning

Implementation Schedule Needed to Meet 2015 Needs

Energy-Only with Support for DR

Conceptual Market Design Decisions

Support for DR
- Support DR to accelerate the transition to a self-sustaining energy-only market

Increase Operating Reserves
- Maybe increase operating reserves to boost scarcity pricing frequency and increase investment
- Or adopt wait-and-see approach based on minimum acceptable RM

No Backstop Generation Procurement

Who: PUC, with input from: Stakeholders (TAC) ERCOT Board

Timeline: by Dec 2012

Development of Market Rules

Product(s) Definition
- Notification time
- Availability requirements (no. calls, hours, etc.)

Auction rules
- Qualification process
- Define “demand”
- Price cap

Payment and Penalties
- M&V & baseline definition
- Penalty structure

Cost Allocation
- Allocation formula

Dispatch & Price Formation
- Dispatch signal
- “Sloped” scarcity curve
- Eliminate LCAP
- Evaluate HAM and “Loads in SCED”

Who: Stakeholders (TAC) ERCOT Board Subject to PUC approval

Timeline: Jan June 2013

Implementation

Set up Auction

Expand ERCOT DR Team
- To qualify resources and track performance

IT Systems Modification
- Implement fixes for price reversal
- Settlements
- Any SCED modifications (or HAM introduction) may take longer than the timeline shown below for procuring resources

Who: ERCOT

Timeline: July Dec 2013

Go Live

Hold DR capacity auction

REPs and CSPs solicit DR resources

Additional DR resources available for dispatch (and maybe incremental generation too)

Who: ERCOT

Timeline: early 2014

Summary of Key Risks

Can't implement fast enough to address impending 2015 issues?

- DR will take time to develop, e.g., with auction in 2014 for 2015, then take 3 years to reach "realistic potential"
- Generation needs time to respond to withholding
- Exacerbated by any implementation delays

Rapid Residential DR Deployment

- Potential quality issues with rapid deployment; potential supply chain limitations
- Potential customer dissatisfaction, esp. in an extreme weather year with frequent calls
- Limited capacity value due to 4-hour maximum duration, limited calls; opt-outs; snap-back; summer-only
- If equipment is funded through TDUs, cost adds to T&D rates

Reliance on DR Capacity Market

- Discrimination against non-DR can lead to inefficient investment/retirement decisions and higher "capacity" prices and all-in costs than a full capacity market approach
- Must define baselines correctly and require performance in order to provide incremental reliability

Energy Price Impacts of Increased DR

- DR is most accretive to reliability if it strikes at cap (and ERCOT holds prices at cap); less so if it strikes at lower prices and/or if there is price reversal

Increased Regulatory Risk from Administrative Withholding

- Future regulators may be tempted to release reserves
- Estimated need made 3 years in advance could prove to have been wrong
- Mitigate risk by limiting reliance on withholding

Cost Volatility

- Extreme energy prices in a hot year. Imagine 2011 weather, but with a much lower reserve margin from a pricing perspective (and higher price caps) than in 2011
- More weather-sensitive and volatile than a capacity market with high reserve margins
- But market participants can hedge financially and physically

Composite Option #2
A Texas Capacity Market

Design Elements

A Texas Capacity Market

Design Overview

- 3-year forward auction for 1 delivery year
- Single region-wide market
- Demand curve: trade-offs between vertical and sloped
- No Minimum Offer Price Rule (MOPR), but a “statement of principles”
- Align resource obligations and incentives with resource adequacy value (special considerations for generation, intermittent resources, DR)
- Complement capacity payment & penalty structure with continued strong scarcity pricing in the energy market
- Cost allocation based on cost causation
- Transition period (until 2017): options for managing initial price shock and price formation issues with compressed forward periods

Forward Period

3-year forward period is sufficient to include new builds in supply curve without creating risks of very long-term forward commitments

Forward clearing has the following advantages:

- Allows new entrants to compete with existing
- Elastic forward supply curve improves price formation (costs are not sunk)
- Stabilizes boom-bust
- Can respond effectively and efficiently to supply challenges, *e.g.*, EPA rules

Annual incremental auctions should be implemented to adjust for changes in supply and demand conditions

Capacity Market Design Elements

Region-Wide Market

Texas has a robust transmission system

- New transmission is solving the largest import and export constraints
- But still, nodal energy prices provide incentives to build generation where needed

A larger, region-wide market is easier and more stable

- Less susceptible to price volatility, lumpiness, market manipulation
- Avoids subjecting market participants to price gyrations from changes in administratively-determined import constraints
- Avoids the complexity of a locational market

Capacity Market Design Elements

Demand Curve: Vertical vs. Sloped

Vertical is the simplest design

- But can lead to volatile prices and incentives to exercise market power
- Seems unnatural for the marginal value to be so discontinuous

Sloped demand curve works better but creates controversy

- Better market characteristics
  - Lower volatility benefits buyers and suppliers
  - Less incentive to manipulate prices
  - Recognize that falling slightly below the target is not a disaster and buying a little additional reserves has incremental value (but loads don't always like paying for "extra" capacity)
- These benefits are present, but not as great in a high-growth, large (non-locational), three-year forward capacity market, as proposed for a Texas Capacity Market
  - Forward market has elastic supply, which moderates volatility; new resources can set prices
  - But what if growth slows and locational zones are needed in the future? Better to introduce slope now?
- High risk of ongoing litigation and associated market uncertainties
  - More controversial (and viewed as more "administrative") to define price-quantity curve rather than just quantity
  - Argue about the shape, slope, and height of the curve
  - PJM and NYISO set the price at (or near) the target RM at "Net CONE"; Net CONE becomes the most controversial parameter
  - Reference technology and its capital cost?
  - Appropriate levelization and cost of capital?
  - Energy margin offset -- especially difficult to calculate in ERCOT with its more volatile energy prices

No Minimum Offer Price Rule (MOPR)

A MOPR is not needed in ERCOT

- A strong MOPR is very important in eastern capacity markets to prevent states from manipulating markets by adding uneconomic capacity to suppress the price
- But MOPR rules would be less meaningful in one-state RTO regulated by PUCT (and Legislature)
  - Can't write rules to prevent future regulators from changing the rules
- And buyer-side manipulation is less likely in ERCOT
  - Pro-market regulators have demonstrated a commitment to protecting markets from intervention even for reliability
  - There are no buyers in ERCOT with a large enough net short position to justify offering new generation below cost to suppress capacity prices (incentive is based on net short after constructing the new resource)
  - Texas' high load growth makes any price suppression transitory, decreasing incentive

But a "Statement of Principles" would be helpful

- Principle is that out-of-market additions (e.g., state-sponsored procurement or major subsidies for reliability or other policy reasons) displace in-market investment, undermine investor confidence, and threaten to destroy the market
- A clear statement of principles provides stakeholders with more regulatory certainty

And the IMM should be given discretion to identify clear cases of manipulation and recommend mitigating measures to the Commission

Supplier Offer Mitigation

Suppliers will be disciplined by competition with unlimited new entry on a 3-year forward basis

But still need to guard against the exercise of market power

- Particularly when new entry is not needed
- Or if there are barriers to entry (*e.g.*, in the transition period)

Develop rules through the stakeholder process in coordination with the IMM

Resource Obligations and Incentives

Resource Value and Obligations

- Align resource obligations and payments with resource adequacy value
- Recognize that limited DR and intermittent resources do have value, but not as much as traditional generation resources

Performance Incentives and Penalties

- Other ISOs have had issues with resource performance
- Resources must be available whenever needed; lose capacity payments if not
- Maintain strong scarcity pricing signals in energy market

Energy Pricing Provisions

There is a trade-off between price volatility and having price signals that accurately reflect the value of energy to the system

- We recommend maintaining high price caps and scarcity pricing
  - Scarcity prices can incent resources to be available when needed more strongly than administrative penalties
  - Value should reflect demand's willingness to pay and/or LOLP*VOLL when depleting operating reserves and a price cap set to VOLL when shedding load; need VOLL study
  - However, we recommend reducing the *generator offer cap* to $1000/MWh if capacity payments are available
- We recommend against an energy margin "clawback" mechanism to recover revenues earned during scarcity
  - Generators are largely not exposed to spot prices. Shouldn't clawback margins they didn't earn
  - Would undermine energy price incentives if not designed carefully
  - Total cost volatility (from energy + capacity prices) is lower with a capacity market than energy-only

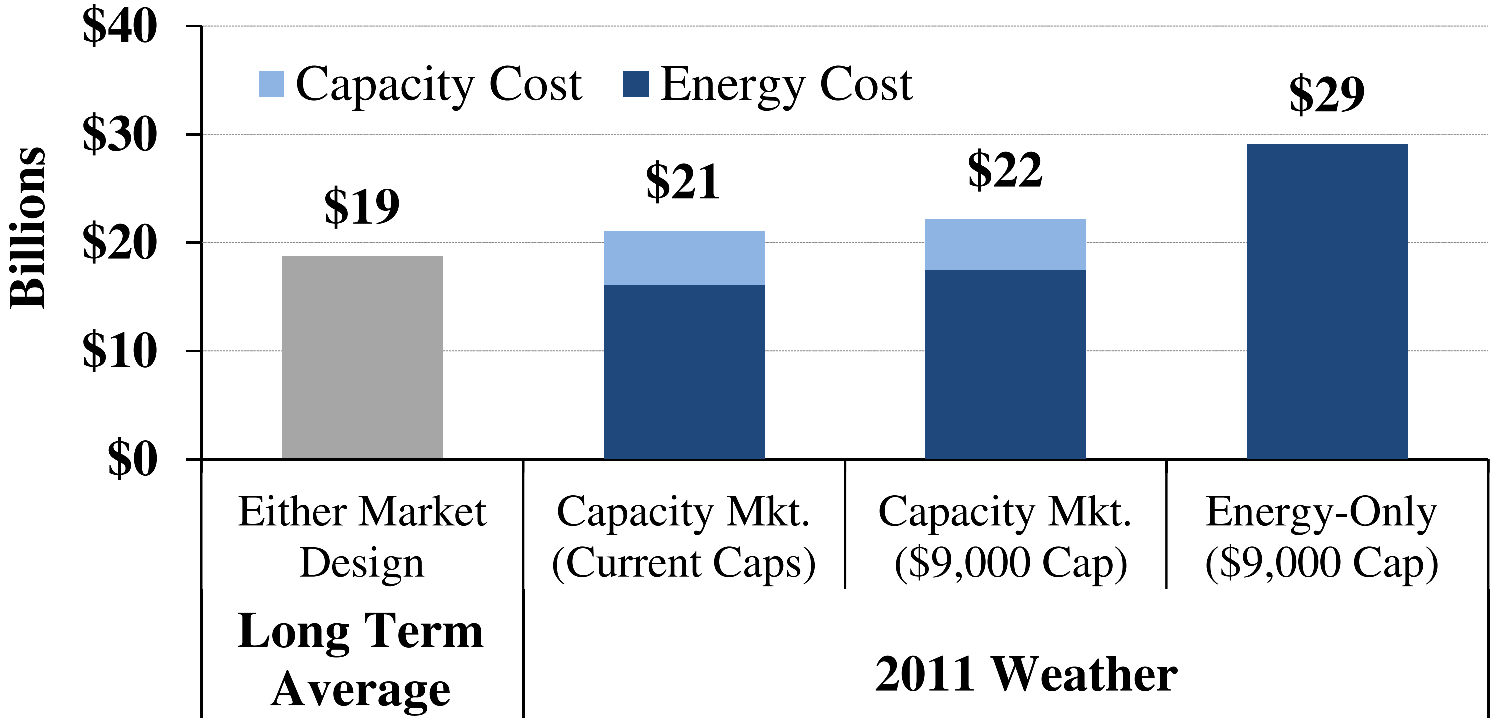
Even with extreme weather, energy price volatility is less than in an energy-only market because the frequency of scarcity pricing is lower at the higher reserve margin from a pricing perspective (see next slide)

Evaluation of Options against Policy Objectives

Capacity Market Costs are Less Volatile

A Texas Capacity Market Would Reduce Customer Costs in Extreme Weather Years

(Even with High Energy Price Caps)



Notes: Assumes energy costs are 75% hedged. Capacity prices are assumed to be the same "Net CONE" across weather years. The $9,000 Cap Scenario includes a $300,000 PNM threshold, a $4,500 Low Cap, and a gradually sloping scarcity pricing function.

Cost Allocation Based on Cost Causation

Costs should be allocated to load based on their contribution to demand for reliability

- Cost allocation based on 1CP and 4CP load is simple, but does not fully reflect reliability demands imposed on the system
- Many hours contribute to loss-of-load probability, which drives RA needs
- Cost allocation should be simple enough to incentivize loads to manage their consumption

DR reductions must be reconstituted to avoid double-payment

Capacity Market Design Elements

DR Rules

Supply-Side DR

- Defining “Negawatts” improves visibility of DR for planning purposes
- Enables third-party curtailment service providers to participate; they are responsible for much of the DR growth in other markets
  - Specialized expertise in a complex sales and engineering process
- However, clear product definition, obligations, and measurement and verification (M&V) are critical
  - Must define customer baselines carefully to avoid gaming and double-payment
    - Learn lessons from other RTOs
    - For example, the customer’s baseline should be no greater than its peak load contribution
  - Resources with limited calls are valuable, but may be less valuable
    - Consider PJM approach

Another Option: Demand-Side Load Management Only

- Simple, with no baseline, gaming, or double-payment issues
- But lower resource visibility; untested; slower DR development

Transition Period Challenges

Because there is no supply surplus to ease the transition, there are two serious challenges:

- "Timing" – If market design is completed in late 2014, there may not be enough time developers to meet 2015 needs
- "Sticker Shock" – Sudden addition of capacity costs will cause "sticker shock" for customers and risks a backlash
  - Prices have to rise significantly above today's levels in order to attract new generation under any construct. With the first capacity auction, that increase is likely to materialize all at once. All of the increase would be perceived to be caused by "capacity," a difficult-to-explain product.
  - Short forward period in first incremental auctions increases risk of 'bimodal' pricing, including the risk of prices at the cap (while energy prices might be high too)

Potential Solution

- "Timing" challenge: announce 2015 auction price floor in Spring 2013. This will provide a clear price signal with more lead time for new generation and other resources in 2015, even if not all details of the capacity market are yet established
- "Sticker Shock" challenge: consider phasing in payment to existing resources (*e.g.*, existing resources receive 30% of the clearing price in 2015, 70% in 2016, and full in 2017/18)
  - This is discriminatory and could discourage economic capital expenditures to maintain existing resources, but would ease the transition substantially
  - It is *critical* to commit to never discriminate again after this one-time transition to the full forward period

Potential Alternatives

- Alternative 1: increase operating reserves immediately (and temporarily) to start higher costs sooner, perhaps stimulate more near-term investment, and perhaps lower capacity prices in 2015/16. But this may be problematic for parties to existing contracts.
- Alternative 2: impose a very sloped demand curve and/or tight collar on the price for 2015/16; but this could lead to inadequate near-term investment or could force customers to over-pay

Implementation Schedule Needed to Meet 2015 Needs

Texas Capacity Market

Conceptual Market Design Decisions	Development of Market Rules	Implementation	Go Live
Forward Period • We recommend 3 years with incremental auctions **Demand Curve** • "Sloped" vs. simple vertical **Transmission Constraints** • We recommend a single market without locational prices **Buyer-Side Market Power Mitigation** • We recommend a statement of principles but no MOPR **Energy Market Design** • Keep high scarcity prices • Lower gen offer cap **Transition Period** • Decide on transition options **Cost Allocation** • Provide guidelines for allocating predictably and according to cost causation	**Qualification, Performance Requirements, and Penalties for Generation** • Determination of MW ratings • Performance reqs.,penalties **Comparable Rules for DR** • MW rating must reflect RA value; address "Limited" **Auction Rules** • Format • Bid/offer rules **Cost Allocation** • Basis • Reconstitution of DR? • Load tracking for REPs **Supplier Mitigation** • Rules for supplier market power monitoring **Transition Parameters** • Rule on price floor for 2015 auction ASAP • Discount for existing in 2015 and 2016 only?	**Auction Software** • Not particularly complicated once demand is set and resources are qualified as MW **Settlement Systems** **ERCOT Staffing** • To qualify resources and track performance • Manage auctions **Begin Resource Qualification** (6 months) • Determine MW ratings of each resource	**Auction** • Finalize resource qualification • Finalize auction parameters (updated peak forecast) • Hold auction in early 2015 for 6/15-5/16. **2015/16 Delivery Year** • Track resource performance • Track load shifting • Settlement **Beyond** • Hold auctions for 2016/17, 17/18, and 18/19 later in 2015 to transition to 3-year forward
Who: PUC, with input from: Stakeholders (TAC) ERCOT Board	Stakeholders (TAC) ERCOT Board Subject to PUC approval	ERCOT	ERCOT
Timeline: assume Dec 2012	Jan'13 June'14	July '14 Dec'14	Early '15+

Evaluation of Options

Key Risks: Texas Capacity Market

Can't implement fast enough to address impending 2015 issues?

- We suspect that investors will start responding today in anticipation of a capacity payment upon delivery
- But setting a 2015/16 price floor in early 2013 will strongly mitigate the risk of shortfall in 2015
- In general, capacity markets make significant shortages unlikely, since prices rise rapidly when short

Many administrative determinations

- The load forecast, reserve margin requirement, demand curve shape, and resource adequacy qualification rules have a big effect on prices. Becomes important to forecast more accurately
- Ongoing litigation over parameters and rules can create market uncertainty; but this can be somewhat reduced by the "Texas" design we have presented here

Sticker shock (rates must increase in any case to support investment) that people could attribute to the new and hard-to-explain capacity product

- Consider the transition mechanisms we presented

Volatile prices, particularly with vertical demand curve

- Mitigated by high load growth and a 3-year forward period, which produce an elastic supply curve
- Also mitigated by DR activity since it can enter and exit at a range of prices

Future regulators abandon market and/or discriminate against existing assets

- A threat under any market construct
- Can make it less likely by designing the market to avoid extreme price and reliability outcomes

Evaluation Of Options

Reliability

Worst ... Best

Energy-Only with Support for DR

DR potential is uncertain, so shortfalls are more likely if there is no administrative withholding

If DR is complemented with increased operating reserves, the reserve margin could be near the target, but still uncertain

- But the amount of incremental DR and generation investment that will be achieved is highly uncertain
- Uncertainty is compounded if generators' regulatory risk (surrounding energy-only prices that are supported by administrative withholding) undermines market investment

Texas Capacity Market

Achieves required reserve margin more reliably than other approaches

- Steep capacity price increase in shortfall should attract sufficient investment
- 2015 reliability challenge could be helped by early announcement of price floor
- Going forward, would help maintain adequate reserves even with challenging environmental regulations and as market conditions change

Some have raised concern that the "reserve margin" does not translate to "real reliability"

- Capacity payments have to be tied to performance: availability whenever needed
- Maintaining strong energy (and ancillary) scarcity price signals will maintain incentives to be available for any unanticipated operational or resource adequacy challenges
- No construct provides perfect reliability

Economic Efficiency and Cost

Worst … Best

Energy-Only with Support for DR

Assuming it achieves the same reserve margin, “Energy-Only with Support for DR” probably costs a little more

Exclusion of generation in capacity auctions may not procure the lowest cost resources

Administratively withholding generation by increasing reserves is operationally inefficient and creates regulatory risk for investors

Same spot price volatility as energy-only

Texas Capacity Market

All types of resources compete in the market to meet an administratively-determined reserve margin requirement, resulting in least-cost resource solution

No need for operational distortions in the energy market

Performance signals almost as strong as energy-only if performance requirements well-designed and scarcity price provisions are maintained

Less volatile annual customer costs

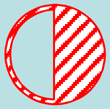
Moreover, differences in regulatory risk can produce significant differences in cost (see later slide)

Regulatory Stability and Investor Risk

Regulatory stability and investor risk affect both long-term viability and cost

For example, if a capacity market reduces investor risk and hurdle rates by 50 bp (0.5% point difference in after-tax weighted average cost of capital), expected total wholesale costs would be 1.5% lower

Energy-Only with Support for DR



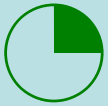
DR provides reliability with more regulatory stability than administratively supporting large amounts of (relatively low strike-price) generation through backstop procurement and/or increased operating reserves

However, if administrative withholding is used to make scarcity prices more frequent and attract more generation, regulatory risk increases

Investors face the risk that future regulators may be temped to release the extra reserves at low prices, particularly in an extended high-priced events

This exacerbates the risk from volatility and potential intervention that investors already perceive in a pure energy-only market

Texas Capacity Market



Somewhat less volatile total returns than energy-only (especially less than energy-only with administrative holding), but still no long-term price guarantee for investors

Ongoing uncertainty in administrative parameters, such as load forecast

Rules and parameters may be subject to lobbying influence

Evaluation of Options against Policy Objectives

Implementation Complexity

Worst | Best

Energy-Only with Support for DR

Same fundamental design as today, but with new complications

- Establishing a DR-only "capacity market" (or equivalent) involves many administrative decisions: product definitions, auction rules, cost allocation, M&V/baselines, etc. (same issues as in a full capacity market)
- Increasing operating reserves would add complexity: need to design reserve product; estimate quantity needed 2-3 years forward

Texas Capacity Market

Many administrative determinations

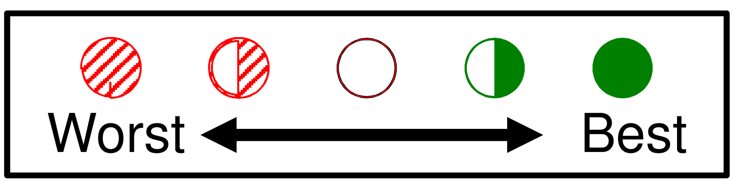
But no MOPR and no locational market reduce complexity substantially; a vertical demand curve could also reduce complexity if desired

Most complex elements are sloped demand curve, resource performance requirements and penalties, load forecasting, and resource ratings for limited DR products

Risks mitigated by experience (good and bad) gained in other regions

Scorecard

	Reliability	Economic Efficiency and Cost	Regulatory Stability and Investor Risks	Implementation Complexity
Energy-Only with Support for DR				
Texas Capacity Market				



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Next Steps

Timing is critical even though reserves may be adequate through 2014

- Still need substantial new resources by 2015 if we are to maintain the current target reserve margin
- Resource developers likely need at least 2 years (for new generation, could be closer to 3 years) and 6-12 months for DR
- Hence, developers need to make investment decisions by next summer
- EITHER framework presented here would require actions by next spring
    - Energy-Only with Support for DR: commit to MW of withholding for 2015
    - Texas Capacity Market: decide on price floor for first auction for 2015
- To meet that schedule, the Commission would have to decide on a framework by the end of this year

Resource Adequacy Roadmap

GOAL: Electric Reliability and Efficient Markets

Resource Adequacy Risks Identified ✓
- 2011 extreme weather
- ERCOT reports on potential long-term reliability challenges

Adjustments for Summer 2012 ✓
- Scarcity pricing signals
- Emergency response tools
- Offer cap increased to $4,500/MWh

Examine Long-Term Market Fundamentals ✓
- Brattle Group study (issued June 1, 2012)
- Report identifies risks and presents policy options

Evaluate Policy Options and Proposals ✓
- Market participant comments and proposals
- PUC workshops
- Consideration of long-term offer cap rulemaking

Develop "Composite" Alternatives
- Brattle Group refines energy-only and capacity market options
- Gather additional demand response data

PUC Policy Direction

Implementation Process
- Revise PUC rule and ERCOT protocols as necessary
- Define implementation timeline
- Ongoing measurement of impacts