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PROCEEDING RELATING TO RESOURCE ADEQUACY IN THE ERCOT POWER REGION	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

<u>COMMENTS PROVIDED ON BEHALF OF THE ERCOT RELIABILITY ADVOCATES IN RESPONSE TO THE COMMISSION'S QUESTIONS ON RESOURCE ADEQUACY</u>

Calpine Corporation ("Calpine"), Exelon Generation Company, LLC ("Exelon") and NextEra Energy Resources, LLC ("NextEra"), collectively the ERCOT Reliability Advocates (the "Advocates"), have been active participants in the Commission's proceeding on resource adequacy. The Advocates appreciate the Commission's decision to move forward with a robust discussion of market design options that will ensure the long-term reliability of the ERCOT market, which includes the Commission's questions and agreement to schedule Commission workshops on January 29-30 and sometime in mid-February.

Roy J. Shanker, Ph. D, an independent consultant, was retained by the Advocates to respond to the Commission's questions, particularly the questions regarding a capacity market. Dr. Shanker's comments are attached for your consideration.

Respectfully submitted,

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PROJECT NO. 40000

PROCEEDING RELATING TO RESOURCE ADEQUACY IN THE ERCOT POWER REGION OF TEXAS	)))	PUBLIC UTILITY COMMISSION of TEXAS

COMMENTS OF ROY J. SHANKER PH.D.

ON BEHALF OF

ERCOT RELIABILITY ADVOCATES

December 16, 2013

1) My name is Roy J. Shanker. My address is P.O. Box 1480, Pebble Beach, California, 93953. The opinions expressed in these comments are my own, but the comments are provided on behalf of the "ERCOT Reliability Advocates" (ERA).[1]

2) I am an independent consultant with almost 40 years of experience in energy markets, with most of that work dedicated to the electric utility industry, and for the past 18 years to the development of the market designs for independent system operators (ISOs) and regional transmission organizations (RTOs).[2] Most relevant in the context of Project 40000 is my experience in the development and design of capacity markets. In both the PJM and NYISO markets I have worked on the capacity market designs and changes since prior to the initial operation of the markets. I am one of the sponsors of several of the basic design attributes in the PJM Reliability Pricing Model ("RPM"), and coined the term "missing money" as part of the description of the underlying revenue adequacy concerns related to organized markets with mandated reliability targets and price caps. I have participated in a number of related proceedings in ISO-NE and MISO. I have been a frequent participant at the Federal Energy Regulatory Commission ("FERC") technical sessions on related issues for approximately 15 years. A summary of my background and regulatory experience is presented as an attachment.

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[1] ERA has previously filed comments in Project 40000. ERA is an ad hoc group consisting of Calpine Corporation ("Calpine"), Exelon Generation Company, LLC ("Exelon") and NextEra Energy Resources, LLC ("NextEra").

[2] A summary of my relevant work and testimony is attached hereto.

3) I recently participated in Docket AD13-7 at the FERC.[3] It was intended to address many of the same issues and concepts being considered in Project 40000, including a large overlap with the types of questions and underlying issues addressed through the specific requests posted by the Commission. In preparing these comments, I lean heavily on that paper and the remarks I submitted at FERC because in many ways, while everyone wishes to preserve the notion of regional differences, there are many fundamentals for electric market designs that all regions share with respect to the issue of resource adequacy. However, I have also reviewed many of the topics addressed specifically in Project 40000 over the last months, and have tried to make sure that I have captured as much as possible of the Texas specific considerations and factual differences.

4) I also have separately addressed questions posed by the Commission, with a particular emphasis on those questions specifically related to capacity markets because that is my primary area of expertise. As a result and in an effort to avoid redundant comments, the responses are primarily to the original questions posted and I believe, in most instances address the bulk of the capacity market questions subsequently posted for this round of comments.

[3] Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators Docket No. AD13-7-000.

5) I similarly have provided a copy of my comments in AD13-7-000, which while repetitive, contain citations to FERC decisions and dockets that may be of interest to the Commission and its staff.[4] Similar to the cumulative filings in Project 40000, there has been a great deal of reference material, proposals and testimony accumulated addressing capacity markets in other jurisdictions.

Discussion

The Key First Step

6) Though it sounds a bit like a jingle and not serious, the unambiguous first determination by the Commission, as manifest in this proceeding, is addressing the question: "Is reliability in terms of capacity adequacy intended to be a market outcome or output, or rather, is adequacy to be an input and constraint on the overall market and a basic principle of the market design?" In many ways, following a somewhat complex path, this has appropriately been the underlying theme and question of Project 40000. In simple terms, the key question is whether the Commission is going to continue with an "energy only" market structure, take its "hands off" and be comfortable with the reserve margin outcome? Or, is the Commission going to mandate a reserve margin as an inviolable input, and design an efficient structure to achieve the result?

[4] Comments of Roy J. Shanker, Ph.D, Independent Consultant, filed September 11, 2013, Docket No. AD13-7-000.

7) If reliability is to be an output/outcome of the market design, the path for the Commission is easy. Don't do anything, and there isn't a need for a capacity market, and arguably, directly or indirectly no other scarcity pricing or rationing mechanisms will need to be created. Resources will build in response to demand and associated short-term margins, long-term bilateral agreements, and/or a combination of both. Total supply will be a function of willingness to pay; the ability to convey that willingness in terms of price signals, metering and business arrangements. Most importantly, to the extent the resulting reserve margin is not high enough to cover all load during the peak hours, the notion of demand response would likely take on a much more "real" meaning, as either ERCOT or the distribution companies take actions to translate the underlying business and pricing relationships into hard curtailments on the grid.

8) In this type of construct, power will be available to those willing and able to pay, and who have metering and systems in place to control their load. Others, such as those without direct controllable load, or an ability to express price responsiveness, may experience involuntary curtailments as ERCOT physically rations available energy to serve load. Seen in this light of availability or unavailability based on financial considerations, it isn't clear that the term "reliability" actually has the same connotation that we typically give it.

9) But the ability to implement and make rationing and interruption of supply real is a logical requirement in the "reliability as an outcome" type of approach. Without it, there is no way to discipline the market to make sure that those unwilling to pay do not free ride on the system's resources at the expense of others who have committed either via reservation, hedging or payment to maintain service. This is not different than most other commodities where this notion of reliability via rationing or denial of service is common. If you want a specific car or appliance, you may find the one you want only at a premium price, have to purchase a lesser substitute, or simply do without. If you want a true market approach to electric reliability, the options have to basically be the same. Inherent in this, I see no way to ignore the fact that parties need to be willing to find a true market approach to denial and rationing of electric service under the "reliability as an output" paradigm. While this is seldom discussed, it is one of the underlying realities of why directly or indirectly, this policy result does not seem viable in most situations for electric supply.

10) This directly leads to consideration of the alternative, reliability as an input. Very simply put this acts as a direct constraint on the long-term properties of the electric system. Either through mandate or some sort of market-like mechanism some exogenous action must be taken or be prepared to be taken to assure that the constraint in met. Most typically in the United States we see the imposition of this exogenous standard as a variant of the "1-in-10-year" loss of load event standard.

11) In this alternative, resources are consciously procured to meet infrequent peak demands based on the exogenously set reliability standard. That is, policymakers consciously contemplate a world in which some units may seldom, if ever, operate in order for the overall market to be assured of sufficient supply in these low probability events. In addition, because the market is so tight in these instances, and because most loads have no or very limited price elasticity, most markets have explicit offer caps on energy supply pricing and energy pricing mitigation in times of scarcity. In combination, infrequent operation and capped/mitigated energy offer prices result in a situation where low capacity factor units earn little if any returns above their marginal operating costs and have little opportunity to recover fixed costs. As the Commission is aware, even with modifications to scarcity pricing being considered, the implied value of loss load to meet these traditional reliability objectives are generally very large, and not likely to be adopted because of the implicit volatility associated with such results. Thus, a revenue shortfall occurs. I have referred to this inherent property of markets where adequacy is an input constraint as the "missing money" issue, which ultimately requires some mechanism to allow payments outside of the energy market to attract new capacity resources and retain needed existing capacity resources.

12) While this notion of "input" or "output" for reliability, even when recognized, is typically seen as a simple dichotomy, the reality is actually much different. And the associated nuances are worth considering further, as ultimately this question appears to be driving the entire discussion in Texas. I have often heard the

discussion of alternatives being considered here as the choice between an energy-only market and a combined capacity/energy market design. But the reality appears to be that whether recognized or not, reliability as an "administrative input" has already implicitly been selected, as evidenced by this Project and other previous Commission actions. The only real issue is how the Commission chooses to implement its choice going forward.

13) I say that the choice had already been made because my understanding is that regardless of the market structure at the moment, at any time in the past the Commission would have acted to "back-stop" a perceived reliability shortage; however that shortage would have been defined. Further, it seems likely that this type of regulatory/administrative intervention was never "off the table" in terms of anyone's perception of what constituted the ERCOT electricity markets. This is explicitly recognized in ERCOT's authority to award Reliability Must Run ("RMR") type contracts as well as contracts for Emergency Response Service ("ERS"). This means that the reality has always been that reliability has been an input; just less defined than the formal capacity market currently being debated, but nonetheless a formal construct. These actions are undertaken in an "out of market" fashion, with many of the deficiencies that accompany that sort of capacity design.

14) This somewhat ad hoc, but real ability to enforce a minimum capacity adequacy standard by the Commission is materially different than having no capacity market at all. And this type of choice has and will continue to have consequences. Effectively

the Commission has kept in place a type of "option" in terms of installed capacity in the market. Suppliers have to operate in anticipation of the potential consequences of such an option on both energy supply, the future details of a capacity market, and the resulting process of price formation for longer-term hedges between themselves and Retail Electric Providers ("REPs") or other load interests. At the same time consumers' behavior is also influenced by this implicit option. The willingness of consumers to enter into longer term hedge agreements would be expected to be significantly depressed by the existence of such an option, as whenever the option is executed, it suppresses prices at just the point in time that most people are worried about when they are motivated to consider putting in place hedge protection for both energy and capacity. Thus the option, coupled with ongoing uncertainty has direct and adverse consequences.

15) It should be noted that this characterization is not intended to criticize the Operating Reserve Demand Curve ("ORDC"). But the reality is that major elements of the ORDC are administratively determined, however the overall process represents an important improvement of moving scarcity information into real time prices while also addressing part, but not necessarily all, of the missing money issue.

16) Thus the ORDC doesn't resolve the fact that reliability has been determined to be an input and thus an effective over-riding constraint on the need for minimal adequacy resources in the market. Once it becomes clear that such a constraint exists, the only correct approach is to recognize it and design the markets to

represent the potential requirement most efficiently (which in my opinion is not the status quo). Like all other constraints, in application the requirement may not "bind" and no additional actions would be necessary (e.g. resulting capacity pricing would be zero). Regardless, an efficient market design will always represent the constraint, because it is most important that it be in place and represented exactly when it does bind. This is the proverbial "what you don't see does hurt you", should a known constraint be excluded from the market. Without the potential constraint represented, a material factor will be missing from price formation, necessary compensation, and incentives for both buyers and sellers in the market.

Four General Principles

17) The issues that we are addressing via the Commission's question are what constitute the best way(s) to achieve that "appropriate capacity mechanism" and what associated design criteria should be utilized. Fortunately, most of the "heavy lifting" with respect to capacity market design in central markets has already been done in the evolution of these types of markets in the eastern RTO's.

18) There are a series of decisions at the FERC that have dealt with just about every aspect of these market elements, and collectively they present a well-informed set of discussions and determinations assembled over a decade. In particular, the initial testimony of Dr. Steven Stoft that was presented in *Devon Power LLC*, Docket No. ER03-563 (also known as the New England locational ICAP proceeding) contains an

excellent discussion of the overall use of central auctions and the associated use of a demand curve, including the slope and point of inflection of an efficient demand curve. These concepts are also discussed in the Initial Decision by the Administrative Law Judge in that proceeding, that in large part approved ISO-New England Inc.'s (ISO-NE) 's proposal.[5] Likewise, the August 31, 2005 filing by PJM Interconnection L.L.C. (PJM) to establish the RPM and the associated testimony in support of PJM's filing in Docket Nos. EL05-148 and ER05-1410 contain an excellent summary of the rationale behind several of these key design criteria, including the forward commitment, the downward sloping demand curve, and locational clearing, many of which are reiterated in the Commission's order approving the RPM settlement issued on April 20, 2006. [6]

19) One of the biggest problems that has occurred in the following development of these markets was that actual implementation was a collection of compromises, rather than intelligent improvements building on these fundamental findings. One of the benefits of approaching this problem at this time is that Texas can avoid most, if not all of these missteps.

20) Based on my experience, should Texas proceed to a central capacity market design, I believe that these filings and associated FERC orders set forth the building

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[5] *Devon Power LLC*, Prepared Direct Testimony of Steven E. Stoft on behalf of ISO New England Inc., filed Aug. 31, 2004, Docket No. ER03-563-030; *Devon* Power *LLC*, 111 FERC ¶ 63,063 (2005).

[6] *See, e.g., PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006).

blocks for resolving virtually all of the questions under discussion in Texas. In general the content was solid, and but for the erosion of factual conclusions by settlement, the referenced orders and underlying filings resolved many of the questions that are still in dispute or are being considered yet again in this technical conference. These results actually give Texas the advantage of learning from both the intellectual content of many years of debate, and hopefully avoiding what in hindsight were many of the obvious pitfalls, including any incremental "creep" towards discriminatory results.

21) My review of these previous capacity market proceedings and the associated orders identified four general principles and a number of specific sub-areas that are relevant to addressing the conceptual building blocks of any central capacity market.[7] These core principles may be summarized as follows:

> Principle 1—Capacity markets must permit sufficient revenue to average true net CONE [cost of new entry] over time in order to attract new entry and retain economic generation.
>
> Principle 2—Capacity markets must compensate similarly-situated generation assets consistent with the law of one price

[7] *ISO New England Inc.*, Testimony of Roy J. Shanker PH.D on Behalf of New England Power Generators Association at 5-6, filed July 1, 2010, Docket Nos. ER10-787-000, et al. ("*Shanker Testimony*")

in order to prevent undue discrimination and inefficient price signals that stifle competition.

Principle 3—Capacity markets must reflect all locational and reliability constraints in order to accurately reflect the true value of generation assets.

Principle 4—Capacity markets must mitigate both buyer and seller market power.

22) *First,* over time, compensation must be sufficient to attract new entry and retain existing economic generation.[8] This means that, on average and over time, the recovery from the bulk power markets *for both* energy and capacity must result in payments expected to be equal to the cost of new entry.[9] This should be an obvious starting point if the goal is to attract new investment. Implicit in this principle is the fact that if prices are lower than average some of the time, they *must* be higher than average during other periods. This property must be present in any resulting

[8] *See ISO New England Inc.*, 125 FERC ¶ 61,102 at P 43 (2008) ("The purpose of the New England FCM is to attract and retain sufficient capacity to maintain ISO-NE's Installed Capacity Requirement . . . ."), *order on reh'g*, 130 FERC ¶ 61,089 (2010).

[9] *See Blumenthal v. ISO New England, Inc.*, 117 FERC ¶ 61,038 at PP 82-87 (2006), *order on reh'g*, 118 FERC ¶ 61,205 (2007) (determining that the long-term design of electric market must be based on competitive outcomes and that over the long- term just and reasonable rates are equal to marginal cost of generation); *Devon Power LLC*, 115 FERC ¶ 61,340 at P 114 (explaining that offers at prices below a resource's long- term average costs, net of non-FCM market revenues, should be mitigated in order "to reset the clearing price to a level that would be expected in a competitive market").

market design.[10] It is important to note that nothing in these statements is inconsistent with the actions being contemplated by Texas to increase energy scarcity pricing signals via the ORDC or potentially other mechanisms. That simply will result in lower or even possibly zero dependence on revenue recovery via the capacity markets put in place. But it doesn't eliminate the need for such a market.

23) The Commission may be concerned about the price volatility of such a structure, which is at the heart of the considerations for the use of a downward sloping demand curve and the institution of a multi-year forward time frame for the capacity market.[11] As I explain further in response to the questions below, and as excellently discussed in Dr. Stoft's testimony cited above, the key property of a downward sloping demand curve is that it can be used as a *control* mechanism for both quantity and speed of adjustment for total capacity adequacy resources. As the demand curve is shifted up and down (right and left), the targeted capacity sought can be adjusted. Indeed it was a key insight, captured by Dr. Stoft, that in order to maintain a market based quantity at or above their reliability targets most of the

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[10] It should be emphasized that this is referring to net CONE. If the energy and ancillary markets are providing sufficient rents, this value would be zero.

[11] Dr. Patton and others have expressed similar strong support for the use of a down sloping demand curve. *See* Comments of David Patton, Ph.D., Potomac Economics, *Resource Adequacy in Wholesale Electricity Markets: Principles and Lessons Learned* at 5-6, filed September 23, 2013, Docket No. AD13-7-000 (Comparison of vertical and sloped demand curves and concluding the sloped demand curve: provides more efficient prices that reflect the prevailing surplus, improves price stability, which should facilitate investment by reducing price risk and reduces incentives to withhold capacity by raising the opportunity costs of withholding (foregone revenues) and decreasing its price effects), ("*Patton Comments*"). More diverse views exist with respect to the types of benefits of a forward market; however, I have never seen any rebuttal to all of the attributes of a forward market I discuss here and below.

time, the "anchor point" on the demand curve, (where price was equal to an expectation of the cost of new entry) would have to be greater than the specific reliability target for the market area itself. This would allow the market control mechanism (the demand curve) the flexibility to result in quantities that move above and below the anchor point over time, recover adequate compensation, and still meet reliability targets.[12] PJM came to this same recognition and explicitly shifted their demand curve to the right. After several years, NYISO reached a similar conclusion, and addresses the issue indirectly through market calculations that reflect a surplus. This is indicative of the type of cumulative experience that is available to Texas in terms of a development advantage based on previous experiences of other markets.

24) Similarly, it is recognized that the slope of the demand curve is an important control tool as well. When supplies are short (below the reliability target) it makes sense to have a demand curve with a steeper slope, encouraging new entry and retention by a rapid escalation in price. When supplies are in excess, it is logical to flatten the curve, to prevent the precipitous retirement of existing resources due to lower, but necessary levels of compensation. Experimental simulations are used to show how the shape of the demand curve influences investment behavior and overall level of capacity and associated total costs to consumers. This work has been

[12] It is interesting to note that while so many cogent observations regarding the benefits of a well-designed demand curve were presented and supported in New England, much of what I perceive as problems in that market stem from the fact that ultimately no demand curve was adopted, and apparently "settled away".

done by Dr. Benjamin Hobbs of Johns Hopkins University. Dr. Hobbs built extensive simulations around just these principles to demonstrate the ability of the demand curve to function as a tool for controlling both quantity and volatility in price.

25) All of this emphasizes that the specific values and shape of these types of demand curves relate to the control function, not the marginal value of capacity, in the situation where the reliability target was set as an input to the market design. One of the continuing obfuscations presented in arguments surrounding capacity market design and demand curves is the misrepresentation that capacity (or operating reserve) demand curves should be exact representations of marginal values of reliability versus as control mechanisms. The overall process minimizes costs to achieve the target reliability via the control tools, the curves.

26) These same considerations are manifest in the use of a forward procurement process, which provides for more transparency in forward pricing generally. I discuss this at length in the specific answers to the Commission's questions. The most obvious benefit is that this allows for elasticity in supply by providing sufficient time to build resources "into" the target delivery year and facilitates new entry at a price consistent with that paid to other resources.[13] As discussed in the specific answer there are three additional benefits, in particular the ability to coordinate transmission development with supply option; the ability to notice and

[13] Similar to the design limitation regarding the lack of a demand curve in ISO-NE, NYISO chose a structure that did not include forward procurement, limiting the ability of the market to physically respond to auction price signals.

coordinate retirements in an orderly manner; and also to coordinate hedging and procurement in a systematic way to complement retail competition.

27) *Second,* all competitive capacity resources within a given location should be compensated at the same price.[14] This a fundamental economic principle, often referred to as the law of one price. It is easily understood via an example. Assume that ERCOT has a peak demand requiring 52,000 MWs, but only has 50,000 MWs of resources. While some may argue the "need" is only for an additional 2,000 MWs, that simply isn't true. The need is for 52,000 MWs, and if 2,000 MWs were added, the removal of 2,000 MWs of the existing resources would put reliability back into the exact same shortage position. Hopefully that makes clear that with respect to adequacy, and adjusted for actual availability, a MW is a MW (old or new). The FERC presented a good summary of this general principal in opining about the RPM solution in PJM:

> In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity. Such competitive market mechanisms provide important economic advantages to electricity customers in comparison with cost-of-service regulation. . . . This market result benefits customers, because over time it results in an industry with more efficient sellers and lower prices.[15]

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[14] *Id.*

[15] *See, e.g., PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 141. *See also, Commonwealth Edison Co.*, 113 FERC ¶ 61,278 at P 43 (2005) (nondiscriminatory single-clearing price capacity auctions "ha[ve] the benefit of encouraging all sellers to place bids that reflect their actual marginal opportunity costs" and have been "found to produce just and reasonable rates for all the energy and ancillary service markets currently operated by the independent system operators and regional transmission organizations under our jurisdiction."), *order on reh'g*, 115 FERC ¶ 61,133 (2006); *Devon Power LLC*, 110 FERC ¶ 61,315 at P 45 (2005) (paying all "generators the same market-clearing price creates

The universally accepted "law of one price" for similarly-situated competitive units providing the same reliability service is a basic economic building block, and price discrimination among competitive supply is inefficient and in the long run will increase costs.[16] The suggestion in any manner that old versus new capacity has a differential reliability value is totally unfounded, and typically is only supported by desires to suppress market prices via discriminatory practices. Again Texas has the ability to cut these erroneous assertions off at the inception of a capacity market, and prevent the inevitable problems that come with such discrimination.

28) The Commission should recognize that these observations are applicable to virtually any type of "backstop" process or related ancillary service. Ultimately the notion of a backstop is synonymous with some form of price discrimination and artificial price suppression. If the backstop is intended to address a reliability adequacy need, then there is no difference between adequacy resources (old or

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incentives to minimize costs, because a generator's cost reductions are retained by the generator and thus increase its profits" while paying "different amounts to different generators based on the level of compensation needed to keep the generator in operation would create a unit-specific cost-based system and undermine the advantages of a market for capacity."); *New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,244 at P 65 & n.76 ("Efficient pricing requires that suppliers receive the highest market value for their resources, independent of their bids [as] [t]his gives all sellers the proper incentive to offer their resources at the marginal cost of their highest valued use."), *order on reh'g*, 113 FERC ¶ 61,155 (2005); *New York Indep. Sys. Operator*, 103 FERC ¶ 61,201 at P 81 ("[A]ll capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market.... The Commission does not see how [more expensive] generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover, those are the types of market signals the Commission would expect to encourage new generation additions.").

[16] *Blumenthal v. ISO New England Inc.*, 117 FERC ¶ 61,038 at P 83.

new) in addressing the *total system* reliability need. To the extent that a backstop is needed, it is indicative of the value that should be paid to all suppliers.

29) As to the *third* general principle, capacity markets must include locational and associated reliability constraints to create price signals that reflect the fact that capacity in certain congested areas potentially has greater value than capacity located elsewhere.[17] In general, the market also should be designed so that any capacity with attributes that provide for a differential reliability benefit (for example, beyond locational value the consideration of attributes such as quick start capability) will be recognized for those attributes and compensated accordingly.[18] A corollary of this principle is the desire to minimize, if not eliminate, the need for out-of-market contracts, such as RMR agreements.[19] The goal is to prevent the Commission from having to take actions that would otherwise have been incented by direct compensation in the capacity market design.

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[17] *See, e.g., PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318 at P 76 (2007) ("Capacity market prices must be locational in order to be fully effective. Because of transmission constraints . . . separate capacity prices are necessary in separate locations in order to reflect the differences in costs and capacity needs among the locations."); *Devon Power LLC*, 103 FERC ¶ 61,082 at P 37 (2003) (directing ISO-NE to develop "a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market" so that capacity within zones "may be appropriately compensated for reliability").

[18] In general there is an obvious partition among these attributes between those that would be best represented in the energy market as ancillary services and those that are best characterized within the capacity market. For the purposes of this discussion, that distinction is basically ignored other than for the fact that it can be represented. But some features, particularly locational adequacy are only reasonably represented for planning adequacy in the capacity market.

[19] Shanker Testimony at 7.

30) Thus, the notion of determining electrically cohesive areas wherein capacity is fungible, but areas between which capacity transfers are limited, is key to assuring reliability. Again, I give a longer and more generic characterization of this concept in the direct answers to the Commission questions, but the drivers for a locational attribute in the capacity market are similar to the drivers to locational pricing in the energy market. The key observations are the need to consistently represent the physical limitations of the market within the modeling structure of the capacity adequacy market. I discuss the need for this consistency in general terms in the answers below. Obviously each region will need to establish its own metrics, and fashion of integrating the results in terms of transmission planning and capacity market design. Here again ERCOT is in a position to benefit from the various attempts at this type of effort in other RTO's.

31) One shortcoming of all the eastern markets, in my mind, is a continuing corrosive interest in diluting locational price signals that is based on the perverse belief that a correct locational signal is somehow bad (translate "expensive") for market participants. This belief is rather perplexing as it is axiomatic that if a locational constraint binds, prices will indeed stay the same or increase on the "high" side of a constraint, but similarly, they will stay the same or decrease on the low side. Thus ignoring this information must create both winners and losers in pursuit of the right answer. It is not, as many suggest, only a winning proposition to ignore the physical reality of the transmission system. Despite this obvious observation, it appears that there is great zeal in supporting/perpetuating the lack

of accurate locational information in markets despite the recognized problems created with respect to reliability.

32) *Fourth,* the exercise of market power by sellers and buyers must be mitigated to ensure that prices are neither artificially inflated nor artificially suppressed.[20] The exercise of market power by either side of the market is destructive for competition and long-term consumer welfare.[21]

(33) To conclude my general comments, I'd like to address a common complaint about capacity markets, which is that they are a return to the traditional regulated utility model, suggesting that a Texas Reliability Market would somehow be counter to the competitive nature of the current ERCOT market. Two questions posed by the Commission squarely raise this issue:

(i) How does the cost of paying all capacity a clearing price at the cost of incremental capacity compare to traditional utility rate of return regulation?

(ii) How does pricing energy market revenues based on the market clearing price of energy compare to traditional utility fuel recovery?

[20] *See, e.g., New York Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211 at P 32 (2008) ("We find NYISO's proposal is a just and reasonable methodology for mitigating supplier market power, while maintaining revenue adequacy for suppliers . . . ."); *id.* at P 100 ("We accept NYISO's proposal for net buyer mitigation, with modifications, in order to prevent uneconomic entry that would reduce prices in the NYC capacity market below just and reasonable levels."); *Edison Mission Energy v. FERC*, 394 F.3d 964, 968-70 (D.C. Cir. 2005) ("[T]he Commission's contradiction of its prior rulings acknowledging the potential ill effects of forcing down prices absent structural market distortions [and yet still imposing seller market power mitigation] is the epitome of agency capriciousness."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,043 at P 78 (noting appellate court's "concerns with mitigation plans that mitigate workably competitive markets, suppress prices and deter market entry"), *order on reh'g*, 112 FERC ¶ 61,086 (2005).

[21] *See Devon Power LLC*, 115 FERC ¶ 61,340 at P 114.

In short, the answers to the two questions is that they should result in the same level of cost to consumers over time, however, there is a significant difference in risk allocation between the two models. In the traditional utility model, ratepayers bear the risks of technology improvements, cost overruns, performance shortfalls, load changes, etc. Conversely, in a competitive market model, third party investors bear these risks, not ratepayers.

The underlying objective for both a traditional utility model and a combined clearing capacity and energy model is to achieve the "right" total compensation that achieves a mandated level of reliability.

It is easiest to see how the comparison works by starting with a traditional rate regulation perspective. Assuming the regulated entity's "prudence", its customers would purchase energy from each source "at cost" and also pay the full embedded costs for generation regardless of need or utilization.

This notion of the "regulatory" bargain has evolved over approximately a century. My perspective, as characterized in various court and regulatory proceedings, is this type of cost based regulation was intended to replicate what a competitive return and result would be to the *regulated* entity. This is a key observation.

Other ways of envisioning the regulated paradigm is the equivalent of load collectively entering into a tolling agreement with their local utility's capacity, where the toll rate is the embedded cost of the capacity for each element of supply, and load gets all energy output as needed and at cost. Another equivalent perspective is where load pays the full capacity costs, but also receives all of the energy and ancillary services revenues that would accrue if the energy were sold on a market-clearing basis.

Combining these perspectives helps in seeing the near equivalence of clearing market-based paradigms to a traditional utility model.

A well-designed combination of clearing markets for energy and capacity should have approximately the same results. In theory, and in equilibrium, the receipt of the marginal cost of capacity and all of the infra-marginal energy rents (E&AS value) by a generator should equal the same payments as receiving the full embedded costs of the generation (inclusive of return on and off capital) and selling the energy at cost. This is because the expected cumulative payments of the E&AS value should equal the difference between the full economic cost of the marginal capacity unit and the capacity costs of the actual unit providing the capacity.[22]

[22] This is probably best seen by a simple example. Assume that a simple cycle combustion turbine (CT) is the cheapest source of "pure" capacity. In a market where there was a mandated reliability standard as an input, it would be expected that whenever that unit operated, it would set price, and its infra-marginal rents would be zero. Thus for this example the "missing money" would be the payment equivalent of the full embedded costs of the CT over time. Say that is $100 per KW year. For a rational operator, the CT would be converted to a combined cycle (CC) whenever the supply got out of equilibrium, and the marginal energy rents exceeded the costs of converting the unit. So assume that it costs $25 per KW year to convert the CT to a CC. As soon as the infra-marginal energy rents reach this level or say $26 per KW year for a CC, the unit is converted. This conversion would take place until the infra-marginal rents were all arbitraged away by the conversion of additional CC's. So the converted CC would still be "short" the same missing money, e.g. the $100 per

The net result of recognizing this property of the clearing markets should demonstrate that if the capacity market is designed to allow recovery of the full costs of the marginal source of pure capacity then the expected energy rents over time from a clearing energy market would allow the recovery of any additional embedded costs related to more capital intensive and efficient generation.

Over time, the result of a clearing market is that costs to load are approximately the same. This would be true even with the addition of payments based on something like the ORDC, which would increase the E&AS margins, but in a properly designed capacity market would also reduce or possibly even remove capacity payments. Also, different approaches to hedging by market participants could also produce variance and change the particular result for any specific party.

It should not be surprising that this rough equivalence exists because and as noted above, that was one of the intents of regulated rate making. However, this doesn't mean that the two approaches are equivalent in terms of other features that should be of importance to the Commission.

The capacity and energy model has two major benefits over the utility model, including efficiency in terms of price signals and the relative allocation of risk

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KW year, but expect to recover the embedded cost of conversion ($25) from the energy market. Obviously this example is a simplification, and the market results would be volatile.

between producers and load. In the clearing market model (for both energy and the type of central capacity market design I discussed earlier) the potential exists for very efficient marginal price signals for energy and capacity (inclusive of scarcity). In the clearing market model, there is also a material shift of risk from consumers to suppliers: the "cost of errors", such as changes in load forecast, construction and operational cost overruns and underperformance, and technology obsolescence is borne by investors, not utility ratepayers. Conversely, in the utility model, ratepayers bear these risks.

In summary, a clearing market model relies on competitive market forces for capacity and energy prices, while the traditional utility model is not transparent and by guaranteeing a return, allocates the cost risk to consumers.

34) These conclude my remarks on general principles. In the next section I have tried to put in place more targeted comments addressing the Commission's specific questions.

Elements of a Reliability Market: Response to Commission Inquiries

As an overarching comment, I would emphasize that many of the elements of the following responses interact, which is why I consistently urge regulators to pursue an integrated approach to all of the elements of a reliability market. The combination of elements selected for a specific market design must be screened to assure this type of consistency is incorporated in the final solution. As a result, and not unexpectedly, there is some repetition because the issues interact and overlap.

1. What resources should be allowed to participate in the market?

There should be no limitation on what resources are allowed to provide capacity, provided its contribution to adequacy is appropriately measured, they meet the defined performance standards and their capacity offered is consistent with the underlying planning assumptions for the system (See Answer 3 below).

The most typical general metric to measure a resource is its "unforced capacity." To obtain a resource's unforced capacity, units are tested to confirm some measure of maximum output (seasonally or temperature adjusted), or "installed capacity", and then derated by their forced outage rate. Thus, a typical thermal unit (e.g. combined cycle) would have a summer and winter rating for quantity, and a forced outage rate factored into its overall contribution.

The same general approach is appropriate for intermittent resources. Typically the wind doesn't blow with consistency or reach its quoted installed capability during periods of peak demand. My understanding is that wind resources in ERCOT are de-rated to 8.7%, but ERCOT is considering providing higher and different values for coastal units and West Zone units. Solar resources should be treated similarly, with different de-rates applied based on historical performance.

Given sufficient storage time to meet underlying assumptions, energy storage facilities could also be counted as adequacy resources, perhaps either derated, or aggregated to account for storage limitations if appropriate.

Demand response (DR) offers the same capacity potential, but there are several key issues for Commission consideration. First, similar to physical resources, the measurement and verification (M&V) of DR capacity programs is a vital function for the system operator, and continually evolving.[23]

Second, DR performance requirements are needed to ensure the resource meets its obligation as a capacity resource. My perspective is that DR should be required to match generation requirements as closely as possible. The notion of limited or occasional obligations, for any resource, is anathema to any reasonable planning process and directly at odds with the associated derived adequacy requirements. DR

[23] This is closely linked to the need for a customer base-line (CBL) or "but for" counter factual basis of comparison for the DR participant, i.e. what would the customer have consumed "but for" the presence of the DR obligation.

as a supply option actually is very desirable if it meets what I call the "button" test. If a controller in the operations center can push a button and get X MW of nodal load reduction in Y minutes, with comparable certainty to a generation resource, then DR is a reasonable supply resource. Ideally, at some point this would or should be a property of all DR.

2. How far forward should the procurement occur? What are the trade-offs of different forward procurement times?

My recommendation would be that a forward market for resource adequacy products be held at least 3 years in advance. While the focus is typically on allowing time for new resources to be built, there are at least four major considerations that all favor a minimum 3-year forward procurement.

i) Supply elasticity, price signals to the market. The most obvious benefit is that this type of lead-time allows for true forward procurement and associated supply elasticity. People can bid, and then build contingent on the results of an auction. Albeit, the resulting hedge for the seller may only be a year, but someone can build a new resource in the lead-time. The auction price signal and the string of price signals from several past years out into the future all provide valuable information that helps participants make decisions about new entry investment. Without a forward market, a potential resource would only have an opportunity to observe this "trend" *after* his new facility was built, creating significant risk. A three-year forward auction product, notwithstanding suggestions seemingly to the contrary during the October 8, 2013, workshop[24], provides real supply elasticity and is a powerful tool in terms of price formation, price transparency and limiting the potential exercise of market power.

ii) Informed/orderly retirement of existing resources. While it is not often emphasized, a very material benefit of longer lead times is sending a very transparent signal with respect to intentions or expectations related to unit retirements. One concern with having a "one-year ahead" auction is there is not enough time for resources to announce their retirement, and then allow new generation or transmission resources to replace them. Instead, what could happen is "perpetual RMR" where an uneconomic unit desires to shut down, but can't because of the detrimental impact to system reliability. However, the "three year ahead" auction would provide plenty of time for new resources to replace retiring resources, minimizing the need for RMR.

iii) Coordination with transmission planning. Similarly, the basic auction information regarding future prices and quantity also can be a powerful indicator

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[24] Dr. Patton commented during the workshop that it was reasonable for the Commission to consider shorter forward periods, i.e., NYISO model. *See Patton Comments*, slide 4 and Transcript, *FERC Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, Docket No. AD13-7-000, September 25, 2013 at 63, lines 5-11 ("I think there are some potential benefits and drawbacks to forward markets, and I think it's useful that we're doing both. I think it is premature to determine that one is the right answer. So I think it's a great opportunity to collect data, compare performance and make a decision in the future about how valuable forward procurement is.").

for transmission solutions. In some (not all) cases transmission can be a direct substitute for generation. Given that neither resource can be built overnight, there is a material benefit of coordinating the time step for transmission planning with generation adequacy procurement. The longer time period allows comparable economic evaluation of generation and transmission alternatives so the market can "see" the implications of the alternatives for both and ideally, these resources, could be offered in the central auction for a more efficient result. At minimum, a reasonable lead time allows the RTO (ERCOT) transmission planning process and the market to support market driven decisions for transmission investment, retirements and new generation entry over a timely horizon.

iv) Coordination with Retail Access. A forward capacity market has an explicit advantage for buyers and sellers in a competitive retail market. Underlying any retail offers, other than spot price based offers, is the need to establish a forward hedge that can be the basis for setting a forward price without the inclusion of a material risk premium. That is, if you can see a forward price for both capacity and energy, it becomes possible to put in place hedges that translate into prices for consumers that do not carry risk premiums associated with a lack of information or illiquidity. Based on my understanding of the competitive retail market in Texas, given the existence of either a capacity or reliability requirement, or an open exposure to scarcity (e.g. the ORDC), the existence of a forward central capacity market offers the basis for hedging this type of risk exposure. In turn, this makes longer term retail sales agreements available to consumers who are interested in hedging their forward costs at a more efficient, transparent, and presumably lower cost.

3. What qualification, performance requirements, and penalties should be in place for resources?

A. Qualification and Performance. There are a number of different combinations of these characteristics/rules that could be implemented. The requirements for certain capacity resources may be somewhat different, but I would expect the following elements, at a minimum, as requirements for generation participation and performance: (i) minimum levels of availability, to be determined based on installed capacity and forced outage rates; (ii) mandatory requirements for coordination of scheduled outages; (iii) seasonal performance testing of maximum generation; (iv) operating characteristics for the units (e.g. notification, start up and minimum run times) consistent with the modeled assumptions; and (v) locational requirements[25] consistent with the modeling assumptions.

Again the common resolution depends on the consistency of the entire capacity adequacy mechanism. For these particular features, the key consideration is a "bottoms up" form of consistency between the underlying planning elements used in establishing an adequacy requirement, and the subsequent requirements for adequacy resources in terms of qualification and performance. *Simply put, the*

[25] "Locational requirements" are discussed in response to Question 4.

metrics for performance and qualification in real time have to match the assumptions made in setting the requirements for adequacy resources used in planning.

A corollary of this observation is that resulting adequacy products should be comparable or as comparable as reasonably possibly while matching the bottoms up assumptions. *Again, this should be obvious, if one assumed a certain form of performance and qualification in setting adequacy requirements, then all the products accepted into the market should presumably match/meet these same assumptions.* I have concluded that a major problem in the development of the eastern RTO capacity markets is a failure to follow this simple comparability guidance.[26] For example, if the associated reserve margin was calculated using a Monte-Carlo simulation approach which included, among other criteria, random unit outages based on historic forced outage data, then the unit performance requirements should be symmetrical; based on random unit outages, not peak periods.

The key is to recognize the need for consistency, and match product requirements and definitions as closely as possible to those assumptions, or if product characteristics are deemed more important, than work backwards into a planning process that appropriately reflects the different performance and adjusts reserve margins and

[26] For example in PJM's adequacy planning process their initial analytic step assumes random outages from annually available resources, and effectively infinite internal transmission. They then go through a number of adjustments, some consistent, some not, modifying their actual market requirements and products to accommodate the facts that transmission is not unlimited, and inferior products are allowed in the market (e.g. load reduction that can be called as little as 60 hours per year).

operating rules accordingly. The benefit of this approach for the Commission and ERCOT is to avoid what I see as an error in the eastern RTOs.

B. Penalties. I have no specific guidance to offer on penalties other than to note that they need to be high enough to motivate the desired behavior, and not so high as to drive reasonable participants from the market. Regulators should recognize there should be a consistency requirement between any penalty structures put in place and the rest of the product and market rules/requirements. For example, for planned future adequacy resources undertaking performance obligations, it would make sense to link credit requirements for future performance to at least the level of penalty for non-performance.

Anecdotally, I am aware PJM is considering increasing the penalties for non-performance, due to concerns whether current penalty structure is a sufficient deterrent. In fact, during the Commission's October 8 workshop, Calpine observed PJM's penalty structure was not sufficient and stated it supported doubling the current penalty for certain non-performances. I make no judgment whether this is the correct level, but it suggests to me that market participants are as interested as regulators in ensuring that performance penalties adequately support reliability objectives.

4) Should there be a locational reliability requirement in ERCOT? If so, what factors would dictate separate locational requirements?

Yes. There must be a locational reliability requirement in any reasonable reliability market design. So long as there is the potential for transmission limitations to constrain the ability of resources in any one part of ERCOT to support load in other areas (consistent with limits and assumptions made in setting the reserve requirements) the market design must allow for this type of constraint to be "seen".

Ignoring these types of constraints in adequacy planning would be equivalent to ignoring major transmission contingencies in the dispatch of the energy market. You might be able to "get away with it" if the contingency doesn't bind, but you would never knowingly ignore this type of constraint in operating the energy market and the associated consequences should the contingency occur. Similarly, removing a necessary constraint would have the exact same types of distortions in the energy market, and likely result in some out of market dispatch that would not participate in price formation.[27]

The starting point for determining which constraints to model in the capacity market would be the identification of what are sometimes referred to as "electrically coherent" regions or load pockets. This means identifying areas where internal resources are fungible, but where imported capacity supplies would be limited by

[27] In fact, in explaining the general issue of capacity market design, I often use the analogy of thinking about the problem as solving for a peak hour security constrained dispatch and associated locational marginal prices ("LMP's"), with simplified contingencies. Capacity is offered in to satisfy peak (peak related) demand subject to the limitations of the transmission system to import the adequacy product into the load pocket areas while meeting aggregate demand.

the transmission system. It would also suggest identifying such areas where peak load exceeds internal resources and imported generation is necessary.

For these reasons, identifying capacity constrained areas not only sets locational constraints for the procurement of adequacy products, but it also provides guidance to transmission planning, and the integration of transmission procurement into the adequacy solution process/auction.

5) Should a transition mechanism be considered? If so, what issues would a transition mechanism be intended to address and how should it be structured?

Yes, because ERCOT participants have commercial arrangements in place based on the current market structure, and because it may take some time to fully implement the capacity market.

Regarding existing commercial arrangements, how would firm energy purchase agreements with no provisions at all related to capacity be treated? Should they be recognized as equivalent capacity for some interim period? If so, what locational property would be attributed to them? Transitional rules might set the requirements for answering these types of questions.

As far as fully implementing the capacity market, there are two considerations:

First, how quickly can data be assembled and software implemented to implement the market? Data assembly should not be a major problem as presumably the necessary planning data exist. ERCOT can take advantage of several existing software platforms with different RTO implementations. Also, as far as I know, this type of "engine" would work on a stand-alone basis and not be integrated with any operating software. Although I recommend consideration of existing platforms, these products do not relieve the Commission of its responsibility to adopt the best platform for ERCOT after rigorous review. However, all of these factors suggest the ability to implement would not be software or system constrained.

The second implementation consideration is how to transition the market to a 3-year forward structure. At one end of the spectrum is a hypothetical three-year forward market, with three "transitional" auctions that could be implemented in relatively quick fashion, and then move to an annual cycle. This would allow the capacity market to be effective for the first operational year after systems are completed. At the other end of the spectrum the market could hold its first forward auction after system completion and commence actual operations under the new adequacy design three years later.

6) Should the Commission consider a Minimum Offer Price Rule (MOPR) or a statement of principles?

A MOPR is not needed in ERCOT if the state adopts the following two simple rules:

First, the state will not allow out of market payments for generation procured in a discriminatory fashion (e.g. new only), or will not allow any generation receiving such out of market payments to sell capacity into the ERCOT wholesale market. Second, entities that opt out of participating in the ERCOT wholesale reliability market cannot sell capacity into that market.

I believe these two rules, which are simple to express and enforce, can replace all of the complexity that has arisen in the eastern RTO markets regarding MOPR provisions. Further, it is my understanding that such rules would philosophically be most compatible with the policy positions regarding competitive markets that have been undertaken by the Commission.

If however, the State wishes to retain some ability to support via out of market payments, capacity procured in a discriminatory manner, then some form of specific MOPR regulations would be needed, along with rules for reference cost development, evaluation of bids, and provisions for exemption. I would strongly urge the use of the above two rules.

In the following paragraphs I provide significantly more detail as to why I reach this conclusion:

In other markets, MOPRs have been implemented to mitigate buyer side market power, which can potentially occur when a "net short" party (i.e. a buyer of capacity) wants to suppress overall capacity market prices by adding otherwise uneconomic supply to the market.

For example, if an entity served 10,000 MW of load and needed to buy capacity for that amount, it has an incentive to pay above market, non-competitive, rates to bring in 500 MW of new unneeded capacity, in order to crash prices for the remaining 9,500 MW of capacity it has to purchase. This phenomenon is especially pronounced if the capacity market employs a very steep or completely vertical demand curve, where small changes in supply can significantly drive down prices.

This example is not abstract, and not only has the FERC recognized this potential for market price distortion, but federal courts in Maryland and New Jersey have acknowledged the same potential, and acted to prevent this type of abuse in federal jurisdictional markets. [28]

Texas is less likely to suffer the potential exercise of buyer side market power because it does not have a concentrated retail supply sector. However, ultimately in a situation with a potential residual monopsony (e.g. the state), some

[28] *See PPL Energyplus, LLC v. Nazarian*, No. MJG-12-1286 (D. Md. Sept. 30, 2013) and *PPL Energyplus, LLC v. Hanna*, No. 11-745 (D. N.J. Oct. 11, 2013).

consideration must be given to these types of rules to prevent the exercise of market power to suppress prices.

7) How would the reliability obligation be allocated to load serving entities?

The answer lies in matching the obligation to the underlying assumptions about load responsibility that drove the mandated reliability requirement. If a single coincident peak ("CP") drove the reliability assessment, billing determinants for individual customers should echo that. If a 5 or 10 CP assumption was used in planning, billing determinants for individual customers should mirror that. If annual load shapes were used (as is likely the case for residential and small commercial customers), coupled with a determination of a distribution of loss of load probability over the entire year, than an analogous approach should be taken to determining billing.

Thus the answer lies in bottom up consistency coupled with the generic notion of beneficiaries pay – the assumptions about load shape and aggregate demand that are used to establish the reliability requirement for the adequacy market should be paralleled in the allocation of the costs of adequacy resources back to load

As usual, the complications are in the details. With a high degree of retail access and transfers, representative load profiles are needed for residential customers that lack advanced metering. Provisions also are necessary for monthly or seasonal cost allocations if such assumptions were in the underlying planning, and customer migration can occur. These types of adjustments all need to be wary of potential gaming of the associated allocations. Also, as discussed above, should DR be treated as a supply resource, "add backs" are necessary to properly account in the cost allocation for the DR payments. Similarly rules are needed to assure that use of differing counter factual CBL's don't allow for double counting.

It is difficult to point out more than these general considerations absent a specific proposal.

8. If the market includes a centralized or residual auction, how should the auction be structured?

The following summarizes the specific design elements for a capacity auction. Obviously much more detail would evolve out of specific choices, some of which are discussed in my respective responses to the Commission's set of questions.

i) The market should be centralized, with mandatory offer requirements and procurement for 100% of expected load.

ii) The procurement, at a minimum, should be based on a three-year forward auction for a single performance year.

iii) The reliability product should be uniform and expressed in terms of availability related performance (e.g. unforced capacity) that matches underlying planning assumptions. The market should be considered a "physical" market to the extent possible.

iv) Inherent in all of these elements is that there should be a clearing "one price" market within each market locality. The market clearing mechanism should be non-discriminatory. A corollary of this would be that no discriminatory mechanisms such as backstop or RMR actions would be utilized.

v) There should be at least one interim auction between the initial auction and the performance year to allow parties to adjust/cover any positions/obligations that are incurred.

vi) The auction process should also allow for the offer of transmission as a "spread" product between constrained areas. That is, a private party can offer to fund transmission in exchange for increasing the flow of capacity between one locational area and another. Their compensation would be market based and derived from the difference (if any) between the clearing locational capacity price in the sink capacity market locality of the transmission versus the price in the source capacity market locality.

vii) A segmented downward sloping demand curve should be used to represent demand for ERCOT. The shape of the demand curve should be "anchored" related to the net cost of new entry for the cheapest source of pure capacity, e.g. a peaking combustion turbine. The specific shape should be set to encourage entry during shortage and rational retirement during excess.

viii) Local adequacy requirements should be established and jointly represented in the auction with associated import limitations, whether or not they bind. Locational constraints should represent all known load pockets or other area import limitations.

ix) The auction solution "engine" should use an optimal programming approach with the objective function to minimize cost while meeting the specified load requirements and observing the locational constraints. This should result in uniform clearing prices within any locality (or across any non-binding locational constraints).

x) Market power screens should exist to identify the potential exercise of market power by buyers and sellers. Appropriate mitigation provisions should be in place where any screens are triggered.

9. If the market allows for self provision, how should that be structured?

Self-supply, in the context of hedging one's own needs should certainly be allowed.

However, for a central market to function properly in terms of open and transparent price formation, these "self supplies" should simply be offered into the central process/auction as price takers, and the resulting cleared resources "booked" to the benefit of their owners. This accomplishes self-supply similar to a contract for differences with yourself. You sell into the market, and essentially buy back at the same price. Note that with a demand curve, no hedge could be assured of being exact, as the exact requirements will vary from auction to auction. The above comment is conditioned on the previous and following comments regarding market power protections and MOPR.

What is inappropriate in a central market design is the removal of parts of load from participation or continual "in and out" participation. To the extent that there is a desire not to participate at all (versus self-supply as described above), alternatives are available to simply partition such areas from the rest of the market. It is not clear how practical such options would be in a market that has the degree of retail access that exists in Texas. However, if load serving entities are allowed to "opt out" of the central market they must be excluded from the market's centralized system reliability function, but such entities must be required to meet the target capacity requirement set by the Commission and commercially segregated from the rest of the market.

10. Should a vertical or sloped demand curve be adopted?

It is hopefully clear at this point that there is a very strong analytical consensus of the appropriateness of a downward sloping demand curve in the design of a centralized capacity adequacy market. A vertical curve leads to highly volatile and illogical results, where the value of capacity effectively drops to zero when supply exceeds demand by a single MW.

I strongly recommend a downward sloping demand curve that can be used to convey logical and material information to both market sellers and buyers. There are several important observations related to the use of a demand curve. First, the structure and placement of the demand curve sets quantity, not price. In a competitive market place, without material barriers to entry and open access to information, the marginal net cost of capacity additions would be expected to be roughly flat, i.e. the supply curve would be expected to flatten out at this competitive level. In turn, with a flat supply curve, the relative positioning of the demand curve simply changes quantity, not price. This presents the second important property, that the placement and shape of the demand curve can be used as a control "tool" to help stabilize supply and reliability in the central auction process. For example, by steepening the slope of the curve when supply is below reliability targets, it is possible to incent greater/faster new entry. Similarly, by flattening the curve when the market is in surplus, unit retirement can be paced and orderly.

The basic design criteria should result in a demand curve and associated view of the control process that will allow the potential for economic cost recovery over time. It also would be appropriate for the slope of the demand curve to be such that as the overall amount procured increases, and unit price declines, total payments also decline. This assures appropriate benefit to load, in the aggregate, for supporting a larger set of resources in periods of surplus.

ATTACHMENT RJS-1

QUALIFICATIONS
AND
EXPERIENCE OF

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EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 60450 Potomac MD 20854 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc.

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Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
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Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2013

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of 220-Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

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