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COMMISSION PROCEEDING	§	BEFORE THE
TO ENSURE RESOURCE ADEQUACY	§	PUBLIC UTILITY COMMISSION
IN TEXAS	§	OF TEXAS

RESPONSE OF CPS ENERGY TO QUESTIONS ASKED
BY COMMISSIONER KENNETH W. ANDERSON, JR.

CPS Energy offers comments and answers to Commissioner questions in the above styled project on the issue of resource adequacy.

The Commission has asked a series of extensive and very thought provoking questions. Many of which could easily consume a filing or a workshop on their own. CPS Energy views this filing as an initial opportunity to offer high level responses and would encourage the Commission to engage in further discussions to flush out additional details.

Questions of General Applicability

• What is the legal basis for adopting a resource adequacy mechanism? What restrictions exist on the Public Utility Commission of Texas' (PUCT) authority? Does the PUCT have the legal authority to implement any mandatory generation obligation outside of an energy-only market (EOM) construct?

Since the introduction of wholesale and retail competition, the Commission has had numerous proceedings on resource adequacy wherein many potential mechanisms to achieve the Commission's objectives were considered. In the past, the Commission's decisions have been made based on good public policy that recognized the existing and forecasted conditions in the ERCOT market. A simple reading of PURA shows no preference for a particular market construct. Furthermore, upon legislative inquiry, the Commission has not indicated any shortfall in authority to make decisions regarding a reliability market construct.

The incumbent nature of the EOM construct does not prejudice its merits in one direction or another. The faults or benefits of a capacity market aside, a capacity market would work in conjunction with the energy market in ERCOT.

• Does the PUCT have the authority to require municipal utilities and electric cooperatives to share the cost of any resource adequacy construct?

CPS Energy and other Municipal Utilities have been participating in the ERCOT wholesale market since the competitive wholesale market was created. CPS Energy enjoys the benefits of participating in the market and, up to this point, has also shared in the costs. The Commission has made multiple decisions over a myriad of subjects that

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imposed costs on CPS Energy. These charges range from administrative charges, to reliability based capacity products, to transmission charges, to backstop procurements and costs associated with market redesign.

CPS Energy has paid its allocation of the ERCOT fee, an administrative charge and a Commission approved fee. Perhaps more closely related to this docket, CPS Energy is charged and pays the capacity charge associated with Emergency Response Service (ERS). This service was adopted by the Commission through the rulemaking process and was implemented for the purpose of improving reliability.

Other Commission actions are noteworthy in responding to this question. First, in the summer of 2011, when the Commission approved ERCOT's acquisition of out-of market capacity in the form of additional Reliability-Must-Run units, the cost of the acquisitions was shared by CPS Energy. Second, the uplift costs associated with the Operating Reserve Demand Curve (ORDC) which has been frequently touted for its resource adequacy benefits are also shared by CPS Energy on a load-ratio-share basis.

Of equal importance, when there are capacity shortages in the market, CPS Energy suffers equally. If there is not enough capacity to serve load on system-wide basis, CPS Energy load is shed the same as load throughout ERCOT—even though CPS Energy has taken steps funded by its customers to ensure that it has sufficient capacity to meet its native load.

In summary, while municipally-owned utilities operate under different regulatory oversight than other market participants, some costs have been imposed in the past that have not been found to be in violation of PURA. In the abstract, it is difficult to say where the lines would be drawn between permissible and impermissible regulatory fees and requirements.

• **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?**

Traditional rate of return regulation paid the utility for capacity deemed "used and useful." A capacity market pays all generation that clears the auction the market clearing price. In both cases the capacity owner receives compensation (or, under traditional regulation, an *opportunity to earn* compensation) for all the capacity that the system needs. However, there are significant differences between the two systems.

In a capacity market the capacity payment varies depending on the price offered by the marginal clearing resource. All cleared capacity receives the same price, but this price may vary from year to year, and there is no guarantee that the capacity value fully compensates the resource. Because the capacity value is set by the marginal unit annually, the risk of resource selection and efficiency associated with building and operating the resource is still on the owner. If another resource can meet the capacity requirement at a lower cost, the new resource will reduce or possibly eliminate the capacity payment for other resources.

Under rate of return regulation, once the plant has been approved, it goes into rate base and remains there for the useful life of the plant. Rate of return regulation allows the utility an opportunity to earn a return on the value of each plant (asset) over the life of each plant. In addition, the cost of the plant is recovered through depreciation over the plant's useful life. Assuming that the regulated utility operates efficiently, it will recover its investment in a plant plus earn a return on that investment, but the recovery will occur over a long period of time, e.g., 40 years.

- **How does pricing energy market revenues based on the market clearing price of energy compare to traditional utility fuel recovery?**

Fuel prices are a component of an energy offer which has several other components. The resulting energy price from the single clearing price auction is paid for all energy. Traditional utility fuel recovery allows recovery of fuel expenses through a fuel factor established based on some type of administrative review of the fuel contracts. Depending on the regulatory lag inherent in the administrative process applied, full fuel expense recovery may be delayed.

- **For a backstop procurement or in a capacity market, is it appropriate to price both capacity and energy based on a market clearing price?**

CPS Energy is not sure what a "backstop procurement" entails. In a centralized forward capacity market, the payment to all resources of a market clearing price in energy and capacity is efficient, provided certain conditions are met –namely competitive offers and bids. An efficient outcome is appropriate. Importantly, a departure from competitive bids and offers which reflect marginal benefit and marginal cost would lead to inefficient outcomes and call into question the appropriateness of a single market clearing price. Such outcomes apply jointly and individually to both energy and capacity auctions.

- **For a backstop procurement or in a capacity market, is it appropriate to pay the resources a market clearing price for energy if capacity payments guarantee return on and of capital?**

In a capacity market an energy clearing price (resulting from an efficiently designed auction) ensures the most efficient dispatch of the system. A centralized forward capacity market does not guarantee a full return on capital because the market clears based on the marginal offer needed to meet the capacity requirement. New resources can push out old resources before full return on capital.

• What extra capacity (in MW) would be required over and above the economic equilibrium reserve capacity provided by an energy-only market?

CPS Energy does not have an answer for this question at this time.

• How many hours per year would that incremental extra capacity be called upon to be available?

The answer to this question is dependent on system conditions during the year in question including, but not limited to, factors such as: weather and unit outages.

• How much would it cost for ERCOT to have that amount of capacity built?

CPS Energy would be better able to answer this question if a reserve margin requirement were defined.

• What is the average value of lost load (in $/MWh) in the ERCOT market?

The best way to estimate the average value of lost load is through a study. ERCOT hired a consultant to conduct such a study, but the study appears to be incomplete at this time.

•Is the average value of lost load in the ERCOT market appropriate as liquidated damages for capacity generation that has been purchased but is not available when called upon?

CPS Energy has no reply to this question at this time.

• What is the net present value of the $400 million per year cost of a capacity market as described in Charles River Associates study commissioned by NRG?

CPS Energy has no reply to this question at this time.

• What would be the cost to reduce transmission and distribution related outages per MWh?

CPS Energy has no reply to this question at this time.

• What is the cost of eliminating resource adequacy related outages per MWh under each of the following:

(1) a capacity market;

(2) EOM plus construction of state-owned generation; and

(3) any other backstop or supplemental generation mechanism?

It is difficult to estimate the costs of these questions in the time provided. The type of analysis required for a complete answer is better suited to be provided through a study.

Backstop Generation as an Ancillary Emergency Reserve Service in EOM

It is unclear what is specifically meant by backstop generation, but if the reference is to procurement of additional generation to fill in the gap between an existing reserve margin and a requirement, backstop mechanisms can introduce inefficiencies into the broader market. The first issue involves the unequal treatment of generation within the market. Achieving the target would create two classes of generation: those receiving backstop generation payments and those that do not. Over time, generation ineligible for the backstop payment would leave the market, and additional backstop would be procured. In conclusion, although a backstop may be possible, it will change the market dramatically to a less efficient design.

• Could new ancillary services be used to address resource adequacy? Why or why not?

Yes, but such a design would create generation that received a capacity payment and generation that did not.

• If a new ancillary service were created as a resource adequacy backstop, how far forward would it need to be applied?

CPS Energy has no reply to this question at this time.

• If a backstop ancillary service were created, what resources would be able to provide the service?

The service should have performance requirements, and any resource that could meet these requirements should be eligible.

• On what basis should backstop resources be selected?

Selection would be based on the resource's ability to meet the performance requirements at the lowest price. Some type of market-based procurement is ideal.

• What requirements would be needed to ensure that backstop resources were available to meet the need for which they were procured?

The backstop resources would need to have availability and offer requirements similar to those found in centralized forward capacity markets.

• **Would deployment of the backstop ancillary service cause inappropriate price reversal?**

Absent any limits on energy offers or administrative adders, the backstop resources would distort the energy market.

• **How should backstop service payments be billed to the market? As all other ancillary services are billed?**

Backstop service should not be billed to the market on a cost causation basis. If a Load Serving Entity (LSE) can demonstrate it has sufficient reserves to meet the requirement, then it should not be charged. An LSE that has contracted for most of its share of the obligation should not be charged the same as an LSE that has not contracted for any of its obligation.

• **What is the appropriate trigger for a backstop ancillary service procurement to occur?**

The answer is dependent on the nature of the reserve margin. If the reserve margin is a requirement, then the procurement should occur for years forecasted to fall below the required margin. If the reserve margin is not a requirement, then the purpose of a backstop is less clear.

Reserve Margin Obligation on load serving entities (LSEs)

• **How could a mandatory reserve margin be imposed on LSEs?**

By rule the Commission could place a requirement that all LSEs procure reserves in excess of their peak load.

• **How do you ensure sufficient transparency so as to prevent affiliated generation and LSEs from exercising undue price influence in the market?**

Other markets such as PJM have rules that cover such activity. Once the Commission has determined the nature of the reserve margin, additional workshops would be useful to examine the ideal market design.

• **What additional measures should be imposed to prevent market power abuse by large generators and independent power producer (IPP) generators that are affiliated with LSEs?**

Generally, the rules required for such markets involve controls over the exercise of market power by both buyers and sellers.

- **What additional measures should be imposed to prevent market power abuse by large generators and IPP generators that are affiliated with LSEs?**

CPS Energy has no response to this question at this time.

- ❖ **How should the market be designed so as to avoid the problem of large incumbent IPPs keeping out small generators? Should the PUCT market power abuse rules be modified to lower the generation ownership limit to less than 10% of installed capacity?**

CPS Energy has no response to this question at this time.

- ❖ **To minimize market power abuse concerns, should generators be required to divest themselves of any LSE? Should non opt-in entities (NOIEs) be exempt from this obligation? Alternatively, is it sufficient to require non-NOIE generators to prove that they offer non-affiliated retail electric providers (REPs)bilateral contracts that are no less favorable than the terms that they offer their affiliated LSEs? Should they be required to offer more favorable terms to avoid market concentration problems?**

There is no need to force divesture to address issues of market power abuse. Rules that govern appropriate bids and offers are sufficient for all market participants.

<u>Centralized Forward Capacity Market</u>

- **How should the demand curve be implemented so as to avoid the boom and bust cycle?**

During periods of sustained load growth, there is less likelihood of boom and bust cycles. In such times there still are advantages to a demand curve because it allows for additional price reliability. The study on the economic reserve margin will be useful in this instance as it could help with the shape of the demand curve.

- **If a sloped curve is used, how is a minimum margin achieved?**

The slope could begin at the minimum level. Thereby, you would always procure the minimum level and procure additional reserves if the additional benefit met or exceeded the cost.

- **What should be the forward and commitment periods? Why?**

CPS Energy has no response to this question at this time.

- **What products should be permitted to participate in a capacity market?**

CPS Energy has no response to this question at this time.

- **What performance requirements should be imposed on capacity bidders beyond an obligation to bid in the day ahead market (DAM)?**

CPS Energy believes that the Commission should first decide if the reserve margin is a requirement or not; if it is a requirement, the next step would be to determine the reserve requirement based on the economically optimal objective. Only after these determinations are made can the proper market design be ascertained.

❖ **What additional measures should be imposed to prevent market power abuse by large generators and IPP generators that are affiliated with LSEs?**

CPS Energy has no response to this question at this time.

❖ **How should the market be designed so as to avoid the problem of large incumbent IPPs keeping out small generators? Should the PUCT market power abuse rules be modified to lower the generation ownership limit to less than 10% of installed capacity?**

CPS Energy has no response to this question at this time.

❖ **To minimize capacity market manipulation, should generators participating in any capacity auction be required to divest themselves of any LSE? Should NOIEs be exempt from this obligation? Alternatively, is it sufficient to require non-NOIE generators to prove that they offer non-affiliated REPs bilateral contracts that are no less favorable than the terms that they offer their affiliated LSEs? Should they be required to offer more favorable terms to avoid market concentration problems?**

CPS Energy has no response to this question at this time.

❖ **Should generation successfully bidding in the capacity auction be required to submit bids in the DAM? If so, how is withholding of power to be determined? Should short-run marginal cost be required with respect to their bids?**

CPS Energy has no response to this question at this time.

❖ **Does the PUCT need to define what constitutes a violation of its market power abuse rules for purposes of a capacity market? Should each MW bid for each hour above short-run marginal cost be deemed to be a violation for purposes of the PURA penalty provisions?**

CPS Energy has no response to this question at this time.

❖ **To minimize capacity market manipulation, should generators participating in any capacity auction be required to divest themselves of any LSE. Should NOIEs be exempt from this obligation? Alternatively, is it sufficient to require non-NOIE generators to prove that they offer non-affiliated REPs bilateral contracts that are**

no less favorable than the terms that they offer their affiliated LSEs? Should they be required to offer more favorable terms to avoid market concentration problems?

CPS Energy has no response to this question at this time.

- **Should any working group at ERCOT which recommends protocols to implement any mandatory capacity construct be composed at a minimum equally between resources and load?**

CPS Energy has no response to this question at this time.

- **How would the costs of a mandatory capacity market be allocated?**

CPS Energy has no response to this question at this time.

- **If a mandatory capacity market contains a forward component, how are payments to be applied to customers who switch? How do REPs allocate their capacity charge? Will REPs be left with what amounts to a stranded cost?**

CPS Energy has no response to this question at this time.

Respectfully submitted,
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