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PUC PROJECT NO. 40000

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

COMPETITIVE RETAIL ELECTRIC PROVIDERS' JOINT COMMENTS ON SOLUTION B+ CASES 1-4

The Texas Energy Association for Marketers (TEAM)[1], Direct Energy, and Con Edison Solutions Inc. (collectively referred to as Competitive Retail Electric Providers (REPs)) file these Joint Comments on the analyses of ERCOT and the Brattle Group of Solution B+ Cases 1-4 as described in the ERCOT filing of July 23, 2013. The Competitive REPs are active Retail Electric Providers in ERCOT with a significant interest in the ongoing discussions regarding resource adequacy. Competitive REPs appreciate the opportunity to offer input regarding the work that the Commission, ERCOT, and market stakeholders have done to address potential challenges in the market's near future.

I. Introduction

Competitive REPs consistently support competitive market-based solutions to market design issues and advocates that any significant changes to the Texas electric market retain the fundamental structures that have made it the most successful competitive electricity market in the country. Individual members of the Competitive REPs have previously filed comments addressing the potential impacts of an Operational Reserve Demand Curve (ORDC) proposed as Solution B+ to Retail Electric Providers (REPs) and their customers. [2] These comments focus on the specific Solution B+ Cases on which ERCOT and the Brattle Group have conducted further analysis.

[1] The members of TEAM participating in this proceeding are: Accent Energy d/b/a IGS Energy; Cirro Energy; DPI Energy (d/b/a Trusmart); Entrust Energy; Just Energy; Spark Energy; StarTex Power; Stream Energy; and TriEagle Energy.
[2] *Texas Energy Association for Marketers' Comments on Solution B+* (May 31, 2013).

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II. Solution B+ Cases 1 and 2

Solution B+ Cases 1 and 2 analyzed by ERCOT and the Brattle Group employ a minimum contingency level (X) of 1375 MW and also incorporate Value of Non-Market Actions (VNMA) at $5,000/MWh and $7,000/MWh respectively. The costs of Non-Market Actions are already born by load and should only be incorporated into the ORDC if those costs are insufficient to support the economic value of those actions. Otherwise, load will be effectively overpaying for actions that are already being paid for at an efficient price. The analysis of the Independent Market Monitor (IMM) determined that there is no economic efficiency justification for further augmenting the ORDC proposed by Solution B+ to account for the value of potential non-market actions.[3] Further, the analysis of the Brattle Group on the resource adequacy implications of Cases 1 and 2 estimated only modest improvement of the ERCOT reserve margin over the status quo, with a projected reserve margin of 9.2% - well below the current ERCOT target of 13.75%.[4] Because the inclusion of VNMA in the ORDC cannot be justified either economically or on the basis of improved resource adequacy projections, Solution B+ Cases 1 and 2 should not be adopted.

III. Solution B+ Cases 3 and 4

Solution B+ Cases 3 and 4 establish minimum contingency levels well above the historically demonstrated level of 1100 MW at which ERCOT has imposed involuntary load shedding and above the largest single generation resource in ERCOT of approximately 1375 MW. The IMM and numerous commenting parties in this project have opposed implementation of an ORDC with an artificially high minimum contingency level.[5] The Competitive REPs agree that if an ORDC is implemented, it should be established using an actual Loss of Load Probability (LOLP) and there is no economic justification for setting a minimum contingency level higher than 1375 MW; indeed, doing so is in direct contradiction to the "first principles" upon which the ORDC was initially proposed. If an ORDC is to be implemented, it should be

[3] *Comments of Potomac Economics* (July 25, 2013).
[4] *Responses to Commission' Request for Analyses of Additional ORDC B+ Scenarios* (July 23, 2013).
[5] *Comments of Potomac Economics* at 3 (May 31, 2013); *see also, for example, Comments of the City of Austin D/B/A Austin Energy* at 5 (May 31, 2013), *Comments of CPS Energy on "Back Cast Interim Solution B+ to Improve Real-Time Scarcity Pricing"* at 3 (May 31, 2013), *Texas Industrial Energy Consumers' Response to Commission Questions* at 2 (May 31, 2013).

used for market efficiency purposes, not for the administrative transfer of wealth to generation resources.

IV. Implications of Solution B+ on Electricity Markets

The Competitive REPs are concerned that the proposal risks substantial uplift to retail customers of dramatic and unpredictable wholesale energy prices and creates additional risk in the ancillary services settlement process that cannot be hedged. These risks are greatest when an artificially high minimum contingency value is established for the ORDC as this effectively forces the market to produce a desired result of higher energy prices by administrative manipulation rather than allowing prices to be established by the market's "first principles" of supply and demand.

Administratively raising wholesale energy prices by setting the minimum contingency value significantly higher than 1375 MW may remove liquidity from the bilateral markets by encouraging generators to remain in the real-time (RT) market to capture the higher prices created by the ORDC. Offers in the day-ahead market (DAM) may similarly be scarce if a large minimum contingency value is imposed and there is a price incentive to be available in RT when price spikes are likely. The removal of liquidity in bilateral markets and DAM will make effective hedging more difficult due to decreased availability of hedges, will raise risk premiums, and will result in further uplift to load in addition to that caused by the higher forward energy prices resulting from the increased likelihood of shortage intervals due to an artificially long ORDC. Jumping to administratively high prices with reserves still available also creates perverse market incentives; it may encourage resources to chase the high prices and overproduce, forcing ERCOT to administratively hold these resources back. This is akin to hitting the gas and the break at the same time. Load ends up paying for these out of market actions twice in high prices and high uplift charges.

If the purpose of Solution B+ is to create more generator revenue regardless of market efficiencies, then the Competitive REPs urge the Commission to consider whether other alternatives should be pursued that may not create as great a risk of volatility and cost increase to load. ERCOT's estimates for the additional peaker net margin (PNM) and energy weighted price adders for Solution B+ Cases 1-4 demonstrate the enormous potential increases in energy prices that could be borne by energy consumers.[6] With a $9,000 VOLL, if a minimum contingency level of 2800 MW is established, average energy prices for a year with weather similar to 2012 would increase by $31.62/MWh.[7] On a per kWh basis this represents a minimum expected increase of more than 30% of the total average prices of residential electricity plans currently prevalent in the competitive market. The percentage increase to the *energy* cost of those plans is significantly greater. A minimum contingency value of 3300 MW would increase prices $108.71/MWh, or over 100% of the total price of service on a per kWh basis.[8] If weather in future years is more severe than in 2012, the impact could be exponentially greater. It is also important to note that these projected increases do not reflect the additional costs to the market that would result from this volatility in the form of increased capital cost requirements before ERCOT. In addition, customers will be exposed to costs from increased risk premiums that would be reflected in forward curve prices as a result of the "adders" in Solution B+.

An increase of energy costs on this scale cannot be absorbed by load serving entities and will be borne by consumers. If the Commission decides to proceed with an ORDC consistent with Cases 1-4, then it is critical that this significant market design modification be implemented with sufficient advance notice so that it does not interfere with existing fixed price contracts and that the process for assigning the increased costs be sufficiently predictable so that risk management strategies can be employed to preserve the continued viability of market participants.[9]

V. Conclusion

The Competitive REPs appreciate the opportunity to offer these comments and the comprehensive dedication to this issue demonstrated by the Commission, Commission Staff, and ERCOT market participants.

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[6] *Responses to Commission's Request for Analysis of Additional ORDC B+ Scenarios* at Attachment A, slide 3 (July 23, 2013).
[7] *Id.* at Attachment A, slide 3.
[8] *Id.*
[9] In the alternate, the market design modification could specify that these additional costs will be considered changes in law/regulation that can be passed through to customers on fixed-price contracts. This would not be the preferable means of dealing with these costs but if significant advance notice is not provided for the market design change it will be necessary to avoid severe adverse consequences to the market.

Respectfully submitted,

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