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PROJECT NO. 52373

REVIEW OF WHOLESALE	§	**PUBLIC UTILITY COMMISSION**
	§	
ELECTRIC MARKET DESIGN	§	**OF TEXAS**

ENGIE NORTH AMERICA, INC.'S COMMENTS IN RESPONSE TO COMMISSION STAFF'S QUESTIONS FOR COMMENT

Engie North America, Inc. ("Engie") files its comments in response to Public Utility Commission Staff's ("Staff") questions for comment, filed on August 5, 2021. Consistent with the request, this response is timely filed. Engie would show as follows:

I. RESPONSE TO STAFF'S QUESTIONS FOR COMMENT

Engie appreciates the opportunity to respond the list of questions filed in Project 52373. Engie's subsidiaries produce and sell electric energy in key U.S. markets, including the Electric Reliability Council of Texas ("ERCOT") region, with an overall Texas investment plan totaling around $2.8 Billion. Winter Storm Uri was a major disaster for both Texans and the ERCOT market. Reliability of the ERCOT Grid is a complete necessity for the citizens of Texas. Whatever implementation decisions the Commission makes need not adversely impact renewable investment, which is developed only upon consumer demand. To help move the needle for increased reliability, without impacting existing renewable investment and overall economic development in Texas, Engie offers the following comments.

A. Executive Summary

To drive investment in new and dispatchable generation, Engie recommends that the Commission change the structure of the Operating Reserve Demand Curve "ORDC" to a "piecewise linear curve" as illustrated and described more fully below. A "piecewise linear curve:"

- may be adjusted in a more pointed manner to provide the desired level of revenues in the market for reliability,
- would provide a level of revenues into the market on a more regular basis rather than those provided in reliance on near emergency events to incent investment in dispatchable generation.

The current ORDC has resulted in consequences that mitigated much of the intended benefits of the ORDC. This is due to the probability that is applied to the Value of Lost Load ("VOLL") which, at the minimum contingency level of "X," is only 50%. This issue revealed two negative consequences: (1) significant value was taken out of the overall construct - as much as 50% of the expected ORDC value, and (2) prices jump dramatically to $9,000/MWh when the supply stack moves from 2001 MW to 2000 MW. Any abrupt price jump such as this creates both optimization and potential market behavior issues that should be avoided in any efficient market design.

Engie also recommends that the Commission increase the amount of reserve where the VOLL is to at least 2500 MW or change the value to be a percentage of load due to the continuing increase in ERCOT load expectations. This change would protect more reserves going into an emergency and provide increased overall grid reliability.

Engie further recommends that the Commission reduce the VOLL to $4500 MWh. While this may seem counter intuitive to the goal on increased revenues, the piecewise linear curve and reserves level should be adjusted in conjunction with this change to more efficiently provide the needed revenues for reliability.

Engie's comments on each of Commission Staff's remaining questions are provided below.

B. Introduction and Background

The issues facing the ERCOT region is the problem of the "missing money" in a short run marginal cost real-time market to a level that will incent investment into the market. Engie also understands that with the investments in zero marginal cost generation (renewables) replacing the "missing Money" means increases in revenues. This dynamic is caused by the differing economic development demands in the region. Renewables are built and operated solely based on consumer demand and their desire to enter into long term contracts to meet their sustainability goals. On the other hand, dispatchable generation, mainly coal, gas and nuclear generation development, relies on the market forces and overall revenues to incent investment in the absence of long-term contracts. Both models are economically viable economic models. Based on this, whatever implementation decisions the Commission makes should not adversely impact renewable investment, which is developed only upon consumer demand. Any adverse impact to the economics of renewables would adversely affect existing investments and overall economic development in Texas. Therefore, Engie strongly suggests that any market adjustments have a verifiable and measurable positive effect on the reliability of the ERCOT grid.

Engie, during the Commission's Resource Adequacy Docket No. 40000, was known as IRP-GDF Suez Inc. and later GDF Suez Inc. We were deeply involved in resolving the resource adequacy issue the ERCOT region was facing at that time. In our August 30, 2012, filing at the Commission, we proposed that Texas needs to increase operating reserves by 3,300 MWs in order to close the gap between the operating reserve market design and the implied reliability standard of 1 event in 10 years. The remainder of the filing went on to explain our support for the proposal. This proposal did not get any traction at the Commission. GDF Suez still believed that in an energy only market, the key to future investment was through reserves and scarcity pricing. Therefore, GDF Suez filed comments that included a paper entitled "Electricity Scarcity Pricing Through Operating Reserves: An ERCOT Window of Opportunity" by William W.

Hogan, dated November 1, 2012. GDF Suez then worked with Dr. Hogan, stakeholders and the Commission to refine and ultimately implement the ORDC.

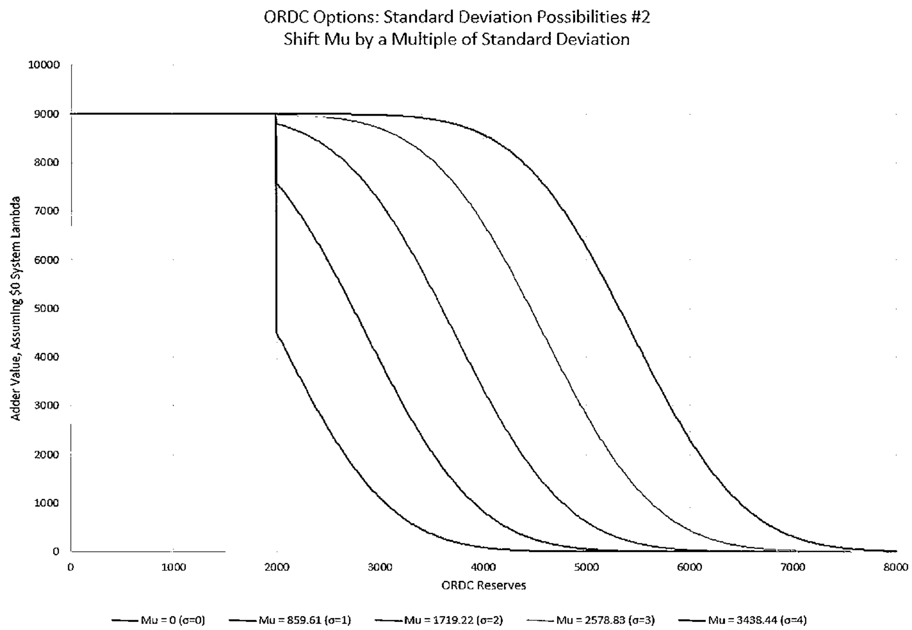
At the September 12, 2013, Open Meeting, all Commissioners agreed to move forward with the implementation of an ORDC in ERCOT. The Commission provided guidance to stakeholders and ERCOT regarding several critical inputs to the ORDC and began the implementation using a VOLL set at $9,000/MWh with a minimum contingency level of 2,000 MW. The Commission also agreed to use a "real" curve (a cumulative distribution function) in lieu of a "piecewise" linear curve that was originally in the proposal (both curves will be described further below).

1. **What specific changes, if any, should be made to the Operating Reserve Demand Curve ("ORDC") to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market ("DAM"). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?**

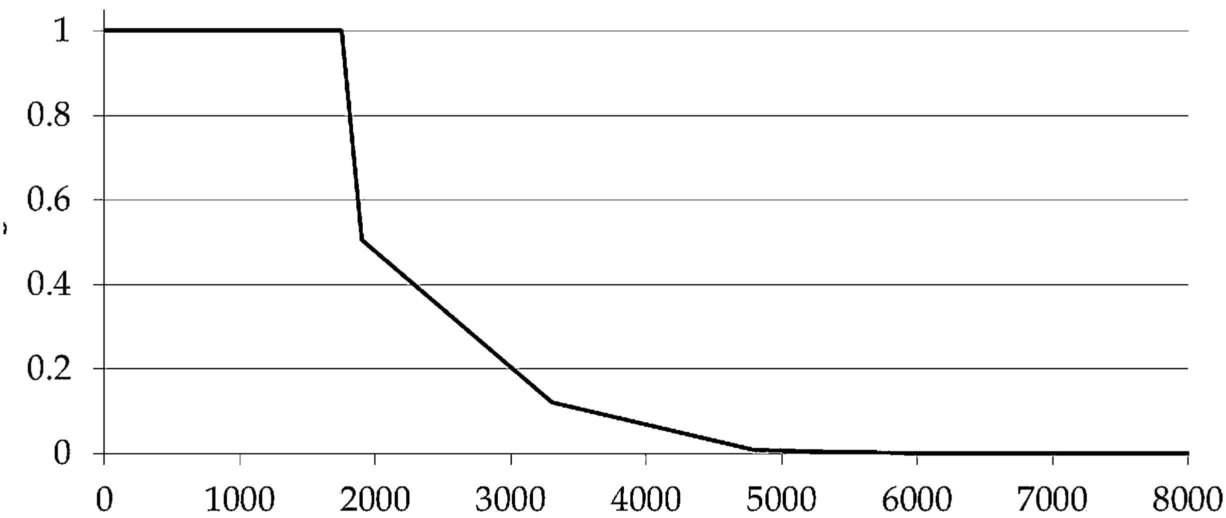
RESPONSE:

Engie believes there are several changes that could be made to the current ORDC that should help in supplying some of the "missing money" to incent future dispatchable generation.

As stated above, the current curve utilized in the ORDC is a cumulative distribution function. The shape of the curve is illustrated below along with the effects of changing the standard deviation that is used to develop the curve.



This "real" curve has resulted in consequences that mitigated much of the intended benefits of the ORDC. This result is due to the probability that is applied to the VOLL which, at the minimum contingency level of "X," is only 50%. This issue reveals two negative consequences: (1) significant value was taken out of the overall construct - as much as 50% of the expected ORDC value, and (2) prices jump dramatically to $9,000/MWh when the supply stack moves from 2001 MW to 2000 MW. Any abrupt price jump such as this creates both optimization and potential market behavior issues that should be avoided in any efficient market design. Therefore, Engie suggests the first change to the ORDC is to implement a "piecewise linear curve" as illustrated below.



By instituting this curve, the ORDC can be adjusted in a more pointed manner to result in the desired level of revenues in the market. This curve would rectify the two concerns listed above. Engie also believes that the ORDC should provide a level of revenues into the market on a more regular basis rather than those provided in reliance on near emergency events to incent investment in dispatchable generation.

Engie recommends that two other changes be considered. The first is an increase to the amount of reserve where the VOLL is reached. We suggest this be raised to at least 2500 MW or change the value to a percentage of load due to the continuing increase in ERCOT future load. This change would show a resolve to protect more reserves going into an emergency and provide increased overall grid reliability. Secondly Engie believes the VOLL should be reduced to $4500 MWh. While this may seem counter intuitive to the goal on increased revenues, the piecewise linear curve and reserves level should be adjusted in conjunction with this change to more efficiently provide the needed revenues for reliability.

Consider ORDC applying only to generators who commit in the day-ahead market ("DAM")

Engie reads the first sub question as only applying to that generation "committed" in the Day Ahead Market. Our comments are based on this understanding. Only allowing the ORDC to be available to those that are committed undermines the whole concept of valuing reserves in real-time which is the fundamental pillar of the ORDC. Only applying ORDC to generation in the DAM would create a settlement of load and generation that would be completely mismatched. The generation locational marginal price ("LMP") would be without the ORDC and the settlement point would include the ORDC.

Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

Engie does not see a need for seasonal curves. If the Commission elects to change to the piecewise linear, the curve represents an attempt to meet longer term investment goals as well as real-time reliability.

2. **Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?**
    a. **If so, how should that minimum commitment be determined?**
    b. **How should that commitment be enforced?**

RESPONSE:

Overall, Engie understands that all generation does have day ahead must offer requirements in other markets such as PJM. However, those commitments are in conjunction with capacity market requirements. ERCOT does not include a capacity market in the current design.

Engie is not convinced that a minimum commitment in the day ahead market would create any measurable increase in real-time reliability. Renewables already hedge nonperformance of contract conditions in the bilateral market. A requirement for a minimum commitment in the day ahead market would create the need for major changes to contracts and forecasting. This would be difficult to do for renewables with real-time settling purchase power agreements that are based upon a high percentage of as generated output. Further, day ahead commitment would force projects to take the additional day ahead/real time risk.

How should that minimum commitment be determined?

Determining a minimum commitment amount would be difficult to decide as determining the best mechanism would create major changes. Minimum commitment would need to be determined based on project output exceeding 50% of nameplate in our opinion. For wind projects, the day ahead forecast error is significant at lower loads. If over 50% of nameplate, an Effective Load Carrying Capability ("ELCC") calculation would probably be a reasonable metric that would put wind and solar at a commitment level around 20% of nameplate into the day ahead market. Another mechanism is to require wind and solar to commit to the amount that is used in the capacity, demand, and reserves ("CDR") on a seasonal basis, this would also create varying commitments for generation in differing regions in the state of Texas. Finally, the commitment could be based upon the individual generator's own forecast to the next day. A generator should not be held accountable for ERCOT forecast errors for a day ahead commitment.

How should that commitment be enforced?

Engie is unable to opine on how such a commitment could be enforced until the commitment requirement is defined.

3. **What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.**

RESPONSE:

First and foremost, any new ancillary service must have a direct, verifiable and measurable effect on grid reliability. With this in mind, Engie believes that it is ERCOT and not stakeholders who must determine what is needed to provide a reliable grid under extreme conditions. Once ERCOT has determined its need, then the stakeholders can develop the products and necessary markets for procurement with the goal to try and ensure the markets are liquid.

Engie believes the ultimate benefactor of ancillary services is the load in Texas. Therefore, Engie strongly suggests the current efficient process of allocating costs of ancillary services remain as originally designed on a load ratio share.

Further, Engie strongly suggests that any changes to the ancillary service be transparent, be in a liquid market and remain stable for the future. Without these three parameters being met, it will be difficult if not impossible for retail providers to procure these services to provide accurate fixed price contracts.

4. **Is available residential demand response adequately captured by existing retail electric provider ("REP") programs? Do opportunities exist for enhanced residential load response?**

RESPONSE:

Engie has no specific product suggestions; however, demand response is an integral part of grid reliability. The Commission and ERCOT should encourage additional demand response as part of the efforts to improve grid reliability.

5. **How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?**

RESPONSE:

Engie has no comments on this question.

6. **How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?**

RESPONSE:

See response to question number three with these further comments.

To manage the three reliability needs, Engie believes that setting an overall reliability level for the real-time grid and procuring the level of reserves to achieve that requirement is key. Inertia has been discussed by ERCOT and the stakeholders for some time; however, the need for a specific product has not yet been necessary. That is, that product may well be necessary in the future.

On voltage support, this is an unpaid ancillary service that generators provide to the grid. This product does create some additional operating cost through the maintenance and operation of providing the service. Engie suggests that this be changed to a compensated product as other markets currently do.

II. CONCLUSION

Engie requests that the Commission consider these comments in adopting recommendations aimed at improving the reliability of the ERCOT grid. We look forward to working together to implement improvements to the ERCOT energy-only market that will provide greater reliability and reflect sound market design principles.

Respectfully submitted,

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