PUCT PROJECT NO. 52373

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

NRG ENERGY, INC.'S COMMENTS ON THE COMMISSION'S AUGUST 2, 2021 QUESTIONS FOR COMMENT

NRG Energy, Inc. ("NRG") appreciates the opportunity to provide feedback on the market design questions issued by the Public Utility Commission of Texas ("Commission") on August 2, 2021. ERCOT market design reform is one of the most important topics for the Commission and ERCOT market participants to consider following winter storm Uri. NRG understands the urgency to improve grid reliability through enhanced financial incentives for dispatchable resources and demand response and is working diligently to meet the Commission's expedited schedule for finalizing a plan for market design reform. To assist in these efforts, NRG has contracted with consulting firm Energy and Environmental Economics ("E3") and Beth Garza, the former ERCOT Independent Market Monitor and now a senior fellow with the R Street Institute, to provide an actionable proposal on market-design reforms for the Commission to consider. That report is targeted for publication in September. Consequently, the responses NRG offers here are informed by ongoing discussions with those consultants and other market participants, as well as NRG's own observations, and should be viewed as preliminary and subject to revision as the Commission continues to deliberate on market design reform.

I. EXECUTIVE SUMMARY

The existing energy market structure in ERCOT is the right foundation but it must be supplemented to achieve a higher level of reliability during peak load seasons and over the long-term. The objectives of this project should be to 1) preserve a competitive market that allows retailers to innovate while also requiring them to perform a critical role in ensuring reliability; 2) maintain the energy market as the cornerstone of the market structure to ensure transparency and that resources are compensated for services they actually provide; and 3) evaluate supplemental reliability products that fill gaps in the existing market design to improve grid reliability in Texas.

NRG recommends the following categories of ERCOT market reforms be considered to achieve these objectives:

- Properly value operating reserves through Operating Reserve Demand Curve ("ORDC") reforms and reward dispatchability;
- Explore a contractual obligation for Load-Serving Entities ("LSEs") to contribute to system reliability by demonstrating they have a sufficient amount of firm resources committed to meet their non-interruptible customer demand;
- Create new ancillary or reliability services as required by Section 18 of SB 3; and
- Strengthen opportunities for demand-side solutions in the competitive retail market, including by participating in the features listed above.

It is important to note that a combination of the market design recommendations included in these comments will be required to achieve the objectives of this project. The events of Winter Storm Uri made it clear that grid reliability must be a priority and cannot be compromised going forward. This will require more than minor tweaks to the ERCOT market design.

II. RESPONSE TO COMMISSION STAFF QUESTIONS

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?*

Generation resources should be paid for their actual contributions in maintaining system reliability. The best way to do that is to ensure the energy market remains central to ERCOT's market structure. The current market design provides highly concentrated incentives to produce energy when the system is in tight conditions. Yet looked at another way, this design creates a "feast or famine" situation where generation resources only recover marginal cost for most hours of the year, and then earn substantial scarcity revenue during a small set of hours that verge on crisis. This creates a highly uncertain investment environment. One potential remedy for this situation is to extend the length of and flatten the shape of the ORDC curve. This would allow the market to reflect the public concern around tight supply conditions, while at the same time mitigating the highest prices that may be realized. Extending the ORDC also better reflects the value of operating reserves consistent with ERCOT's recently adopted operating practice of procuring and committing excess operating reserves. An extended ORDC is one tool, complementary with the reliability service products described in answer to Question 3, to reflect the need and value of these additional reserves. An extended ORDC should be constructed to reflect a higher value for operating reserves. This higher valuation will encourage the commitment of additional resources through market forces rather than the persistent use of command-and-control actions through the Reliability Unit Commitment ("RUC") process.

In addition to extending the shape of the ORDC, the Commission should also flatten it. Flattening entails reducing the value of lost load ("VOLL") and the system wide offer cap to temper market volatility. In other words, ORDC reform should allow energy revenues to be distributed more consistently. It is NRG's experience that, when the ERCOT market conditions tighten, liquidity in the bilateral market dries up and the forward market ceases to function due to the risk of extreme price volatility. While a lower VOLL and offer cap may sometimes understate possible scarcity value and potentially damage the economics of investments targeted exclusively to peak load, such as the residential demand response programs discussed in response to Question #4, a flattened and extended ORDC on balance will help improve liquidity and keep the forward markets working ahead of extreme weather events.

An extended and flattened ORDC may produce unanticipated consequences that the Commission should be aware of. For example, wind and solar resources would earn additional ORDC-related revenues if the ORDC was extended, relative to the status quo (or an approach in which ORDC payments were even more highly concentrated). While that could be a reason to entertain additional levels of complexity in ORDC design, such as a day-ahead commitment or a claw-back of revenue for non-dispatchable resources, the underlying issues of reliability and net load uncertainty are better dealt with through the concepts introduced in reply to Questions #2 and #3. It is a fundamental principle of energy price formation that there be a single, uniform product that is paid the same price at any given location for the same interval. Reforms that result in a non-uniform energy settlement price would have a detrimental effect on the certainty of bilateral and financial transactions for energy, which should be encouraged to allow load-serving entities to secure supply in advance of the operating day. To the degree that certain resources, through their intermittency, create the need for additional reserves, those resources should be responsible for addressing the reliability need through a construct described in answer to Question #3.

Similarly, while conceptually sound, NRG does not recommend ORDC curves that vary by season because of the difficulties they would introduce in secondary markets, which are essential for hedging. To address the interest the Commission and ERCOT have shown to promote day-ahead commitments raised in Question #2, the Commission should consider directing ERCOT to implement an extended ORDC in the Day-Ahead Market ("DAM") to reflect the need for additional operating reserves and encourage additional commitment of dispatchable resources.

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 the minimum commitment be determined?*
    b. *How should that commitment be enforced?*

The PUCT should not mandate a must-offer obligation in the absence of a fundamental reform to the ERCOT market. While a "must-offer requirement" could offer a solution to ERCOT's need to ensure commitment of excess reserves, more analysis would be required to assess the full breadth of market and operational impacts, and additional reforms would need to accompany it to compensate for the mandatory participation. NRG is not aware of any electricity market design in the world that has a "must-offer obligation" in the absence of a forward capacity payment, or a reliability requirement imposed on load-serving entities ("LSEs") to contract in advance for a sufficient amount of resources to supply their customers' projected demand.

Under a forward capacity construct, resources may sell in advance an amount of qualified capacity, which is correspondingly subject to a "must-offer obligation," typically in the day-ahead market. NRG does not support a centralized capacity market in ERCOT, where a central monopsony would buy all capacity thought to be needed and then socialize the costs across all LSEs. Such a reform cuts against the grain of a market characterized by a high degree of retail competition, where it is retail electric providers ("REPs", a form of LSE)—and not a central market operator—who should be in charge of managing a portfolio to supply their customers.

It would be consistent with the competitiveness of the ERCOT market, however, to introduce a reliability obligation that requires LSEs to make a showing that they have a sufficient amount of qualified resources under forward contract with the desired reliability attributes, subject to a penalty.[1] Robust qualification standards should properly value firm or dispatchable characteristics, while reducing the capacity value ERCOT attributes to renewables in their reserve

[1] Alternatively, as a substitute for a showing that relied entirely on generating resources, LSEs could demonstrate compliance by showing that certain loads they serve were interruptible prior to EEA3 conditions.

margin projections. This reform also would cause LSEs and the portfolios they (or their agents) manage to play a meaningful role in "firming up" supply for their customers. It is important to note under this approach there would be no forward procurement of capacity by ERCOT. Such a construct exists in the Southwest Power Pool[2] and is under consideration for adoption in the Northwest Power Pool.[3] A similar approach may be used if ERCOT or the Commission determines that additional generation investment is required for reliability, but is not being supported by the energy and ancillary-services markets. Australia's market, which like Texas's is one of the world's few energy-only markets, has introduced a "Retailer Reliability Obligation" to perform that function.[4] These approaches are adaptable to ERCOT, and NRG encourages the Commission to use one of its work sessions to fully consider the concept.

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?*

The main reliability challenges for the ERCOT grid going forward are having sufficient firm capacity to manage large swings in net load, caused both by variability in renewable resource output and load patterns. Winter storm Uri saw a common mode failure that resulted in both high loads and high resource failure, including dispatchable resources. Yet the most consistent influence on net load variation going forward likely originates from renewables as they become a larger part of the supply mix. Section 18 of SB 3 combines these topics, but they should be addressed separately.

A. Winter-time fuel security

Section 18 of SB 3 contemplates the creation of a reliability service to ensure reliability during extreme cold weather conditions by procuring a sufficient amount of winter resource

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[2] "Resource Adequacy," Southwest Power Pool. https://www.spp.org/engineering/resource-adequacy/.

[3] "NWPP Resource Adequacy Program: Detailed Design," Northwest Power Pool (July 2021). https://www.nwpp.org/private-media/documents/2021-08-10_NWPP_RA_2B_Design_v4_final.pdf.

[4] "Retailer Reliability Obligation," Australian Energy Regulator. https://www.aer.gov.au/retail-markets/retailer-reliability-obligation. (Requires a showing that sufficient resources are committed to LSEs only when a system-wide shortfall is determined.)

capabilities such as "on-site fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days."[5] Most of the costs associated with these capabilities are fixed costs and facility upgrades could require substantial retrofits. The Commission could consider these attributes within the qualification process for an LSE obligation as contemplated in reply to Question #2 but that may be too burdensome on the competitive retail market.

The Commission could alternatively consider a planned approach to wintertime fuel security by introducing a new reliability service that is procured by ERCOT years in advance through an "as-bid" contract procurement. Under this approach, ERCOT would specify the requirements to qualify for participation in the procurement through a Request for Proposal process. A resource's capabilities would be demonstrated to ERCOT's satisfaction prior to being awarded compensation. The amount of procurement of these winter fuel security capabilities should be based on a risk analysis of winter storm Uri by ERCOT and established by the Commission.[6]

B. Net load variability

In regard to a reliability service that deals with "times of low non-dispatchable power production,"[7] a broader approach such as that contemplated in response to Question #2 would require LSEs to show contractual commitments to a sufficient quantity of firm resources needed for reliability. That alone does not solve the question about the near-term, operational uncertainty of intermittent resources' impact on the system. The Commission should consider a reliability service that procures or requires demonstration by renewable resources of dispatchable reserves on a day-ahead basis in a quantity consistent with the reliability risk associated with higher load levels and renewable performance uncertainty. This would encourage renewables to contribute to reliability through bilateral procurement or installation of energy storage. Complementing the inclusion of the ORDC reforms offered in response to Question #1 in the DAM, such a net-load-

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[5] Public Utility Regulatory Act ("PURA") § 39.159(c)(2).

[6] Previously, in the Commission's weatherization docket, NRG has proposed that only those resources meeting an enhanced standard, as well having firm-fuel characteristics discussed here, would qualify to provide the winter reliability service contemplated under PURA § 39.159. *Rulemaking to Establish Electric Weatherization Standards,* Project No. 51840, NRG Energy, Inc.'s Comments on the Commission Staff's Discussion Draft and Questions for Comment at 4-6 (July 30, 2021).

[7] PURA § 39.159(b)(3).

uncertainty product should be an "in-market" solution to replace ERCOT's need to commit additional operating reserves through RUC as seen this summer.

C. Forward procurement of ancillary services

It is difficult for LSEs to hedge the current ancillary service products on a forward basis due to lack of liquidity in the bilateral market, similar to congestion price risk between Settlement Point Prices. The Commission should direct ERCOT to explore the implementation of a 3-year forward market for ancillary services like the Congestion Revenue Rights auction structure. The auction should be voluntary in nature and provide the opportunity for both loads and generation resources to transact amounts of ancillary services well in advance of the DAM.

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

Current REP programs demonstrate robust customer interest and participation in residential demand response. By way of just one example, Reliant (NRG's largest REP) offers residential customers the opportunity to participate in *Degrees of Difference with smart thermostats* program, which rewards customers for reducing consumption when electricity demand is high. Under this program, Reliant will automatically adjust the customer's smart thermostat to help them conserve and save money.[8]

In addition to this program, Reliant offers a *Degrees of Difference with manual thermostats* program to encourage behavioral demand-response.[9] Rather than automating a reduction in demand, Reliant communicates with its customers to encourage conservation at certain times (e.g., peak usage hours during the upcoming week when temperatures are forecasted to be high) and the customer takes the steps necessary to accomplish that conservation by delaying activities that use larger amounts of electricity such as laundry, cooking, and running pool pumps. The customer's reduced usage is evaluated against their baseline usage to determine whether conservation has occurred. If it has, the customer receives an incentive (e.g., bill credit). Behavioral demand

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[8] Customers enrolled in Reliant's *Degrees of Difference with smart thermostats* program are always in control and can change their thermostat temperature at any time.

[9] Although this program includes "with manual thermostats" in its name, a customer could participate in even if they had a smart thermostat because they could still take the actions requested to reduce demand.

response does not require a smart thermostat, increases awareness of grid conditions, and encourages active, positive participation in conservation.

Residential demand response through both dispatchable and behavioral thermostat control could account for a meaningful reduction in summertime peak loads, assuming other REPs increase offerings of such programs and wider adoption of such rate plans at a customer level, based on NRG's evaluation. In short, substantial additional opportunities exist for enhanced residential load response considering the millions of residential customers in the ERCOT competitive retail market.

The Commission should prioritize peak-load-reducing programs and should leverage REPs to do so, since it is REPs in the Texas market that are the primary interface between residential customers and the wider energy market. To expand the number of REPs that are able to offer demand response programs to residential customers, NRG recommends that the Commission restructure the ERCOT Transmission and Distribution Utility ("TDU") energy efficiency programs to increase the amount of funding dedicated to REP-offered energy savings products and services (e.g., smart thermostat programs) as well as REP participation in TDU residential load management programs. Additionally, TDU energy-efficiency programs should facilitate REP behavioral demand-response programs that are targeted toward peak-load reductions.[10]

The ERCOT TDUs expend significant resources each year to satisfy their statutory obligation under PURA § 39.905 to achieve certain minimum energy savings goals through market-based standard offer programs ("SOPs") and targeted market transformation programs ("MTPs"). For example, in 2020, the ERCOT TDUs collectively spent approximately $110 million in SOPs and MTPs, and those expenditures will ultimately be recovered in their rates.[11] Currently, a relatively small amount of the TDUs' annual energy efficiency program dollars are spent on REP-offered energy savings products and services and REP participation in residential load management SOPs.[12] Dedicating a greater portion of the TDUs' annual energy efficiency funding to such programs would ensure that more residential customers can be incentivized to reduce their

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[10] Consistent with PURA Section § 39.905(d)(16).

[11] *See 2021 Energy Efficiency Plans and Reports under 16 TAC § 25.181*, Project No. 51672.

[12] *See*, e.g., Project No. 51672, Revision to CenterPoint Energy Houston Electric's 2021 Energy Efficiency Plan and Report Pursuant to 16 TAC § 25.181(l) at 32, Table 11 (Jun. 1, 2021) (setting forth 2020 total program expenditures, including line items for individual programs).

electricity consumption during the summer and winter peak demand season. To eliminate concerns that such efforts would lead to increased TDU rates, the Commission could evaluate which lower-performing existing SOPs or MTPs could have their funds rededicated to REP-offered residential products, services, and demand response programs to enable the overall dollars of the TDU Energy Efficiency Programs to remain level.

Finally, more granularity in TDU meter data would help residential demand response programs reach the next level. The TDUs' existing smart meters have the capability to provide more granular data for REPs to use data analytics to better understand what devices are in a home so that demand response programs can be tailored to the customer's equipment. Last year, the Commission determined that its rules should not retain a requirement for TDUs' advanced metering systems ("AMS") to support the capability to provide direct, real time access to customer usage data;[13] however, it would be beneficial to explore ways to facilitate REPs being able to join devices to the TDUs' smart meters to retrieve such data. Retrieval of this level of detail should not utilize or burden the TDUs' AMS network except for a one-time request for a device to join the meter.[14] All other additional data retrieval would not use the TDUs' AMS network and could provide substantially more data for REPs to understand their specific loads, which could be utilized to design additional load curtailment offerings for customers.

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?*

ERCOT's Emergency Response Service ("ERS") program could provide additional reliability benefits if it were modified better accommodate residential demand response. Specifically, ERCOT's registration, rules, and requirements for ERS participation should be revised to provide a meaningful pathway for a REP to aggregate residential customers into a performance block for purposes of providing ERS. The REP would, in turn, be able to provide incentives to their customers for their consent to participate. Under the Commission's rules,

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[13] *See Rulemaking Relating to Advanced Metering,* Project No. 48525, Order Adopting Amendments to §§ 25.5, 25.130, and 25.133 as Approved at the April 17, 2020 Open Meeting at 18 (Apr. 20, 2020).

[14] The Smart Meter Texas website originally had the option to join a device to a smart meter but this functionality has since been removed because it is no longer a requirement. *See Commission Staff's Petition to Determine the Requirements for Smart Meter Texas*, Docket No. 47472 (Jul. 12, 2018).

ERCOT's current authorization for ERS spending per calendar year is up to $50 million.[15] A meaningful portion of this spending and any additional increased spending in ERS should be dedicated to enabling residential demand response in the manner described above given the currently untapped potential of millions of residential customers.

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?*

Supplemental ancillary service products can be created to establish market-based mechanisms to manage low system inertia and voltage fluctuations. Thermal generation resources have been providing these grid services at no cost since the market opened but could be compensated for doing so going forward to reflect their value to preserving grid stability. ERCOT and stakeholders have discussed creating such ancillary service products in the past. The creation of these products would rely on ERCOT determining the amount of each service required to manage inertia and voltage support and procuring those amounts in the DAM similar to the existing AS products.

III. CONCLUSION

NRG appreciates the Commission's efforts to gather stakeholder feedback during the development of potential market design changes. NRG looks forward to continued participation and opportunities to work with stakeholders and the Commission on market design solutions.

Respectfully submitted,

Bill Barnes

Bill Barnes
Sr. Dir. Regulatory Affairs
NRG Energy, Inc.
1005 Congress Avenue, Suite 950
Austin, Texas 78701
Telephone: (512) 691-6137
bill.barnes@nrg.com

[15] 16 TAC § 25.507(b)(2).