Control Number: 41061

Item Number: 70

Addendum StartPage: 0

PROJECT NO. 41061

RULEMAKING REGARDING DEMAND RESPONSE IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT) MARKET	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

JOINT COMMENTS OF THE RETAIL ELECTRIC PROVIDER GROUP AND THE TEXAS COMPETITIVE POWER ADVOCATES

I. INTRODUCTION

The Retail Electric Provider Group ("REP Group"[1]) and the Texas Competitive Power Advocates ("TCPA"[2]), (collectively, "Joint Commenters"), timely submit these comments in response to the questions posed by the Staff of the Public Utility Commission of Texas ("Commission") concerning barriers to participation by load resources in the ERCOT energy and ancillary service markets on December 12, 2017 in this project.

The Joint Commenters support integration of and participation by load resources into the ERCOT energy and ancillary markets via demand response. Joint Commenters believe that Load Serving Entities ("LSEs") including Retail Electric Providers ("REPs") are best suited to facilitate load resource participation within the framework of ERCOT's competitive wholesale and retail markets. In competitive portions of ERCOT, REPs are the primary customer facing entity for electric service and bear responsibility for customer usage in wholesale settlement.

The Commission made a significant investment in demand response in the ERCOT region when it adopted 16 Tex. Admin. Code ("TAC") § 25.130, *Advanced Metering,* in 2007 and subsequently approved the deployment of advanced metering systems for each of the ERCOT transmission and distribution utilities ("TDUs"). As a result, today over 7 million electricity consumers in the competitive areas of ERCOT have smart meters at their premises. This important step by the Commission provided the competitive retail market with the necessary information and technology to enable the provision of demand response product

[1] The REP Group consists of the following: Champion Energy Service, LLC; Constellation NewEnergy Inc.; Direct Energy, LP; NRG Retail Companies; and TXU Energy Retail Company LLC.

[2] The comments contained in this filing represent the position of TCPA as an organization, but not necessarily the views of any particular member with respect to any issue.

70

offerings. The retail market responded as REPs greatly expanded the scope of demand response products and services and customers responded to the availability of those products in a significant way. In fact, in the Final Order adopting 16 TAC § 25.130, the Commission noted, "In making its assessment of the required functionalities, the commission is balancing the interest in minimizing the costs of deployment and obtaining broad capabilities that will support higher levels of service quality, both through automation of the meter reading and data management processes and providing more information on a more timely basis to REPs, *so that they can offer valuable new services to customers.*[3]" By 2013, the first year after smart meters had been substantially deployed in the ERCOT region, 179,195 retail customers were subscribed to demand response products.[4] By 2016, this number increased to 906,646 retail customers.[5] Because ERCOT retail market product and price development is highly competitive, REPs have developed innovative demand response products that customers desire without technical limitations that accompany ERCOT-administered demand response products such as Loads in Security Constrained Economic Dispatch ("SCED"), Load Resources in Responsive Reserve Service ("RRS"), and Emergency Response Service ("ERS"). The most popular REP-administered demand response products today include peak rebate products that compensate customers for reducing consumption during peak periods and time-of-use ("TOU") products, which price energy according to the period in which customers use electricity. As of 2016, there were 478,243 retail customers subscribed to peak rebate products and 331,138 retail customers subscribed to TOU products.[6] These commendable statistics demonstrate the value that REPs place on demand response in the competitive market and their commitment to continuing to grow load participation in the ERCOT energy market.

---

[3] *Rulemaking Related to Advanced Metering*, Project 31418, Order Approving Rule (May 14, 2007). Order Approving Rule at 11.

[4] Carl Raish, Presentation to Demand Side Working Group, Retail Demand Response Survey Participant Headcounts 2013 – 2016 at 3 (Feb. 16, 2017) (http://www.ercot.com/content/wcm/key_documents_lists/117219/DSWG_Retail_Demand_Response_Survey_Participant_Headcounts_2016.pptx).

[5] *Id.*

[6] *Id.* at 17.

II. RESPONSE TO QUESTIONS

1) What technical obstacles discourage participation by load resources in the ERCOT energy and ancillary services markets? "Technical" refers to the interface between the load resource and ERCOT operations, including but not limited to such issues as telemetry, response to SCED base point instructions, ramp rates, and response time and duration.

a. Do these obstacles differ by customer class (i.e., residential, commercial, industrial)? If so, please describe in detail the nature and characteristics of the load resources in each class, the technical obstacles that exist for each class, and what solutions might be employed to reduce or eliminate these technical obstacles.

The primary obstacle to greater load participation in the ERCOT market is a financial one, as numerous opportunities exist for loads to participate for both energy and capacity compensation. Loads can participate in the ERCOT energy market by responding to prices through a retail product and avoid any technical dispatch requirements or limitations imposed by ERCOT. The reduced consumption would avoid high energy costs and be settled through the customer's LSE or REP based on the terms of their contract. This type of demand response is typically referred to as passive demand response. Passive demand response is not part of an ERCOT-administered program, but rather offered through the competitive retail market based on customer demands for these products. Loads that are capable of responding to dispatch instructions and meet certain performance criteria can qualify to submit bids via a Qualified Scheduling Entity ("QSE") into and be dispatched by SCED as Controllable Load Resources. Qualified Load Resources may also participate in the ERCOT Ancillary Service market, including four ancillary service products – RRS, REG UP, REG Down, and Non-Spin. Load Resources may also participate in other demand response markets in Texas, including ERCOT-dispatched ERS, TDU-administered load management programs, and in response to Four Coincident Peak ("4CP") transmission cost allocation avoidance incentives.

ERCOT stakeholders recognized the importance of allowing demand response to participate in energy price formation and explored numerous approaches to accommodate more demand response in the energy market. Specifically, the ERCOT Demand Side Working Group ("DSWG") and its Load Resources in SCED subgroup ("LRIS") spent considerable time exploring integration of load resources into the ERCOT energy and ancillary service markets. The technical obstacles related to load participation in the ERCOT-administered real-time market (i.e., SCED) have been documented by the LRIS and generally include temporal constraints (*e.g.*, ramp times, minimum response periods, maximum deployment times, load restoration periods, and post curtailment dispatch availability times), demand response curtailment validation issues, and settlement issues.[7] Many of these issues may be "solvable" but require significant investment to support telemetry and dispatch instructions needed to qualify as a Controllable Load Resource in ERCOT. Given the recent price history of the ERCOT wholesale market, investments to qualify load resources as Controllable Load Resources have largely been uneconomic. The load weighted average electricity prices in ERCOT have averaged $28.33, $33.71, $40.64, $26.77, and $24.62 in 2012, 2013, 2014, 2015, and 2016.[8] Prices at these levels have not signaled a need for new resources (demand response or otherwise) and would likely render any curtailment in SCED as uneconomic. When the ERCOT market signals a need for new resources through persistent higher energy prices, the value of demand response services will increase, providing REPs with further incentive to make additional investments in real-time telemetry, nodal dispatch and settlement, notification lead times, and continuous controllability (or partner with 3rd party demand response providers for such services).

The ERCOT stakeholder process explored many of the technical and regulatory issues included in the subject matter in the Staff questions through the DSWG and LRIS. ERCOT stakeholders discovered that there is the potential to create perverse financial incentives (i.e., double payments) by adopting certain policies intending to encourage demand response by 3rd parties in SCED. As further explained in the response to Question No. 4, some of the proposals intending to facilitate 3rd party participation in SCED are highly complex and would significantly disrupt the competitive retail market. Ultimately, ERCOT stakeholders determined that the complexity, perverse financial incentives, and disruption to the retail market presented issues that greatly exceeded the benefits of proceeding with the proposals. As such, the Commission should not burden the retail market with implementation costs and disruption to subsidize pursuit of uncertain benefits from incremental 3rd party demand response participation that should occur through the retail market once energy market economics signal their need. In addition, even if

[7] *See generally*, ERCOT, Current Loads in SCED Technical Barriers, http://www.ercot.com/content/committees/board/tac/wms/dswg/keydocs/2014/Current_Loads_in_SCED_Technical_Barriers_08182014_blackline.doc.

[8] Potomac Economics, 2016 State of the Market Report for the ERCOT Electricity Markets at 4 (May 2017) (2016 SOM Report).

these complex proposals were adopted, the level of participation by 3rd parties is uncertain and susceptible to the same economic forces that have limited demand response in the past. By way of an example, ERCOT implemented Loads in SCED in June of 2014, yet no market participant has participated in the program.

Most importantly, demand response participation in ERCOT's wholesale markets should be nondiscriminatory and non-preferential in application. If the Commission does require changes, as an initial matter it must ensure the performance standards for load participation in ERCOT's energy and ancillary service markets are equivalent to generation performance standards. Without equivalent performance standards for the same wholesale market service, investments in dispatchable generation resources will be undermined and may harm long-term resource adequacy.

2) What organizational and regulatory obstacles discourage participation by load resources in the ERCOT energy and ancillary services markets? "Organizational and regulatory' refers to the relationship of load resources to other entities, including but not limited to customers, Retail Electric Providers (REPs), Non Opt-In Entities (NOIEs), Qualified Scheduling Entities (QSEs), Transmission and Distribution Service Providers (TDSPs), ERCOT (including ERCOT financial settlements), and the Commission.

Characterizations of organizational and regulatory obstacles by certain parties are overstated and pale in comparison to the simple economic obstacles that load resources (and all other resources) face in depressed market conditions. During ERCOT stakeholder discussions, 3rd parties complained about the inability to interact with and be compensated by ERCOT as a QSE. Those 3rd parties, however, have two obvious solutions that would allow them to immediately participate in the ERCOT energy and ancillary service market: 1) obtain a REP certificate and participate in the market as a REP; or 2) partner with a LSE, such as a REP. The Commission is right to emphasize the competitive retail market as the ultimate provider for demand response products and services for consumers. ERCOT's retail market is highly successful and fiercely competitive. There are 117 REPs[9] offering hundreds of products available at any given time. A key design feature that has allowed the retail market to be so

[9] http://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx, Accessed 1/16/18

successful is the requirement for REPs to own the customer relationship for electric service. This simplifies the customer experience and allows competition on a level playing field.

Some parties may argue in this Project that the Commission should adopt policies that would encourage 3rd parties to interfere with the REP-customer relationship through their provision of demand response products. Joint Commenters oppose such proposals. Allowing 3rd parties to directly access customers without comparable certification requirements or customer protections can create an unfair advantage for 3rd parties competing with REPs when selling demand response products. Proper oversight and comparable requirements for 3rd parties are essential. Furthermore, to the extent entities other than REPs are allowed to offer demand-response products and services to residential and small commercial customers, the customer protection rules should apply to such 3rd parties in the same manner as they apply to REPs. Currently, the Commission rules do not cover these 3rd parties, therefore the rules must be expanded to provide the same customer protections and establish proper Commission authority and oversight to properly protect customers.

a. Do these obstacles differ by customer class (i.e., residential, commercial, industrial)? If so, please describe in detail the nature and characteristics of the load resources in each class, the organizational and regulatory obstacles that exist for each class, and what solutions might be employed to reduce or eliminate these barriers.

The financial obstacles to demand response only differ with respect to economies of scale and the demand response opportunities that make sense for each class as a result. For instance, customers of all classes have widely adopted TOU offers from REPs (as noted above), but only certain customers have made the investments to be technically capable of pursuing other demand response opportunities such as ERS and 4CP. Because the obstacles to increased load participation are primarily financial, there are no "solutions" that need be employed to reduce or eliminate them. Market signals will, over time, dictate the appropriate level of demand response.

b. What authority, if any, does the Commission have over demand response providers that may seek to participate in the ERCOT energy and ancillary services markets? Is the existing legislative framework sufficient to enable load participation in these markets while ensuring adequate oversight of participating entities?

The Commission's current authority over 3rd party demand response providers is limited at best. While the Commission has previously concluded that its statutory jurisdiction extends to the enforcement of administrative penalties against demand response providers of ERS pursuant to PURA §§ 14.001-003, 14.051, 15.023-024, 39.151(d), and 39.151(j)[10], these findings have been limited exclusively to the ERS program (an ERCOT reliability program) and cannot be assumed to confer a broader authority to the Commission over demand response providers generally. Neither PURA nor the Commission's Rules utilize the specific term "demand response provider," so it is unclear what, if any, authority the Commission currently has over demand response providers beyond enforcement of 16 TAC 25.507's provisions regarding ERS. Therefore, Joint Commenters recommend that the Commission conduct a rulemaking to clearly establish authority over 3rd parties and define certification and customer protection rules if the Commission desires to expand 3rd party participation in demand response.

3) In April 2017, following a study by ERCOT of the costs and benefits of implementation of a Multi-Interval Real-Time Market (MIRTM), the Commission accepted ERCOT's recommendation that the cost-benefit relationship did not support moving forward with implementation of a MIRTM at that time (Project No. 41837). Among the benefits cited for implementation of a MIRTM was increased participation by load resources in the real-time market. Does the decision not to move forward with MIRTM implementation create an insuperable barrier to load participation in the real-time market?

No. As noted above, load currently participates in the ERCOT market via REP product offerings and as Load Resources that are dispatched by ERCOT for ancillary services and ERS. Moreover, ERCOT wholesale prices have simply not supported investment in the controls necessary for load participation in the wholesale market – that is, the only "insuperable barrier" has been the economics of the wholesale market itself. In the review of MIRTM, ERCOT and stakeholders concluded that, "the MIRTM study demonstrates that the estimated costs are in excess of the measured benefits and therefore insufficient to support a recommendation to move

---

[10] For example, see *Notice of Violation by Viridity Energy Inc. of PURA § 39.151(d); 16 TAC § 25.503(f)(2); and ERCOT Protocols § 8.1.3.3.1 Regarding Suspension of Qualification of Non-Weather-Sensitive Emergency Response Service Resources and/or Their Qualified Scheduling Entities*, Docket No. 46946 (July 28, 2017) and *Agreed Notice of Violation and Settlement Agreement Relating to Energy Curtailment Specialists, Inc.'s Violation of PURA §39.151(d), PUC Subst. R. §25.505(f)((2), and ERCOT Protocols §8.1.3.3.1(1)(b), Relating to Performance Criteria for Qualified Scheduling Entities Representing Emergency Response Service Resources*, Docket No. 43457 (November 14, 2014).

forward with MIRTM at this time."[11] The study also found that "system conditions and the balance of supply and demand during the period studied did not present a significant need for the types of resources that would participate in MIRTM." Neither conclusion was premised on creating an insuperable barrier to load participation in the real-time market – merely that MIRTM did not make sense on balance for ERCOT at present (but recognizes that future market conditions may differ).

4) In 2011, the ERCOT Technical Advisory Committee (TAC) endorsed the formula "LMP-G" as the basis for compensation of loads participating in the ERCOT energy markets.

In 2011, ERCOT stakeholders were particularly focused on one specific design construct referred to as "LMP-G.," or the locational marginal price minus the retail price. The objective of the LMP-G construct is to facilitate 3rd party demand response participation directly in the ERCOT real-time market (SCED) without going through a LSE or REP. The LMP-G concept attempts to mimic the settlement of a retail transaction involving demand response provided by a 3rd party and electric service provided by a LSE or REP. Under this proposed construct, when a 3rd party contracts directly with a retail customer to provide demand response there would be a financial arrangement whereby the 3rd party receives direct payment from the ERCOT wholesale market and compensates the customer for reducing consumption of electricity. In concept, the customer is selling electricity back to the ERCOT wholesale market (through the 3rd party provider) after it has purchased it at a retail rate. The 3rd party retains a portion of the "sales" as profit. As later outlined in the response to Question 4(c), there are numerous complications with this approach that may conflict with Commission Rules and would create significant disruption to the competitive retail market in ERCOT.

It should be noted that ERCOT stakeholders resoundingly rejected a competing proposal to LMP-G referred to as "Full LMP." Full LMP has the similar objective of facilitating 3rd party participation directly in SCED, but with a much different economic outcome that is detrimental to economically efficient incentives. Under Full LMP, the customer and 3rd party demand response provider are compensated twice for the same quantity of reduced consumption because

[11] ERCOT, Summary of Multi-Interval Real Time Market (MIRTM) Feasibility Study at 4 (Feb. 22, 2017) (http://www.ercot.com/content/wcm/key_documents_lists/103986/8_MIRTM_Study_Summary.pdf).

the customer is never charged the retail rate. Explained differently, the customer is compensated for selling electricity that it never purchased. Thus, the customer avoids the cost of buying electricity at the retail rate and then is paid a market price for the same avoided consumption. This equates to a double payment for the customer and the 3rd party demand response provider since they share the payment based on the terms of their arrangement. The Federal Energy Regulatory Commission ("FERC") considered and even temporarily adopted the Full LMP mechanism in 2015. However, there was swift and overwhelming opposition to that approach. A joint filing of 21 leading power market economists filed by the Electric Power Supply Association ("EPSA") in the Court of Appeals explains the issue with Full LMP very clearly:

> In competitive markets, purchasers who reduce their consumption in response to price, reselling the input to others, earn the difference between the existing market price and the price at which they are entitled to buy. For example, if a retail customer has signed a long-term contract at $.10/kWh and the wholesale price rises to $.15, the customer can sell electricity at a profit of $.05—the difference between the $.10 he paid under the long-term contract and the wholesale market price. FERC's chosen demand-response mechanism, however, forces Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to pay retail customers the full market price for reducing retail consumption, without offsetting the purchase price the customer avoided (*i.e.*, to pay the full $.15 in the above example [instead of $.05]).
>
> That cannot be reconciled with basic economics. FERC erred by assuming that *not using* a megawatt-hour of electricity is economically equivalent to *producing* a megawatt-hour. And FERC's apparent assumption that more demand response is always better, regardless of the effect it has on other market participants, is false. FERC's chosen mechanism leads to distortions and social welfare losses it nowhere justified. By overcompensating purchasers for not consuming energy, FERC will cause them to forgo otherwise economically beneficial activities when neither true costs nor competitive prices would lead them to do so.[12]

It is for these reasons that ERCOT stakeholders resoundingly rejected Full LMP as a market design construct to facilitate 3rd party participation. To eliminate any existing confusion regarding Full LMP policy in ERCOT, Joint Commenters recommend that the Commission clearly reject both the Full LMP approach and the LMP-G (and its various permutations) as part of this Project.

---

[12] Brief of Robert L. Borlick, Joseph Bowring, James Bushnell, and 18 Other Leading Economists as Amici Curiae in Support of Petitioners at 5-6, Elec. Power Supply Ass'n, et. al. v. Fed, Energy Regulatory Comm'n, et al., 753F.3d 216 (Jun. 13, 2012) (No. 11-1486), *available at* https://sites.hks.harvard.edu/fs/whogan/Economists%20amicus%20brief_061312.pdf).

a. Has the ERCOT stakeholder process agreed to an approach for implementing this compensation method?

No, the ERCOT stakeholder process has not agreed to an approach for implementing LMP-G. The DSWG and LRIS dedicated more than three years to evaluating the LMP-G concept but the technical complexity and policy impacts prevented the development of a solution that could be implemented.

b. If the answer to 4(a) is yes, please describe this method in detail.
c. If the answer to 4(b) is no, please describe in detail any elements of such a method that have achieved consensus, and what elements remain at controversy.

At the October 6, 2011 TAC meeting, stakeholders endorsed the concept of "LMP-G" rather than "Full LMP" because of the perverse economic incentives associated with Full LMP (i.e., double payments), which were previously discussed.[13] By taking this action, TAC expressly supported the principle that a customer or 3rd party demand response provider should not get the financial benefit of the curtailment twice. The LMP-G concept, as presented to TAC at the time, consisted of a specific approach called "volumetric" LMP-G. This version of LMP-G required the discrete kWh curtailment of each individual customer in an aggregation to be allocated back to them (through the REP) for settlement. Through analysis by ERCOT and discussion by stakeholders at the LRIS and DSWG, it was determined that customer-specific curtailment could not be estimated accurately for the vast majority of customers in ERCOT, and all residential customers could not be estimated accurately, which were the primary target of the effort. The "volumetric" LMP-G approach would require REPs to bill customers for their curtailment as if it were metered consumption, which ERCOT stakeholders believed would conflict with PURA and Commission rules. Since the "volumetric" LMP-G concept was not feasible, ERCOT stakeholders evaluated a different version of LMP-G called "LMP-Proxy $G." LMP-Proxy $G simplifies the disaggregation of curtailment from the customer level to the REP level, but requires the designation of a proxy retail rate to be used for settlement for all 3rd parties and customers. Under LMP-Proxy $G, payment to the 3rd party for the curtailment is reduced by the proxy retail rate, which is designed to replicate the purchase of energy first at the retail rate

[13] ERCOT, Minutes of the Technical Advisory Committee (TAC) Meeting at 9 (Oct. 6, 2011), http://www.ercot.com/content/meetings/tac/keydocs/2011/1006/APPROVED_Minutes_TAC_20111006.doc

and sell back at LMP. It is unlikely that the 3rd party demand response provider would know each individual customer's specific curtailment to accurately allocate the Proxy $G charge, therefore, some customers will likely still receive double payments under this method. While slightly simpler, the LMP-Proxy $G concept still contained a host of technical and policy issues that were revealed through detailed evaluation at the LRIS and eventually became too overwhelming for the majority of ERCOT stakeholders to support.

Despite the lack of consensus on LMP-G, at the November 19, 2015 TAC meeting stakeholders did affirmatively endorse a motion to accept "LMP-Proxy $G" as a substitute for "LMP-Volumetric G."[14] However, TAC deliberately did not proceed with the approach and parties interested in pursuing the concept further were encouraged to submit a Nodal Protocol Revision Request ("NPRR") for consideration by the ERCOT stakeholder process. No NPRR for LMP-G has since been filed.

The technical complexity and policy impacts of the LMP-G concept that are outlined more fully below exemplify the issues that prevented the development of a solution that could be implemented. In detailing some of the technical and policy issues relevant to the LMP-G concept, the Joint Commenters again encourage the Commission to reject proposals to implement the LMP-G concept (or its permutations) due to the disruption it would cause the retail market. Joint Commenters are confident that 3rd party demand response technology and services will be more widely adopted by REPs and included in retail product offerings once the economics of providing such services become more compelling.

Below is a summary of some of the technical issues and policy impacts related to LMP-G that are controversial and remain unresolved:

- Customer relationship – REPs offer demand response products as part of the electric service offering. 3rd party demand response providers only offer demand response services. This begs the question of who owns the demand response customer relationship? Can a 3rd party demand response contract interfere with or supersede a REP contract for retail electric service? Will this create confusion for retail customers?

[14] ERCOT, Minutes of the Technical Advisory Committee (TAC) Meeting at 5 (Nov. 19, 2015), http://www.ercot.com/content/wcm/key_documents_lists/79528/APPROVED_Minutes_TAC_20151119.doc

- Customer protection – Because the Commission has no (or at most, very limited) oversight over 3rd party demand response providers, if the customer is subject to predatory behavior by the 3rd party, what is their recourse? The Commission must establish rules to define consumer protection, including the right of rescission and privacy of proprietary customer information, and any "change in law" preconditions. Additionally, the Commission should consider the question of how REPs will be protected if they receive complaints as a result of bad behavior by 3rd parties the customer has a contract with.
- Switching and notification process and system requirements – Assuming that concerns about defining the customer demand response relationship and implementing appropriate customer protections could be resolved, REPs and 3rd parties would require switching and notification rules, a system similar to the existing rules that govern retail switching, and the Texas Standard Electronic Transaction ("SET") transaction definitions. In order to properly hedge their business and manage the customer's risk accurately, REPs would need to be notified as to when a 3rd party provider contracts with one of the REP's customers for demand response service. A customer engaged in demand response has a very different risk profile that changes the way REPs hedge that load. Without knowledge that their customers have engaged in demand response services outside the REP-customer relationship, REPs would be exposed to unpredictable financial risk that would raise costs of service. A REP will have no way of knowing why the customer's consumption patterns are different from what the REP initially assumed or observed based on past behavior. In addition, REPs will be unaware of when the 3rd party sends the customer curtailment instructions that will change the customer's consumption patterns. This is an issue because REPs analyze historical usage for customers in order to hedge their portfolios. The interaction with 3rd party demand response providers would disrupt this hedging process, and could spill over into a customer's billing depending on whether/how a customer's contract allocates swing risk between REP and customer. In order for REPs and 3rd party providers to transparently manage this issue, a switching and notification system, similar to the Texas SET process for existing retail transactions, would need to be developed. Under the concept, a REP or 3rd party would be designated as a Demand Response Provider of Record ("DRPOR") similar to the REP of Record

concept. Thus, when a 3rd party contracts with a customer, a series of electronic transactions would be sent to ERCOT and the REP of Record so all parties are aware that the customer is now on a demand response product not provided by the REP. To do this the Commission would have to adopt rules to:

- detail the mechanics of switch administration;
- govern customer engagement and recruitment;
- define consumer protection, including right of rescission and privacy of proprietary customer information;
- track, validate, and contest (if erroneous) customer switching (e.g., from a REP demand response program to a 3rd party); and,
- define requirements and information disclosures to residential and small commercial customers (similar to the Electricity Facts Label).

- Protections to prevent double dipping – Continuing from the hypothetical above, if a 3rd party demand response provider were to sign up a customer that was already on a demand response rate with a REP (such as a Peak Rebate product), a process would need to be established to ensure the customer could not double dip by getting compensated twice for the same curtailment event. This could occur during high price events when both the REP and the 3rd party would send deployment signals (e.g., the REP through rates or direct curtailment instructions/actions, and the 3rd party through direct curtailment instructions/actions). The process discussed in the LRIS would mimic a drop to Provider of Last Resort ("POLR") event. To illustrate what would be required, assume a REP has a particular customer on a demand response rate so the REP is the REP of Record as well as the DRPOR. When a 3rd party signs up the same customer on a demand response product, a series of electronic transactions would be initiated to inform ERCOT and the REP (as outlined above) that the 3rd party is now the DRPOR. Since the customer was on a demand response rate provided by the REP, the REP would need to put the customer on a different, non-demand response product to prevent double dipping. This process would undoubtedly create significant disruption to the retail market and create customer confusion as customers are forcibly moved off of their REP provided demand response product, potentially incurring early termination penalties, driving PUC complaints, and incremental bad debt on disputed bills.

- Customer aggregation size requirement – During the stakeholder discussions, ERCOT was clear that it is not possible to estimate the curtailment of individual residential and small commercial customers. ERCOT is only able to estimate the curtailment of an aggregation of these customers of certain size (e.g., more than 200 customers). Therefore, qualification and maintenance rules are required to ensure a 3rd party is participating with an aggregation of sufficient size with ERCOT defining the aggregation size requirement. A 3rd party would need to list the Electronic Service Identifier's ("ESIIDs") that are part of the aggregation for ERCOT to validate and complete the registration of the entity. Through the DRPOR notification system described above, if the 3rd party aggregation lost customers and fell below the minimum aggregation size, ERCOT would have to disqualify the 3rd party aggregation and remove their ability to offer into SCED.
- Customer aggregation curtailment allocation – To perform the LMP-Proxy $G settlement, ERCOT would have to allocate the curtailment of the aggregation controlled by the 3rd party to the REPs that are serving the individual customers. Practically speaking, ERCOT would be performing the curtailment estimation for an aggregation of customers by REPs. Thus, an aggregation of 500 total customers may consist of an aggregation of 100 customers being served by REP A, 200 customers being served by REP B, and 200 customers served by REP C. Due to the aggregation size requirement described above, the overall aggregation would need to be either fully disqualified or partially disqualified for the portion assigned to REP A. Assuming all size requirements are met, ERCOT would have to develop a process and create a settlement mechanism to add the curtailment quantity to the REP's load. This process would clearly be complicated due to the robust nature of the competitive retail market. ERCOT processed almost one million switch transactions in 2017.[15] Customers are switching REPs constantly and ERCOT would need to keep track of each customer in every 3rd party aggregation for every 15-minute settlement interval in order to perform the proper LMP-Proxy $G calculation.

[15] ERCOT Monthly Operational Overview (December 2017) at 46 (Jan. 15, 2018), http://www.ercot.com/committee/board/2017 (showing as of December 2017, ERCOT processed 997,452 switch transactions).

- Can REPs bill customers for consumption that never occurred? – The implementation of "volumetric" LMP-G would require the REP to bill customers for curtailment as if it were metered consumption. The objective of LMP-G is to prevent the double payment (paid for the curtailment and paid to avoid the cost of consumption). To do this, ERCOT would allocate the curtailment quantity of the customer aggregation to each REP that is serving the curtailed customers. The REP then has the burden of identifying the customers being served by the 3rd party, and billing them for the curtailment as if it did not occur. 16 TAC § 25.479 clearly identifies what REPs may bill customers for including kWh metered consumption. The Rule requires billing based on accurate kWh metering data.[16] Therefore, it is not clear how REPs would bill customers under "volumetric" LMP-G without a rulemaking to clarify how the "curtailment related" consumption should be reflected on the retail bill. REPs would not want to misrepresent the kWh metered consumption in any way. It was this complication that led stakeholders to pursue LMP-Proxy $G.
- If LMP-Proxy $G is considered, the questions of how to define Proxy $G and how often it should be updated must be addressed. The implementation of LMP-Proxy $G would require a process to establish and update Proxy $G. Again, the concept of LMP-G must produce a financial outcome that eliminates the double payment for the curtailment. To do this, the 3rd party provider and customer are paid for the curtailment quantity at the market price (i.e., LMP) minus a proxy for the retail rate that the customer is on (i.e., Proxy $G). Unfortunately, the Proxy $G retail rate will never match exactly what the REP is actually billing the customer since the 3rd party would not (and should not) know that specific rate. Thus, Proxy $G is intended to be a general representation of retail rates in ERCOT. The LRIS explored a process to define Proxy $G and reached consensus that an ERCOT-wide average of POLR EFL rates would be a reasonable and conservative value for Proxy $G. As POLR rates are updated, Proxy $G could be updated as well, and at a minimum would be updated annually. Moreover, POLR rates are not fully without issue, however, given that POLR Electricity Facts Label ("EFL") rates include both fixed and variable components (therefore the average rate varies with actual consumption), are based on aged wholesale price inputs, represent *minimum* POLR rates, and are only

[16] 16 Tex. Admin. Code § 25.479(c).

explicitly calculated on the EFL for residential and small non-residential customer classes.

- Rules to ensure fair competition between REPs and 3rd parties – In order to implement LMP-G, rules would need to be established and enforced to prevent deceptive business practices that undermine fair competition between 3rd parties and REPs for demand response services. For example, rules to prevent slamming (i.e., enrollment on a product without customer consent) by 3rd party providers would be required. There would also have to be customer acknowledgement that they signed an agreement with the 3rd party before the 3rd party assumes the role of DRPOR in ERCOT's registration and settlement system. Another area of concern discussed at LRIS was the potential for "DR Blocking," where a REP prevents a 3rd party provider from enrolling the customer. This issue would also need to be addressed by the Commission before implementing LMP-G.
- Rules to resolve competing claims of customer enrollment - The Commission would need to adopt rules to resolve competing claims of customer enrollment by both a 3rd party and a REP (if both say they own the customer demand response relationship), similar to REP of Record dispute resolution processes.
- Customer protections and dispute resolution rules would need to be expanded to include 3rd parties as they are currently not covered under these rules. The Commission needs authority over these entities in order to protect customers. However, as noted above, the Commission's statutory authority over 3rd parties is not abundantly clear.

The list above is not exhaustive as there are additional technical issues that remain unresolved with the LMP-G mechanism that are not mentioned here. However, the list does demonstrate the level of complexity and disruption to the retail market that should make it clear to the Commission that LMP-G is not worth pursuing in ERCOT.

5) What specific rulemaking activity could the Commission undertake that would reduce obstacles to participation by load resources in the ERCOT energy and ancillary Services markets?

Joint Commenters encourage the Commission to remain focused on promoting efficient scarcity price signals and the capability and performance of metering systems, including improved access to IDR meter data. Today, data from IDR-read meters, representing approximately 24% of load, is not available for initial ERCOT settlement. This delayed access to IDR read meters impacts ERCOT settlements and may harm the ability of REPs to quickly measure, validate and compensate IDR customers for demand response actions. The Joint Commenters recommend examining means of reporting IDR data to Customers, REPs and ERCOT on par with current AMS standards.

III. CONCLUSION

The REP Group and TCPA appreciate the Commission's consideration of these comments. LSEs including REPs are best suited to facilitate load resource participation within the framework of ERCOT's competitive wholesale and retail markets given their wholesale settlement and customer facing responsibilities. If price signals are sufficient, investment in load resource participation will continue to occur, without Commission involvement.

Respectfully submitted,

By: B P Sams

Bryan Sams
NRG Energy Inc., on behalf of the REP Group
1303 San Antonio Street., Ste 700
Austin, TX 78701
(512) 691-6126
Bryan.Sams@nrg.com

With Permission
BPS

By: Lindsey Hughes

Lindsey Hughes
Executive Director
Texas Competitive Power Advocates
1001 Congress Ave., Ste. 450
Austin, TX 78701
(512) 771-8622
LHughes@competitivepower.org
www.competitivepower.org