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PROJECT NO. 47199

PROJECT TO ASSESS PRICE-FORMATION RULES IN ERCOT'S ENERGY-ONLY MARKET	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.'S REPORT IN RESPONSE TO COMMISSION STAFF'S REQUEST

As discussed at the June 7, 2017 Open Meeting of the Public Utility Commission of Texas ("Commission"), and pursuant to the request made in the May 31, 2017 Commission Staff memorandum, Electric Reliability Council of Texas, Inc. ("ERCOT") hereby files its report in response to Commission Staff's request. The requests from the May 31, 2017 Commission Staff memorandum are as follows:

1. Provide a status update on recent changes, if any, made to:
   a. ERCOT's transmission planning methodology and assumptions;
   b. Assumptions and procedures used to determine the need to issue a RUC instruction or commit an RMR resource to support local reliability or for system-wide capacity; and
   c. Out-of-market operator actions and associated pricing rules.
2. Comment on the need and/or cost of introducing a local reserve product or local operating reserve demand curves in conjunction with real-time co-optimization.
3. Provide an estimate of the implementation time and cost of incorporating marginal losses into dispatch and pricing.

In addition, at the June 7, 2017 Open Meeting, Commissioner Anderson requested historical information related to the magnitude of transmission losses that have been allocated to

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Load Serving Entities ("LSEs") since the implementation of the Texas nodal market. ERCOT's response to the Commission's request is included in Request No. 3.

RESPONSE TO REQUEST No. 1.a.

Introduction

ERCOT and stakeholders made several changes to the transmission planning methodologies during 2016 and early 2017. The Nodal Protocol Revision Requests ("NPRRs") and Planning Guide Revision Requests ("PGRRs") and are summarized below.

Changes impacting planning methodology and assumptions

January 2016 marked the full implementation of North American Electric Reliability Corporation ("NERC") Reliability Standard TPL-001-4, Transmission System Planning Performance Requirements, which was approved by the Federal Energy Regulatory Commission ("FERC") in October 2013.[1] NERC Reliability Standard TPL-001-4 changed transmission planning processes and criteria requiring that additional transmission planning studies be included in an annual system assessment and several "raise-the-bar" reliability criteria requirements.

NPRR788, RMR Study Modifications, was approved by the ERCOT Board of Directors ("Board") on October 11, 2016.[2] This NPRR changes the criteria used in Reliability Must-Run ("RMR") studies and aligns the customer demand forecasts used in RMR studies with forecasts used in other transmission planning studies. These changes will reduce the overall use of RMR contracts.

[1] NERC Reliability Standard TPL-001-4 may be found on NERC's website at the following link: http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[2] ERCOT Board Report for NPRR788 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/NPRR788#keydocs

PGRR042, Regional Transmission Plan Model Reserve Requirement and Load-Generation Imbalance Methodology, was approved by the Board on December 13, 2016.[3] PGRR042 revised the processes that ERCOT uses to conduct the annual Regional Transmission Plan and the independent review of large (Tier 1) transmission projects. Specifically, the PGRR makes the following changes:

- Impose requirements for ERCOT to reconcile future forecasts of customer demand produced by Transmission Service Providers with similar forecasts produced by ERCOT;
- Allow for more stakeholder input into the scope and assumptions used in transmission planning studies; and
- Require ERCOT to perform specific load and generation sensitivities to inform stakeholder review of project need.

The required generation sensitivity could indicate projects that may not be required if uncommitted future Resources in the interconnection queue are completed.

PGRR053, Addition of Proposed Generation Resources to the Planning Models, was approved by the Board on February 14, 2017.[4] The PGRR clarifies the modeling requirements for new generation projects to be added to the transmission planning models. These changes ensure that committed generation will be added to the transmission planning models in a timely fashion. This change will result in ERCOT having access to the most current information when assessing improvements and changes in the ERCOT System.

[3] ERCOT Board Report for PGRR042 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/PGRR042#keydocs

[4] ERCOT Board Report for PGRR053 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/PGRR053#keydocs

PGRR052, Stability Assessment for Interconnecting Generation,[5] **PGRR054**, Stability Limits in the Full Interconnect Study,[6] and **NPRR809**, GTC or GTL for New Generation Interconnection,[7] were approved by the Board on April 4, 2017. These combined revisions establish a quarterly stability assessment process for studying the combined impact of new generation on grid reliability. In doing so, these changes standardize and streamline the synchronization process for new Resources. In addition, ERCOT has made several internal improvements in order to facilitate the generation interconnection process, including:

- Improvements to the generation interconnection project database;
- Updates to the database used by Resource owners to provide engineering specifications for new and existing Resources; and
- Consolidation of generation interconnection responsibilities under a single manager.

RESPONSE TO REQUEST No. 1.b.

Introduction

As part of the normal review ERCOT conducts on market and reliability outcomes, ERCOT observed a significant increase in the instances where Reliability Unit Commitments ("RUCs") were required in 2016. In fact, 2016 saw the highest instances of need for RUC since

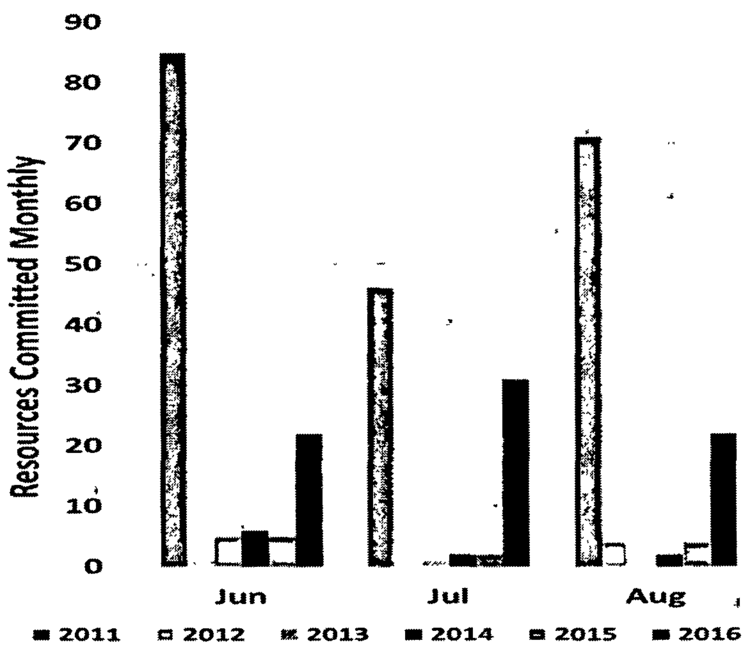
[5] ERCOT Board Report for PGRR052 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/PGRR052#keydocs

[6] ERCOT Board Report for PGRR054 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/PGRR054#keydocs

[7] ERCOT Board Report for NPRR809 may be found under "Key Documents" on ERCOT's website at the following link: http://www.ercot.com/mktrules/issues/NPRR809#keydocs

2011. ERCOT reported this outcome to both the Board and stakeholders. Figure 1 below shows the increase in RUCs during the summer of 2016.

Figure 1



RUC Background

The RUC engine provides commitment recommendations to ERCOT operators to ensure adequate Resource and Ancillary Service capacity commitments in the proper locations to serve ERCOT forecasted Load. The commitment recommendations are made only if the capacity shortage or congestion cannot be resolved by Qualified Scheduling Entity ("QSE") self-commitments, as provided via Current Operating Plans ("COPs"). ERCOT Operations reviews the commitment recommendations and has the discretion to issue RUC instructions only to those Resources that are near their last hour of possible commitment, based on the provided Resource notification time. In general, ERCOT operators defer these commitment decisions for as long as possible, since Resources with shorter lead times allow the affected QSEs the maximum time to make the decision to self-commit, thus providing market-based solutions to the identified problems. The provisions for QSEs to buy back RUC commitments, and thus operate these Resources as self-committed market resources, reduces the amount of out-of-market capacity in the ERCOT System. QSEs can wait until near Real-Time to make the self-commitment decision based on the RUC recommendation. The centralization of RUC commitments within the Independent Organization helps to ensure that minimal commitments are made to resolve the issues, avoiding potential over-commitment that could result from individual QSE decisions.

Dynamics for the Increases in RUC

There were two principal drivers for the 2016 increase in RUCs: a) an increase in congestion, and b) the introduction of the buy-back option from a RUC instruction. Figure 2 below compares congestion in the summer of 2015 to 2016. The buy-back option created in NPRR416, Creation of the RUC Resource Buyback Provision (formerly "Removal of the RUC Clawback Charge for Resources Other than RMR Units"), allows a generator to push its decision to self-commit closer to Real-Time and thereby maximize the probability that the QSE's worst financial case would be RUC Settlement (to be made whole to its costs plus a small adder). With this new provision, if energy prices were low, the Resource could wait and be committed as RUC. If energy prices were high, the buy-back clause could be exercised. Prior to this change, Resources were required to make commitment decisions much earlier, meaning that both the ERCOT operator and the RUC engine would see the Resources come online, thus reducing the need for RUC but potentially leading to over-supply of capacity. The ERCOT Independent Market Monitor also identified the RUC buy-back as a "potential contributor" to higher levels of RUCs in 2016.[8]

[8] Potomac Economics, "2016 State of the Market Report for the ERCOT Electricity Markets," page 92, May 2017.

Figure 2

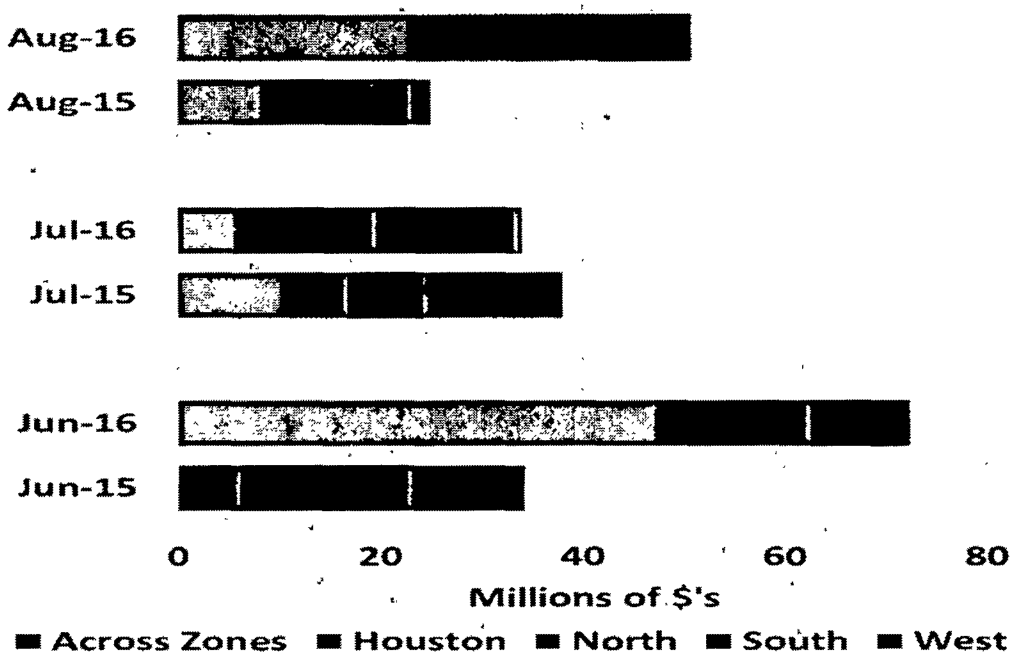
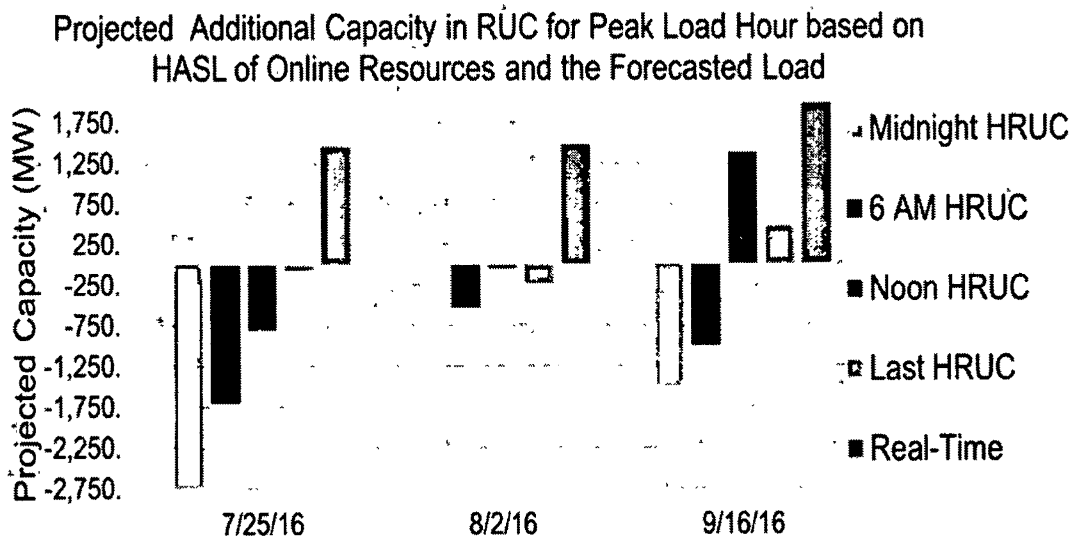


Figure 3 below shows that following the implementation of the buy-back option, Resources have been waiting closer to real-time to make their commitment decisions. The result of this behavior is that under certain circumstances, ERCOT saw an increased need to RUC the Resources because neither the operators nor the RUC engine would know the price point at which the Resources would self-commit. ERCOT does not necessarily view Resources waiting close to real-time for commitment as a negative outcome. In fact, during low-price time periods, Resources wishing to wait can be rational, so long as the RUC option can provide the necessary process to commit resources when necessary.

Figure 3



Market Design Changes which have impacted RUC

Following is a summary of improvements that have been made to the RUC process, including approved revisions to the ERCOT Protocols, internal ERCOT improvement efforts to the RUC engine, and upgrades to internal processes intended to improve control room RUC management. These changes have made RUC an evolving process, and ERCOT has and continues to modify its processes as a consequence.

- **NPRR416**: Allowing QSEs to buy back RUC commitment and operate those Resources as self-committed Resources.
- **NPRR435**, Requirements for Energy Offer Curves in the Real Time SCED for Generation Resources Committed in RUC: Setting $1,500/MWh as the offer floor for RUC Resources in Security Constrained Economic Dispatch ("SCED"), to ensure formation of appropriate scarcity pricing when RUC Resources are dispatched for capacity but not for local reliability with local market power.

- **NPRR575**, Clarification of RUC Resource Buy-Back Provision for Ancillary Service: Allowing QSEs to carry Ancillary Services on Resources that are self-committed via the RUC buy-back process.
- **NPRR626**, Reliability Deployment Price Adder (formerly "ORDC Price Reversal Mitigation Enhancements"): Mitigates system-wide price suppression associated with the deployment of Load Resources and/or other blocky, "must-take" MWs, including the energy produced from between startup (0) and Low Sustained Limit ("LSL") from Resources committed via RUC and RMR. Output above LSL is priced based on the Resource's offer curve.
- **NPRR679**, ONOPTOUT for RUC Given After the Adjustment Period: Allowing buy-back by dispute using telemetered status adjustment for Resources committed after end of adjustment period.
- **NPRR 793**, Clarifications to RMR RUC Commitment and Other RMR Cleanups: Revision includes changing the COP status for an RMR Resource from "OFF" to "EMR" to ensure that the RUC engine doesn't recommend commitment of the RMR Resource ahead of other offline and available Resources.

Latest changes:

NPRR744, RUC Trigger for the Reliability Deployment Price Adder and Alignment with RUC Settlement, clarifies and improves the RUC buy-back process. The NPRR was approved by the Board on April 19, 2016, and effective in ERCOT systems June 1, 2017. These revisions streamline the buy-back process by allowing QSEs to opt-out of RUC settlement by telemetering a Resource status of ONOPTOUT during the first SCED interval the Resource is online and available to SCED during the first hour of a RUC commitment.

Previously, in order to opt-out of RUC, the QSE would need to update its COP prior to the end of the adjustment period or by dispute. COPs are updated hourly and are not always well-synched with real-time conditions.

The NPRR revisions will allow more time for a QSE to decide whether to be paid market prices or receive RUC settlement. In addition, these revisions will resolve inconsistencies between settlement treatment and the triggering of the Real Time Reliability Deployment Price Adder (RTRDPA), and will provide improved real-time information for ERCOT Operations to evaluate in making RUC decisions.

ERCOT Actions to Address Increases in RUC

The RUC optimization engine was recently changed in order to reduce the maximum shadow price (or penalty) from $1 million per MWh to $100,000 per MWh. This value sets a cap on the costs that the system could incur to resolve a transmission constraint. By lowering this value, the number of Resources the RUC engine would identify as being able to resolve the congestion decreases, thus leading to fewer RUC recommendations.

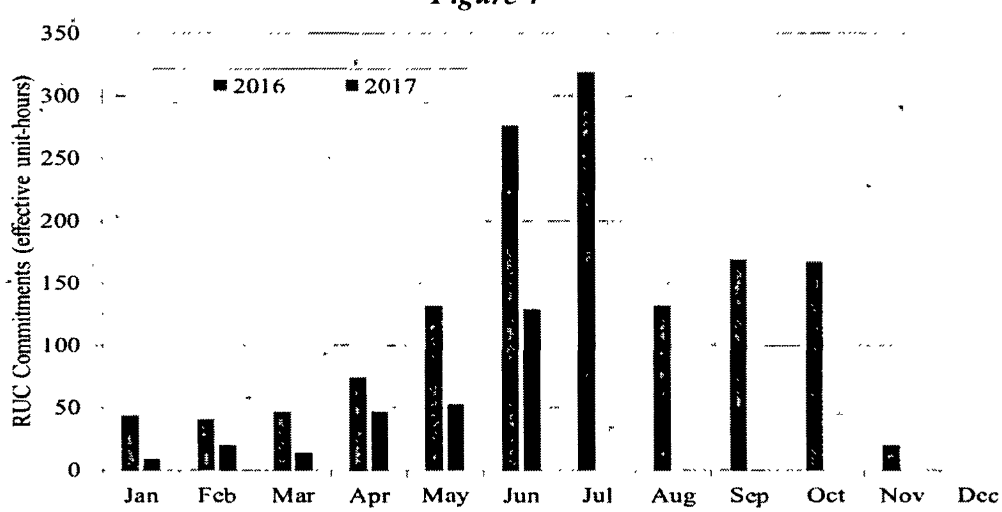
Additionally, the dashboard displays available to ERCOT operators were improved to provide operators with better visibility into the reason commitments are recommended by the RUC engine. In particular, the system now displays load distributed slack bus shift factors, which brings the information in alignment with how SCED inputs are displayed. This provides the ERCOT operator with improved ability to understand how effective a Resource would be in solving the congestion. Another important piece of information for the operator is the length of time it will take for a Resource to be online and available for dispatch following a commitment instruction. Recent improvements to another display provide the operator with more precise information on which Resources could be available in an hour or less, allowing the operator to identify options that could be available closer to real time.

In order to maximize available capacity that could be available in shorter lead times, ERCOT continues to improve tools that would allow the operator to see capacity from online combined cycle configurations that could be dispatched for congestion or, alternatively, add capacity to the system via RUC instruction. RUC optimization currently sees only a single configuration of an online combined-cycle Resource when making decisions on available capacity — potentially leaving significant capacity as unavailable to the RUC engine. This is a particularly challenging issue requiring modifications to settlement treatments as well as RUC engine functionality and logic rules.

Current Year RUC Activity

While it is still early in the year, there has been a reduction in RUC commitments through June 2017, as compared to 2016. There are likely multiple factors associated with this reduction and ERCOT does not imply any specific causation.

Figure 4



RESPONSE TO REQUEST No. 1.c.

A table listing potential out-of-market actions and the associated pricing rules is included as Attachment 1.

RESPONSE TO REQUEST No. 2.

As indicated during the discussion in this Project at the June 7, 2017 Open Meeting, ERCOT will require additional time to assess the potential need and/or cost of introducing a local reserve product or local operating reserve demand curves in conjunction with Real-Time Co-optimization ("RTC"). Although the potential need for a locational reserve product has been recently suggested, no specific design has been discussed. ERCOT has begun review of local reserve or Ancillary Service products used in other markets, investigating the basis for the locational reserve requirements to better inform the assessment of whether such local reserve requirements may be necessary or desirable in the ERCOT market. ERCOT will endeavor to provide the Commission with additional information as soon as practicable, but anticipates that it may take a couple of months to gather the appropriate information relating to the possible need and definition of a locational reserve product in the ERCOT market. As such, ERCOT will provide this information no later than a week prior to the Commission's October 12, 2017 Open Meeting. Finally, although an assessment of the potential need of a local reserve product remains ongoing, as indicated in ERCOT's recent filing in Project No. 41837, the estimates associated with the potential implementation of RTC have been developed under the assumption that the ability will exist to accommodate local reserve requirements if such requirements are warranted in the future.

RESPONSE TO REQUEST No. 3.

As indicated during the discussion in this Project at the June 7, 2017 Open Meeting, ERCOT will require more time to develop an estimate of the cost and time of implementing marginal losses into dispatch and pricing. As a matter of procedural history, the concept of incorporating marginal losses into the ERCOT nodal design was suggested in the development of P.U.C. Subst. R. 25.501 in 2003. At that time, the Commission chose to prescribe in the rule fundamental market design elements that it believed were essential, while leaving ERCOT the flexibility to address many other important design elements, such as the precise definition of nodal energy price.[9] Following the promulgation of P.U.C. Subst. R. 25.501, while there is indication of some discussion of marginal losses early in the Nodal Protocol development process, the concept never advanced to a stage of consideration to provide for the conceptual design documentation.

Consideration of these design and implementation details will require additional time to develop an implementation cost and time estimate, which ERCOT expects to be able to provide well in advance of the Commission's October 12, 2017 Open Meeting. However, all other organized electricity markets in the United States include marginal losses as a design feature, and based on review of these markets, ERCOT provides below a high level summary of the changes required to implement marginal losses in the ERCOT market.

Generally, changes will be required to the clearing engines for the Real-Time and Day-Ahead Markets ("RTM and DAM") to incorporate transmission loss sensitivity factors such that the marginal cost of transmission losses is included in the SCED and pricing. These changes do not require changes to the Congestion Revenue Rights ("CRR") auction process; however, with the introduction of marginal losses, locational marginal price ("LMP") differences will exist even at times when there are no binding transmission constraints (under the current approach of using

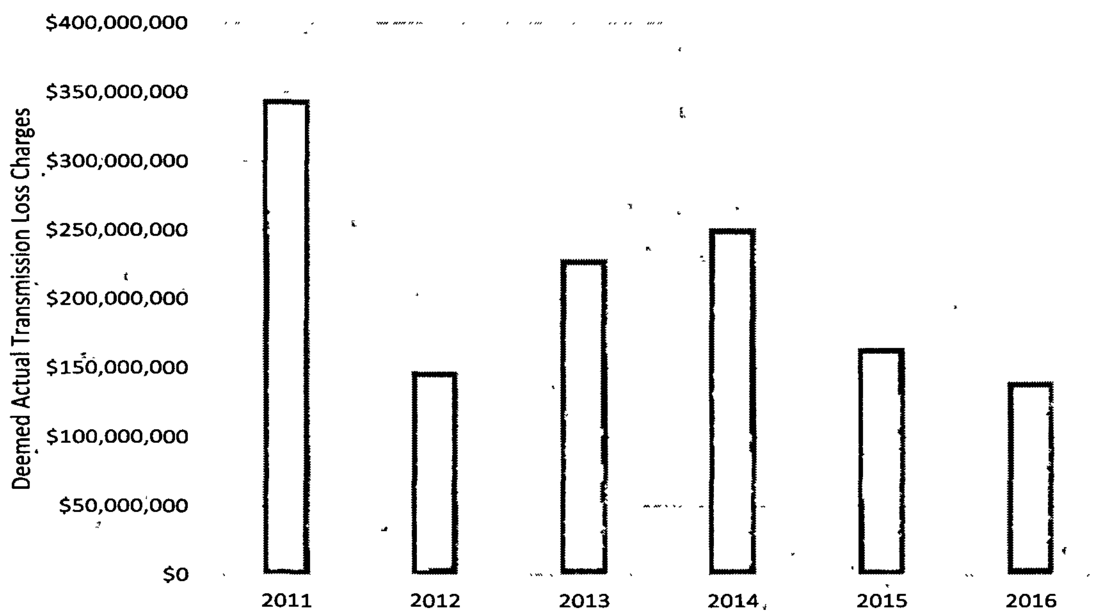
[9] *Order Adopting New §25.501 As Approved at the August 21, 2003 Open Meeting*, Project No. 26376, at 96-103 (Sept. 23, 2003).

average transmission losses, LMPs are equal at all locations in the ERCOT System when there are no binding transmission constraints). With the introduction of marginal transmission losses, LMPs would be separated into three components: energy, congestion and losses. In the DAM, CRRs would settle based only on the difference in the congestion component between locations. Prices for Point-to-Point Obligations purchased in the DAM would be based on the total LMP difference between locations in the DAM, and would be settled in Real-Time based on the total LMP difference between locations in the RTM. Because the cost of transmission losses would be included in the LMPs with the implementation of marginal losses, the volumetric adjustments for average transmission losses in the current settlement processes would need to be modified. Finally, because the revenues collected from marginal losses are approximately twice those collected from average losses, a mechanism would need to be developed to distribute these excess revenues (*e.g.*, in the PJM market excess total loss related revenues are allocated to transmission users on load plus export ratio shares).

Related to the marginal transmission losses discussion at the June 7, 2017 Open Meeting, Commissioner Anderson requested historical information related to the magnitude of transmission losses that have been allocated to Load Serving Entities since the implementation of the nodal market. Figure 5 below shows the annual total of deemed actual transmission loss charges for the ERCOT market from 2011-2016, ranging from a low of about $140 million in 2016, to a high of almost $350 million in 2011. While the deemed actual transmission loss factors vary somewhat from year to year, most of the annual variation in the deemed actual transmission loss charges shown in Figure 5 below is explained by changes in the annual average energy prices.

The values in Figure 5 are based on the methodology in ERCOT Protocols Section 13 related to the calculation of deemed actual transmission losses. Deemed actual losses for settlement intervals may vary from actual transmission losses, and such differences would show up as debits or credits to Unaccounted for Energy ("UFE"). Because ERCOT does not have historical actual transmission loss data, deemed actual transmission losses provide the best indication available of the historical cost of transmission losses that has been allocated to ERCOT loads on a Load Ratio Share basis.

Figure 5



ERCOT appreciates the opportunity to provide this information to the Commission and will be available to discuss any questions or comments at the Commission's July 28, 2017 Open Meeting as well as the planned August 10, 2017 Workshop.

Respectfully submitted,

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RELIABILITY COUNCIL OF TEXAS, INC.

ATTACHMENT 1 – Potential Out-of-Market Actions and Associated Pricing Rules

Number	ERCOT Action	Action Description/Triggers	How is this Addressed in Pricing?
1	Identify transmission constraints that may limit generation output and coordinate with TSPs and Resource Entities to identify alternative congestion management solutions, such as: a) Relaxing pre-contingency over-loads that can be quickly resolved post-contingency b) Making adjustment to network topology (i.e. restoring outages, changing phase angle tap positions, or making other configuration changes).	Advisory (PRC less than 3000) in cases where conditions are expected to deteriorate into EEA 2 or 3. Note that Operators will wait until the occurrence of EEA 2 or 3 before actually relaxing pre-contingency overloads.	These actions are intended to better reflect real scarcity pricing and does not need to be addressed.
2	Identify transmission constraints that may limit generation output and are associated with double-circuit contingencies. Coordinate with TSPs to determine if the double-circuit failures at a high risk of occurring.	Advisory (PRC less than 3000) in cases where conditions are expected to deteriorate into EEA 2 or 3. Note that Operators will wait until the occurrence of EEA 2 or 3 before relaxing double-circuit constraints that are not determined to be high-risk.	These actions are intended to better reflect real scarcity pricing and does not need to be addressed.
3	Deploy Non-Spin that has not already been deployed as part of a standing On-Line Non-Spin deployment.	a) PRC is less than 2500; or b) SCED-available capacity is less than expected 30-minute load ramp.	This is addressed by the ORDC Price Adder. In addition, On-line Non-Spin capacity is continuously released to SCED via a standing On-Line Non-Spin deployment and all Non-Spin capacity has an Energy Offer Curve price floor of 75 $/MW-h.
4	Release RRS capacity from Generators and Controllable Load Resources to SCED for scarcity conditions.	a) PRC is less than 2000; or b) SCED-available capacity plus expected 5-minute load ramp is less than 200 MW.	This is addressed by the ORDC Price Adder.

ATTACHMENT 1 – Potential Out-of-Market Actions and Associated Pricing Rules

Number	ERCOT Action	Action Description/Triggers	How is this Addressed in Pricing?
5	Commit available capacity through Hourly Reliability Unit Commitment or through manual instructions to avoid PRC dropping below EEA level 1 threshold.	Commitments are done as needed just prior to EEA 1. In EEA 1, all remaining available capacity is requested.	This is address by the Reliability Deployment Price Adder.
6	Commit available Reliability-Must-Run Resources.	Just prior to EEA 1	This is address by the Reliability Deployment Price Adder.
7	Request additional DC Tie imports, if available.	EEA 1	This issue is before the Commission in dockets involving DC ties, NPRRs are possible based on the outcomes of the dockets.
8	Deploy Emergency Response Service-30.	EEA 1	This is addressed by the Reliability Deployment Price Adder (Note that ERS is not currently considered in the ORDC Price Adder or ORDC reserves), although it was discussed).
9	Suspend any on-going Resource testing.	EEA 1	Does not need to be addressed.
10	Instruct TSPs and DSPs to use voltage reduction measures to reduce customer load, if beneficial.	EEA 2	None. The reduction in load is not quantifiable by ERCOT.
11	Instruct TSPs and DSPs to use available load management plans to reduce customer load.	EEA 2	None. The reduction in load is not quantifiable by ERCOT.
12	Deploy Emergency Response Service-10.	EEA 2	This is addressed by the Reliability Deployment Price Adder (Note that ERS is not currently considered in the ORDC Price Adder, although it was discussed).
13	Deploy Responsive Reserve Service being supplied by Load Resources.	EEA 2	This is addressed by the ORDC and Reliability Deployment Price Adders.

ATTACHMENT 1 – Potential Out-of-Market Actions and Associated Pricing Rules

Number	ERCOT Action	Action Description/Triggers	How is this Addressed in Pricing?
14	Issue a media appeal for voluntary energy conservation.	EEA 2 (if not already done earlier)	None. The reduction in load is difficult to estimate by ERCOT.
15	Use Block Load Transfers to transfer load to other Control Areas.	EEA 2	This issue is before the Commission. Revisions to Real-Time On-Line Reliability Deployment Price Adder Categories is a possibility.
16	Instruct TSPs and DSPs to shed firm load.	EEA 3	None. (Note that firm load shedding is not currently considered in ORDC or Reliability Deployment Price Adder, although inclusion was discussed). During EEA 3 prices should be at the SWOC.