Filing Receipt

Received - 2021-08-16 02:48:06 PM
Control Number - 52373
ItemNumber - 45

PROJECT NO. 52373

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

COMMENTS OF APEX COMPRESSED AIR ENERGY STORAGE, LLC IN RESPONSE TO PUBLIC UTILITY COMMISSION OF TEXAS QUESTIONS FOR COMMENTS REGARDING THE REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN

Apex Compressed Air Energy Storage, LLC (Apex), a Houston based power development organization, has been engaged for over ten years in development of the Bethel Energy Center, a 324 MW compressed air energy storage facility, to be constructed at the Bethel Salt Dome in Anderson County, Texas. Over the course of this development effort, Apex has engaged extensively with financial advisors, debt and equity capital providers in efforts to secure construction financing for the Bethel project. By virtue of this activity, Apex has a highly informed appreciation for the challenges of raising capital for new dispatchable generation in ERCOT, and it is with this understanding that Apex offers the following comments regarding potential changes to the ORDC pricing mechanism that could meaningfully enhance investor willingness to support new dispatchable generation in ERCOT. In addition, the operating characteristics of the Bethel Energy Center are ideal for supplying both firm, dispatchable energy and Ancillary Services. In this regard, Apex has closely followed market developments impacting the various Ancillary Services products and is pleased to offer comments intended to ensure that Ancillary Services markets will continue to function in a fashion that enhances reliability.

EXECUTIVE SUMMARY

PUCT question #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?"*

The current ORDC methodology has produced dramatic variability in year-to-year dispatchable margins. The most significant shortcoming with the existing ORDC curves is the fact that the majority of a generator's annual margin is dependent upon market conditions over a very few hours, resulting in a "feast or famine" outcome that is decidedly unappealing to investors. Over the past five years, Peaker Net Margin (PNM) has ranged from \$36/kW-year to \$163/kW-year, which translates to a cash yield (after fixed costs and taxes) of 1% to 12% per year.

The current methodology creates significant exposure to unplanned outages. The magnitude of the price cap (\$9,000/MWh) produces excessive risk to market participants. Both unhedged and hedged generators have exposure to the potential for unplanned outages that coincide with scarcity events. An unhedged generator can miss out on 70% of its annual profit opportunity by missing the highest priced 1% of hours. At the same time, a hedged generator that fails to perform during these scarcity hours would be exposed to liquidated damages that could offset multiple years of expected margin.

Under the current methodology, realized returns have failed to produce an investment profile attractive to investors in new dispatchable generation, nor has the current ORDC mechanism been effective in raising forward prices sufficiently to attract investor interest.

ORDC margin results are "benchmarked" against a flawed view of the cost of new entry (CONE) that is unrealistically low. Previous ERCOT and PUCT leaders, as well as the IMM, have focused on a comparison of generator margins to the estimated CONE for dispatchable generation when assessing the efficacy of scarcity pricing mechanisms. ERCOT's CONE calculations assume a relatively low weighted average cost of capital (WAAC) of 7.5%, based on an assumption of 75% debt leverage. However, this degree of leverage would only be achievable for a resource fully hedged on a relatively long-term basis (a minimum of 7 to 10 years). Unfortunately, the ERCOT market structure is not conducive to long-term hedging, as the sales agreements by unregulated retailers are relatively short term in nature. Notwithstanding this understated view of the CONE, the ERCOT market failed to produce sufficient margins to achieve this return in 4 out of the last 5 years.

The ORDC mechanism is a real-time incentive, unlike a long-term capacity market, and thus the appropriate CONE comparison is to an unhedged asset. An unhedged dispatchable resource will be financed primarily with equity, and a more realistic hurdle rate (WAAC) should be on the order of 12%, resulting in a significantly higher CONE than is currently estimated. Hence any adjustment to ERCOT's approach to scarcity pricing must not only produce more stable year over year margins, but also higher margins, before meaningful investment in new dispatchable generation can be expected.

The ORDC curve can be modified to produce higher generator margins with far less variability and less acute outage exposure. The number of hours with meaningful ORDC uplift and the aggregate uplift in the market would increase while simultaneously reducing the outage exposure for generators by:

a) Reducing the deemed Value of Lost Load (the price cap) from $9,000 to $2,000/MWh;
b) Increasing the Minimum Contingency Level (the level of reserves at which the price cap is reached) from 2,000 to 3,500 MW; and
c) Increasing the assumed standard deviation of reserves from ~1,200 to 1,260 MW.

The net result of these proposed adjustments would equate to a 12% unlevered return for a peaker (based on a back-cast over the period 2016 to 2020 and reflecting actual system lambdas and level of reserves). These illustrative ORDC curve modifications would have produced a 7x24 price of $34.96/MWh, an increase of $6.25/MWh over the actual average price over the 2016 to 2020 time frame.

PUCT question #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?"*

Firm, sustained energy supply from Ancillary Service (AS) providers is critical during emergencies, as evidenced by the February EEA event. A review of system conditions during the February 2021 severe weather event reveals a dire situation during the period between 11:00 PM on Sunday, February 14, and 3:00 AM on Monday, February 15, when ERCOT narrowly avoided complete system failure. Involuntary load shedding lagged the timing of ERCOT's instructions to the distribution entities, and energy deployment from AS providers was crucial to avoiding grid collapse during this time. Of critical importance was energy from resources providing Responsive Reserve Service from Generation (RRS-Gen), a service that plays dual roles in supporting the grid. During "normal" operations, RRS-Gen provides Primary Frequency Response (PFR), which is deployed often to offset frequency deviations, and is intended to arrest frequency decay in the event of a large generating unit trip. During emergency conditions (per the ERCOT Protocols), ERCOT calls on energy supply from resources providing RRS-Gen.

Energy Storage Resources (ESRs) with limited duration supplying RRS-Gen performed poorly during the EEA. A subset of ESRs provided RRS-Gen capacity during the EEA event, but delivered very little energy, notwithstanding the emergency requests for energy made by ERCOT. In fact, across the EEA withdrawals of energy exceeded energy supplied across the ESR fleet. More than one ESR moved their RRS-Gen responsibility to the Controllable Load Resource (the charging side of the battery) during an ERCOT request for 100% of RRS-Gen energy (and at a point when frequency was dangerously low). This behavior resulted in failure to provide both requested emergency energy and PFR.

ESRs have provided an increasing volume of AS in recent years, and given the substantial amount of planned battery capacity in the GIS queue, could largely displace conventional generators in RRS-Gen, Reg-Up, and Non-Spin (Up-AS) markets. Batteries built prior to 2019 generally have less than 1 hour of storage and participate exclusively in the Fast Regulation Markets. Batteries built in 2019 and afterwards generally have 1-2 hours of storage and are increasingly participating in the RRS-Gen market, with modest participation in Regulation-Up Service (Reg-Up). Projected battery additions are substantial, totaling 1.7 GW by year-end 2020 – these resources could come to dominate the RRS-Gen market – and potentially other Up-AS markets as well.

Because the timing and severity of grid conditions requiring AS energy deployment are inherently unpredictable, reforms are needed to ensure that any resource providing Up-AS in a given hour (or multiple hours) is capable of providing energy for that entire period. For an ESR with limited energy storage providing Up-AS, this means energy inventory should be sufficient to meet maximum possible energy deployment, with recognition that charging an ESR is prohibited during an EEA event and the timing and severity of EEA events are unpredictable. Further, if an ESR with limited storage duration desires to provide an Up-AS product during consecutive hours, consideration must be given to the potential energy delivery requirements over the entirety of consecutive award periods.

The PUCT could choose to separate the frequency management role and the emergency energy deployment role of RRS-Gen by creating a PFR product for provision by ESRs capable of managing frequency but not capable of providing energy delivery across each hour of an award. This new product should not reduce the volume of RRS-Gen procured – otherwise, reliability would be diminished.

Similarly, the PUCT should support creation of an independent market for Fast Responding Regulation Service Up (FRRS-Up). FRRS-Up deployments are limited to 90 seconds per event, and therefore FRRS-Up is not a sustained source of energy during emergency conditions. Current protocols stipulate that FRRS-Up volumes directly displace Reg-Up procurement, thereby reducing the amount of energy available during emergency conditions. FRRS-Up volumes should be procured independently of Reg-Up, and priced based on co-optimized offers for this service.

COMMENTS REGARDING PROPOSED MODIFICATIONS TO THE ORDC METHODOLOGY

The current ORDC methodology has failed to encourage significant new investment in dispatchable generation over the past 5 years. Since the beginning of 2016, operational thermal and hydroelectric resources have dropped from 65.9 GW to 65.2 GW, for a net reduction of 1% in the summer capability in the dispatchable fleet.[1]

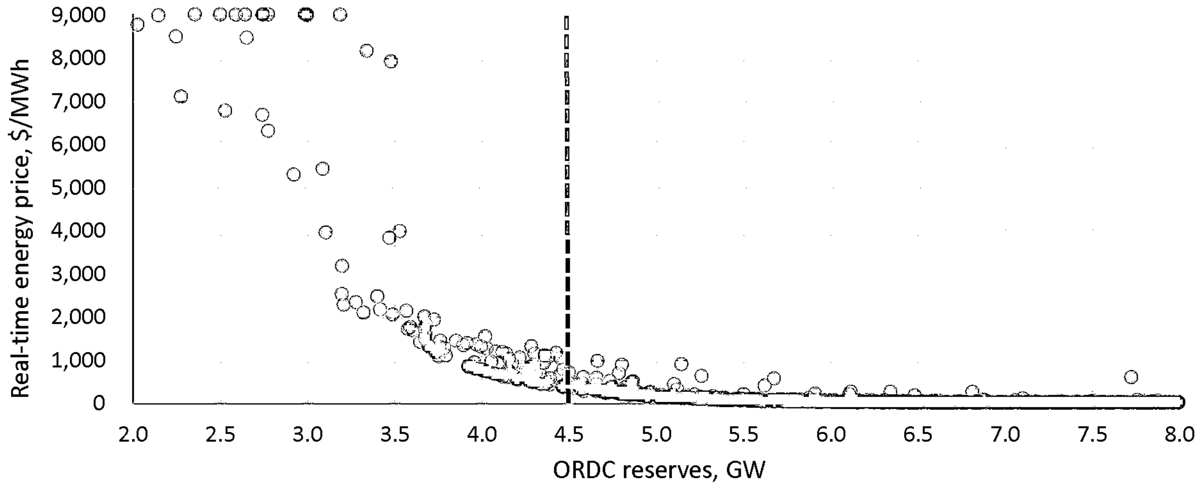
The current ORDC methodology has produced dramatic variability in year-to-year dispatchable margins

By concentrating the magnitude of the price adder to very few hours of the year, the current ORDC price adder creates a high level of sensitivity to unpredictable factors impacting reserves, such as weather variability, outages, wind production, and solar production in any given year, as well as longer term uncertainties, such as load growth, supply additions, and policy changes. ORDC parameters only produce meaningful price increases when ERCOT reserves below 4.5 GW, which is two large outages away from emergency conditions (**Figure 1**). Furthermore, conditions producing such tight reserve

[1] ERCOT Seasonal Assessment of Resource Adequacy (SARA), May 2016; ERCOT SARA, May 2020

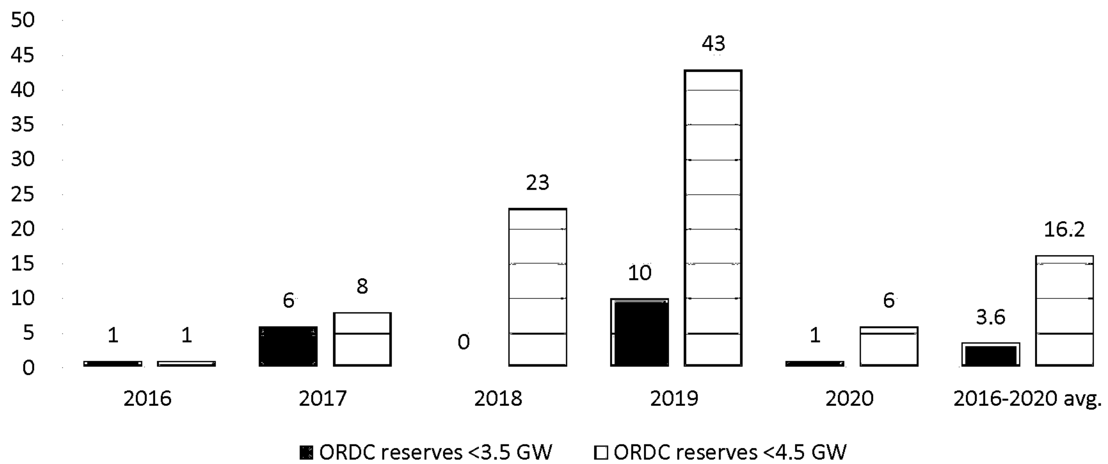
levels are exceptionally difficult to predict, and subject to the influence of a large number of events outside the control of a generator.

Figure 1 – 2019 Jul-Aug onpeak ORDC reserves and energy price (15-minute intervals)



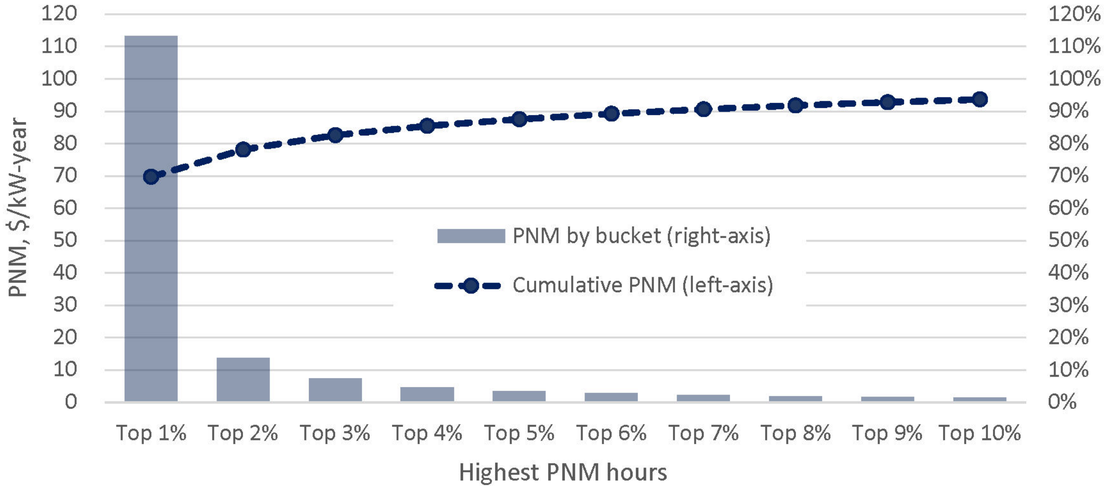
Over the past 5 years (prior to 2021), reserve levels below 4.5 GW occurred during as little as 1 but no more than 43 hours per year, and the greatest occurrence of reserve levels of <3.5 GW was in 10 hours of a year (**Figure 2**). The current ORDC parameters apply only to a small bit of the left-tail of ERCOT reserve distribution – less than 1% of all hours in a year.

Figure 2 – Hours per year with operating reserve levels below 4.5 GW and 3.5 GW



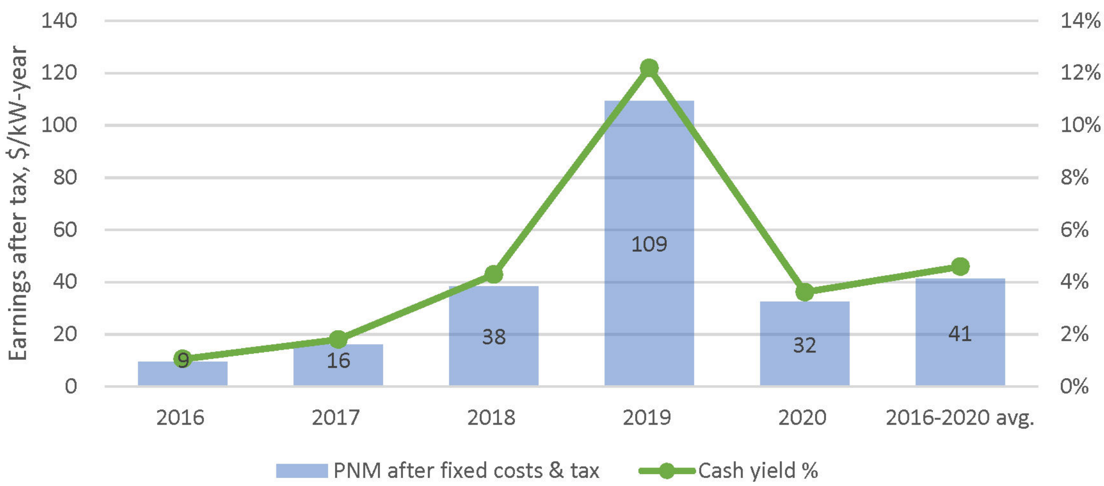
An astonishing 70% of the calculated Peaker Net Margin for 2019, the "best" year out of the last five in terms of scarcity and hence ORDC contribution, was earned in approximately 1% of the hours of the year (**Figure 3**).

Figure 3 – 2019 Peaker Net Margin ranked across the top 10% of hours



Evaluating PNM after fixed costs (e.g., O&M, property taxes, insurance, etc.), and after income taxes, more properly reflects the margin uncertainty to investors. After taxes, earnings for a peaker in ERCOT over the past 5 years have ranged from $9 to $109/kW-year, or 1% to 12% cash yields annually[2] (**Figure 4**). This wide range of earnings uncertainty is daunting to potential investors in new dispatchable generation.

Figure 4 – 2019 to 2020 Peaker Net Margin after fixed costs and taxes



Looking forward, the range of reserve uncertainty is likely to grow. Continued wind and solar capacity additions will increase the variance of reserves in peak net load hours; the wider range of reserve outcomes will make future margins even more unpredictable.

The current methodology creates significant exposure to unplanned outages

The uncertainty of reserves and extreme concentration of margins in very few hours creates an acute margin risk to unhedged and hedged generators. The average dispatchable resource will suffer unplanned/forced outages in 5% to 10% of all hours. If these unplanned outages occur during the top 1% of scarcity pricing hours (a low probability, but possible), the unhedged generator could sacrifice as much as 70% of its annual margin (see **Figure 3** above). Likewise, the concentration of extreme pricing in the top 1% of hours creates acute performance risk for hedged generators in long-term power sales

[2] Based on $898/kW (overnight costs) for combustion turbine, fixed costs of $24.10/kW-year, and 21% income tax rate

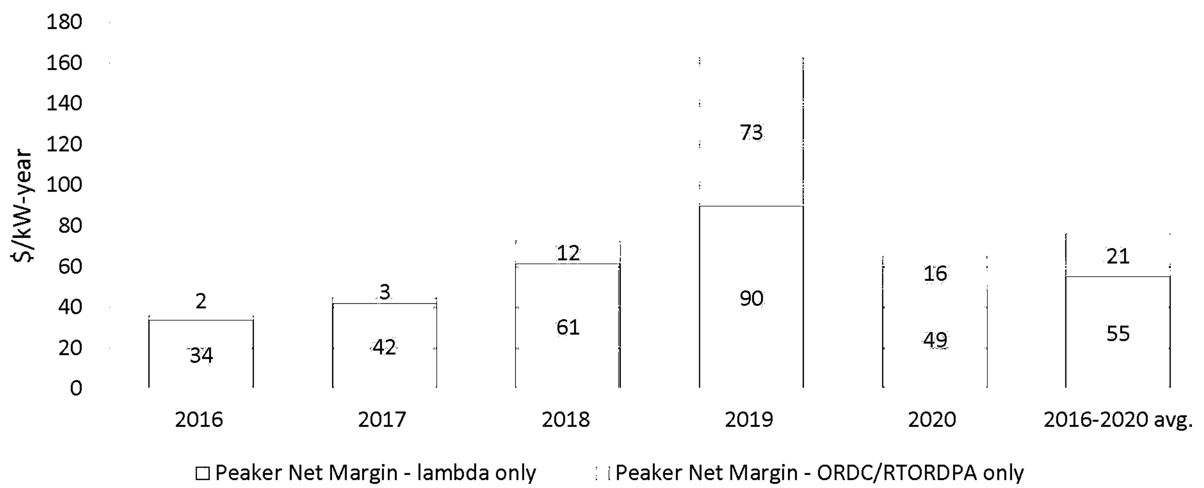
with "liquidated damages" penalties. If the hedged generator fails to produce during a scarcity hour, then it must pay replacement costs for the missing power.

ORDC margin results are benchmarked against a flawed view of the CONE that is unrealistically low

ERCOT's method for estimating the CONE, used to evaluate the efficacy of the scarcity pricing mechanism in producing attractive generator returns, is inherently flawed, resulting in an erroneously low estimate of $93.50/kW-year. At issue is ERCOT's assumption of an after-tax weighted cost of capital of 7.5%, based on an assumption of 75% debt-to-equity.[3] In today's capital markets, this high leverage rate and corresponding low WACC can only be achieved with a healthy amount of forward hedging – at least 75% of revenues for a period of 7-10 years. Unfortunately, the ERCOT market structure is not conducive to long-term hedging, as the sales agreements by unregulated retailers (representing ~75% of energy deliveries in ERCOT) are relatively short term in nature.

Municipal and Coop entities have ready access to capital and will construct new resources to meet their needs, but they will not build to supply the broader market. Further, the large incumbent generators have shown no willingness to construct new dispatchable resources – leaving ERCOT dependent on private capital (power generation focused private equity) as the source of funding for new dispatchable resources. Under the current ORDC construct there are few private investors with an appetite for unhedged merchant generation in ERCOT. Those investors willing to contemplate such an investment target returns in the mid to high teens. Taken together, these considerations support a conclusion that the current estimation of the CONE is not consistent with realities of the ERCOT market.

Figure 5 – 2016 to 2020 ERCOT Peaker Net Margin broken out by ORDC/RTORDPA vs lambda



From 2016 to 2020, the annual margins produced by ORDC price adders and marginal prices (i.e., system lambda) fell ~20% below the ERCOT estimate for CONE of $93.50 kW-year.[4] The annual value of the ORDC price adders has been highly variable, ranging from $2.66 to $72.92/kW-year (**Figure 5**); on average the ORDC and RTORDPA adders accounted for 28% of the Peaker Net Margin (PNM).[5]

While the exact cost of capital needed to "fix" the market is not readily knowable, Apex believes investor interest would increase significantly if projected margins were to increase to a level sufficient to produce after tax returns of ~12% for a

[3] "PJM Cost of New Entry", Brattle Group, Aug. 2018, pg. 35
[4] "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024", Astrape Consulting, Dec. 2020, pg. 21
[5] Peaker Net Margin calculated based on a 10.0 MMBtu/MWh heat rate and Katy Daily natural gas index.

dispatchable resource, under the further conditions that the year-to-year variability of generator margins and exposure to unplanned outages are reduced materially.

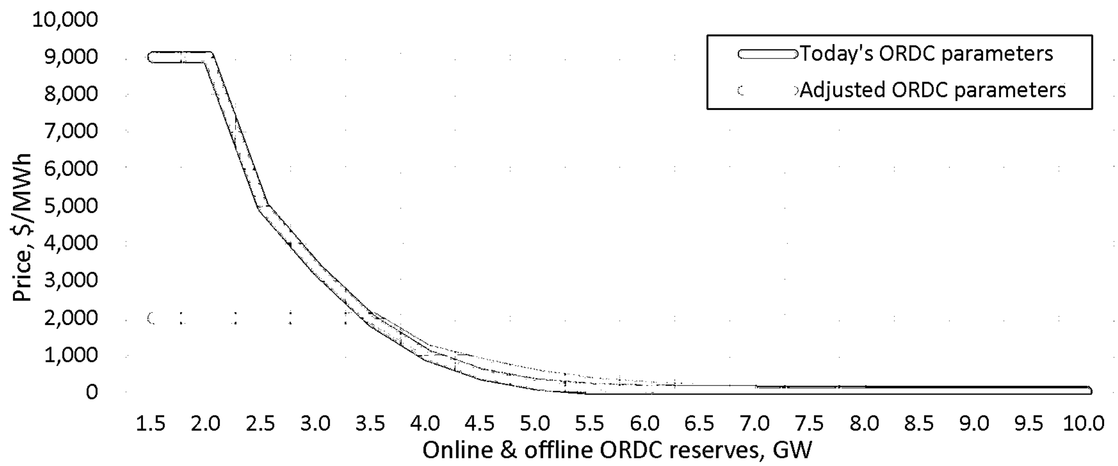
The ORDC curve can be modified to produce higher generator margins with far less variability and less acute outage exposure

There are three key variables in the ORDC methodology: 1) Value of Lost Load (VOLL or the price cap), 2) Minimum Contingency Level (MCL or "X", the level of reserves at which the price cap is reached), and the standard deviation of reserves (**σ**), which impacts the slope of the ORDC curve as reserves approach the MCL and directly impacts the number of hours with scarcity price adders. The current VOLL is $9,000/MWh, about 300 times the average annual price of power, the MCL is 2,000 MW, and the standard deviation of reserves varies by time period (but is generally ~1,200 MW). To produce a margin profile acceptable to new generation investors, Apex recommends that the ORDC parameters be adjusted as follows:

- **Dramatically increase the number of hours with meaningful ORDC price adders** with a higher standard deviation and higher MCL to reduce margin variability and increase the PNM level; and
- **Lower the VOLL/price cap** to reduce outage exposure and PNM variability.

Any number of variations in the key ORDC variables could produce pricing results more acceptable to investors. **Figure 6** depicts an ORDC curve that would produce the targeted 12% level of return based on trailing five-year historical system lambdas and reserve levels.

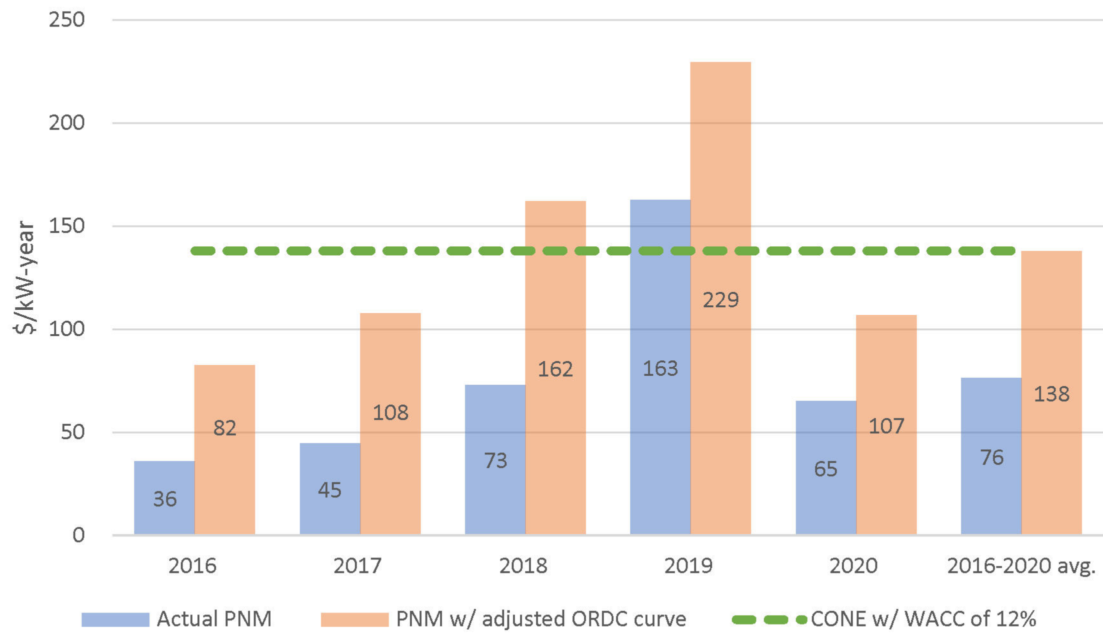
Figure 6 – ORDC curve aligned with CONE at 12% (VOLL = $2,000, X = 3,500 MW, σ = 1,260 MW)



In this proposed ORDC adjustment, the price cap has been dropped from $9,000 to $2,000/MWh, the MCL increased from 2,000 to 3,500 MW, and the standard deviation increased from ~1,200 to 1,260 MW. These adjustments "stretch" the curve, such that ORDC reserve levels between 4.5 GW to 6.5 GW produce prices ranging from $70 to $750/MWh, instead of $30 to $450/MWh. The adjusted curve exceeds today's curve at every reserve level until it reaches the new price cap of $2,000/MWh at the 3.5 GW reserve level. As pointed out above, less than 1% of all hours from 2016 through 2020 reached reserves below 3.5 GW.

The average realized PNM over the 2016 to 2020 period was $76/kW-year. Under the proposed changes, the calculated PNM over this period would increase to $138/kW-year. Annual cash yields (after tax) would range from 5% to 18%, instead of 1% to 12% experienced over the period. This recommended ORDC curve with a much lower price cap and many more hours with meaningful ORDC price adders would have produced PNM greater than $100/kW-year from 2015 to 2020 based on actual reserve levels (**Figure** 7).

Figure 7 – 2016-2020 back cast with Peaker Net Margins that reaches CONE at 12% vs actual PNM



Adjusting the ORDC parameters to find the "missing money" necessary to attract new dispatchable investment will increase average power prices. The recommended ORDC parameters presented above would result in a 7x24 price of $34.96/MWh, an increase of $6.25/MWh, or 22%, over the 2016-2020 average price.

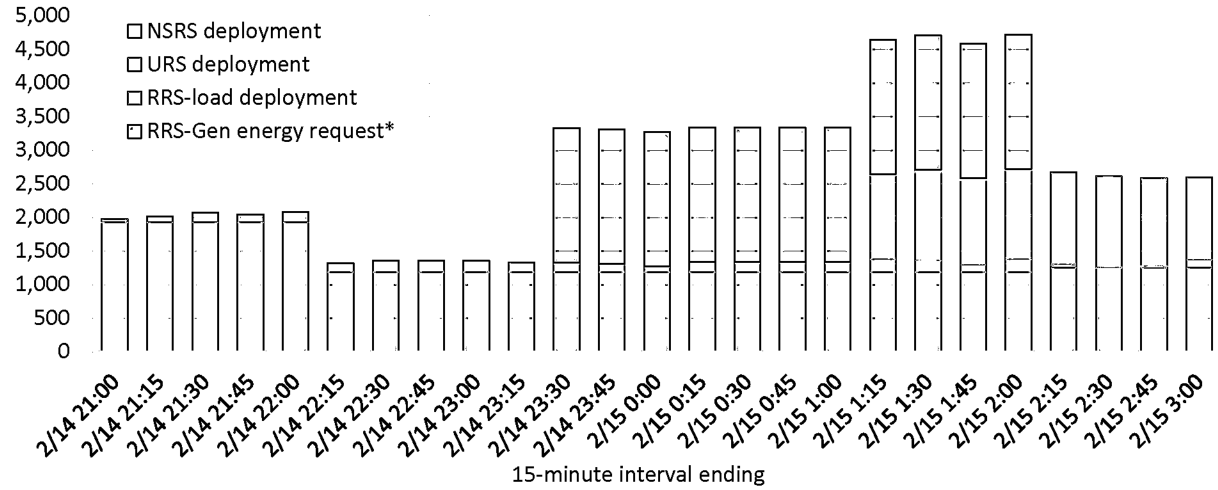
COMMENTS REGARDING CHANGES TO EXISTING ANCILLARY SERVICE PRODUCTS THAT SHOULD BE MADE TO ENSURE RELIABILITY UNDER A VARIETY OF EXTREME CONDITIONS

Firm, sustained energy supply from AS providers is critical during emergencies, as evidenced by the February EEA event

Historically, AS have been provided for the most part by thermal generation with the capability to provide "deployment" energy when called by ERCOT, constrained only by the resource ramp rate. In 90%+ of all hours, AS products help to balance supply and demand with relatively modest energy deployments. However, during emergency conditions, energy from AS providers can be critical to the avoidance of grid collapse, as evident from a review of system conditions during the February EEA. System conditions were particularly dire during the period between 11:00 PM on Sunday, February 14, and 3:00 AM on Monday, February 15, when ERCOT narrowly avoided complete system failure. Involuntary load shed lagged the timing of ERCOT's orders, and without energy from AS providers it is highly likely that the grid would have collapsed.

As shown in **Figure 1** below, ERCOT deployed all up-services (~4.6 GW) by 1:15 AM on February 15, at which time ~2 GW of energy came from RRS-Gen, 0.2 GW from Reg-Up, 1.2 GW from Non-Spin, and 1.3 GW from RRS-load. Energy from RRS-Gen resources was requested between 11:19 PM on February 14 and 2:03 AM on February 15 – this request remained in effect for almost 3 hours.

Figure 1: RRS-Gen energy requested, RRS-load triggered, Reg-Up deployment, and Non-Spin deployment by 15-minute interval during critical period of EEA, MW[6]



*Maximum RRS MW assumed to be sustained throughout the request; average RRS-Gen responsibility during this energy request was 1,951 MW

Approximately 15 GW of generation, online during the period shown above, is designed to trip when system frequency remains at 59.4 Hz/or for 9 minutes.[7] The system frequency was between 59.3 Hz and 59.4 Hz for ~5 minutes on the morning of February 15. Without the energy supply from AS providers, it is highly likely that the system frequency would have fallen below the nadir of 59.4 Hz, and remained below this level for a period of time sufficient to cause a grid collapse.

Energy Storage Resources with limited duration supplying RRS-Gen performed poorly during the EEA

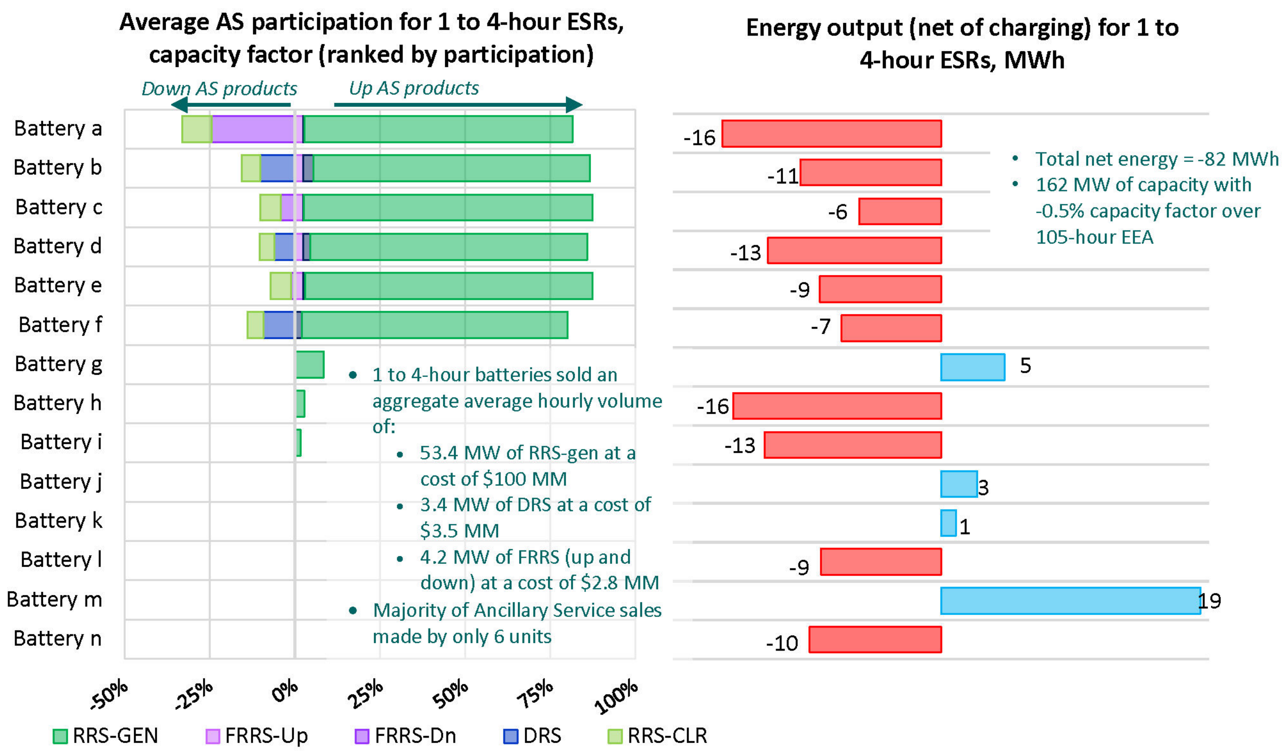
RRS-Gen energy is deployed in one of two ways: Primary Frequency Response (PFR),[8] or energy supplied in response to ERCOT requests during an emergency.[9] Throughout the EEA, energy delivered as a result of PFR-Up totaled only 0.9 MWh per 1 MW of RRS-Gen provision, while RRS-Gen energy requests totaled 19.5 MWh per 1 MW of RRS-Gen provision. There were several substantial requests for RRS-Gen energy, the longest of these lasted 8 consecutive hours, with another lasting for 6 consecutive hours. The reliability attributes of RRS-Gen center around the ability to respond to ERCOT energy requests. RRS-Gen can represent a pivotal value to grid reliability when online reserves are very tight, i.e., during an EEA event and/or when operating reserves are <3 GW, and online energy reserves are immediately needed to prevent severe under frequency conditions. ESRs with limited storage duration simply cannot provide multiple hours of energy reserves without recharging, which will be prohibited during future EEA events.[10]

A subset of ESRs (batteries a through f in **Figure 2** below) sold <u>multiple contiguous hours</u> of RRS-Gen throughout the event – far more than their storage duration could support in the event of substantial RRS-Gen energy requests. To remain active in the market (and thus earn payments for providing RRS-Gen), these ESRs minimized energy provision by offering

[6] Sources: ERCOT Market Notices, ERCOT Monthly Operations Reports, Apex estimate based on DAM procurement volumes, ERCOT Ancillary Service Capacity Monitor
[7] ERCOT Winter Event presentation to PDCWG, 8/11/2021: http://www.ercot.com/content/wcm/key_documents_lists/220125/Winter_Event_2021_PDCWG_08112021.pptx
[8] Per ERCOT protocols, PFR deployment occurs at significant frequency deviation reaching a frequency dead band (+/- 0.017 Hz from 60 Hz); RRS-Gen PFR is deployed instantaneously, reaching instructed level after 30 consecutive seconds – deployment duration is dependent on duration of frequency deviation outside dead band; RRS-Gen procurement volume provides online PFR to arrest the frequency drop associated with a sudden outage on the largest ERCOT generator (i.e., 2,850 MW South Texas Project) per NERC BAL-001-TRE-1; additionally, all online ERCOT resources with "headroom" also provide PFR at no cost, and the "no cost" PFR is typically 2 to 6 times larger than the RRS-Gen capacity; under "normal" conditions characterized by an ample supply of energy reserves, RRS-Gen PFR deployments are relatively small and easily accommodated by short-duration storage resources.
[9] Per ERCOT protocols, ERCOT can request capacity from resources providing RRS-Gen be released to SCED; it is then dispatched to provide energy when energy offer price exceeds the system lambda; output is expected to reach instructed level after 10 consecutive minutes
[10] Upon implementation of NPRR1002 (ercot.com) in early 2020

energy at the price cap, and opportunistically moving RRS-Gen responsibility between Generation Resource and Controllable Load Resource (CLR).[11] These ESRs received capacity revenues of ~$100 MM, but failed to supply requested energy – in fact, these ESRs had net withdrawals of energy across the entire EEA event.

Figure 2: Energy storage performance during February EEA[12]

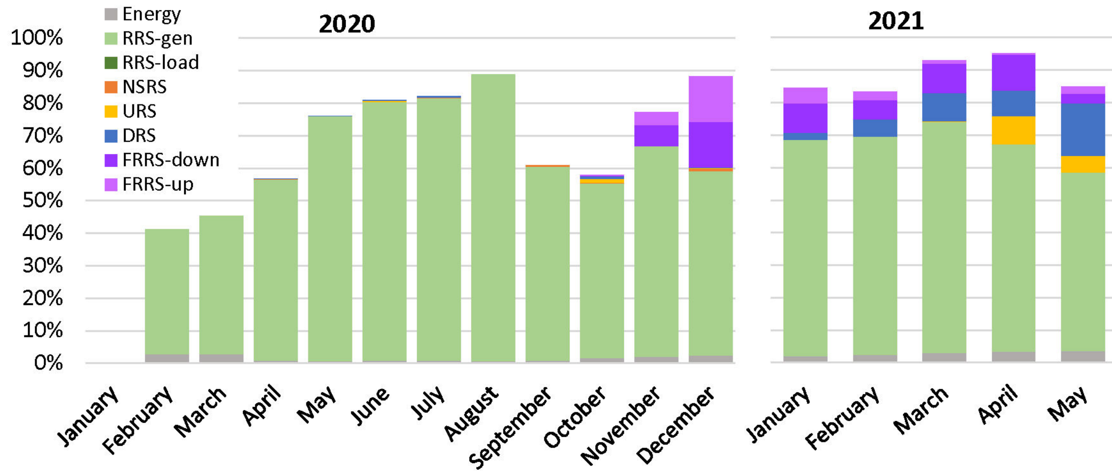


Energy Storage Resources have provided an increasing volume of AS in recent years, and there is a substantial amount of planned battery capacity in the GIS queue

Most batteries built since 2019 have 1 to 2 hours of storage duration. **Figure 3** below shows historical market participation by 1 to 2-hour batteries across 2020 and 2021. These ESRs have focused primarily on RRS-Gen with no material participation in the energy market.

[11] RRS-Gen can be offered from CLR, which represents the charging side of an ESR; data source: 60-day SCED resource data
[12] Apex analysis based on 60-day SCED data and Day-ahead Ancillary Services prices; analysis assumes output, charging, and AS capacity reported at the beginning of each 15-minute interval are sustained for that interval

Figure 3: ERCOT market participation by 1 to 2-hour ESRs, average hourly capacity factor[13]



The GIS queue indicates a substantial amount of planned battery additions – as of July 31, 1.7 GW of batteries are expected to be operational by year-end 2021 (the entire battery interconnection queue totals ~29 GW).[14] Based on available information, it appears that these new batteries are similarly short in storage duration, able to provide 1-2 hours of energy before recharging is necessary. Given historical AS market participation patterns exhibited by existing 1 to 2-hour batteries, it is likely that new batteries are designed to participate in RRS-Gen and Regulation markets.

While the February 2021 experience may be viewed as an extreme condition, as the contribution of renewable resources in ERCOT continues to grow, the variability of output from such resources significantly increases the potential for large generation shortfalls during high system demand periods, and in the future ERCOT can increasingly expect to see multiple hours when energy deployment from RRS-Gen resources will be needed to maintain reliability. Given the limited energy storage duration of batteries, displacement of thermal resources (possessing firm, sustainable energy delivery capability) by resources with constrained delivery capability, if not addressed by policy makers, will inevitably reduce ERCOT's ability to respond to emergency conditions.

Because the timing and severity of grid conditions requiring AS energy deployment are inherently unpredictable, reforms are needed to ensure that any resource providing Up-AS in a given hour (or multiple hours) is capable of providing energy for that entire period.

Recommendation 1: Reforms should focus on ensuring the energy delivery capability associated with provision of RRS-Gen, Up-Reg, and Non-Spin, all of which played a critical role during the February EEA event. To ensure Up- Services retain their reliability attributes and grid operators have access to dependable, sustained energy from these resources in an emergency, ERCOT should implement a requirement that any resource providing an hour of RRS, Up-Reg, or Non-Spin must be able to provide energy, if requested by ERCOT, for the entire operating hour. Qualification for AS should reflect the maximum potential energy deployment associated with provision of the AS product, with recognition that charging an ESR is prohibited during an EEA event and EEA events cannot be predicted with certainty.

[13] Source: ERCOT 60-day SCED reports for operating intervals January-December 2020 & January-May 2021; projects with SCED data indicating testing or very early operations were NOT included in the analysis for a given month; not all batteries actively participated across all months; output and AS responsibilities reported at the beginning of each Settlement interval are assumed to be sustained throughout the 15-minute period; ESRs built prior to 2019 (~85 MW) generally have a storage duration less than one hour and participate in the Fast Regulation markets exclusively (except for Castle Gap, which has four hours of storage and participates exclusively in energy). Batteries built during and after 2019 generally have a storage duration of 1-2 hours. This analysis focuses on the latter group.

[14] ERCOT Generation Interconnection Status Report, July 31, 2021

Further, if an ESR with limited storage duration desires to provide Up-AS during consecutive hours, consideration must be given to the potential energy delivery requirements over the entirety of the award period (i.e., a 2-hour resource should only be permitted to sell two contiguous hours of Up-AS at nameplate capacity at a time), assuming the resource is positioned to possess its full 2-hour duration at the outset of the first hour of service. Sufficient state of charge should be verified via telemetry to ERCOT operations.

In addition, providing RRS-Gen as a CLR should be prohibited during an EEA. Under the ERCOT Protocols, RRS-Gen can be procured from either a Generation Resource or a CLR; during normal operations (i.e., not during an EEA), RRS-Gen from a CLR is considered an equivalent product to RRS-Gen from a Generation Resource. During an EEA, these two types of RRS-Gen are not equivalent whatsoever, because CLR charging imposes a new demand on the system, crowding out consumer energy, and increasing the risk of physical/economic harm attributable to involuntary customer load shed. During an emergency, any RRS-Gen provided as a CLR instead of a Generation Resource represents a loss in energy deployment capability.[15]

Recommendation 2: For resources capable of providing PFR but lacking sufficient energy duration to fulfill the potential energy deployments across an hour of award for RRS-Gen, the PUCT may choose to create a separate Ancillary Service for procurement of PFR. If this approach were implemented, PFR volumes should not displace RRS-Gen volumes, otherwise reliability will be diminished. Further, a PFR product should be procured independently of RRS-Gen and should be priced based on co-optimized offers for this service.

Recommendation 3: ERCOT should create an independent market for Fast Responding Regulation Service Up (FRRS-Up). FRRS-Up deployments are limited to 90 seconds per event, and therefore FRRS-Up is not a sustained source of energy during emergency conditions. Current protocols stipulate that FRRS-Up volumes directly displace Reg-Up procurement, thus reducing the amount of energy available during emergency conditions. FRRS-Up volumes should be procured independently of Reg-Up, and priced based on co-optimized offers for this service.

Apex appreciates the opportunity to provide these comments and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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[15] The implementation of NPRR 1002 will prohibit charging during an EEA (unless a resource is providing down-regulation, FRRS-Down, or PFR-down). There is also language relating to ESR charging in Battery Energy Storage Task Force Key Topic Concept (KTC) 15.7 (http://www.ercot.com/content/wcm/key_documents_lists/190662/KTC_15-7_AS_Responsibility_Compliance_TAC_Approved_07292020.docx), which addresses the issue of Ancillary Service Responsibility compliance related to EEA Level 3 charging suspensions. It states that any AS responsibility carried on the charging potion of an ESR modeled as a CLR in the "combo" model era will be considered deployed under an EEA Level 3 but does not explicitly prohibit the provision of RRS-Gen from the CLR during an EEA.