Filing Receipt

Received - 2022-11-17 05:04:52 AM
Control Number - 54335
ItemNumber - 12

PUC PROJECT NO. 54335

RESPONSE OF JACOB MAYS TO COMMISSION STAFF'S REQUEST FOR COMMENTS ON REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)

1. Introduction

Jacob Mays is an Assistant Professor in the School of Civil and Environmental Engineering at Cornell University. His research focuses on the design and analysis of electricity markets. He holds an AB in chemistry and physics from Harvard University, an MEng in energy systems from the University of Wisconsin–Madison, and a PhD in industrial engineering and management sciences from Northwestern University. He is the lead author of the article "Private risk and social resilience in liberalized electricity markets," published in *Joule*, which discusses the electricity market design implications of the catastrophic failures experienced in ERCOT in February 2021.[1]

Section 2 of this document is intended to help interpret the modeling results of E3/Astrapé and reconcile them with competing results submitted by ICF. Section 3 discusses the narrow finding that none of the proposed reforms would provide net benefits to Texans and suggests ways to clarify the assessment of benefits. Section 4 describes the primary inadequacy of the modeling framework shared by both studies, accounting for which would likely strengthen the case for the risk-sharing aspect of the LSEO/LSERO/FCM proposals and weaken the case for the BRS as a long-term solution. Section 5 discusses the substantial administrative challenges associated with defining a separate product for resource adequacy and argues that the obligation should instead be structured as a contract settled around full-strength spot prices for energy. Section 6 concludes, and Section 7 includes more specific responses to select questions posed by Staff.

[1] Mays, J. et al. Private Risk and Social Resilience in Liberalized Electricity Markets. *Joule* 6(2), 369–380 (2022)

2. Reconciling E3 and ICF results

The ICF modeling represents a projection of short-run impacts upon introduction of potential market reforms, while E3/Astrapé examines a situation of long-run equilibrium. In my view, the goal of a durable design means that market reforms should be pursued primarily for their long-run effects. Nevertheless, the short-run analysis can be useful in guiding implementation decisions to avoid undue wealth transfers as part of any adopted reforms.

Dispatchable Energy Credits

While the two models give apparently conflicting top-line results with respect to Dispatchable Energy Credits, closer examination reveals greater consistency. Figure 32 in the ICF report exhibits consistently lower EBITDA for generators under the DEC proposal. This is consistent with the weaker entry of new resources (or accelerated retirement of existing ones) projected by E3. What this suggests is that the benefits of DEC projected by ICF are at best ephemeral, reliant on the finding that accelerated entry of storage may outpace the net loss of other resources in the near term. Had the ICF modeling reported results beyond 2030, I would expect degradation of reliability and higher costs to consumers relative to the results shown for 2027–2030. Overall, DECs offer no clear long-run benefit to consumers.

Reliability obligations

The ICF result that the LSEO is both expensive and ineffective is similarly focused on the short term. As indicated in Figure 19 of the ICF report, the annual net cost falls rapidly over the period studied. By construction, the LSEO/LSERO/FRM options target a level of reliability higher than what could be expected under the status quo. Accordingly, the market will inherently be in disequilibrium upon introduction of the new reliability standard. The ICF results highlight the importance of the timing any new requirements to avoid undue windfalls to the supply side of the market.

3. Assessing value for money

A fundamental challenge in the results from ICF and E3/Astrapé is that both studies report higher net system costs under any of the proposed reforms, seemingly implying that none should be pursued. On page 58, E3 reports for the LSERO/FRM case that "At an assumed value of lost load (VOLL) of between $5,000/MWh to $50,000/MWh, the total value of reduced loss-of-load could be between $62 million and $620 million per year; this benefit is not included in the total system costs." The incremental cost of the reform, meanwhile, is assessed at $460 million per year (Table 22). At first blush, this would seem to imply that to adopt the proposal, Texans must implicitly place a value on lost load of at least $37,000/MWh. Alternatively, it can be argued that the use of expected value to assess outcomes is inappropriate and an averse risk measure should instead be used to assess system cost. In either case, assessing the net benefits of the proposals could be more straightforward with a clearer assumption on the value of reliability. To be clear, I take no position on what the correct valuation should be. From a market design perspective, however, a higher valuation makes it even more important for long-run efficiency that consumers have a straightforward way to opt out their less critical loads.

4. Risk and market equilibria

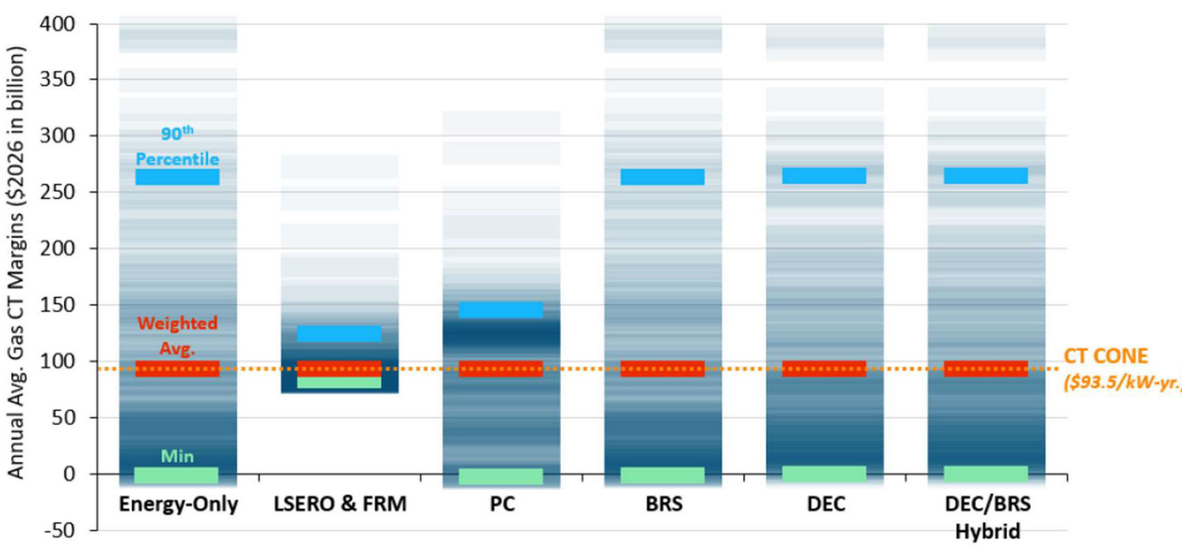
In the status quo Energy-Only case, E3 reports Expected Unserved Energy (EUE) of 14,093 MWh/yr (Table 16). An analysis performed prior to the outages in the February 2021 event using the same methodology estimated an EUE of approximately 2,300 MWh/yr.[2] Winter Storm Uri resulted in approximately 1,000,000 MWh of lost load, i.e., two orders of magnitude above the expectation found in the modeling studies. In other words, the modeling approach was clearly revealed by Winter Storm Uri to be inadequate in its assessment of reliability outcomes. Unless it is believed that Phase I reforms materially changed the situation, some skepticism around the modeling framework used by both E3 and ICF is warranted. This observation has a direct implication for market design: to achieve reliability commensurate with the modeling, the primary focus should not be on the choice of a reliability target within the chosen market

[2] Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region 2018 Update. Available: https://www.ercot.com/files/docs/2019/01/23/2018_12_20_ERCOT_MERM_Report_Final.pdf

construct, but rather on ensuring that markets perform smoothly enough that the chosen construct will deliver in practice.

In my view, the primary methodological shortcoming of the existing study framework is in its assumption that the cost of capital for new generation, as well as incremental investment in winterization or other forms of hardening, depends only on expected value of revenues and is invariant to investment risk. As discussed at length in the E3 report, the LSERO/FRM leads to substantially lower volatility in net margins for peaking resources (Figure 31). This risk reduction for supply resources makes the LSERO/FRM qualitatively different from the other proposals, which increase the revenue available to generators but have limited impacts on investment risk. For reference, I copy Figure 31 from the E3 report here, which displays the much higher floor on net revenues for peaking resources under the LSERO/FRM design.

Figure 31. Gas CT Net Margins Variability Across Market Designs[40]



It should be noted that there is not universal agreement as to the effect of this compression of the net revenue distribution on the cost of capital and investment equilibria. Indeed, the ICF report takes the opposing view, arguing that the short-term nature of the payment does not give additional incentives for risk-averse capital. In my view, however, investors are more easily able to finance around these less volatile annual revenues, leading to a greater reliability advantage for the LSERO/FRM over the other studied options than what is shown in the modeling results. At the same time, however, this does not imply that the LSERO/FRM is the best approach overall to facilitating risk sharing between consumers and investors in generation.

5. Ensuring value for customers

As indicated in Section 4, it is my view that the risk sharing aspect of the LSERO/FRM means it is the only proposal among the options studied that addresses the core issue. The failures of February 2021 were not primarily a matter of insufficient revenue available for generators; spot prices during the event were well above what would be needed to pay for incremental investment in winterization.[3] Instead, the issue was in translating the potential for high spot prices into forward-looking investments. As described in both the ICF and E3 reports, however, the administrative complexity of the LSERO/FRM approach is not to be underestimated, and there is significant risk that the program will either fail to deliver its promise of greater reliability or be unnecessarily expensive for customers. In my view, the E3 report understates those administrative challenges.

A primary source of confusion and inefficiency in resource adequacy constructs used across the organized wholesale markets in the U.S. stems from the fact that capacity itself has no value to consumers. What has tremendous value is energy during scarcity. In theory, "Capacity" or "Resource Adequacy" as a product derives its underlying value from the undercompensated sale of energy, especially during scarcity. What has set ERCOT apart historically is that the energy-only design already compensates energy during scarcity with spot prices that, while capped, are high enough to plausibly support an efficient level of reliability. In my view, the Commission should seek to retain those full-strength spot prices and organize the LSERO/FRM as a financial derivative around those spot prices. If the Commission wishes to establish a reliability target above what can be plausibly supported by spot prices under the current parameterization of the ORDC, the economically efficient approach is to adjust that parameterization upward until it is consistent with the reliability target.

Such an arrangement would likely have several advantages over the resource adequacy programs used in other U.S. markets. First, there would be clear value to consumers and no potential for "double payment." Second, there would be no need to establish penalties within the LSERO/FRM mechanism; non-performing suppliers would instead need to buy back their position at spot prices. In other words, non-performance risk would be explicitly held by generators rather than implicitly socialized across consumers. Third, the stakes of the

[3] Gruber, K., T. Gauster, G. Laaha, P. Regner, and J. Schmidt (2022). Profitability and investment risk of Texan power system winterization. Nature Energy 7(5), 409–416.

accreditation process would be far lower, as 1) cleared resources would be exposed to non-performance risk and 2) non-accredited or uncleared resources, despite the lack of a forward position, would still have the ability to realize the full value of services they are able to provide during scarcity events. This would help ensure that the market does not foreclose on future innovation by shrouding the value of resource adequacy in administrative processes.

Ideally, a contracting obligation would be structured in such a way that it complements other risk management being performed by retailers and electricity consumers in the market. Two notes are relevant in this regard. First, the risk sharing facilitated by the LSERO/FRM is particularly beneficial for peaking resources. This feature is highlighted in Figure 30 of the E3 report, which shows that ~90% of the net margins for the gas CT category are due to its reliability credit. As a consequence, the LSERO/FRM will be particularly effective in facilitating the financing of peaking resources. Without complementary instruments for other resources, this could lead to overreliance on gas relative to an efficient portfolio.[4] Second, the contract mandated through the LSERO/FRM may in some cases conflict with contracts (existing or future) that may be better adapted to the needs and preferences of market participants. Along these lines, the Commission should be aware of the potential for a mandatory contract to crowd out more effective risk management performed by market participants and may wish to enable greater flexibility for participants to satisfy obligations through alternative contracting.

6. Concluding thoughts

Two separate issues have compromised the ability of liberalized markets to deliver resource adequacy. The first, "missing money," refers to a condition that, when resources are adequate to achieve a given reliability target, revenues in the market are insufficient to support those resources in expectation. The second, "missing markets," refers to difficulty financing resources due to the underlying volatility in fundamental value and frictions in long-term risk sharing. In ERCOT, the second is the relevant concern. Efforts primarily focused on increasing the expected revenues to generators misdiagnose the core issue exposed by the February 2021 crisis and merely represent a transfer from consumers to generators with questionable benefit. The LSERO/FRM is the option among those studied that has the strongest effect on the problem of

[4] Mays, J., D. Morton, and R. O'Neill. Asymmetric risk and fuel neutrality in electricity capacity markets. *Nature Energy*, 4, 948–956 (2019)

missing markets and is thus the option among those studied that should be given the most serious consideration.

With that said, the LSERO/FRM as studied gives only a partial solution to the problem of missing markets and presents substantial administrative challenges. Depending on the evolution of the design, these challenges could lead to 1) compromised reliability as the product definition and accreditation increasingly diverge from actual system needs and resource contributions and/or 2) unnecessary cost to consumers as the system procures more of the ill-defined product to compensate for that divergence. In my view, the version of reliability obligation most likely to benefit consumers would take the form of a contract settling around full-strength spot prices. Such an approach could help resolve the problem of missing markets while preserving incentives and avoiding the most serious administrative challenges.

7. Responses to select questions

Q2: Would the PCM design incentivize generation performance, retention, and market entry consistent with the Legislature's and the commission's goal to meet demand during times of net peak load and extreme power consumption conditions? Why or why not?

A2: Any departure from full-strength spot prices will likely lead to poor incentives for generator performance and even worse incentives for the demand side of the market. Given its novelty, I am not yet prepared to offer a comparison as to how poor the incentives provided by PCM are relative to other proposals. More importantly, however, the PCM does relatively little to facilitate risk sharing and thus is unlikely to facilitate market entry to the degree modeled.

Q3: What is the appropriate reliability standard to achieve the goals stated in Question 2? Is 1-in-10 loss of load expectation (LOLE) a reasonable standard to set, or should another standard be used, such as expected unserved energy (EUE). If recommending a different standard, at what level should the standard be set (e.g., how many MWh of EUE per year)?

A3: The 1-in-10 standard is underspecified in terms of the length and depth of outages, and therefore difficult to evaluate based on the standard goals of market efficiency. If a single metric is to be chosen, expected unserved energy should be seen as superior. Regardless of which standard is adopted, consistency and efficiency suggest the adoption of mechanisms that have the potential to produce prices in the real-time market consistent with that level of reliability.

Q4: The E3 report examines 30 hours of highest reliability risk over a year. Is 30 the appropriate number of hours for this purpose? Should the reliability risk focus on a different measure?
A4: I am skeptical of any arbitrary choices for reliability risk, as it contributes to the potential that actual system needs will diverge from the product definition. This skepticism is part of my preference for full-strength spot prices, which are better able to reflect which hours and locations have the highest risk. In particular, proposing a fixed number of hours is could cause significant issues if and when ERCOT has a large quantity of battery (or other) storage operating in the market. If storage resources are expected to contribute to resource adequacy, then calculations become more complicated: production for several hours leading up to the hour of peak net demand becomes relevant for reliability, as it can affect the amount of stored energy available as the system approaches the peak. In the long term, it is preferable to have a market design that will be robust to this likely evolution in the resource mix.

Q9: If implementing a short-term design as a "bridge" delays the ultimate solution, should it be considered? Is there an alternative to a bridge solution that could be implemented immediately, using existing products, such as a long-term commitment to buy the additional 5,630 MW of Ancillary services necessary to achieve the 1-in-10 LOLE reliability standard?
A9: Regardless of the chosen long-term solution, it is my view that ERCOT should prioritize real-time cooptimization of operating reserves and institute dynamic sizing of ancillary services to reduce its present reliance on out-of-market Reliability Unit Commitment processes. The procurement of ancillary services should be primarily determined by real-time operational needs; depending on product definitions, modifying real-time procurement for the sake of resource adequacy would likely degrade efficiency in operations. A more theoretically sound approach would be to increase VOLL to achieve the 1-in-10 (or other) standard.

Q12: In what ways could the Dispatchable Energy Credit design be modified through quantity and resource eligibility requirements, e.g., new technology such as small modular nuclear reactors, in such a way that it incentivizes new and dispatchable generation?

A12: Regardless of design specifics, it is likely that that resources supported by DECs will merely replace unsupported resources, adding cost for little if any benefit.

PUC PROJECT NO. 54335

RESPONSE OF JACOB MAYS TO COMMISSION STAFF'S REQUEST FOR COMMENTS ON REVIEW OF MARKET REFORM ASSESSMENT PRODUCED BY ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3)

EXECUTIVE SUMMARY

In summary:

1. The Commission should prioritize the long-run equilibrium impacts of any design change but be aware of short-term wealth transfers caused by regulatory changes that could push the market farther from equilibrium. Results submitted by ICF should be understood as an analysis of potential short-term effects.
2. Reliability outcomes projected by the modeling should be interpreted with some skepticism given the failure of the modeling framework in the 2021 crisis. The primary issue is not determining the level of reliability that the market should be able to deliver in theory, but rather ensuring that the market will perform smoothly enough to deliver that level of reliability in practice.
3. From the generation investor perspective, the core issue in the energy-only market design is not insufficient revenue available in spot prices, but rather incomplete ability to translate the potential for that revenue into forward-looking investments. Facilitating longer-term risk sharing is likely to have a stronger impact on reliability outcomes than merely boosting expected revenues. The risk-sharing aspect of the LSERO/FRM option is a major advantage over the other studied options.
4. The administrative complexity of the LSERO/FRM option as studied is a significant risk. A departure from full-strength scarcity prices will lead to poor generator incentives, uncertain reliability outcomes, and unclear value for consumers.
5. As such, the version of the LSERO/FRM option most likely to yield benefits would take the form of a derivative settling around full-strength spot prices. This approach would ensure strong incentives for both generators and responsive loads and make the benefit to consumers clear.