An Economic Evaluation of the LSE Obligation Proposal

Ron McNamara, PhD*
December 10, 2021

FIRST
PRINCIPLES
ECONOMICS

From the Latin *Ab initio*, First Principles cannot be deduced from any other propositions – they are the only reliable foundation for discovery.

Analysis

Winter Storm Uri painfully made transparent the effects of mis-managing volume risk on the Texas electricity grid. The Texas legislature responded to the devasting storm by passing legislation with the intention that Texas is prepared when the next storm of Uri's magnitude hits the state. In effect, the legislature has done their job. Accordingly, the Commission has aggressively and diligently pursed an agenda over the past six months designed to put in place the policies and procedures that will meet the objectives of the legislature. Specifically, the Commission has been addressing the issue of ensuring that Texas has the necessary installed generation capacity to meet two identified problems; (1) the capacity needed to meet load growth while allow for retirements and outages, and (2) the capacity needed when intermittent resources are not able to produce. The latter has been defined as "dispatchable" energy or capacity, i.e., power that is independent of wind or the sun.

Following the discussion at the last meeting, the Commission has narrowed their focus to two possible solutions – the Load Serving Entity ("LSE") Obligation and the Dispatchable Portfolio Standard. The former is simply an obligation on Load Serving Entities to procure, via contract, 100% of their expected load 36-months in advance. The latter proposal is modeled after the Renewable Portfolio Standard ("RPS") that began in Texas in 2001 following the passing of the necessary legislation in 1999. Under the RPS program retail entities are given a requirement to purchase a specific amount of Renewable Energy Credits ("REC") based on the goals of the program every year. Failure to acquire the required number of RECs results in a penalty. The DPS proposal operates similarly. Retail entities will be given a requirement to procure a specific amount of Dispatchable Energy Credits ("DEC"). Failure to comply will result in a penalty. Just like the objective of the RPS program was to increase the demand for a specific type of generation, i.e., renewable generation, the objective of the DPS program is to increase the demand for a specific type of generation technology, i.e., generation that is dispatchable.

Volume risk is the risk that actual consumption will vary from anticipated consumption. While this risk is not unique to electricity, the consequences of not properly managing it in electricity are massively significant – as evidenced by the effects of Uri. When there is a supply/demand imbalance in other commodity markets, the price mechanism works to eliminate either excess supply or demand. In those instances when there is no price that will equilibrate supply and demand for a specific commodity the market has failed and there are three potential options for the participants – (1) involuntarily eliminate or (2) reduce desired consumption or (3) make use of a substitute commodity. The physical properties of electricity are well understood[1] and there is no benefit from summarizing them here. Rather our focus is on creating a commercial structure that will ensure the proper management of volume risk. The two previously mentioned proposals are exactly that – commercial structures designed to increase the amount of generation capacity in Texas.

These two proposals offer very different "visions" of the world. The LSE obligation is, in effect, backward looking and is an attempt to import certain aspects of the vertically integrated industry structure that existed prior to the implementation of non-discriminatory open access into the current framework. In contrast the DPS is forward looking and takes explicit account of the changing technological foundation of the electricity sector.

By integrating decisions regarding investment, production, transportation and sales into a single entity, vertical integration provided a "solution" to the management of volume risk. This solution reflects a specific technological base, i.e., economies of scale in the production of electricity. And while it may have been effective it was not efficient. The question raised by the requirements of SB3 is whether or parts of this model are transferable to the current situation.

[1]Specifically, the importance of Kirchhoff's and Ohm's laws.

The LSE obligation model mandates that all Retail Electric Providers ("REP") must contract for power to meet 100% of their expected load in 36 months. Under this proposal the REP has been given the explicit responsibility to manage volume risk for their customers for next three years. Failure to do so will result in fines. At its core, this requirement is precisely the same as what a vertically integrated monopoly would have faced twenty or more years ago. As is widely known this structure gave rise to the Averch-Johnson[2] effect in which regulated vertically integrated monopolies are incentivized to over accumulate capital.

The Commission should expect inefficiencies caused by REPs over-procuring their needed capacity as well as other inefficiencies that are inherent in this proposal. Over-procurement by the REPs is expected as a way for them to minimize the risk of market growth, growth in their share of the (expanding) market, and forecast error. The whole intent of the LSE Obligation proposal is to increase the demand for generation capacity. That the demand for capacity will be inefficiently increased beyond what it should be is the result of the likely way in which the REPs will manage the risks associated with market growth, growth in their share of the market and forecast error. While putting "steel in the ground" is the intended consequence, the Commission should also be aware of, and concerned about, the unintended consequences.

The standard structure of capacity markets is for the RTO/ISO to centrally create a demand curve via a forecast, accept capacity offers from approved resources, i.e., create a supply curve, determine the price of capacity, and finally, allocate the costs to load. The LSE obligation is based on creating a decentralized demand curve, mandating that each LSE find, i.e., determine the supply curve, and procure the capacity, i.e., determine the price, needed to meet their forecast. Accepting for the moment the subtle differences, broadly speaking the LSE obligation proposal will create a *de facto* capacity market in ERCOT, albeit one that relies on both decentralized forecasts, procurement and untransparent pricing. Given the similarity between the two, the questions of how and why the LSE obligation proposal will yield different results than a capacity market must be asked and answered. Furthermore, the two RTOs that share a boundary with ERCOT – MISO and SPP both have forms of a capacity market in place. In SPP and in the parts of MISO that are still regulated, capacity is procured through the standard regulatory process. Since MISO contains non-regulated generation as well, they administer a FERC-approved capacity market. Both markets enacted involuntary load shedding during Uri.

With respect to at least one difference between the LSE obligation and a centralized capacity market, the LSE obligation necessarily creates an added significant inefficiency. This inefficiency arises from the requirement that each REP will be responsible for deriving a forecast of their expected load and purchasing the necessary capacity to cover their own individual exposure. Thus, rather than having a single entity forecasting system demand in the aggregate 36 months into the future – and then either directly procuring or assigning the responsibility for procuring the necessary capacity – there will be as many forecasts as there are REPs and *each individual forecast will reflect their expected share of the aggregate load and not the aggregate load* itself. In other words, rather than having a single entity responsible for making the forecast of the total amount of load in 36 months, the LSE obligation proposal is based on having many different REPs forecast their own expected individual piece of aggregate load in 36 months. From the perspective of effectively and efficiently managing volume risk, this result is problematic. System reliability depends not on one or more REPs correctly forecasting their load but rather *all* the REPs being "correct."[3] Only when *all* of the forecasts are consistently correct will the

---

[2] Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". American Economic Review, **52** (5): 1052–1069.

[3] The argument that a diversity of forecasts will result in a more accurate aggregate forecast than if it is done by a single entity does not hold in this case because what is of interest is not the accuracy of any individual (or set) of forecast(s) but rather their accuracy in combination. That is, the system cares not about the accuracy of any individual REP but rather the accuracy of the

"correct" amount of capital be procured. Thus, the LSE obligation proposal introduces an inefficiency that is not inherent in the standard capacity market model.

Given these inherent problems the Commission should expect further integration of generation and retail activities, i.e., further vertical integration in the sector, resulting in further consolidation of the retail market. Why? Primarily because vertical integration is the appropriate way to manage the risks that are inherent in the LSE obligation proposal. Internalizing generation with load provides a natural hedge for the expensive "long" generation position and in the current environment it does so without the burden of regulatory oversight that buttressed the vertically integrated structure of the past. Similarly, capacity can, and in large part should, be procured "in-house" (lower credit requirements, reduced transaction costs, etc.) without any need to go to the market. Demand response initiatives will be muted and will take a back seat to the objective of covering the generation positions.

Regardless of these negative, largely unintended consequences, the central question remains – will the LSE obligation proposal solve the stated problem? The definitive answer to this question won't be known until the next Uri, but implicit assumption underlying this proposal is that more generic capacity will provide more reliability. It is important to understand that volume risk cannot be eliminated. Rather it must be managed. Any idea or belief that volume risk can be eliminated – short of getting rid of electricity – is unhelpful to the debate. There will always be some amount of volume risk and the objective should be to manage this risk such that, both now and in the future;

- We achieve the desired level of security, i.e., the optimal level of volume risk,
- Volume risk is allowed to "flow" to those best able to manage it, and finally,
- The desired level of security is achieved in the most efficient manner.

Accordingly, the question of whether the LSE obligation proposal will solve the problem can be restated as follows, will the LSE obligation proposal, if adopted achieve the desired level of security now and in the future, allow risk to flow to those best able to manage it now and in the future and lead to the least cost solution for managing volume risk now and in the future?

Concluding Remarks

The underlying premise of the LSE obligation proposal is that specific elements of the "old" vertically integrated paradigm in the electricity sector are still relevant and appropriate. In particular, the proposal assigns physical volume risk to a specific entity – the Load Serving Entity – and then requires them to forecast their expected demand 36 months into the future and procure 100% of the capacity necessary for them to meet their load. In this way it is similar to the capacity markets adopted by other RTOs/ISOs as well as the process used with regulated entities. Accordingly, it should be expected that, if adopted, the following results will occur:

- LSE's will over procure capacity.
- The aggregate amount of capacity procured will be inefficient relative to a centralized procurement process.
- There will be added incentive for the continued vertical integration of generation and retailing.
- There will be further consolidation of the retail market.

sum of all the forecasts. Even if the sum of the forecasts is identical to the aggregate forecast made by a single entity – the variance will necessarily be greater (higher risk) in the forecast made by many agents.

- There will be more churn – which does not imply more competition – in the retail market, as the vertically integrated companies seek to maintain their physical hedge.
- The spot or energy market will become less important for price discovery relative to the capacity market.
- New entrants as well as independent/stand-alone generators and retail market participants will be disadvantaged.
- Existing/legacy technology will be locked in and new technology, including demand response, will face barriers to entry.

* Ron McNamara is an economist with over 30 years of experience in electricity and energy markets. A former academic economist at the University of Auckland (New Zealand), he was responsible for co-designing and then implementing, operating, and monitoring the New Zealand wholesale electricity market, which was the first nodal-based competitive wholesale electricity market in the world. The New Zealand nodal-based market design is the foundation for all the electricity markets in the United States as well as the markets in Alberta, Central America, Singapore, and the Philippines. Subsequently as the Vice President of Market Management and Chief Economist with the Midcontinent ISO (MISO) market he was responsible for all aspects of designing and then operating the market. He served as a state regulator in Queensland, Australia with responsibilities over the electricity, natural gas, and ports sectors. In addition to his work in the United States, New Zealand and Australia, he has been involved in projects in Georgia (the country) the Philippines, Ghana, Nigeria, Pakistan, East Africa (East Africa Power Pool), and Central America (CRIE/CDMER) and has advised government and industry officials from Italy, Georgia, Canada, China, Japan, Singapore, Malaysia, Indonesia, Viet Nam, Thailand, Lao PDR, Cambodia, the Philippines, Guatemala, Honduras, El Salvador, Costa Rica, and South Africa on open access and electricity market design, implementation, operation, regulation and monitoring.