ERCOT's Growth and Adaptation to New Markets

Generation Capacity, Renewable Energy Subsidies, and the Operating Reserve Demand Curve

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Executive Summary

The first big test of Texas' transition to a competitive electricity market was congestion pricing. The Public Utility Commission of Texas (PUC) met this challenge head on by moving from zonal to nodal pricing that would better allocate congestion costs to those who caused them. However, the PUC is not taking such a direct approach to the current challenge of generation capacity. Renewable energy subsidies have brought increases in wind generation that reduce the price but not the economic cost of the state's energy. The reductions have, in turn, lowered incentives to build dispatchable generation, the absence of which will degrade reliability as intermittent power looms larger in the resource mix. Instead of directly addressing renewable energy subsidies, the PUC has chosen to broaden the use of its Operating Reserve Demand Curve (ORDC), the chief effect of which will be to raise generator revenues. The new process has replaced estimation of prices that would have prevailed absent the ORDC with a tool intended to stimulate generator revenues in hopes of adding reserves. If regulated prices under the ORDC increasingly replace market prices they will undermine competition in ERCOT. The PUC estimates that the cost of the change would be only $80 million if certain conditions are met. Other estimates discussed below, however, project that if this year's conditions resemble last year's, the outcome could be a $1.3 billion increase in power costs for Texas consumers that could grow to $2.5 billion by 2020.

The more efficient and economical resolution is to eliminate subsidies for intermittent renewable energy. If doing so proves politically impossible, the PUC's best option will be to reduce rather than expand the scope of the ORDC by directly changing ERCOT's rules to require that wind and solar operators rather than consumers bear the costs of intermittency. That cost will almost certainly fall short of the $3 billion that the augmented ORDC will impose on consumers.

Key Points

- Renewable energy subsidies have brought increases in wind generation which has lowered incentives to build the dispatchable generation that is needed to maintain reliability of the Texas electricity grid.
- Instead of directly addressing renewable energy subsidies, the PUC has chosen to broaden the use of its Operating Reserve Demand Curve (ORDC) that could lead to a $1.3 billion increase in power costs for Texas consumers that could grow to $2.5 billion by 2020.
- A more efficient and economical resolution than the ORDC is to eliminate subsidies for intermittent renewable energy.
- If eliminating subsidies proves politically impossible, the PUC's best option will be to reduce the scope of the ORDC by directly changing ERCOT's rules to require that wind and solar operators rather than consumers bear the costs of their intermittency.

Introduction

ERCOT was the first regional transmision organization (RTO) to be authorized by FERC, at a time when the full scope of potential wholesale power transactions was unforeseeable. At the start it was a set of rules for bulk power exchanges among transmission-owning utilities which operated their own weakly linked control areas. Beyond such vaguely defined standards as the Federal Power Act's requirement that rates be "just and reasonable," ERCOT's members and its regulators at the PUC had a nearly blank slate on which to design transactions for the rudimentary market environment that prevailed. Only with experience and experimentation do markets become more complex. The histories of other RTO markets, particularly California's, exemplify the costs and risks if operating rules are administratively imposed rather than seasoned through operating experience.

Markets develop as buyers and sellers explore the benefits that might arise from adding complexity to simple bilateral exchanges. Complexity evolves as the benefits come to exceed the costs of arranging and governing transactions. Prime among the benefits of more complex exchanges (e.g., forward relative to spot contracts) is the creation of valuable information that allows improvements in both short-term forecasting and long-term investment planning.

Here we examine four cases in which changes in ERCOT have altered the ranges of feasible transactions and markets that its institutions can support. For each case we address a basic question: how to compare the performance of markets imposed by regulation (often said to be "designed") with that of markets that evolve "organically" from simpler transactions.

If this year's conditions resemble last year's, the outcome could be a **$1.3 billion** increase in power costs for Texas consumers that could grow to **$2.5 billion** by 2020.

ERCOT Evolving: Background

ERCOT's markets have expanded in scope and grown in competitiveness. The 1995 amendments to the Texas Public Utility Regulatory Act deregulated wholesale generation and enabled ERCOT members to respond by restructuring operations. In 1996 they consolidated 10 fragmented utility control areas to form a nonprofit Regional Transmission Operator (RTO) under FERC jurisdiction. Unification facilitated simple exchanges among the members at a time when organized markets for reserves and other ancillary services did not exist. The paucity of transactors and the simplicity of their trades would have produced small benefits relative to the costs of setting up markets that might never come into being. In 1996 the alternatives grew when PUC rules allowed non-utility generators and wholesale power marketers to transact on their own accounts rather than have utilities make the choices for them as in the past. As the range of transactions grew with the proliferation of transactors, information became more valuable to all participants.

The value of market prices and market information further increased with rules that allowed "retail" competition for household and business consumers in 2002. As producers and marketers competed to offer service packages to heterogeneous customers, the benefits of market energy prices grew. Those prices both determined immediate profit and showed the most valuable sites for new generation and transmission. Information about demands became more valuable as new Retail Energy Providers ("REPs") competed to offer innovative delivery contracts and consumers sought supplies that matched their preferences, whether for rate stability or the warm feeling some got by paying premia for environmentally clean power. The institutions of production and distribution now centered around Qualified Scheduling Entities (QSEs), which would assemble wholesale power packages and sell them to downstream consumers and midstream intermediaries. As regulated prices were replaced by market prices, retail competition brought new risks that suppliers had not faced under regulation as their acumen in understanding markets would determine who survived and who failed.

Retail competition expanded both opportunities and risks. Beyond simple energy trades, QSEs would now pay competitive prices for reliability as they obtained (or sometimes self-supplied) reserves and other ancillary services. Under traditional regulation a monopoly utility could often pass on the costs of its mistakes, but now they were priced in competitive markets. Some competitive outcomes would be measured almost in real time as a "balancing market" priced energy shortages and surpluses over periods of minutes. Other power would flow under wholesale contracts at whatever terms the parties could reach agreement, and even the small amount (usually below 5 percent of the total) of balancing market throughput now carried a competitive price. As markets grew, so too did the value of exchanges with more complex time dimensions that facilitated planning (e.g., day-ahead markets for energy and ancillary services). The growth of ERCOT and its markets was not pre-planned by any single entity that operated in them. Rather markets co-evolved with changes in the legal and technological environments they operated in.

The Four Cases

Nodal Prices

The transformation from zonal to nodal prices changed ERCOT's inefficient system of markets to a more efficient one. ERCOT was mapped into four zones with a surcharge on each megawatt of power that crossed their boundaries. The surcharges were not true market prices that indicated scarcity. Instead they were based on historical costs and patterns of use, making them inadequate for determining the future costs and benefits of relieving a transmission constraint. Perhaps more importantly buyers and sellers whose transactions actually caused congestion were only coincidentally paying for it because the old system averaged ("uplifted") its cost over a wider area. Actual operation corresponded poorly to changing system conditions because zoning rules often froze inefficient historical patterns of generation and transmission use.

If competition were to grow and produce more efficient patterns of transmission investment and use, the simple algebra of a zonal system was unsustainable. Some market participants would be located in zones where they consistently received payments determined by locational peculiarities rather than supply and demand factors, while those less fortunately located would pay. In the longer term the zonal system's inefficiency was compounded because generators would not locate new plants where their output was most valuable but instead chose locations that offered them the largest transfers. No matter how many zones are mapped, prices determined by a formula will at times be economically inefficient because the value of power at a given location varies with conditions everywhere on the grid.

The transformation from zonal to nodal prices changed ERCOT's inefficient system of markets to a more efficient one.

Under nodal prices, bottlenecks are visible at locations where market participants would bid to relieve congestion. The prices would encourage investment at the critical spot and at others in the region where the effects of the given bottleneck ("spillovers") would also be felt. Nodal prices acknowledge electrical reality, while a zonal system conceals risk and inefficiency by maintaining uniform prices in locations where they should be fluctuating. Further, a nodal system accounts for congestion between two points by requiring generators and/or loads to pay for the right to crowd available capacity. Market participants can now hedge unpredictable nodal prices by purchasing congestion revenue rights (CRR) through regularly scheduled auctions run by ERCOT. The holder of a CRR has bought the right to receive a profit if actual charges turn out to exceed the auction price. Prices in ERCOT's nodal market now better reflect actual scarcity conditions than they did when prices were determined by *ad hoc* formulas. The shift to a nodal system was necessary for sustaining competition in ERCOT.

Generation Adequacy and Markets for Capacity

Assurance of sufficient generation to meet load in newly competitive markets has been the most important organizational issue faced by ERCOT. Its importance is best illustrated by examining choices that the RTO declined to make. Midwestern and northeastern RTOs chose to institute a compulsory planning process to ensure that generation capacity in their areas would meet projected future loads and be constructed in amounts that ensured adequate returns to investors. Had ERCOT chosen a mandatory capacity market, its members would likely be seeing problems similar to those in other RTOs, most importantly the Pennsylvania-New Jersey-Maryland Interconnection (PJM), which extends into the Midwest.

Elementary economics suggests that an industry with durable capital goods can sustain itself whether it is competitive or monopolized because profit-seeking producers will compete to put new capital in place when doing so is warranted. Unexpected events or poor forecasts in any market can lead to mistakes in retrospect, but we can expect that producers will rationally allocate their resources between current production and long-term investment. Mandatory capacity markets have been phenomena in quest of a rationale since their inception. Advocates believe that generation adequacy demands centralized planning and decisions, but there are no clear reasons for instituting them either in theory or practice. Milk passes through wholesale and retail markets on its way to the consumer, transacted at every level at prices measured in dollars per gallon. The milk industry's survival suggests that there is little rationale for a fluid milk market that operates in tandem with one for "cow capacity," since long-term milk prices must cover costs of both types. Similarly, any utility will rationally choose a mix of baseload, intermediate, and peaking generation, and there are few reasons to expect chronic underinvestment in some subset. Even if there are difficulties, history gives few reasons for optimism about investments compelled by regulators.

Some capacity market advocates claim that they alleviate a hypothetical problem of "missing money." Specifically, they expect that price in a competitive market (like those for energy in RTOs) will be driven down to marginal cost and leave owners of depreciated generators with insufficient revenues to replace them. We do, however, know that firms in capital-intensive industries usually survive and reinvest using both retained earnings and funds elicited from the capital markets. ERCOT, by contrast, offers strong evidence that a mandatory capacity market is not necessary. Its "energy only" system allows free entry of generators and imposes no capacity requirements. A glance at ERCOT history tells an almost uniform story: in any given year, ERCOT's reserves suffice to meet its requirements, but today's commitments for generation five years ahead will leave it with reserves that will not meet standard reliability criteria. As time passes additional capacity is built and reserve inadequacies corrected as market forces incentivize additional construction (the recent unexpected retirement of four coal-fired generators would have affected ERCOT's current reserve position whether or not a capacity market existed). We know little about the financial performance of plants in ERCOT because unlike most regulated states Texas does not require extensive disclosures for individual generators. They are governed by voluntary and confidential contracts of the type that might be encountered in any competitive market (Michaels). The record of steady growth and reinvestment in generation thus far, however, shows that those plants can be funded by competitive capital markets.

History gives few reasons for optimism about investments compelled by regulators.

It is becoming clear that RTOs with capacity markets have neither lower costs nor superior reliability relative to "energy-only" organizations like ERCOT. There are several plausible explanations, but the most important may come from the economic theory of regulation. Despite the seeming precision of some estimates there is no consensus definition of a generator's capacity value, which depends on both RTO operating practices and the composition of its generation fleet and power purchases. Even with a well-defined figure for capacity value, we face the problem of aggregation over plants with different locations and operating characteristics. Problems of commensurability are becoming more acute with the rise of intermittent wind turbines and proliferation of such uncertain sources as demand response. Despite assertions that PJM policy facilitates competitive generation markets, its most important functions appear as throwbacks to the era of comprehensive regulation. A new generator is warranted if PJM determines that its value exceeds an assumed "cost of new (generator) entry (CONE)." PJM's planning process incorporates such calculations as its "Minimum Offer Price Rule" to ensure that new generators will not be built in volumes and locations that depress prices by enough to make existing plants unprofitable (Morrison, 9). This is more reminiscent of cartels than competition, and it may not be surprising that the governments of PJM states are strongly opposed to such attempts to support high-priced power. Despite the conflict with competitive ideals, FERC has prohibited new state-subsidized plants that would reduce regional prices on grounds of federal regulatory preemption.

"Planning for competition" with price-fixing and command-and-control policies like PJM is an oxymoron that has in practice brought few of the benefits of real competition. Its experience has been that planning begets more planning, which is largely necessary to undo errors and omissions in previous plans. The difficulty in PJM is one commonly discussed by supporters of competition: Administratively controlling a single price or product in a complex system is generally impossible because doing so spreads related shortages and surpluses around the market, necessitating further controls. The more complex the system the harder these problems will be to undo, particularly because past investors will have made commitments based on rules that they expected would determine profitability and would continue in effect. A filing at the PUC by industrial power users stated:

> *"Each and every aspect of a forward capacity auction must be administratively determined, leading to contentious stakeholder debates, regulatory decisions, and subsequent litigation, as demonstrated by the experience in PJM. There are approximately 50 separate, voluminous documents governing the PJM capacity auctions. Even assuming that the MOPR [minimum offer price rule] and locational capacity markets are not created this would only reduce the number of governing documents by four"* (TIEC 2012, 7).

By contrast, ERCOT is the embodiment of simplicity. Unlike PJM's planning process, ERCOT's reliability assessment exists for advisory purposes only and does not impose any investment requirements on generators (ERCOT 2018). ERCOT requires that QSEs submit operating plans for all resources they represent and leaves them individually responsible for obtaining required ancillary services in the day-ahead and real-time markets or from their own resources. A generator or marketer may self-supply or go to those markets for reserves and does not face a "hard" requirement that it hold certain types of assets (ERCOT 2019). Perhaps the most disturbing outcome of PJM's centralization is that its policies have failed to modernize generation. As of 2018, PJM consumers had paid or were pledged to pay $102 billion in capacity charges through mid-2021, or approximately $1,700 per resident in its footprint. In reality, over 90 percent of capacity procured through PJM's market has come from already-existing power plants and only 2 percent from new and reactivated generation (APPA, 2). The perverse incentives are clear: Why take chances on a new plant when you can get liberal (and guaranteed) capacity payments for owning an otherwise obsolete one?

ERCOT and PJM illustrate the two broad ways in which market participants adapt to disruptive change. In an ordinary market, competition takes the form of adjustments that are determined by economic factors. That competition eliminates suppliers who are slow to adjust and replaces them with those more competent in devising efficient ways to profit from the change. Disruptions also affect regulated markets, but in them political competition may supplant rivalry in markets. Rent-seekers can direct their efforts toward obtaining wealth through politics, which is less likely than market competition to be a positive-sum game. PJM has some aspects of a market system, but it is also so politicized that political choices are often dominant. For example, PJM assigns largely arbitrary capacity values to demand response and investments in efficiency, sometimes compounding the difficulties by imposing uniform policies in situations that should vary with the underlying economics. ERCOT is at the other pole, more heavily reliant on economic principles, allowing choices in contracting rather than mandating the details of market relationships. PJM's capacity provisions essentially memorialize and perpetuate past generation investments while those in ERCOT acquire their value by being more efficient for the future.[1]

Renewable Subsidies and Negative Prices

Like some other RTOs, ERCOT at times experiences intervals when its real-time energy price is negative. In 2015 its North Hub displayed them in approximately 1.5 percent of all operating hours (Wiser, 27). In effect a negative price means that generators are paying users to take power. This happens because the federal Production Tax Credit (PTC), accelerated depreciation, and various state-level subsidies allow producers to bid negative prices and still make a profit net of subsidies. Even with no fuel costs, the market price of power must on average be high enough to facilitate capital investments, but a subsidy reduces that price. Subsidies to wind generation bring additional costs because this power is only useful as a component of a steady regional flow, which in Texas requires other investments the cost of which are not borne by wind generators. We now have an "externality" problem that economists will find familiar: investment in wind generation is excessive because its full costs to the economy exceed those incurred by the generation owner.

The importance of marginal costs and differences in generator efficiencies allow us to characterize situations conducive to negative market prices. They are more likely when ERCOT is experiencing "minimum load" conditions that require operating some dispatchable fossil-fuel generators (that cannot instantly adjust production) in anticipation of higher loads later in the day. Energy prices below zero are seldom seen, but excessive wind generation lowers the price of all energy in the market. This reduces incentives to build dispatchable fossil-fuel generation that will be needed for reliability as intermittent wind power looms larger in the resource mix. Resolution of the negative price problem leaves a difficult choice: its roots are in regulations the content of which is jointly determined by engineering reality and subsidy policies. Undoing them will require important changes in policy with no guarantee that the outcome will be closer to that of a competitive market, particularly if viewed in light of the history of federal power regulation. A full assessment of the options will require consideration of all the costs of wind power's proliferation and the formation of a rational program to minimize them net of any associated benefits. Intermittent generation is growing, but Texas has yet to see studies that will allow an evaluation of its full costs and benefits.

The Operating Reserve Demand Curve (ORDC)

The ORDC is an intervention that initiates shortage pricing as ERCOT reaches the limits of its reserves. Under current procedures, energy and reserves are traded in separate markets, but as the system is stressed (often by renewable energy subsidies) the expected relationship between their prices can become a misleading indicator of economic scarcity. Specifically, energy prices may be low (indicating relative abundance) while prices for reserves are high enough to indicate a shortage that could potentially affect reliability.

The problem's underlying sources are market distortions that can change normal relationships between prices and scarcity and can give rise to negative prices. Most important is the wind PTC, a federal policy that ERCOT cannot alter. The PUC, however, has some powers to modify its consequences. The ORDC is an attempt to place a value on reserves that reflects their actual scarcity and adds it to the energy price in the expectation that doing so will incentivize additional production of energy and reserves. The value on the ORDC (the "Real Time Price Adder") can increase

1 "James Wilson, a consultant to the consumer advocates for New Jersey, Pennsylvania, Delaware, Maryland and D.C., said he agreed with APPA that capacity markets are a 'very expensive and very administrative and very inefficient way to' ensure resource adequacy. 'The capacity market is one way to go,' Wilson said. 'The other way is what ERCOT is doing. ERCOT's got an energy-only market and every few weeks you read about another new power plant'" (RTO).

up to the Value of Lost Load (VOLL), currently set at $9,000 per MWh. The ORDC is currently triggered when available generation falls below 2,000 MW.

The ORDC is unrelated to demand curves familiar in economic theory, because it is not a consequence of market choices by producers and consumers. It is instead a regulatory creation that appears to arbitrarily distort market pricing. The difficulty is that in extreme situations the prices determined by ERCOT's methods may also fail as measures of scarcity. This is a consequence of the separation of energy and reserve markets, coupled with renewable subsidies that increase uncertainty. There is thus an implicit tradeoff: the ORDC is an attempt to remedy an inaccuracy that is largely due to subsidy-related mispricing. Uncertainty brings an unpalatable choice: Subsidies distort market prices, but the ORDC may produce outcomes superior to those that would prevail absent any link between the prices of energy and reserves. Use of the ORDC can bring resource misallocations, but a failure to use it may also yield prices unlike those in subsidy-free competitive markets. In any case its importance is relatively minor. In 2017, it was active only 250 hours of the 8,760 total and its average effect on real-time energy price was 16 cents per MWh (Potomac Economics, 21-22).

The ORDC is thus an imperfect compromise but one that is somewhat consistent with ERCOT's basic market orientation. ERCOT's operating institutions do not offer a universally perfect option. The ORDC today is a precisely defined intervention that can only be invoked in clear but rare situations in which no market participant has an informational advantage over others. However, recent discussions at the PUC have contemplated expanding the ORDC to operate outside of existing conditions of scarcity. Doing so would turn it from a method of approximating prices that would occur absent market intervention to a tool for increasing the revenues of generators in hopes of adding reserves. The result would be to increase the use of regulated prices in place of market prices that are more reliable indicators of scarcity, and in the process undermine competition in ERCOT. Expanding the scope of the ORDC would itself signal the PUC's willingness to allow economic misallocations resulting from subsidies and to maintain inefficient operating procedures that favor intermittent renewables.

In formulating the ORDC, ERCOT rejected a number of more complex proposals with rationales which may have been more "perfect" in theory but seldom work out that way in practice. Taking the lessons of PJM, it is a near-certainty that the complications of minutely detailed and planned policies will engender further complications and add to uncertainty in already-uncertain situations. For evidence that a wide spectrum of stakeholders value dependability in the ORDC, compare the filings in PUC docket 45572. Generation owners generally disagreed on the adequacy of compensation rather than the conceptual basis of the ORDC.

One important attribute of the ORDC is the constrained environment in which it can be used. These limits affect operations only occasionally and are unlikely to yield outcomes at variance with principles of efficiency and distort investment choices. In an uncertain world, adding to the flexibility of the ORDC will likely increase the risks of inefficient decisions. The ORDC was in important ways "contrived" in its choices of trigger prices and percentages, but at least it was designed to operate in limited conditions while attempting to mimic market prices. Expanding the ORDC to intervene in choices about generation adequacy will, in effect, make it a permanent replacement for market prices that are themselves often distorted by subsidies.

That is possibly where ERCOT is heading. At its January 17th meeting in 2019, the PUC expanded the use of the ORDC after more than a year of discussion about recent declines in ERCOT's forecasts of summer reserve margins. The latest forecast shows a 7.4 percent margin for the summer of 2019 (ERCOT 2019). At the direction of the PUC commissioners, ERCOT must "implement a .25 standard deviation shift in the loss of load probability (LOLP) calculation using a single blended ORDC curve as soon as practicable with a second step of .25 in the spring of 2020" (Walker, 2). The practical effect of these changes is that the non-market interventions of the ORDC may be more active in the future than in the past. How much more active and at what cost remain open questions, and the answers will depend largely on market conditions.

The PUC "estimated that the change would increase wholesale power costs by nearly $80 million over two years, assuming that new power plants come online to boost supplies, old plants stay online for longer than they would have otherwise and people react to higher prices by cutting their consumption" (Douglas). The estimated consequences are less certain. On the pessimistic side it takes approximately three years to build a new gas-fired generation plant and the favorable effects of other interventions are uncertain to some degree. Generation owners have suggested that the costs may be much higher. For example, Exelon has estimated that a shift of one standard deviation in the LOLP would result in price increases totaling $4 billion (Collier), and the PUC's estimate for a 50 percent shift translates to roughly $2 billion, which is also close to Texas Industrial Electric Consumers estimate of $2.5 billion (TIEC 2018, 2). These estimates are based on the additional costs reflected on customer bills had Exelon's proposal been in place in summer of 2018.

There are, however, some reasons to expect that ERCOT will continue to operate reliably and efficiently even if the pessimistic forecasts for summer 2019 become reality. If those forecasts come true, it becomes increasingly unlikely that there will be additional generator retirements and less need for more drastic pricing interventions. Markets themselves are already building forecasts into prices, and the sooner prices move, the easier it will be for both buyers and sellers to adjust to the unpleasant reality. The recent coal plant retirements have already been factored into forward prices on the International Commodity Exchange, and this summer's prices are well above those of last year (TIEC).

Less noticeable is the fact that competition can mitigate the effects of these shortfalls. Major generator NRG has stated that it intends to expand the competitive scope of its operations by devising internal hedges to deal with retail price risks and expanding demand management programs to better cope with market fluctuations. It has also altered its maintenance schedules and practices to better cope with that price volatility. NRG intends to treat its abilities to better hedge retail fluctuations as competitive tools to gain market presence and profits. (An NRG spokesperson noted that "we have an opportunity to complement our physical assets with short- to medium-term contracts that better align with our load obligations" [Patel].) Likewise Vistra has claimed that unifying its wholesale and retail businesses has reduced costs by $3 to $4 per MWh. More generally, REPs are free to compete by instituting programs to better compete with other REPs and avoid being abandoned by their customers. The PUC has approved operating practices (beyond existing interruptible programs) that compensate customers willing to reduce their demands in emergencies and is expanding its coordination with other state agencies to ensure that gas supplies are deliverable when needed. New generation is just one of many competitive strategies to cope with future emergencies and scarcities, and in ERCOT's system they can be undertaken by REPs, generators, customers (including distributed generation), and firms specialized in load management.

Conclusions: What We Learn from ERCOT

The likely effectiveness of a policy depends on both its theoretical underpinnings and on the institutions that carry it out. ERCOT embodies both ideas and institutions, and an understanding of its effectiveness requires both economic and political analyses. Its capacity market is "missing" in only one sense: ERCOT's governing institutions have not specified the details of many protocols and rules. ERCOT has become a proving ground for exploring transactional designs, and competition among those designs has been a major contributor to its efficient and successful resource acquisition process. The rationales underlying RTO-based capacity markets are logically questionable and dependent on rules the existence of which may reflect politics rather than economic efficiency. In PJM the details have been worked out by parties interested in both political and market outcomes and have given rise to rules piled on top of rules with no end in sight. PJM's history is one that has allowed regulated entities—particularly generators—to avoid the consequences of decisions that were mistakes in retrospect and allowed exactions from ratepayers to make up the losses. ERCOT, by contrast, operates markets that are largely voluntary in nature. Those markets facilitate competition among generators whose only safety nets are the products of agreements with customers on the characteristics of wholesale transactions. ERCOT's virtue is that its institutions are attempts to minimize the possible role of politics as a determinant of market outcomes, to the extent that even regulators do not know the details of many transactions taking place. It is an ongoing collection of predictable institutions on which market participants can build their desired superstructures, while the micro-detailed markets in other RTOs have themselves become major sources of uncertainty.

The four cases discussed in this chapter examine institutions that are consistent with ERCOT's pro-market orientation. The first, the adoption of nodal prices to replace a zonal system, was not devoid of politics. The inherited structures of rates and zones virtually ensured that predictable transfers due to zonal rules would not persist under a nodal regime. The design and testing of locational marginal prices entailed policy debates among the various stakeholders, but an examination of the record has uncovered no clear attempts to misuse economics in defense of the indefensible transfers of a zonal regime. The changeover to nodal prices increased the economic value that ERCOT's operations could create because it increased the likelihood that generators would be located where they and the power they produced were more valuable. The change benefitted both generators and consumers, while the creation of previously infeasible congestion revenue rights allowed the trading of risks that would have been difficult or impossible to hedge under a zonal regime.

The second case, the capacity market, has been more problematic. Here the experience of other RTOs has shown that adding layers of capacity rules has done little to improve the competitiveness of their markets or foster upgrades of generation. A comparison of PJM's and ERCOT's experiences shows the opposite: The financial security offered by

PJM's capacity payments has allowed survival of an ossifying fleet of generators instead of "creative destruction" that would replace older units with more efficient new ones. At the same time, RTOs are coping with an influx of intermittent generation that was barely anticipated at the time of their formation. Concerns of capacity market advocates that ERCOT could not invest in adequate generation have thus far turned out to be misplaced. The real problems appear to have arisen with the micromanagement of capacity markets, which operate under a fundamental conflict induced by regulation and planning: to stabilize prices while alleviating generation shortages and at the same time attempting to allow both efficient and inefficient generators to survive. The upshot in PJM and elsewhere has been the imposition of capacity constraints and bidding rules that would violate legal standards of competition in almost any other market, followed by changes in the rules to cope with the ingenuity of market participants attempting to circumvent them. On the other hand, ERCOT offers reality-based institutions that foster innovative competition and discourage politicized attempts to undo economic reality. As in any other competitive market, ERCOT has generally sought to allow generation investments and energy prices to be market-determined, under whatever contractual terms producers and consumers find mutually agreeable.

Our third case, negative market-clearing prices, is a variant of many questions about renewables. Negative prices became problematic because wind (and soon solar) power grew to sizes that would not have been possible prior to the introduction of subsidies and other interventions in ERCOT. As long as the PTC has been in effect wind has received subsidies like the PTC, while market rules prioritize its use, and costs are "uplifted" onto ratepayers. The policy question that matters is whether to remove the subsidies and directly address their negative effects or to devise new institutions and modify existing ones to paper over the inefficiencies that have come with wind's arrival. Adding to the uncertainty and dislocations, changes will be within the jurisdictions of both FERC and the PUC.

Our fourth case, the Operating Reserve Demand Curve, examines the inefficiencies that have resulted from subsidized energy prices and unclear operating rules. With subsidies, operational difficulties when the grid is stressed are a technical fact: the separation of the energy and reserve markets (both of which provide economically valuable price information) can produce perverse outcomes. Subsidizing intermittent renewables can produce inefficient market outcomes, but the ORDC's plausible but arbitrary triggering rules may also do so. Inefficiency in the face of subsidies is inescapable whether or not there is an ORDC policy, and here the question is to minimize the likely loss from incorrect choice of actions. The better solution is almost surely to eliminate subsidies to intermittent renewable energy. If that proves politically impossible, then the PUC's best option, instead of expanding the ORDC, would be to directly change its operating rules to force wind and solar operators to pay for the costs they impose on the system.

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Michaels is an expert on regulation and competition in electricity and gas, including issues in market design and renewable power. He has advised state regulatory commissions, electric utilities, competitive power producers, natural gas producers, industrial energy users, public interest organizations, and governments on regulatory and competitive issues.

Michaels has participated in electricity restructurings in California, Japan, and New Zealand. He has served as an expert witness in utility merger proceedings before the Federal Energy Regulatory Commission and has testified on the economics of electricity market monitoring. He has also testified before the California Public Utilities Commission, Illinois Commerce Commission, Mississippi Public Service Commission, Vermont Public Service Board, and Washington State Energy Facilities Siting Council, among others. He has testified on four occasions as an invited expert before committees of the U.S. Congress.

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