Resource Adequacy Challenges in Texas

Unleashing Demand-Side Resources in the ERCOT Competitive Market

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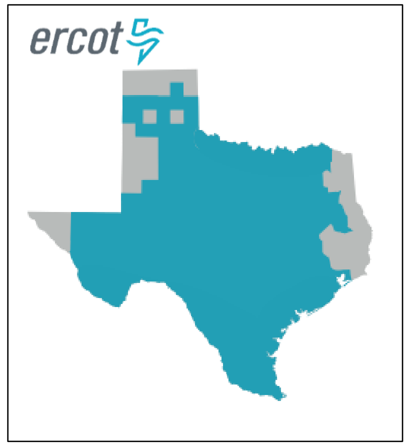
NOTE: Most of the data in this paper reflect market conditions and forecasts made before March 2020. Given the economic impact and human tragedies created by the coronavirus it is certain that the supply and demand levels projected herein overstate near-term future conditions within ERCOT.

1.0 Introduction and Executive Summary



On Sunday, August 11, 2019, most of Texas was in the grip of a heat wave that was predicted to last another week, with highs every day over 100°F. On August 12, with scorching heat and air conditioning loads rising, the ERCOT grid operator issued an operational advisory when electric generation reserves fell below 3,000 MW and the system hit a record high peak load of 74,820 MW.[1] Generation reserves fell below 3,000 MW each day that week. On two afternoons, when reserves fell below 2,300 MW, ERCOT called on customers to voluntarily conserve energy and asked compensated customers for emergency load cuts in order to avoid involuntary blackouts. Real-time electric prices rose to record highs for several hours and ERCOT operators and observers experienced many nervous hours, but the lights stayed on everywhere.

Even under the pressure of August heat and record peak load, the ERCOT market worked as designed.

In recent years, energy and peak demand in ERCOT have been growing rapidly at the same time that the region's energy resource mix is transforming from one heavily fossil-based toward a system with growing levels of wind and solar generation. This change is driven principally by the favorable economics of renewables relative to fossil and nuclear resources and increased customer demand for clean energy. Given a formal state policy commitment to market-based supply determination, rather than mandatory resource planning or capacity markets, ERCOT has experienced volatile, sometimes low, reserve margins. At the same time, energy efficiency, behind-the-meter distributed generation,

[1] "ERCOT Fact Sheet, March 20, 2020".

energy storage and electrification of non-electric uses are changing customers' electricity usage patterns and consumption levels.

Texas' unique electric market structure facilitates choices by energy customers and producers that contribute to grid reliability in ways that differ from every other region in North America. ERCOT relies on market competition and price signals to assure that real-time electric supply matches demand. Some question the wisdom of trusting an "energy-only" market and issue warnings every summer of impending blackouts in the August heat. To date, however, the combination of high prices and falling resource costs have increased the amount of generation installed in ERCOT and the availability of the generation fleet during tight market conditions.

In short, ERCOT's market design works efficiently and effectively, and it should be maintained.

ERCOT's experience has shown that Texas' market structure supports electric reliability in an economically effective and environmentally sustainable way. Over the past 18 years, wholesale electric competition within ERCOT system has attracted extensive new investment in renewable and fossil resources, energy storage and price-responsive demand. These investments have leveraged technology innovations, including the replacement of inefficient natural gas and coal plants with highly efficient natural gas and extensive wind and solar generation capacity.

ERCOT's competitive wholesale market enables robust retail competition that empowers electric customers to choose or create retail service combinations of fuel sources, reliability levels, technologies and price.

This paper discusses the key features of the ERCOT energy-only market structure, explains how it advances electric reliability and resilience, and offers recommendations for maintaining ERCOT's electric reliability and resilience. These recommendations focus heavily on ways that policymakers can protect and de-risk ERCOT's price-managed market structure by more effectively using two key assets: demand-side resources and distributed resources.

Resource adequacy is a function of both supply and demand. When the idea of resource adequacy was first developed, it was assumed that all resources were generation and all customer demand must be served absolutely, without controlling or limiting end-use consumption beyond crude energy efficiency. Today, however, many electricity uses can be managed directly by the customer or an authorized third party in response to energy prices, automated devices, or direct control signals. Thus, demand response and price-responsive demand have become resources that can operate in parallel to supply-side resources to manage the supply-to-demand balance.

Distributed energy resources, such as photovoltaic solar and storage, and demand-side measures, such as energy efficiency and automated and price-responsive demand, can respond to prices as well as to grid management signals. In a time of rapid demand growth and uncertain supply, these assets should be used to de-risk the electric system by reducing peak load and ancillary service needs (fast ramping, in particular). This reduces the burden and cost of assuring adequate supply and flexibility services and protects customers while enhancing system and community resilience. All of these resources can be coordinated and integrated with advanced monitoring, forecasting, analytics, communications, and controls to integrate and balance demand with supply for reliable, affordable and sustainable electric service.

The onset of the global coronavirus pandemic and its economic consequences will certainly affect Texas' energy economy and ERCOT's electricity market. The pandemic has already changed electricity demand patterns and prospects; for five weeks in March and April 2020, while many Texans have been staying at home to avoid COVID-19 infection, daily peak loads within ERCOT have decreased by 2%, and weekly energy use has dropped 4 to 5%.[2]

Texas faces a related crisis – the precipitous collapse in oil and gas prices – which will also affect electricity use and prices in ERCOT. The combination of declining oil and gas prices over recent years was exacerbated by an oil over-production price war between Russia and Saudi Arabia and then slammed by a 30% drop in U.S. oil consumption in March due to sudden, widespread COVID-19 quarantines. Texas produces over 42% of

[2] C. Opheim, "COVID-19 Load Impact Analysis," ERCOT, April 21, 2020.

the nation's crude oil,[3] much of that from the Permian Basin in west Texas. Given the crash in oil prices and demand, many oil companies are stopping new drilling, shutting in wells and laying off workers. This will create long-term shifts in ERCOT demand, since Permian Basin production was expected to be ERCOT's greatest near-term electric load growth challenge. Additionally, since oil and gas production was directly or indirectly responsible for one-sixth of the jobs in Texas,[4] job losses associated with the oil industry collapse will lead to a multi-year drop in residential and commercial energy use.

These current crises will delay, but not negate, the long-term challenges outlined in this paper. Texas' energy profile will continue to change and become more complicated. New technologies and energy resources – particularly more demand response and energy efficiency -- offer ways to improve resilience, maintain reliability, reduce costs, and further modernize ERCOT's successful competitive market.

[3] Financial Times, "Oil bust and pandemic strike double blow for Texas," March 28, 2020.
[4] R. Perryman, "The Texas Energy Sector and Beyond," July 15, 2019.

2.0 ERCOT overview

As the operations and planning manager for Texas' stand-alone electric grid, ERCOT serves 90% of Texas electric customers and 75% of the state's land area. It is a stand-alone interconnection with over 680 generation units, 46,500 miles of transmission lines and only 1,250 MW of direct current ties to the eastern and Mexico interconnections. As of March 2020, ERCOT has over 102,000 MW of installed capacity, composed of 52.8% natural gas, 23.3% wind (23,834 MW, more than any other state), 14.5% coal, 5.1% nuclear, and other sources.[5]

The ERCOT electric market is one of the most competitive in the world. Under regulatory and market designs established by the Texas Legislature in 1997 and 1999, all large-scale generation is owned by merchant generators (excepting that owned by cooperatives and municipally-owned utilities). Generators compete against each other to serve load. Transmission and distribution lines are owned and operated by regulated utilities, and the costs of new and existing transmission are allocated to all customers within ERCOT. ERCOT has retail competition, with over 100 Retail Electric Providers competing to serve end-use customers; over 90% of customers eligible for retail competition have switched providers one or more times.

2.1 ERCOT's electric market structure

Buyers and sellers within ERCOT use bilateral contracts and energy-only spot markets with scarcity pricing for electricity transactions. Power producers in ERCOT only earn revenue from the sale of energy and ancillary services. They decide whether to keep or retire existing plants and build new plants based on the competitiveness of those plants relative to prevailing energy prices and forward market prices.

ERCOT has a real-time energy market that re-dispatches resources every five minutes, a day-ahead market, ancillary services markets and financial congestion rights.[6] [7] Sellers

[5] "ERCOT Fact Sheet, March 20, 2020".
[6] See the "ERCOT Summer 2019 Update" to the NERC Member Representatives Committee, November 5, 2019, for a brief overview of ERCOT's market structure, and Potomac Economics, "2018 State of the Market Report for the ERCOT Electricity Markets," June 2019, for extensive detail.
[7] ERCOT is working toward the 2024 implementation of Real-Time Co-optimization between the Day-ahead, Real-Time and Ancillary Services markets. This will improve reliability and lower costs in all

and portfolio managers within ERCOT can hedge their real-time positions using fuel-price hedging with their own generation, power sales contracts with buyers, positions in the day-ahead market, and demand response contracted with end use customers. Electric buyers can use long-term purchase contracts, day-ahead positions, and demand response and distributed generation from their customer portfolios to manage their exposure in the real-time market.

High prices during times of scarcity or peak demand are an essential feature of the ERCOT market. This market design incents investment in long-term generation supply and power plant operational improvements, along with temporary demand reductions, to meet or balance customer loads. To date, this market model has yielded reliable operation with no summer load-shedding events.[8]

2.2 The role of prices in ERCOT

The average ERCOT real-time energy price was $35.63/ MWh in 2018 and $38.00/MWh in 2019. Real-time prices peaked at $9,000/MWh on the two peak demand days. To assure that energy price signals accurately reflect scarcity, Texas regulators created a $9,000/MWh offer cap and implemented an energy price adder[9] called the Operating Reserve Demand Curve (ORDC) that kicks in under scarcity conditions when there is a shortage of available supply and demand relief resources. ERCOT hit that cap during four hours in the summer of 2019. The effect of the ERCOT ORDC is to increase prices during conditions of scarcity – which occurred not at the time of peak load (around 6

markets by creating better resource assignments and continuity between and across the various market time horizons. Once implemented, RTC could lower the costs of energy, congestion and ancillary service provision. (See B. Garza, "GCPA Pre-conference workshop, Real-Time Co-optimization," October 14, 2019).

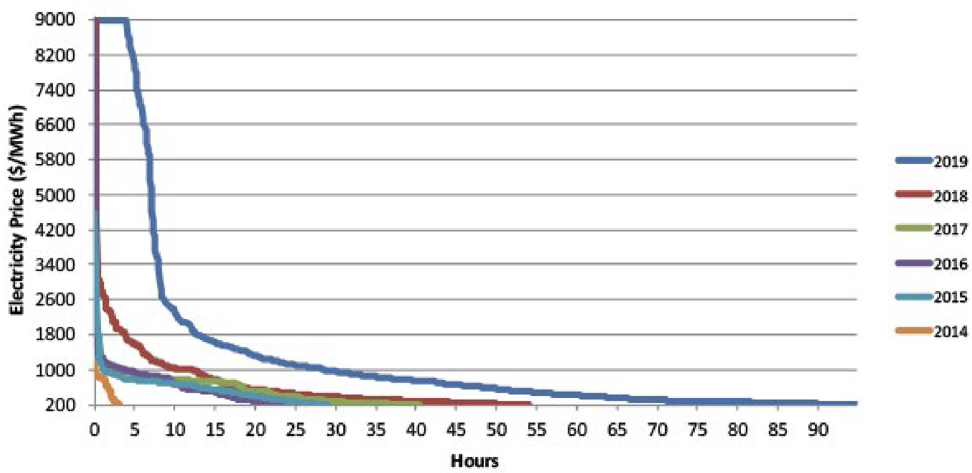
[8] It is useful to note the distinction between summer reliability issues, which test total generation capacity relative to peak customer demand, and winter reliability issues, which tend to test generation resilience associated with cold weather winterization and fuel supplies. In February 2011, ERCOT had to impose rolling outages after severe cold weather and a storm knocked out 152 of 550 generating units due to equipment failures and natural gas delivery curtailment problems. In both summer and winter cases, ERCOT may call on Emergency Response Service (ERS) customers to cut load in order to avoid involuntary rolling blackouts that would affect many customers. ERS providers are contracted and paid to cut specified amounts of load, if needed, for limited hours in each season.

[9] ERCOT's energy price adder is called the Operating Reserve Demand Curve. The assumption behind the $9,000 price cap is that if there were a power outage, ERCOT customers would value the first MWh of electricity that would be lost at $9,000 per MWh (Value of Lost Load).

P.M.) but during peak net load (total load net of wind and solar generation, which occurred around 4 P.M.).[10]

Figure 1 shows the spread of electric energy prices for the months of January through September for the years 2014 through 2019. ERCOT's highest price periods tend to occur in the hot summer hours of July through September, and are low in October through December. In 2019, prices exceeded $200/MWh for 95 hours, reaching the system bid cap of $9,000 per MWh for four hours and 10 minutes in August and September.[11]

Figure 1 – Electric energy price duration curve in ERCOT, $/MWh, January through September, 2014-2019[12]



High prices signal to new generators that they can recover their operating and capital costs. They also motivate retail electric providers to sign contracts directly with generators to lock in predictable prices and shield themselves against future price spikes and contract with retail customers to provide future demand response when needed. And power contracts help generators finance new plants and demand aggregators finance new demand management projects.

[10] These price spikes do not affect many retail customers because most Retail Electric Providers use power purchase contracts and other hedging mechanisms to assure that they are insulated against wholesale price volatility.
[11] R. Gramlich, "ERCOT 2019: Final Proof of a Successful Market Design?," RTO Insider, October 15, 2019.
[12] Source: R. Gramlich, "ERCOT 2019: Final Proof of a Successful Market Design?," RTO Insider, October 15, 2019.

These signals have worked in ERCOT. In anticipation of high prices and extremely high price spikes, generators kept efficient existing plants online and in good condition – market monitor data show that generators operated their plants to maximize output in summer periods, with lower deratings and planned outages than in other months.[13] Many customers used less electricity in high-priced hours, whether through voluntary individual reductions or through formal demand response programs that pay users to reduce electricity use in times of operational need. Customers reduced their electricity usage between 1,600 and 3,100 MW through individual usage reductions in response to high prices, formal REP-initiated demand response and voluntary conservation (in response to ERCOT Emergency Alerts). Distributed generators increased net output by an estimated 150 to 200 MW.[14]

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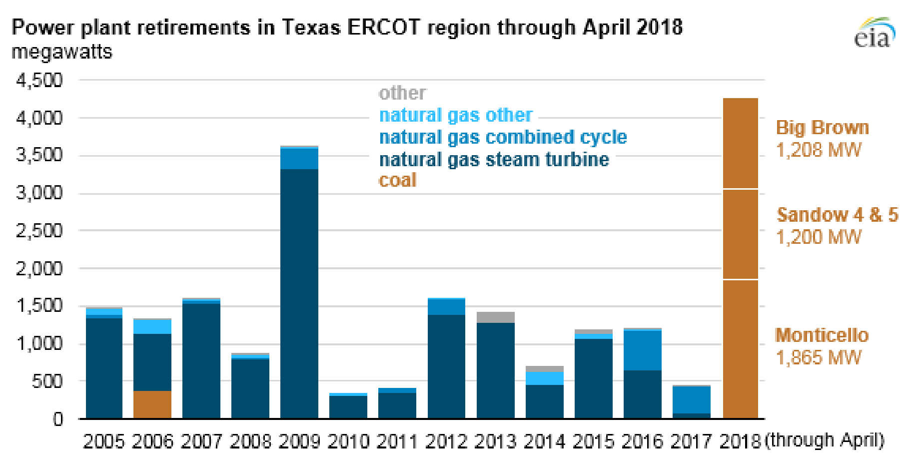
[13] B. Garza, "Item 6: Independent Market Monitor (IMM) Report," October 8, 2019.
[14] ERCOT, "ERCOT's Review of Summer 2019, revised," October 11, 2019, pp. 26 and 53.

3.0 Supply response to the ERCOT market

Ease of entry and exit in the ERCOT power producer ranks contributes to ERCOT's low prices. On the entry side, ERCOT has managed its interconnection queues relatively effectively, Texas transmission and distribution utilities are obligated to interconnect new generation, and new transmission can be sited and built more quickly than in many other regions. This makes it easier for new generation within ERCOT to interconnect to the bulk power system.

Because most generation in ERCOT is competitively owned,[15] merchant owners are quick to retire a plant when it becomes uncompetitive and unprofitable. Figure 2 shows extensive generator retirements in ERCOT, with over 5 GW of fossil-fired power plants retiring since May 2017.

Figure 2 – Older natural gas and coal plants retired in ERCOT[16]

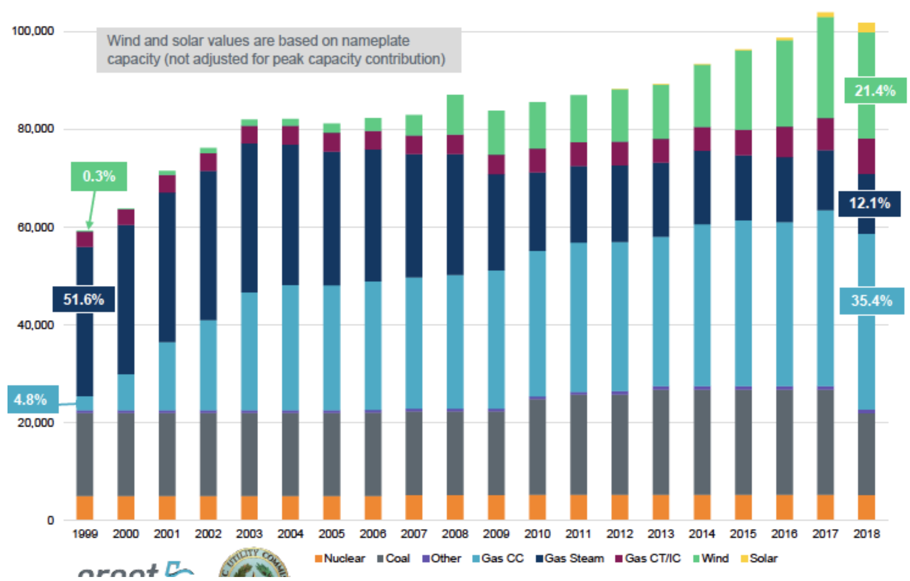


Although power plant retirements are often accompanied by warnings of impending shortages and rotating outages, neither has yet happened in ERCOT because so much new generation has come online to replace it. Since 2005, about 21,000 MW of new generation has been built in ERCOT, dominated by natural

[15] The only non-merchant generation in ERCOT is owned by municipal and cooperative utilities.
[16] Source: EIA, "Coal plant retirements and high summer electricity demand lower Texas reserve margin," July 2, 2018

gas and wind resources to replace the retiring natural gas-fired steam and coal plants. (See Figure 3)

Figure 3 -- ERCOT Installed Capacity, 1999 through 2018[17]



Between summer 2018 and summer 2019, 2,400 MW of wind and solar capacity was added onto the ERCOT grid. Another 7,663 MW of renewables and small gas-fired generation are expected to come online before summer 2020, bringing the projected summer 2020 reserve margin to 10.6%.[18] Capacity and reserve margins are expected to continue growing over the near future, as shown in Figure 4.

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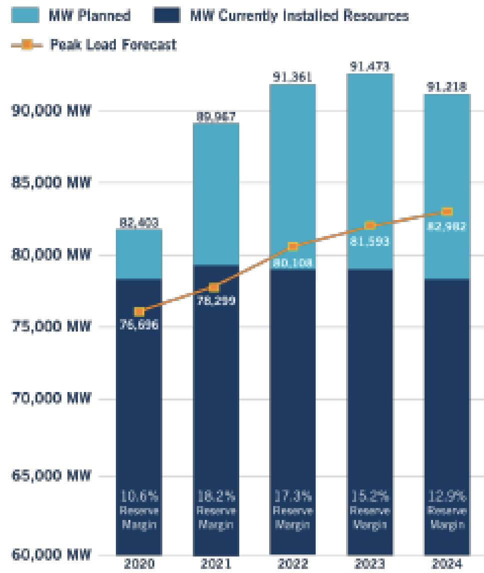
[17] Source: "ERCOT Summer 2019 Update, briefing to the NERC MRC," November 5, 2019.
[18] P. Ring, "ERCOT: Reserve Margin Climbs 2% for Summer 2020 versus 2019," December 5, 2019, EnergyChoiceMatters.com.

Figure 4 – ERCOT anticipated capacity, 2020 through 2024[19]



ERCOT reports that total installed utility-scale renewable generation capacity could reach 47 GW by 2021 (35.8 GW of wind and 11.4 GW of solar). Much of the new solar and wind development beyond 2021 will depend on the development of additional transmission from West Texas eastward to population and load centers. Another 4 GW of energy storage projects and about 4 GW of rooftop photovoltaics are under study in ERCOT's 2020 Long-Term System Assessment (now in development).[20] [21] Renewable resources and natural gas generation have displaced less competitive coal generation, but ERCOT expects gas to remain the primary fuel serving ERCOT through 2033 (based on 2018 analyses).[22]

No grid operator assumes that every MW of generation capacity on the ground will be fully available at the time of system peak demand. Rather, planners and operators assume that some capacity will be subject to planned and unplanned (forced) outages or undeliverable due to transmission outages and that intermittent wind and solar generation will operate at some fraction of their full nameplate capacity. During the

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[19] Source: Bill Magness, "Senate Business & Commerce Testimony," February 6, 2020.
[20] ERCOT, "Report on Existing and Potential Electric System Constraints and Needs," December 2019, p. 18.
[21] Distributed solar is discussed below in the section on ERCOT demand.
[22] ERCOT, "2018 Long Term System Assessment for the ERCOT Region," December 2018, p. 8.

August 2019 peak week, fossil generation outages in ERCOT ranged from about 3,500 MW to 3,950 MW[23], while wind and solar output exceeded forecast levels.

ERCOT planners expect solar photovoltaic generation to operate at 74% at the time of peak load demand – but peak load in ERCOT lasts for several hours and PV output peaks several hours earlier. West Texas wind tends to blow in late afternoon (as solar generation is ramping down) through morning hours while coastal wind blows more steadily. An increasing number of the solar and wind projects in the ERCOT interconnection queue include a battery storage component to enhance each project's output during more of the high-priced peak load hours.

ERCOT uses a wide set of advanced monitoring, analytics, forecasting and field technologies to plan and operate its complex system and integrate its diverse supply and demand resources. These include sophisticated security-constrained economic dispatch software for day-ahead and real-time markets, sophisticated day-ahead and real-time wind and solar forecasting techniques, real-time field monitoring using SCADA and synchrophasor technology, and complex system protection schemes. These systems are built on a secure, high-speed communications and control network. ERCOT and its members conduct extensive system planning and engineering analyses to anticipate system resource and engineering challenges and design the transmission system and associated protection schemes to address those issues.

3.1 Resource adequacy and mandatory reserve margins

August and September 2019 were two of the hottest months on record in Texas, where building air conditioning is a dominant summer energy use. ERCOT entered the summer with 78,929 MW of electric generating capacity at expected peak hour and a predicted reserve margin of 8.6% over projected summer peak demand of 74,853 MW.[24] When electric customers' peak demand hit a record of 74,820 MW on the afternoon of August

[23] ERCOT, "ERCOT's Review of Summer 2019," October 11, 2019, p.39.
[24] ERCOT, "Final Seasonal Assessment of Resource Adequacy for the ERCOT Region, Summer 2019," May 8, 2019.

12, 2019,[25] ERCOT had an operating reserve of only 1,460 MW available in case demand rose further or a power plant or transmission line was lost.[26]

Reserves are capacity that is available to be used, but will not provide energy until called on by its owner or the grid operator. Unlike other regions, ERCOT does not require a mandatory reserve margin.[27] [28] Rather, reserve margins in ERCOT fluctuate based on generators' decisions about whether to build or shutter a power plant in the region, and customers' decisions on how much energy to consume and when. Both supply and demand decisions are driven by economic price signals: low real-time prices indicate that energy is cheap and over-supplied, while high prices mean that energy is valuable.

Most of North America's electric operating regions have planning reserve margins (the proportion of projected availability of anticipated electric generation and load management resources to meet forecasted customer peak load) ranging from 13 to 97% over projected customer load.[29] Customers in these regions essentially make advance payments, whether through capacity market charges or through rate-base payments to bundled utilities, to assure the availability of what policymakers deem to be adequate capacity levels during annual or seasonal peak periods. In these regions, the Federal Energy Regulatory Commission (FERC) limits shortage- or scarcity-related energy price caps to $2,000 per MWh, and price spikes in those regions are viewed as market problems.

The premise for setting planning reserve margins has historically been that grid operators should have sufficient generation in excess of load that generation shortfalls (rotating outages or full blackouts) should occur no more than one day in every ten

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[25] ERCOT, "Quick Facts," December 2019.
[26] ERCOT, "Project No. 49852, Review of Summer 2019 ERCOT Market Performance, ERCOT's Review of Summer 2019," October 11, 2019, revised. This number excludes about 1,100 MW of industrial loads on under-frequency relays providing responsive reserve.
[27] ERCOT has a 13.5% "Reference Reserve Margin" but that is not mandatory.
[28] Most of North America's electric operating regions have planning reserve margins (PRM, the proportion of projected availability of anticipated electric generation and load management resources to meet forecasted customer peak load) ranging from 13 to 97% over projected customer load. (See NERC, "Summer Reliability Assessment, 2019," June 2019) These regions make advance payments, whether through capacity market charges or through ratebase payments to bundled utilities, to assure the availability of adequate capacity during peak periods. In these regions, FERC limits shortage- or scarcity-related energy price caps at $2,000 per MWh, and price spikes in those regions are viewed as market problems.
[29] NERC, "Summer Reliability Assessment, 2019," June 2019.

years. These outdated assumptions ignore the fact that demand is no longer absolute; many customers now have the capability to manage their electricity usage through active or automated means in response to price signals or grid conditions. Furthermore, since over 99% of actual customer outage minutes occur due to failures of transmission and distribution (mostly affected by severe weather events)[30] rather than insufficient generation, it is likely that incremental additions of generation capacity will have little impact on customer outages.

ERCOT and the Public Utility Commission of Texas (PUCT) recently examined what ERCOT's reserve margin would be if it were based on a market equilibrium, consistent with ERCOT's market design, rather than at an arbitrary level. The resulting study simulated a variety of ERCOT supply, demand and weather conditions to estimate a market equilibrium reserve margin of 10.25% under projected 2022 market conditions. This level represents a balance between the marginal costs of providing electric energy and capacity and the expected value of scarcity pricing, which is meant to represent the lost value from disruptions in electric service. The study also estimated an economically optimal reserve margin, which minimizes total system capital and production costs, to be 9.0%. Above this margin, the costs of adding new gas generation capacity exceeds the benefits from reducing generation-caused outages.[31] ERCOT's projected 2020 reserve margin will be about 10.5%, close to the estimated market equilibrium curve.

High levels of capacity cost money, and capacity payments fund those costs. PJM's capacity market mechanism – in combination with over-high demand forecasts – entered the summer of 2019 with a 29% reserve margin (relative to a "reference margin" level of 15.9%). Over several years, PJM's own analyses consistently found that the region needed to keep forward generation reserve margins around 16% for resource adequacy, with diminishing reliability returns to additional capacity above that level.[32] One study estimates that for the year 2021 alone, excess capacity costs (capacity above "reference reserve margins") will cost electricity customers over $1.15 billion in PJM, $156 million in ISO-New England, and $84 million in New York ISO, all recovered

[30] T. Houser, J. Larsen & P. Marsters, "The Real Electricity Reliability Crisis," October 3, 2017.
[31] S. Newell, R. Carroll et al., "Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update," The Brattle Group, December 20, 2018.
[32] PJM Interconnection, "2018 PJM Reserve Requirement Study," October 10, 2018.

through capacity payments or rate-based recovery of utility-owned generation.[33] In those regions, much of the new capacity additions have been natural gas-fired plants funded primarily by capacity market revenues.

Wholesale and retail electric prices in ERCOT are low because, as a matter of state policy, ERCOT electric rates do not include capacity payments to generation to meet an arbitrary level of resource adequacy. Most Retail Electric Providers (REPs) use a variety of short- and long-term contracts and other hedging mechanisms to protect against having to buy much energy from the spot market during price spikes. Overall, ERCOT customers pay for new capacity by paying very high scarcity prices occasionally rather than paying for generation capacity support year-round. Estimates of the cost of a capacity market vary, but groups supporting continuation of the energy-only market estimated that a capacity market would have cost Texas $4.7 billion in 2011 (about $200 per household).[34] Many observe that capacity markets based on a resource adequacy requirement mandate expenditures on additional resource investments above the energy market-set level to support the incrementally required capacity.[35]

The Public Utility Commission of Texas designed the 2019 ERCOT ORDC change to increase the number of hours when scarcity prices could rise up to $9,000/MWh to incent new generation, with a projected cost to customers of about $80 million in direct payments over two years.[36] The higher cost of short-term ORDC payments is expected to deliver benefits from increasing investment in clean renewable, storage and high-efficiency natural gas plants, slowing power plant retirements, and encouraging customer load reductions and behind-the-meter distributed generation.

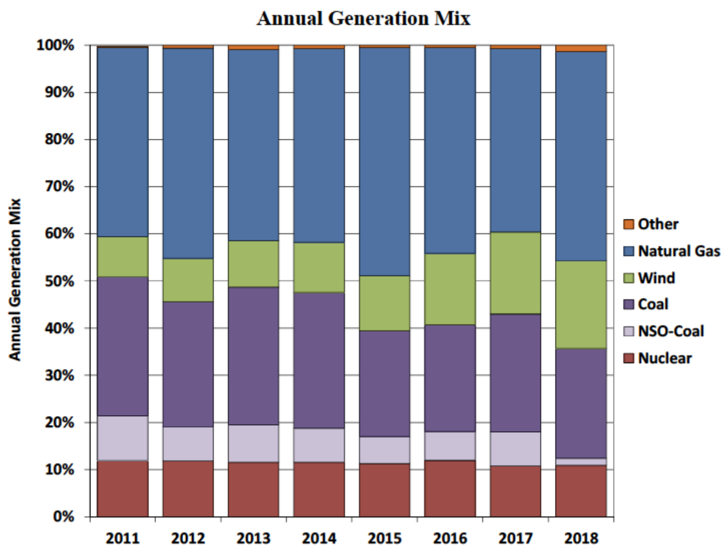
3.2 ERCOT's supply mix has changed

The net combined effects of easy market entry and exit are shown in Figure 5, which shows how drastically ERCOT's resource mix has changed over the past decade. While Figure 3 (above) shows capacity (nameplate MW) additions, Figure 5 shows actual

[33] R. Gramlich & M. Goggin, "Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform," November 2019.
[34] Kate Galbraith, "Texas' Blackout Avoidance Measures Could Cost Billions, Group Says," Texas Tribune, June 21, 2012.
[35] See, for instance, Sam Newell et al., Brattle Group, "ERCOT Investment Incentives and Resource Adequacy," June 1, 2012.
[36] This estimate comes from the Public Utility Commission of Texas.

energy production by fuel type; this shows more clearly how coal production has fallen as wind and natural gas-fired generation increased. Where ERCOT's annual energy mix included 42% natural gas, 37% coal and 6% wind in 2010,[37] in 2019 ERCOT's energy mix included 47% natural gas, 20% wind and 20% coal.[38]

Figure 5 -- ERCOT fuel mix changing over time [39] [40]



ERCOT's interconnection queue reflects these changes and the underlying changes in technology and economics. At the end of 2019, there were 584 projects with over 110,000 MW of capacity in ERCOT's interconnection queue.[41] Five percent of that total capacity is for gas projects, 27% wind, 61% solar, (over 43 GW of utility-scale PV), and 7% of battery storage projects. ERCOT had 2,281 MW of PV capacity and 23,860 MW of wind capacity installed and operational at the end of 2019. By the end of 2021, utility-scale solar capacity could exceed 8,000 MW, with potentially 500 MW of battery storage.

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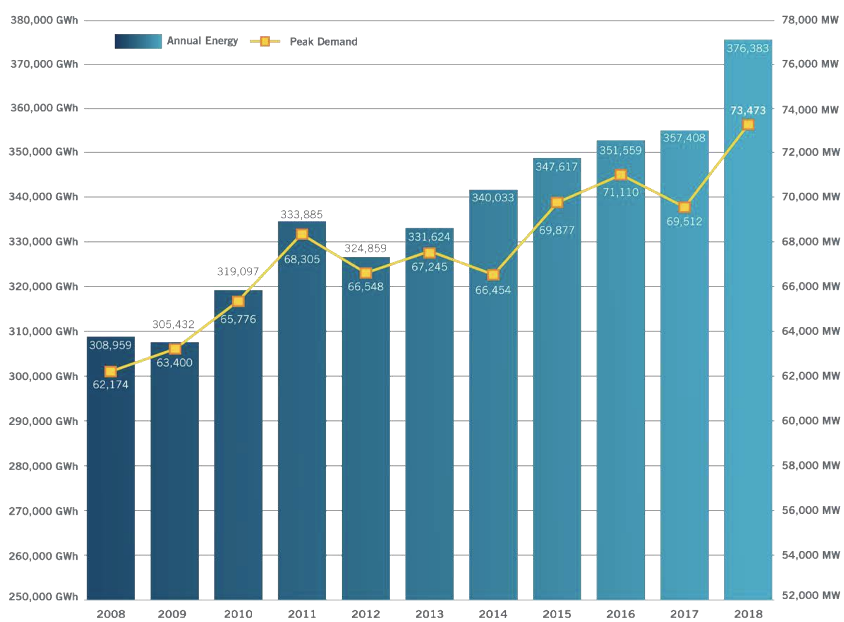
[37] ERCOT, "ERCOT 2009 Annual Report," 2010.
[38] ERCOT, "ERCOT Fact Sheet," March 2020.
[39] Source: Potomac Economics, "2018 State of the Market Report for the ERCOT Electricity Markets," June 2019.
[40] NSO-Coal means Notice of Suspension of Operations, indicating that the coal resource owner has notified ERCOT that the plant will be mothballed or retired from operations in the coming year.
[41] ERCOT, "ERCOT GIS Report, December 2019."

4.0 ERCOT demand keeps growing

In December 2019, ERCOT's 2019 "Capacity, Demand and Reserves Report" projected another year of growing electric energy and peak demands, over 7,000 MW of supply resources, and steady increases in the reserve margin from 7.4% in the summer of 2019 up to 10.6% in 2020.

Texas' economy and population have grown significantly over the past decade, driving electricity use higher. (See Figure 6) The state's population growth is projected to continue, growing from 29.47 million in 2020 at the current rate of 1.8% per year. Most of the population growth and in-migration will occur in the large cities and suburbs within ERCOT.[42]

Figure 6 -- ERCOT energy and peak load growth, 2008 through 2018[43]



ERCOT's peak load hit 74,820 MW in August 2019. ERCOT projects that this will grow to 76,696 in summer 2020 (a rise of 2.5%), driven in particular by growth in West Texas oil and gas production and Gulf Coast industrial loads. ERCOT's 2019 long-term load forecast projects summer peak demand of 88,751 MW by 2029, an average annual

[42] "World Population Review, Texas," and Texas Demographic Center, "Texas Population Projections, 2010 to 2050," January 2019.
[43] Source: "ERCOT Summer 2019 Update", November 5, 2019.

growth rate (AAGR) of about 1.6% per year.[44] The historic peak demand growth rate was 1.6% from 2009 through 2018.[45] Annual energy use is projected to grow at 2.3% AAGR from 2020-2029; the historic growth rate was 2.1%.[46]

Historically, Texas' and ERCOT's electricity demand have been driven by the number of buildings (residential, business and industrial), population, and weather conditions across the region. Texas' strong economic growth over the past two decades has outpaced the rest of the United States, with a long-term job growth rate of 2.1% from 1990 through 2018;[47] this has sustained continuing population in-migration and electric demand growth.[48] ERCOT's load forecasts incorporate the effects of projected population growth. They also factor in the growth of industrial uses such as oil and gas production, which were booming in West Texas, and growing manufacturing and refinery loads along the Gulf Coast.

Load forecasting in ERCOT just became harder due to the effects of two events: the coronavirus pandemic and the collapse in oil and gas prices. Since the pandemic led many Texas cities and residents to quarantine in mid-March, daily peak loads within ERCOT have decreased by 2%, and weekly energy use has dropped by 4 to 5%.[49] The economic effects of the economic shutdown include significant business failures and job losses that could take several years to come back. Beyond the certainty that electricity use will be lower, it is difficult to predict the specific changes in electricity peak and energy demands.

The collapse in oil and gas prices will also affect electricity use and prices in ERCOT. After several years of declining oil and gas prices, oil prices fell by 75% in March 2020 (relative to average prices from January through March) with the onset of coronavirus quarantines and the sudden 30% drop in U.S. oil consumption. Since Texas produces over a third of U.S. fossil fuel, in-state producers are reacting by ending new drilling, shutting in wells and laying off workers. This will create long-term shifts in ERCOT

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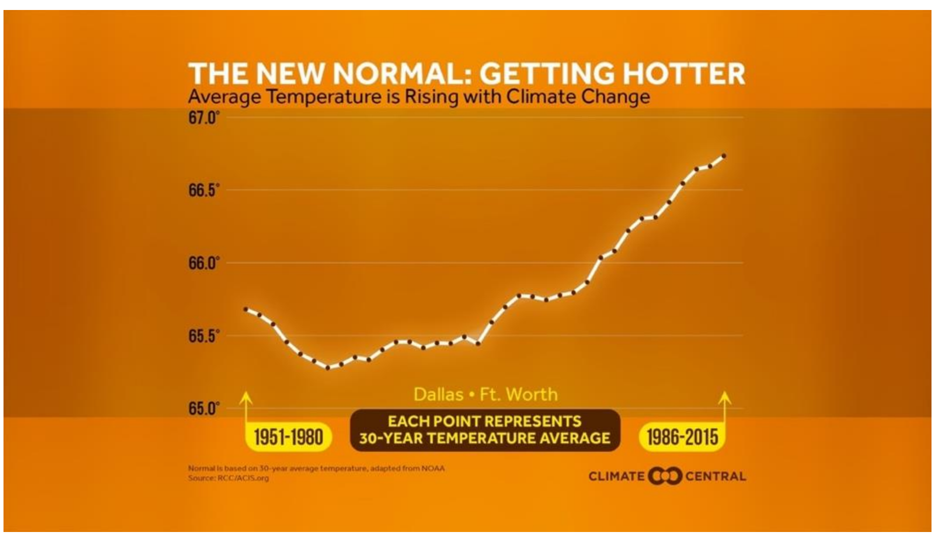
[44] ERCOT, "2020 ERCOT System Planning, Long-Term Hourly Peak Demand and Energy Forecast," December 31, 2019.
[45] Ibid.
[46] Ibid.
[47] Federal Reserve Bank of Dallas, "Your Texas Economy," November 17, 2019.
[48] See NOAA National Centers for Environmental Information, "State Climate Summaries – Texas."
[49] C. Opheim, "COVID-19 Load Impact Analysis," ERCOT, April 21, 2020.

demand, since the Permian Basin production was expected to be ERCOT's greatest growth challenge over the near term. Direct and indirect job losses associated with the oil and gas collapse will lead to a multi-year drop in residential and commercial energy use.

4.1 Factors that complicate demand forecasts

ERCOT's demand forecast assumes no significant changes from current (2014-19) levels of energy efficiency,[50] price-responsive loads, distributed renewable generation (rooftop PV), or electric vehicle usage, treating all these inputs as "frozen" at recent levels.[51] The forecast is also based on historical weather conditions. Texas temperatures, however, have been increasing over recent decades, as exemplified for Dallas-Fort Worth in Figure 7. This is not clearly reflected in ERCOT's weather volatility assumptions. The impact of higher summer temperatures is particularly important for peak loads in Texas because over half of ERCOT's peak load is driven by air conditioning.

Figure 7 – Average temperatures in Dallas-Fort Worth have risen with climate change[52]



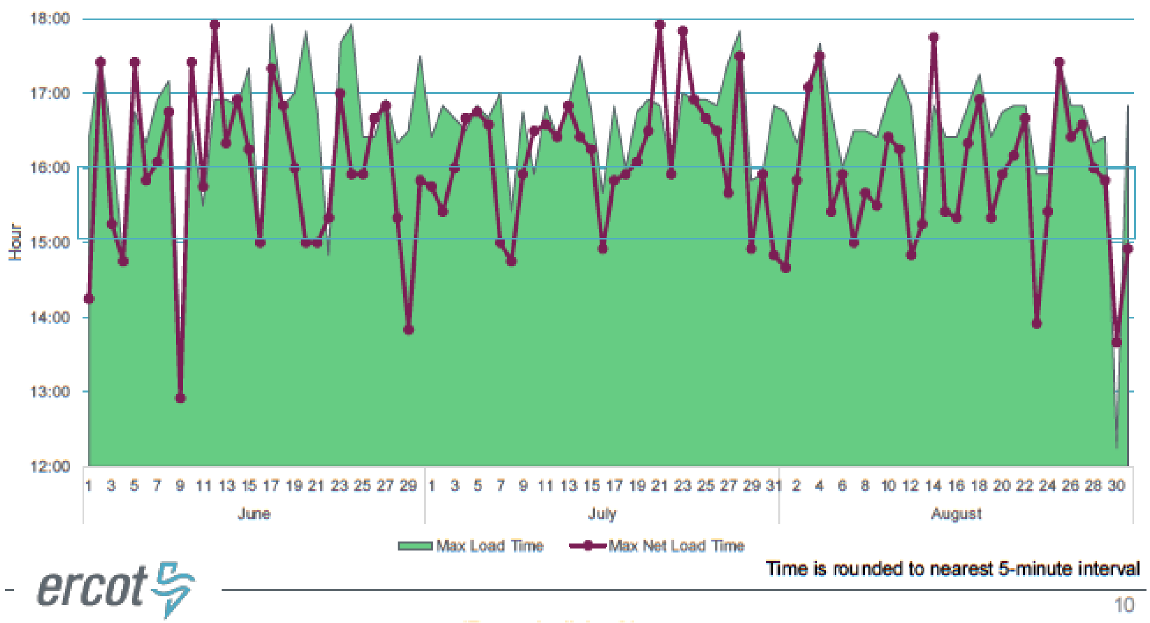
[50] Texas requires the investor-owned electric transmission and distribution utilities to implement energy efficiency programs that reduce end use customers' demand growth by 0.4% of peak load, with services delivered to all customer classes. This entails both energy use and peak load reductions. All of Texas' investor-owned utilities have consistently exceeded these legislatively set goals. See Frontier Energy, "Energy Efficiency Accomplishments of the Texas Investor-Owned Utilities Calendar Year 2018."
[51] Ibid.
[52] Source: Climate Central, "The New Normal: Earth is getting hotter," May 16, 2016.

By the end of 2018, there was about 1,300 MW of distributed energy resources (DER, including distributed generation and storage) in ERCOT.[53] Rooftop photovoltaic and on-premise distributed generation adoption in ERCOT has been growing at a rate of over 60% per year, dominated by solar, with smaller amounts of natural gas and diesel generation,[54] customer-sited batteries, diesel-fired generators and natural gas-powered microgrids. At the end of October 2019, there was a total of 577 MW of distributed (i.e., not utility-scale) residential and non-residential solar photovoltaic generation installed across 59,068 sites in Texas.[55] Since ERCOT contains 90% of the load and population within the state, it is probable that about 90% of that PV is located within ERCOT.

Day-to-day summer PV generation is broadly coincident with summer demand. However, peak net load (load net of wind and solar generation) often occurs about two hours earlier than peak load, often before 4 P.M. (See Figure 8, which shows the hour of peak load and peak net load each day over June, July and August 2019.) Scarcity hours often occur between 2 and 4 P.M., after which wind generation begins increasing faster than customer demand. The timing of peak versus net peak load matters because wind and solar generation in different locations across ERCOT have varying generation patterns over time, with "anti-correlated peaks and valleys in intensity throughout the day."[56] Automated demand response, particularly managing air conditioning loads, has the capability to perform fast-ramp services to maintain grid reliability under these conditions.

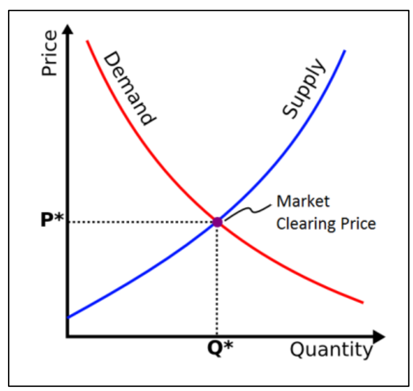
[53] ERCOT reports a steady growth in reported distributed generation (defined as 50 kW or under, by owners with over 2MW of DG capacity), as shown in its quarterly Unregistered Distributed Generation Reports; cumulative reported DG in ERCOT reached 567 MW at the end of the third quarter 2019 (which likely understates total installed distributed PV).
[54] ERCOT, "Emerging Grid Issues Briefing," November 11, 2018.
[55] Solar Energy Industries Association & Wood Mackenzie, Texas data for 3d quarter 2019.
[56] Slusarewicz, Joanna & Daniel Cohan, "Assessing solar and wind complementarity in Texas," Springer Open, Renewables, 2018.

Figure 8 – Peak net load earlier than peak load in ERCOT, summer 2019[57]



The combination of rapid population growth, rising summer temperatures and very fast growth of distributed renewable generation means that the magnitude and shape of customer electricity loads and net loads will change rapidly. ERCOT loads will be harder to forecast and more challenging to serve.

4.2 ERCOT electricity consumption – close to a real demand curve



The most effective economic markets have active supply and demand curves, wherein suppliers can decide how much of the product they want to offer at any price, and customers can decide how much they want to consume at each price. The interaction of these supply and demand curves sets product prices. In markets where many active suppliers compete, such as ERCOT, the market-clearing price will be a time-series of short-run marginal costs, reflecting the cost to produce the last unit consumed.

[57] Source: ERCOT, Project No. 49852, Review of Summer 2019 ERCOT Market Performance, ERCOT's Review of Summer 2019," October 11, 2019.

Classic microeconomic theory holds that rational consumers will want more of something if its price decreases and buy less of it when its price rises. This is reflected in the classic microeconomic demand curve (above). In the case of electricity, however, some electricity uses (such as medical ventilators or an active integrated circuit production line), are so valuable that the user is indifferent to the price of electricity and will consume the same amount at almost any price. Traditionally, most electricity consumers have no real-time information about the price of electricity because they are buying flat-priced energy, and their providers never reveal either the real-time cost of electricity or the amount of electricity that the user is consuming. These limitations create a steep, near-vertical demand curve that is relatively unresponsive to rising electricity prices.

ERCOT's demand curve has become fairly price-responsive because many customers have the opportunity to access information on their electricity usage and access to retail electric rate options that encourage using less electricity in times when it costs the most. ERCOT estimates that during the peak load week of August 12-16, 2019, when load was very high and three actual or near-critical peak loads occurred, at least 17% of load was exposed to real-time energy prices,[58] and customers reduced their peak load use by 1,600 up to 3,100 MW.[59]

Ninety percent of ERCOT's electric meters are advanced meters that measure and record use data in 15-minute or faster time increments.[60] This means that it is theoretically possible for almost 7 million ERCOT electricity users to monitor their electricity usage in near-real time.[61] Texas regulators are presently considering rule changes for real-time electricity use data access that could greatly compromise customers' and third party energy managers' ability to access real-time electricity usage data and act upon that information promptly with price- or use-responsive energy management actions.[62]

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[58] B. Garza, "Item 6, Independent Market Monitor (IMM) Report, Review of Summer 2019," p. 17.
[59] Preliminary estimates from ERCOT, Dan Woodfin, "Review of Summer 2019," GCPA Fall Conference, October 15, 2019.
[60] FERC Staff, "2019 Assessment of Demand Response and Advanced Metering," December 2019.
[61] Association of Electric Companies of Texas, Inc., "The Retail Electric Market in ERCOT, 2019," January 2019.
[62] Many states, including Texas, approved the adoption of advanced interval meters based in part on the promised value of those meters for use in demand response and energy management, to rationalize grid operations and system infrastructure. The recent ACEEE paper, "Leveraging Advanced Metering Infrastructure to Save Energy," explains all the ways that utilities could use AMI data more effectively to

ERCOT has robust retail competition. About 70% of electric residential, commercial and industrial customers have left their default or distribution-affiliated electric provider for service from 116 competitive Retail Electric Providers (REP).[63] In any month in 2018, between 275,000 to 440,000 ERCOT customers shopped for a new REP.

Many electricity customers can participate in retail time-of-use rates and demand response programs. REPs in ERCOT offer over 300 rate plans and products;[64] while many rate plans offer fixed rates (a single price per kWh over an extended contract period), others offer time-varying priced electric rates. These include time-of-use and real-time-pricing rates that increase prices during late afternoon peak use periods, critical peak pricing, and options that offer "free nights and weekends" programs that incent customers to move their energy use away from costly daytime energy use to times when abundant, cheap wind energy is available.[65] In 2018, 1,254,734 ERCOT end-use customers were enrolled in some type of retail time-of-use or price-responsive rate, representing up to 1,415 MW of load that might respond to some form of time-based electric retail prices.[66] These include REP customers and customers served by municipal utilities, such as Austin and San Antonio, that are not open to retail competition. Such retail programs affect how much ERCOT electric customers, in aggregate, are willing to pay for electricity at various times and price levels and thus affect market-clearing electric prices.[67]

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save and manage energy and money. Reducing customers' real-time access to energy usage compromises the ability to achieve these goals.

[63] Public Utility Commission of Texas, "Report Cards on Retail Competition and Summary of Market Share Data," and Public Utility Commission of Texas, "Scope of Competition in Electric Markets in Texas," January 2019.

[64] Association of Electric Companies of Texas, Inc., "The Retail Electric Market in ERCOT, 2019," January 2019.

[65] Texas Power Guide, "Indexed and Time-of-Use Plans Roundup," May 11, 2017.

[66] ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, p. 10.

[67] It is worth noting that most ERCOT REPs were hedged during the peak demand hours and price events in August 2019, so most REPs did not go broke and their retail customers did not experience extraordinary price hikes. However, one company that passes low "wholesale" electric prices directly through to its retail customers did pass along the $9,000/MWh energy market prices. Griddy's end-use customers who were not monitoring the company's price alerts, actively controlling their air conditioning, or offsetting their energy use with on-site solar generation ended up with household electric bills of over $125 and $250 per day during the August peak week. See A. Autler, "Griddy Customers Report Dramatic Spike in Electric Bills During August," CBSDFW.com, August 20, 2019.

ERCOT's transmission and distribution utilities also offer limited load management programs. Many programs pay end-use customers to take a limited number of curtailments on summer weekday afternoons. Over 250 MW of load participates in these programs. These curtailments are dispatched for grid operational reasons and may be deployed during a Level 2 Energy Emergency Alert.[68] Some municipal and cooperative utilities also deploy Conservation Voltage Reduction to lower voltage and thus lower demand by 1-3% along selected feeders during peak load conditions.[69]

The "4CP" mechanism is one of the most impactful demand-shifting mechanisms in ERCOT. Cost allocation rules allocate ERCOT-wide transmission costs based on distribution utilities' and large customers' individual electric demands on the four 15-minute intervals when ERCOT's maximum coincident peak (CP) demand occurs. Therefore, many of ERCOT's REPs and portfolio managers alert customers when a peak demand day is expected so the customer can cut its energy usage to reduce the level of the next year's demand charges. This helps the REP manage its energy portfolio and costs. ERCOT estimates that about 2,475 large customers cut or shifted their peak demand by between 920 and 1,781 MW during 4CP and "near-4CP" events in 2018, materially changing the level and time of peak demand.[70] Estimated 4CP demand in August 2019 ranged from 946 to 2,136 MW on the maximum load and near-coincident peak days.[71]This demand avoidance is not a response to energy prices, but rather an effort to avoid demand charges (presently set at $53.58 per kW for transmission cost recovery). 4CP days occur on the hottest days of the year but are not often coincident with the highest energy prices.[72]

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[68] ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, p. 7-8.
[69] See, for instance, T. Mohammed (CPS Energy) and L. Zhu (Frontier Energy), "Demand Response Potential Using Conservation Voltage Reduction (CVR)," PLMA Conference, May 15, 2019, and Guadalupe Valley Electric Cooperative's explanation of its use of CVR during ERCOT EEA conditions.
[70] ERCOT, "2018 Annual Report of Demand Response in the ERCOT Region," March 2019, p. 8. 2019 data are not yet reported.
[71] ERCOT, February 6, 2020 Letter from Kenan Ogelmann to Public Utility Commission of Texas Commissioners, "Re: PUC Project No. 49852 – Review of Summer 2019 ERCOT Market Performance, Updated Total System Demand Response Price Response Results for Summer 2019, Peak Week August 12- August 16, 2019."
[72] P. Wattles (ERCOT), "External Impacts on System Load," presentation, Gulf Coast Power Association Pre-conference workshop, October 1, 2018.

Large industrial customers and aggregated smaller customers have the option of participating in ERCOT's ancillary and reliability services markets.[73]

- Responsive Reserve Service (RRS) is the dominant option for loads. Loads controlled by high-set under-frequency relays are paid if they are called to provide frequency response. Over 3,000 MW of load is qualified to provide RRS.
- Regulation Service and Fast Responding Regulation Service are attractive options for storage resources, which act as generation resources when injecting energy into the grid and controllable load resources when charging. The number of resources qualified to provide these services will increase as ERCOT's installed storage capacity grows.
- Non-Spinning Reserve options for load resource participation are under development.
- ERCOT can call on Emergency Response Service (ERS) customers to meet grid emergency conditions. ERS has 10-minute and 30-minute ramp requirements that can be provided by loads and small generators. The August 15, 2019 ERS deployment delivered almost 750 MW of load reduction over a 1.5 hour period, exceeding the required reduction level.

ERCOT issues Energy Emergency Alerts (EEAs) when remaining operating reserves fall below 2,300 MW. An EEA triggers ERCOT's use of various levels of Emergency Response Services, REP and other calls for voluntary conservation, and actions such as distribution utility implementation of Conservation Voltage Reduction. Two EEAs were issued during August 2019. In each case, a suite of actions taken on the customer side – response to 4CP signals, distributed generation and customer energy management – and REP demand response chasing high prices and EEA-associated voluntary conservation produced load reductions from 1,800 up to up 3,100 MW during peak hours.[74] These load reductions reduced electricity demand by over 3% in some of the highest-priced hours of 2019 and were essential for maintaining reliable grid operation.[75]

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[73] See ERCOT's "2018 Annual Report of Demand Response in the ERCOT Region," March 2019 for details on these programs.

[74] ERCOT, "PUC Project No. 49852 – ERCOT's Revised Presentation, Review of Summer 2019 ERCOT Market Performance," October 9, 2019, p.26.

[75] Per ERCOT's data, record peak load on August 12, 2019 hit 74,666 MW. On August 12, many larger customers implemented load reductions to reduce 4CP charges. ERCOT estimates total load reductions of 2,500 MW that day. Had the 2,500 MW load reductions not occurred, total peak might have been 77,166

Customer-owned distributed energy resources also affect ERCOT customer demand and load shapes. ERCOT registers larger facilities (1 to 10 MW) and cannot effectively track unregistered (smaller than 1 MW) distributed generation located on a customer's site. At the end of 2018, ERCOT had over 1,300 MW of energy storage and solar, diesel, natural gas, and other generation connected at the distribution level, growing at over 60% per year.[76] Distributed solar PV alone is forecasted to reach 2,580 MW by 2024.[77] ERCOT estimates that distributed generation across ERCOT increased net output by 150 to 200 MW during the August 12-16, 2019 peak periods.[78]

All of the factors and programs above affect the balance between electricity supply and demand in ERCOT and the resulting market equilibrium prices, regardless of whether the demand or distributed resources are actively bid into the market or operate quietly behind the customers' meter or the REP's portfolio. Any non-market measure that affects the level of demand (such as population growth and temperature levels) and the availability of substitutes (such as energy efficiency and photovoltaics), customer price elasticity (such as through demand response) influences the equilibrium market price. If many customers gain the capability to see and respond to real-time electricity prices, their actions will affect market-clearing electricity prices. Though it is appealing to have demand and DER resources show up as active, quasi-supply bidders in the spot market, the rules and high entry costs of becoming active market participants may dissuade such participation and limit demand and distributed generation initiatives. This could harm, rather than enhance, ERCOT's system reliability and resilience.

MW, so load reductions represented over 3.2% of the potential peak. Estimated load reductions rose to 3,100 MW on August 13, 2019, after ERCOT issued an Energy Emergency Alert, when loads were slightly lower but reserves were tighter. Data from ERCOT, "PUC Project No. 49852 – ERCOT's Revised Presentation, Review of Summer 2019 ERCOT Market Performance," October 9, 2019.

[76] ERCOT, "Emerging Grid Issues Briefing," November 8, 2018.

[77] NERC, "2019 Long Term Reliability Assessment Report," December 5, 2019, p. 92.

[78] ERCOT, "PUC Project No. 49852 – ERCOT's Revised Presentation, Review of Summer 2019 ERCOT Market Performance," October 9, 219, p. 53.

5.0 Assessing ERCOT market effectiveness to date

ERCOT's recent experiences – including low reserve margins and occasional high prices – offer evidence that the energy-only market design is working effectively. This evidence includes:

- Continuing turn-over in supply-side resources – Following years with low average prices, ERCOT has seen on-going retirement of older, less efficient generators and continued investment in new generation. Due to continuing resource additions, ERCOT projects a 10.6% reserve margin in 2020 and an 18.2% reserve margin in 2021.
- Good generator operational performance in summer – Generators operated with very low forced and planned outage rates in the summers of 2018 and 2019 to assure high unit availability to capture high prices and maximize revenues during summer scarcity events.[79]
- Increasing demand response – High levels of customer response to high prices and grid scarcity conditions made a material difference to ERCOT's reliability.
- Continuing reliability – Working in concert with its regulators, customers, generators and transmission and distribution utilities, ERCOT has been able to maintain a continued balance of supply and demand during many years of growing summer peak demand, despite tight reserve margins.
- Low wholesale prices – Historically, wholesale electricity prices in ERCOT have been consistently lower than other regions – with the exception of short, severe price spikes on peak summer days.[80]
- Strong competition – The ERCOT wholesale market has been able to support a thriving, creative, highly competitive retail market.

[79] Potomac Economics, "Item 6: Independent Market Monitor Report, ERCOT Board of Directors Meeting," October 8, 2019, p. 17.
[80] See, for instance, Energy Information Administration, "Wholesale energy prices were generally lower in 2019, except in Texas," January 10, 2020.

5.1 Challenges for ERCOT's market and operations going forward

The key question is whether ERCOT's market will be able to maintain this performance and keep delivering reliable electric service to Texans in the future. Looking ahead, there are four major factors that will affect the continuing effectiveness of North American electric grid – including ERCOT:

1) the ongoing replacement of older fossil-based, rotating mass generation with clean intermittent, inverter-based renewable generation and storage,
2) the complex and interrelated trends of manageable customer loads, load growth from electrification of fossil end uses, and energy efficiency of electric end uses,
3) the effects of climate change upon electric demand and energy infrastructure,
4) in the case of ERCOT alone, whether Texas policymakers are willing to hold firm to the principles and structure of this unique market.

5.1.1 Intermittent renewable resources

Recent and projected generation investment patterns make it clear that wind and solar generation and storage projects (both stand-alone and in various hybrid combinations) are now the most economical supply-side resources to build in ERCOT. Thanks to advanced inverter controls and increasing use of storage with renewables, intermittent resources are becoming increasingly dispatchable. But intermittent renewables have operational challenges that controls and storage can't remedy – most obviously, the fact that the wind doesn't always blow and the sun doesn't always shine. These change net load shapes create ramping and flexibility challenges and reduce the proportion of rotating mass-based inertia on the grid. Operationally, higher levels of intermittent renewables are lowering and flattening wholesale energy prices, making it more difficult for operators to select and dispatch resources when so many resources are bidding near-identical low prices.

As Texas' $7 billion CREZ (Competitive Renewable Energy Zones) project illustrated, new utility-scale renewable generation may require extensive new transmission build-out to link generation sites to the grid and load centers. Many of the projects in the ERCOT transmission interconnection will be delayed until new transmission can be sited and built. There is more than $6 billion of additional transmission investments planned and expected in service by 2025, with 25 GW of renewable generation expected to be interconnected in West Texas by that time.[81]

However, the electric industry has been developing many tools and technologies to enable reliable grid operation at high renewables penetration levels. ERCOT is among the world leaders in developing and using innovative analytical tools and engineering practices to plan and operate a high-renewables power system delivering reliable service at reasonable cost. And intermittent renewables offer documented benefits besides low cost, including technology diversity, geographic dispersion, low emissions, low water use, economic development for rural areas, and good jobs.

5.1.2 Activating demand-side resources

The traditional way to deal with resource adequacy – assuring that there is always enough supply to meet customer demand – has been to manage supply to cover varying demand levels. But given the high rate of Texas and ERCOT population and load growth and the rapidly changing supply landscape, it is not reasonable to expect that we can maintain the balance between electric supply and demand by managing only the supply side resources. There are many risks and uncertainties today affecting supply assurance. These include the competitive deterioration and closure of many traditional fossil and nuclear power plants, the availability of capital to fund new renewables and storage investments, getting transmission built quickly to interconnect new generation in remote locations, how to recover the capital costs of new generation when energy prices remain quite low, and how to assure resilience as well as reliability when both load and supply conditions are changing faster than ever before.

It is therefore prudent to consider how we could manage and use demand to keep supply and demand in balance. Over the operational time horizon, it is possible to use analytics, communications, automation and control technologies to make many end-use loads dispatchable. This means a grid operator, REP or energy service provider could actively use customer facilities and energy uses to lower demand for peak reduction, raise demand to absorb high levels of on-site PV generation or remote night-time wind generation, or manage demand to manage grid frequency, provide fast-ramp services,

[81] ERCOT, "Report on Existing and Potential Electric Constraints and Needs," December 2019.

respond to local voltage fluctuations, and more.[82] It is also possible to automate many electricity end uses so they can operate within customer sites and distribution feeders to absorb on-site PV and reduce the magnitude and volatility of net demand before it creates a potential problem at the bulk system level. These demand management capabilities of speed and flexibility are essential to deal with growing levels of intermittent renewable generation.[83]

Over the longer planning horizon, we can use energy efficiency (building codes, building and industrial efficiency retrofits, and high-efficiency appliances) to slow and perhaps flatten the rate of growth of peak load and energy demand. Energy efficiency is a particularly useful resource for Texas because of its value for reliability and resilience. As outlined above, it is challenging to operate a rapidly growing energy and peak demand on a power system with tight reserve margins. Although ERCOT and its generation owners have been successful thus far, grid operations become more challenging to manage every year with higher levels of intermittent renewable generation and distributed resources that the grid operator does not directly dispatch. It would be easier to operate the grid and protect system reliability and affordability if the electricity peak and energy demand growth were slowed by more aggressive use of energy efficiency. This would give grid operators and planners more time to adjust market operations, technology and infrastructure to the changing resource mix and growing loads and enable more demand-side solutions to complement supply-side options.

Texas consumes more energy than any other state and was the first state to adopt an energy efficiency resource standard (EERS). Today, however, Texas' EERS, implemented through transmission and distribution utility programs, only requires annual savings of 0.4% of peak demand. Comparable standards in other states aim for between 1 and 3%

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[82] See, for instance, the Brattle Group study, "The National Potential for Load Flexibility – Value and Market Potential Through 2030," June 2019, and the National Institute of Standards & Technology, "Characterization of Residential Distributed Energy Resource Potential to Provide Ancillary Services," October 2018.

[83] A variety of analyses indicate the value of demand response for renewables integration, including: Nolan, Burke et al., "Synergies between wind and solar generation and demand response," 13th Wind Integration Workshop Proceedings, 2014; "Synergies between renewable energy and energy efficiency," IRENA, August 2017; Institute for Sustainable Futures, "Renewable Energy and Load Management," 2017, and C. Linville et al., "Flexibility for the 21st Century Power System," Regulatory Assistance Project, October 29, 2019.

energy savings.[84] The U.S. Department of Energy recently estimated that Texas has more economic energy efficiency potential than any other state and could be saving 12.3% of annual state electric sales across all sectors in 2025 and 18.8% in 2035 if it were to implement high-quality energy efficiency efforts.[85] That study found that 53% of Texas' current summer peak load and 44% of winter peak load is weather-sensitive and, therefore, ripe for efficiency improvements.

Energy efficiency offers multiple benefits. As one of the lowest-cost resources available, energy efficiency:

- is cost-competitive with wind and solar generation,
- lowers energy bills and improves energy affordability for end-use customers,
- creates real economic savings that can feed the state's economy and economic competitiveness,
- creates high-quality jobs,[86]
- protects human health and safety,
- reduces energy-related pollution and greenhouse gas emissions, and
- enhances customer and community resilience against extreme weather events and grid failures.

5.1.3 Climate change

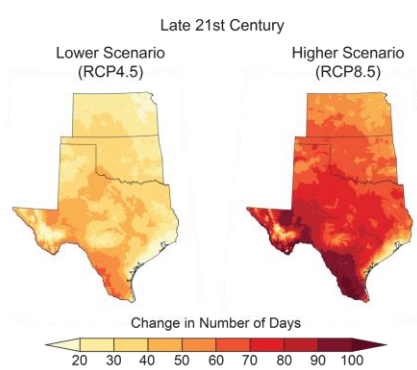
The future reliability and resilience of electric service in Texas will be threatened by the anticipated effects of climate change. These impacts will include factors that will significantly increase the demand for electricity (such as drought and higher temperatures) and may compromise grid asset operations and integrity (such as sea level rise, extreme storms and higher temperatures).

[84] W. Berg, S. Vaidyanathan et al., "The 2019 State Energy Efficiency Scorecard," American Council for an Energy Efficient Economy, October 2019.
[85] Electric Power Research Institute for U.S. DOE, "State Level Electric Energy Efficiency Potential Estimates," May 2017, p. 4-4.
[86] The report, "Energy Employment by State – 2019" from the National Association of State Energy Officials and the Energy Futures Initiative estimated that 162,816 Texans already work in energy efficiency-related jobs (including equipment manufacturing, construction, HVAC and insulation).

ERCOT's ten-year forecasts incorporate a rolling 15-year temperature history, but do not reflect forward-looking temperature changes relating to climate change. The Texas-specific summary of the Fourth National Climate Assessment indicates that the effects of climate change will include, "a variety of extreme weather events, including hurricanes, tornadoes, droughts, heat waves, cold waves, and intense precipitation."[87] It warns of an increase in intense rainfall and that Texas temperature ranges could rise substantially. Some climate change threats that could affect electric system operations include, drought, wildfires, sea level rise and extreme precipitation events. These risks should be considered explicitly in ERCOT's risk assessments and forecasts.

Increased Temperatures – Climate change is expected, "to lead to an increase in average temperatures as well as frequency, duration, and intensity of extreme heat events and a reduction in extreme cold events," with average annual temperatures higher by 3.6° to 5.1°F by 2050 relative to the late 20th century. As shown in Figure 9, Texas is likely to have three or four times as many days with temperatures over 100°F as it does today.[88] Between 2041 and 2050, for example, the mean August temperatures in Dallas-Fort Worth could rise from a mean of 86°F at the end of the 20th century to an average of 94°F with extreme temperatures up to 120°F. These factors will amplify urban heat island effects, causing as much as a 10°F temperature difference between downtown cities and adjoining rural areas and significantly increase the amount of cooling load that the grid will be expected to serve reliably.

Figure 9 -- Projected increase in number of days above 100ºF[89]



[87] National Climate Assessment, "Texas State Summary," NOAA National Centers for Environmental Information.
[88] Environmental Protection Agency, "What Climate Change Means for Texas," August 2016.
[89] Source: National Climate Assessment, "Texas State Summary," NOAA National Centers for Environmental Information, p. 990.

Drought – Texas is already vulnerable to periods of drought. Looking forward, naturally occurring droughts will likely be more intense and last longer as temperatures rise and remain high. Drought reduces the water supply availability for power plant cooling and raises the temperature of the water available (particularly for plants with reservoir cooling), thus reducing its cooling effectiveness. This affects nuclear, coal, natural gas combustion turbine and combined cycle generators, particularly those using surface lakes, reservoirs or run-of-river water for cooling.

In a recent example of water scarcity impacts, Xcel Energy announced plans to cut back non-summer operations and close the 1,067 MW Tolk coal-fired power plant in the Texas Panhandle no later than the end of 2032 (although original plans were to run it through 2042) because the plant requires cooling water from the Ogallala aquifer. That aquifer is drying out due to high agricultural, urban and industrial water demands.[90]

During the 2010-2015 Texas drought, a number of water-cooled power plants were derated or placed on forced outage due to low lake levels.[91] A longer, deeper drought might have forced more widespread plant shutdowns, compromising grid reliability at a time when over 80% of ERCOT's capacity required significant amounts of water for cooling. ERCOT reports that most reservoirs have enough storage capability to withstand one to two very dry years[92] under past temperature and wind conditions; however, such reservoir capability would be compromised by evaporation due to hotter temperatures and higher winds and longer extreme drought conditions. Thus, future droughts pose a significant threat to the long-term reliable operation of ERCOT's fossil generation-based supply system and may justify derating fossil plants in some resource forecasts.

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[90] K. Balaraman, "Water scarcity accelerates plans to close Xcel's Tolk coal plant by a decade," Utility Dive, January 15, 2020. This plant is not in ERCOT, but it illustrates the impact of drought upon generation availability.
[91] ERCOT, "Retrospective Analysis of the 2010-2015 Drought in ERCOT," 2016.
[92] Ibid., p. 24.

Wildfires – Cycles of drought, heat and extreme rainfall increase the frequency and magnitude of wildfires in both forests and grasslands. Wildfires threaten the safe operation of utility transmission and distribution assets, which may need to be shut down when a wildfire is near. This means that even if there is sufficient operational generation capability to meet demand, a wildfire could compromise deliverability of that energy to customers.

Sea Level Rise – Sea levels along the Texas Gulf coast have already risen 5 to 17 inches over the last century and could rise one to 8 feet by the end of the century. A 1,000 square mile area of Texas lies within 5 feet of the now-moving high-tide line, including roads, hospitals, refineries, and four power plants, and $9.6 billion in current assessed property value and homes.[93] Coastal flooding destroys customer facilities that consume electricity as well as the utility assets that produce and deliver electricity.

Extreme Precipitation – The increased frequency of longer-duration heavy precipitation events will cause more severe inland flooding, which could wash out or otherwise harm electric transmission and distribution facilities and damage customer facilities and associated electricity usage.

As a short-term measure, ERCOT companies can use new hedging and insurance tools to mitigate wholesale price risk due to high temperature or extreme wind events.[94] As a longer-term matter, major insurance and finance companies have begun reassessing how much they are willing to support assets at risk to climate change. Some companies have announced major insurance rate increases for assets at risk to sea level rise and climate change-exacerbated wildfire risk. Such policies will become more widespread and will begin to affect the pattern and

[93] U.S. Global Change Research Program, "Fourth Annual Climate Assessment, Chapter 23, Southern Great Plains."
[94] M. Watson et al., "New instruments developing to hedge power market weather risk: Swiss Re," Electric Power, November 21, 2019.

location of energy uses as well as the assets and methods that electricity providers use to serve their customers. ERCOT and the PUCT should be cognizant of how these changing risks may affect system assets and costs in the future.

5.1.4 Texas Regulation

There is a risk that Texas legislators or regulators could lose faith in the long-term effectiveness of the ERCOT energy-only market structure. This structure will only work if capital investors and customers have confidence that the market rules and principles will hold over the long term, without the major modifications and interventions that have occurred in other markets. Texas policymakers have held fast to the promise of full competition and the energy-only market since these were first established in the late 1990s; it appears likely that these competitive principles and structures will stand for the coming decades.

5.2 How to assure ERCOT's continued reliability and resource adequacy going forward

ERCOT's vibrant competitive electric market has worked effectively since competition began in 2001, but additional extra-market policies and market-specific changes could protect and enhance both competition and electric reliability in the years ahead. Though many of these recommendations directly address elements that are integral parts of the ERCOT market structure, others address factors that affect supply and demand outside the wholesale market structure and rules.

Over the last two decades, Texas' electric industry and its regulatory and policy apparatus have refined the specifics and nuances of electric supply resource technology and development, power system operation, and wholesale market rules. Much less attention has been paid to how demand-side factors and distributed energy resources affect system reliability and resource adequacy. This set of recommendations addresses market operations and supply issues, but focuses primarily on ways that demand and DERs can be used to complement the ERCOT market and serve Texans.

5.2.1 Distributed generation and energy storage

- Customer choice is a core principle of Texas energy policy. Given the explosion of technology options for customer-sited energy generation and storage and the falling prices for these technologies, regulators should assure that DER interconnection rules and TDU rate structures do not stifle DER adoption.
- The PUCT should require all new customer-side and distribution-connected generation and storage to use IEEE 1547-compliant smart inverters for interconnection; this could be inserted into state building codes as well as implemented for utility DG interconnection purposes. This will protect grid operations at the distribution level, improve data collection and monitoring on the grid, and facilitate integration of DERs.
- Since photovoltaic generation is coincident with many hours of air conditioning load in Texas, it is a desirable asset for the state's grid. ERCOT and the TDUs should explore how to use energy storage and building energy management techniques to reduce the PV-caused ramping burden in late afternoon and early evening and find ways to use distributed customer resources to actively manage PV impacts at the local and bulk power levels.

5.2.2 Energy efficiency and demand response

- All electric TDUs should be required to deploy enough energy efficiency to cut peak load by no less than 1.0 % per year starting in 2022 and 1.5% per year starting in 2025, with an additional requirement to cut energy use no less than 1.0 % by 2023 and 1.5% per year by 2026. These targets should rise further over time.

    - The state should change energy efficiency funding rules and raise spending caps accordingly. A focus on peak reduction as well as energy overall reduction is consistent with the rise in high temperatures and heat waves that Texas has been experiencing over the past two decades, and the rising heat levels forecast ahead.
    - Texas should end the industrial customers' ability to opt out of funding energy efficiency programs.
    - The state should recognize the efficiency benefits from T&D capital and line loss savings. Texas should also value and reward the risk reduction

benefits associated with efficiency in calculating deemed savings and program and portfolio cost-effectiveness.

    - Energy efficiency measures that qualify for TDU programmatic support should be expanded to include sensors and automated energy end uses, communications and controls, and coordinated with demand response and demand flexibility opportunities to support grid operations as well as customer energy savings. These would enable ERCOT to dispatch demand to help balance intermittent supplies, rather than placing all the burden on dispatching supply.

- Texas should adopt the next generation of building energy efficiency standards and standards for zero-net-energy buildings and building energy certification. The state should not adopt any statutes or provisions that limit local jurisdictions' options to exceed the state's requirements for renewable energy or energy efficiency.
- Texas should encourage customers who wish to add rooftop PV to first secure an energy efficiency audit and undertake energy efficiency improvements to the host facility.
- The PUCT should consider how to implement "Pay as You Save" and "Property Assessed Clean Energy" loan financing through TDUs to remove additional barriers to efficiency investments.
- A significant amount of Texas' electricity is used to pump, process and move water, and a significant amount of Texas' water is presently used for electricity production (although this is diminishing as fossil-fired plants retire). The PUCT should work with the Texas Water Development Board to study the nexus between water and energy use and the potential impacts of climate change on water and energy and develop policy recommendations to constructively address these impacts in both arenas.
- Texas should reject proposals to limit customer and third-party energy service providers' access to real-time meter data and instead improve customers' real-time access to their personal energy consumption and meter data.

5.2.3 Equity

- Many Texans in lower-income and communities of color do not share in the benefits of the state's strong economy. And many Texans pay more than 10% of their income on energy bills. These same communities are likely to be disproportionately harmed by the adverse health and infrastructure effects of climate change. Texas should adopt, fund and expand programs that engage and support these communities, including energy bill discounts, energy efficiency investments, community solar, job training for clean energy jobs, and climate change adaptation and relocation assistance.
- Texas should significantly expand funding for the State Energy Conservation Office's Loan Star revolving fund for energy conservation investments to make that funding available to state and local governments, schools and community action organizations for a wide variety of energy efficiency, demand response, energy storage and renewable energy investments.

5.2.4 Electrification

- The state should prioritize customer energy end uses that can be electrified in ways that can improve T&D asset utilization, rather than merely increasing electric load in ways that might exacerbate reliability problems. Examples include using electric water heaters in lieu of gas and using electric vehicle batteries and customer-owned battery storage devices to provide ancillary services such as fast-ramping to the grid.

5.2.5 Market changes

- ERCOT, the Independent Market Monitor and the PUCT should monitor and maintain the effectiveness of the ORDC as a mechanism to signal resource scarcity in appropriate times. Any mechanisms intended to replace ORDC must be tested rigorously to assure that they deliver the same impact for wholesale prices to motivate both demand and supply responses.
- ERCOT should continue and expand its efforts to create energy and ancillary service market products that maximize operational speed and flexibility. These products should be performance-based and technology-neutral, so that they can be provided by supply, demand and storage resources, and take maximum

advantage of the technology capabilities of new inverters and load controllability. All energy and ancillary services products should be subject to co-optimization between market products and time horizon.

- Consistent with the above, the PUCT and ERCOT should facilitate participation in ERCOT's wholesale market of customer-aggregated, automated demand response and other distributed energy resources as dispatchable resources (e.g., a "virtual power plant") that are integrated into the electricity supply stack.
- ERCOT should continue to exercise restraint in the use of emergency procedures which suppress or interfere with price formation[95] through the direct interaction of supply and demand.
- The PUCT should maintain or strengthen requirements that all major power purchasers – REPs and Qualified Scheduling Entities – are credit-worthy counter-parties. This will protect the value of power purchase agreements for financing new investments and reduce the risk of defaults for customers and the market as a whole.

5.2.6 Transmission and distribution utilities and resilient infrastructure

- Preserve the allocation of transmission costs across all loads on the basis of customer load-share so all electric customers bear a fair share of the costs of the infrastructure that serves them.
- The PUCT should work with the TDUs and market stakeholders to make distribution system planning more transparent for both real-time operations and planning purposes. This could include using artificial intelligence tools to identify distributed energy resources below feeders and behind customer meters.
- TDUs should be required to examine non-wires alternatives – customer-sited and distribution-interconnected DG, community solar, storage and demand response – and adopt them as alternatives to new transmission construction if the

[95] Market prices are used to establish and express the equilibrium between supply and demand. "Price formation" is commonly used in the electric industry to mean the process and rules by which locational marginal prices that result from the wholesale market bid and dispatch process. Because low natural gas prices and growing levels of near-zero marginal cost renewables are bidding into centralized electric spot markets, spot market average prices have been falling and supply resources are receiving lower energy market returns. Market participants complain about price formation and market design flaws when prices are lower than they want, but rarely complain about price formation when prices are high.

distribution-level alternatives can cost-effectively defer or avoid new transmission investments.[96]

- The PUCT should conduct a detailed study to examine the many ways that climate change-associated extreme weather can damage T&D infrastructure in Texas and direct the TDUs to plan how to modify or strengthen utility infrastructure to enhance future resilience and reliability. This should include consideration of how to evaluate the prudence of new T&D investments in areas that will be vulnerable to reasonably foreseeable harm from sea level rise, inland flooding and wildfires. This examination should also consider how to serve citizens in at-risk zones through alternate approaches and technologies beyond classic central grid-connected technologies.
- Since Texas will continue to need some gas-fired generation for the coming decades, the PUCT and Texas Railroad Commission should conduct a detailed study on the likely effects of climate change-associated extreme weather upon the state's gas delivery infrastructure and consider what changes are necessary to enhance its resilience and reliability in the future.
- The PUCT should support additional grid modernization projects that facilitate grid monitoring, two-way power flows, secure grid operations, and sophisticated controls that help distribution- and customer-level tools and resources to integrate with and support overall power system reliability and efficiency.

5.2.7 New renewables

- Support the addition of wind and solar resources, particularly those combined as hybrids or virtual hybrids with energy storage capability. These will improve the capability of these resources to provide ancillary services such as fast-ramp and frequency control and reduce the impact of electric generation on water use.
- Maintain the ERCOT policy of building new transmission to interconnect new generation, to enable the continuing development of new generation in prime resource locations.

[96] In addition to the extensive literature on non-wires alternatives, see the Texas Advanced Energy Business Alliance's paper, "The Value of Integrating Distributed Energy Resources in Texas," November 2019, which enumerates the beneficial impacts of using DERs in lieu of T&D expansion.

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