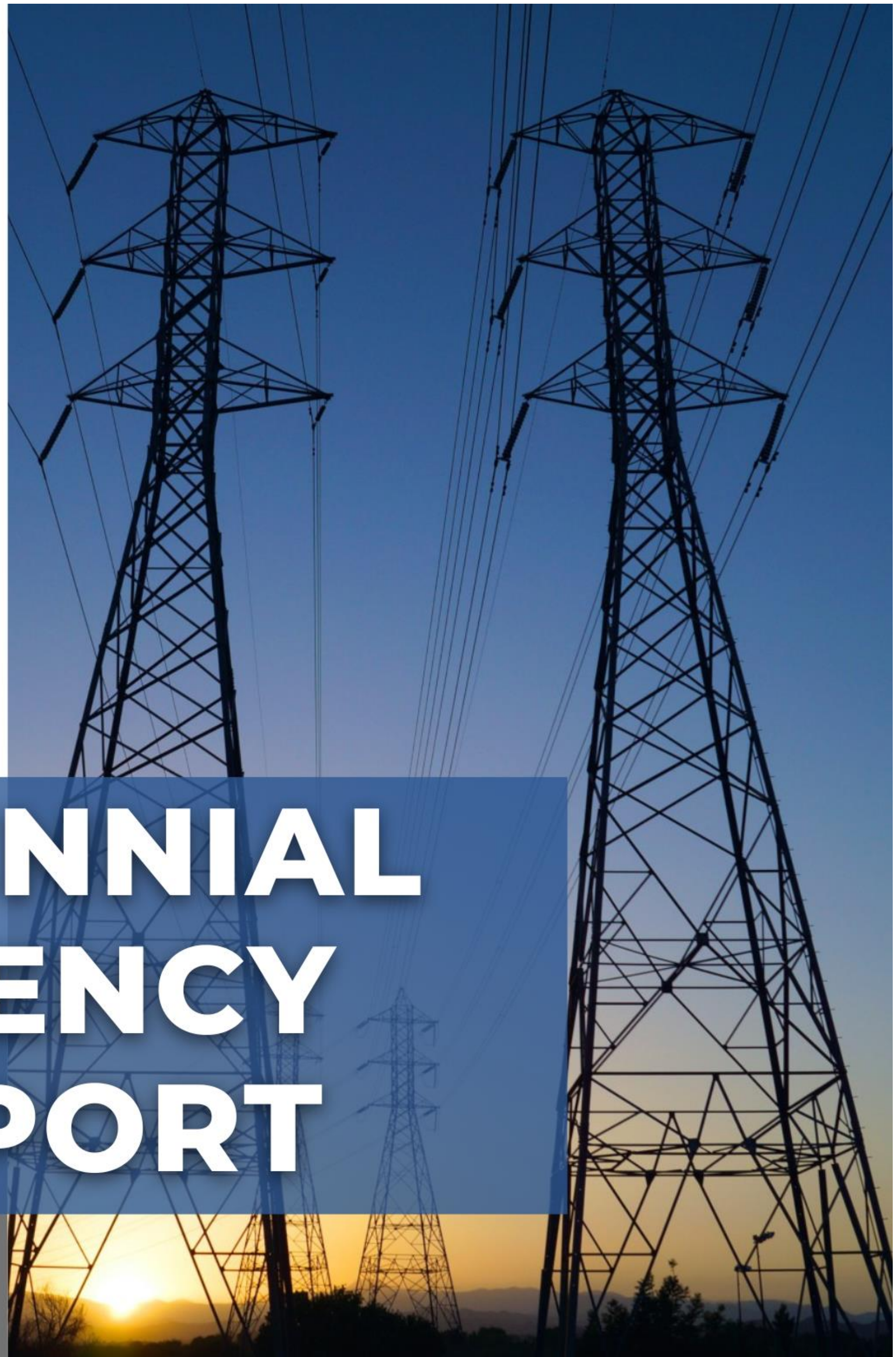
JANUARY 2023



BIENNIAL AGENCY REPORT

TO THE 88TH TEXAS LEGISLATURE

Introduction

What We Do

The Public Utility Commission of Texas (PUCT) regulates the state's electric, telecommunications, and water and sewer utilities, implements related legislation and helps resolve consumer complaints.

Mission

The PUCT protects customers, fosters competition, and promotes high quality and reliable infrastructure.

Purpose and History

The PUCT was established in 1975 to protect the public interest inherent in public utility rates and services. The Public Utility Regulatory Act (PURA)[1] was enacted to ensure rates and services that are just and reasonable to consumers and utilities. The Texas Legislature passed legislation in 1995 that significantly altered the PUCT's role by establishing a competitive electric wholesale market. Furthermore, the Federal Telecommunications Act of 1996 significantly impacted the PUCT's responsibilities by allowing competition in telecommunications wholesale and retail services. The Texas Legislature provided additional restructuring of the electric utility industry in 1999, opening many areas of Texas to competitive retail electric provider choice.

The PUCT's mission and focus remains on rate and service regulation, competitive market oversight and compliance enforcement of statutes and rules for the electric and telecommunications industries. Effective oversight of competitive wholesale and retail markets for electric and telecommunication companies is necessary to ensure that consumers receive the economic and reliability benefits of competition.

The PUCT initially regulated water utilities, but in 1986 jurisdiction was transferred to the Texas Water Commission. The PUCT took over economic regulation of water and sewer utilities from the Texas Commission on Environmental Quality (TCEQ) in 2013. This transfer included programs governing the regulation of water and sewer rates and services, the certification of service territories, and the ownership of water utilities.

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.302 (West 2016 & Supp. 2018), §§ 59.001-66.016 (West 2007 & Supp. 2018) (PURA).

Guide to this Report

Statute requires several reports to the Legislature from the PUCT. For convenience, this report consolidates some of those reports into one document. Specifically, this report fulfills the following requirements:

- Legislative recommendations (PURA § 12.203), beginning on page 94;
- Scope of competition in electric markets (PURA § 31.003), beginning on page 13; and
- Scope of competition in telecommunications markets (PURA § 52.006), beginning on page 57.

Unless otherwise specified, all legislative bills discussed in this report refer to those passed by the 87th Texas Legislature, Regular Session.

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Agency Highlights

During the 2021-2022 biennium, the PUCT faced significant challenges and accomplished numerous objectives in support of its mission. This chapter highlights some milestones, with more information available throughout the report.

New Commissioners

On June 18, 2021, Senate Bill (SB) 2154 was signed into law by the governor. SB 2154 amended PURA § 12.051(a) to expand the number of Commissioners serving at the PUCT from three to five. Four Commissioners were appointed in 2021, and on August 5, 2022, Kathleen Jackson was appointed as the fifth Commissioner of the PUCT.

	Peter M. Lake Chairman Appointed April 12, 2021
	Will McAdams Commissioner Appointed April 1, 2021
	Lori Cobos Commissioner Appointed June 17, 2021
	Jimmy Glotfelty Commissioner Appointed August 6, 2021
	Kathleen Jackson, P.E. Commissioner Appointed August 5, 2022

Reorganization

Since January 2021, the PUCT has undergone several changes to better serve Texans and address market, compliance, and rulemaking issues that arose after Winter Storm Uri. The following are the organizational changes:

Market Analysis

The Market Analysis division was expanded to include an attorney and an engineer to help manage the complex legal and technical issues facing the competitive Texas electricity market. This legal and engineering expertise allows Market Analysis to provide comprehensive review of topics including new technologies entering the market, complaints against the Electric Reliability Council of Texas (ERCOT), ERCOT Protocol revisions, and compliance with PUCT rules and orders.

Division of Compliance and Enforcement

In July 2020, the PUCT's enforcement staff merged into the Legal Division to make more efficient use of agency resources. At that time, the Legal Division's larger team of attorneys offered more flexibility in addressing various legal issues. After Winter Storm Uri, the PUCT determined a division solely committed to ensuring compliance with PUCT rules was appropriate. The Division of Compliance and Enforcement (DICE) was created in September 2021. DICE investigates and enforces potential violations of laws and rules regulating the electric, water, and telecommunications utility industries that have the potential to impact the broader public interest. DICE also participates directly in informal and formal proceedings related to PUCT rule violations and settlements for administrative penalties.

Rules and Projects Division

In September 2021, the Rules and Projects Division (RAP) was created to address the large number of rulemakings required to implement legislation from the 87th Legislative Session. RAP ensures consistency and compliance with the Texas Administrative Procedure Act and allows subject matter experts in other divisions to focus on substantive policy implementation.. RAP also assists in drafting agency reports, performs research on current legal issues, and supports improvements to agency processes.

Office of Public Engagement

In August 2022, the Office of Public Engagement (OPE) was created to make the PUCT more accessible for all Texans. OPE serves as a resource to explain PUCT administrative processes and instruct Texans on how to participate in rulemakings, rate cases, hearings, and other important activities the PUCT regularly performs.

New Initiative: Multi-Language Team

In February 2021, a multi-language team was created to enhance communication with Spanish-speaking consumers. The agency's Customer Protection Division (CPD) has traditionally employed bilingual staff who are focused on assisting consumers with utility-related concerns. The multi-language team adds subject matter experts in utility regulation and attorneys as a cross-divisional initiative. The team reviews PUCT documents to reflect the language diversity of the State. The multi-language team also ensures new and existing forms and notices used or received by utility consumers are in plain English and Spanish and therefore are understandable to consumers.

New Initiative: Enhanced Communications

In January 2022, the PUCT began an effort to dramatically improve its external communications with the public, regulated industries, stakeholder groups, and media by authorizing the expansion of the agency's Communications team. As of November 2022, the role has grown from a single full-time employee to four positions. The team now includes a director of communications, a web and social media content creator, a web administrator, and a press officer. The expansion of the team has significantly increased the PUCT's social media activity and outreach by directly engaging with Texans through consumer advocacy and assistance-related content, as well as real-time updates during critical events. The team has enhanced interaction with news media and initiated website upgrades to improve consumer accessibility to PUCT content.

Agency's Actions in Response to Winter Storm Uri 2021

In February 2021, Winter Storm Uri produced an extreme cold weather event across the Eastern, Central, and Southern United States. Major load centers across Texas endured sustained and severe low temperatures, dropping to -2°F in Dallas, 13°F in Houston, 12°F in San Antonio, and 6°F in Austin. On the evening of February 14th, consumers started experiencing service outages as the extreme cold, wind, ice, and snow impacted local electric infrastructure. Electric generation units also experienced forced outages as wind turbines froze and thermal generators tripped offline due to weather or limited fuel resources. On Monday, February 15th at 12:15 a.m., ERCOT declared an Energy Emergency Alert (EEA) Level I event because operating reserves were less than 2,300 Megawatts (MW) and not expected to recover within 30 minutes. The event progressed quickly. By 1:20 a.m., ERCOT had declared an EEA level 3 event and ordered firm load shed that was implemented by electric utilities with rotating outages. Rotating outages are controlled, temporary interruptions of electric service that are required in extreme circumstances to balance supply and demand on the electric system. Firm load shed is involuntary load shed that the end-user did not initiate or previously contract for to reduce load. The controlled outage orders remained in place until 12:42 a.m. on Thursday, February 18. However, some consumers remained without power because of storm-related damage to transmission and distribution infrastructure. ERCOT did not return to normal operations until 10:35 a.m. on Friday, February 19.

Winter Storm Uri greatly impacted the electric and water industries under the PUCT's regulatory jurisdiction and the consumers it's charged to protect. The PUCT has been working to address problems that arose during and after the storm. These efforts include process improvements, policy initiatives, and increased collaboration with other state agencies and ERCOT. The PUCT has also worked to implement legislation enacted in response to the storm. Key efforts in the PUCT's response are highlighted below. Specific long-term reforms related to ERCOT reliability operations and market design are detailed in the section titled Electricity: Resiliency and Market Design.

The PUCT held five emergency open meetings to address Winter Storm Uri-related issues between February 15th and February 21st. During these meetings, the PUCT issued a series of orders focused on wholesale market pricing issues in ERCOT. The orders also granted ERCOT some discretion to resolve financial obligations resulting from the event. The PUCT took other actions including ordering transmission and distribution utilities (TDUs) to rotate consumers when subject to load shed obligations and providing enforcement discretion for load resources deployed during the event who were unable to follow standard processes for restoring operations. The PUCT also directed ERCOT to ensure, through its Protocols, that real time energy prices reflect the value of any firm load shed during energy emergencies (EEA 3) to provide effective economic signals to the market. Financial issues have been addressed through the adoption of securitization orders as required by SB 3 and contested cases before the PUCT and bankruptcy courts.

The PUCT also addressed problems faced by consumers during Winter Storm Uri through emergency orders. Good cause exceptions were granted to certain consumer protection rules to provide relief to electric, water, and sewer consumers affected by Winter Storm Uri. The PUCT suspended disconnects for nonpayment, waived late fees, and reaffirmed the requirement, established in response to the COVID-19 pandemic, to offer deferred payment plans to consumers. For electric consumers in areas open to competition, the PUCT allowed additional Retail Electric Providers (REPs) to volunteer to offer Provider of Last Resort (POLR) service. This helped provide retail market stability and guarantee competitive rates to affected consumers as financially distressed REPs were no longer able to provide service. Many of these actions have been codified in rulemakings to provide immediate relief in any future emergency events.

The PUCT opened its consumer assistance call center on Sunday, February 14, 2021, operating the phones from 2 – 7 p.m. This was the first activation of the call center on a weekend in the PUCT's history. PUCT staff took calls again on Monday, February 15th, the President's Day holiday. Staff from across the agency filled in to triple the size of the call center. From February 14th to February 19th, the call center received 4,107 calls, or about a typical week's worth of calls each day.

Immediately following the storm, PUCT staff began evaluating ERCOT governance. The efforts looked at the PUCT's complete authority over ERCOT and focused on improvements to communications, governance, and cooperation between ERCOT, Inc. and the PUCT. Several touchpoints for increased engagement have been established, including standing calls between PUCT and ERCOT leadership. ERCOT has also dedicated specific subject matter experts to work with PUCT staff, including a Vice President of Corporate Strategy & PUCT Relations as the primary contact and facilitator. SB 2 enacted major reforms at ERCOT including establishing a new board of directors independent of market interests. SB 2 also requires the PUCT to explicitly approve all rules adopted by ERCOT before the rules may take effect. The PUCT has approved bylaws addressing the revised board composition along with 127 market rule revisions. The PUCT has also directed ERCOT to refine its roles and responsibilities at the State Operations Center when activated for an emergency event.

Additional efforts have focused on gas-electric coordination, including engagement with the Railroad Commission of Texas (RRC) and formalizing the Texas Energy Reliability Council (TERC). Prior to Winter Storm Uri, TERC was an informal body that included leadership from the PUCT, RRC, and ERCOT, as well as industry representatives. SB 3 formalized TERC to ensure that the energy and electric industries in Texas meet high priority human needs and address critical infrastructure concerns. TERC also enhances coordination and communication in the energy and electric industries. TERC is comprised of state agency leadership, including the PUCT Chairman, and energy industry leaders appointed by these state agencies. As required by SB 3, the PUCT made 8 appointments to TERC on October 19, 2021. The appointees represent numerous sectors of the electricity market, including transmission and distribution, dispatchable electricity, renewable electricity, electric storage, retail electric providers, and municipal and cooperatively owned utilities. The PUC's Chairman, staff, and appointees actively participated in the TERC process and provided valuable contributions to TERC recommendations report that was finalized in November 2022.

PUCT and RRC have also worked together on legislative implementation, including rules regarding critical natural gas facilities and the development of the Texas Electricity Supply Chain Map. PUCT has also directed ERCOT to create a firm fuel product and to ensure that a facility producing natural gas critical to electricity generation does not volunteer to reduce power usage during emergency events.

Winter 2022

Winter 2021-2022 marked the first cold weather season following Winter Storm Uri. In preparation, PUCT implemented targeted reforms and worked closely with ERCOT on a reliability-focused operating approach. ERCOT advocated for a revised 2022 Ancillary Services Methodology that increased the minimum amounts of ancillary services it would procure and moved forward the timelines for deployment. It also noticed the market of its intention to bring more generation reserves online and deploy them earlier if needed to ensure supply would meet demand. Following adoption of the PUCT's weatherization rule, ERCOT conducted 302 inspections of generating units and inspected 22 transmission facilities for weatherization compliance starting in November 2021. ERCOT also reviewed the availability of on-site fuel supplies.

The grid performed well. There were two cold weather events in February, which caused tight conditions, but no EEAs were declared. A single advisory notice was issued for a Winter Weather Watch spanning February 2 to February 6. Peak demand for Winter 2022 was 68,954 megawatts (MWs).

Summer 2022

Summer 2022 saw record demand on the ERCOT system. The all-time ERCOT system peak demand record was broken 10 times in total, ultimately hitting 80,038 MW on Wednesday, July 20. The grid also set a new unofficial weekend peak demand record of 77,359 MW on Saturday, July 9. Working with the PUCT, ERCOT managed tight conditions through reliability actions designed to better capture and mitigate risks. The PUCT amended 16 TAC § 25.507, the Emergency Response Service (ERS) rule, to provide ERCOT flexibility in the implementation and administration of the program. Other tools employed included increasing ancillary service quantities and committing more generation resources to meet Physical Responsive Capability (PRC) targets on high variability days.

The grid performed well. Despite repeated instances of tight conditions, no EEAs were declared. ERCOT did issue two watch notices along with conservation appeals on July 11 and July 13. An Advisory due to PRC below 3000 MW was also issued on July 13. Ancillary services and ERS were deployed in line with PUCT directives to utilize the programs prior to reaching emergency conditions.

ELECTRICITY

Texas is the only state served by all three major electricity interconnections in the United States: The Eastern Interconnection, the Western Interconnection, and ERCOT. Power is generated from fuel sources such as natural gas, coal, nuclear power plants, solar, wind, hydroelectric dams, and batteries. In Texas, retail consumers receive service from competitive retail electric providers (REPs); investor-owned vertically integrated utilities; electric cooperatives; and municipally owned utilities (MOUs).

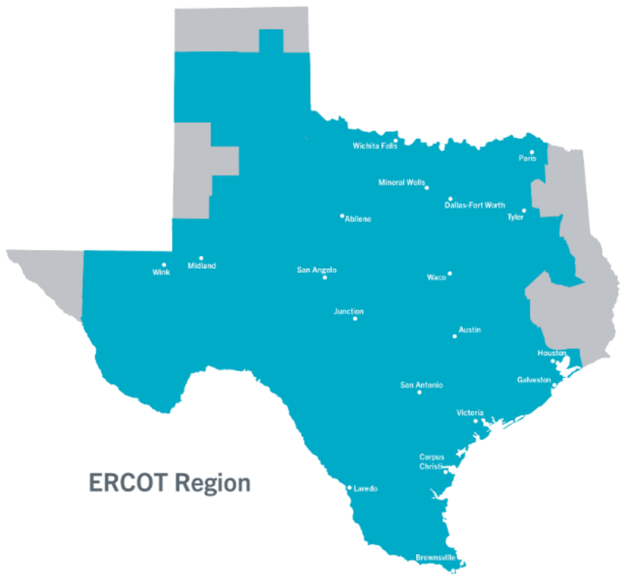

Figure 1. The area covered by the Electric Reliability Council of Texas (ERCOT)

In the El Paso area, the Panhandle, Northeast Texas, and Southeast Texas, more than 1.2 million consumers receive their power from one of four investor-owned, vertically integrated electric utilities. These utilities are outside the ERCOT grid and connect to other states. The PUCT regulates the bundled retail rates of these utilities and local reliability. The Federal Energy Regulatory Commission (FERC) has regulatory jurisdiction over interstate wholesale power sales and interstate transmission rates for these utilities.

Throughout the state, MOUs and electric cooperatives serve approximately 4.7 million homes and businesses in Texas. There are 75 member-owned electric cooperatives in Texas, governed by elected boards. Additionally, 72 municipalities own and operate utilities, including Austin Energy and CPS Energy in San Antonio. The PUCT does not have retail rate-setting jurisdiction over electric cooperatives or MOUs. However, the PUCT does have limited appellate authority for the retail rates of the MOUs. Through its authority over wholesale transmission rates, the

PUCT sets the wholesale transmission rates of MOUs and electric cooperatives in ERCOT and regulates reliability issues.

ERCOT Region

The ERCOT region features a competitive retail and wholesale market. Consumers within ERCOT that are not served by an MOU or electric cooperative have a choice of REP in the competitive retail market. REPs that serve these consumers buy power in the competitive wholesale market, in which power generation companies, MOUs, electric cooperatives, and traders in the ERCOT region all participate. Electricity delivery by transmission and distribution utilities (TDUs) remains fully regulated.

ERCOT, Inc. is the regional transmission organization (RTO) and independent system operator (ISO) for the ERCOT region, which is fully contained within the state. ERCOT manages the flow of electric power to more than 26 million end users and 90% of the electric load in Texas. ERCOT also performs the financial settlement of the wholesale electric market within its region. ERCOT is governed by an independent board of directors and subject to the oversight of the PUCT and the Legislature.

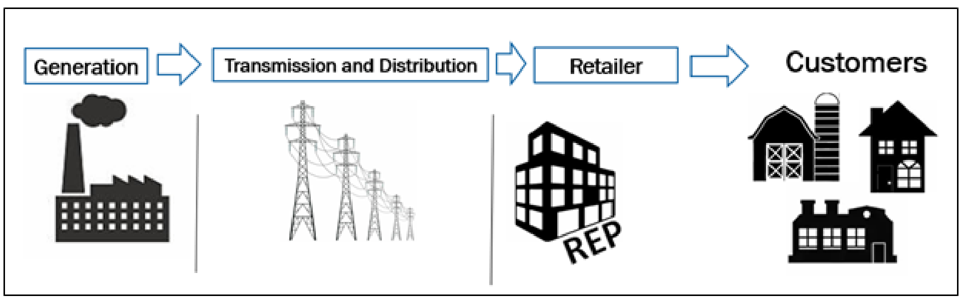

Figure 2. The path of electricity from generation to consumption.

Competitive Retail Market

Retail Electric Providers

Texans in areas open to retail competition choose electricity products from a variety of REPs. A REP buys power from power generators and sells it to its consumers. A REP also manages the retail relationship with the consumer, including billing and customer service. Nearly all eligible consumers have exercised the right to choose their electricity provider since the market opened.[2] During the 2021-22 biennium, the number of REPs and offers in the competitive market areas of

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[2] *Provider of Last Resort Counts*, ELECTRIC RELIABILITY COUNCIL OF TEXAS, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.ercot.com%2Ffiles%2Fdocs%2F2022%2F03%2F01%2FObserved_Selection_of_Electric_Providers_November_2022.pptx&wdOrigin=BROWSELINK (last updated November 2022).

ERCOT has increased. Thirty-eight new REPs have been certificated by the PUCT and 19 REPs have relinquished their certificates to operate in Texas. There are currently 138 REPs authorized to sell electricity in the Texas competitive market.

Each REP can offer a wide variety of plans to suit consumer preferences. As of September 2022, plans are available that offer 100% renewable electricity, time-of-use pricing such as free electricity on the weekends, and prepaid plans. Contract terms vary from one month up to 60 months.

The variety of plans available in the competitive retail market allows consumers to choose a plan that best fits their needs and budget. As of March 2022, REPs in the competitive market serve 6,869,461 residential premises, 1,175,922 commercial premises, and 4,715 industrial premises.[3] The average prices available on powertochoose.org for a 12-month, fixed-rate plan across the TDU service territories in November 2022 ranged from 14.83¢ per kilowatt hour (kWh) to 16.93¢ per kWh.

Electricity Brokers

Electricity brokers are relatively new entrants into the competitive market and the services that they offer continue to evolve as the market matures. These electricity brokers do not sell electricity to consumers, and a consumer does not need to have a relationship with an electricity broker to receive electric service. Most electricity brokers provide shopping services for consumers so that they may switch electricity plans among REPs. They also provide supplementary services to their customers, such as energy management services or bill management services. The PUCT gained regulatory authority over brokers with the passage of SB 1497 (86th Legislature, Regular Session). As of November 2022, there are 1,287 active brokers registered with the PUCT.

Transmission and Distribution Utilities (TDUs)

Within the ERCOT competitive market, an investor-owned TDU is responsible for maintaining the infrastructure that delivers power to the end-use consumer. This infrastructure includes high-voltage transmission lines, substations, local distribution lines, and the consumer's meter. TDU rates are regulated and set by the Commission. TDUs are responsible for managing the reliability of their transmission and distribution system. A TDU delivers electric power to the end-use consumer but does not sell power to the end-use consumer. In the ERCOT competitive market, the TDU is responsible for the physical infrastructure, and the customer relationship is managed by a REP.

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[3] *POLR Counts Energy 2020 Reporting Final,* PUBLIC UTILITY COMMISSION OF TEXAS http://www.ercot.com/mktinfo/retail (March 2022)

Competitive Wholesale Market

Participants in the ERCOT wholesale market own or operate more than 1,030 generation units producing power for 358 load serving entities (LSEs). Owners and investors in power plants decide to invest in or retire units based on expected costs and profits. A robust stakeholder process at ERCOT implements the policies set by the PUCT for the wholesale market. The ERCOT stakeholder process, with oversight by the ERCOT Board of Directors and PUCT, continues to implement changes to improve wholesale market efficiency.

Wholesale Market Prices

Wholesale market prices are charged by generators for electric power they produce. Electric power is sold in the wholesale market to buyers, who may be LSEs, like REPs, electric cooperatives, or MOUs. LSEs sell the power at a retail rate to their end-use customers. Most end-use consumers do not pay wholesale prices. Consumers pay retail prices determined by the contract with their provider before the energy purchase in the wholesale energy market. House Bill (HB) 16 banned retail rates that pass real time, wholesale prices directly to residential and small commercial consumers. Larger consumers may choose such rates but must specifically acknowledge the potential risks.

Fuel costs for generation units are a primary driver of electricity costs. Most generation units are fueled by natural gas. There are still coal-fueled plants in Texas, but the number of those plants and the megawatts they produce are steadily declining.

Transmission costs are another factor in electricity costs. Consumers must pay for the poles and wires that transport electricity from point to point. Transmission congestion, when transmission lines have reached their capacity limit to deliver power safely from one point to another, can have a significant impact on cost. If the transmission lines necessary to deliver power from the lowest cost power plant is already at maximum capacity, then electricity must be purchased from a more expensive plant where transmission capacity is available to deliver the power where it is needed. This difference in the prices is the cost of transmission congestion. The cost of transmission congestion is a signal to the market that generation should be added closer to load to increase grid efficiency and reduce the congestion.

Increases in energy from renewable resources (wind and solar in particular) also have an impact on the average wholesale price of electricity. These renewable resources have a $0 fuel cost as compared with thermal resources that purchase fossil fuels to generate electricity. The growing prevalence of energy delivered from renewable resources has driven down average wholesale prices because more electricity is being created from zero-cost fuel sources.

Unlike ERCOT, most electricity regions in the United States have capacity markets in addition to their wholesale energy markets. This means consumers, in addition to buying electricity, must also pay generators for electricity capacity that is committed to be made available at a specified time in the future. The amount of purchased capacity is based on the estimated peak demand on the future system plus an extra amount intended to serve as a buffer. In contrast, in an energy-only market like ERCOT, generators are not paid for excess capacity beyond that reserved for reliability-related services. In ERCOT the Operating Reserves Demand Curve (ORDC) adder supplements real-time energy prices to reflect the increased value of dwindling, real-time operating reserves. The ORDC acts as another opportunity for generators to recover their costs and realize profits.

LSEs generally do not buy electricity in real-time through the ERCOT wholesale market. Instead, they enter private contracts with generators. The risk of incurring high prices in the wholesale market provides an incentive for LSEs to "hedge" by negotiating with generators to buy power in advance of real-time operations. These advance purchases are a stable source of revenue for the generators and ensure the LSE is not subject to the price volatility of the real-time market. LSEs are also incentivized to request conservation by their consumers to ensure they do not have to buy power from the real-time market when prices are high, which typically occurs when power is scarce.

Meeting Electricity Demand

ERCOT operates an energy-only market, meaning that the PUCT does not set a mandatory reserve margin. Instead, generators in ERCOT decide whether to participate in the market based on their perception of its profitability. ERCOT currently produces two reports that assist ERCOT in planning for and managing electricity demand.. These are known as the Capacity, Demand, and Reserves Report (CDR) and the Seasonal Assessment of Resource Adequacy (SARA). These reports are important because they indicate estimated new generation needed to serve future load and can be used to plan for the risk of outages going into the upcoming season. ERCOT publishes the CDR twice a year for the summer and winter seasons of the following year. The CDR details generation capacity that is either currently online or has met certain financial milestones and is expected to be online in the coming years. This amount of total electric capacity is then compared to the forecasted highest (or peak) demand for electric power by consumers. The difference between the amount of expected available capacity and the amount of forecasted peak demand is the calculated annual reserve margin (generation in excess of forecasted demand). Similarly, the SARA is published for each season, with a final report on expectations for the upcoming season and a preliminary report on the following season. The SARA is an overview of available generation capacity, demand scenarios, and weather conditions that could cause reliability events on the system.

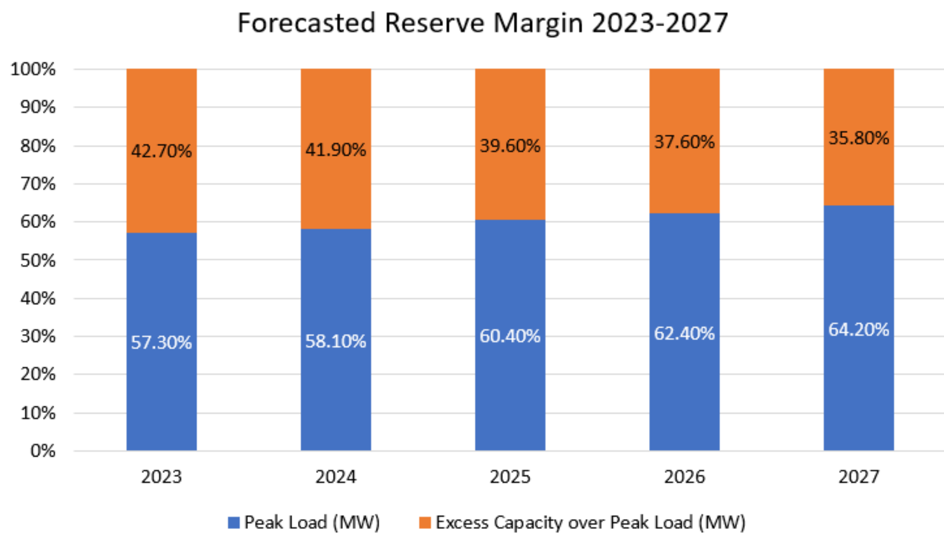

Figure 3. Forecasted Reserve Margin 2023 to 2027 from ERCOT Capacity Demand and Reserve Report May 2022

Historically, electricity demand is highest in the summer, largely due to the increased need to power air conditioning. Beginning with Summer 2021, the PUCT expanded its public communications for seasonal preparedness by holding press conferences jointly with ERCOT leadership to highlight grid reliability efforts. These events also discuss ERCOT's SARA and CDR reports. These press conferences are held before summer and winter seasons, which historically are the seasons when electricity demand is highest. These press conferences are in addition to seasonal preparedness efforts, begun in 2017 to evaluate potential electricity demand against expected unit retirements and delivery constraints in the coming summers. The PUCT works in close coordination with ERCOT and the RRC to facilitate communication among electricity market participants and fuel suppliers to protect and strengthen system reliability. ERCOT also hosts an annual summer preparedness communication workshop where LSEs, generators, TDUs, other market participants, and ERCOT discuss potential communication issues.

Finally, ERCOT has worked to improve market transparency on rescheduling of planned outages by the operator and to ensure that the market better understands its forecasting tools. The PUCT continues to monitor these issues to ensure the health of the market and system reliability.

The market continues to evolve, and the PUCT is conducting a market design review, particularly as changes in fuel sources affect system management. For example, renewable resources have grown because of growth in consumer demand for renewable energy and continued federal subsidies. The growth of intermittent renewable generation in ERCOT has added to the complexities of ERCOT's market and system operations. Peak net load, which measures consumer demand less the contribution from intermittent renewable resources, is becoming an increasingly important metric for ERCOT.

Independent Market Monitor (IMM)

PURA § 39.1515 requires the PUCT to contract with an independent entity to function as the wholesale electric market monitor. Potomac Economics, a consulting firm, currently serves as the independent market monitor, or IMM. The IMM provides PUCT staff with information on potential instances of market power abuse as they occur. The IMM also reports annually on the state of the ERCOT market. This report examines whether market power exists and whether attempts have been made to exercise it. The IMM report identifies market inefficiencies and recommends improvements. In addition, the IMM recommends changes to ERCOT Protocols and processes to improve market efficiency. In both the 2020 and 2021 *State of the Market Reports* for the ERCOT electricity market, the IMM found that the ERCOT wholesale market performed competitively.

Outside ERCOT: Vertically Integrated Utilities

Electric utilities outside of the ERCOT region remain vertically integrated. The utility is responsible for owning generation, transmission, and distribution assets and selling power to end-use consumers. Those utilities are El Paso Electric Company, Southwestern Public Service Company (SPS/Xcel), Southwestern Electric Power Company (SWEPCO), and Entergy Texas, Inc. The PUCT sets retail rates for the vertically integrated utilities. Consumers served by these utilities do not have a choice of provider.

FERC has regulatory jurisdiction over wholesale power transactions and transmission rates for vertically integrated utilities in the non-ERCOT areas of Texas. The Legislature has granted the PUCT authority to retain outside counsel and consultants to help protect the interests of Texas consumers and stakeholders. These consultants participate in a variety of activities before FERC, including rulemakings, contested cases that may affect Texas jurisdictional rights or utilities. They also represent the PUCT in court proceedings where FERC decisions affecting Texas or utilities operating in Texas are challenged. The PUCT and its counsel monitor those FERC proceedings to decide when Texas's interests call for participation. The PUCT takes part in discussions at the stakeholder level and works with other state commissions to address matters before an issue is filed at FERC.

Southwest Power Pool (SPP)

SPP is the FERC-authorized RTO and ISO for areas of Northeast Texas and the Texas Panhandle. SPP oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies. The PUCT collaborates with outside counsel and other state regulatory bodies to participate in FERC proceedings and rulemakings that impact the SPP tariff. The PUCT is primarily concerned with ensuring fairness of costs that may be allocated to Texas consumers and ensuring fair treatment of our member utilities in the SPP footprint. SPP covers 14 states, including parts of Texas, Arkansas, Iowa, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Wyoming, and all of Kansas and Oklahoma. The SPP footprint for Texas includes SWEPCO, SPS/Xcel, several electric cooperatives, and various MOUs in parts of Northeast Texas and the Texas Panhandle.

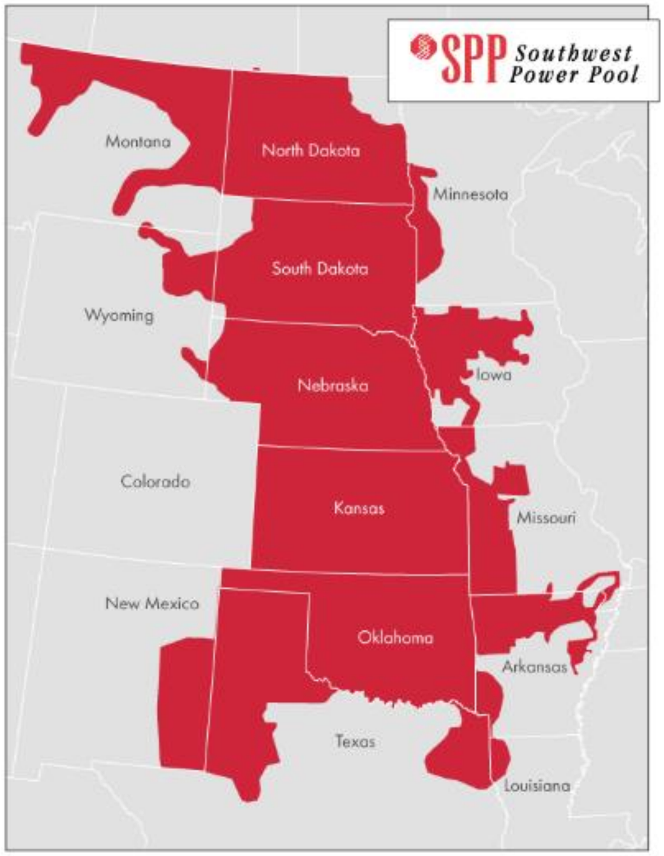

Figure 4. The area covered by the Southwest Power Pool (SPP) in the US

Commissioner Will McAdams represents the PUCT as a voting member on SPP's Regional State Committee (RSC), which consists of the state regulatory agencies in the region. The RSC meets quarterly and is the decision-making authority at SPP on issues such as allocating costs for transmission upgrades, allocation of Financial Transmission Rights, and generation resource adequacy across the SPP region. The SPP Market Monitoring Unit, its version of an IMM, has reported that SPP market results were competitive overall in 2021.[4]

[4] *State of the Market 2021* at 56, SPP MARKETING MONITORING UNIT, https://spp.org/documents/67169/2021%20annual%20state%20of%20the%20market%20presentation.pdf (May 11, 2022).

Midcontinent Independent System Operator (MISO)

MISO is an RTO and ISO that serves all or part of 15 states in the central United States and the Canadian province of Manitoba. The part of eastern Texas served by the vertically integrated utility, Entergy Texas, Inc., is within the MISO footprint. The PUCT collaborates with outside counsel on FERC proceedings about the MISO tariff. The PUCT advocates for the right to address generation resource adequacy at the state level, increased regulatory certainty, fair transmission cost allocation across MISO states, and increased market transparency and efficiency. The MISO IMM concluded that the MISO energy and ancillary services markets generally performed competitively in 2021.[5] Potomac Economics is the IMM for both MISO and ERCOT.

Figure 5. The area covered by the Midcontinent Independent System Operator (MISO) in the US

Commissioner Lori Cobos represents the PUCT as a voting member of the Organization of MISO States (OMS). The OMS meets monthly and coordinates regulatory oversight in the MISO region and makes recommendations to MISO, FERC, and other entities. Commissioner Cobos also represents the PUCT as a voting member of the Entergy Regional State Committee (ERSC). The ERSC consists of regulators from Arkansas, Louisiana, Mississippi, Texas, and the Council of the City of New Orleans. The ERSC provides retail regulator input on the Entergy transmission system, including the cost allocation for certain transmission projects and the addition of transmission projects to the Entergy construction plan.

[5] *2021 State of the Market Report for the MISO Electricity Markets*, POTOMAC ECONOMICS, June 2022. Available at: https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf

MISO-SPP Seams Issues

SPP and MISO are electrically interconnected. This connection can cause congestion as electricity flows across the lines between the two grids; thus, there is a need to coordinate power flows between SPP and MISO. This also affects transmission planning. Improved coordination between both organizations means that consumers may benefit and avoid the cost of overbuilding transmission on each side. Some states, like Texas, are in both organizations, enhancing the need for coordination.

State utility commissioners in SPP and MISO have recognized that these issues prevent efficient economic transmission planning, market and operational issues, and resource integration along the SPP-MISO "seam". In late 2018, the MISO OMS and the SPP RSC jointly formed a Seams Liaison Committee to identify issues and potential solutions to enhance the benefits to consumers from better coordinated seams policies. In 2021, the Seams Liaison Committee provided recommendations to further their goals. These recommendations touched on key policy issues, including creating a new transmission project category on the MISO-SPP seam, and prioritizing interregional transmission planning.[6]

After finalizing these recommendations, the Seams Liaison Committee shifted into a more limited, monitoring mode, with members actively working within the MISO and SPP stakeholder processes to implement these recommendations.

Western Electric Coordinating Council (WECC)

WECC is a regional entity that includes the area surrounding El Paso and extends from Canada to Mexico, including the provinces of Alberta and British Columbia, the northern part of Baja California, and all or portions of the 14 western states. WECC is the regional entity responsible for bulk electric system reliability in the western interconnection and associated compliance monitoring and enforcement. WECC connects electric utilities in the West to operate at a common, synchronized frequency, with 38 separate balancing authorities. Unlike ERCOT, SPP, and MISO, WECC does not have a single RTO or an organized wholesale energy market. El Paso Electric Company is the only electric utility in Texas that is a member of WECC.

Cybersecurity

A significant issue in the electric industry is cybersecurity. In 2019, SB 475 (86th Legislature, Regular Session) established the Texas Electric Grid Security Council. Members include the chairman of the PUCT, the chief executive officer of ERCOT, and the governor's designated

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[6] OMS and RSC Seam Liaison Committee (SLC) Final Recommendations2021. Available at: https://www.misostates.org/images/stories/Filings/Board_comments/2021/RSC_Final_Recommendations_for_SLC.pdf

representative. This council serves as an advisory body to facilitate the creation, coordination, and dissemination of best security practices for the electric industry. The council has held quarterly meetings since September 2019.

The PUCT established the Critical Infrastructure Security and Risk Management Division in September 2019. The division utilizes cybersecurity and emergency management practices to facilitate collaboration between utilities and the PUCT.

The North American Electric Reliability Corporation (NERC) holds a Grid Security Exercise, or "GridEx" every two years. GridEx is a simulated operational exercise for electric utilities, governmental entities, critical infrastructure partners, and supply chain organizations to test responses to cyber and physical security threats. The objectives for GridEx include exercising incident response plans, expanding local and regional response, and improving communication. During the two-day GridEx event, participants respond with simulated internal and external operational activities as they would during an actual event, including sharing information within their organizations and externally according to their established procedures. After GridEx concludes, NERC holds an invitation-only discussion for industry executives and senior government officials. PUCT and ERCOT staff participate in the GridEx exercises.

In 2021, the PUCT conducted a cybersecurity-focused tabletop exercise with regulated electric utilities in collaboration with the Department of Energy (DOE) and the National Association of Regulatory Utility Commissioners (NARUC). The PUCT served as the pilot state regulator to test the newly developed Tabletop Exercise Guide for state commissions. In 2022, the PUCT executed two remote tabletop exercises and facilitated an in-person, two-day cybersecurity symposium and training event for utilities.

Emerging Issues

Since the end of the 87th Legislative Session, the PUCT has ordered a range of policy changes to improve reliability and resiliency during the most extreme circumstances that the electric system could face. This review is detailed in the section titled "Electricity: Resiliency and Market Design." The PUCT is monitoring emerging issues regarding specific technologies, growth areas, and events.

Energy Storage

Battery energy storage continues to grow in ERCOT due to improved technologies and decreased cost. To date, ERCOT market procedures have generally been designed to accommodate resources that either inject power onto the grid (like power plants) or solely take power from the grid (like consumers). For energy storage, both properties exist. Energy storage may act as a consumer and take electric service, while at other times it may function as a resource to put power on the grid. Battery energy storage technology can provide benefits to consumers, but its integration must be thoughtfully managed.

In September 2022, MISO included Electric Storage Resources as a resource type in its market portfolio for the first time. This new resource type enables batteries, pumped storage facilities, and compressed air energy storage to participate in MISO's energy and operating reserves markets as supply and demand. The near-term benefits of the new Electric Storage Resource model are modest due to the small volume of storage resources in MISO. However, this new resource type will allow MISO to accommodate the expected increased storage participation in the coming years.

SPP's Electric Storage Resources Steering Committee was set up in early 2020. The committee finished its work and completed many new policies and procedures to integrate electric storage resources into the SPP grid. New policies were approved by the SPP Board throughout 2021. FERC filings are pending.

Distributed Energy Resources

Electricity markets and grids have seen an increasing number of resources on the distribution system. For example, rooftop solar panels, conventional back-up generators, small-scale batteries, and other small-scale resources are becoming more common in ERCOT and are classified as "distributed energy resources." These units are significantly smaller than traditional generation units, typically about 10 MW or less. Because these resources are smaller than traditional resources, the interconnection processes are less detailed but still require the utility to ensure the safety and reliability of the resources and the bulk power system. The Institute of Electrical and Electronic Engineers (IEEE) developed a new standard for electric grid operators to help incorporate these technologies in a way that provides system security and reliability.

The PUCT continues to discuss additional changes for incorporating distributed energy resources and advancements in technology. These include shortening timelines for interconnection, standardizing interconnection fees, standardizing information required for utility studies to ensure clear expectations, distributed energy resource aggregations, updating the cost allocation methodology for resources interconnecting on the distribution system, and moving to a grid model that accounts for the distributed energy resources that are interconnected. These changes will ensure a level playing field and provide clarity for market participants.

Demand Response

Demand response refers to consumers reducing electricity usage in response to expected high market prices or to provide reliability benefits. Structured demand response programs are available to electricity consumers across the state. These programs are offered by investor-owned utilities (IOUs), MOUs, and electric cooperatives. In the competitive choice areas of ERCOT, REPs may also offer these programs. These programs encourage consumers to reduce electricity usage when called upon by the program provider, often in exchange for an incentive payment.

In the ERCOT market, demand response also has a key role in supporting the region's resource adequacy. Price signals encourage market participants and their consumers to reduce power consumption at key times. When electric power is most in demand, saving an additional MW of consumption is more cost effective than an additional electric power plant coming online to provide power. Demand response programs are evolving as the market becomes more sophisticated and familiar with the programs. The PUCT and ERCOT continue to discuss how to better understand the effect of demand response on the market.

The PUCT oversees the demand response programs delivered by the state's eight IOUs. While most demand response offered through the IOU programs is provided by medium to large commercial consumers, residential demand response participation is increasing. For IOUs in ERCOT, the demand response programs have traditionally been designed to operate during the summer peak period when demand for electricity is at its highest. The programs can be activated when called upon by ERCOT during an EEA 2 event or by the IOU to address a local system emergency. SB 3 granted each TDU (i.e., ERCOT IOU) the ability to design and operate a load management program outside the summer peak for nonresidential consumers to be used during an EEA2 event or when the utility has otherwise been directed to shed load. The TDUs developed programs for the 2021-2022 winter period and have provided notice that they intend to continue programs for the 2022-2023 winter period. To monitor the growth of demand response providers in the SPP and MISO footprints, in 2019 the PUCT opened a project for SPP and MISO to file a list of new demand response providers registering with those grid operators. The PUCT continues to supervise demand response development in these areas.

West Texas Transmission

Oil and gas extraction and processing in West Texas has led to record growth in electricity demand in this area. In addition to demand for electricity, West Texas continues to see growth of renewable generation resources. This added power flow must be carefully managed by ERCOT in its role as grid operator. These factors have all contributed to transmission congestion in the West Texas region.

Five of the ten most frequent transmission constraints in 2021 were in the load zone that serves West Texas.[7] The PUCT has been engaged with both utilities and consumers to ensure that

[7] 2021 State of the Market Report for the ERCOT Electricity Markets, Potomac Economics (May 2022) at p. A-49

electric service quality remains reliable and to examine options for improved load forecasting and transmission planning. Utilities that serve the West Texas region continue to build new infrastructure to serve the demand in the region.

Large Flexible Loads

Since 2021, many cryptocurrency mines and datacenters have sought interconnection to the ERCOT system. These types of consumers are often referred to as large flexible loads because of the relatively large MW demand of the facility paired with its ability to quickly ramp up or down in response to price signals. They are different from other large loads because (1) these loads are seeking to interconnect and be operational within six months of siting a location for their facilities, (2) there is no historical data available on these large flexible loads' consumption patterns, (3) the loads have the ability to start up and shut down in seconds making it easier for these loads to be price responsive, which can result in frequent large fluctuations in energy demand for ERCOT to manage,

ERCOT has created the Large Flexible Load Task Force to review new issues that could arise with the anticipated influx of these large flexible loads, which can draw as much as 2,000 MWs from the grid at a given time—equal to the output of the largest power plant in Texas. The task force is reviewing the timelines necessary for interconnecting these large flexible loads, options for including these large flexible loads in load shed plans, and new measures necessary to ensure reliability of the ERCOT system.

Aggregate Distributed Energy Resource (ADER) Pilot Project

An ADER consists of multiple homes or businesses that can combine resources and respond to ERCOT dispatch instructions as if it were one resource. This aggregated resource can be any combination of generation, energy storage, or controllable load. Each combination, known as an aggregation, must be able to provide at least 100 kW by reducing consumption or supplying power from generation or storage. The governing document for the initial phase of the ADER pilot project was approved by the PUCT on November 3, 2022. This pilot, which will initially include up to 80 MW of resources, will examine how aggregated resources can support reliability.

Lubbock Transition to Competition

In February 2022, the Electric Utility Board of the City of Lubbock passed a resolution to implement retail electric competition in the Lubbock Power and Light (LP&L) service area. LP&L is the MOU serving the City of Lubbock. It serves over 108,000 electric consumers, including Texas Tech University, and has a peak electric load of approximately 640 MW. This will be the first MOU to opt into the competitive retail electric market.

Upon the transition to competition, LP&L will cease serving retail consumers and will operate solely as a TDU. LP&L has an ongoing campaign to educate consumers on retail choice and to assist them in selecting a REP. LP&L has issued a bid for REPs to serve consumers who do not choose a REP before the date of competition. PUCT staff have been working on the terms and conditions for access that will apply in the LP&L territory and any future MOUs or cooperatives who opt into retail choice. Electric choice for LP&L is expected to begin in October 2023.

In March 2018, the PUCT approved LP&L's application to transfer 470 MW of load into ERCOT. The transfer was completed in May 2021. There is approximately 170 MW of LP&L load remaining in SPP. LP&L has filed a petition at the PUCT to request transfer of the remaining load to ERCOT. That docket is currently pending.

El Paso Electric Energy Imbalance Market (EIM)

In February 2021, El Paso Electric, the integrated utility serving the western tip of Texas, elected to join California ISO's (CAISO) western EIM in 2023. The EIM is an energy trading function of CAISO's broader power markets that allows entities outside of the footprint to buy and sell excess generation capacity in real-time. The EIM will benefit El Paso Electric's resource adequacy, reliability, and generation costs by allowing it to procure additional resources to balance load in short notice and at market-based prices. This is expected to lower overall costs and allow for the integration of additional renewable resources in the service territory. El Paso Electric may also sell any excess generation capacity through the EIM.

Rulemakings

Oversight of Wholesale Market Participants

Project No. 50602, Rulemaking to Review 16 TAC § 25.503, Oversight of Wholesale Market Participants. In February 2021, the PUCT approved amendments to 16 TAC § 25.503, relating *to Oversight of Wholesale Market Participants*. These amendments updated the criteria used by the PUCT to select the entity to monitor wholesale market reliability-related requirements for ERCOT.

Electric Weatherization Standards

Project No. 51840, Rulemaking to Establish Electric Weatherization Standards. In October 2021, the PUCT adopted new 16 TAC § 25.55, implementing the provisions of SB 3 related to weatherization requirements and weather emergency preparedness reports. The rule requires generators to implement winter weather readiness recommendations identified in the *2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices*. Generators must also fix all known, acute issues that arose from winter weather conditions during the 2020-2021 winter weather season. The rule also requires transmission service providers to implement key recommendations contained in the *2011 Report on Outages and Curtailments During the*

Southwest Cold Weather Event on February 1-5, 2011, jointly prepared by FERC and NERC. They also must fix any known, acute issues that arose during the 2020-2021 winter weather season. Further, the rule requires all generation and transmission resource owners to file a notarized attestation from the highest-ranking representative, official, or officer with binding authority over each of the above entities attesting to the completion of all required actions.

Project No. 53401, Electric Weatherization Standards Phase II. In September 2022, the PUCT adopted new 16 TAC § 25.55, relating to Weather Emergency Preparedness. The adopted rule is the second of the two phases in the PUCT's development of robust weather emergency preparedness standards to ensure that the electric industry is prepared to provide continuously reliable electric service. Specifically, it requires generation entities and transmission service providers in ERCOT to maintain weather preparation measures for both winter and summer seasons. The new rule requires ERCOT to conduct on-site inspections of every generation resource and transmission facility in its footprint. Additionally, the new rule requires entities who do not comply with weatherization preparedness standards to undergo an independent assessment by a qualified professional engineer.

Critical Natural Gas Facilities and Entities

Project No. 52345, Critical Natural Gas Facilities and Entities. In November 2021, the PUCT adopted amendments to 16 TAC § 25.52, relating to *Reliability and Continuity of Service*. The rule was adopted in collaboration with the RRC as directed by SB 3 and HB 3648. The rule increases the coordination between the electric and gas industries during energy emergencies. A critical natural gas facility, or a "critical customer" as defined by the RRC, is required to provide specific information to the utility from which it receives electric delivery service. The utility must incorporate this information into its load-shed and power restoration planning. The RRC adopted its own new rule, § 3.65, relating to *Critical Designation of Natural Gas Infrastructure*, which will operate in conjunction with the amendments. The rule also implements SB 1876 by adding end stage renal disease facilities to the list of health facilities prioritized during system restoration following an extended power outage.

Retail Electric Customer Protection

Project No. 51830, Review of Certain Retail Electric Customer Protection Rules. In December 2021, the PUCT adopted amendments to implement SB 3 and HB 16 along with added consumer protections and disclosure requirements. The rules require REPs and electric utilities to provide clear and uniform information to consumers. They also limit the offering of wholesale indexed products by banning the sale of such products to residential or small commercial consumers and place conditions on the enrollment of larger consumer classes.

Electric Service Emergency Operations Plans

Project No. 51841, Review of 16 TAC § 25.53, relating to *Electric Service Emergency Operations Plans.* In February 2022, the PUCT adopted new 16 TAC § 25.53, relating to *Electric Service Emergency Operations Planning*. This rule implements standards for emergency operations plans for electric utilities, TDUs, power generation companies, MOUs, REPs, and ERCOT as required by Tex. Util. Code § 186.007 as amended by SB 3.

Administrative Penalty Authority

Project No. 52312, Review of Administrative Penalty Authority. In February 2022, the PUCT adopted amendments to 16 TAC § 22.246, relating to *Administrative Penalties*, and § 25.8, relating to *Classification System for Violations of Statutes, Rules, and Orders Applicable to Electric Service Providers*. These rules implement an amendment to the PURA § 15.023 enacted by SB 3 that establishes an administrative penalty not to exceed $1,000,000 for violations of PURA § 35.0021 or § 38.075, each relating to *Weather Emergency Preparedness*. In response to filed comments, these rules also clarify the application of certain statutory provisions relating to the commission's penalty authority and applicable remedy periods.

Middle Mile Broadband

Project No. 52845, Middle Mile Broadband. In March 2022, the PUCT adopted new 16 TAC § 25.218, relating to *Middle Mile Broadband*. This rule facilitates implementation of middle mile broadband service in unserved and underserved areas of Texas by allowing amenable electric utilities to lease excess fiber capacity to internet service providers so they can offer broadband service in remote areas

ERCOT Scarcity Pricing Mechanism

Project Nos. 51871, 52631, 53191, Review of the ERCOT Scarcity Pricing Mechanism. The PUCT adopted three successive amendments to 16 TAC § 25.505, relating to *Reporting Requirements and the Scarcity Pricing Mechanism in the ERCOT Power Region*, in separate proceedings from June 2021 to April 2022. In June 2021, the first set of amendments modified the value of the low system-wide offer cap (LCAP) by eliminating a provision that ties the value of the LCAP to the natural gas price index and replaced it with a provision that ensures resource entities can recover their actual marginal costs when the LCAP is in effect. In December 2021, the second rule amendment changed the value of the high system-wide offer cap (HCAP) by lowering it from $9,000 per MWh and $9,000 per MW per hour to $5,000 per MWh and $5,000 per MW per hour. In April 2022, the PUCT repealed 16 TAC § 25.505 and reorganized the provisions of repealed § 25.505 into three new rules.

- § 25.505 prescribes resource adequacy reporting requirements in the ERCOT region and requires ERCOT to give to the PUCT a biennial report on the Operating Reserve Demand Curve;
- § 25.506 sets forth the requirements for the publication of resource and load information in ERCOT; and
- § 25.509 establishes a scarcity pricing mechanism for the ERCOT market.

Additionally, the adopted new rules decouple the value of lost load from the system-wide offer cap (SWOC) in effect.

Power Outage Alert Criteria

Project No. 52287, Power Outage Alert Criteria. In May 2022, the PUCT adopted new 16 TAC § 25.57, relating to *Power Outage Alert Criteria*. This rule establishes the criteria for the content, activation, and termination of regional and statewide power outage alerts as required by SB 3. Specifically, this rule requires ERCOT to notify the PUCT Executive Director when it issues load shed instructions or if its forecasts indicate system-wide generation supply is likely to be insufficient to meet demand within the next 48 hours. The PUCT Executive Director may recommend that the Texas Department of Public Safety (DPS) issue a power outage alert after an assessment of available information. The rule also establishes similar procedures for power regions other than ERCOT.

Statutory Definitions

Project No. 52313, Statutory Definitions. In May 2022, the Commission adopted amendments to 16 TAC §25.5, relating to *Definitions for Chapter 25*. Changes to §25.5 revise definitions to comport with changes made by HB 1572 and SB 1202, passed by the (87th Legislature, Regular Session). Specifically, the Commission adopted the statutory definition of "electric generation equipment lessor or operator" and amended the definitions of "retail electric provider" and "electric utility" to clarify that a person who rents to or operates for compensation on behalf of a third party electric generation equipment for use by that third party until it is able to obtain sufficient electricity service is not, for that reason, considered a retail electric provider or electric utility. Similarly, the Commission amended the definitions of "retail electric provider" and "electric utility" to clarify that a person that owns or operates equipment used solely to provide electricity charging service for consumption by an alternatively fueled vehicle is not, for that reason, considered a retail electric provider or electric utility.

Emergency Response Service

Project No. 53493, Emergency Response Service. In August 2022, the PUCT adopted amendments to 16 TAC § 25.507, relating to *ERCOT Emergency Response Service (ERS)*. The rule increases the annual budget for ERS to $75 million and allows ERCOT to exceed this amount, subject to PUCT approval, by up to $25 million for ERS contract term renewals. The adopted rule also provides ERCOT greater flexibility to procure ERS for longer amounts of time with a contract term from individual ERS resources to better address seasonal needs and makes other administrative changes to the program.

Transmission Planning Criteria

Project No. 53403, Transmission Certification Criteria. In November 2022, the PUCT adopted amendments to 16 TAC § 25.101, relating to *Certification Criteria* to implement the provisions of SB 1281 and HB 1510. The rule introduces a consumer economic benefit test for new transmission projects. The economic analysis test will identify transmission lines that will reduce transmission costs to consumers. The amended rule also includes a new biennial *Grid Reliability and Resiliency Assessment* conducted by ERCOT and designed to identify projects to enhance the grid's reliability and resiliency. The PUCT created new resiliency criteria for the approval of transmission projects that will reduce the impacts of extreme weather on consumers.

ERCOT Export Tariff

Project No. 53169, ERCOT Export Tariff. In November 2022, the PUCT adopted amendments to 16 TAC § 25.192, relating to *Transmission Service Rates* to modify the transmission charge for exporting power outside the ERCOT region. The amended rule implements a flat transmission charge for exporting power outside the ERCOT region and eliminates increased charges for exports during the summer. The amended rule will also provide additional transparency on transmission charges associated with DC ties by requiring ERCOT to file a monthly report with the PUCT that states the total amount of energy imported and exported over each DC tie.

ELECTRICITY: RESILIENCY AND MARKET DESIGN

The PUCT is undertaking a full-spectrum review of the ERCOT market to improve reliability and resiliency during the most extreme circumstances the electric system could face. These changes resulted from both implementing bills that the 87th Legislature passed in response to Winter Storm Uri, and a proactive effort from the newly appointed Commissioners to identify potential improvements to ERCOT Inc., the ERCOT grid, and the competitive wholesale market design. This review addressed ERCOT governance, generation resource resiliency, transmission constraints, consumer protection, transparency, and communication, stability in financial markets, and improvements to market price signals.

Market Design Blueprint

Starting in late Summer and continuing throughout Fall 2021, the PUCT held extensive public work sessions. These full-day sessions consisted of testimony from utility experts, ERCOT operators, IMM, state climatologist, former regulators, stakeholders, and market participants from every ERCOT market segment – wholesale, retail, transmission, and consumers. The newly appointed Commissioners asked questions and examined every angle of the ERCOT market to identify weaknesses and opportunities for improvement.

These sessions culminated in December 2021 with the adoption of a two-phase Blueprint for ERCOT market design that codified incremental changes adopted by the PUCT and expanded market reforms.[8] The PUCT then issued directives that spurred a range of market enhancements and a plan to explore more fundamental changes to the ERCOT market requirements that financially reward dispatchable resources for performance during times of energy scarcity.

Enhancements to the Current Market Design (Phase I)

Phase I of the Blueprint includes near-term operational market enhancements prioritized by the PUCT to improve reliability in ERCOT. The changes incentivize the utilization of dispatchable generation through market signals, give ERCOT more tools to improve reliability and avoid scarcity conditions, and enhance the participation of consumers across the system to reduce demand before reaching emergency conditions.

Improving Price Signals and Operational Reliability

The resource mix in ERCOT is constantly changing, and Texas's unique geography and load growth must be met with additional ways to enhance grid stability. The PUCT has responded by creating new operational tools for these new challenges.

[8] *See Review of Wholesale Electric Market Design*, Project No. 52373, Item No. 336

Operating Reserve Demand Curve. The PUCT directed ERCOT to modify the ORDC to improve reliability and incentivize more generation to come online sooner to meet real-time conditions. The ORDC allows prices to rise in real-time as resource scarcity occurs. As the reserve margin of additional generation resources available shrinks, the ORDC incentivizes an economic and efficient response from both generators putting power on the grid and consumers that can respond by reducing their consumption. The ORDC changes included reducing the offer cap from $9,000 per MWh to $5,000 per MWh and changing the Minimum Contingency Level (MCL) to 3,000 MWs. The reduction of the offer cap ensures that consumers will not pay the high sustained price cap that occurred during Winter Storm Uri. Changes to the MCL update the shape of the curve to signal scarcity pricing sooner. This incentivizes generation resources to come online sooner and encourages flexible consumers to reduce demand. Changes related to the ORDC were implemented January 1, 2022, in anticipation of the 2022 winter season.

Demand Response. The PUCT directed ERCOT to pursue technical upgrades and improvements to price signals that will allow more consumers of all sizes to participate in demand response such as moving from zonal to nodal pricing and consumer load aggregations (sometimes referred to as “virtual power plants”).

Emergency Response Service Reform. In Fall 2021, the PUCT made critical changes to enhance ERS. ERCOT purchases megawatts from qualified loads and generators that can be used during specific scarcity conditions on the grid. Funds for ERS were reallocated to make more funding available during winter weather. The timing of ERS deployment was also changed to ensure this emergency measure can be used before the grid reaches emergency conditions. The PUCT revised the ERS rule in August 2022 to increase the ERS budget and modify the program year.

Enhancing Ancillary Services

Fast Frequency Response Service (FFRS). The ERCOT grid must maintain a constant frequency by balancing power supply and demand. The PUCT ordered ERCOT to move forward with a new ancillary service product that will serve as a regulation service able to respond quickly and predictably to changes in the grid frequency. These frequency changes can become more common as the diversity of the ERCOT fleet increases. FFRS went live in October 2022.

Loads in Non-Spinning Reserve Service. The PUCT ordered ERCOT to expand the types of resources able eligible to participate in Non-Spinning Reserve Service. The necessary ERCOT Protocol changes to allow this participation became effective in May 2022.

Firm Fuel Product. In response to directives in SB 3, the PUCT ordered the development and procurement of a Firm Fuel Supply Service (FFSS) to pre-purchase power from generators that is both dispatchable and able to operate continuously for several days during extreme winter conditions. The initial FFSS resources will be procured for a one-year contract term while the PUCT determines future eligibility and term requirements for an expanded program. Amendments to the ERCOT Settlement and Billing system needed to facilitate FFSS were adopted in March 2022. ERCOT procured 2940.5 MW of FFSS at a clearing price of $6.10/MW/hour for the November 15, 2022 through March 15, 2023 obligation period. During the period December 22 to 25, ERCOT deployed FFSS across 22 Resources. Over the four days, ERCOT deployed 2,693 MWs of FFSS. ERCOT issued a Market Notice alerting market participants to the deployment.

Voltage Support Compensation. The PUCT ordered ERCOT to develop a product to compensate resources for voltage support services to help maintain grid stability as inverter-based resources, such as wind, solar, and storage, enter the market. Voltage support is a critical ancillary service provided by generators, storage resources, and transmission reactive devices to maintain the voltage within a narrow range for efficient and reliable operation of the transmission system. Resources in ERCOT provide voltage support service without compensation as part of their interconnection requirements.

ERCOT Contingency Reserve Service (ECRS). The PUCT ordered ERCOT to accelerate the development of the ECRS product to provide the grid operator an additional operational reliability tool. ECRS will reserve generation capability to compensate for variable output of renewable resources, such as wind and solar. ECRS will be market-ready in Spring 2023.

Market Design Proposals (Phase II)

The PUCT engaged Energy and Environmental Economics, Inc. (E3) to evaluate a range of potential new reliability mechanisms and long-term changes to the ERCOT market. New market design concepts will incentivize the retention of existing generation and investment in new dispatchable generation that has the flexible capabilities necessary to meet the full range of grid conditions. The evaluation includes analysis of the expected costs and reliability results from adopting modeled proposals

The consultants released the final report in November 2022.[9] They evaluated the following seven market proposals:

- Energy Only – Status Quo
- Load Serving Entity Reliability Obligation (LSERO)
- Forward Reliability Mechanism (FRM)
- Performance Credit Mechanism (PCM)
- Backstop Reliability Service (BRS)

[9] *See Review of Market Reform Assessment Produced by Energy and Environmental Economics Inc. (E3)*, Project No. 54335, Item No. 2. *See also Review of Wholesale Electric Market Design*, Project No. 52373, Item No. 382

- Dispatchable Energy Credits (DEC)
- DEC and BRS Hybrid

E3's analysis recommended that the PUCT implement the FRM. PUCT staff filed a memo on November 10, 2022, noting that the PCM proposal met the principles and criteria laid out in the comprehensive market design Blueprint. The PUCT requested public comment on the E3 analysis, including specific questions related to the PCM proposal.

Energy Only – Status Quo

The Energy Only proposal preserves the existing Energy-Only and ancillary service market as-is with no explicit reliability standard and incorporates the implementation of the Blueprint's Phase I enhancements.

Load Serving Entity Reliability Obligation

The LSERO proposal establishes a reliability standard and identifies the corresponding quantity of reliability credits that are needed to meet that standard. Under this proposal, ERCOT would require LSEs to procure reliability credits through bilateral contracts with resources in advance of any forecasted reliability risks. Such credits would be assigned to resources based on their contribution to system reliability, with an emphasis on a resource's capability to deliver energy during the highest periods of reliability risk, such as peak net load. This contribution-based reliability metric is commonly known as a resource's Marginal Effective Load Carrying Capability (MELCC).

Forward Reliability Mechanism

Similar to the LSERO proposal, the FRM proposal establishes a reliability standard, identifies the corresponding quantity of reliability credits that are needed to meet that standard, and assigns those credits to resources based on each resource's MELCC. However, instead of bilateral contracts between LSEs and resources, the FRM proposal would utilize a mandatory, centrally cleared forward market that is administered by ERCOT for reliability credits. This forward market would clear based on a sloped demand curve for price stability and retrospectively allocate cost to LSEs based on each LSEs share of system load during hours of highest reliability risk

Performance Credit Mechanism

The PCM proposal places a financial responsibility on the consumer-facing LSEs to ensure ERCOT market participants have procured sufficient generation for a range of scenarios to maintain a reliable grid. The PCM is a new and separate reliability service that does not impact the current competitive real-time wholesale market. The PCM proposal is a voluntary forward offer market for resources paired with a retroactive obligation for LSEs. It allocates load share requirements to LSEs based on availability during the hours of greatest scarcity in ERCOT. The

PCM seeks to ensure LSEs have secured enough power from generators that can adjust output to meet both consumer and grid reliability needs across a range of scenarios. The PCM proposal provides a forward price signal to generators to encourage commitment to the market's electricity demand and incentivizes investment in dispatchable resources, such as natural gas. The PCM proposal is designed with clear performance standards, dynamic sizing for different types of generators, and is proportional to grid reliability needs. It compensates resources based on capability and real-time availability using a backward-looking assessment.

Backstop Reliability Service

The PUCT is evaluating whether a reliability service product such as BRS should be adopted as a bridge to the longer-term grid reliability solutions. The BRS provides an additional cushion of dispatchable generation to help prevent emergency conditions. BRS would allow ERCOT to procure qualified dispatchable generation resources on a competitive basis to serve as a backstop to be deployed only after generation in the real-time energy market and ancillary services have been exhausted. The BRS would send price signals to incentivize new investment and encourage the existing dispatchable generation fleet to remain in service.

Dispatchable Energy Credits

DEC requires each load serving entity to procure dispatchable energy credits (DECs) from eligible resources at a quantity equal to 2% of its annual energy (MWh) load. DECs can be generated by resources with a five-minute startup time, below 9,000 British Thermal Units per kWh heat rate, and 48-hour duration that clear in energy and ancillary service markets between 6-10 p.m. in any day.

DEC and BRS Hybrid

This DEC and BRS Hybrid merges the DEC and BRS products by assigning to eligible LSEs a requirement to provide DECs in addition to the creation of an ERCOT-procured fleet of backstop generators. The hybrid model is intended to address any capacity deficiencies associated with the DEC proposal.

Enhanced Operational Control and Improvements to Electric Grid Reliability

Discussions between PUCT and ERCOT Inc. leadership regarding enhanced operational controls for the ERCOT grid began in May 2021 in advance of the summer season. A series of reliability actions was implemented starting in July 2021. These actions focused on increasing operating reserves, amending ERCOT Protocols to allow for the deployment of reliability tools earlier (i.e., before entering emergency conditions), and improving transparency.

ERCOT currently targets a minimum of 6,500 MW of operating reserves, known as PRC, on high variability days. ERCOT has increased the minimum quantities of ancillary services

(Responsive Reserve service and Non-Spinning Reserve services) for peak load hours on all days. The threshold for deployment of these resources has been adjusted to more accurately reflect system needs and provide grid operators the ability to deploy resources earlier, reducing the likelihood of entering emergency conditions. ERCOT is also committing more generation resources sooner and managing planned outage requests to ensure targeted levels of capacity. Systems were updated to ensure long-lead time units could receive reliability commitment instructions earlier, diversifying the resource mix eligible to be called online. ERCOT now sets the maximum allowable planned outages for maintenance at a given time. ERCOT then reviews, coordinates, and approves outage requests.

In addition to updated ancillary service methodology, procedures for ERS and certain utility-level measures were amended to allow for greater deployment flexibility. As described earlier, the PUCT increased the ERS budget and allowed ERCOT more flexibility regarding when to use ERS. The PUCT also directed ERCOT to amend its Protocols to allow it to instruct TDUs to use distribution voltage reduction measures prior to an emergency.

The PUCT has also directed ERCOT to make changes related to data transparency. Specifically, ERCOT must provide important information about resource outages to the public in a more complete and timely manner. ERCOT now posts a public report three days after each operating day with information on generation resource forced outages, maintenance outages, and forced derates. The report will include the name of the affected resource, fuel type, information regarding the outage duration, and any available information about the cause of the event. In the case of an EEA event, this information may be immediately disclosed to state governmental authorities upon request. ERCOT Protocol changes also included provisions requiring better information from resources regarding forced outages, forced derates, and start-up failures.

The PUCT has approved revision requests for all ERCOT Protocols and rules associated with these reliability enhancements.

System Wide Offer Cap

After the heat wave in 2011 forced ERCOT to declare EEAs to meet system demand, the PUCT increased the HCAP to $9,000 per MWh, over several incremental upward shifts:

- From $3,000 per MWh to $4,500 per MWh on August 1, 2012;
- Up to $5,000 per MWh on June 1, 2013;
- Up to $7,000 per MWh on June 1, 2014; and
- Up to $9,000 per MWh on June 1, 2015.

The $9,000 price cap was seldom reached after it was implemented. However, after the Winter Storm Uri in February 2021, the PUCT reevaluated the HCAP and set it to $5,000 per MWh. This revised cap strikes a balance of ensuring appropriate generation is available using market-based mechanisms and incentivizing demand response during scarcity events while limiting extraordinary financial liability for all market participants and protecting consumers.[10] This change went into effect on January 1, 2022. The PUCT also directed ERCOT to set the offer cap for ancillary services equal to the SWOC for energy and approved the subsequent ERCOT Protocol changes.

Consumer Protection

The PUCT has ordered a range of consumer-facing changes to the ERCOT market. These changes protect Texas consumers from extreme prices, alert consumers to potential outages, and designate certain facilities as critical during a rolling power outage, which prioritizes system reliability and human needs.

After the passage of HB 16, the PUCT implemented rules eliminating wholesale-indexed products for residential and small-commercial consumers, as described previously. The rules also include disclosure requirements for REPs when notifying consumers of the end of a contract. The PUCT also clarified that fixed price contracts could not be changed due to increases in ancillary service charges or other increased costs that REPs experienced.

Some residential critical care and commercial critical load consumers did not have their critical status registered with their REP or TDU. To ensure the proper designation of critical customers and to educate the public, the PUCT required electric utilities and REPs to periodically provide public service notices to consumers concerning load shed events, the eligibility requirements for critical care or critical load designation, and how to reduce electricity use at times when involuntary load shed events are implemented. Additionally, the PUCT implemented rule changes to require electric utilities and REPs to inform residential customers of any special policies or programs for designation as a chronic condition or critical care customer.

Financial Improvements

Following Winter Storm Uri, market participants left billions of dollars in unpaid invoices with ERCOT. These unpaid debts would ultimately have to be paid by consumers for decades to come and push many REPs into bankruptcy, reducing consumer choices and making the market less competitive. The PUCT has taken major steps to address credit requirements for market

[10] *See Review of the ERCOT Scarcity Pricing Mechanism*, Project No. 52631, Item No. 45.

participants. These actions protect consumers by placing financial risk on the market participants rather than consumers.

Credit Requirements for Market Participants

Many market participants were unable to pay counterparties for the power that they procured from ERCOT to serve their consumers during Winter Storm Uri. Many of the payment defaults were by market participants with unsecured credit limits. This increased the overall costs to other market participants such as load (e.g., consumers). Before Winter Storm Uri, certain market participants could transact in the market with unsecured credit limits based on agency credit ratings, equity, or net worth. The PUCT and ERCOT determined that unsecured credit limits are inconsistent with actual creditworthiness. Accordingly, subsequent ERCPT Protocol changes require market participants operating in the ERCOT market to provide additional financial collateral to prevent widespread defaults from being shifted to consumers.

Securitization

Any debts left on ERCOT's balance sheet must ultimately be paid by market participants. Because companies may generally pass such costs along to consumers, the Legislature enacted law to securitize debts accrued due to Winter Storm Uri through debt-obligation bonds. This allows affected companies to spread the repayment of these debts over time, rather than bill consumers in one lump sum. This method of repayment stabilizes the financial foundation of the ERCOT market while dampening the high cost to consumers.

In October 2021, the PUCT approved two debt obligation orders to stabilize the wholesale energy market after the economic impacts of Winter Storm Uri, pursuant to HB 4492.[11] The first debt obligation order authorized approximately $800 million that was used to compensate short-paid wholesale market participants and reimburse ERCOT for money that it used to partially fund these short-paid wholesale market participants. Proceeds of this debt obligation order were distributed in November 2021. The second debt obligation order authorized approximately $2.1 billion that was used to prevent defaults and maintain competition in the wholesale energy market by providing liquidity to wholesale market participants that were subjected to extraordinary costs. Proceeds of this debt obligation order were distributed in June 2022.[12]

[11] *See Application of Electric Reliability Council of Texas Inc. for a Debt Obligation Order pursuant to Chapter 39, Subchapter M, of the Public Utility Regulatory Act*, Project No. 52321, Item No. 214; and *Application of Electric Reliability Council of Texas Inc. for a Debt Obligation Order pursuant to Chapter 39, Subchapter N, of the Public Utility Regulatory Act*, Project No. 52322, Item No. 312

[12] *See generally HB 4492 Securitization*, Electric Reliability Council of Texas, https://www.ercot.com/about/hb4492securitization/.

ERCOT worked with the PUCT to develop Protocols regarding the collection and distribution methods of the funds.

Power Outage Alert system

The PUCT adopted a rule to establish criteria for alerting Texans prior to potential regional and statewide power outages, as described previously.[13] Notice to the public may include information alerting consumers to the possibility of outages in their region, locations to receive assistance in the power region if an outage occurs, and other relevant information regarding the present outage.

Transmission

The PUCT took historic steps to fortify the transmission system in the Rio Grande Valley. This area of Texas has been a challenge to service geographically, but recent population and load growth has made connecting it a priority. The PUCT ordered a second circuit to be built in an existing right of way to send additional power to the region. Additionally, the PUCT identified and accelerated new reliability lines across the region so that the most affordable power can reach consumers in the region.

The PUCT passed rules to implement SB 1281, which introduces a consumer economic benefit test for new transmission projects.[14] The economic analysis test will identify transmission lines that will reduce transmission costs to consumers. Congestion costs occur when transmission lines reach their capacity to transfer power, and more expensive energy must be dispatched from plants where transmission capacity is available to reach the area. Introducing the consumer economic benefit test will identify lines where the construction cost will be offset by congestion cost savings.

[13] *See Power Outage Alert Criteria*, Project No. 53403, Item No. 35.

[14] *See Review of Chapter 25.101*, Project No. 53403, Item No. 86.

ERCOT Governance

The Legislature reaffirmed the Commission's complete authority over ERCOT and made fundamental changes to ERCOT Inc. governance in SB 2. Specifically, SB 2 restructured the ERCOT Board of Directors to be comprised only of independent board members appointed by a selection committee and subject to specific qualifications. The first new board members were announced October 11, 2021, including the appointment of a new chair. The Board approved amendments conforming the ERCOT Bylaws to the legal requirements imposed by SB 2 on October 12, 2021. The PUCT approved the ERCOT Bylaws changes on October 20, 2021.

ERCOT Board of Directors

Paul Foster, Chair
Bill Flores, Vice Chair
Carlos Aguilar, Director
Julie England, Director
Robert "Bob" Flexon, Director
Peggy Heeg, Director
Courtney Hjaltman, Public Counsel (ex officio)
Peter Lake, Chairman of PUCT (ex officio)
John Swainson, Director
Pablo Vegas, President and CEO of ERCOT (ex officio)

The final new board members were announced on December 28, 2021. Since that time, the Board, including the PUCT Chair as an ex-officio member, continues to review ERCOT governing documents and processes considering SB 2. On September 9, 2022, ERCOT opened public comment on additional proposed amendment to the ERCOT Bylaws. These amendments would clarify the role of ERCOT's corporate members, expand the ability of board to fully participate by teleconference, add a requirement for minimum qualifications and a certification process for corporate members' Technical Advisory Committee representatives, and other changes to better align with the intent of SB 2. Additional discussion has centered on the role of the Technical Advisory Committee and stakeholders in the ERCOT rule development processes and how items requested by the PUCT, or board can be expedited or otherwise prioritized. The PUCT must approve any changes to the bylaws or ERCOT Protocols.

SB 2 requires the PUCT to explicitly approve any rules adopted by ERCOT before they may take effect. Previously, changes to ERCOT Protocols and guides took effect after approval by the Board and only ERCOT Bylaw changes required explicit approval by the Commission. PUCT staff has developed a process of evaluating and recommending action on each new ERCOT rule passed by either the Technical Advisory Committee or the ERCOT Board. A staff memo is filed before an open meeting and the PUCT can deliberate on the rule changes. Based on a staff memo recommending approval, the PUCT approved the first set of ERCOT rules on July 15, 2021. To date, the PUCT has approved 125 ERCOT rule changes, including 63 Nodal Protocol Revision Requests (NPRRs).

ELECTRICITY: INTERCONNECTION

Senate Bill 1 (SB1)[15] requires the PUCT to report on whether the interconnection of the ERCOT power region to neighboring grids would protect and further the interest of the public. PUCT staff has reviewed data regarding the direct-current (DC) tie interconnections between ERCOT and neighboring grids. This report discusses legal considerations regarding further interconnections and Federal Energy Regulatory Commission (FERC) jurisdiction over ERCOT and details policy matters that may warrant further consideration. Public comments related to this report were received October 21, 2022.[16]

Current ERCOT Interconnections

Currently the ERCOT power region has three DC ties and one Variable Frequency Transformer (VFT) that connect ERCOT to adjacent grids. For simplicity, all four facilities are collectively referred to as "DC ties." However, the Laredo interconnection is a VFT, not technically a DC tie.

The existing ERCOT-connected DC ties are back-to-back facilities – the power transfer occurs at a single point on the "seam" between two adjacent bulk electricity systems. Another conventional use for DC ties is to space the two AC/DC converter stations a great distance apart, connected by a high-voltage direct current (HVDC) transmission line.

VFTs do not convert Alternating Current (AC) to DC but connect asynchronous AC systems together by converting electric energy at one frequency to electric energy at another frequency. Unlike AC interconnections, DC ties and VFTs can be directly controlled to achieve a specified MW level of flow, resulting in an injection from one region and a corresponding withdrawal from the adjacent region. While DC ties and VFTs allow the transfer of real power from one region to another, they also insulate the adjacent power systems from certain undesirable electrical phenomena, such as inter-area oscillations.

Two DC ties connect ERCOT to the Southwest Power Pool (SPP) in the North American Eastern Interconnect (Eastern Interconnect). One DC Tie and one VFT connect ERCOT to the Mexican

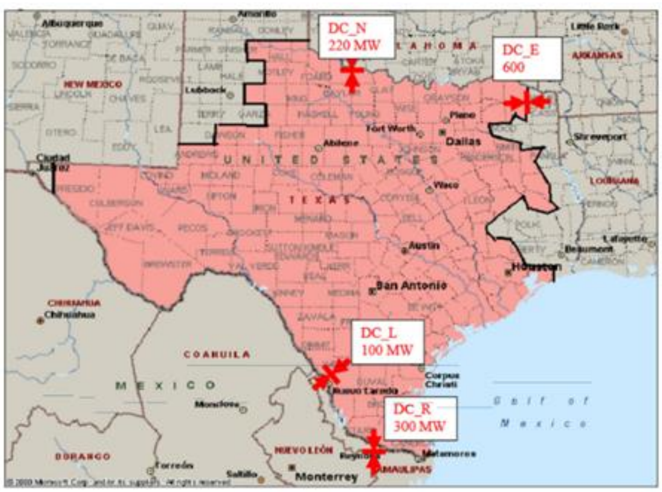
[15] SB 1 (General Appropriations Act) Public Utility Commission Biennial Report. " *Detail in the Biennial Report required under Sec. 12.203, Utilities Code, whether ERCOT interconnection to Eastern and/or Western Interconnects and/or Mexico would protect and further the interest of the public. It is the intent of the Legislature that the commission, out of the funds appropriated above to the Public Utility Commission, and to the extent permitted under general law, detail within its Biennial Report the benefits and costs associated with interconnecting ERCOT to other grids, including Eastern and Western Interconnects, and Mexico. The Report must determine: if reliability could be increased; the impact on customers' energy costs; the potential for economic development benefits to the state from exporting energy to other interconnects; and if ERCOT could remain independent of federal regulation if and when larger direct current ties are established than those that currently exist.*"

[16] See *PUC Project No. 54163, ERCOT Interconnection Study for 2023 Biennial Report.*

power grid Comision Federal de Electricidad (CFE), operated by Centro Nacional de Control de Energia (CENACE).

The four existing DC Ties and the locations are provided in the figure below:

DC Tie Name	Transfer Capability	Adjacent Grid Operator	Technology	DC Tie Operator
East	600 MW	SPP	HVDC Converter	AEP
Laredo	100 MW	CENACE	VFT	AEP
North	220 MW	SPP	HVDC Converter	AEP
Railroad	300 MW	CENACE	HVDC Converter	Oncor



Two additional DC ties are pending regulatory approval at the PUCT. In 2017, the PUCT issued a Certificate of Convenience and Necessity (CCN) to interconnect a fifth asynchronous interconnection, the Southern Cross DC Tie, to link East Texas to the Southeastern United States through a 2,000 MW HVDC transmission line.[17] The project received FERC approval in 2014. Energization of the Southern Cross CCN is contingent upon ERCOT's completion of tasks list tied to specific directives determined by the PUCT. ERCOT has developed rules to address many of

[17] Order on-rehearing, PUC Docket No. 45614, *Application for the City of Garland to Amend a Certificate of Convenience and Necessity for the Rusk to Panola Double-Circuit 345-KV Transmission Line in Rusk and Panola Counties* (May 23, 2017).

the reliability risks associated with connecting such a large facility to the ERCOT region.[18] Construction and energization of the Southern Cross project is pending.

In 2022, Grid United Texas LLC filed an application for a CCN for a 1500 MW DC Tie that would connect ERCOT to the Western Interconnection via El Paso.[19] The application raises questions regarding the method of establishing the need for such a facility and the regulatory considerations for constructing and operating the DC tie. Grid United's CCN application is pending before the PUCT. The Southern Cross and Grid United cases are further discussed in the Legal Considerations section of the report.

Historic DC Tie Operations

DC ties are used as open-access transmission facilities and are an important tool available to ERCOT to ensure the reliable operation of the grid. Under normal operations, ERCOT does not control flows over the ties. Rather, Qualified Scheduling Entities (QSEs) schedule transactions over the ties on a first-come, first-served basis, subject to approval by the operators of the adjacent grids. The Transmission Service Provider (TSP) that operates each DC tie aggregates the approved schedules for each hour and then controls the flow on the DC tie to achieve the aggregate scheduled flow value for that hour. As a general principle, DC ties allow QSEs to schedule power transfers such that less expensive power from one region can be used to serve load in another region.

While imports and exports occur throughout every month of the year, the two DC ties between ERCOT and SPP (North and East) tend to import more energy in the summer and export more in the winter. The two DC ties between ERCOT and CENACE (Railroad and Laredo) generally export more energy from the ERCOT region than they import. The tables below provide information on DC tie imports and exports for the years 2019-2021.

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[18] See *Southern Cross Transmission - Electric Reliability Council of Texas* https://www.ercot.com/mktrules/puctDirectives/southernCross

[19] Application, PUC Docket-No. 53758, *Application of Grid United Texas LLC for Partial Certificate of Convenience and Necessity Rights Under PURA § 37.051(c-1) and 37.056(b)(2)* (Jul.5, 2022).

East DC Tie (2019-2021)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Average Hourly DC Tie Flow(MW)	67	128	135	102	91	160	144	253	201	112	105	86
Max Hourly DC Tie Flow(MW)	611	611	598	598	611	598	598	598	599	598	611	607
Min Hourly DC Tie Flow (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Average Monthly Import Energy (MWh)	(23,695)	(69,730)	(88,639)	(66,373)	(44,798)	(113,846)	(105,943)	(186,222)	(145,031)	(71,105)	(57,552)	(23,520)
Average Monthly Export Energy (MWh)	25,901	25,247	12,120	9,757	22,737	5,185	1,087	1,953	4,802	12,227	20,243	40,625

Laredo DC Tie (2019-2021)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Average (MW)	15	28	32	18	26	24	20	19	23	23	9	11
Max (MW)	101	101	105	100	101	91	91	91	95	94	97	105
Min (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Average Monthly Import Energy (MWh)	(1,390)	(2,723)	(3,400)	(3,515)	(1,934)	(950)	(407)	(1,322)	(1,902)	(3,055)	(457)	(1,838)
Average Monthly Export Energy (MWh)	9,519	18,063	20,422	9,623	17,326	16,851	14,800	12,559	15,560	13,888	5,901	6,704

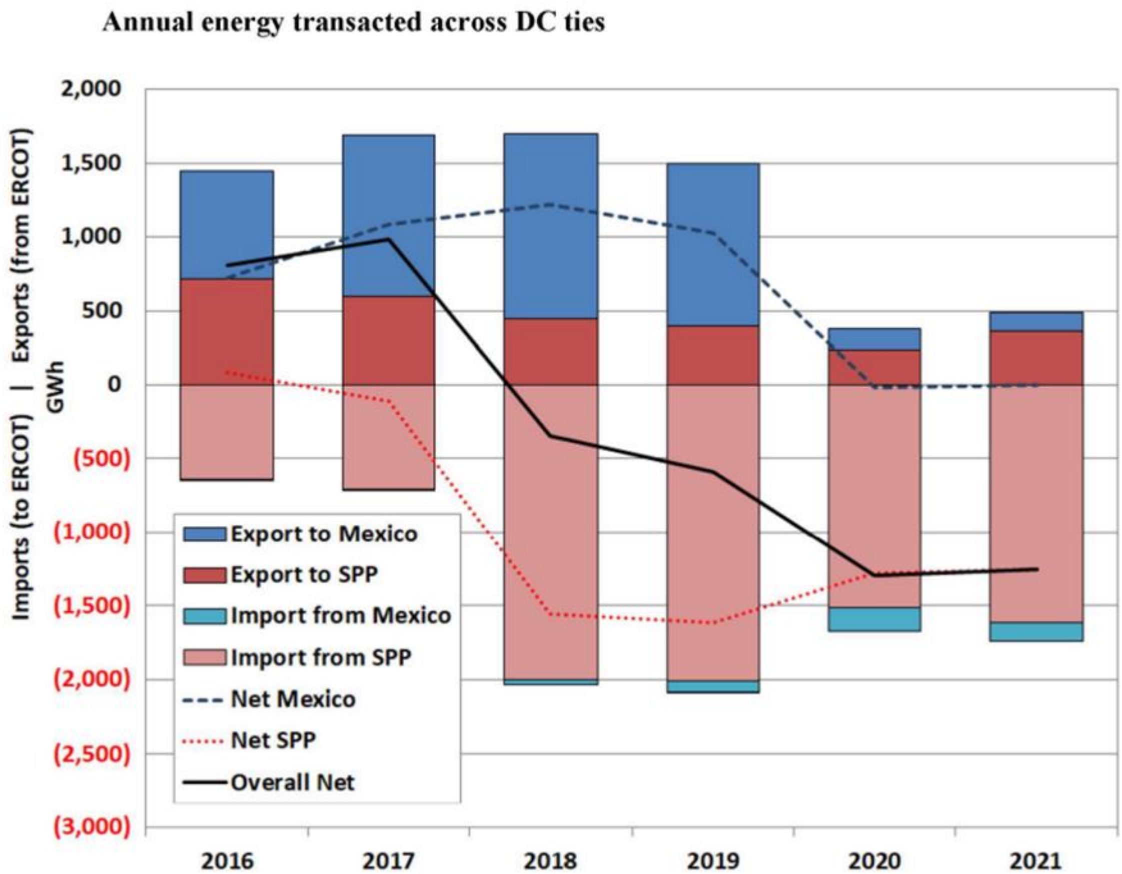
North DC Tie (2019-2021)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Average (MW)	82	96	71	65	77	108	99	123	117	122	122	98
Max (MW)	225	225	225	225	225	226	225	225	225	225	225	225
Min (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Average Monthly Import Energy (MWh)	(44,024)	(52,845)	(41,200)	(38,227)	(43,217)	(73,280)	(65,624)	(86,314)	(81,676)	(66,611)	(79,240)	(58,666)
Average Monthly Export Energy (MWh)	16,939	18,885	11,917	10,154	14,340	7,025	7,826	5,043	5,361	23,987	11,303	13,993

Railroad DC Tie (2019-2021)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Average (MW)	33	52	23	45	51	46	42	62	54	35	29	17
Max (MW)	291	292	292	292	293	292	291	294	292	292	292	303
Min (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Average Monthly Import Energy (MWh)	(3,212)	(8,922)	(2,869)	(16,288)	(11,124)	(5,203)	(5,816)	(6,350)	(5,387)	(13,625)	(8,374)	(6,906)
Average Monthly Export Energy (MWh)	21,055	30,009	14,287	17,378	27,087	29,119	25,321	39,777	34,947	12,455	13,532	5,893

The graph below shows the aggregated flows for the most recent six years for both the DC ties interconnected to SPP and those interconnected to CENACE. Even in the two years in which ERCOT was a net exporter, there were still over 500,000 megawatt-hours (MWh) of energy imported into ERCOT. Similarly, even though ERCOT was a net importer in both 2018 and 2019, there were still 1,500,000 MWh or more of energy exported from ERCOT in each of those years.



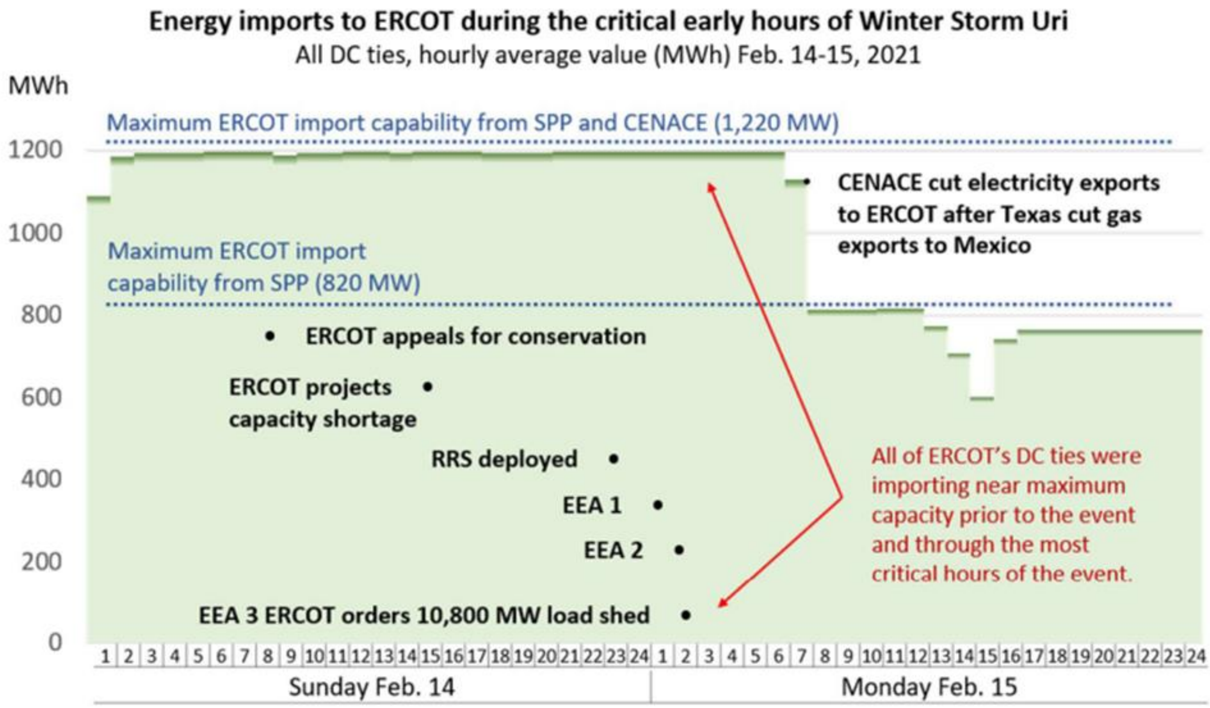
Potomac Economics, *2021 State of the Market Report for the ERCOT Electricity Markets*, Fig. 23, p. 34.

DC ties can provide reliability benefits during certain emergency situations. For example, ERCOT could request that a DC tie operator schedule emergency imports from the neighboring region into an energy-deficient region. By avoiding or mitigating the need to shed firm load, DC ties can provide a reliability benefit to grid operators.

During Winter Storm Uri, both of the grid operators on either end of the southern DC ties were experiencing an energy emergency. Therefore, the flows on these DC ties were limited-or entirely curtailed-because of a lack of available power to export from one region to another. The two DC ties between ERCOT and CENACE (Railroad and Laredo) provided no import capability for most of the period from early February 15 until mid-morning February 19 when firm load was being shed in ERCOT as part of the Level 3 Energy Emergency Alert (EEA). This is because Winter Storm Uri also impacted northern Mexico, leading CENACE to curtail exports on the interconnections with ERCOT.

The two DC ties between ERCOT and SPP (North and East) did import for most of the event. However, SPP partially or fully curtailed flows on those ties for several hours on February 16 and

17, 2021, due to an energy deficiency in its own region. All ERCOT-connected DC ties were importing near maximum capacity for the entire day prior to ERCOT's order to shed firm load during the emergency. All of these ties maintained maximum import during the critical hours of the onset of the storm and for several more hours after the ERCOT system had stabilized.



In the past, DC ties have also provided some imports during intervals with relative scarcity of generation supply, though they have not always imported at full capacity during these periods. The table below illustrates the level of imports for all 529 hours of scarcity when the Physical Responsive Capability (PRC) was less than 3,000 MW from 2019 through 2021. ERCOT observed full imports on the East DC tie for 36% of those hours, on the North DC tie for 54% of those hours, and on the Laredo and Railroad DC ties for 0% of the hours.

Scarcity hours statistics – 529 hours PRC < 3000 MW from 2019 to 2021

	East DC Tie		North DC Tie		Laredo DC Tie		Railroad DC Tie	
	Number of Hours	% of hours	Number of Hours	% of hours	Number of Hours	% of hours	Number of Hours	% of hours
Import at full capacity	192	36%	286	54%	0	0%	0	0%
Import >= 75%	293	55%	333	63%	12	2%	14	3%
Import >= 50%	349	66%	367	69%	29	5%	27	5%
Import >= 25%	407	77%	391	74%	58	11%	70	13%

Recent changes affecting ERCOT pricing could change the incentives for imports, but this historical data suggests that scarcity does not necessarily result in imports over the ties—especially the DC ties with Mexico.

ERCOT Alternating Current (AC) Tie Studies

Currently, ERCOT does not maintain any ongoing AC interconnections to neighboring power systems. Permanent AC interconnections would introduce a number of technical and operational complexities that are avoided by using DC interconnections. However, transmission utilities in the ERCOT region have previously constructed transmission facilities that enable temporary AC interconnections during an emergency in which consumers in either ERCOT or a neighboring region have become disconnected from their native power grid. These arrangements can ensure service to a limited part of the grid during a weather event that impacts transmission lines, such as a hurricane or tornado, or during a grid-wide emergency requiring an extended period of firm load shed.

Interim ERCOT CEO Brad Jones testified at the joint hearing of the House State Affairs and House Energy Resources Committees on September 13, 2022, regarding the possibility of AC tie interconnections with ERCOT and other interconnections.[20] ERCOT is currently collaborating with

[20] The archived video broadcast of this hearing is available at the following link: https://tlchouse.granicus.com/MediaPlayer.php?view_id=46&clip_id=23529

Baylor University and Texas A&M University to identify any benefits or risks of interconnecting with an external electric grid for support during a black start event. These are targeted studies reviewing the specific potential of projects for an identified system need. A broader cost-benefit analysis of interconnection as a whole is not underway at this time.

Texas A&M was asked to study interconnection points with the Eastern Interconnect that could provide frequency support during a black start event, identify potential risks and associated benefits. The objective of this study is to explore the technical requirements of incorporating support from the Eastern Interconnect at specific locations during recovery from a black start event. The study should identify which location or locations would provide appropriate support, and whether there are any risks associated with using support from an external grid.

For this effort ERCOT provided grid models (power flow and dynamics), and black start procedures to the Texas A&M team. The Texas A&M team also had access to Eastern Interconnect models that were used for a previous study performed in 2020 for SPP which evaluated the dynamic aspects of a potential AC interconnection of the Eastern Interconnect with the Western Electricity Coordinating Council.

The study is nearing completion as of December 2022. Deliverables for Texas A&M team are:

- Identify the substations in the existing black start plans that could interface with the Eastern Interconnect as potential connection points.
- Identify additional substations that could be the possible connection points between ERCOT and the Eastern Interconnect – based on distance and voltage levels.
- Identify the temporary cranking path switching sequences.
- Perform a transient stability analysis to evaluate the restoration of the system using the cranking paths identified.

Baylor was asked to identify potential interconnection points with other external grids that could be used during a black start event. In response to this request Baylor developed a black start simulation program that has been completed and is currently being tested by university students.

The tool uses load-flow data to identify cranking paths after a starting point is entered into the program. A cranking path is a portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the start-up of one or more other generating units. The program then creates specific load-flow data cases, one at a time, that represent portions of the grid. Each case must be solved with a load-flow analysis. This iteration continues until the entire grid is restored.

Legal and Jurisdictional Concerns

ERCOT and its market participants are not presently subject to the plenary regulatory authority of FERC, which regulates wholesale power markets in other regions of the United States. Under the Federal Power Act (FPA), FERC' s jurisdiction over the electric industry is limited to "to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."[21] The ability of ERCOT to remain independent of federal regulation if and when larger direct current ties are established than those that currently exist is a threshold issue when contemplating further interconnecting of ERCOT to other grids and the benefit of such interconnections to the state. In response to PUCT Staff's request for public comment, a number of parties explained the legal and procedural history of the existing DC ties to ERCOT. This history is discussed briefly below.

ERCOT is located entirely within the State of Texas and is not synchronously interconnected with either the Eastern or Western Interconnections. Beginning in 1981, FERC has ordered construction of DC ties under the Federal Power Act (FPA) to create asynchronous connections between ERCOT and other parts of the country. The transmission of electricity in interstate commerce is subject to regulation by FERC under the FPA. Under the FPA, FERC has jurisdiction over the rates and conditions for the interstate sale and transmission of wholesale electricity. Under sections 210 and 211 of the FPA, FERC can order transmission interconnections and transmission of electricity in interstate commerce. However, orders issued under FPA sections 210 and 211 do not subject entities complying with these orders to FERC's plenary jurisdiction. Section 201(b)(2) of the FPA also provides that "[c]ompliance with any order of the Commission [FERC] under the provisions of section 203(a)(2), 206(e), 210, 211, 211A, 212,215, 215A, 216, 217, 218, 219, 220, 221, or 222, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than "ensuring compliance with such an order."[22]

FERC 210 and 211 Authorization

As discussed in the overview above, Texas currently has three DC ties and one Variable Frequency Transformer (VFT) that are used to import power to and export power from ERCOT with an aggregate transfer capability of 1,220 MW.[23] Each existing interconnection and the related transmission service has been authorized by FERC under Sections 210 and 211. A fourth DC tie, the Southern Cross tie, connecting ERCOT to a DC converter station in Louisiana, was

[21] 16 U. S.C. § 824(b)(1)

[22] 16 U.S.C. § 824(b)(2).

[23] *Central Power and Light Co.,* 17 FERC para 61,078 (1981) (North DC Tie); *Central Power and Light Co.*, 40 FERC para 61,077 (1987) (East DC Tie).

approved by FERC in 2014 with an interconnection order under FPA sections 210 and 211.[24] This is the most recent consideration of a new ERCOT interconnection by FERC.

The PUCT approved the City of Garland's application for a CCN to build a new 38-mile 345kV transmission line connecting ERCOT to the Southern Cross DC converter station just over the Texas border in Louisiana.[25] The PUCT later used authority granted under the Public Utility Regulatory Act (PURA) § 37.051(c-2) and issued an order directing ERCOT to complete 14 directives that the PUCT concluded were necessary to accommodate the new DC ties.[26] In September 2022, the PUCT issued an order stating that it agreed with ERCOT's solutions to the 14 PUCT directives.[27]

The PUCT has intervened and actively participated in most of the previous FPA section 210-211 proceedings at FERC. The PUCT has an ongoing interest in maintaining and protecting the independence of ERCOT that is codified in the FPA. In the Southern Cross Transmission case before FERC, the PUCT intervened and filed comments on the application.[28] The FERC order approving the Southern Cross Transmission application provided as follows:

> (A) Garland is hereby directed to interconnect with Southern Cross pursuant to section 210 of the FPA under the applicable tariff and rate schedules, as discussed in the body of this order.
> (B) Oncor and CenterPoint are hereby directed to provide transmission service pursuant to section 211 of the FPA under the applicable tariff and rate schedules, as discussed in the body of this order.
> (C) Offer of Settlement is hereby approved, and its terms incorporated by reference, as discussed in the body of this order.

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[24] 147 FERC para 61,113, *Southern Cross Transmission LLC and Pattern Power Marketing LLC*, FERC Docket No. TX11-1-001, *Final Order Directing Interconnection and Transmission Service* at page 8 (May 15, 2014).

[25] *Application of the City of Garland to Amend a Certificate of Convenience and Necessity for the Rusk to Panola Double-Circuit 345-KV Transmission Line in Rusk and Panola Counties*, Docket No. 45624, Order on Rehearing (May 23, 2017).

[26] *Oversight Proceeding Regarding ERCOT Matters Arising Out of Docket No. 45624 (Application of the City of Garland to Amend a Certificate of Convenience and Necessity for the Rusk to Panola Double-Circuit 345 -KV Transmission Line in Rusk and Panola Counties*), Project No. 46304, Revised Order Creating and Scoping Project (May 23, 2017).

[27] *Oversight Proceeding Regarding ERCOT Matters Arising Out of Docket No. 45624 (Application of the City of Garland to Amend a Certificate of Convenience and Necessity for the Rusk to Panola Double-Circuit 345 -KV Transmission Line in Rusk and Panola Counties*), Project No. 46304, Order Closing Project, (Sept. 30, 2022).

[28] 137 FERC para 61,206, *Southern Cross Transmission LLC and Pattern Power Marketing, LLC, Proposed Order Directing Interconnection and Transmission Services and Conditionally Approving Settlement Agreement* at paragraphs 13 & 15 (Dec 15, 2011).

> (D) Compliance with this order and the Offer of Settlement shall not cause ERCOT, Oncor, CenterPoint, or any other ERCOT utility or other entity that is not already a public utility to become a "public utility" as that term is defined by section 201 of the FPA and subject to the jurisdiction of the Commission for any purpose other than for the purpose of carrying out the provisions of sections 210 and 211 of the FPA.[29]

The key provision of the Southern Cross Transmission FERC order is paragraph (D) which preserves the jurisdictional independence of ERCOT and ERCOT market participants that were the subject of the FERC order. All other FERC FPA section 210-211 orders contain similar language preserving the jurisdictional status quo for ERCOT and ERCOT market participants.[30]

FERC Emergency-Use Authorization

FERC has also granted emergency-use only interconnections and related transmission service to the Eastern Interconnection. In the City of College Station[31] case, FERC directed Entergy Texas, Inc. to provide interconnection and transmission service to the City of College Station in certain declared emergency conditions that enable block load transfers of power between ERCOT and the Southeastern Electric Reliability Council (SERC). FERC's directive in this case was issued under sections 210-211 of the FPA. This interconnection, like the DC tie connections discussed above, does not establish a synchronous interconnection between ERCOT and the Eastern Interconnect and thus will not subject ERCOT or entities within ERCOT to FERC jurisdiction under the FPA.[32]

Continued FERC Independence

Under current federal law, additional DC ties into ERCOT, provided they are constructed under FPA sections 210-211, would not subject ERCOT or entities within ERCOT to FERC jurisdiction for any reason other than compliance with FPA sections 210 and 211. However, as noted by ERCOT in its comments on this report, "the growth in DC tie transfer capacity between ERCOT and other regions could lead some to argue that optimal use of the ties requires coordination through greater federal oversight. Consequently, it is plausible the addition of new DC ties could create some long-term risk to the independence of the ERCOT region from FERC jurisdiction."[33]

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[29] 147 FERC para 61,113, *Southern Cross Transmission LLC and Pattern Power Marketing LLC*, FERC Docket No. TX11-1-001, *Final Order Directing Interconnection and Transmission Service* at page 8 (May 15, 2014).

[30] *See Id*. at paragraph 2. ("To date, the only interconnections between ERCOT and facilities in the United States outside of Texas, and the transmission of power over those interconnections have been made pursuant to Commission orders under sections 21 and 211 of the FPA." (citations omitted).

[31] *City of College Station*, 137 FERC Para. 61,230 (2011).

[32] *City of College Station,* 137 FERC Para 61, 230 at p. 30.

[33] PUCT Project No. 54163, *ERCOT Interconnection Study for 2023 Biennial Report*, Comments of ERCOT, Inc. at 9.

In 2018, FERC also raised the possibility that ERCOT's jurisdictional independence could be jeopardized under certain circumstances. In the *AEP Energy Partners, Inc.*[34] case, FERC considered electric service to be provided over DC ties between ERCOT and Mexico. The ERCOT entities involved in these projects were Sharyland Utilities, LP, AEP Texas, Inc. and Electric Transmission Texas, LLC. The first project was a DC tie connecting the Comision Federal de Electricidad (CFE) national grid in Sonora, Mexico, to Nogales, Arizona in the Western Interconnect. The second project considered as part of the AEP Energy Partners, Inc. case was a transmission connection between CFE and the CFE Baha California system, which is also connected to the Western Interconnect in California.[35]

Grid United

In July 2022, Grid United Texas LLC filed an application for a CCN for a DC Tie to connect ERCOT to the Western Interconnection through El Paso Electric Company. The initial size of this proposed DC tie would be 1,500 MW, but Grid United's application indicates that this tie could be expanded to 3,000 MW. This application remains pending at the PUCT. Grid United has stated its intention to seek an appropriate order from FERC under FPA section 210-212 to interconnect this project with the Western Interconnect.

Under PURA § 37.051(c-1), the PUCT is required to review a proposed DC tie project under the same standards by which it reviews electric transmission lines. Under § 37.051(c-1), a person, including an electric utility or MOU, may not interconnect a facility to the ERCOT transmission grid that enables additional power to be imported into or exported out of the ERCOT power grid unless the person obtains a certificated from the commission state that public convenience and necessity requires or will require the interconnection.

The PUCT is required to apply the standards of PURA § 37.056 in assessing the need for a proposed DC tie under § 37.051(c-1). The factors of § 37.056 include the need for additional service and the probable improvement of service or lowering of economic cost to consumers affected by the proposed project. In its order approving the Southern Cross DC tie project, the PUCT included a number of conditions to protect ERCOT and ERCOT consumers.[36] Among the conditions imposed by the PUCT on the Southern Cross DC tie project were that ERCOT ratepayers should not bear the costs to "construct, operate, maintain or upgrade or decommission the facilities."[37] The PUCT further found that Southern Cross should be required

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[34] 164 FERC Para 61,056 (2018)

[35] *Id*. at paragraph 4.

[36] *See Application of the City of Garland to Amend a Certificate of Convenience and Necessity for Rusk to Panola Double Circuit 345 kV Transmission Line in Rusk and Panola Counties*, Docket No. 45624, Order on Rehearing (May 23, 2017).

[37] *City of Garland* at 10.

to "back down or temporarily terminate exports if ERCOT determines that such is necessary to avoid or mitigate a potential reliability issue."[38] The PUCT will review the proposed Grid United DC tie application under the requirements of § 37.051(c-1).

Policy Considerations

Interconnecting ERCOT to other grids presents unique policy considerations given its independence from FERC jurisdiction and competitive market construct.

Interconnections present distinct reliability implications for the grid. Impacts may vary based on location, technology type, and whether the tie is operating as a load or resource at the time. Like any transmission facility, DC or AC tie projects must be evaluated on a case-by-case basis in order to be granted a CCN.[39] In addition to the standard CCN criteria, an application for an interconnection tie must also include a study of the tie line by ERCOT including an ERCOT-approved reliability assessment of the proposed facility.[40] Any directive looking to further expanded interconnection capacity will need to evaluate if the current CCN process for tie lines identifies and fully evaluates the impacts of the proposed facility.

ERCOT is a competitive wholesale electric market where prices are charged by generators for the electric power they produce. The impact of expanded interconnections on wholesale electric prices would be largely dependent on overall market conditions on both sides of the tie line and regulatory constructs for how and when the tie facilities are operated. The impact on consumers' overall energy costs for additional ERCOT interconnections will largely be determined by how costs for the transmission facilities need to enable the interconnections are borne by the market and allocated to consumers by their utility.

These regulatory determinations may warrant further consideration when determining if and how additional interconnections with ERCOT should be established.

Current Related Proceedings

There have been other activities that could affect interconnection issues within ERCOT. Several recent proceedings at a national level have addressed these issues as highlighted below.

For example, in 2022, Congress considered a bill that would have amended the FPA in significant ways. The Energy Independence and Security Act of 2022 (EISA) would have amended FPA § 216 to allow the DOE Secretary to designate areas as "national interested transmission corridors." The EISA would have allowed the DOE Secretary to designate proposed transmission facilities "in the national interest" without first conducting a study to identify such national

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[38] *Id*. at 11.

[39] See *16 TAC § 25.101. Certification Criteria*.

[40] *Id*.

transmission corridors. The EISA also would have removed existing language from FPA §216 related to state permitting authority and would have allowed FERC to issue permits for facilities designated by the Energy Secretary as "in the national interest." While the EISA amendments would not have directly affected ERCOT's current exemption from FERC jurisdiction, the amendments could possibly have allowed FERC to issue a permit to build a transmission line into ERCOT in apparent violation of FPA §216(k) which states that FPA § 216 does not apply within ERCOT. Congress did not pass EISA, but these proposed amendments could be considered by Congress again in the near future.

Additionally, the Department of Energy (DOE) has issued a proposed National Transmission Needs Study. Under section 216 of the FPA, DOE is required to study electric transmission capacity constraints every three years. The DOE Needs Study implements this provision. The current DOE Needs Study includes both historic and anticipated future transmission needs as required by Congress as part of the Infrastructure Investment and Jobs Act (IIJA), Section 40105, (Pub. L. 117-58). The IIJA requires DOE to study transmission needs, congestion, and capacity constraints. DOE issued a consultation draft of the Needs Study on October 21, 2022, and requested comments from state, tribal and regional entities. On November 23, 2022, ERCOT submitted comments on the consultation draft of the Needs Study. ERCOT pointed out a number of concerns with and questions about the draft Needs Study and its possible effect on the ERCOT region. After consideration of comments on the consultation draft, DOE is expected to publish a draft Needs Study in the Federal Register for general public comment.

The joint FERC/NARUC Task Force on Electric Transmission has also discussed the possible establishment of a minimum level of interregional transfer capability. This idea was discussed at the Task Force meeting in July 2022.

In evaluating current PUCT rules and ERCOT Protocols and reviewing public comment, Staff has identified a number of policy matters that may need to be reviewed should interconnection capacity with ERCOT be expanded.

ERCOT DC Tie Line Study

The ERCOT study required in 16 TAC §25.101 regarding potential new DC tie lines should be evaluated to determine if the appropriate criteria are being considered as well as the initiation and timing of the study. This should also consider if DC tie lines should be subject to ERCOT's Regional Planning Group Project Review Process.

ERCOT Operations in Emergency and Scarcity Conditions

ERCOT Protocols and policies surrounding DC tie interconnections were reviewed following the Southern Cross proceeding. These Protocols should be reviewed further given the potential impacts of expanded DC tie interconnections and AC ties to facilitate specific reliability needs. All expansion of ties should ensure that ERCOT loads and generation are adequately protected from the impacts of tie line operations.

Economic Dispatch of Ties

If DC tie capacity is expanded, the ability for real-time dispatch of the ties may be considered. Such dispatch has been implemented in other markets and may provide savings in reduced ancillary service costs and reduce the reliance on Reliability Unit Commitments.

TELECOMMUNICATIONS

The telecommunications market in Texas is made up of voice, broadband, and cable and video services. Wireless technology continues to dominate the voice market. Using Voice over Internet Protocol (VoIP) technology, any broadband internet connection can also provide voice service. The PUCT regulates the intrastate rates and services of some providers of traditional voice service that use facilities that are largely wired and are commonly referred to as landline or wireline services.

Voice Service

Landline Service

Intrastate landline service, including basic local telephone service (BLTS), was historically provided over copper-wired facilities. Today this service is often provided via a combination of copper-wired, fiber-wired, and fixed wireless facilities. These facilities may be used in providing other telecommunication services, such as interstate calling, and information services. The PUCT regulates some aspects of the companies that provide intrastate landline service under PURA.

Voice over Internet Protocol

VoIP enables voice communications over a broadband connection and allows users to both place and receive calls. Copper, fiber, fixed wireless, and coaxial cable can provide broadband for VoIP services. VoIP continues to be a popular alternative to landline services as broadband subscribership increases. For a consumer who is a broadband subscriber, VoIP can be a less expensive alternative to landline services. The PUCT does not have regulatory authority over VoIP.

Wireless

Many Texans use wireless service as a replacement for landline service. Wireless service is made up of mobile phone service technologies that include non-smart mobile phones, smartphones, and satellite phones. While calls can be placed and received wirelessly, at some point, wireless phone calls travel over wired infrastructure to reach their destination. The PUCT does not have regulatory authority over the provision of wireless service.

Market Share of Voice Services

The voice services market is no longer dominated by companies using landline infrastructure. Some consumers keep wireline service for additional applications such as a backup to wireless service or for alarm systems. National data shows that 68.7% of households rely solely on wireless service for voice telecommunications, while only 1.7% of households rely exclusively on landline service.[41] For households with children, reliance on wireless service is even more pronounced, with only 0.4% of households relying exclusively on landline service. This suggests that the preference for wireline reliance skews to an older demographic and that the trend toward wireless service can be expected to continue.

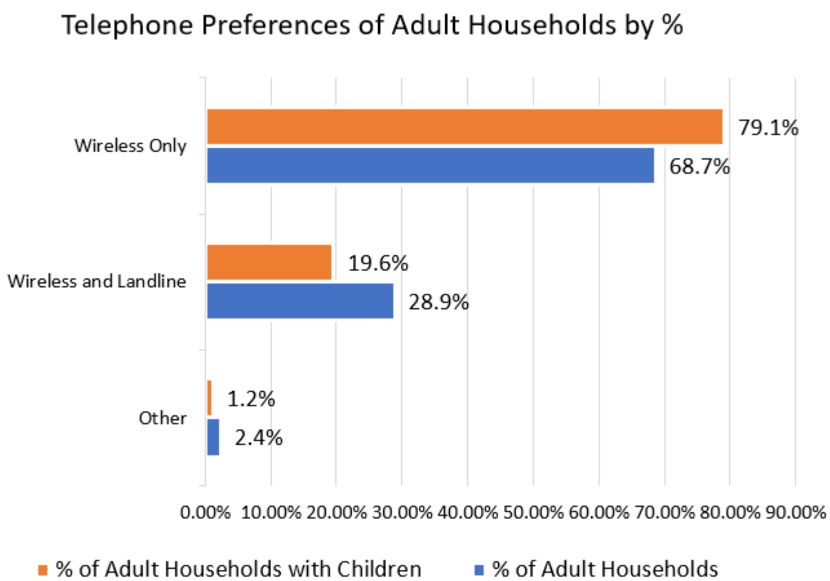


Figure 6. Percentage based telephone status of adult households and households with children in the US

Jurisdiction

Incumbent Local Exchange Carriers (ILECs)

ILECs are entities that held a certificate of convenience and necessity (CCN) for landline service as of September 1, 1995. Through multiple chapters, PURA allows for five distinct classifications of the 61 Texas ILECs as shown on Table 1 below.

[41] *Wireless Substitution: Early Release of Estimates from the National Health Interview Survey, July-December 2021*, NATIONAL CENTER FOR HEALTH STATISTICS, https://www.cdc.gov/nchs/data/nhis/earlyrelease/wireless202205.pdf (last updated May 2022).

Table 1. Summary of PURA ILEC Regulation

PURA Chapter	Type of Regulation	General Description of ILEC	Universal Service Support	Average Residential Single-Line Rate	Average Business Single-Line Rate	Number of ILECs
52	**Rate-of-return (fully regulated)** must maintain tariff with the PUCT; must request PUCT review to change rates.	≤ 31,000 lines usually serve rural parts of Texas	eligible for support	**$18.29**	**$23.33**	**44** *Examples:* Big Bend Telephone Company; Hill Country Telephone Cooperative
53	**Rate-of-return (partially deregulated; cooperatives only)** must maintain tariff with the PUCT; can change rates with formal notice	≤ 31,000 lines usually serve rural parts of Texas	eligible for support	**$21.48**	**$26.77**	**3** *Examples:* Valley Telephone Cooperative; Colorado Valley Telephone Cooperative
58	**Incentive** met multiple infrastructure milestones as of January 1, 2000; pricing flexibility for existing services only; can change rates with informal notice	≥ 31,000 lines serving off-shoots of urban areas	eligible for support	**$15.99**	**$31.28**	**11** *Examples:* CenturyTel; Windstream
59	**Incentive (new services)** met multiple infrastructure milestones as of January 1, 2000; pricing flexibility for new and existing services; can change rates with informal notice.	No ILECs currently choose Ch. 59 regulation	eligible for support	**--**	**--**	**0**
65	**Deregulated** do not maintain a tariff with PUCT; can change rates at own discretion Note: If an entire ILEC territory is not deemed competitive, the ILEC is considered "transitioning."	Large ILECs that serve areas deemed competitive typically serve populated urban areas	**NOT eligible** for high-cost support, but **are eligible** for social service support (transitioning companies can receive high-cost support for areas still regulated)	**$30.75**	**$143.57**	**3** *Examples:* AT&T; Frontier Communications; CenturyLink (Transitioning)

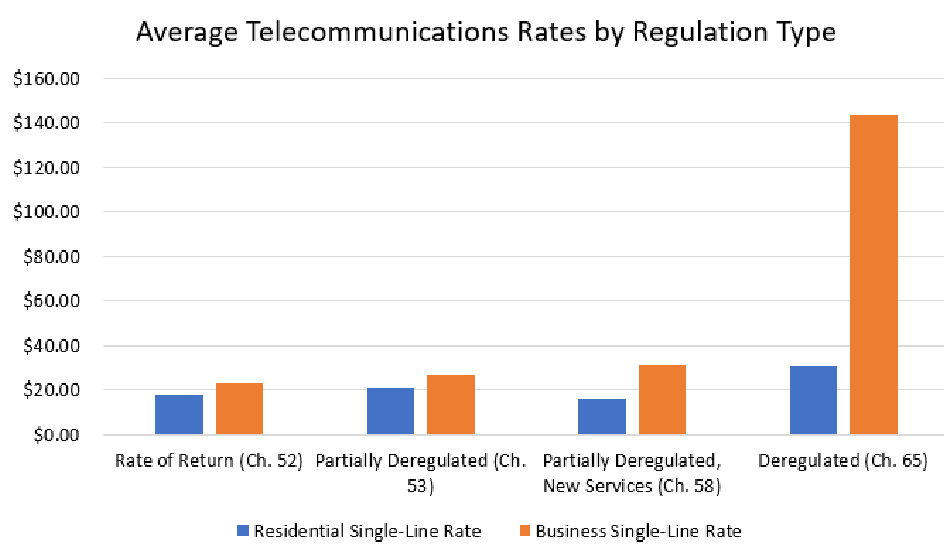
ILECs and Competitive Local Exchange Carrier (CLEC) Affiliates

Many regulated ILECs provide non-regulated services through their ILEC designation or a CLEC affiliate. CLECs are providers that entered the market after September 1, 1995. As of November 2022, the PUCT has 291 registered CLECs and 61 registered ILECs.

For an ILEC to provide landline services outside of its service area, it must obtain a certificate from the PUCT unless certain exceptions apply. A CLEC affiliate similarly cannot offer landline service to consumers within an ILEC's territory. However, a CLEC may offer broadband and video services within an ILEC's territory, including VoIP service as an alternative to the ILEC's landline services. Many of the facilities that CLECs use (for voice, broadband, and video services) are leased from an ILEC. These are the same facilities being used to serve the ILEC's customers and the services may be in direct competition with the ILEC.

Rates Around the State

Local telephone rates for business consumers are typically higher than those charged to residential consumers. In most cases, rates in rural areas served by small companies are less than the rates charged by larger ILECs serving consumers in more urban areas. For example, Eastex Telephone Cooperative, Inc., an ILEC serving consumers in small and rural areas in East Texas, offers residential landline service at a rate of $22.50. Conversely, AT&T provides service in most large urban areas throughout Texas and offers residential landline service at a rate of $44.00 per month. AT&T is a fully deregulated company, and their rate exchanges, except for certain grandfathered rates, are uniform throughout AT&T Texas' deregulated service territory.



Similarly, the rates for single-line business service by small and rural ILECs are often less than those charged by ILECs providing single-line business service in urban areas. For example, Frontier Communications charges a single-line business rate of $49.99 in its exchanges found in larger urban areas. Conversely, West Plains Telecommunications, Inc. offers single-line business service in small and rural areas, subsidized by the Texas Universal Service Fund (TUSF), at a rate of $22.18. Frontier Communications is a deregulated company with pricing flexibility not available to Chapter 52 companies like West Plains Telecommunications, Inc. The rates for companies that provide multi-line business service are also generally higher than the rates charged for single-line business service. The general pricing scheme for this service also follows the pattern described above. A deregulated company offering service under Chapter 58 or 65 can offer business service at a higher rate because the company is deregulated (Chapter 65) or has greater pricing flexibility (Chapter 58). Small and rural ILECs remain fully regulated and are thus limited in their ability to offer higher rates.

Registration with the Commission

To provide local exchange telephone service, BLTS, or switched access service in the State of Texas, a person must obtain a CCN, a Certificate of Operating Authority (COA), or a Service Provider Certificate of Operating Authority (SPCOA) from the PUCT. Since the deregulation of the local exchange market in 1996, all certifications for telephone service are either COAs or SPCOAs. For fiscal year 2022, the PUCT processed a total of 40 COA and SPCOA dockets.

Similarly, to provide cable or video service in the State of Texas, a person must obtain a State-Issued Certificate of Franchise Authority (SICFA) from the PUCT. As of November 2022, there are 79 active SICFAs in Texas

Texas Universal Service Fund (TUSF)

The Federal Communications Act of 1934, as amended by the Telecommunications Act of 1996[42], designated interstate landline service as a universal service that all Americans are entitled to access at just, reasonable, and affordable rates.[43] This act also created the federal universal service fund (FUSF) to offer support to aid companies providing landline service. Federal universal service was later expanded to include VoIP data and wireless/broadband data.[44]

Established in 1987 and revised in 1995, the TUSF was created to implement a competitively[45] neutral mechanism to enable all residents of the state to obtain BLTS. The PUCT is charged with

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[42] 1934 and 1996 Acts: 1934 Communications Act, ch. 652, 48 Stat. 1064. (1934) (codified as amended at 47 USC 254 (1996)). See also 1996 Telecommunications Act, ch. 652, 110 Stat. 71. (1996).
[43] See generally FCC 97-157.
[44] *See* FCC 11-103, ¶4 at 24-25
[45] See *Review of TUSF Rate*, Project No. 50796, Item No. 60.

adopting and enforcing rules requiring local exchange companies to establish universal service and administering the TUSF in a way that ensures reasonable rates for BLTS.

The TUSF is funded through a surcharge based on an estimate of ILEC and CLEC consumers' intrastate telecommunications service usage. Typically, ILECs and CLECs pass through the surcharge costs to consumers on their bills. The PUCT reviews the fund requirements and may change the TUSF rate to meet the obligations of the fund.

The TUSF surcharge is only assessed on the estimated intrastate voice service portion of Texas ILECs' and CLECs' taxable receipts. The TUSF surcharge is not assessed on data services. In FY 2019, wireless service providers (including Texas ILECs and CLECs) reevaluated their service packages to determine how much of the package was devoted to voice service compared to data services. When those studies were completed, the companies determined that a much smaller part of service packages were devoted to providing voice service than previously estimated. The companies adjusted accounting practices to collect the TUSF surcharge only from the portion of the customer's bill devoted to voice service. Since the accounting change, a smaller amount of taxable receipts is eligible for TUSF surcharge assessment. As a result, funds into the TUSF program have been reduced. This created a significant unanticipated shortfall in TUSF revenues, as shown below.

Programs Funded by TUSF

TUSF funds eleven programs separated into two major categories: high-cost programs (Table 2) and social service programs (Table 3). The high-cost programs mainly help telecommunications providers offer landline service at reasonable rates in high-cost-to-serve rural areas of Texas. The social service programs provide financial assistance for voice services for low-income consumers and support programs for Texans with disabilities such as relay services for hearing-impaired consumers. Expenses for the High-Cost Support programs include approximately 90% of the total TUSF expenditure. On the following pages are breakdowns of the programs that fall under high-cost or social service support.

December 2020 was the last fully funded monthly TUSF obligation. From January 2021 to September 2022, the fund paid 15% - 35% of high-cost expenditures. On July 14, 2022, the PUCT raised the TUSF assessment from 3.3% to 24%, effective August 1, 2022. The increase in the TUSF assessment rate will allow the PUCT to pay current obligations each month along with obligations in arrears. It is estimated that it will take 12 months to fully pay down the obligations in arrears, at which time the PUCT can lower the assessment to a rate sufficient to meet current obligations.

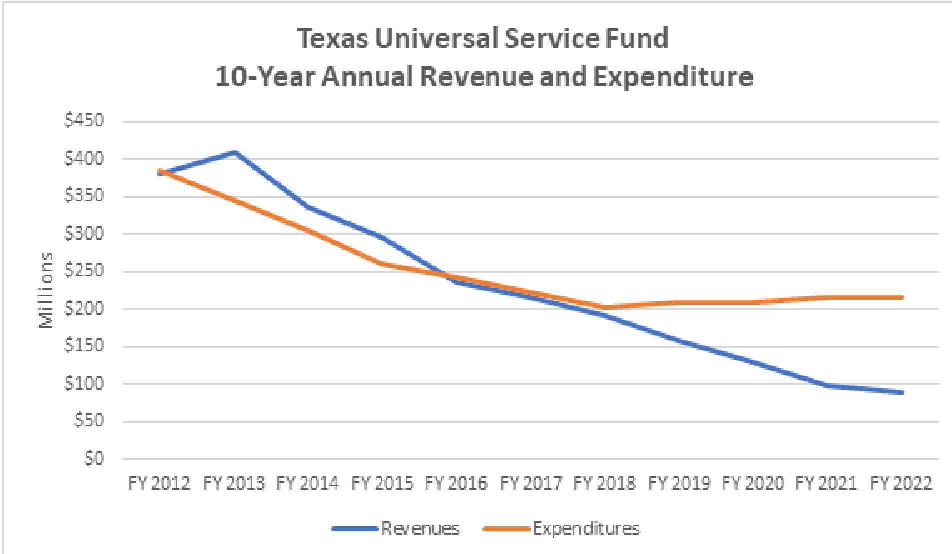
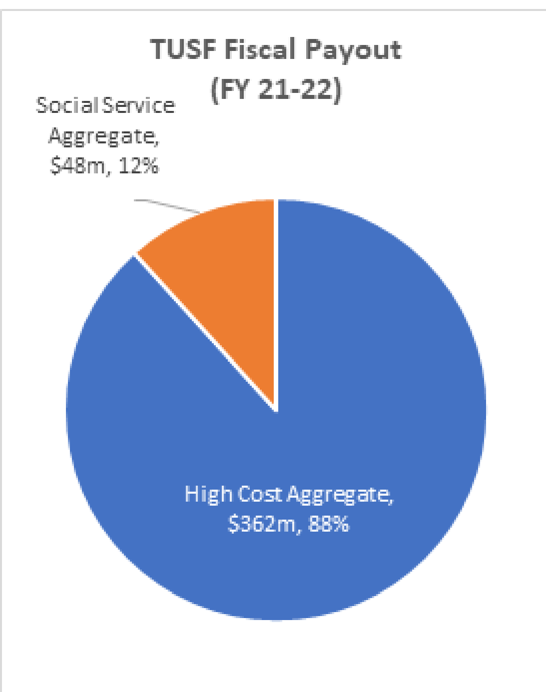

Texas Universal Service Fund
10-Year Annual Revenue and Expenditure
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Millions
FY 2012
FY 2013
FY 2014
FY 2015
FY 2016
FY 2017
FY 2018
FY 2019
FY 2020
FY 2021
FY 2022
Revenues
Expenditures

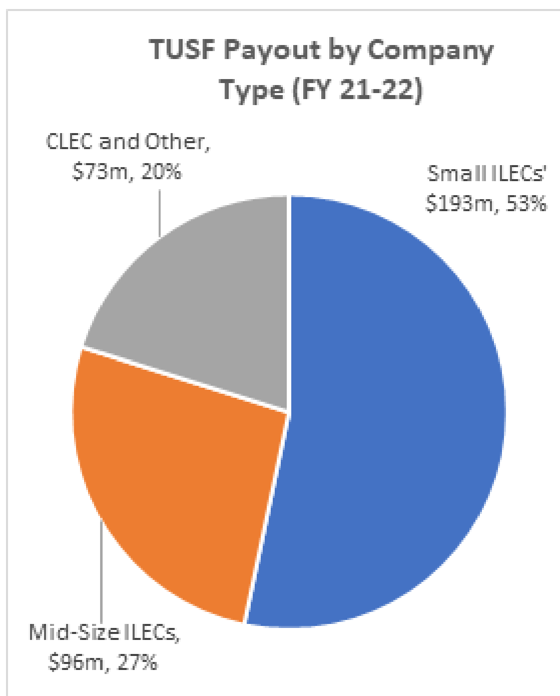
Table 2. High-Cost Programs

Program	Description	2021 Payout	FY 2022 Payout
Texas High-cost Universal Service Plan (THCUSP)	Support for **large** phone companies offering landline service in **high-cost-to-serve areas and rural areas**.	$85,027,341	$80,876,913
Small and Rural ILEC Universal Service Plan (SRIUSP)	Support for **small and rural** companies offering landline service in **high-cost-to-serve and rural areas**.	$89,391,493	$87,611,349
Additional Financial Assistance	Additional revenue for ILECs drawing funds from the THCUSP or SRIUSP under certain conditions (see PURA §§ 53.105, 53.151, and 53.406). Has never been used to seek additional support.	$0.00	$0.00
PURA § 56.025 Make-Whole Provision	Support for ILECs that serve **< 31,000** access lines to maintain reasonable rates for landline service. ILECs can request additional support from the **TUSF to match projected funding loss from changes to federal or state legislation**.	$4,360,782	$13,922,230
IntraLATA Support	Universal Service Fund Reimbursement for Certain IntraLATA Service. Reduces certain rates for **schools, libraries, nonprofit telemedicine centers, not-for-profit hospitals, and health centers**.	$192,885	$135,950
High-cost Uncertified	High-cost Universal Service Plan for Uncertificated Areas where an **Eligible Telecommunications Provider volunteers** to -provide BLTS. Financial assistance for ILECs that serve uncertificated areas of the state and have volunteered to provide landline service to residential and single-line business premises.	$200,632	$200,138
	Total:	**$179,173,133**	**$182,746,580**

Table 3. Social Service Programs

Program	Description	2021 Payout	FY 2022 Payout	FY 2022 Participation
Lifeline	Reduces monthly voice rates **for low-income consumers**.	$8,967,809	$4,633,902	764,456
Texas Relay Service	Allows Texans with speech or hearing disabilities to communicate using **specialized devices and operator translations**.	$1,010,395	$824,878	32,042 (completed calls)
Specialized Telecommunications Assistance Program (STAP)	Reduces the costs **of telephone equipment** for consumers with speech or hearing disabilities.	$16,137,996	$15,879,662	15,072 vouchers
Audio Newspaper Program	Free telephone service that allows blind and visually impaired persons access to the text of newspapers by using **synthetic speech**.	$427,585	$514,704	54,801 Registered users
Tel-Assistance Support	Reduces monthly voice rates **for low-income consumers**. No longer an active program. Only consumers who were receiving it prior to its discontinuation and did not want to switch to Lifeline still receive support through Tel-Assistance.	$1,225	$939	122
	Total	**$26,545,010**	**$21,854,085**	





Emerging Issues

Continued Need for POLR Designation

A telecommunications POLR is an ILEC or CLEC obligated to provide landline service at a reasonable cost to requesting consumers throughout its service territory. Through POLR obligations, ILECs and some CLECs must provide facilities and services to any consumers within their service territories, even if this requires building infrastructure for a single consumer to use.

Since POLR requirements were established, the telecommunications market has changed remarkably. The availability of alternative voice services (predominantly wireless) and continued buildout of facilities means consumers in competitive areas of Texas may be able to access voice services from a variety of providers at a reasonable cost. Beginning in 2015, companies serving competitive areas could request to be relieved of their POLR obligation. Companies have also started to contemplate the use of alternate technologies to meet POLR obligations.

Definitions of "Universal Service," "High Cost," and "Rural"

When the concept of universal service was established, landline voice service over copper-wire access lines was the primary telecommunications method. As a result, landline service was the technology supported by the FUSF and state universal service funds (for Texas, the TUSF). Since that time, technology and facilities have evolved. In 2011, the FCC began amending the FUSF programs to support wireless and broadband service.[46] Changes have included retiring programs that support landline service and creating new programs to support wireless and broadband.

As standard telecommunications service shifts away from landline to broadband service, the question of what constitutes meaningful "universal service" is evolving.

In Texas, broadband is now the primary communication method, and wireless voice services are now more prominent than landline services using voice data.[47] The PUCT does not have regulatory authority over the provision of wireless or VoIP services. However, the PUCT has authority over "voice data" for TUSF funding. "Voice data" is becoming increasingly merged into and indistinguishable from "wireless data," making the basis for funding universal service difficult to determine.

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[46] See generally FCC 17-166. The FCC is authorized to regulate all aspects of telecommunications and carriers providing "interstate telecommunications." Companies providing interstate voice data, VoIP data, and wireless/broadband data are required to contribute to the FUSF.

[47] The Texas Legislature has specifically defined "broadband service" under PURA § 43.003 as "retail Internet service…with the capability of providing a download speed of at least 25 megabits per second and an upload speed of at least 3 megabits per second." See PURA § 43.003. See also Tex. Gov't Code 490 1.0101. The Legislature's definition of "broadband service" is consistent with the FCC's definition. See FCC 15-10, ¶3 at 3.

In 2021, Texas was the fastest growing state according to U.S. Census statistics and had an estimated population of 29,527,941.[48] The significant growth in population poses questions to what the term "rural" means in the context of TUSF program funding. Some areas of the state that were previously rural with low population density are transitioning into suburban and urban centers as Texas grows but are still deemed "rural" for purposes of TUSF. Neither "high-cost," nor "rural" is defined for this purpose in PURA or PUCT rules.

Sustainability of the Texas Universal Service Fund

As discussed under the "Texas Universal Service Fund" header, the global transition from voice data to wireless data is a solvency issue for the TUSF.

Since Q1 of FY 2018, the TUSF balance has decreased. Beginning in Q3 of FY 2019, the ending balance of the TUSF began to precipitously decline year over year, starting with losses of approximately 10-20% of the total fund balance and ending with losses of approximately 20-33% annually.

Historically, the PUCT collects approximately $100 million for the TUSF annually, however, this amount is decreasing every year.[49] In FY 2020, approximately $198 million was disbursed from the TUSF. Therefore, to maintain the solvency of the TUSF, the PUCT would have to either dramatically reduce TUSF support or collect an additional $100 million (for a total of $200 million) annually.

In June 2020, the PUCT considered whether to raise the assessment rate to maintain support for all TUSF programs. It was determined that increasing the assessment fee from 3.3% to 6.4% as proposed by PUCT staff would not sustain funding for all the programs in the long term. Additional increases to the assessment would be needed as revenue continued to decline. As a result, the PUCT chose not to increase the TUSF assessment rate at that time given the COVID-19 pandemic and resulting economic crisis, particularly since the increase would not have guaranteed long-term solvency.[50] As of Q2 of FY 2021, the PUCT had reduced TUSF disbursements by 60-70% of actual amounts to prevent insolvency of the fund.

PURA § 56.025(c) requires the PUCT to use TUSF funds to make companies whole for reductions in federal USF support due to an order, rule or policy of the Federal Communications

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[48] "With a population of 29,527,941 in 2021, Texas had the largest annual and cumulative numeric gain, increasing by 310,288 (1.1%) and 382,436 (1.3%), respectively." *See* https://www.census.gov/newsroom/press-releases/2021/2021-population-estimates.html

[49] For FY 2021, the PUCT collected approximately $98 million for the TUSF.

[50] At the June 12, 2020, Open Meeting, the then-Commissioners declined to adopt PUCT staff's recommendation and did not increase the § 26.420(f)(6) assessment from 3.3%. *See Review of TUSF Rate*, Project No. 50796, Item Nos. 2 and 15.

Commissions. The requirements of PURA § 56.025(c) could worsen the already precarious financial condition of the TUSF.

TUSF Litigation

On January 20, 2021, the Texas Telephone Association (TTA), on behalf of and with its participating members, filed a lawsuit in Travis County against the Commission. The suit alleged that, in reducing the disbursements to TUSF participants in Q2 of FY 2021, the PUCT acted without authority and violated state law.[51]

Summary Judgment was issued by the 200th District Court of Travis County on June 7, 2021, in favor of the PUCT.[52] On June 25, 2021, the case was appealed by TTA, and on June 30, 2022, the Third Court of Appeals rendered judgment in favor of the appellants, reversed the District Court, voided the PUCT actions in 2020, and enjoined the Commissioners from not fully funding or reducing disbursements to the TUSF.[53] On July 14, 2022, the PUCT raised the TUSF assessment from 3.3% to 24%, effective August 1, 2022, in accordance with the judgment from the Third Court of Appeals.[54] The PUCT began paying current months' requests for reimbursements for eligible carriers beginning in October 2022.

A separate matter was initiated on August 30, 2021, when AMA TechTel filed a lawsuit in Travis County against the Commission.[55] On November 17, 2021, the district judge granted the injunction, and on November 18, 2021, the PUCT appealed the case to the Third Court of Appeals.[56] The Third Court of Appeals granted injunctive relief requiring the PUCT to reimburse AMA TechTel past due TUSF disbursements. As of October 2022, the PUCT has paid all past due TUSF disbursements to AMA TechTel.

On November 10, 2021, Alenco Communications, Inc. (Alenco) filed an application at the PUCT to recover funds from the TUSF. The application requests a prorated, monthly distribution of TUSF funds from the current TUSF balance and seeks to prioritize disbursements to Alenco over other TUSF funding recipients. The PUCT dismissed this case on July 14, 2022.[57]

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[51] *See Plaintiff's Original Petition*, Cause No. D-1-GN-21-000311, TRAVIS COUNTY DISTRICT COURT, 200th District.

[52] *See* Cause No. D-1-GN-21-000311*, Case Summary*, Travis County.

[53] Cause No. 03-21-00294-CV. *Judgement of Texas Court of Appeals, Third District,* THIRD COURT OF APPEALS.

[54] *See Review of TUSF Rate*, Project No. 50796, Item No. 60.

[55] See Cause No. D-1-GN-21-004498, Case Summary, TRAVIS COUNTY

[56] See Cause No. 03-21-00597-CV, Case Summary, THIRD COURT OF APPEALS.

[57] See Applications…to Recover Funds from the TUSF… Project No. 52808, Item No. 39.

WATER AND SEWER

The PUCT is charged with overseeing the financial and managerial aspects of water and sewer utility services in Texas. The PUCT regulates the retail rates of water and sewer IOUs. The PUCT has limited appellate jurisdiction over the rates of MOUs, districts and river authorities, water supply corporations (WSCs), and certain counties' wholesale and retail water and sewer rates. The PUCT issues and regulates any amendment or change in control of CCNs for water and sewer service providers. The PUCT also appoints temporary managers for abandoned or non-functioning IOUs to ensure that consumers receive continuous and adequate service. PUCT staff assist the utilities in staying in compliance by answering compliance-related questions and raising awareness about the rules and regulations. TCEQ regulates the health and safety standards of water and sewer utility services in the state. The PUCT and TCEQ coordinate on temporary managers and receiverships to ensure continuous service for Texans.

There are 3,989 water and sewer service providers holding CCNs under the PUCT's jurisdiction. As of the end of FY 2022, these CCNs encompass 10,744,157 water connections serving residences and businesses in the state. A CCN grants its holder the exclusive right to provide retail water or sewer utility service to an identified geographic area. Texas Water Code (TWC) Chapter 13 requires a CCN holder to provide continuous and adequate service to the area within its CCN boundary. Most Texans are served by large and medium-sized retail public utilities, including municipalities, districts, river authorities, and water supply and sewer service corporations. Small retail public utilities, typically serving fewer than 2,300 connections, serve the rest of the population. Counties that meet certain economic criteria or are within 100 miles of the US-Mexico border (Affected Counties) and all IOUs, WSCs, and sewer service corporations must hold a CCN to provide water and sewer services. Municipalities, districts, and counties other than Affected Counties are not required to have a CCN to serve in areas that are not already being lawfully served by another retail public utility. However, some municipalities and districts choose to obtain a CCN to protect their service area from encroachment. Figure 7 depicts the percentage of the CCNs by type of retail water and sewer providers.

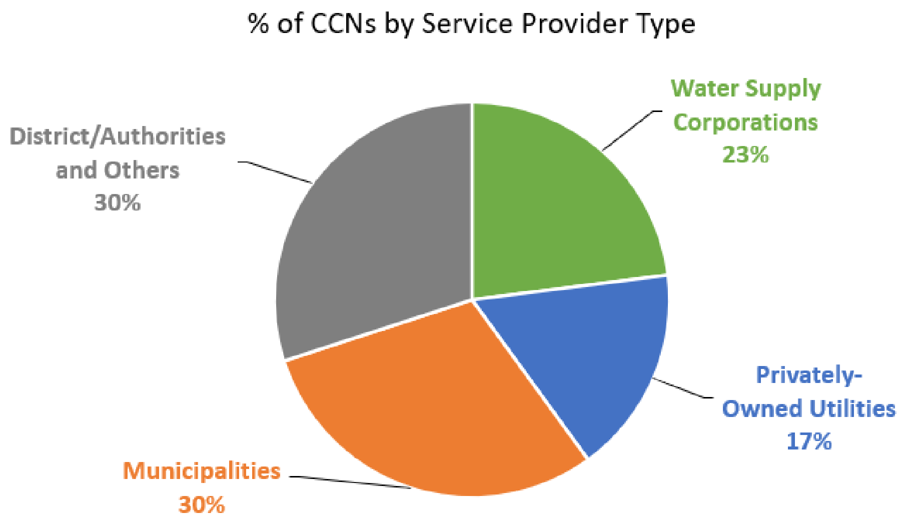

Figure 7. Percentage of water and sewer CCNs by service provider type

Primary Service Provider Types

Investor-Owned Utilities

Private companies offering sewer or potable water services are called IOUs. IOUs provide service for profit and range in size from small sole proprietorships or partnerships to large corporations. IOUs must hold a CCN to provide water or sewer services. As of the end of FY 2022, the PUCT regulated 553 active CCNs held by IOUs.

Water Supply Corporations

WSCs are member-owned, member-controlled nonprofit businesses that offer sewer or potable water services. Each entity sets up bylaws and articles of incorporation that govern how it operates. WSCs that only provide sewer service are also referred to as sewer service corporations. A WSC must hold a CCN to provide the public retail water or sewer service. As of the end of FY 2022, the PUCT regulated 758 WSCs.

Exempt Retail Public Water Utilities

Certain IOUs and WSCs are exempt from the requirement to hold a CCN to provide retail water utility service. Exemptions are available for utilities serving fewer than 15 service connections and are not owned or affiliated with a retail public water utility or any other entity that provides potable water service. This exemption is not available for utilities that provide sewer service. If the exempt utility is a MOU, it must register with the PUCT and declare its existence. The PUCT has appellate jurisdiction over exempt utilities' rates. If 50% or more of consumers request intervention, the PUCT will review a utility's rates. As of the end of FY 2022, 39 exempt retail public water utilities were registered with the PUCT.

Districts

A district is a local governmental entity that provides water, sewer, or both services to its consumers and residents.[58] A district does not have to hold a CCN to provide retail water or sewer service to its consumers unless it intends to provide service in an area already served by a retail public utility.[59] The most common types of districts are municipal utility districts, water control and improvement districts, and special utility districts.

River authorities are a type of district.[60] As political subdivisions of the state, river authorities operate major reservoirs and are granted authority to control and distribute the waters of a specific geographic region. River authorities may provide water, sewer, or both services, along with other services such as water conservation, irrigation, flood control, firefighting, garbage collection, and recreation facilities. Like districts, river authorities do not have to hold a CCN.[61]

The number of districts, including river authorities, that opted to obtain a CCN from the PUCT was 960 in FY 2022.

Municipally Owned Utilities

Many Texans receive water and sewer service from a MOU. A MOU includes any retail public utility owned, operated, and controlled by a municipality or by a nonprofit corporation with directors appointed by one or more municipalities. Like districts, MOUs do not have to hold a CCN to provide retail water or sewer service inside or outside their extraterritorial jurisdiction. However, a MOU must obtain a CCN if it wishes to serve consumers in an area already served by another retail public utility. In FY 2022, 990 MOUs held CCNs.

Certificates of Convenience and Necessity

The PUCT has sole jurisdiction over water and sewer CCN regulations. The PUCT must ensure that a CCN applicant has the financial, managerial, and technical capability to run a utility. Any overlaps in a proposed service area with neighboring utilities, cities, or districts must be resolved before the CCN is granted. If the service area requires the construction of a new water or sewer system, the CCN applicant must also obtain engineering plan approval from TCEQ.

Utilities seeking to obtain a new CCN or amend an existing CCN to change the boundaries of its certified service area must file an application with the PUCT. Decertification, expedited release, and streamlined expedited release proceedings remove all or a part of a certificated service area from a CCN. A utility that receives a request to provide service to an area outside its

[58] Tex. Government Code Ann. § 49.001(1).
[59] Tex. Government Code Ann. § 49.215(d).
[60] Tex. Government Code Ann. § 49.001(8).
[61] Tex. Government Code Ann. § 49.215(d).

CCN boundaries must first amend its CCN and add the requested area to lawfully provide service to the new area. Political subdivisions such as municipalities, districts, and counties may obtain a CCN but are not required to do so unless they plan to provide service in an area where another utility is already lawfully serving.

During FY 2021 and FY 2022, the PUCT finalized 317 CCN-related applications, including requests for new CCNs, amendments, decertification, and expedited release cases. Figure 8 shows the quarterly number of finalized CCN-related applications in FY 2021 and FY 2022.

Figure 8. The number of finalized CCN-related applications in each quarter of the 2021 and 2022 fiscal years.

Utility Acquisitions

Any change of control, such as a sale or acquisition of a CCN holder's water or sewer system, requires notice to consumers and neighboring utilities and approval from the Commission. A sale may also require the transfer of the CCN to the purchaser. The transfer and related sale of facilities is commonly known as a sale, transfer, or merger (STM). The acquiring entity may be either an existing utility or a new market entrant. Like the process for granting a new CCN, during a STM proceeding the PUCT examines the financial, managerial, and technical capability of the acquiring entity to provide continuous and adequate service to the service area defined by the CCN, plus any areas already served by the acquiring entity. The applicant's financial health, compliance history with TCEQ's health and safety standards, and any consumer complaint history are considered in the proceeding. To obtain PUCT approval, the applicant must also show that the proposed STM is in the public interest.

There has been an increase in acquisitions of smaller water and sewer utilities by larger IOUs during the past few years. With the continued growth of the Texas economy, several IOUs, including those based in other states or countries, are actively pursuing acquisition and consolidation of smaller utilities in Texas. Economies of scale gained through acquisitions provide value to IOUs along with regulatory and operational efficiencies. In addition, new regulatory processes, such as fair market value and filed rate doctrine help facilitate transactions.

Expedited Release

The owner of a tract of land of at least 50 acres can petition the PUCT to receive service from a different retail public utility through an expedited release proceeding. The petition can include all or a part of the tract. The landowner may initiate such a petition requesting service from another provider if the CCN holder for its geographic area is either not providing service or if the service cost is so prohibitively expensive as to constitute a denial of service. Petitions for expedited release must identify an alternative provider that can provide service in the level and manner requested by the landowner. The CCN holder can oppose the expedited release and may refute any information submitted by the petitioner. The landowner requesting the expedited release must provide adequate and just compensation to the CCN holder for release. An expedited release can occur anywhere in the state, except within cities with a population

Streamlined Expedited Release (SER)

The owner of a tract of land of at least 25 acres that is not receiving water or sewer service may petition for a streamlined expedited release from the current CCN holder for its geographic area. The landowner must provide adequate and just compensation to the CCN holder for such a release. Streamlined expedited release is available in the following 33 counties under TWC § 13.2541: Atascosa, Bandera, Bastrop, Bexar, Blanco, Brazoria, Burnet, Caldwell, Chambers, Collin, Comal, Dallas, Denton, Ellis, Fort Bend, Galveston, Guadalupe, Harris, Hays, Johnson, Kaufman, Kendall, Liberty, Montgomery, Parker, Rockwall, Smith, Tarrant, Travis, Waller, Williamson, Wilson, or Wise Counties.

CCN Revocations

Revocation of a CCN is necessary when the CCN holder does not provide or is incapable of providing continuous and adequate retail water or sewer service. This failure could be the result of the utility's insolvency, the dissolution of the company that owns the CCN or the death of the CCN holder. A revocation may also be necessary if the utility has never provided service and has no active plans to do so in the future. Because a CCN grants the holder an exclusive right to provide utility service to a defined geographic area, other potential service providers are prevented from providing water sewer service to consumers in the area. DICE conducts investigations and initiates proceedings to revoke the CCNs of failing utilities. The CCN must be revoked to limit harm to consumers and ensure a quality provider may instead serve the area.

Ratemaking

Water and sewer utilities must have sufficient revenues to cover daily operations, repair and replace equipment, and repay debts. A utility must maintain a strong balance sheet and sufficient cash flows to attract investors or lenders and raise the funds necessary to invest in capital-intensive water and sewer systems. A utility must also generate enough annual cash flow to repay any accrued debt and to pay for operating expenses.

A utility's primary revenue source is the payment of consumers' bills. The rates charged to consumers must be established to recover the utility's reasonable and necessary cost of providing service. These include the costs for production, treatment, storage, collection, and distribution.

Rates must be periodically reviewed and, if necessary, reset to reflect a utility's change in costs. Stagnant rates can result in a utility collecting insufficient revenues over time and may prevent investment in system repairs or improvements necessary to maintain service or increase efficiency. This is particularly true for smaller utilities with limited access to capital markets to fund investment. Conversely, a utility could over-earn if its rates are not reviewed in a timely manner. Over-earning allows benefits to accrue for shareholders or owners at the expense of the consumers.

PUCT rate cases establish just and reasonable rates for water and sewer utilities. During FY 2021 and FY 2022, the PUCT finalized 121 water and sewer utility rate applications. Figure 9 shows the quarterly numbers of completed rate applications in FY 2021 and FY 2022.

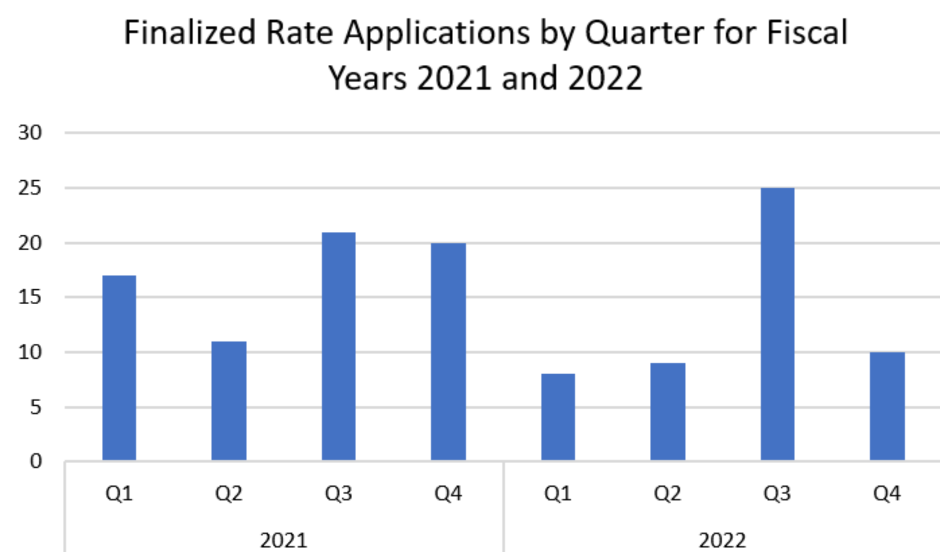

Figure 9. The number of finalized rate applications in each quarter of the 2021 and 2022 fiscal years

Jurisdiction

Original jurisdiction over fees charged by water and sewer providers depends on the utility's type and location.

The PUCT has original jurisdiction over IOUs' retail water and sewer rates in most cases. The PUCT has appellate jurisdiction over the rates of IOUs where the service area is within a municipality's corporate boundaries. In this case, the municipality has original jurisdiction over the retail rates unless the city surrenders its rate jurisdiction to the PUCT. The following cities have surrendered to the PUCT jurisdiction over IOUs' rates within its corporate boundaries:

- City of Coffee City – effective 12/4/1993
- City of Nolanville – effective 04/18/1996
- City of Aurora – effective 04/04/1997
- City of Arcola – effective 05/05/1998
- City of Waco – effective 02/07/2012
- City of San Antonio – effective 01/30/2014
- Village of Jones Creek – effective 12/04/2014 and
- City of Hideaway – effective 09/26/2016.

The PUCT has limited appellate jurisdiction over the retail rates of WSCs, Affected Counties, and districts, including river authorities. The governing board of a WSC or a district sets retail water and sewer rates for its consumers. After the board approves a rate change, if 10% or more of the consumers protest, the rates can be appealed to the Commission. The PUCT also has limited appellate jurisdiction over the rates of consumers served by MOU but residing outside of the governing city's territorial limits. The city council or a separate board established for consumers may set rates for services provided by MOUs. Consumers that reside outside of the city limits and are therefore not represented by the MOU's governing body may appeal these ratemaking decisions to the PUCT. To date the PUCT has not received an appeal regarding the retail rates of an Affected County. Figure 10 shows the percentage of service connections over which the PUCT has appellate or original jurisdiction.

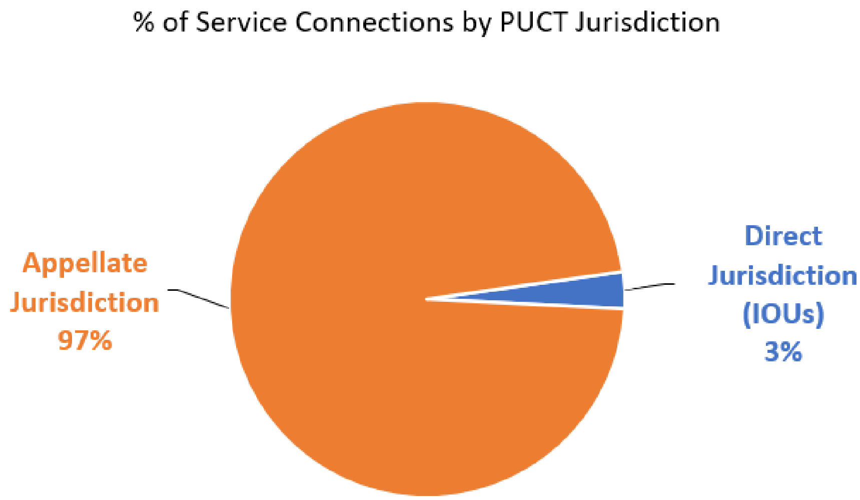

Figure 10. Percentage of service connections by PUCT Jurisdiction

Formal Ratemaking Proceedings

A utility must file its rate case with the regulatory authority with original jurisdiction over its water or sewer rates. Although homeowner associations, property owners' associations, and cooperatives are nonprofit entities, TWC treats them as utilities for ratemaking purposes. Utilities can file for a rate change no more than once in a 12-month period.

Rate-filing requirements for IOUs under PUCT jurisdiction vary depending on the utility's classification. TWC classifies water or sewer utilities by the number of active connections served. Sewer utility connections are not counted for classification purposes unless the utility only provides sewer service. The number of connections determines the classification as either a Class A, B, C, or D utility, as shown in Table 1. The percentages of the number of utilities and the total connections served by each utility class are shown in Figure 11.

Table 4. IOU Classification is based on the number of connections.

IOU Classification	Number of Connections
Class A	10,000 - greater
Class B	2,300 - 9,999
Class C	500 - 2,299
Class D	0 - 499

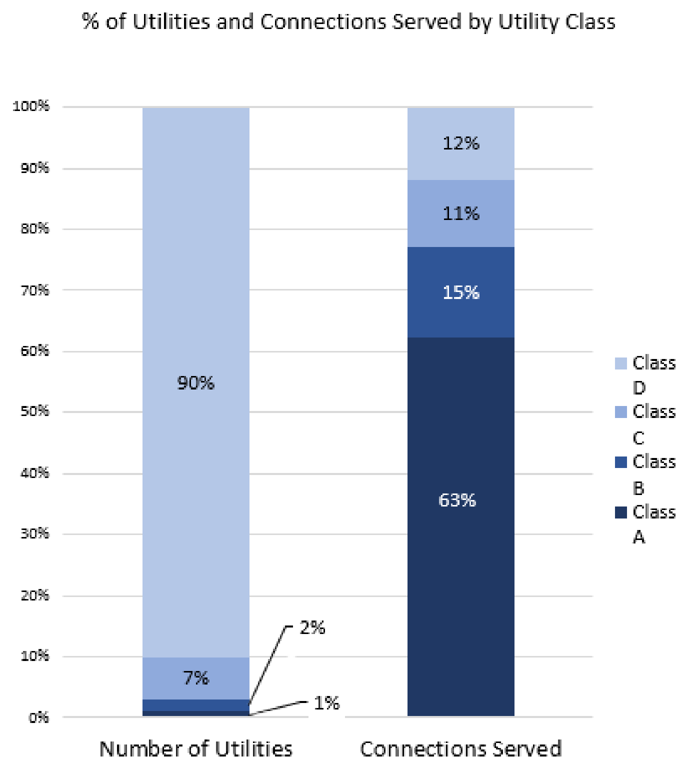

Figure 11. Percentage of utilities and connections by utility class.

Class A utilities have the most stringent rate-filing requirements. A Class A utility must show cost information, provide rate schedules, and include written testimony supporting the requested rates. The utility must also provide all information regarding affiliate charges. The rate application must include a notice to affected consumers and the regulatory authority with jurisdiction over its rates.

Class B and Class C utilities have simplified filing requirements that require fewer rate schedules and less detailed financial information. Written testimony is not required unless a formal hearing is requested. Class B and Class C utilities must also provide all information regarding affiliate charges and comply with notice requirements for affected consumers and the regulatory authority with jurisdiction over its rates.

Class D utilities have the simplest rate filing requirements. A Class D utility may apply to implement an annual rate adjustment of up to five percent without a hearing. The utility must provide notice to its consumers at least 30 days before the effective date of the proposed change. This simplified rate adjustment treatment may be utilized up to four times before a comprehensive base rate proceeding is required. A Class D utility must file the more detailed Class C utility application for a comprehensive base rate proceeding or a rate increase over five percent.

Pass-Through Adjustments

A pass-through adjustment is a minor rate change that allows a retail public utility to obtain a rate increase or decrease to account for changes in costs imposed by governmental entities and wholesale water providers. These costs are typically outside the utility's control and are not reflected in the utility's cost of service. Pass-through rate adjustments are typically processed within 60 days and provide timely recovery of a utility's costs. A utility can apply for an update to the pass-through rate each time the governmental entity increases or decreases the rates to the utility. These changes may happen several times a year. To recover the adjusted rate and meet the revenue requirement, the utility must separate the costs of a pass-through rate from the other charges.

Alternative Ratemaking

SB 700 (86th Legislature, Regular Session) established alternative ratemaking methodologies for water and sewer rates and established a system improvement charge (SIC). These methodologies include the use of multi-step rates, the cash needs method, and the ability to request the addition of a new customer class. Alternative ratemaking provides utilities and the PUCT additional tools to implement rate changes outside intensive base rate proceedings.

Multi-step rates allow the utility to implement rates over time without filing multiple rate applications. Once established in a comprehensive base rate proceeding, multi-step rates allow a tiered approach to raise rates over time and reduce rate shock on consumers. The cash needs method enables a utility to recover operating expenses, debt service costs, and an additional margin consisting of either an operating margin or an incremental revenue amount. The cash needs method is only available to a Class C or Class D utility and the utility must support its use. Specifically, the method must be deemed necessary for the utility to provide continuous and adequate service or other good cause exists. Generally, a utility may request the addition of a new customer class or classes in its tariff and extend the timeline for a comprehensive rate case. The utility's application must demonstrate that the rates are based on standard cost-of-service and rate design principles. Revenues to be recovered from the new class must be a limited percentage of the utility's total annual revenue.

A SIC allows a utility to seek recovery of the cost of eligible facilities through a rider instead of a comprehensive base rate case. Unless a hearing is requested or the filing is deemed insufficient, an SIC application can be processed within 120 days after filing. SIC helps ensure the timely recovery of utility infrastructure investments. Costs recovered through a SIC are subject to reconciliation in the utility's next comprehensive rate case, required within four to eight years, depending on the utility's size.

Submetering and Allocation

Businesses such as apartments, condominiums, manufactured home communities, office parks, and marinas may provide water or sewer service to their tenants. These businesses obtain water and sewer services from a utility and may choose to pass the bills on to tenants through submetering or allocation. For submetering, the business is responsible for installing and maintaining individual meters, so consumers are billed for actual usage. If allocating, the business must use specific formulas based on characteristics such as the number of occupants and size of the unit to charge the tenants an equitable share of the total usage. The PUCT has jurisdiction over business owners, operators, or managers who submeter or allocate their units. Businesses are responsible for following the PUCT's rules which provide safeguards for tenets and ensure just and reasonable rates.

Property owners that submeter or allocate utility charges must register with the PUCT. There are currently 3,689 entities registered to submeter and 7,071 registered to allocate the water or sewer utility service charges to tenants. The high number of entities submetering and allocating services presents challenges for ensuring consumers are properly informed and billed. Many property owners are unaware of the legal requirements surrounding submetering and allocation. Submetering and allocated bills complaints typically include disputes regarding billing or allocation methods, lack of communication, limited notice of billing changes, or billing changes made without update to the tenant's lease agreement. There are also frequent changes in ownership and owners changing billing procedures without approval by the Commission. Many underlying noncompliance issues appear to stem from ignorance of the rules rather than intentional noncompliance.

Distressed Utilities

While health and safety issues fall within TCEQ's jurisdiction, the PUCT is responsible for ensuring that utilities provide continuous and adequate service to their consumers. A healthy rate structure is necessary for the sustainability of a utility's operation. The PUCT is responsible for ensuring that utilities have rates that generate enough funds to safely maintain and operate the system.

While a utility must demonstrate the financial, managerial, and technical capability to provide continuous and adequate service to obtain a CCN, these capabilities can diminish over time. This is especially true with smaller utilities that may have their financial, managerial, and technical capability tied to a single person. Additionally, lack of access to financial resources is a significant challenge for smaller utilities. It is difficult to generate sufficient revenues through rate increases, given the limited number of consumers. Inadequate revenues and insufficient access to capital can make it difficult or impossible for a utility to make necessary improvements to its system.

Utilities in financial distress may fail to perform basic business tasks such as answering consumer calls, reading meters, billing according to the utility's tariff, maintaining adequate records, or paying electricity and wholesale water supply bills. TWC provides temporary management, supervision, and receivership as tools to assist these utilities. These tools can help utilities get the qualified management they need to provide continuous and adequate service in compliance with PUCT and TCEQ regulations. The PUCT can assist these utilities in finding new ownership.

Temporary Management

A temporary manager may be appointed to operate a nonfunctioning water or sewer utility that has discontinued or abandoned operations. Both TCEQ and the PUCT have jurisdiction to appoint a willing person, municipality, or political subdivision to temporarily manage a utility. Only IOUs may be placed in temporary management.

A temporary manager has the power and duty to ensure the continued operation of the utility and the provision of continuous and adequate water or sewer service to consumers. This includes reading meters, billing consumers and collecting revenues, making necessary repairs to the system, and conducting required sampling. Temporary managers must meet detailed reporting requirements including monthly reports on the utility's properties, business transactions, the status of systems, significant events, and consumer complaints. PUCT staff monitor each filing for compliance with the rules throughout the temporary manager's tenure.

In the case of an abandoned utility, immediate action may be needed to protect consumers and ensure public safety. The PUCT's Division of Utility Outreach (DUO) oversees identifying abandoned utilities, finding suitable and willing temporary managers, referring the utilities for temporary management or receivership, and coordinating with other state agencies. DICE provides legal and investigative support during the appointment process and, upon referral from DUO, prepares the petition to appoint a temporary manager. The PUCT's executive director can issue an emergency order and appoint a temporary manager for an abandoned utility. The PUCT must ultimately approve, modify, or set aside the emergency order. Appointments can also be made by order of the PUCT after a hearing.

When the temporary manager is appointed, the PUCT sets a compensation fee for the manager's time and services that will be added to the consumers' bills. The temporary manager can also apply for temporary rates to cover the reasonable costs associated with the utility's operations and maintenance. This rate may cover the costs the temporary manager incurs to make service available or to bring the nonfunctioning system into compliance with PUCT and TCEQ's requirements. Upon filing notice, the temporary manager may immediately begin imposing the temporary rates. The PUCT must approve or adjust the temporary rates within 90 days of implementation. Temporary rates may continue after a nonfunctioning utility is acquired by another utility for a period determined by the Commission.

Since the beginning of FY 2021, the PUCT has appointed nine temporary managers to abandoned water utilities encompassing 14 public water systems. As of the end of FY 2022, there were 11 utilities encompassing 16 active public water systems under temporary management.

Receivership

The PUCT and TCEQ each have the authority to refer a water or sewer utility to the Office of the Attorney General (OAG) to seek the appointment of a receiver for a nonfunctioning system. The OAG may seek a court-ordered appointment of a receiver to manage and operate a nonfunctioning water or sewer utility. A receiver has more power over a utility than a temporary manager, including the ability to seek court approval to sell the utility. A receiver is also authorized to charge temporary rates; however, the Commission PUCT must set those rates. Table 5 summarizes and compares the authorities and responsibilities of temporary managers and receivers according to TWC.

Table 5. Comparison of authorities and responsibilities between temporary managers and receivers.

	Temporary Manager	Receiver
Eligibility	May be a natural person, partnership, water supply or sewer service corporation, or corporation.	Must be an individual – not an entity, group, or organization. A receiver is accountable to the state district court.
Process to appoint	Appointed by order of the PUCT or TCEQ and accountable to the appointing agency.	Appointed by the court with Commission's referral and accountable to the state district court and the appointing agency.
Reporting	Must submit monthly reports to both TCEQ and PUCT.	Must submit monthly reports to the Court, TCEQ, and PUCT.
Authority to sell	Cannot sell the system.	May file a motion at the court and seek authorization to submit an STM to the PUCT and sell the system.
Compensation	The PUCT sets a temporary manager's fee which is added to the consumer's bills.	The court sets a receiver's fee which is added to the consumer's bills.
Rates	May apply to the PUCT to charge temporary rates.	May apply to the PUCT to charge temporary rates.

As of the end of FY 2022, eight utilities were in receivership, four of which had STMs either in progress or completed.

Supervision

The PUCT is the only agency with the authority to place a utility under supervision. A utility may be placed under supervision if it has exhibited gross or continued mismanagement, gross or continued noncompliance with TWC Chapter 13, or has exhibited noncompliance with PUCT orders.

When a utility is placed under supervision, the PUCT may require the utility to abide by specific conditions and requirements. This could include placing restrictions on hiring, salary or benefit increases, capital investments, borrowing, issuance of stocks, and the use of funds. The PUCT may also impose conditions on the priority of payments and other financial obligations. Currently, the PUCT lacks the resources to utilize this tool and there are no utilities under supervision.

PUCT Resources

Working with utilities in temporary management or receivership situations requires significant agency resources. PUCT staff spends considerable time helping temporary managers through temporary rate applications and, if necessary, helping them obtain or amend a CCN. Staff also assist the temporary manager or receiver with coordination between local, state, and federal agencies and explain reporting requirements. Staff often hold consumer meetings and contact neighboring utilities and other entities to facilitate the acquisition of the nonfunctioning utility.

In some cases, the period of temporary management must be extended, or a new temporary manager must be found. This can occur because the existing temporary manager is no longer willing to continue with the appointment or the purchasing party is no longer interested in buying the nonfunctioning utility. The average time a nonfunctioning utility remains in temporary management, supervision, or receivership is between two and four years.

During the 2021-22 biennium, the PUCT has closed four temporary management appointments, with three systems having finalized STMs and one returning to the original owner. The PUCT has completed processing the transfer of four utilities in receivership and worked closely with the OAG and TCEQ to dismiss the receivers. All these utilities were abandoned, and consumers were experiencing substantial issues with their services. With new owners, the systems have restarted regular operations.

Emerging Issues

Consolidation and Regionalization of Retail Public Utilities

As federal health and safety regulations on public water and sewer systems increase, many retail public utilities must make large capital investments to stay in compliance with revised standards. Without a substantial rate increase, these utilities are unable to make these needed investments. In lieu of increasing their rates, many utilities contact the PUCT to express an interest in selling their systems. Some entities have already found a potential buyer, while others need help finding a purchaser. In some instances, the utility has already been sold, but because the sale was not approved through the STM process required by TWC § 13.301, the sale is rendered void.

The PUCT's DUO works closely with retail public utilities seeking to find a viable entity to acquire, purchase, or consolidate their systems with another utility. DUO also works with entities that have acquired or sold systems without first going through the required regulatory approvals to become compliant, by helping them navigate the regulatory process and understand applicable rules.

Assisting Utilities During and After Winter Storm Uri

Winter Storm Uri affected water systems across Texas were affected and many consumers experienced the loss of water service. The PUCT worked with water and electric utilities to identify affected water facilities and help restore and maintain electric service. The PUCT worked with TCEQ to identify water utilities without power and required boil water notices to safely restore service. The PUCT also implemented a temporary moratorium on water utility disconnections during recovery from Winter Storm Uri.

In the aftermath of Winter Storm Uri, some utilities had difficulty paying their electric bills due to insufficient revenue from water sales and the inability to disconnect for nonpayment. PUCT staff worked with the water and sewer utilities' electric providers to ensure continuous electricity for the utility. Electric providers set up payment plans to help affected water and sewer utilities have the time necessary to pay their bills in full.

Critical Water Facilities

SB 3 requires entities that meet the new definition of “affected utility” under TWC § 13.1394 to file specific information to help identify emergency contacts and facility locations in an emergency event. The term “affected utility” is defined as a retail public utility, exempt utility, or provider or conveyor of potable or raw water service that furnishes water service to more than one consumer and is not in Fort Bend or Harris Counties. Utilities must identify the location and provide a written description of all water and sewer facilities that qualify for critical load status, emergency contact information for a primary and an alternate point of contact, and the utility’s address. In addition to filing this information at the PUCT, the utility must provide a copy to each TDU that provides electric service to the affected utility, each REP that sells power to the utility, the office of emergency management of each county where the utility has water and sewer facilities that qualify for critical load status, and the Texas Division of Emergency Management (TDEM) of the Governor. November 1, 2021 was the initial deadline for affected utilities to provide the required information. As of September 2022, the PUCT has received more than 1,500 critical water filings in the project created as a repository for the filings. Since 2021, PUCT staff has conducted extensive SB3-related outreach activities. DUO has given 13 presentations regarding the critical facilities requirement at conferences and trade associations, created a new Utili-Facts document, and conducted educational campaigns, including both mass email and regular mail, to inform the affected utilities about the requirement.

Rulemakings

Alternative Ratemaking

Project No. 50322, Alternative Ratemaking Mechanisms for Water and Sewer Utilities. In December 2021, the PUCT repealed 16 TAC § 24.75 and adopted new 16 TAC § 24.75, relating to *Alternative Ratemaking Methodologies*. The rule implemented specific provisions of TWC § 13.183(c) enacted by SB 700 (86^{th} Legislature, Regular Session) by establishing alternative ratemaking methodologies for determining water and sewer utility rates. New 16 TAC § 24.76, relating to *System Improvement Charge* implements a method for a utility to ensure the timely recovery of infrastructure investment between comprehensive rate cases.

Customer Protection

Project No. 52405, Review of Certain Water Customer Protection Rules. SB 3 provides for consumer protection during extreme weather events. The law applies to retail public utilities that must possess a CCN, districts, and affected counties that furnish retail water or sewer utility service. In October 2022, the PUCT adopted new rules 16 TAC § 24.173, relating to *Late Fees and Disconnections During an Extreme Weather Emergency for Nonpayment* and 16 TAC § 24.364, relating to *Civil Penalties for Late Fees and Disconnections During an Extreme Weather Emergency for Nonpayment*, to implement the statute. The rules prohibit a utility from charging a consumer late fee or disconnecting the consumer for nonpayment during a defined extreme weather emergency. Utilities must offer payment plans for bills due during an extreme weather emergency and adopt a civil penalty classification system to be used by the OAG and the courts for violations of the requirements.

Class D Water and Sewer Utility Rate Adjustments

Project No. 54062, Class D Water and Sewer Utility Rate Adjustments. In November 2022, the PUCT adopted amendments to 16 TAC § 24.49, relating to *Application for a Rate Adjustment by a Class D Utility Under Texas Water Code § 13.1872*. The amendments simplify the application process for a Class D water utility rate adjustment and provide the utility with PUCT resources to aid with regulatory compliance. The PUCT also adopted amendments to the corresponding Class D utility rate adjustment application form.

ENFORCEMENT

The PUCT's enforcement efforts focus on violations of PUCT rules and statutes, such as PURA and TWC. Wholesale electric market and grid reliability investigations also involve the ERCOT Protocols, operating guides, and other documents. Ensuring compliance protects consumers, the electric markets, and the reliability of the grid. Compliance ensures quality of service to all Texans who rely on regulated electric, water, sewer or telecommunications services.

Other PUCT divisions oversee the informal and formal complaints of individual consumers. DICE was created in August 2021. DICE focuses on larger, systemic violations of law and rules and on those violations which have the most significant impact on the public interest. Enforcement matters were managed by the Legal Division from September 1, 2020, through July 31, 2021.

The PUCT's compliance and enforcement program goals are accomplished through investigations, audits, and enforcement actions. Throughout the process, DICE's enforcement analysts and lawyers collaborate with subject matter experts across the agency. The Customer Protection, Infrastructure, Legal, and Market Analysis divisions work closely with DICE. Experts from ERCOT, the IMM, and the ERCOT Reliability Monitor also provide critical expertise to inform and support DICE investigations. Analysts provide technical and factual expertise while attorneys provide legal analysis and litigation management. Experts advise DICE attorneys on fact-based issues to help develop effective legal enforcement strategies.

Investigations

The PUCT has statutory authority to investigate regulated electric, water, and telecommunications entities. DICE monitors consumer complaints filed with CPD and will open an investigation if the issue appears to have systemic or broad implications for a group of consumers. Additionally, DICE launches investigations in response to self-reporting by entities, press reports, and legislative inquiries. For the wholesale electric market, ERCOT, the ERCOT Reliability Monitor, and IMM can also inform DICE of potential violations for investigation. Most investigations are resolved through settlement rather than litigation of contested cases.

During the 2021-22 biennium, PUCT staff closed 104 investigations into the electric industry, five investigations into the telecommunications industry, 20 investigations into the retail water and sewer industries. Ten investigations related to apartment complex billing matters were investigated. An investigation can be closed by determining no violation occurred, issuing a warning letter, gaining approval of an order imposing monetary penalties, or revoking a license or certificate.

Penalties, Refunds, and Donations

In the 2021-2022 biennium, the PUCT assessed $1,785,250 in penalties against regulated entities. These penalties are remitted to the state's general revenue fund. The distribution of the penalties based on the industry is shown in Figure 12. In addition, DICE has started tracking refunds to consumers and donations to consumer assistance agencies that resulted from enforcement proceedings. In FY 2022, the PUCT secured $385,973.10 in refunds to consumers and donations to consumer assistance agencies.

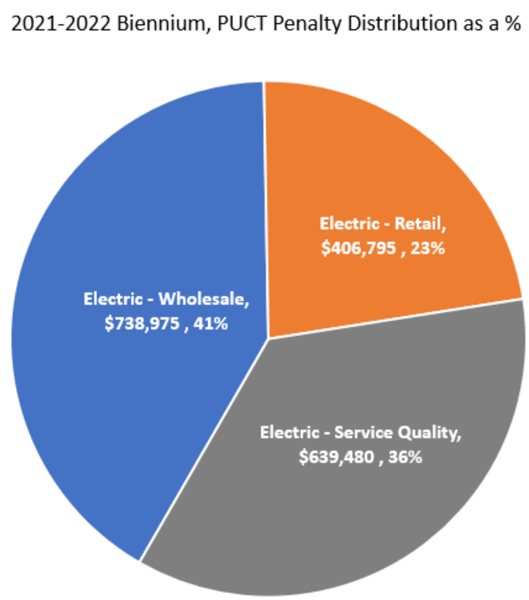

Figure 12. Penalty distribution

Winter Weather Preparation Reporting

Following SB 3, the PUCT adopted a new rule governing the winter preparedness of generation resources and transmission voltage substations and switchyards.[62] SB 3 also increased the PUCT's administrative penalty authority to $1 million per violation, per day for violations related to weather preparation regulations. DICE was tasked with ensuring compliance with these new, first-in-the-country regulations. PUCT and ERCOT subject matter experts worked together to develop a compliance and enforcement regime. Detailed technical filings were received from more than 800 entities and reviewed by PUCT and ERCOT staff. More than 90% of power generation entities and 95% of transmission companies complied with the new regulations. DICE launched compliance investigations or enforcement proceedings against the

[62] 16 TAC § 25.55, *Weather Emergency Preparedness*.

remaining entities. Enforcement cases were filed against eight entities specifically for failing to follow the detailed regulations. These cases are pending.

SB 3 also added new provisions to TWC enhancing the PUCT's ability to safeguard retail water or sewer consumers from disconnection for nonpayment during winter weather emergencies. Among other provisions, TWC § 13.414 enables the PUCT to refer violating utilities to the Office of the Attorney General for the collection of enhanced administrative penalties. The PUCT has adopted rules codifying this enhanced enforcement ability.

Loss of Certificates

In addition to financial penalties, the PUCT has other enforcement tools, such as revoking a company's certificate to operate. Some companies may be required to relinquish a certificate as part of a settlement after enforcement action has concluded. Notably, DICE revoked seven REP certificates and settled on an agreed relinquishment for an additional REP certificate following the financial fallout from Winter Storm Uri. Two REP certificate revocation proceedings have been filed and are pending action by the Commission.

Warning Letters

DICE issues warning letters to companies for minor infractions or where no administrative penalty is necessary. DICE may issue a warning letter when an entity proactively works to resolve violations early in an investigation. The warning letters remain on file and can be referenced by DICE to demonstrate patterns of violation over time. During the 2021-2022 biennium, DICE issued 55 warning letters to entities found not in compliance with PUCT rules.

Power Line Inspection and Safety

HB 4180 (86th Legislature, Regular Session) established the Power Line Inspection and Safety program. All overhead distribution and transmission voltage equipment that crosses one of the 178 lakes identified in PURA § 38.004 must comply with vertical clearance standards in effect at the time the equipment was built. Noncompliance must be remedied, or the equipment rebuilt to meet today's standards.

Electric utilities with overhead distribution or transmission voltage facilities must file reports documenting adherence to vertical line clearance standards. PURA § 38.102 requires utilities to file an annual report, a five-year report, and a one-time training report. DICE monitors these reports for compliance with filing deadlines and for required compliance disclosures.

Following an investigation in March 2022, DICE determined that 13 utilities were not in compliance with vertical clearance standards. As of the date of this report, eight utilities remain out of compliance. DICE has required each of these entities to file monthly progress reports detailing the activities each are taking to bring the affected facilities into compliance.

Reliability Monitor Function

The PUCT is required to adopt and enforce rules related to the reliability of the ERCOT transmission network. PURA allows the PUCT to delegate some or all this responsibility to an independent organization. ERCOT, Inc., under complete authority and oversight by the PUCT, is charged with adopting rules related to the reliable operation of the transmission system in the ERCOT power region.

From 2010 to 2020, the PUCT contracted with the Texas Reliability Entity to provide monitoring services related to ERCOT's reliability rules and to assist the PUCT with its obligation to enforce those rules. Since 2020, PUCT staff have worked closely with ERCOT staff to continue monitoring industry adherence to these reliability rules. In November 2022, the PUCT directed ERCOT, Inc. to formally assume the duties of the reliability monitor for the ERCOT power region. This action will enable the PUCT to put safeguards in place to prevent conflicts of interest and ensure the independence of the ERCOT personnel working on reliability monitoring activities.[63]

[63] Project No. 54248.

RESOURCES FOR TEXANS

The PUCT's Customer Protection Division assists electric, water and telephone utility consumers with complaints against utilities and answering general questions about consumer issues.

The PUCT's CPD Intake Center answers various questions from consumers received via phone, mail, email, and the PUCT website. CPD investigators analyze and respond to complaints. Licensing and Compliance oversees the registration of various market participants.

Consumer Assistance

The Intake Center is most consumers' only interaction with PUCT staff. Common inquiries include how to read one's bill, what to do if service is disconnected, information on outages, and how to file a complaint. For the competitive electric market, the Intake Center answers questions about the PUCT's Power to Choose website and provides consumers with information to help them select a REP. Additionally, the Intake Center responds to inquiries and takes complaints regarding the Texas No Call list. During the 2021 to 2022 biennium, CPD answered over 63,500 calls.

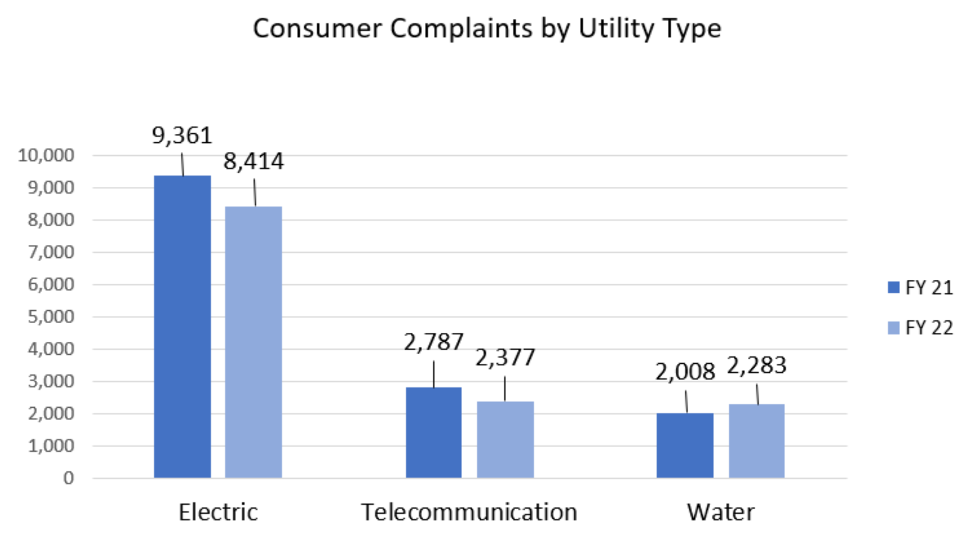

Figure 13. The number of consumer complaints for Electric, Telecommunication, and Water utility services received in FY 2021 and FY 2022.

A Texan who has a dispute with a provider of electric, telecommunications, or water and wastewater services can make an informal complaint to CPD. Once an informal complaint is filed, the utility is asked to show compliance with PURA or TWC and with PUCT rules. Water and sewer providers must respond within 15 days. Electric and telecommunications providers must respond within 21 days. A CPD investigator then reviews all information received from both the consumer and the provider to determine whether the provider's actions are consistent with applicable regulations. The investigator's conclusion regarding the complaint is sent to both the consumer and the provider. The investigator identifies any potential compliance issues and may recommend corrective action. A consumer dissatisfied with the investigation's results may file a formal, docketed complaint with the PUCT.

Social media accounts

The PUCT engages directly with Texans every day through multiple social media accounts. We regularly inform the public about the agency's activities, responsibilities, rules, and regulations, consumer tips and emergency information, when necessary. The agency's active social media accounts include:

- Public Utility Commission of Texas–Facebook
- PUC of Texas–Twitter
- Public Utility Commission of Texas–LinkedIn
- PUCTX– Instagram
- Power to Choose–Facebook
- powertochoosetx–Twitter

Social media engagement by the public can vary widely from month to month, based on several factors, including weather, electricity demand, fluctuations in the cost of electricity and others. For example, the number of social media impressions, or times content was seen by users in June 2022, was 34,000 times. In August 2022, during periods of record heat and demand, it was 138,000 times. We continue to experience steady growth in engagement since adding an FTE dedicated to social media engagement in May 2022 and expect that trend to continue.

Websites

puc.texas.gov

Our external website serves as the "virtual front door" of the agency and provides several tools to assist Texas utility consumers, utility providers, and industry leaders with matters and information relating to the PUCT. The PUCT's website averages more than 255,000 page views per month. Data shows beyond the home page, the most-visited pages include Paying Your Bill, Industry Filings, Rules pages and Know Your Rights. Additional resources and tools include:

- Online informal complaint filing for electric, telecommunications, water, and wastewater issues
- An outage resource section with contact information to report local electric utility outages to providers and links to local outage maps to monitor outages

- Access to information about electric, telecommunications, water, and wastewater providers
- Links to live internet broadcasts and calendar for open meetings
- News releases and updates from the PUCT

PUCT Interchange (interchange.puc.texas.gov)

The Interchange is a web-based application for submitting and accessing documents filed with the PUCT. The Interchange Filer system is used to file documents with the PUCT electronically. The public can use the PUCT Interchange to locate information officially filed with the PUCT in Central Records, including projects, dockets, and tariff applications. Documents can be searched for by Case Style (the Docket Description), Utility Type, Utility Name, Filing Party, Item Type, Filing Description, and date range. Central Records staff can be reached via email (centralrecords@puc.texas.gov) to answer any questions about filing documents or locating documents that have been filed with the PUC including hard copies of utility tariffs.

Power to Choose (powertochoose.org)

The PUCT's consumer education website for the competitive retail electric market is known as Power to Choose. It's an educational tool for consumers about the evolving marketplace. Power To Choose (and its Spanish language counterpart, Poder De Escoger) provides a portal for Texans who live in an area open to retail electric choice to browse electricity plans offered by REPs. Information on the shopping process, plan options, and questions to ask when shopping is also available. REPs are not required to post prices or rate plans on the site, but most choose to use it to reach consumers directly. The site is free for both consumers and REPs.

Power to Save (powertosavetexas.com)

The PUCT promotes smart energy use through the Power to Save Texas website (and its Spanish language counterpart, Poder de Ahorrar). The website educates Texans about conserving energy, especially during the summer peak times of 3 pm to 7 pm, when demand for electricity tends to be the highest. The site includes links to additional resources for Texas to learn how to manage their electric use.

Map Viewers

The PUCT's Water and Sewer CCN Viewer gives users access to retail public water and sewer CCNs.[64] Users can search by address to find a water or sewer service provider. Utilities can

[64] *Public Utility Commission Water and Sewer CCN Viewer*, PUBLIC UTILITY COMMISSION OF TEXAS, https://www.puc.texas.gov/industry/water/utilities/map.aspx

prepare map filings for applications to obtain a CCN and amend or transfer a CCN. By giving the public direct access to this information, it reduces the call volume at the PUCT.

The PUCT's website links to electric utility outage maps.[65] This feature is highlighted on the PUCT's Storm Resources page and is used by the PUCT's Emergency Management Response Team to prepare for, respond to and recover from disasters and conduct emergency management activities. It's also used by the public to report and monitor local outages.

[65] *Outage Maps*, PUBLIC UTILITY COMMISSION OF TEXAS, https://www.puc.texas.gov/storm/contact.html.

LEGISLATIVE RECOMMENDATIONS

Administrative

Improve Consumer Response Time on Small Claims

Currently, only one process is available for a consumer to get a binding resolution of a complaint against a regulated service provider. A consumer can get informal assistance from the PUCT's Customer Protection Division, but that resolution cannot be enforced by the PUCT. A binding resolution, which the PUCT can enforce, is accomplished through a contested case under the Administrative Procedures Act. A contested case is a trial-type procedure presided over by an administrative law judge at the PUCT or State Office of Administrative Hearings (SOAH), and any hearing generally is conducted by SOAH. This process is often expensive and time-consuming for the consumer, the PUCT and SOAH. When considering the salaries of state employees assigned to such a proceeding, the cost to resolve such a proceeding can greatly exceed the amount in dispute. To ensure the best use of resources and decrease the time taken to resolve these claims, the PUCT recommends a streamlined process that does not require a contested case for claims under a certain dollar amount, such as $500.

Background Checks for PUCT Personnel

PUCT personnel have access to critical information related to Texas' electric grid. Currently, the PUCT is not required to and does not have the ability to conduct background checks on PUCT employees. A background check is a simple tool to ensure that PUCT staff does not immediately present a safety risk to Texas' electric grid. To conduct background checks on state employees, state agencies must have explicit authority from the Legislature. To protect Texas' electric grid, the PUCT recommends that it be granted statutory authority to conduct background checks on employees.

Electricity

Establish a Texas Energy Efficiency Council (TEEC)

In addition to building more electric generation, reducing energy consumption is a tool for Texans and Texas businesses to meet current demand and demonstrate how Texas will be able to maintain future grid stability. Presently, there is no single entity tasked with evaluating potential opportunities in energy efficiency to ensure a reliable, dependable, and affordable power supply for Texas.

An Energy Efficiency Council comprised of State Agencies and industry representatives appointed by those agencies would serve as a central repository and resource for all the energy efficiency measures that are ongoing throughout the state. This Council would strategically position Texas to utilize all the resources available, including identifying cost saving measures for Texas ratepayers. The PUCT recommends the Legislature create parameters around the scope and make-up of the Texas Energy Efficiency Council.

Require Registration of Large Flexible Loads

The number of large flexible loads interconnecting to ERCOT is increasing. Unlike other large loads, these consumers can be turned on or off within seconds of receiving an instruction to do so. There is a significant risk to the ERCOT region if large loads, almost instantly, have the ability to go on or off the grid. To limit the reliability risk created by these large flexible loads, the PUCT recommends that ERCOT have the authority to require large flexible loads register and follow standards on allowable behaviors.

Aggregate Distributed Energy Resources

An aggregate distributed energy resource (ADER) consists of multiple homes or businesses that can combine resources and respond to ERCOT dispatch instructions as if one resource. The PUCT is currently overseeing the implementation of an ADER pilot project in the ERCOT power region. The design of this pilot project has given rise to areas of statute that bear clarification. To facilitate development of such resources, the PUCT recommends the Legislature consider clarifying that:

- the owner of a distributed energy resource (i.e., the owner of the home or business) need not be registered if an aggregator has registered the resource.
- the PUCT may establish simplified registration requirements for ADERs similar to those for distributed natural gas generation facilities
- A REP that aggregates distributed energy resources does not become a power generation company simply by doing so.
- the PUCT's rules, including customer protection rules, jurisdiction, and authority extends to market participants' and consumers' participation in an ADER.

Electricity Supply Chain Map

The Texas Legislature mandated the creation of an electricity supply chain map as part of SB 3 passed during the 87th Legislature. The map was created by the Texas Electricity Supply Chain Security and Mapping Committee. This important tool has created better coordinated preparedness and faster response time during weather emergencies. The PUCT has identified several additions to bolster the map.

Add Water Facilities

Currently water facilities are not included in the Electricity Supply Chain Map. Water is a key component to the production of electricity in Texas. In emergency situations, location transparency for all critical infrastructure is essential. To provide decision makers with the information needed to coordinate between electric, gas, and water industries, water facilities should be added to the Electricity Supply Chain Map.

Add Texas Department of Transportation (TXDOT) to the mapping committee and give them access to the Electric Supply Chain Map.

During Winter Storm Uri, road crews were unable to reach critical infrastructure facilities due to inclement weather and there was no visibility into which roads were inaccessible. To ensure road crews have pertinent information needed during disasters or weather emergencies, TXDOT should be added to the mapping committee and have access to the Electricity Supply Chain Map.

Allow Transmission Distribution Service Providers (TDSPs) access to their specific portion of the Electric Supply Chain Map.

To verify the accuracy of information for critical natural gas facilities needed to serve black start generating units, the TDSPs need access the Electricity Supply Chain Map. A black start unit is one that can start its own power without support from the grid in the event of a collapse or blackout. The PUCT recommends that each TDSPs be allowed access to its specific portion of the Electricity Supply Chain Map to prioritize service to critical natural gas facilities needed to serve black start generating units in times of emergencies.

ACRONYMS

- Aggregate Distributed Energy Resource (ADER)
- Alenco Communications, Inc. (Alenco)
- Backstop Reliability Service (BRS)
- Basic local telecommunications service (BLTS)
- California ISO (CAISO)
- Capacity, Demand, and Reserves Report (CDR Report)
- Certificate of Convenience and Necessity (CCN)
- Certificate of Operating Authority (COA)
- Competitive Local Exchange Carrier (CLEC)
- Customer Protection Division (CPD)
- Department of Energy (DoE)
- Direct Current (DC)
- Dispatchable Energy Credits (DEC)
- Division of Compliance and Enforcement (DICE)
- Division of Utility Outreach (DUO)
- Emergency Response Service (ERS)
- Energy and Environmental Economics, Inc. (E3)
- Energy Emergency Alerts (EEAs)
- Energy Imbalance Market (EIM)
- Entergy Regional State Committee (ERSC)
- ERCOT Contingency Reserve Service (ECRS)
- Fast Frequency Response Service (FFRS)
- Federal Energy Regulatory Commission (FERC)
- Federal Universal Service Fund (FUSF)
- Firm Fuel Supply Service (FFSS)
- Forward Reliability Mechanism (FRM)
- Full-Time Employee (FTE)
- High system-wide offer cap (HCAP)
- House Bill (HB)
- Incumbent Local Exchange Carriers (ILECs)
- Independent Market Monitor (IMM)
- Independent system operator (ISO)
- Internet service providers (ISPs)
- Investor-owned utilities (IOUs)
- Kilowatt-hour (kWh)
- Load Serving Entities (LSEs)
- Load Serving Entity Reliability Obligation (LSERO)

- Low system-wide offer cap (LCAP)
- Lubbock Power and Light (LP&L)
- Market Design Blueprint (Blueprint)
- Marginal Effective Load Carrying Capability (MELCC)
- Megawatt-hour (MWh)
- Megawatts (MWs)
- Midcontinent Independent System Operator (MISO)
- Minimum Contingency Level (MCL)
- Municipally owned utilities (MOUs)
- Nodal Protocol Revision Requests (NPRRs)
- Non-Spinning Reserve Service (Non-Spin Reserve)
- North American Electric Reliability Corporation (NERC)
- Office of Public Engagement (OPE)
- Office of the Attorney General (OAG)
- Operating Reserve Demand Curve (ORDC)
- Organization of MISO States (OMS)
- Performance Credit Mechanism (PCM)
- Physical Responsive Capability (PRC)
- Provider of Last Resort (POLR)
- Public Utility Commission of Texas (PUCT)
- Public Utility Regulatory Act (PURA)
- Qualified Scheduling Entity (QSE)
- Railroad Commission of Texas (RRC)
- Regional State Committee (RSC)
- Regional Transmission Organization (RTO)
- Retail electric providers (REPs)
- Rules and Projects Division (RAP)
- Sale, transfer, or merger (STM)
- Seasonal Assessment of Resource Adequacy (SARA Report)
- Senate Bill (SB)
- Service Provider Certificate of Operating Authority (SPCOA)
- Small and Rural ILEC Universal Service Plan (SRIUSP)
- Southwest Power Pool (SPP)
- Southwestern Electric Power Company (SWEPCO)
- Southwestern Public Service Company (SPS/Xcel)
- Specialized Telecommunications Assistance Program (STAP)
- State-Issued Certificate of Franchise Authority (SICFA)
- Streamlined Expedited Release (SER)

- System Improvement Charge (SIC)
- System Wide Offer Cap (SWOC)
- Technical Advisory Committee (the TA Committee)
- Texas Commission on Environmental Quality (TCEQ)
- Texas Department of Public Safety (DPS)
- Texas Division of Emergency Management (TDEM)
- Texas Energy Reliability Council (TERC)
- Texas High-Cost Universal Service Plan (THCUSP)
- Texas Telephone Association (TTA)
- Texas Universal Service Fund (TUSF)
- Texas Water Code (TWC)
- the Electric Reliability council of Texas (ERCOT)
- the Institute of Electrical and Electronic Engineers (IEEE)
- the National Association of Regulatory Utility Commissioners (NARUC)

APPENDICES

Texas Electricity Supply Chain Security and Mapping Report – January 2022

Load Shed Protocols for the Electric Reliability Council of Texas (ERCOT) Region – August 31, 2022

Weather Emergency Preparedness Report – September 30, 2022

Texas Universal Service Fund Report – August 31, 2022

Texas No-Call List Report – October 2022

PUCT Approved ERCOT Revision Requests

Texas Electricity Supply Chain Security and Mapping Committee

Mapping Report

January 2022

MAPPING REPORT

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MAPPING REPORT OF THE TEXAS ELECTRICITY SUPPLY CHAIN SECURITY AND MAPPING COMMITTEE

I. Introduction

As part of SB 3, the Legislature created the Texas Electricity Supply Chain Security and Mapping Committee (the Committee). The Committee is composed of the executive director of the Public Utility Commission of Texas (PUCT), the executive director of the Railroad Commission of Texas (RRC), the chief of the Texas Division of Emergency Management (TDEM) and the president and chief executive officer of the Electric Reliability Council of Texas, Inc. (ERCOT).[1] The executive director of the PUCT serves as the chair of the Committee. Among other things, the Committee is charged with mapping the electricity supply chain in Texas and identifying the critical infrastructure sources in the electricity supply chain.[2] The electricity supply chain map must be completed no later than September 1, 2022.[3] No later than January 1, 2022, the Committee is required to provide a report to the Governor, Lieutenant Governor, Speaker of the House of Representatives, the Legislature and the Texas Energy Reliability Council addressing progress in fulfilling its statutory obligations. Specifically, the Mapping Report must:

A. provide an overview of the Committee's findings regarding mapping the electricity supply chain and identifying sources needed to operate critical infrastructure;

B. recommend a communication system for the PUCT, RRC, TDEM, ERCOT and critical infrastructure sources to ensure that electricity supply is prioritized for critical infrastructure during extreme weather events; and

C. include a list of best practices and recommended oversight and compliance standards to prepare natural gas and electric service facilities to provide service to critical infrastructure in extreme weather events.[4]

The Committee submits this Mapping Report in compliance with PURA §38.204(a). This Committee's work on each of these objectives is ongoing and this report outlines the Committee's progress to date on meeting the objectives of this statute. Although SB 3 only requires the mapping report to be submitted one time, §38.203(b) requires the Committee to update the supply chain map at least once a year. The Committee further commits to prepare an updated Mapping Report for the Legislature by January 15 of each odd-numbered year. This schedule corresponds to the schedule for the PUCT to file its Biennial Report as required by PURA §12.203.

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[1] Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. §38.201(c) (West Supp. 2021).
[2] *Id.* at §38.203(a)(1) & (2).
[3] Acts 2021, 87th Leg., R.S., ch. 426 (SB 3) §37 (eff. June 8, 2021), Tex. Sess. Law Serv. 832, 852.
[4] PURA §38.204(a).

II. Executive Summary

The Committee has made substantial progress in identifying sources for information needed to create the electricity supply chain map. The Committee will use a combination of existing data from Committee member agencies and third party data to create a comprehensive electricity supply chain map. The initial supply chain map must be completed by September 1, 2022. However, the Committee is working to complete the map well before this date.

For purposes of this initial Mapping Report, the requirement to recommend a communication system for the Committee members and critical infrastructure sources includes an update on improvements in communication and coordination among Committee members and the electric and natural gas industries. This Report also provides an update on how each of the Committee members is preparing for the winter of 2021-2022.

Finally, on the best practices, recommended oversight and compliance standards that must be addressed in this Report, the Committee has provided an update on the legislative implementation activities of each Committee member, including all completed and ongoing rulemakings to implement SB 3 and House Bill (HB) 3648.

III. Status of Mapping Electricity Supply Chain and Identifying Sources Necessary to Operate Critical Infrastructure

A. Mapping the Electricity Supply Chain

The PUCT, RRC and ERCOT have been actively working on multiple aspects of the electricity supply chain map. Much of this work began in the summer of 2021 and is ongoing. The Committee has met monthly since August 2021. The Committee has established various teams composed of staff members from the PUCT, RRC and ERCOT to compile the data that will be needed for the supply chain map. The primary Committee teams are:

1) critical facilities;

2) database;

3) mapping; and

4) weatherization.

Each of these teams is led by one or more PUC staffers and includes staff from the RRC and in some cases, ERCOT. These teams have been meeting regularly since August 2021. The mapping team meets on a weekly basis. The activities of the database and mapping teams are discussed below. Additional activities of the PUCT, RRC and ERCOT related to the identification of critical natural gas facilities will be discussed in more detail in throughout this Report.

Database and mapping issues:

Database and Information Sharing

The PUCT and RRC have executed a memorandum of understanding (MOU) that will allow the agencies to share the confidential datasets needed to prepare the electricity supply chain map. The PUCT and RRC are working to add ERCOT and TDEM to the MOU. After all Committee members have executed the MOU, the Committee will consider allowing other agencies that are not members of the Committee (e.g., Texas Department of Transportation and possibly the Department of Public Safety) to sign the Non-Disclosure Agreements to be able to view the electricity supply chain map and pertinent facilities as appropriate and necessary.

Mapping and IT personnel from the PUCT and RRC have agreed on a method to integrate gas and electric industry information into a single database that can be used to create the electricity supply chain map. These agencies are also actively meeting and working with gas and electric industry market participants on various data and mapping issues. The PUCT has also had several discussions on mapping and related information and technology (IT) issues with ERCOT staff. Finally, the PUCT and RRC will coordinate with TDEM to ensure that the electricity supply chain map will include all relevant information needed by TDEM at the State Operations Center (SOC) to respond to extreme weather emergencies.

Data Collection Process and Mapping

PUCT

The PUCT has conducted an initial inventory of its current electric facility dataset that includes transmission lines, electric generation facilities, and transmission substations. The PUCT has also researched various options, including S&P Global and U.S. Department of Homeland Security's Infrastructure Foundation Level Data (HIFLD) and ERCOT to update the PUCT's current electric facility dataset. The PUCT has received updated electric datasets from several outside sources (open-source and vendor). The PUCT is currently aggregating data from multiple sources, including data securely provided by ERCOT, into a single, reliable dataset that can be included in the electricity supply chain map. ERCOT will update its information for the PUC dataset quarterly. Updates from S&P Global and HIFLD will be incorporated as they become available. PUCT geographic information system (GIS) experts have converted data received from ERCOT into a format that can be used with the PUCT's mapping software. The PUCT will continue a thorough gap analysis to identify information needed and available or needed but currently lacking to complete the electricity supply chain map. The RRC and PUCT have agreed to securely share GIS datasets through ArcGIS online.

RRC

Data collection for the supply chain map by the RRC will be through three main methods:

1) data requests directly sent by the RRC to critical gas suppliers;

2) the RRC's existing data sets and;

3) data received from critical gas suppliers as required under the RRC's new critical gas infrastructure rule discussed in more detail below.

The RRC will be using its existing online filing system, RRC Online, to collect critical customer information from natural gas facilities that are designated either as:

1) critical gas suppliers or

2) critical customers of electric utilities municipally owned electric utilities, and electric cooperatives.

Natural gas facilities that are designated as either critical gas suppliers or critical customers under the RRC's newly adopted Rule 3.65[5] will be required to submit a completed Form CI-D and Form CI-D Attachment. The forms must include information such as facility location, contact information, gas production/handling volumes, and electric utility electric service identifier (ESI-ID) number and information. These forms are available on the RRC's website. The critical natural gas entities will also be required to submit a copy of the same forms to their electric delivery service provider via email, as required by recent amendments to PUCT's Rule 25.52.[6] While the critical designation rules are in place to ensure that electric utilities have the correct information regarding natural gas facilities for purposes of planning load shed, the RRC forms will provide helpful information in the Committee's mapping endeavors. The RRC will facilitate access to the critical customer information by the PUCT and ERCOT as required by the MOU terms. The RRC GIS Mapping staff has also provided transmission pipeline datasets to PUCT staff for a proof-of-concept map layer that when finalized, will provide read-only access to members of the Committee for review. The RRC is currently compiling additional datasets from internal sources that will be provided to PUCT as they are completed. Each of these datasets will add a new feature set and increase the robustness of the supply chain map.

As of November 2021, the RRC's mapping team has developed a preliminary map for those pipelines that directly serve a power plant, as well as a map layer for underground storages.

ERCOT

ERCOT has provided power generation facility, transmission line and substation data to the PUCT. ERCOT will provide the PUCT updated data on a regular basis. ERCOT is also reviewing and preparing its digital electric facility data to be used in building the electricity supply chain map. Much of ERCOT's data has been designated as ERCOT Critical Energy

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[5] 16 Tex. Admin. Code §3.65.
[6] *Id.* at §25.52.

Infrastructure Information (ECEII) under the ERCOT protocols and is therefore confidential. ERCOT and the PUCT have agreed upon a process to facilitate sharing of digital facility data between ERCOT and the PUCT.

TDEM

The mapping team has met with TDEM Leadership and TDEM Operations Technology GIS staff to:

1) introduce TDEM staff to the mapping work undertaken thus far on the electricity supply chain map;

2) underscore the importance of TDEM's input on the final product that will be used at the SOC when the SOC is activated; and

3) set-up protocols to coordinate and share GIS layers that TDEM maintains that can augment the electricity supply chain map.

The mapping team now includes TDEM staff participating in the weekly mapping team meeting to construct the electricity supply chain map. The PUCT SOC representative will work closely with the RRC SOC representative and TDEM to ensure the mapping team collects and includes on the electricity supply chain map the attribute data for each piece of critical infrastructure that will be the most useful in an emergency.

TDEM manages an enterprise GIS system that operates on the same mapping software platform that the PUCT, RRC and ERCOT utilize. Going forward, this will allow TDEM to seamlessly share and collaborate GIS web maps, data, and geospatial analysis with those agencies during inclement weather and power outages. TDEM maintains a Common Operating Picture (COP) Web Map Portal within its GIS system that delivers geospatial maps and data in a secure manner to Texas State Operations Center (SOC) member agencies and external emergency management agencies.

TDEM manages a crisis information management system (CIMS) that is used to manage information among TDEM, the Texas State Operations Center (SOC) and TDEM's regional and district offices and its local emergency management stakeholders. TDEM is developing a CIMS and COP web portal in FY-22 for ESF-12 ENERGY[7] for managing maps, CIMs data and analysis in one secure location for SOC support during energy related emergency incidents.

[7] Emergency Management in Texas is divided into 15 Essential Functions as designated in the Texas Emergency Management Plan. The PUCT is the lead agency designated in the Texas Emergency Management Plan for Energy Support Function (ESF) 12-which addresses the energy sector of the state. For more information on the PUCT's activities in support of ESF-12, *see* Attachment 1 of this Report.

TDEM is taking additional steps in fiscal year (FY)-2022 to ensure its cloud server system meets newly implemented standards required by Texas Government Code § 2054.003 (13) and is adding an additional data management software system to enhance access to critical infrastructure data.[8]

B. Identifying Sources Needed to Serve Critical Infrastructure

SB 3, sections 4 and 16, and HB 3648 enacted by the 87th Legislature require the PUCT to collaborate with the RRC to adopt establishing a "process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during energy emergencies."[9] The PUCT, RRC, ERCOT and gas and electric industry market participants worked together to establish criteria to identify critical natural gas facilities and to prioritize electric service to these facilities. As required by HB 3648[10], both the RRC and PUCT have adopted their critical natural gas facility rules as of December 1, 2021. The details of the rules adopted by both agencies are outlined below.

<u>RRC Rule 16 Tex. Admin. Code §3.65--Critical Designation of Natural Gas Infrastructure</u>

The RRC has adopted a new rule on the designation of critical natural gas facilities as required by HB 3648 and section 4 of SB 3.[11] HB 3648 requires the RRC to adopt the rule no later than December 1, 2021.[12] The RRC adopted its critical designation rule on November 30, 2021. Rule 3.65 implements the requirements of HB 3648 to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical customers or critical gas suppliers during energy emergencies.

The new rule defines "energy emergency" and "critical customer information" and clarifies how to calculate gas volumes as indicated in the rule. The rule designates the following facilities as "critical gas suppliers" during an energy emergency:

1) gas wells producing gas more than 15 Mcf/day;

2) oil leases producing casinghead gas more than 50 Mcf/day;

3) gas processing plants;

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8 8 TDEM's activities in this area are governed by Chapter 20154 of the Texas Government Code. Section 2054.001 states that information and information resources of the State of Texas are strategic assets belonging to the residents of Texas and must be managed as valuable state assets.
9 PURA §38.074(a) (West Supp. 2021).
10 Acts 2021, 87th Leg., R.S., ch. 931 (HB 3648) §3 (eff. June 8, 2021) Tex. Sess. Law Serv. 2372, 2373.
11 *See* TEX. NAT. RES. CODE §81.073(a) (West Supp. 2021).
12 Acts 2021, 87th Leg., R.S., ch. 931 (HB 3648) §3 (eff. June 8, 2021) Tex. Sess. Law Serv. 2372, 2373.

4) natural gas pipelines and pipeline facilities including associated compressor stations and control centers;

5) local distribution company pipelines and pipeline facilities including associated compressor stations and control centers;

6) underground natural gas storage facilities;

7) natural gas liquids transportation and storage facilities; and

8) saltwater disposal facilities including saltwater disposal pipelines.

A critical gas supplier will be required to weatherize provided other statutory requirements are also met.

The rule also defines "critical customers" which are a subset of "critical gas suppliers." Critical customers are critical gas suppliers who need electricity provided to operate. The new RRC rule requires a critical customer to send its "critical customer" information, such as account number and premise identifying information, to its electric utility for load shed planning purposes during an energy emergency.

Subsection (c) of the rule allows facilities that are not designated as critical gas suppliers or critical customers to apply to be designated as critical if the facility's operation is required for another critical facility to operate. Objective evidence must be included with the application and the request may be approved or rejected by RRC Staff. Additionally, a facility that is not designated as critical in subsection (b) but is later included on the electricity supply chain map published by the Committee must apply to the RRC to be designated as critical.

Section 4 of SB 3 states that the RRC cannot designate as critical facilities that are not prepared to operate during a weather emergency. Such a facility would require an exception from designation as a critical facility. Based on comments received, the adopted rule includes a list of facilities that are not eligible for an exception to the critical designation because of their importance to the natural gas supply chain. The facilities that are not eligible for a critical facility exception are the following:

1) a facility included on the electricity supply chain map produced by the Texas Electricity Supply Chain Security and Mapping Committee;

2) gas wells or oil leases producing gas or casinghead gas more than 250 Mcf/day;

3) gas processing plants;

4) natural gas pipelines or pipeline facilities that directly serve local distribution companies or electric generation;

5) local distribution company pipelines or pipeline facilities;

6) underground natural gas storage facilities;

7) natural gas liquids storage and transportation facilities; and

8) a saltwater disposal facility, including a saltwater disposal pipeline, that supports a facility listed in (1) through (7) above.

The final rule adopted by the RRC requires operators of critical facility to provide critical customer information to the RRC and the operators' electricity utilities. The RRC will provide both the PUCT and ERCOT with access to the critical customer information to assist with creating the electricity supply chain map.

PUCT Rule 16 Tex. Admin. Code §25.52—Reliability and Continuity of Service

PUCT Rule 16 TAC §25.52 was amended to implement HB 3648 and PURA §38.074 that require the PUCT to collaborate with the RRC to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during energy emergencies.[13] The rule defines the terms "critical natural gas facility" and "energy emergency" and clarifies that critical natural gas standards apply to each facility in Texas designated as critical customer under the RRC's rule 16 TAC §3.65. Section 25.52 applies to transmission and distribution utilities (TDUs) municipally owned utilities (MOUs), and electric cooperatives (Coops). Under the rule, critical natural gas facilities must provide critical customer information to their respective electric delivery service providers and to ERCOT. This information must be provided by email using RRC's form CI-D and any attachments.

The PUCT must maintain a list of utility email addresses to be used to communicate critical customer information. Utilities are required to provide updates to their contact information within 5 business days. The rule also requires utilities to evaluate critical customer information within ten days of receipt, for completeness and provide written notice to natural gas facility operator regarding the status of its critical designation.

The utility is required to notify the operator of the natural gas facility about its critical status, the date of its designation, any additional classifications assigned to the facility by the utility, and to notify the operator that its critical status does not constitute a guarantee of an uninterrupted supply of energy.

Under the rule as adopted, neither a utility nor an independent system operator receiving or sending critical customer information regarding a critical natural gas facility may release critical customer information to any person unless authorized by the PUCT or the operator of the critical natural gas facility. This prohibition, however, does not apply to the release of such information to the PUCT, the RRC, the utility from which the critical natural gas facility receives electric delivery service, the designated transmission operator, or the independent

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[13] A similar provision was included in SB 3. *See* TEX. NAT. RES. CODE § 81.073(a) (West Supp. 2021).

system operator or reliability coordinator for the power region in which the critical natural gas facility is located.

The rule specifies that a critical natural gas facility is a critical load during an energy emergency and further requires a utility to treat a natural gas facility that has self-designated as critical using the voluntary *Application for Critical Load Serving Electric Generation and Cogeneration form* as a critical natural gas facility, as circumstances require.

Finally, §25.52:

1) requires a utility to prioritize critical natural gas facilities for continued power delivery during an energy emergency;

2) allows a utility to use its discretion to prioritize power delivery and power restoration among critical natural gas facilities and other critical loads on its system, as circumstances require; and

3) requires a utility to consider any additional guidance or prioritization criteria provided by PUCT, RRC, or the reliability coordinator for its power region to prioritize among critical natural gas facilities and other critical loads during an energy emergency.

For the winter of 2021-2022, the TDUs, MOUs and Coops will rely on the voluntary critical load applications submitted by natural gas entities. ERCOT TDUs have advised that to prepare for the 2021-2022 winter season, they must have received critical load applications by no later than November 1. These critical load application requests will be incorporated into the load shed plans of the TDUs.

<u>Electric Service to Critical Natural Gas Facilities</u>

Since Winter Storm URI, TDUs have received a substantial increase in the number of registrations from natural gas facilities, seeking to be designated as critical load. The TDUs have expressed concern that the increase in the number of critical load registrants may make it difficult for TDUs to effectively rotate outages during a load shed event. TDUs have been working with natural gas industry market participants to define tiers of criticality so that during a load shed event, TDUs will have an established hierarchy of critical infrastructure for load shed purposes. Natural gas industry market participants, including the Texas Oil and Gas Association (TXOGA) addressed the tiering concept for natural gas facilities in their comments on the RRC critical designation rulemaking and in the PUCT critical designation rulemaking. Based on comments received by the RRC, the Chairman of the RRC provided the Chairman of the PUCT with a letter outlining the facilities that the RRC knows are most important to the natural gas supply chain during an energy emergency. The PUCT will consider this input when issuing tiering guidance pursuant to the PUCT's jurisdiction and the requirements of SB 3 in Tex. Util Code §38.074(b)(2) and (3). The PUCT will be providing guidance in January to its regulated industry on the designation of load shed tiers during a weather emergency.

ERCOT

ERCOT, the PUCT and RRC have been discussing other electric/gas coordination issues. On, October 8, 2021 the RRC sent a letter to all natural gas fired power plants in Texas, requesting the name of each generating facility's gas supplier and pipeline operator. The RRC sent this request to 54 entities that operate natural gas-fired generation plants in the state. Of the 54 entities that received this request, 51 generators provided responses. To date, one generator has failed to respond to the RRC letter. The PUCT and RRC will continue to work with all industry participants to obtain the information necessary to complete the electricity supply chain map.

ERCOT recently issued a request to each generator requesting the name of each generator's gas supplier. ERCOT has received this information for approximately 95% of generation units and will soon make this information available to the PUCT and RRC. Ultimately, the pipeline operator and gas supplier for each gas-fired generator in Texas will be included in the electricity supply chain map.

Current Challenges Related to the Electricity Supply Chain Map

The above-discussed rules by the RRC and PUCT are expected to be very helpful to the Committee in creating the electricity supply chain map. One challenge for the Committee will be obtaining and mapping the electric distribution infrastructure that serves the critical natural gas infrastructure identified in the RRC and PUCT rules. Because the PUCT does not currently have ready access to electric utility distribution level mapping data, the Committee will need to obtain this information from the electric utilities that serve the critical infrastructure sources. To incorporate this information into the electricity supply chain map in an expedient manner, the Committee must provide the electric utilities with lists of premise identifiers that are associated with the critical infrastructure sources the RRC has identified. This information will allow the electric utilities to quickly identify and provide the associated distribution level information to the Committee for mapping. Under the RRC's critical facilities rule, a natural gas facility must, among other things, provide its premise identifier to the electric utility that serves the facility to be considered a critical load. The RRC must share with the Committee members the same data it requires natural gas facilities to provide to electric utilities so that this information may be used to build out the electricity supply chain map and to provide the map's end users with information relevant to maintaining electric service in an emergency event.

TDEM

A primary role of TDEM in supporting the requirements contained in SB-3 is to provide emergency management support through the resources comprised by the State Operations Center Emergency Support Functions (ESFs). TDEM will work with the Committee to update the ESF-12 (Energy) Annex[14] to address lessons learned from the 2021 Winter Storm and add additional agreed upon procedures for: 1) Reporting, 2) Response, and 3) Communications.

The following activities have been identified and are recommended by TDEM as needed to ensure the ESF-12 (Energy) support function and state are better prepared for future energy disruptions:

1) Secure management and access to the energy critical infrastructure map database and map services.

2) Identification of cascading impacts from the failure of key critical infrastructures and remediation procedures and support requirements.

3) Identification of logistical and other support resources needed for responding to energy disruptions and an operational plan for staging and managing resources.

4) Development of a contact database and notification system for energy related critical infrastructure owners, operators, and regulators.

5) An operational playbook for ESF-12 (Energy) that includes procedures for:

   i. Reporting: Procedures for utilities and regulators to report outages or impending outages in a uniform manner.

   ii. Response: Procedures for requesting assistance and activating response and support resources for energy related critical infrastructure types, and specific facilities.

   iii. Communications: Procedures for coordinating, managing, and issuing ESF-12 (Energy) related communications and notifications (citizen, private sector and governmental).

6) On-going training and exercises for ESF-12 (Energy) related incident scenarios.

IV. Communication System to Ensure Electricity to Critical Infrastructure

PURA §38.204(a)(2) requires the Mapping Committee… "to recommend a clear and thorough communication system….to ensure that electricity supply is prioritized to [critical infrastructure] sources during extreme weather events…" The recommended communication system applies to communications among and between the PUCT, RRC, TDEM, ERCOT and critical infrastructure sources. These entities have been working together since the passage of SB 3 to develop a comprehensive and effective communications system to ensure electricity is prioritized to critical infrastructure during an extreme weather event. The development of this

[14] For more information on this issue, *see* Attachment 1 of this Report, *PUCT Responsibilities as a member of the Texas Emergency Council.*

communication system is an ongoing effort that will be reviewed and revised as necessary in the future. Actions taken by each of the Committee members to improve communication are outlined below.

A. Preparation for the winter of 2021-2022

The electricity supply chain map is the key element to improved communication between the PUCT, RRC, TDEM, ERCOT and the gas and electric industries. Once this map is finalized, it will be much easier for these agencies and industries to communicate more effectively and efficiently in a weather emergency. The supply chain map must be completed by no later than September 1, 2022, but the Committee is working to complete the map before September 1. However, as work on the supply chain map continues, the Mapping Committee agencies are working on improving their communications for the winter of 2021-2022.

B. Regular communications between PUCT, RRC and ERCOT

The PUCT, RRC and ERCOT have been communicating regularly on the implementation of key bills passed by the 87th Legislature, especially SB 3 and HB 3648. PUCT Chair Peter Lake and ERCOT President Brad Jones meet weekly to discuss relevant issues including reliability and implementation of legislation.

The Executive Directors of the PUCT and RRC meet weekly to discuss legislative implementation issues, current rulemakings, and mapping committee issues. The Committee, created as part of SB 3, meets monthly to discuss progress and resolve issues related to the creation of the electricity supply chain map. The Committee has established 7 teams to address various aspects of the supply chain map. These teams are:

1) administrative,
2) communications,
3) critical facilities,
4) database,
5) mapping,
6) mapping report and
7) weatherization.

Each of these teams is chaired by a staffer from the PUCT and each includes additional staff from the PUCT and RRC. These teams meet regularly to discuss and resolve various issues related to the supply chain mapping project. Their work is ongoing.

The PUCT, RRC, ERCOT and electric and gas industry market participants have been working to identify certain key natural gas facilities that are critical for the electricity supply chain to be better prepared for the winter of 2021-2022. Some of this work has taken place in the PUCT and RRC rulemakings related to critical natural gas facilities. As noted above in the discussion of the activities related to the supply chain mapping, the RRC's rule on critical natural gas facilities provides a list of the types of natural gas facilities that would be designated as critical for the electricity supply chain.

C. RRC—Winter Preparation

The RRC has taken multiple proactive actions to ensure facilities in its jurisdiction are prepared to operate during Winter 2021-22 to help protect Texans in the event of severe weather.

On October 7, 2021, the RRC issued a notice to operators of gas facilities and gas pipeline facilities to take all necessary measures to prepare to operate in extreme weather. The notice included a reminder to update each facility operator's *Application for Critical Load Serving Electric Generation and Cogeneration* with their respective electric utilities and identified several best practices operators could utilize for winter weather preparations. A second notice with additional best practices that operators could utilize was issued on December 9. Copies of these two notices are attached to this Report as Attachment 2.

In October 2021, in conjunction with the PUCT, the RRC hosted a joint electric and gas industry meeting regarding potential load-shed tiers for use by electric utilities in a potential upcoming load shed event. In late October the RRC sent another notice to remind operators to timely complete and file the ERCOT application with their electric utilities to be designated as critical customers for load shed purposes. Applications for designation as critical load were due on November 1 to allow TDUs to plan for the winter of 2021-2022.

The RRC has also held meetings with executives of major gas pipelines, pipeline facilities, and natural gas producers on their weatherization practices and operation plans. In conjunction with the meetings, the RRC's newly formed Critical Infrastructure Division and field inspectors have been conducting site visits to large natural gas producers, natural gas storage facilities, and natural gas transmission pipelines to observe and inquire about preparedness for the upcoming winter.

From the beginning of fall to mid- December 2021, the RRC has conducted approximately 3,000 site visits which include:

1) oil and gas leases that have more than 17,000 active producing or disposal wells;
2) large gas storage facilities;
3) processing plants;

4) more than 70 pipelines directly serving gas-fired power generators; and

6) more than 200 other transmission pipeline facilities used to transport natural gas.

These site visits will continue through the winter of 2021-2022.

The RRC has also hosted several industry-specific webinars in December for RRC staff and operators. This included a presentation by a major oil and gas producer on how the company prepares for winter operations, which is information beneficial to operators looking for peer guidance.

Other ongoing work includes surveys of experts in other large oil and gas producing states and Canadian provinces seeking their input on best practices. That information is part of the best practices section discussed later in this Report.

The RRC also issued a solicitation for a technical advisory contract to assist the agency on weatherization technology training, audits, and best practices.

Electric generators requested the RRC to create a definition of "firm fuel" and more visibility into when and under what circumstances natural gas suppliers will invoke force majeure in their contracts with generators. The PUC provided draft "firm fuel" language to the RRC and the RRC solicited feedback from natural gas producers on inclusion of this language in future gas contracts with generators. The PUCT, RRC and industry market participants will continue to discuss how best to address this issue.

During an extreme weather event in which natural gas flows may be limited, gas suppliers and pipelines have noted that knowing the amount of gas that will be needed by electric generators would be helpful for gas companies to plan their winter operations. This will require more coordination between electric generators and natural gas suppliers and pipelines. The PUCT, RRC and gas and electric industry market participants are actively discussing these issues. These issues are being actively discussed by members of the Texas Energy Reliability Council (TERC) and its various industry working groups.

D. ERCOT

The ERCOT Protocols currently require generation owners to submit an annual attestation that, in relevant part, requires each owner to identify the natural gas pipelines connected directly to each generating facility it owns and to provide contact information for each pipeline operator. ERCOT is in the final stages of assembling this pipeline information. ERCOT also recently requested that each generation owner identify each of the gas suppliers that sell gas to each generation facility through the pipelines, as the gas supplier is not always the same entity as the operator of the pipeline serving the generation facility. ERCOT has received gas supplier information from approximately 95% of the generation owners and will soon provide this information, along with the pipeline information, to the PUCT and RRC. The names of the natural gas pipeline operators and natural gas suppliers are confidential under the ERCOT Protocols.

ERCOT has also developed a crisis communication plan that outlines roles and responsibilities within ERCOT for communicating during an emergency event. This document will ensure that ERCOT is providing regular, consistent, and accurate information to the PUCT, market participants, the media, legislative leaders, and the public. A copy of this plan is attached to this report as Attachment 3.

Additionally, ERCOT has assigned two staff members to be present in the SOC when the SOC is activated. ERCOT personnel have not traditionally been present in the SOC during an activation. The addition of ERCOT staff to the SOC should enhance the ability of the SOC to respond to weather emergencies.

Finally, ERCOT has been working closely with the PUCT and the generators to assess whether generating units are weatherized and prepared for the winter of 2021-2022 in accordance with recently adopted PUCT rules. ERCOT recently hired a Director of Weatherization and Inspection who will oversee these inspections.

E. TDEM

TDEM is actively participating and communicating with the Committee throughout the planning process. As noted previously in Section III. of this Report, TDEM maintains a crisis information management system that it is customizing for ESF-12 Energy. The CIMS will contain custom data management forms to better manage and communicate ESF-12 related information in the State Operations Center and will include notification capabilities. The CIMS will also be connected to the GIS to ensure TDEM SOC maps immediately display current incident conditions as the information is entered into the CIMS database.

TDEM is also working to deploy enhanced communications infrastructure to better support state notifications, public alerts, public media and social media messages and alternative communications infrastructure and capabilities.

F. TERC

The Texas Energy Reliability Council (TERC) is also in the process of developing improved communication among relevant regulatory agencies and the electric and gas industries. TERC is composed of leaders from the PUCT, RRC, ERCOT and members of the natural gas and electric industry and is intended to ensure that gas and electric industries address critical infrastructure concerns and enhance the coordination and communication in the energy and electric industries. In furtherance of TERC goals, the PUCT has established two Microsoft Teams meeting groups. The first group will consist of the regulatory agencies that are members of TERC. These agencies are the PUC, RRC, OPUC, TCEQ, Texas Transportation Commission, ERCOT, and TDEM. The second Teams group will include the regulatory agencies of TERC and the electric and gas industry market participant members of TERC. These meeting groups are intended to encourage frequent communication among relevant regulatory agencies and gas and electric industry participants on operational and planning issues. The expectation is that frequent communications among these various constituencies will assist TERC members in preparing for emergency operations and sharing of information which in turn should enhance the ability of all TERC members to timely respond to extreme weather emergencies.

TERC is currently meeting monthly to ensure that critical electric and natural gas facilities will be prepared for the upcoming winter. Under SB 3, TERC is required to file reports in even-numbered years on the reliability and stability of the electricity supply chain in this state. The first such report is due on November 1, 2022.

V. Recommended Best Practices and Compliance Standards

A. FERC/NERC Weatherization Standards

In June 2021, NERC adopted three modified Reliability Standards designed to ensure that the North American power system can withstand extreme cold weather events. The newly adopted reliability standards apply to the entire bulk power system in the US, including ERCOT.[15] By order issued on August 24, 2021, FERC approved without changes, these revised NERC reliability standards. A copy of the FERC Order Approving Cold Weather Reliability Standards is attached to this Report as Attachment 4.

The three reliability standards modified by NERC include:

1) EOP-011-2 (Emergency Preparedness and Operations)

2) IRO-010-4 (Reliability Coordinator Data Specification and Collection)

3) TOP-003-5 (Operational Reliability Data)

NERC proposed these changes in response to findings made by a joint NERC/FERC report on a 2018 weather event in the south central US. The changes to these reliability standards require an operator of generation facility to have a cold weather preparedness plan that addresses freeze protection measures, inspection procedures and cold-weather operating limitations, require the reporting of weather-related design specifications and operating limitations to reliability coordinators throughout the US (e.g., ERCOT, the Southwest Power

[15] While the PUCT regulates wholesale market transaction in ERCOT, FERC and NERC have jurisdiction over the reliability of the bulk power network, including ERCOT. FERC and NERC have established six Regional Entities throughout the US to assist FERC/NERC in enforcing federal reliability standards. In ERCOT, the Regional Entity is the Texas Reliability Entity (Texas RE).

Pool, Midcontinent Independent System Operator) require balancing authorities and transmission operators to determine the reliability impacts of generating unit limitations during cold weather. FERC approved NERC's implementation plan for these new reliability standards which have an effective date of April 1, 2023. FERC strongly encourage utilities to comply with the new standards sooner if possible.

The new standards apply to power generators, transmission operators, and other entities responsible for ensuring the reliability of the electric grid, including balancing authorities and reliability coordinators. The entities subject to the new standards will be subject to annual inspections by reliability coordinators and balancing authorities.

B. RRC Best Practices Report

To ensure oil and gas operators in Texas have the most up-to-date information on preparing facilities for severe weather emergencies, the RRC has conducted research on winterization methods and practices and has also been in ongoing contact with energy industry experts in Texas and other large energy producing states and Canadian provinces on best practices. The information compiled by the RRC, and distributed to operators, attached to this Report as Attachment 5.

C. PUCT and RRC rulemakings

In addition to the FERC/NERC reliability standards, the PUCT and RRC are in the process of implementing legislation from the 87th Legislature that is intended to improve the reliability of the electric power supply system in Texas.

PUCT Rulemakings

Project No. 51840—*Rulemaking to Establish Weatherization Standards*—In this rulemaking the PUCT established weatherization standards for electric generators and transmission service providers (TSPs) in ERCOT as required under SB 3. The Commission adopted new 16 TAC § 25.55 on October 26, 2021. New § 25.55 is phase 1 of the Commission's weather emergency preparedness reliability standards. The new rule requires generators in ERCOT to implement the winter weather readiness recommendations outlined in the *2012 Quanta Technology Report on Extreme Weather Preparedness Best Practices* (2012 Quanta Report). The rule also requires ERCOT generators to fix any known, acute issues that arose during the winter of 2020-2021. Additionally, new §25.55 requires TSPs to implement the key recommendations contained in the joint FERC/NERC report from 2011 entitled *2011 Report on Outages and Curtailments During the Southwest Cold Weather Event on February 5, 2011* and to remedy any known, acute issues that arose during the winter 2020-2021. This new rule requires generators and TSPs to provide a notarized attestation from the highest ranking official from each affected entity attesting to the completion of all actions required by the rule.

New §25.55 requires generation entities and TSPs to submit a "winter weather readiness report" by December 1, 2021. The report must describe the activities undertaken to comply with the weather preparedness standards required by the rule. Most generation entities timely filed winter weather readiness reports. The PUCT's Division of Compliance and Enforcement identified thirteen generation entities owned by 8 companies that missed the filing deadline. On December 8, PUCT staff filed reports of violations against these 8 companies for failing to timely file winter weather readiness reports. The PUCT staff recommended a total of $7.675 million in administrative penalties for these reporting failures. These cases are currently pending before the PUCT.

ERCOT has completed a generation plant inspection form and has begun inspections of approximately 300 generating units for winter readiness. Plants were selected for inspection based on the amount of energy lost during the February 2021 cold weather event. Ss such, the ERCOT inspections will address 85% of the lost MWhs during Winter Storm Uri.

Phase 2 of the PUCT's weatherization standards will be the adoption of more comprehensive, year-round set of weatherization standards for emergency preparedness. The PUCT will begin developing these standards after it reviews the weather study currently being conducted by ERCOT and the Office of the Texas State Climatologist.

<u>Project 52312 – *Review of Administrative Penalty Authority*</u>—SB3 increased the PUCT's administrative penalty authority from §25,000 per violation per day to §1,000,000 per violation per day for noncompliance with the PUCT's weatherization rules. This penalty authority is already in effect under the statute, but the PUCT approved a proposal for publication at the August 19, 2021 open meeting.

<u>Project No. 52345—*Critical Natural Gas Facilities and Entities*</u>—As explained above in Section III., HB 3648 required the PUCT and RRC to collaboratively establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during an energy emergency. Both the PUCT and RRC adopted rules on this issue on November 30, 2021. These amendments are described in more detail above in Section III.

ERCOT TDUs have advised that to prepare for the winter of 2021-2022 they must have critical load designations by no later than November 1. Because neither the PUC nor RRC rule regarding critical gas facilities was adopted by November 1, the critical facility designations adopted by the RRC on November 30, 2021 will not be fully incorporated into TDU load shed and service restoration planning until 2022. However, the PUCT and RRC have conducted a joint effort to get as many critical natural gas facilities to self-designate as critical using the voluntary *Application for Critical Load Serving Electric Generation and Cogeneration form* to ensure that electric TDUs, Coops, and MOUs have as much critical information as possible heading into the winter of 2021-2022. Certain gas, and electric industry market participants have suggested that the PUCT and RRC should issue a guidance document on how electric service priority for critical natural gas facilities should be addressed in the winter of 2021-2022. While the RRC does not have jurisdiction over electricity load shed events or electric industry market participants, the RRC's Chairman provided suggestions on possible priority tiers for critical gas facilities in a letter to the PUCT Chairman in November. The PUCT is continuing to discuss this issue with electric industry market participants and expects to issue a guidance document in January.

Project No. 51888—*Review of Critical Load Standards and Processes*—This rulemaking is essentially phase 2 of the PUCT's critical natural gas facilities rule which was adopted on November 30. After TDUs have incorporated critical natural gas facilities into their load shed planning, it may be necessary to conduct a more comprehensive review of all types of critical loads and to establish an overall service prioritization for these loads. Work on this rule is expected to begin in 2022.

Project No. 51841—*Review of 16 T.A.C. 25.53 Relating to Electric Service Emergency Operations Plans*—The purpose of this rulemaking is to amend the PUCT's existing rule requirements for Emergency Operations Plans in response to SB 3. The PUCT approved a proposal for publication of this rule at the December 2, 2021 open meeting.

Additionally, the PUCT will be issuing a request for proposal for an entity to review the existing EOPs of market participants for compliance with commission rules. The PUCT is aiming to have a contractor in place by March or April 2022.

Project No.52287 *Power Outage Alert Criteria*—The purpose of this rulemaking proceeding is to establish a power outage alert system. PUCT Staff and ERCOT staff are drafting a proposed rule. PUCT Staff anticipates that a draft proposal for publication will be considered by the PUCT at its December 16, 2021 Open Meeting.

RRC Rulemakings

Both SB 3 and HB 3648 require the RRC to adopt rules "to establish a process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical customers or critical gas suppliers during energy emergencies."[16] As explained above in Section III, the RRC adopted a rule on November 30, 2021 to identify critical natural gas facilities. The RRC received comments from the public, legislators, several electric and natural gas industry participants as well as ERCOT

SB 3 also requires the RRC to adopt a rule within six months after the Committee publishes the electricity supply chain map that will require gas supply chain facilities to implement measures to be able to operate during weather emergencies if the gas supply chain facility is

[16] TEX. NAT. RES. CODE §81.073(a).

designated as critical and is included on the electricity supply chain map.[17] This provision requires the RRC to inspect gas supply chain facilities for compliance with the weatherization standards adopted by the RRC. The RRC has started rulemaking efforts on this issue.

Similarly, the RRC is also required to adopt rules requiring gas pipeline facility operators to adopt measures to maintain service quality and reliability during extreme weather emergencies if the gas pipeline facility directly serves a natural gas electric generating facility supplying power in ERCOT or in ERCOT and an adjacent power region and is included in the electricity supply chain map.[18] The RRC is also required to inspect gas pipeline facilities for compliance with the standards adopted by the RRC.

The RRC is also required under SB 3 to analyze the emergency preparedness reports created by "operators of facilities that produce, treat, process, pressurize, store or transport natural gas and that are included in the electricity supply chain map created under [Utilities Code] § 38.203. . ."[19] The RRC is required to submit a biennial report to the Legislature based on its analysis.

The reliability-related requirements for the RRC included as part of SB 3 and HB 3648 applicable to the natural gas industry will be conducted in 3 phases:

1) rulemaking to identify critical natural gas facilities;
2) mapping of electricity supply chain (including critical natural gas facilities); and
3) rulemaking to enact weatherization standards. Under SB 3, the RRC is required to adopt the weatherization standards for gas supply chain facilities or gas pipeline facilities within 6 months after the completion of the electricity supply chain map.[20]

The deadline for completion of the electricity supply chain map is September 1, 2022, but the Committee is working to complete the map before this date.[21]

Finally, the RRC has also proposed amendments to its existing gas curtailment standards. The RRC's current gas curtailment standards are reflected in what is known as Order No. 489 which was originally adopted in 1973. During Winter Storm Uri, the RRC adopted an emergency order that placed electric generation facilities 2nd on the gas service prioritization list to give a higher priority to electric generators during the winter emergency. The PUC and electric generators have requested that the RRC make this prioritization permanent, and that this policy be memorialized in a rule. In response to stakeholder feedback on its emergency order issued in February 2021, the RRC's proposed rule (16 T.A.C. §7.455), relating to

[17] *Id.* at §86.044(c).
[18] TEX. UTIL. CODE §121.2015(a).
[19] *Id.* at §186.008(b).
[20] Acts 2021, 87th Leg., R.S., ch. 426 (SB 3) §38 (eff. June 8, 2021), Tex. Sess. Law Serv. 832, 852.
[21] *Id.*

Curtailment Program) updates the service priority order. The proposed rule clarifies that firm deliveries have priority over interruptible deliveries during a curtailment event. Additionally, the Uri emergency order included electric generators serving human needs customers in the second priority. The proposed rule expands the second priority to include all electric generation facilities, not just those serving human needs customers. Comments on the proposed rule are due by January 7, 2022. The RRC has proposed an effective date of April 1, 2022, for its Curtailment Program rule.

ATTACHMENT 1

ATTACHMENT 1

PUCT Responsibilities as a member of the Texas Emergency Council

The PUCT is a member of the Texas Emergency Management Council (TEMC) under the authority of Governor Abbott's Executive Order GA-05. The PUCT's membership in the Council pre-dated this executive order, however this order has replaced those before it.

Emergency Management in the State of Texas is broken down into 15 "Essential Functions" as designated in the Texas Emergency Management Plan. These essential functions were developed to align with the National Response Framework which was created by the Homeland Security Act of 2002 and Homeland Security Presidential Directive-5. The 15 defined essential functions and the lead agency for each function are as follows:

- ESF 1 – Transportation (Texas Department of Transportation)
- ESF 2 – Communications (Texas Division of Emergency Management)
- ESF 3 – Public Works and Engineering (Texas Department of Transportation)
- ESF 4 – Firefighting (Texas A&M Forest Service)
- ESF 5 – Emergency Management (Texas Division of Emergency Management)
- ESF 6 – Mass Care (Texas Division of Emergency Management)
- ESF 7 – Logistics and Resource Management (Texas Division of Emergency Management)
- ESF 8 – Public Health and Medical Services (Texas Department of State Health Services)
- ESF 9 – Search and Rescue (Texas A&M Engineering Extension Service)
- ESF 10 – Oil and Hazardous Materials Response (Texas Commission on Environmental Quality)
- ESF 11 – Agriculture and Natural Resources (Texas Animal Health Commission)
- ESF 12 – Energy (Public Utility Commission)
- ESF 13 – Public Safety and Security (Texas Department of Public Safety)
- ESF 14 – Long-Term Recovery, has since been superseded by the National Disaster Recovery Framework
- ESF 15 – Public Information (Texas Division of Emergency Management)

The Public Utility Commission has been identified as the lead agency for ESF 12 in the Texas Emergency Management Plan managed by the Texas Division of Emergency Management. The ESF 12 Appendix to the State Plan is currently under revision by TDEM in cooperation with PUCT and other agencies. In addition to the lead role in ESF 12, the PUCT also has a support role in the following essential functions:

- ESF 1 – Transportation
- ESF 2 – Communications
- ESF 5 – Emergency Management
- ESF 15 – Public Information

While the primary function of the PUCT's Emergency Management Coordinator is responding to activations, there are numerous trainings, planning meetings, and other functions which TDEM hosts which require our involvement.

The State Operations Center (SOC) is activated by order of the Governor and may involve some, many, or all the TEMC member agencies depending on the event. When requested, the PUCT provides personnel to staff the SOC where they function as a liaison between the State and the utility industry. Even if not requested to respond in-person to the SOC, the PUCT may participate in SOC operations remotely, especially during pre and post event operations. The PUCT staff working an activation interact with many entities including the Electric Reliability Council of Texas (ERCOT), municipally-owned utilities (MOUs), electric cooperatives (Coops), and transmission and distribution utilities (TDUs), and electric generators.

Some examples of support the PUCT provides during an activation are as follows:

- Provide event specific information and updates from TDEM to the utilities. (Where possible, this usually begins a day/couple of days prior to the event as information becomes available and is presented during daily calls hosted by TDEM).
- Routine updates of outage counts, locations, and restoration times when known which allows the SOC to better focus their response activities.
- Participation in TDEM's daily calls during an event providing situational updates and outage reports to both state-wide and local officials attending the calls.
- Coordination with TXDoT on route clearing when crews discover downed lines across travel routes which need to be cleared. Conversely, since utility repair crews may be the first folks back into an area (post-hurricane for example), they may have information on routes that is helpful to TXDoT which we are able to share with them.
- Assistance in planning routes for TDEM IRATs (Initial Reentry Assessment Teams) and coordinating with utilities to ensure access.
- Providing a direct link between local officials who reach out needing contact information for local utilities.
- Obtaining outage information for specific locations and facilities such as long-term care facilities, hospitals, water utilities, etc.
- Working with HHS to provide information to support their requests for replacement SNAP benefits of the possible issuance of "D-SNAP" benefits. (SNAP benefits which may become available to a slightly larger population due to a disaster)
- Assisting utilities with the process for reporting damages which TDEM uses when requesting federal disaster declarations.
- Coordination with the Texas Commission on Environmental Quality (TCEQ) on potential enforcement discretion regarding air-quality standards during a disaster.
- Providing utilities an access point to request resources through the SOC. Generally this applies to MOUs and Coops due to their governmental or non-profit nature, however the

SOC can also be utilized to help private companies source or acquire resources at the company's expense.

The duration of the PUCT's involvement in an activation is ultimately up to the Governor or the TDEM Chief. The end of an activation does not necessarily end PUCT's involvement in a particular event. Since 2020, the PUCT has become more involved in the actual recovery process, participating in outreach, calls, and training related to the activities TDEM undertakes after a disaster.

ATTACHMENT 2

RAILROAD COMMISSION OF TEXAS
Oil and Gas Division
Oversight and Safety Division

NOTICE TO GAS FACILITY OPERATORS AND GAS PIPELINE FACILITY OPERATORS

Preparation by Operators for Winter 2021-2022

Senate Bill 3 states the Railroad Commission of Texas shall require gas supply chain facilities and gas pipeline facilities, respectively, to "implement measures to prepare to operate during a weather emergency." Adoption of the rules is tied to the map to be published by the Texas Electricity Supply Chain Security and Mapping Committee no later than September 1, 2022. Operators of gas supply chain facilities and gas pipeline facilities under the Commission's jurisdiction are expected to take all necessary measures to prepare to operate in extreme weather conditions during the winter season of 2021-2022. The Commission's highest priority is to ensure that should another extreme winter weather event occur, all available natural gas under the jurisdiction of the Commission in the state is available to be utilized for reliable energy sources for Texans. The Commission is taking additional steps including on-site visits to assess operator preparedness. To ensure that gas facility operators and gas pipeline facility operators are implementing measures to prepare to operate during extreme weather conditions prior to publication of the map, the Commission's Oil and Gas Division and Oversight and Safety Division jointly issue the following best practices for weatherization:

- Update the *Application for Critical Load Serving Electric Generation and Cogeneration* to your electric utility as early as possible.
    - Ensure that you have submitted and updated the above-referenced application to your electric utility for the upcoming winter season 2021-2022. The application may be found on ERCOT's website at http://www.ercot.com/content/wcm/key_documents_lists/174326/Final_-_pdf_-_App_for_gas_pipeline_load_v020320.pdf.
    - The Commission previously notified operators of the application on March 17, 2021 and it is available on the Commission's website at https://www.rrc.state.tx.us/announcements/031721-updated-application-for-critical-load-serving-electric-generation-and-cogeneration/.
- Methanol injection or drip.
    - Introduction of methanol into the gas stream by chemical injection pumps or into the pipeline by methanol drips lowers the freeze point of gas. Methanol injection can also be used to prevent freezing in pneumatic controllers, as well as in preventing liquids from reaching small orifices and passages in these instruments.
- Water removal by solid absorption.
    - Natural gas may be passed through dry bed or molecular sieves, which absorb water. These methods can be used to achieve very dry gas.
- Cold weather barriers.

Austin, Texas **October 2021**

    - Cold weather barriers, such as wind walls, may be installed around certain compressors to block cold winds which may exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines, and other equipment may also help to prevent freezing and stoppage of fluid flow.

- Heat.
    - Heat systems, such as heating blankets, catalytic heaters, fuel line heaters, or stream systems, can be effective for localized freezing problems. Coupling heat systems with insulation is a common technique for protecting flow lines in northern climates.
- Glycol.
    - Natural gas can be passed through glycol inside a contactor. Glycol absorbs water vapor entrained in the stream, allowing dry gas to pass through.
- System Design.
    - Careful planning during the design stage for measurement and regulating systems can reduce the chances of freezing. Any steps that reduce restrictions or prevent areas where liquids can collect will minimize the possibility of freezing. To avoid liquid accumulation, pipe configurations should be set up such that drainage slopes toward drain fittings in low spots. Prevent restrictions by using full opening ball valves and large diameter tubing. Liquids will be drawn toward leaks, so have a leak-free system with tubing that slopes back toward the pipeline.
- Drip Pots.
    - Drip pots and coalescers can be used to eliminate or reduce the amount of water in cases of severe liquid problems or when there is a slug of liquid in a gas supply used for instrumentation.
- Instrument Filters.
    - Filter dryers provide a clean, dry supply of gas to controllers and other instrumentation that functions using instrument gas. These units function under high pressure and can eliminate both liquids and particulates.

Please Forward to the Appropriate Section of Your Company

RAILROAD COMMISSION OF TEXAS
Critical Infrastructure Division

NOTICE TO NATURAL GAS PRODUCERS, GAS FACILITY OPERATORS AND GAS PIPELINE FACILITY OPERATORS

Additional Best Practices for Winter 2021-2022 Preparations

The Railroad Commission of Texas' (Commission's) highest priority is ensuring all natural gas under the jurisdiction of the Commission in the state is available to be used by Texans during the next energy emergency. On November 30, 2021, the Commission adopted Texas Administrative Code §3.65, relating to Critical Designation of Natural Gas Infrastructure, defining critical gas suppliers and critical customers during an energy emergency. In October, the Commission issued a notice with best practices operators should take to prepare for winter. **Operators of gas supply chain facilities and gas pipeline facilities under the Commission's jurisdiction are expected to take all necessary measures to prepare to operate in extreme weather conditions during the winter season of 2021-2022.** That notice is available on the Commission's website at https://rrc.texas.gov/media/r5dbn5b2/2021-nto_preparation-by-operators-for-winter_2021-2022_mlb_10-6-2021.pdf.

Since that notice, the Commission has conducted additional research on weatherization best practices by consulting with energy industry experts in Texas and other large energy producing states and Canadian provinces. RRC inspectors also identified additional processes through site visits, some of which may be appropriate to assist operators' efforts to prepare for extreme weather events. Below is a list of those additional best practices:

- **Line Heaters**
  - Used in wells that flow predominantly gas and small amounts of water, with no appreciable oil, this equipment uses a gas fired flame to heat a fluid filled chamber inside the body of the line heater. Gas passes through a coil that is immersed in a chamber of warmed fluid, which increases the temperature of the natural gas as it passes. When sized appropriately for the volume of gas being produced line heaters effectively heat gas at the first potential point of freezing before it reaches downstream separation or treating equipment.
- **Hot Lubricant and Circulation Heater for Engine Oil or Fuel**
  - Installing external block heaters with an external energy source such as a gas fed flame or electricity can maintain pump or compressor lubricants at an appropriate temperature, even when the equipment is not operational, making it easier to restart the equipment by keeping the oil/fuel in the engine at an elevated temperature. At freezing temperatures pumps designed to circulate lubricant have difficulty functioning,

but using hot lubricant and external block heaters can keep pumps and compressors functional and prevent freeze-offs.

- **Human Capital**

    - While weather specific technologies are critical to sustain natural gas production during cold weather conditions, the maintenance and operation of these technologies begins with human capital—the people trained and able to ensure natural gas continues to serve its essential function in the electricity supply chain despite adverse conditions. Increasing staffing levels in advance of an extreme weather event ensures that appropriately trained employees are readily available—if not pre-positioned on-site—to resolve any equipment or instrumentation failures should temperatures fall below an acceptable operating temperature for sensitive equipment or instruments.

Please Forward to the Appropriate Section of Your Company

ATTACHMENT 3

December 6, 2021

ATTACHMENT 3

ERCOT Crisis Communications: Principles, Roles & Responsibilities

Implementation of Crisis Communications Activities

The VP of External Affairs will coordinate with the Executive Team to begin and end Crisis Communications Team activities.

Principles

Executive Alignment Process

At the beginning of Crisis Communications Team activities, the Communication Leader for the shift (see "Roles & Responsibilities" section below) will meet with the CEO, Operations and others as needed to establish the communications cadence for the day, depending on the significance, severity and anticipated duration of an event. The VP of External Affairs will then notify the Executive Team of the planned cadence. These meeting will also occur at 8:30 a.m. and 8:30 p.m. each day until the need for team activities is over. If for any reason these meetings do not occur, the cadence on the previous day will be used.

Priority of Crisis Communications Messages

During a crisis, all message development that routinely occurs throughout ERCOT for various key audiences, such as employees and legislators, will be suspended in favor of a centralized process for all audiences. However, internal relationship owners will continue to review and edit all messages. This will prioritize timely and consistent messages across all channels and audiences.

External Resources

At the Communication Leader's direction, the Support Team and Communications Coordinator will develop content and supply key messages for use and distribution to key audiences, including but not limited to legislative, regulatory, news media and employees.

Message Discipline

ERCOT messages should be clearly aligned with both current and crisis ERCOT communications strategies.

Roles & Responsibilities

These are the communications roles and responsibilities during a crisis event. Each of these roles will rotate to a different group of team members every 12 hours.

The Crisis Communications Teams will ensure that all internal groups are provided key communications material to ensure message consistency for the duration of the issue or crisis. Internal groups, besides the Executive Team, include, but are not limited to, Operations, Compliance, Security, IT, HR, Legislative, Legal, and Regulatory. Those groups, in turn, are responsible for communicating to important external groups, including but not limited to, FERC, NERC, TDEM, OPUC, RRC, TCEQ, IMM, TRE, and the ERCOT Board of Directors.

developed and that the communications cadence is maintained. Responsible for ensuring key audience communication including news media, legislators, market participants and employees through news releases, web updates, news conferences, social media and other channels.

Media Specialist
Media spokesperson responsible for media inquiry response, interviews and news conferences. This includes the logistics of hosting news conferences or briefings by phone/video.

Communication Coordinator
Document and triage all incoming media inquiries. Develop key messages, draft news releases/updates, and write answers to frequently asked questions. Responsible for all approvals prior to releases/updates.

Legislative Liaison
Responsible for identifying critical information, setting up and hosting conference calls with Texas elected leaders, Texas legislative leadership/ committees/members, Congressional delegation and staff, responding to specific requests and summarizing areas of concern/needs. This position will closely coordinate with PUC Relations.

Web Communicator
Responsible for all internet site and social media updates/posts. Review real-time analytics and website searches to decide placement of information and identify future communications needs.

Support Team
Outside contractors will provide content as needed with approval of the Communication Leader. They will provide the majority of legislative/regulatory one pagers as well as in-depth situation and media analysis, white papers and development of all anticipated media content.

Client Services
Provide support for Market Participants. Public exposure to calls will be minimized by having Client Services provide data and information to the crisis team about questions and comments being received. Phone calls from the public will be handled in compliance with the "Strategy to Manage Public Inquiries."

Crisis Communications Team Assignments
At the launch of the Crisis Communications activities, the External Affairs department will be divided into three teams, each with assigned responsibilities and assigned work times. The teams and work times will not change during the event, except for substitutions.

Team A (8 a.m. – 8 p.m.)
Team A is primarily responsible for communicating to key audiences, including but not limited to news media, market participants, elected officials, and employees.

Leader – Director, Corporate Communications team member
Media Specialist – TBD (Contractor)
Communications Coordinator – Corporate Communications team member
Support Team – TBD (Contractor)
Web – Digital Content Management team member
Client Services – Director level, Client Services team member

Team B (8 p.m. – 8 a.m.)
Team B is primarily responsible for developing the materials needed the following day for Team A, as well as data analysis to support a strategic communications plan recommendation.

Leader – VP of External Affairs, Corporate Communications team member
Communications Coordinator – TBD (Contractor)
Support Team – Digital Content Management team member
Web – Digital Content Management team member
Client Services – Client Services team member

Team C (Substitutions for extended events)
Team C may be called to occasionally assist Team A, but they are primarily responsible for remaining ready to substitute for other members of the team during an extended event to allow those members to rest.

Communications Coordinator – Outside Contractor
Web – Penney Christian, Priyanka Parthasarathy
Support Team – Outside Contractor
Client Services - TBD

Maximum Frequency for Researching, Developing and Distributing Messages (from Crisis Plan)

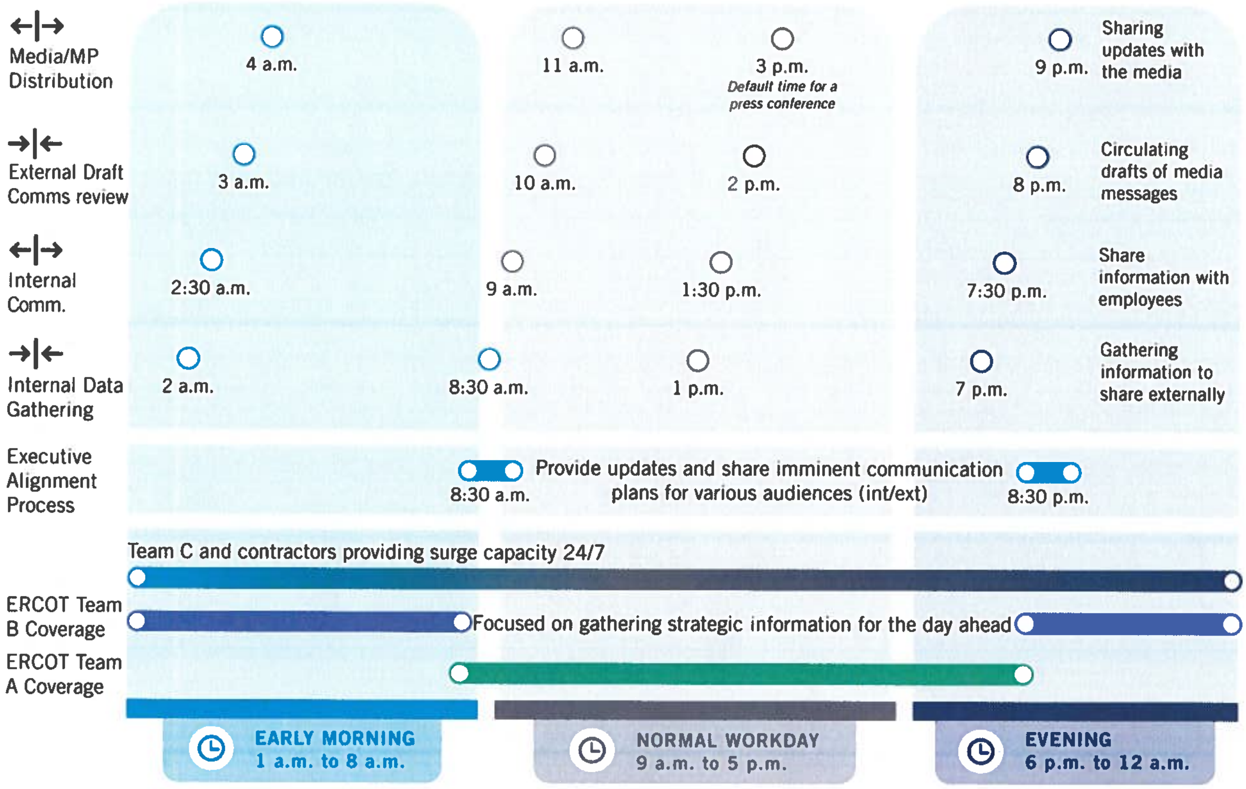
	ERCOT Internal Data Gathering	Internal Communications	External Draft Comms Circulation	Media/MP Distribution
Morning	2 a.m.	2:30 a.m.	3 a.m.	4 a.m.
Mid-Day	8:30 a.m.	9:00 a.m.	10 a.m.	11 a.m.
Evening	1 p.m.	1:30 p.m.	2 p.m.	3 p.m.
Night	7 p.m.	7:30 p.m.	8 p.m.	9 p.m.

NOTES:

1.) The default time for a press conference should always be 3 p.m.
2.) This cadence represents the maximum frequency; actual event cadence will be determined at the start of the event based on significance, severity and anticipated duration.

December 6, 2021

Timeline for Daily Crisis Communications (Maximum Frequency)



ATTACHMENT 4

176 FERC ¶ 61,119
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
Neil Chatterjee, James P. Danly,
Allison Clements, and Mark C. Christie.

North American Electric Reliability Corporation Docket No. RD21-5-000

ORDER APPROVING COLD WEATHER RELIABILITY STANDARDS

(Issued August 24, 2021)

1. On June 17, 2021, the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted a petition seeking approval of proposed Reliability Standards EOP-011-2 (Emergency Preparedness and Operations), IRO-010-4 (Reliability Coordinator Data Specification and Collection), and TOP-003-5 (Operational Reliability Data) (collectively, the Cold Weather Reliability Standards).[1] NERC requested that the Commission approve the proposed Cold Weather Reliability Standards on an expedited basis. As discussed in this order, we approve the Cold Weather Reliability Standards, their associated violation risk factors and violation severity levels, NERC's proposed implementation plan, and the retirement of the currently-effective Reliability Standards immediately prior to the effective date of the revised Reliability Standards.

I. Background

A. Section 215 and Mandatory Reliability Standards

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[2] Pursuant to section 215 of

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[1] The proposed Reliability Standards are not attached to this order. The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RD21-5-000 and on the NERC website, www.nerc.com.

[2] 16 U.S.C. 824o(e).

the FPA, the Commission established a process to select and certify an ERO,[3] and subsequently certified NERC.[4]

B. NERC Petition and Proposed Cold Weather Reliability Standards

3. On June 17, 2021, NERC filed its petition for approval of the Cold Weather Reliability Standards. NERC maintains that the proposed modifications to the Reliability Standards are consistent with Recommendation 1 of the 2018 Cold Weather Event Report;[5] specifically, NERC states that the proposed Reliability Standards "require generators to implement plans to prepare for cold weather and require the exchange of certain generator cold weather operating parameters that would help enhance situational awareness in the operational planning and Real-time operations timeframes."[6]

4. NERC proposes to revise currently effective Reliability Standard EOP-011-1 by adding two new requirements, Requirement R7 and Requirement R8, related to generator cold weather preparedness, including freeze protection and training. In addition, NERC proposes revising two requirement parts, Requirements R1.2.6 and R2.2.9, related to the consideration of the reliability impacts of cold weather conditions in transmission operator and balancing authority emergency operating plans.[7] Further, NERC proposes to revise the currently-effective title of Reliability Standard EOP-011-1 from "Emergency Operations" to "Emergency Preparedness and Operations" in proposed Reliability Standard EOP-011-2 and to modify the purpose statement to reflect the addition of the

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[3] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[4] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[5] FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, at 89, (Jul. 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf, (2018 Cold Weather Event Report).

[6] NERC Petition at 13.

[7] *Id.* at 14.

generator owner as an applicable entity responsible for compliance with the proposed Reliability Standard.[8]

5. NERC proposes to revise the data requirements in the currently-effective versions of the Reliability Standards in proposed Reliability Standards IRO-010-4 for reliability coordinators and TOP-003-5 for balancing authorities and transmission operators to include cold weather data developed by the generator owner under Reliability Standard EOP-011-2, Requirement R7.[9] NERC also proposes to replace the term "Special Protection System" with "Remedial Action Scheme" throughout proposed Reliability Standards IRO-010-4 and TOP-003-5 to align the Reliability Standard language with the approved revised NERC Glossary definition of Remedial Action Scheme.[10]

6. NERC proposes an 18-month implementation plan for each of the Cold Weather Reliability Standards beginning on the first day of the first calendar quarter following the date of applicable regulatory approval. NERC explains that it considered the time necessary for generator owners to develop, implement, and train on their cold weather preparedness plans as well as the time for reliability coordinators, balancing authorities, and transmission operators to develop, issue, and receive data specifications with cold weather parameters.[11] NERC also requests retirement of the currently-effective Reliability Standards EOP-011-1, IRO-010-3, and TOP-003-4 immediately prior to the effective date of the revised Reliability Standards.

7. In addition to the proposed Reliability Standards, NERC also describes potential measures it may take to support reliability prior to the Cold Weather Reliability Standards' mandatory and enforceable date. For example, NERC explains that it may perform outreach and training; use the NERC Alert System; issue compliance practice guides; or use its Winter Reliability Assessment. NERC commits to keeping Commission staff aware of its cold weather preparation efforts.[12]

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[8] *Id.*

[9] *Id.* at 21-22.

[10] *Id.* at 23 (citing *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228 (2015)) (approving the revised definition of Remedial Action Scheme).

[11] *Id.* at 23-24.

[12] *Id.* at 24-25.

8. Finally, NERC notes that the joint inquiry by the Commission, NERC, and Regional Entities staff on the causes of the February 2021 cold weather event in the Midwest and South Central states is currently underway.[13] NERC states that, to the extent the inquiry leads to recommendations for further modifications of the Reliability Standards, it is "prepared to address those recommendations promptly through its standard development process."[14]

II. Notice of Filing and Responsive Pleadings

9. Notice of NERC's June 17, 2021 Petition was published in the *Federal Register*, 86 Fed. Reg. 37,750 (2021), with comments, protests, and motions to intervene due on or before July 29, 2021. The Edison Electric Institute filed a timely motion to intervene and the Electric Power Supply Association (EPSA) filed a timely motion to intervene and comments. PJM Interconnection, L.L.C. (PJM) and the Midcontinent Independent System Operator, Inc. (MISO) filed an out of time motion to intervene and comments.

III. Comments

10. EPSA expresses support for the proposed modifications to the Reliability Standards, noting that "it is imperative that preserving system reliability remain front of mind for policymakers and electric system stakeholders."[15] EPSA also highlights the comprehensive record supporting the need for modifications of the Reliability Standards to address recommendations from the 2018 Cold Weather Report.[16]

11. PJM and MISO state that they support NERC's proposed Cold Weather Reliability Standards.[17] PJM and MISO also recommend that the Commission encourage earlier implementation in certain regions at the "earliest date practicable within those regions."[18] PJM and MISO emphasize the need for comparability among entities' weatherization plans and "encourages" the Commission to clarify "its expectations as to the

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[13] *See FERC, NERC to Open Joint Inquiry into 2021 Cold Weather Grid Operations*, News Release (Feb. 16, 2021), https://www.ferc.gov/news-events/news/ferc-nerc-open-joint-inquiry-2021-cold-weather-grid-operations.

[14] NERC Petition at 25.

[15] EPSA Comments at 3.

[16] *Id.* at 4-5.

[17] PJM MISO Joint Comments at 3.

[18] *Id.* at 4.

comparability and documentation of the required plans."[19] Finally, PJM and MISO request the Commission clarify the need for annual and seasonal reporting requirements for generator owners to report plans to their Regional Entities for validation, which would provide such plans to reliability coordinators for informational purposes.

IV. Determination

A. Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2020), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

13. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant PJM's and MISO's late-filed motion to intervene and comment given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

B. Substantive Matters

14. Pursuant to section 215(d)(2) of the FPA, we approve the Cold Weather Reliability Standards as just, reasonable, not unduly discriminatory or preferential and in the public interest. The Cold Weather Reliability Standards will help to address the reliability of the Bulk-Power System in the event of extreme cold weather.

15. While once described as "unusual," multiple events over the last ten years have highlighted the potential for extreme cold weather to impact the reliability of the Bulk-Power System.[20] Extreme cold weather has led to generating units experiencing outages, de-rates, and failures to start. NERC and Commission reports have identified the lack of generator winterization and lack of accurate data about generator operating limitations for cold weather,[21] which results in inaccurate operational planning analysis, as primary

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[19] *Id.* at 5.

[20] *See e.g.*, FERC and NERC Staff, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations* (Aug. 2011), https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf; NERC, *Polar Vortex Review* (Sep. 2014) (2011 Report), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf; and the 2018 Cold Weather Event Report.

[21] *See, e.g.*, 2011 Report at 196 (noting that balancing authorities, reliability coordinators and generators often lacked adequate knowledge of plant temperature design limits, and thus did not realize the extent to which generation would be lost when

causes for such events. In response, the Cold Weather Reliability Standards improve situational awareness and enhance reliable operations by requiring generator owners to implement plans to prepare for cold weather and to provide certain generator cold weather operating parameters to the reliability coordinator, transmission operator, and balancing authority for use in their analyses and planning.

16. We agree with NERC that the proposed modifications to the Reliability Standards are consistent with Recommendation 1 of the 2018 Cold Weather Event Report.[22] We also appreciate that NERC completed the modifications in a timely manner, and we find that the modifications address the need to winterize and ensure the accuracy of design specifications for generating units and the need for balancing authorities and reliability coordinators to be aware of, and plan for, generating units' limitations during extreme cold weather.[23]

17. As described above, PJM and MISO emphasize the need for comparability among entities' weatherization plans and suggest that the Commission clarify its "expectations" on the matter. PJM and MISO also request that the Commission clarify the need for annual and seasonal reporting requirements for generator owners to report plans to their Regional Entities for validation, which would then provide such plans to reliability coordinators for informational purposes. PJM's and MISO's comments raise concerns regarding implementation of the proposed Reliability Standards, which are better directed to NERC and the Regional Entities. Accordingly, we deny the request for clarification.

18. Finally, we approve NERC's proposed implementation plan. The implementation plan provides that the Cold Weather Reliability Standards will become effective on the first day of the first calendar quarter that is 18 months after the issuance of this order.[24] This implementation plan is reasonable to accommodate entities that may need time to perform various engineering analysis; provide the required training; and develop the necessary capabilities to satisfy revised data specifications. Nevertheless, we strongly encourage entities that are capable of complying with the Cold Weather Reliability Standards earlier than the mandatory and enforceable date to do so. We also encourage

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temperatures dropped); 2018 Cold Weather Event Report at 78 (noting that a failure to properly prepare or winterize generation facilities was the primary cause of both the 2011 Southwest and the 2018 South Central Cold Weather Events); and *Id.* at 89 (noting the need for reliability coordinators and balancing authorities to have sufficient information to identify units that may not be able to perform during an extreme weather event).

[22] *Id.* at 86-87.

[23] *Id.* at 87.

[24] Specifically, the implementation date will be April 1, 2023.

NERC to pursue the measures it describes in its petition to support reliability during the upcoming winter season and any future winter season that elapses before the Cold Weather Reliability Standards are enforceable.[25]

V. **Information Collection Statement**

19. In compliance with the requirements of the Paperwork Reduction Act of 1995, 44 U.S.C. § 3506(c)(2)(A), the Commission is soliciting public comment on revisions to the information collection FERC-725S, Mandatory Reliability Standards for the Bulk Power System; EOP Reliability Standards; FERC-725A, Mandatory Reliability Standards for the Bulk-Power System: TOP Reliability Standard; FERC-725Z, Mandatory Reliability Standards for the Bulk-Power System: IRO Reliability Standards, which will be submitted to the Office of Management and Budget (OMB) for a review of the information collection requirements. Comments on the collection of information are due within 60 days of the date this order is published in the *Federal Register*. Respondents subject to the filing requirements of this order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

20. The information collection requirements are subject to review by the OMB under section 3507(d) of the Paperwork Reduction Act of 1995.[26] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[27] The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

21. The number of respondents below is based on an estimate of the NERC compliance registry for balancing authority, transmission operator, generator operator, generator owner, and reliability coordinator. The Commission based its paperwork burden estimates on the NERC compliance registry as of May 14, 2021. According to

[25] NERC Petition at 24 – 25 ("These measures may include winter weather readiness outreach and training, including site visits and webinars; the use of the NERC Alert System, such as to issue recommended actions to entities; and compliance practice guides. NERC may also use its Winter Reliability Assessment to help assess and document the industry's preparedness based on the input from the aforementioned activities and scenario analysis.").

[26] 44 U.S.C. § 3507(d).

[27] 5 C.F.R. § 1320 (2020).

the registry, there are 98 balancing authorities, 168 transmission operators, 943 generator operators, 1,017 generator owners, and 11 reliability coordinators. The estimates are based on the change in burden from the current standards to the standards approved in this Order. The Commission based the burden estimates on staff experience, knowledge, and expertise.

22. The estimates are based combination on one-time (years 1 and 2) and ongoing execution (year 3) obligations to follow the revised Reliability Standards.

23. For Reliability Standard EOP-011-2, balancing authorities and transmission operators have a one-time cost preparing Operating Plans to mitigate operating Emergencies related to cold weather conditions and generator owners creating and implementing cold weather preparedness plans and providing associated training. Additionally, reliability coordinators will need to review Operating Plans of the balancing authorities and transmission operators. In year three and ongoing, the estimates are lower to reflect the Operating Plans and cold weather preparedness plans are in place and applicable entities are following those plans.

24. For Reliability Standard IRO-010-4, in years 1 and 2 the reliability coordinators must update documented specifications for data to include provisions for notification of bulk electric system (BES) generating units during local forecasted cold weather events. Years 3 and ongoing estimates reflect documented specifications are in place and entities being aware of their responsibilities.

25. For Reliability Standard TOP-003-5, in years 1 and 2 the transmission operator and balancing authorities must update documented specifications for data to include provisions for notification of BES generating units' operating limitations during local forecasted cold weather events. Years 3 and ongoing estimates reflect documented specifications are in place and entities being aware of their responsibilities.

26. Burden Estimates: The Commission estimates the changes in the annual public reporting burden and cost as indicated below:

Proposed Changes Due to Final Rule in Docket No. RD21-5-000					
Reliability Standard & Requirement	**Type[28] and Number**	**Annual Average Number of Respons**	**Total Number of Responses (1)*(2)=(3)**	**Annual Average Number of Burden Cost ($)**	**Total Burden Hours (3)*(4)=(5)**

[28] TOP=Transmission Operator, BA=Balancing Authority, GO=Generator Owner, GOP=Generator Operator and RC=Reliability Coordinator.

	of Entity (1)	es Per Entity (2)		Hours per Response[29] (4)	
FERC-725S					
One Time Estimate - Years 1 and 2					
EOP-011-2	168 (TOP)	1	168	60 hrs. $4,005.60	10,080 hrs. $672,940.80
EOP-011-2	98 (BA)	1	98	60 hrs. $4,005.6	5,880 hrs. $392,548.80
EOP-011-2	1,017 (GO)	1	1,017	150 hrs. $10,014	152,550 hrs. $10,184,238.00
EOP-011-2	943 (GOP)	1	943	80 hrs. $2,670.40	75,440 hrs. $5,036,374.40
EOP-011-2	11 (RC)	1	11	40 hrs. $2,670.40	440 hrs. $29,374.40
Ongoing Estimate – Year 3 ongoing					
EOP-011-2	168 (TOP)	1	168	50 hrs. $3,338.00	8,400 hrs. $560,784.00
EOP-011-2	98 (BA)	1	98	50 hrs. $3,338.00	4,900 hrs. $327,124.00
EOP-011-2	1,017 (GO)	1	1,017	40 hrs. $2,670.40	40,680 hrs. $2,715,796.80
EOP-011-2	943 (GOP)	1	943	50 hrs. $3,338.00	47,150 hrs. $3,147,734.00
EOP-011-2	11 (RC)	1	11	20 hrs. $1,335.20	220 hrs. $14,687.20

[29] The hourly cost figures, for salary plus benefits, for the Reliability Standards are based on Bureau of Labor Statistics (BLS) information (at http://www.bls.gov/oes/current/naics2_22.htm), as of May 2020, 75% of the average of an Electrical Engineer (17-2071) - $72.15, mechanical engineers (17-2141) - $77.50. $72.15 + $77.50/2 = 74.825 x .75 = 56.118 ($56.12-rounded) ($56.12/hour) and 25% of an Information and Record Clerks (43-4199) $42.57 x .25% = 10.6425 ($10.64 rounded) ($10.64/hour), for a total ($56.12+$10.64 = $66.76/hour).

Total for FERC-725S(One time)	**2,237**		**2,237**		**244,390 hrs. $16,315,475.40**
Total for FERC-725S(Ongoing)	**2,237**		**2,237**		**101,350 hrs. $6,766,126.00**
FERC-725Z					
One Time Estimate - Years 1 and 2					
IRO-010-4	11 (RC)	1	11	720 hrs. $48,067.20	7,920 hrs. $528,739.20
Ongoing Estimate – Year 3 ongoing					
IRO-010-4	11 (RC)	1	11	360 hrs. $24,033.60	3,960 hrs. $264,369.60
Total for FERC-725Z(One time)	**11**		**11**		**11,880 hrs. $793,108.80**
Total for FERC-725Z(Ongoing)	**11**		**11**		**3,960 hrs. $264,369.60**
FERC-725A					
One Time Estimate - Years 1 and 2					
TOP-003-5	168 (TOP)	1	168	80 hrs. $5,340.80	13,440 hrs. $897,254.40
TOP-003-5	98 (BA)	1	98	80 hrs. $5,340.80	7,840 hrs. $523,398.40
Ongoing Estimate – Year 3 ongoing					
TOP-003-5	168 (TOP)	1	168	40 hrs. $2,670.40	6,720 hrs. $448,627.20
TOP-003-5	98 (BA)	1	98	40 hrs. $2,670.40	3,920 hrs. $261,699.20
Total for FERC-725A(Onetime)	**266**		**266**		**21,280 hrs. $1,420,652.80**
Total for FERC-725A(Ongoing)	**266**		**266**		**10,640 hrs. $710,326.40**

Titles: FERC-725S, Mandatory Reliability Standards for the Bulk Power System; EOP Reliability Standards; FERC-725A, Mandatory Reliability Standards for the Bulk-Power System: TOP Reliability Standard; FERC-725Z, Mandatory Reliability Standards for the Bulk-Power System: IRO Reliability Standards.

Action: Reductions to Existing Collections of Information FERC-725S, FERC-725A, and FERC-725Z.

OMB Control Nos: 1902-0270 (FERC-725S); 1902-0276 (FERC-725Z); and 1902-0244 (FERC-725A).

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: On occasion (and proposed for deletion).

Necessity of the Information: Reliability Standards EOP-011-2 (Emergency Preparedness and Operation), IRO-010-4 (Reliability Coordinator Data-Specification and Collection) and TOP-003-5 (Operation Reliability Data) are part of the implementation of the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk Power system. Specifically, the revised standards ensure generating resources are prepared for local cold weather events and that entities will effectively communicate information needed for operating the Bulk Power System.

Internal review: The Commission has reviewed NERC's proposal and determined that its action is necessary to implement section 215 of the FPA.

27. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, e-mail: DataClearance@ferc.gov, phone: (202) 502-8663].

28. All submissions must be formatted and filed in accordance with submission guidelines at: http://www.ferc.gov. For user assistance, contact FERC Online Support by e-mail at ferconlinesupport@ferc.gov, or by phone at (866) 208-3676 (toll-free).

29. Comments concerning the information collections and requirements approved and associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. OMB submissions must be formatted and filed in accordance with submission guidelines at www.reginfo.gov/public/do/PRAMain. Using the search function under the "Currently Under Review" field, select Federal Energy Regulatory Commission; click "submit," and select "comment" to the right of the subject collection.

30. Please refer to the appropriate OMB Control Number(s) 1902-0270 (FERC-725S); 1902-0276 (FERC-725Z); and 1902-0244 (FERC-725A) and Docket No. RD21-5-000 in your submission.

VI. Document Availability

31. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

32. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

33. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

The Commission orders:

The Commission, hereby, approves the Cold Weather Reliability Standards, associated violation risk factors and violation severity levels, implementation plan, and the retirement of the currently-effective Reliability Standards EOP-011-1, IRO-010-3, and TOP-003-4 immediately prior to the effective date of the revised Reliability Standards, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

ATTACHMENT 5

ATTACHMENT 5

RRC Report on Natural Gas Facility Weatherization Best Practices

Background

In 2021, the Texas Legislature (SB 3, 87th Legislature, Regular Session, 2021) created the Texas Electricity Supply Chain Security and Mapping Committee comprised of executive leadership from the Public Utility Commission, the Railroad Commission, ERCOT, and the Texas Department of Emergency Management. Senate Bill 3 directed the Committee to establish best practices to prepare facilities that provide electric service and natural gas service in the electricity supply chain to maintain service in an extreme weather event and recommend oversight and compliance standards for those facilities.

The February 2021 winter storm in Texas resulted in a historically high demand for energy. Senate Bill 3 implemented new regulatory oversight to establish compliance standards, provide regulatory oversight for critical infrastructure that are part of the natural gas supply chain for power generation in Texas, and mitigate the risks of system outages during extreme weather conditions.

This report seeks to offer best practices to enhance weather preparedness for the natural gas industry.

Introduction

Natural gas production is broadly affected by several circumstances in a cold weather event. In addition to inadequate weatherization measures, loss of power, loss of telecom and inability to access facilities due to icy road conditions can lead to freeze-offs at natural gas facilities.

The natural gas industry depends on electric utilities to power the instrumentation, compression, pumps, and processing equipment that help move gas from the production fields to end users. The temporary loss of electric power can put a gas production, processing, compression, or storage facility out of service, and the resulting gas outages can then contribute to electricity shortages due to reduced fuel supply to gas fired electricity generating plants. Rolling electric blackouts or customer curtailments that can shut down electric pumping units or compressors on gathering lines may also result in prolonged gas production reduction.

Icy roads can prevent maintenance personnel and equipment from reaching wells to haul off produced water which, if left in holding tanks at the wellhead, can cause wells to shut down automatically. Icy roads can also cause an industry stop work order that prevents third party service personnel from driving on icy roads or inclement conditions. Stop work authority conditions can limit third party service companies from installing, servicing, and maintaining equipment to implement best practices for winter weather conditions.

Keeping gas production facilities in service is critical to maintain an adequate supply of natural gas, while keeping electric-powered compressors running is equally important to maintain adequate pressure in gas transmission lines. Critical load review for gas production and transmission facilities should identify the appropriate priority for power delivery in the event of system stress or load shedding.

Operators of gas supply chain facilities and gas pipeline facilities under the Railroad Commission's jurisdiction are expected to take all necessary measures to prepare to operate in the upcoming winter. The Commission's highest priority is to ensure that should another extreme winter weather event occur, all available natural gas under the jurisdiction of the Commission in the state is available as a reliable energy source for Texans.

Known Risks

Natural gas services, like electric services, can be negatively impacted by extended extreme weather conditions. Extreme weather conditions can trigger temperature related negative direct effects, as well as negative indirect effects that stem from those circumstances directly related to the weather event. During a period of prolonged winter weather conditions, it is critical for the state's electric and natural gas infrastructure systems to function despite the negative effects associated with below freezing temperatures.

Direct effects include icy roads, freezing of products in flow lines and instrumentation, as well as freezing of physical equipment such as compressors, pumps, or separation equipment, along the pathway of natural gas production and transportation. Examples of how these direct effects can impact operations are below:

1. Icy Roads can create unsafe travel conditions for those trained personnel who maintain producing equipment in good working order or to restart an equipment when there is a power outage.
    a. When winter weather conditions remain in an area for an extended period industry field staff may be unable to travel safely on icy roads to well sites, pipelines, or compressor stations to supply and maintain the installed weatherization equipment.
2. Water disposal may be impeded by icy roads, an electrical outage, or inadequate weatherization measures. These circumstances could result in an operator shutting in a well or shutting down a gas treating facility. To maintain stable gas production an operator must, in many instances, be able to dispose of salt water produced from gas wells or dispose of produced water removed at a gas treating facility.
    a. Generally, produced water is temporarily stored in tanks at producing locations and then removed by pumping it through pipes to disposal facilities, or by trucking the produced water from the production site to a disposal facility. If roads are too icy for trucks to operate, and water cannot be moved in other ways when the temporary on-site storage capacity is full, an operator must temporarily shut-in a well. If the water

pumps pushing the water through flow lines are powered by electricity provided by utility companies, an interruption in electrical service can both temporarily cause the operator to shut in the well, and indirectly cause the water lines to freeze up once the water stops moving.

b. Water removal from gas processing facilities faces similar challenges in extreme weather conditions. Electrically powered water pumps experiencing power outages, can experience problems associated with lubrication oil becoming too viscous due to cold temperatures and non-flowing water in the flow lines freezing. Pump equipment at gas processing facilities often rely on power delivered from the electric grid. If electrical power is impaired and water is not removed, once temporary storage capacity reaches its limit, the operator must shut down a gas treating facility.

c. Saltwater disposal well (SWD) operators often require electricity to power injection pumps. If facilities lose electricity, they are unable to take the salt water, often impacting many producing operators and facilities.

3. Natural gas flows directly from the producing wellhead can experience "freeze-offs" when outside temperatures fall below freezing in producing fields. When water produced entrained with natural gas crystallizes or freezes in surface flow lines, it can block the gas flow and can force the shutdown down of a well. A freeze-off can also occur with mechanical separation equipment at producing locations. Liquid dump valves used on separation equipment can become ineffective when outside temperatures fall below freezing unless the equipment is wrapped and warmed by an independent heat source. When separation equipment malfunctions, oil, gas, and water are not separated properly. An operator must shut-in a well until separation equipment can be restarted.

4. Instrumentation plays a large role in the safe and effective operation of production facilities, compressor stations, and gas processing. Instrumentation is included in an information loop that controls a process. Instruments often relay their information, such as pressure, flow rates, temperatures, or RPMs, to a central processor or directly to a controller via pressurized air lines. Any moisture in these air lines can easily freeze when outside temperatures fall below freezing. Although the volumes of moisture are quite small, the impact on an instrument's communication with its control device can often require an operator to shut down producing equipment, compressors, or gas processing facilities until a service technician can troubleshoot the blocked air lines.

Indirect effects can happen when electric power demands are shed from segments of the power grid. The loss of electricity can cause critical natural gas production equipment such as compressors, pumps, or separation equipment to experience a temporary interruption beyond the control of the gas producer, transportation company, or treating plant operator. If natural gas producing equipment lacks adequate electric supply, equipment cannot reliably deliver available gas, including gas needed to generate additional electricity. Rolling electricity blackouts or customer curtailments managed by utility companies can inadvertently cause disruptions in natural gas production. Modern electrically powered equipment at producing facilities, compressors, or processing facilities can be subject to electrical power disruptions during winter storms, which can limit the supply of natural gas to electrical power generating facilities. The interconnected natural gas and electrical power generation facilities are the first link of the supply chain in the state's critical infrastructure during an extreme weather event.

Best Practices

Identifying best practices relies on analysis of the following criteria: effectiveness, efficiency, relevance, sustainability, and the possibility of duplication. Implementing best practices depends on the specific geography and geology of individual well sites. Each operator is expected to take all necessary measures to prepare to operate in extreme weather conditions, given the unique circumstances of their well locations. To ensure that gas facility operators and gas pipeline facility operators prepare to operate during extreme weather conditions, the Commission's Oil and Gas Division and Oversight and Safety Division, through experience and research, identified the following best practices for weatherization:

- Submit appropriate critical load designation application forms for the winter season
- Instrument filters
- Methanol injection or drip
- Water removal by solids absorption
- Cold weather barriers
- Line heaters
- Glycol contact towers
- Drip pots
- Hot oil
- Hot lubricant and circulation heater for engine oil or fuel

This list is not all encompassing, but rather is informative of the practices that exist across the oil and gas industry. Other techniques such as installing instrument covers or heat tracing equipment for critical valves and regulators should be considered as additional preventative measures. Removing sludge and buildup from production and flow lines at a well site or a storage facility will also allow gas to flow unimpeded by frozen water molecules, should be done regularly as preventative maintenance. Keeping additional parts onsite can shorten the down cycle if repairs or replacement are necessary during extreme weather conditions.

The Commission will continue to identify best practices as we survey industry experts and other regulators and leverage contracted technical advisory services.

Submit appropriate critical load designation forms for the winter season

The Electric Reliability Council of Texas (ERCOT) provides an application through which a natural gas operator may request its facility be designated as a "Critical Load Serving Natural Gas-Fired Electric Generation." This designation is an important component of extreme weather preparedness. Forms must be filed with the local electric service provider. In 2021, the form needed to be filed no later than November 1, 2021 to allow electric service providers time to complete their winter extreme weather planning. To allow for summer extreme weather planning, the form is generally due in March of each year.

The Railroad Commission sent several notices to operators in 2021 to review the ERCOT application and file, as appropriate, with the local electric service provider(s).

The Railroad Commission new rules adopted on November 30, 2021 specify the criteria and process by which entities associated with providing natural gas in Texas are designated as critical customers or critical gas suppliers during an energy emergency. Upon final approval of the new rules found in 16 TAC §3.65, §3.107, an operator shall submit a bi-annual acknowledgement of its designation as a critical customer in accordance with the new rule.

Instrument filters

Instrument filters are a critical part of natural gas producing systems and should be installed, maintained, and verified to be in good working order, especially during winter weather. If the water in an air system leading to a control panel freezes it could send a false reading with the potential to cause associated problems, including shutting in equipment. Control of the producing system can often be maintained remotely, even if personnel are unable to reach a facility, if the control panels are receiving high quality responses from their various sensors. Instrument filters generally only clean small volumes of gas or air, and as such tend to work reliably well. They are often installed with redundancy so a filter can be used, shut off and diverted to another filter to allow the filter or desiccant inside the filter to be replaced. A maintenance program is critical for the continuous proper function of inline filters. Filter dryers provide a clean, dry supply of gas to controllers and other instrumentation that functions using instrument gas. Units function under high pressure and can eliminate both liquids and particulates. Filter dryers are in-line devices that hold either a shaped filter made from a material that will collect both fluids—oils and water—as well as solid particles of known sizes, or a dry material bed that acts as a desiccant for collecting moisture and filtering out solids. In-line ensure that control panels receive unimpeded signals from sensors at the well, along the flowlines, or at processing facilities. Proper signals at the control panels ensures that an operator can monitor and manage all equipment regardless of the weather.

Methanol injection or drip

Methanol injection is a well-documented, practical method to reduce the negative impact that hydrates can have on gas flow. Injecting methanol into gas flow streams can lower the freeze point of hydrates, which will effectively inhibit the formation of ice like structures in the flow stream. Hydrates are physical combinations of water and other small molecules found in natural gas that can produce a solid that has an appearance similar to ice. At low ambient temperatures, hydrates can develop a structure able to block normal gas flow in lines and orifices. Liquid methanol can be cost effective to prevent the accumulation of these ice-like structures when injected in a low-pressure point in the gas flow stream. The amount of methanol required to inhibit hydrates is directly related to the amount of water that is found in the gas stream. Methanol injection can replace the need for upstream glycol dehydration in some gas streams and allow gas to flow until it arrives at a processing facility where the remaining water is removed and gas is conditioned the to meet pipeline specifications. Methanol can also be used in gas reinjection systems installed to assist with gas lift for high-volume liquid (oil and water) horizontal wells.

Water removal by solids absorption

In a vapor state all gasses have the capacity to hold water, with drier gas devoid of water molecules that can freeze in low temperatures. Under properly managed conditions, a solid absorption system can reliably work in any weather condition to absorb water as natural gas passes through dry chemical beds. Water removal by solids absorption (desiccant bed) methods can achieve a very dry natural gas stream under certain conditions. On a producing location at the well pad, wet gas is directed into an inlet separator to ensure removal of contaminants and free water from the original gas stream. After the separator, the gas stream is directed into an adsorption tower where water is adsorbed—the adhesion of atoms, ions or molecules from a gas, liquid or dissolved solid to a surface—by the desiccant. When the adsorption tower approaches maximum loading, the gas stream is automatically switched to another tower allowing the desiccant in the first tower to be regenerated. This method usually requires at least two desiccant towers to ensure that a tower is always full of a dry desiccant, rather than a water saturated desiccant. When the equipment is designed and installed properly, and the desiccants are systematically replenished, the removal of water by mechanical and solids absorption is an effective method for creating a dry steam of natural gas with little potential to freeze downstream of the separators. Care must be taken to analyze the amount of water remaining in the gas stream after leaving the separator.

Cold weather barriers

In extreme weather environments locating critical equipment underground or inside heated buildings is required for much of the year and provides necessary safeguards for points along the path of natural gas flow. Cold weather barriers, although effective, are generally not temporary or short-term solutions, and are not as prevalent in all climates. Cold weather barriers, such as wind walls, may be installed around certain compressors to block cold winds which could exacerbate freezing conditions. Wrapping and insulating surface equipment, injection lines, supply valves, water lines, and other equipment may also help to prevent freezing and stoppage of both natural gas and produced water flow. The methods for installing weather barriers and insulating natural gas equipment from cold air temperatures are diverse. Burying flow lines is an effective method to control flowline temperatures. Insulated wrapping can be effective for some equipment, while forced air heating inside buildings as well as small pumps to circulate compressor lubricants can maintain equipment temperatures above the freezing point. Cold weather barriers need to be systematically reviewed, designed, and implemented based on weather conditions that are known to exist at a specific natural gas facility.

Line heaters

Line heaters are a common form of equipment in the production of natural gas and a best practice for some geographic areas, specifically for gas wells that are being choked back at the wellhead, often earlier in a well's producing life. Line heaters heat the gas to avoid freezing immediately downstream of the wellhead. They are commonly used in wells that flow predominantly gas and small amounts of water, with no appreciable oil. The equipment uses a gas fired flame to heat a fluid filled chamber inside the body of the line heater. Gas passes through a coil that is immersed in a chamber of warmed fluid, which increases the temperature of the natural gas as it passes. Line heaters can be sized for high or low pressured wells that pass natural gas through a wellhead choke, which can cool gas to the point of freezing—a Joule-Thompson effect that functions much the same as a conventional refrigeration system. This type of cooling can create an ice formation, particularly when ambient temperatures around the choke are at or below freezing. Line heaters, when sized appropriately for the volume of gas being produced, effectively heat gas in the vicinity of the wellhead before it reaches downstream separation or treating equipment. Downstream of a line heater the potential still exists for freezing with low ambient temperatures, but a line heater can effectively mitigate freezing at the first potential point of freezing off the wellhead.

Glycol contact towers

Glycol units are an accepted industry standard practice and are effective at removing water from a stream of natural gas typically to meet typical pipeline and process specifications. Dry gas that leaves a glycol unit has little propensity to freeze. Relatively low-cost glycol absorption towers can be installed quickly, with a single skid able to service more than one well. This allows a range of options and flexibility to configure systems to address a broad range of gas flow rates and water volumes. While operational costs are generally proportional to the flowing natural gas volumes, such systems can vent releases of both steam and a measurable quantity of hydrocarbon gases. Used as a liquid desiccant, glycol can be introduced through a series of trays, or stages within a unit placed downstream of the wellhead before gas enters a commercial pipeline. Wet gas enters at the bottom of an absorber tower and ascends through a mist extractor where water is removed. As the gas rises through the tower's packing or bubble cap trays water is absorbed by the descending lean glycol, which is continually pumped to the top of the tower. Drier gas exits the top of the tower and passes through a heat exchanger to the gas outlet. The removal of water by glycol is an effective method for creating dry natural gas with little potential to freeze downstream of the separators.

Drip pots

Drip pots are a best practice for most producing systems that can be incorporated along with other winterization practices. Drip pots and coalescers can eliminate or reduce the amount of water when there is a slug of liquid in a gas supply used for instrumentation, or other severe liquid issues. Drip pots come in many shapes that are made primarily from the same materials as the flowlines carrying natural gas. They are located immediately after pressure changes, abrupt increases in flow area, or the lowest elevations in a continuous producing system. Drip pots work by allowing gravity to separate water from gas where the temperature of gas decreases following a significant pressure change. The cooling effect of a notable pressure change can cause liquids to fall out of the gas stream into the drip pot. The natural effects of gravity can cause water to drop from gas at low spots in a flow line. These low spots in flow lines can be an ideal place to locate a drip pot where water is likely to collect. A manual valve or collection system can pull water from the gas stream; a collection system on a timer with servo controls can also automatically dump accumulated water. Drip pots primarily remove larger volumes of water that collect in flow lines, which can cause a hydraulic impedance increasing the pressure drop along a flowline. Drip pots do not generally dry gas or winterize a producing system, but they can reduce the amount of water that reaches downstream natural gas separation or treating facilities. The removal of water will reduce the potential for freezing at points along the gas producing system.

Hot oil

Hot oil can be used to remove paraffins and dissolve asphaltenes to help keep wellbores clean. A hot oil unit uses propane carried on a truck to heat fluid that is drawn into an onboard tank, and then pumped back into the original container—a tank or well—on location. Heating produced oil is one method used to break an oil water emulsion that is susceptible to freezing. Circulating oil through a hot oil truck can raise the temperature, and thus lower the interfacial tension between the oil and water breaking the emulsion. Once the emulsion is broken oil will float to the top of the tank and water settle at the bottom. When the water has had a requisite settling time, a vacuum truck can remove the water from the bottom of the tank. This technique is preventative in its removal of water before it can freeze.

Hot lubricant and circulation heater for engine oil or fuel

Large pieces of oil and gas field equipment, such as pumps or compressors, rely on lubricants to move under pressure, as they are designed to reduce metal on metal contact. Lubricants keep these large pieces of equipment from overheating using fluids that are much more viscous than standard engine oils. When equipment is running lubricant is warmed by the mechanical action of the moving parts. At operating temperatures apparent viscosity can be relatively low, but when ambient temperatures drop to near freezing, viscosity can increase causing lubricants to begin to appear as a solid. When machinery is shut down the lubricant temperature can drop increasing its viscosity. At freezing temperatures pumps designed to circulate lubricant have difficulty functioning. Installing external block heaters with an external energy source such as a gas fed flame or electricity can maintain lubricants at an appropriate temperature, even when the equipment is not operational, making it easier to restart the equipment by keeping the oil/fuel in the engine at an elevated temperature. Using these techniques can keep pumps and compressors functional and prevent freeze-offs.

Human Capital

While weather specific technologies, including those discussed above, are critical to sustain natural gas production during cold weather conditions, the maintenance and operation of these technologies begins with human capital—the people trained and able to ensure natural gas continues to serve its essential function in the electricity supply chain despite adverse conditions. Human capital and experience of employees, along with appropriate safety and technical training specific to extreme weather events is an essential component of reliability and resiliency planning. Increasing staffing levels in advance of an extreme weather event ensures that appropriately trained employees are readily available, if they're not pre-positioned on-site, to resolve any equipment or instrumentation failures should temperatures fall below an acceptable operating temperature for sensitive equipment or instruments.

Conclusions

For new installations, careful planning during the design stage for measurement and regulating systems can reduce the chances of freezing. Any steps that reduce restrictions or prevent areas where liquids can collect will minimize the possibility of freezing. For existing installations, the best practices detailed above, along with any other practices not detailed in this report, should be implemented, as appropriate to the site-specific geography and geology, to prepare facilities providing natural gas critical to the electricity supply chain to maintain service in an extreme weather event.

Load Shed Protocols for the Electric Reliability Council of Texas (ERCOT) Region

Public Utility Commission of Texas

August 31, 2022

Senate Bill 1 (SB1),[1] passed by the 87th Texas legislature, requires the Public Utility Commission of Texas (Commission) to study the effects of load shed protocols in the Electric Reliability Council of Texas (ERCOT) power region. ERCOT conducted a load shed study (2021 Study) in 2021 following winter storm Uri. This 2021 Study identified the individual load shed capabilities and rotating load shed capabilities of all 19 transmission operators (TO) in the ERCOT power region.

Rulemakings

Since 2021, the Commission has implemented legislation related to load shed issues including:

- Adding new categories of critical load designations for load shed,
- Establishing a requirement for filing load shed procedures within the emergency operations plans of entities responsible for implementing load shed,
- Requiring retail electric providers to periodically provide information to customers about the electric utility's procedures for implementing load shedding,

[1] SB 1 (General Appropriations Act) Load Shed Protocols Study. "Using funds appropriated to the Public Utility Commission of Texas, the commission shall study the effects of load shed protocols in ERCOT, as that term is defined by Section 31.002, Utilities Code, and issue a report on the conclusions of the study to the legislature not later than September 1, 2022."

- Requiring ERCOT to conduct load shed exercises, and
- Mapping the Texas electricity supply chain.

In doing so, the Commission conducted rulemakings described below.

- In November 2021, the Commission adopted amendments to existing 16 Texas Administrative Code (TAC) §25.52, relating to Reliability and Continuity of Service. These amendments add end stage renal disease facilities to the list of health facilities prioritized during power restoration after a load shed and increase coordination between the electric and gas industries during energy emergencies by requiring designation of certain natural gas entities and facilities as critical during an energy emergency.

- In December 2021, the Commission adopted amendments to 16 TAC §25.479 that require electric utilities and retail electric providers to periodically provide to customers information concerning load shed, type of customers and procedure to be considered for critical care or critical load, and reducing electricity use at times when load shed events may be implemented.

- In February 2022, the Commission adopted a new rule 16 TAC §25.53, which implements standards for emergency operations plans required of electric utilities, transmission and distribution utilities, power generation companies, municipally owned utilities, electric cooperatives, retail electric providers, and ERCOT.

- In May 2022, the Commission adopted new 16 TAC §25.57 that establish the criteria for the content, activation, and termination of regional and statewide power outage alerts.

Load Shed in ERCOT Power Region

ERCOT is the reliability coordinator that can issue load shed instructions in the ERCOT power region. Load shed is a controlled and temporary interruption of electrical service used as a last resort to restore balance to the bulk electric system. Transmission Operators (TOs), Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) together implement ERCOT's load shed instructions.

A TSP is an entity under the jurisdiction of the Commission that owns or operates transmission facilities in the ERCOT transmission grid. Transmission facilities include power lines, substations, and associated facilities, operated at 60 kV or above. A DSP is an entity that owns or operates a distribution system for the delivery of energy from the ERCOT transmission grid to customers. The distribution system is part of the electric delivery system operating under 60kV. Transmission and distribution systems are commonly thought of as, respectively, the highways and byways of the grid.

Each TSP and DSP interacts with ERCOT through its TO. A TO communicates with ERCOT and is responsible for preserving reliability for a particular portion of the ERCOT system. The ERCOT Protocols require each TSP and each DSP to either register as a TO or designate another entity as its TO. A TO has complete authority to act on behalf of the designating TSP or DSP in the performance of all TO responsibilities. Each TO operating in the ERCOT power region is bound to follow load shed instructions given by ERCOT. In turn, each DSP is also obligated to follow any reasonable instruction given by its TO to fulfill its load shed obligations.

When ERCOT issues instructions for a certain amount of load to be shed, the percentage of that load that each TO is responsible for shedding is its load shed obligation. Load shed obligations are determined by ERCOT for each TO based on its peak load from the prior year. These percentage thresholds are reviewed by ERCOT and revised annually to reflect any new or changed TO designation.

Table 1 below shows the current load shed obligations by TO. Each TO decides how to allocate its load shed responsibility at the distribution level. ERCOT does not have visibility into or authority over which customers or feeders experience a temporary outage during a load shed event.

Table 1: ERCOT Load Shed Obligation by Transmission Operators, 2021

Transmission Operator	2021 Total Transmission Operator Load (% MW)
AEP Texas Central Company	8.41
Brazos Electric Power Cooperative Inc.	4.85
Brownsville Public Utilities Board	0.37
Bryan Texas Utilities	0.52
CenterPoint Energy Houston Electric LLC	25.89
City of Austin DBA Austin Energy	3.54
City of College Station	0.28
City of Garland	0.73
City of Lubbock	0.58
CPS Energy (San Antonio)	6.44
Denton Municipal Electric	0.48
GEUS (Greenville)	0.14
Golden Spread Electric Cooperative Inc.	0.36
Lamar County Electric Cooperative Inc.*	0.07
LCRA Transmission Services Corporation	5.89
Oncor Electric Delivery Company LLC	35.47
Rayburn Country Electric Cooperative Inc. DBA Rayburn Electric	1.34
South Texas Electric Cooperative Inc.	1.92
Texas-New Mexico Power Company	2.72
ERCOT Total	100

*Lamar County Electric Cooperative is a registered TO not on the ERCOT Hotline, City of Garland receives all their calls.
Source: https://www.ercot.com/files/docs/2022/04/18/ERCOT_Load_Shed_Table_Anticipated.xlsx

TOs, along with TSPs and DSPs, determine whether load shed rotation is feasible and how that load shed rotation will be implemented. Load shed rotation or rotating outages prevent individual customers from experiencing extended outages and bearing the full burden of the load shed event.

Discretion for determining load shed and load shed rotation priorities rests with TOs, TSPs and DSPs, because these entities have greater insight into the characteristics and capabilities of their individual systems than ERCOT or the Commission. For example, the load composition, which refers to the mix of different types of load on the system (e.g., transmission-connected industrial, residential, commercial, non-interruptible network, critical, etc.), varies widely by TO, and many of these load types present unique challenges from a load shed perspective. Larger TOs may have as much as 10-20% transmission-connected industrial load, which refers to large industrial facilities that connect directly to the transmission system rather than to the distribution system. Because most load shed is implemented at the distribution level, a high percentage of transmission-connected industrial load makes executing load shed instructions more difficult for these TOs. Similarly, TOs with a larger number of level one trauma centers and other critical facilities must often make deeper cuts in other categories to avoid outages to these facilities.

While the load shed and power restoration priorities established by each entity differ based on the unique characteristics of its system, all entities try to avoid shedding circuits with critical load. Examples of critical load include public safety customers, chronic condition or critical care residential customers, certain industrial customers with potentially hazardous industrial processes, and natural gas facilities that are essential to the electricity supply chain. However, it is important to note that critical status designations do not guarantee customers an uninterrupted supply of energy during a load shed event.

Load Shed Protocols in ERCOT Power Region

There are four main conditions during which load shed is necessary to restore balance to the bulk electric system. A brief overview of these conditions is provided below, and more detailed explanations are found in the ERCOT Nodal Operating Guides available on the ERCOT website.[2]

Under-Frequency Load Shed (UFLS)

The ideal frequency for the ERCOT bulk electric system is 60 Hz, at which supply and demand of power are perfectly balanced. When the system frequency deviates from 60 Hz by certain defined thresholds, North American Electric Reliability Corporation (NERC) reliability standards require TOs to respond with automatic under-frequency load shedding (UFLS). During an under-frequency event, each TO must provide load relief by shedding the required percentage of its DSP load and transmission-level customer load using TO-selected automatic underfrequency relays. Each TO must shed a percentage of its load determined by which frequency threshold has been crossed, as noted on Table 2. TOs must maintain an operational plan for immediate execution that identifies UFLS feeders based on the predictability of

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[2]https://www.ercot.com/files/docs/2022/06/30/July%201,%202022%20Nodal%20Operating%20Guide.pdf

demand on these feeders and to achieve geographic diversity in the feeders selected. Overall, at least 25% of the ERCOT system load must be equipped for automatic UFLS at all times.

An under-frequency event that would trigger the use of UFLS is uncommon and would take the sudden loss of approximately 6,265 MW of generation to reach the first UFLS Stage of 59.3 Hz. ERCOT Nodal Operating Guides Section 2.6.1, *Automatic Firm Load Shedding,* describes in detail the TO and DSP responsibilities to comply with these requirements.

Table 2: Under-frequency Relays and TO Load Relief

Frequency Threshold	TO Load Relief
59.3 Hz	At least 5% of the TO Load
58.9 Hz	At least 15% of the TO Load
58.5 Hz	At least 25% of the TO Load

Under-Voltage Load Shed (UVLS)

UVLS is a voluntary measure used by some TSPs in certain areas as a safety net to limit the impacts of under voltage conditions or voltage dips. While the effects of these under voltage conditions are localized, they can include voltage instability, voltage collapse, and cascading outages. To mitigate these conditions, a UVLS program uses distributed relays and controls to shed load automatically to restore system balance in the local area. Because these systems are automated, they are not designed to respond to ERCOT directives, rather they are preset to respond to real time conditions. However, a TO will consult with ERCOT while developing a UVLS program.

UVLS programs are governed by NERC reliability standard PRC-010, but there is no requirement for any entity to implement a UVLS program. Furthermore, because UVLS programs address localized issues, load shed as part of a UVLS program – or load shed to address other types of local emergencies – is not limited by or count towards a TO's load shed obligation as listed on Table 1 above.

Emergency Load Shed

During a temporary decrease in available electricity supply it may be necessary to reduce ERCOT system electricity demand by way of shedding load to maintain system reliability. A drop in supply may be caused by an unexpected loss of generation, transmission equipment, or other key facilities.

ERCOT directs load shed after it has used all available resources and measures to respond to sudden system frequency disturbances or to maintain sufficient Physical Responsive Capability (PRC). PRC is the total amount of resource capability online and available to respond to system frequency disturbances. When the ERCOT PRC falls below 1,000 MW and is not projected to recover above 1,000 MW within 30 minutes, or when the average system frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT directs TOs to shed load in 100 MW blocks to maintain a steady state system frequency at a minimum of 59.91 Hz. ERCOT Nodal Protocols Section 6.5.9.4.2*, EEA Levels,* describes various levels of Energy Emergency Alert (EEA) and the actions ERCOT must take at each level to preserve the bulk electric system.

Load Shed to Maintain Transmission Security

To comply with NERC reliability requirements, ERCOT must operate the bulk electric system within specified operating limits. Failure to operate the system within these limits can permanently damage equipment that generates, delivers, or uses electricity. When all other mitigation measures, such as transmission reconfiguration and re-dispatching generation, are insufficient to secure system reliability, ERCOT will shed load to ensure that the bulk electric system remains within its operating limits. The ERCOT Transmission and Security Operating Procedure describes this process in detail. Load shed may be implemented to prevent cascading outages.

ERCOT Load Shed Study 2021

ERCOT initiated the 2021 Study to gather substantive and current information about the load shed and rotating outage capabilities of all TOs operating in the ERCOT power region. ERCOT sent out Requests for Information (RFIs) to each of the 19 TOs for available load that could be reasonably shed during an emergency event. Two separate RFIs were sent to each TO. To identify summer seasonal variations in the available load that can be shed, an RFI was sent in May 2021. Another RFI was sent in November 2021 to gather information about the winter seasonal variations. The 2021 Study helped ERCOT better understand how fast load shed might occur, increase its overall situational awareness, and adjust communication processes.

Load Shed RFIs

Each TO provided information about its individual percentage share of load shed obligation and specific load shed responsibility in MWs across three peak electricity demand scenarios for the summer and winter seasons. The three summer peak demand scenarios were based on ERCOT system wide loads of 60 GWs, 70 GWs, and 80 GWs, and the three winter peak demand scenarios were based on ERCOT system wide loads of 55 GWs, 65 GWs, and 75 GWs.

The RFIs also sought data about each TO's load responsibility on critical circuits, UFLS, non-interruptible network load, transmission connected industrial load categories, and the remaining percentage of load not in one of these categories.

Critical circuits load responsibility is the portion of each TO's total load on circuits designated as critical. TOs attempt to exclude these circuits from load shed whenever possible. This category can include circuits with end users such as hospitals, police stations, or gas compression facilities.

UFLS load shed responsibility is the percentage of each TO's total load reserved for under frequency load shed and is otherwise excluded from other types of load shed.

Non-interruptible network loads exist in dense downtown areas of major cities and other similar locations that are served by multiple, redundant distribution feeders. These redundancies make shedding load on a feeder-by-feeder basis unworkable. Networked circuits may also power vital communication equipment, hospitals, warming centers, essential government buildings, and streetlights; and shutting down these networks would also shut down these critical facilities.

Transmission-connected industrial load includes facilities such as refineries and manufacturing plants that may have complex industrial processes. Sudden loss of power to these loads could create dangerous conditions at the facility. TOs avoid shedding these loads due to the sensitivity of industrial processes and public safety concerns.

In response to the RFIs, each TO also identified the percentage of its load that can be shed via automated control systems and what percentage can only be shed manually by field personnel. These automated systems, known as Supervisory Control and Data Acquisition

(SCADA) systems, use a combination of computer programs and user interfaces to monitor, control, and manage industrial processes. TOs' abilities to shed load using SCADA systems vary and not all TOs, TSPs and DSPs have SCADA systems.

The RFI required each TO to identify the time periods within which these loads can be shed and whether they can be shed on a rotating basis. Information was also requested about percentage load on UFLS that can be shed by TOs while maintaining the minimum 25% UFLS obligation described above.

ERCOT aggregated the data gathered from the summer RFIs and presented this information at a Commission workshop on July 26, 2021. The specific RFI responses are classified as ERCOT Critical Energy Infrastructure Information (ECEII) and thus cannot be shared publicly.

Load Shed Capability

The 2021 Study results indicate ERCOT's summer load shed capability at a peak demand of 80 GW was 46%. This includes the UFLS megawatt capacity that could be shed while maintaining the requirements that TOs reserve 25% their loads for UFLS load shed. The system wide load shed capability was reduced to 40% if the TO's entire UFLS equipped load – not just the load required to meet the 25% UFLS requirement - was excluded from its load shed. ERCOT's winter load shed capability at a peak demand of 75 GW was 40% when only required UFLS equipped load was excluded and 35% when all UFLS load was excluded.

The decrease in load shed capability from the summer RFI responses to the winter RFI responses is due to differences in how electricity is used by consumers in different seasons. Residential and commercial electricity usage is higher in summer compared to winter. The largest portion of residential and commercial electricity usage is for air conditioning. Accordingly, the seasonal deviation in usage is smaller in regions that have electric heaters rather than gas heaters.

Table 3: ERCOT Seasonal Load Shed Capability

Description		Summer			Winter		
		60 GW	70 GW	80 GW	55 GW	65 GW	75 GW
1	Load Responsibility not on Critical Circuits, UFLS, Network Load (non-interruptible), or Transmission-connected Industrial load MW	23,346	27,494	31,450	18,755	22,637	26,323
2	- SCADA Interruptible	22,910	26,983	30,838	18,405	22,188	25,776
3a	- Can be shed within 5 minutes (SCADA & Manual)	4,677	5,431	6,258	4,078	4,930	5,796
3b	- Can be shed within 10 minutes (SCADA & Manual)	5,883	6,782	7,748	4,539	5,386	6,236
3c	- Can be shed within 15 minutes (SCADA & Manual)	13,265	15,577	17,831	10,298	12,374	14,385
3d	- Can be shed within 30 minutes (SCADA & Manual)	23,001	27,068	30,951	18,018	21,663	25,149
4a	- Can be rotated by SCADA	22,215	26,129	29,846	17,694	21,293	24,704
4b	- Can be rotated Manually	312	360	427	245	296	349
5	UFLS MW that can be shed while maintaining 25% minimum requirement	4,255	5,137	5,921	2,281	2,951	3,716
6	Total Interruptible Load (#1 plus #5)	27,601	32,631	37,372	21,036	25,587	30,040

Load composition within a TO load affects the total amount of load that can be shed or rotated on a TO's system. Some TOs may have no non-interruptible network load or industrial load while other TOs may have over 20% of their load serving non-interruptible network load or industrial load. Additionally, many TOs have 20% to 30% of their load designated as critical circuits. The load shed capability may be limited by the need to avoid the use of circuits that provide UFLS, serve critical loads, or are on non-interruptible networks. Those TOs without any non-interruptible network load have more flexibility for load shed and load rotation.

The RFI responses indicated that TOs' available load shed capability may vary based on specific weather conditions, time of the day, and season. The percentage of transmission-connected industrial load decreases as the total system load increases. Industrial load typically has smaller fluctuations throughout the day than residential and commercial load. It forms a lower percentage of the overall load during the day when the residential and commercial demand is comparatively higher than in the night. During non-peak hours, industrial load makes up a higher percentage of TOs' load because this load voluntarily reduces electricity usage in response to peak electricity prices.

During winter, residential and commercial load is comparatively lower; therefore, industrial load makes up a higher percentage of a TO's load. However, during the summer months, some industrial loads voluntarily reduce demand to lower their transmission costs.

The largest three TOs, by percentage share of ERCOT load shed obligation, have lower load shed capability as compared to other TOs, as shown on Table 4, due to a low percentage of interruptible load.

Table 4: TO Seasonal Load Shed Capability

TO	SUMMER TO Interruptible Load (%) Excluding UFLS and Critical Loads at 80GW	WINTER TO Interruptible Load (%) Excluding UFLS and Critical Loads at 75 GW
TO1	41%	32%
TO2	45%	41%
TO3	31%	31%
TO4	44%	44%
TO5	28%	25%
TO6	27%	26%
TO7	55%	55%
TO8	65%	65%
TO9	N/A	50%
TO10	53%	60%
TO11	30%	31%
TO12	46%	45%
TO13	N/A	57%
TO14	50%	54%
TO15	56%	45%
TO16	40%	34%
TO17	57%	57%
TO18	46%	34%
TO19	50%	41%

**Note: Data for certain new ERCOT members is unavailable for summer season*

Load Shed Implementation

Most TOs use SCADA systems for load shed. Loads that can be shed by using SCADA systems are called SCADA-interruptible loads. These loads can be shed within 30 minutes. While some SCADA-interruptible loads can be shed in as few as five minutes, others take longer due to communication and manual progress tracking that involves identifying and dropping individual feeders and tracking load shed progress. Therefore, only a small portion of load that is on SCADA automated applications can be shed within ten minutes. These progress tracking procedures and processes vary by TO according to their system characteristics and may lead to differences in the time needed to shed load using SCADA systems.

The 2021 Study assessed that at a peak summer electricity demand of 80GWs nearly 38% of ERCOT load was SCADA interruptible load. During the peak winter electricity demand of 75GWs, this figure fell to 34%.

Table 5: TO Load Shed Systems

Description		Number of TOs
SCADA Systems	Automated Application	8
	Personnel Selected	6
Manual (Field Personnel)		1
Mixture (SCADA and Manual)		4
Total		**19**

SCADA systems can have different operational capabilities, including whether they are personnel selected or automated applications. SCADA-Personnel Selected refers to systems that rely upon TO personnel to select individual load feeders that need to be shed to meet the TOs' load shed obligation. These feeders can only be turned on or off by personnel inside the substations. A TO with this type of system drops one load at a time by opening individual breakers and switches. Although the TO does not have to send personnel to *physically* open breakers and switches, identifying the mix of load to shed and dropping each load one-by-one by utility staff takes time.

SCADA-Automated Application refers to systems that have a single button click in the control system to identify the mix of loads to shed in defined geographic areas. These computerized operations automatically calculate the amount of load on each feeder and when to sequentially turn feeders off and on during a rotation to speed rotate and reduce load fluctuations. Utility staff must continue to monitor a computerized system and may take direct control when circumstances warrant.

Load Shed Rotation Capabilities

Nearly 37% of load could be rotated via SCADA during summer months as compared to 32% during winter months in the ERCOT power region, according to the 2021 Study.[3] TOs have

[3] The 2021 Study only required TOs to provide information related to their load shed and rotating outage capabilities and does not include substantial information or insights about the rotating outage capabilities of DSPs, who are largely responsible for rotating outages at the distribution level.

different capabilities to shed load on a rotating basis. The capability to rotate load depends on characteristics such as TO load composition and the availability of SCADA systems. Most TO feeder breakers have SCADA controls that allow TO personnel to remotely open and close a breaker to shed or restore load. This allows more frequent rotation of load shed. However, not all distribution level systems are SCADA enabled. Non-SCADA systems require a technician to physically go to a location to open or close a breaker or disconnect breakers. The frequency at which a load is rotated also depends on the TOs load shed procedures and the amount of load shed requested.

Moreover, load normally controlled via SCADA can be impacted by abnormal system conditions, communication issues, and cold load pick up issues that would impede the ability to switch remotely. Cold load pick up is the brief initial spike of power when a de-energized load is re-energized before it settles out to normal. This initial spike could, in some cases, cause protective relay actions to trigger or breakers to trip making it difficult to switch or rotate.

There are no guidelines on the amount of time a load can be out of service during a load shed event. Some TOs do not have a defined maximum time to rotate an outage but do have a target time. A common target is 30 minutes, but some larger TOs have a rotating target time of up to several hours. Several TOs noted that rotating outage target time is proportional to the magnitude of the load shed instructions issued by ERCOT.

ERCOT Protocol Revisions

In December 2021, the Commission approved Nodal Protocol Revision Request (NPRR) 1094. This allows a TO and a Transmission and Distribution Service Provider to manually shed load connected to under-frequency relays during an EEA Level 3 event if the affected TO can meet its overall 25% UFLS requirement and load shed obligation.[4] This NPRR increases the load available for rotating outages and helps spread the burden of those outages to a larger and more diverse pool of load.

[4] Nodal Operating Guides Section 2.6.1, Automatic Firm Load Shedding, and Nodal Operating Guides Section 4.5.3.4, Load Shed Obligation.

ERCOT Load Shed Exercises

As required by SB3, ERCOT has conducted two load shed exercises to review load shed procedures and provide training to market participants on various aspects of load shed. A winter load shed exercise was conducted in December 2021 and a summer load shed exercise was conducted in July 2022.

These exercises included ERCOT's explanation of its role in directing load shed – namely, identifying when load shed is necessary and issuing such directives to TOs. ERCOT and stakeholders reviewed the notification requirements in EEA 1, 2, and 3 events along with other communication requirements between market participants and ERCOT during load shed events. ERCOT also conducted simulations of hypothetical events that would eventually require load shed.

Additionally, volunteer TOs presented their load-shed practices and methods, including how they communicate with DSPs and provided explanations of how they would respond to directives issued by ERCOT. Participants shared past experiences, identified tools that assist in efficient load shedding and restoration of service, and recommended best practices. A common issue noted by many participants was that a high percentage of their distribution feeders had at least a small number of critical customers or other critical loads. Such a configuration makes it difficult to execute emergency load shed instructions without shedding any load with these critical designations.

Going forward, these exercises will be held by ERCOT at least twice a year – once during a summer month and once during a winter month. The next exercise is scheduled to be held on December 8, 2022.

Weather Emergency Preparedness Report

Public Utility Commission of Texas

September 30, 2022

Senate Bill 3 (SB3) Section 24, passed by the 87th Texas legislature, requires the Public Utility Commission of Texas (Commission) to analyze emergency operations plans developed by electric utilities, power generation companies, municipally owned utilities, electric cooperatives, and retail electric providers (collectively "entities") and prepare a weather emergency preparedness report on power weatherization preparedness.[1]

The Commission was directed to:

(1) review emergency operations plans on file with the Commission;
(2) analyze and determine the ability of the electric grid to withstand extreme weather events in the upcoming year;
(3) consider the anticipated weather patterns for the upcoming year as forecasted by the National Weather Service or any similar state or national agency; and
(4) make recommendations on improving emergency operations plans and procedures in order to ensure the continuity of electric service.

Overview

The Commission initiated Project Number 51841, Review of 16 TAC §25.53 Relating to Electric Service Emergency Operations Plans, to conduct a formal rulemaking to enact the provisions of Senate Bill 3. The Commission adopted new 16 Texas Administrative Code (TAC) §25.53 on February 25, 2022. The new rule expanded upon the requirements of the Commission's preexisting EOP rule by requiring more entities such as municipally owned utilities to also file emergency operations plans (EOPs) and outlining the specific contents EOPs must contain. The rule also requires each entity to file its EOP in its entirety. Previously, entities were only required to file a summary. Finally, the new rule requires each of the applicable entities to participate in drills to test its plan and provide status updates at the request of Commission staff when the State Operations Center is activated.

The adopted rule applied to the following five entity types that generate power, deliver electricity, or bill customers:

- **Electric utilities (EU)** are defined in Tex. Util. Code §31.002(6) and include transmission and distribution infrastructure owners but exclude the other entities in this list that may own transmission or distribution infrastructure.

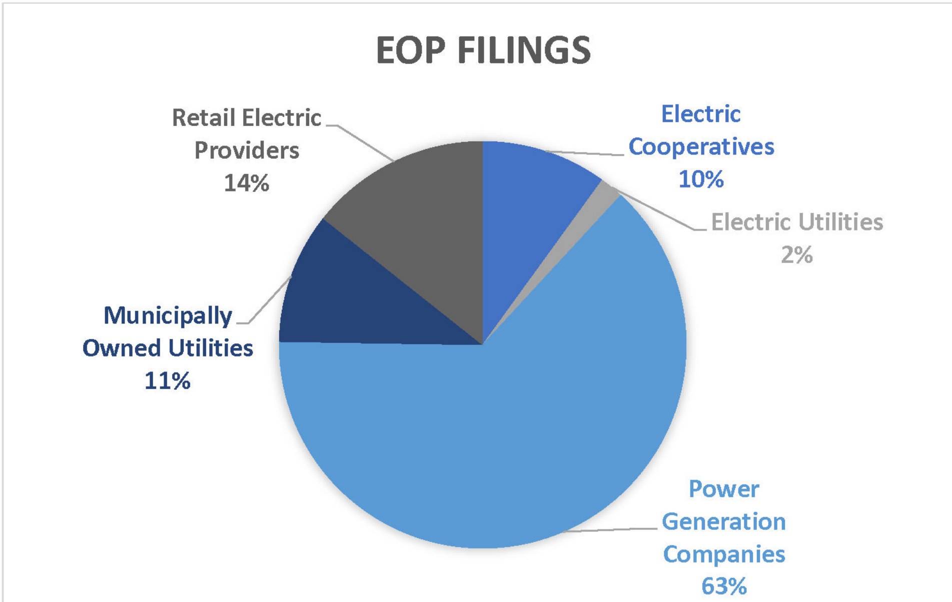
[1] Tex. Util. Code §186.007.

Electric utilities must prepare to ensure continuous delivery of electricity during an emergency event. Some electric utilities also generate electricity and must also prepare to ensure continuous generation of electricity during an emergency event.

- **Power generation companies (PGC)** are defined in Tex. Util. Code §31.002(10) and refer to certain owners of generation facilities that do not own transmission or distribution facilities or have a certificated service territory. These owners are excluded from the definition of an electric utility. Power generation companies must prepare to ensure continuous generation of electricity during an emergency event.
- **Municipally owned utilities (MOU)** are defined in Tex. Util. Code §11.003(11), and refer to utilities that are owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities. A municipally owned utility owns or operates equipment or facilities to transmit or distribute electricity and may also own or operate facilities to generate electricity. A MOU must prepare to ensure continuous delivery of electricity during an emergency event. Those MOUs that also own or operate facilities to generate electricity must also ensure continuous generation of electricity during an emergency event.
- **Electric cooperatives (EC)** are defined in Tex. Util. Code §11.003(9) and refer to corporations organized as electric cooperatives that own or operate equipment or facilities to transmit or distribute electricity. Electric cooperatives must prepare to ensure continuous delivery of electricity during an emergency event. Those ECs that also own or operate facilities to generate electricity must prepare to ensure continuous generation of electricity during an emergency event.
- **Retail electric providers (REP)** are defined in Tex. Util. Code §31.002(17) and refer to entities that sell electricity to retail customers and are prohibited from owning or operating generation assets. REPs prepare to keep their business running and their customers informed during an emergency event.

To analyze and review the emergency operations plans the Commission sought the expertise of a qualified contractor to perform a baseline assessment of the emergency operations plans to develop recommendations for improvements to the plans that can be incorporated in a future rulemaking initiative. Ascenttra, Inc. was selected and began work in April 2022. In total, Ascenttra reviewed and analyzed 691 EOPs filed with the Commission. They evaluated conformance with the requirements of 16 TAC §25.53. Ascenttra also considered additional criteria, identified as best practices within the emergency management community. Appendix 1 to this report is Ascenttra's analysis, exactly as submitted to the Commission without alterations. The analysis below is a summary of Ascenttra's analysis and does not represent the observations or conclusions of the Commission.

The pie chart below shows the 691 EOP filings by entity type.



Ascenttra's EOP review team observed several trends and outliers during the review process. As an example, the entities that filed the EOPs used a variety of plan formats. Many EOPs consisted of standalone documents developed for other purposes that were compiled together to form the plan. Ascenttra reported that this type of filing lacks an organized format and can present difficulty in locating information during an emergency. In contrast, the municipally owned utilities employed a systemized template. Most of the plans included both primary and secondary emergency contacts, as a good practice to ensure prompt responses in an emergency. These trends, in addition to others noted by the reviewers, helped identify strengths and gaps in electric industry best practices.

Methodology

To assess the EOPs, 53 separate criteria were identified from requirements in 16 TAC §25.53. These criteria were then grouped into seven measures[2]:

1. EOP filing
2. Executive summary
3. Record of distribution
4. Emergency contacts
5. Affidavit

[2] The seven measures are referred to as "headings" in Ascenttra's report attached in Appendix 1.

6. EOP required content
7. Required annexes

The EOPs were scored on both the fulfillment of the requirements (i.e., whether the required element was present) and the quality of supporting information provided (i.e., whether the information was clear, complete, and responsive to the requirement).

For each EOP, a score for each of the seven measures was calculated using a simple average of the scores for each criterion under a given measure. Each criterion received a score from zero (worst) to ten (best), with ten indicating the objective was fully achieved. A score for each entity group, by measure, was derived using a simple average of the scores achieved for that measure by all the entities in the group.

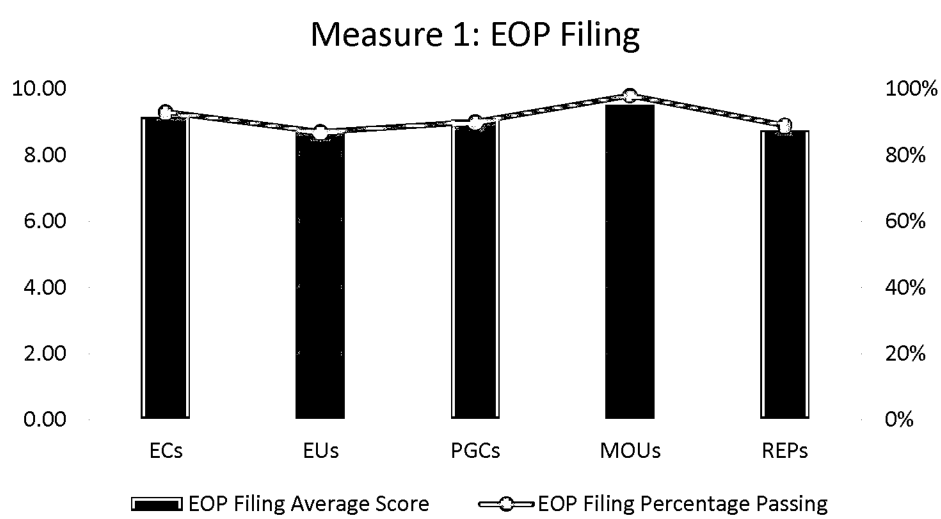
A score of seven or higher for each measure was considered “passing.” The percentage of entities that received a passing score for each measure was also calculated.

Measure #1 - EOP Filing

The criteria for this measure required an entity to:

- File a complete copy with the Commission with all confidential portions removed.
- File an unredacted EOP with ERCOT if operating within the ERCOT power region.
- Make an unredacted EOP available in its entirety to Commission staff, if requested, at a location designated by Commission staff.
- File an EOP annex for each facility that conspicuously identifies the facility to which it applies.
- Demonstrate continuous maintenance of an EOP.

With 91% of entities who filed an EOP receiving a passing score of seven or higher, this was the highest scoring measure. However, many EOPs did not contain a uniform format and were instead a compilation of standalone documents, making information difficult to locate efficiently during an actual emergency. Further, some EOPs were marked "confidential" or "for internal use only" which is contrary to the objective of coordinating with external stakeholders.

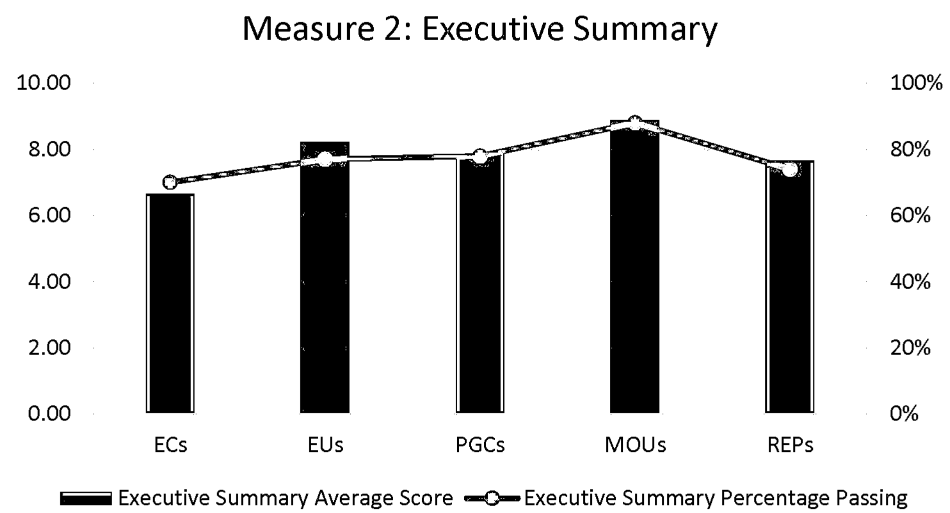


Measure #2 - Executive Summary

The criteria for this measure required the executive summary to:

- Describe the contents and policies contained in the EOP.
- Include a reference to specific sections and page numbers of the entity's EOP that correspond with the requirements of the rule.
- Contain the affidavit required under 16 TAC §25.53(c)(4)(C).

Overall, 78% of the EOPs met the criteria for an executive summary. The municipally owned utilities employed an EOP template with a specific section for the executive summary.

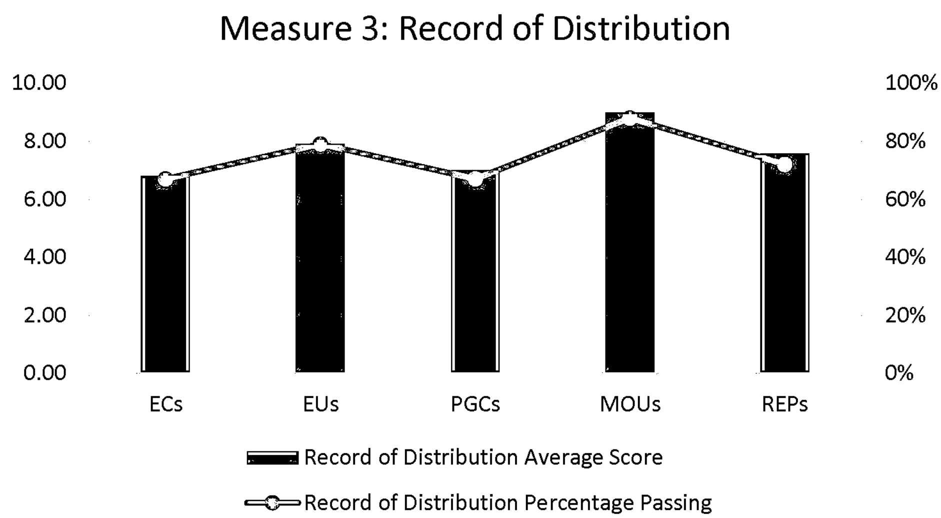


Measure # 3 - Record of Distribution

The criteria for this measure required the EOP to:

- Include a completed record of distribution required under 16 TAC §25.53(c)(4)(A).
- Contain, in table format, the titles and names of persons in the entity's organization receiving access to and training on the EOP.
- Contain dates of access to or training on the EOP.

It was difficult to evaluate the record of distribution because 16 TAC §25.53(c)(4)(A)(ii) provides flexibility whether to file the dates of access to the EOP or dates of training on the EOP.

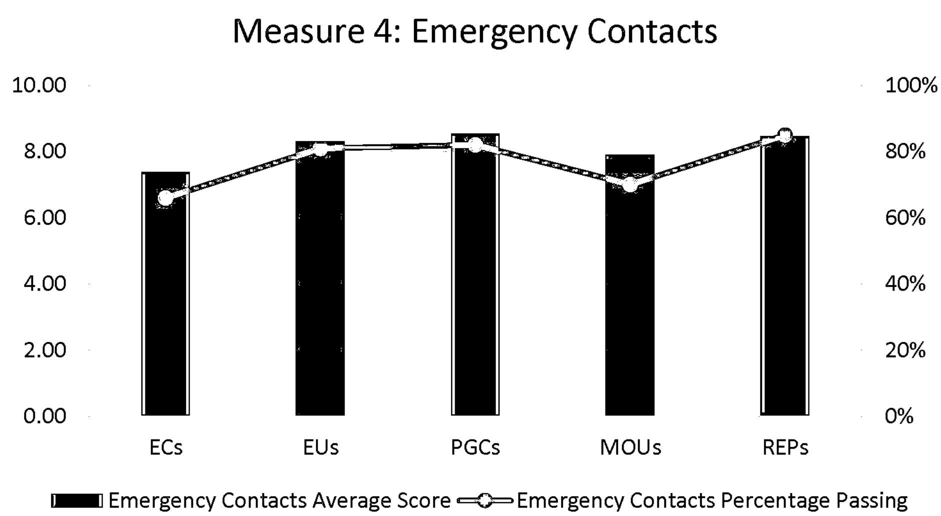


Measure #4 - Emergency Contacts

The criteria for this measure required the EOP to:

- List the primary contacts for the entity.
- List the secondary contacts for the entity.
- Identify specific individuals available immediately to address urgent requests and questions from the Commission during an emergency.

Overall, 80% of the EOPs met the criteria for emergency contacts. Most of the entities provided multiple emergency contacts. However, the information was located in the base plan which would render the plan outdated if there are personnel changes. The list of emergency contacts should be contained in a separate section so that it can be updated regularly to keep up with personnel changes.

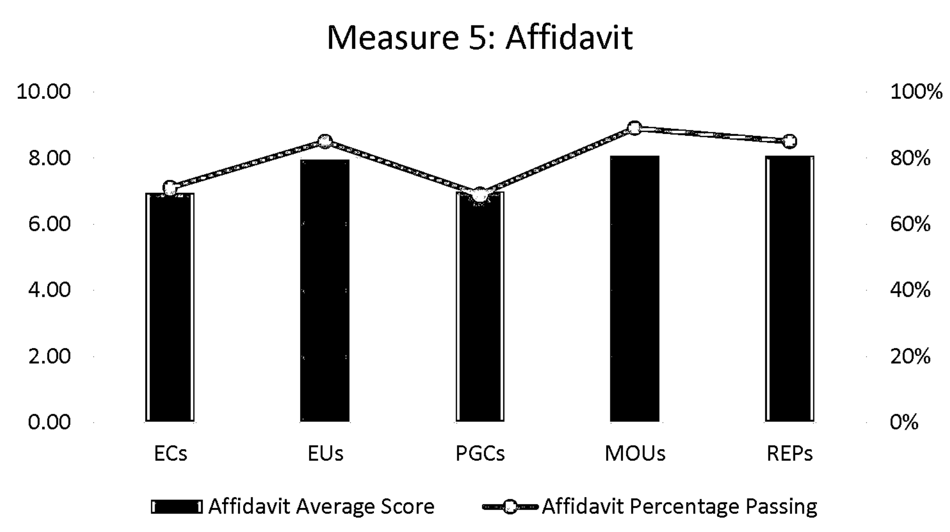


Measure #5 - Affidavit

The criteria for this measure required affidavits to affirm the following:

- Relevant operating personnel have received training on the applicable contacts and execution of the EOP, and such personnel are instructed to follow the applicable portions of the EOP, recognizing that deviation from the plan may be appropriate as a result of specific circumstances during an emergency.
- Appropriate executives have reviewed and approved the EOP.
- Drills have been conducted to the extent required by 16 TAC §25.53(f).
- The EOP or an appropriate summary has been distributed to local jurisdictions as needed.
- The entity maintains a business continuity plan addressing the return to normal operations after disruptions caused by an incident.
- The entity's emergency management personnel who are designated to interact with local, state, and federal emergency management officials during emergency events have received the IS-100, IS-200, IS-700 and IS-800 National Incident Management System training.

The language used in the affidavits often did not contain specific details related to the individual EOP. Some of the content affirmed in the affidavits was not found in the corresponding EOPs.

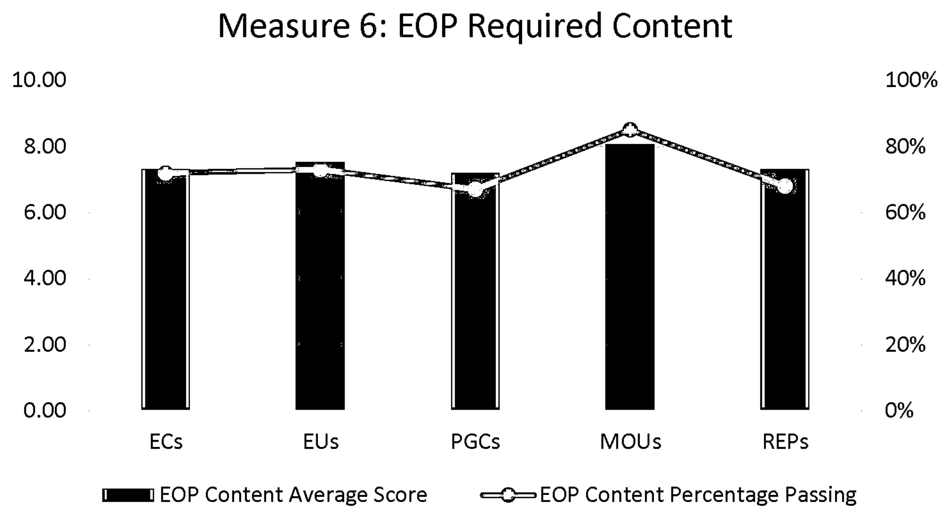


Measure #6 - EOP Required Content

The criteria for this measure requires the EOPs to contain specific items:

- An approval in the form of a signed statement formally recognizing and adopting the plan, how it will be implemented, and indicating that it supersedes all previous plans.
- An introduction.
- An outline of the applicability of the plan.
- A list of the individuals responsible for maintaining and implementing the EOP.
- A list of the individuals who can change the EOP.
- A revision control summary that lists the dates of each change made to the EOP since the initial EOP filing.
- The date the EOP was most recently approved by the entity.
- A communications plan.
- The procedures during an emergency the entity uses for handling complaints.
- Emergency procedures for communicating with the following prescribed groups:
    - the media;
    - customers;
    - fuel suppliers;
    - the Commission;
    - the Office of Public Utility Counsel (OPUC);
    - local and state governmental entities, officials, and emergency operations centers, as appropriate in the circumstances for the entity;
    - the reliability coordinator for its power region; and
    - critical load customers directly served by the entity.
- A plan to maintain pre-identified supplies for emergency response.
- A plan for adequate staffing during emergency response.
- A description of how an entity identifies and plans for weather-related hazards, including tornadoes, hurricanes, extreme cold weather, extreme hot weather, drought, and flooding.
- The process and procedures the entity follows to activate the EOP.

EOP required contents varied widely. Administrative requirements relating to revisions and approval were more readily followed. More information regarding operational processes and procedures relating to communication, ensuring adequate staffing, maintaining critical supplies, implementing procedures for weather emergencies, and activating the EOP is necessary to be better prepared for a weather emergency.


Measure 6: EOP Required Content
10.00
8.00
6.00
4.00
2.00
0.00
100%
80%
60%
40%
20%
0%
ECs
EUs
PGCs
MOUs
REPs
EOP Content Average Score
EOP Content Percentage Passing

Measure #7- Annexes

The criteria for this measure require specific annexes for each entity type. All entities are required to include annexes that address: a pandemic and an epidemic annex, a hurricane annex including evacuation and re-entry procedures if facilities are located within a hurricane evacuation zone, a cyber and physical security incidents annex, and any additional circumstances appropriate to the entity, in addition to those annexes. Further, these are the only annexes REPs are required to include in their EOPs.

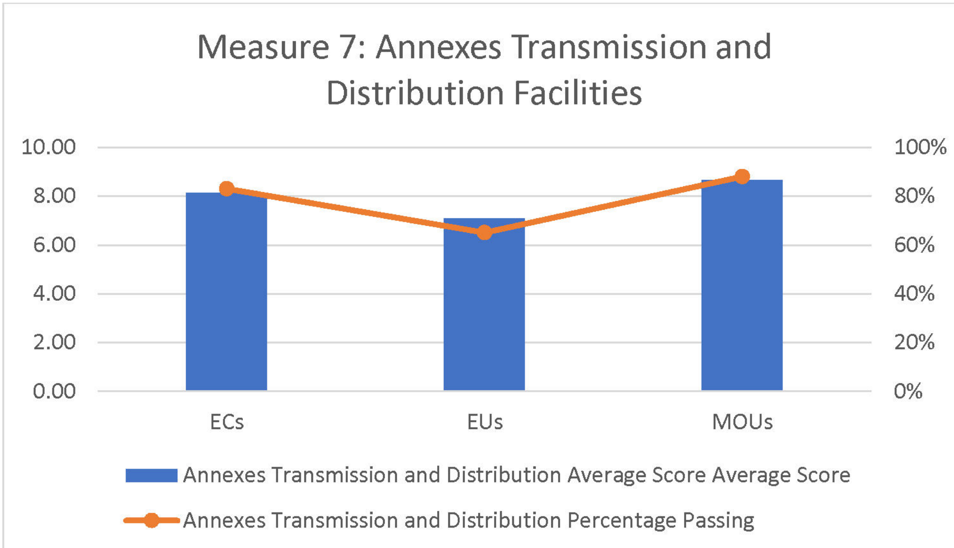
Entities with transmission or distribution facilities must also include:

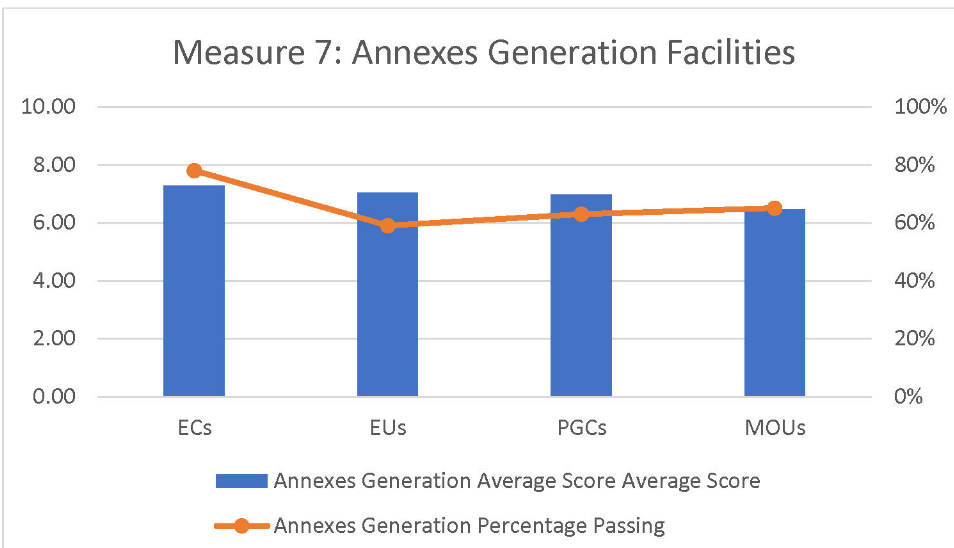
- A weather annex with operational plans for responding to cold or hot weather emergencies and a checklist for facility personnel to use during cold or hot weather emergency response. This annex must include checklists that reflect lessons learned from past weather emergencies to ensure necessary supplies and personnel are available.
- A load shed annex with procedures for controlled shedding of load and lists of priorities for restoring service to customers who were affected by load shedding. This annex must contain procedures for maintaining an accurate registry of critical load customers that is updated as necessary, but at least annually. This annex must also contain procedures addressing aiding critical load customers in the event of an unplanned outage; communicating with critical load customers during an emergency; coordinating with government and service agencies as necessary during an emergency; and training staff with respect to serving critical load customers.
- A wildfire annex.

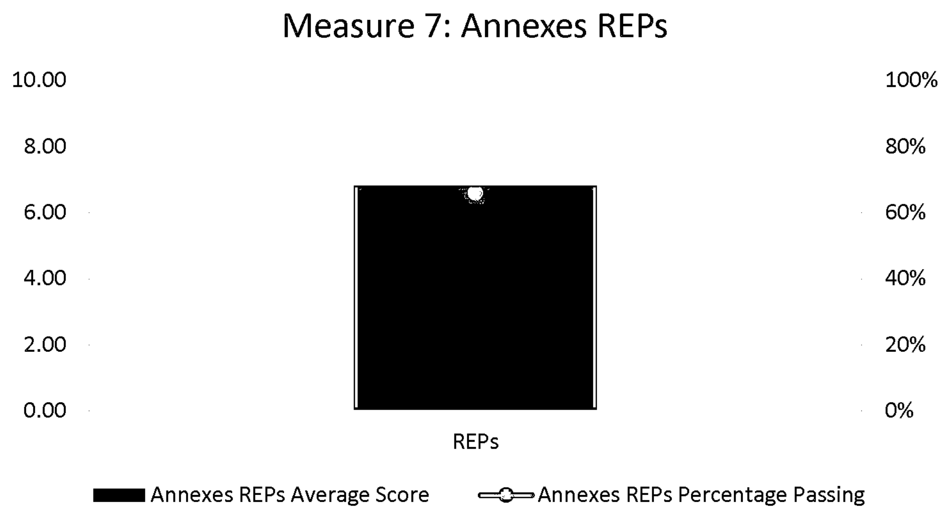
Entities with generation facilities must also include:

- A weather annex that meets all of the requirements of this annex produced by entities with transmission or distribution facilities and also includes a verification of the adequacy and operability of fuel switching equipment, if installed.
- A water shortage annex that addresses supply shortages of water used in the generation of electricity for generation facilities.
- A restoration of service annex that identifies plans and procedures to restore to service a generation resource that failed to start or that tripped offline due to a hazard or threat.

The required annexes and corresponding information varied based on entity type as required by 16 TAC §25.53 (e). However, many entities did not clearly list which annexes were applicable to them. So, for example, some entities did not indicate whether they were located in a hurricane evacuation zone, such that a hurricane annex would be required.






Measure 7: Annexes REPs
10.00
8.00
6.00
4.00
2.00
0.00
100%
80%
60%
40%
20%
0%
REPs
Annexes REPs Average Score
Annexes REPs Percentage Passing

Future Weather Considerations

The winter of 2022-2023 is predicted to be slightly colder than average. The coldest month is predicted to be January with an average low of 39°F and high of 57°F. This is because of the effect of La Niña which is expected to continue during the winter months of December 2022 through February 2023.

During a La Niña event, warmer than average sea surface temperatures in the Atlantic and Caribbean Seas as well as weaker tropical Atlantic trade winds predict an above-normal active Hurricane season. It is uncertain when the La Niña event will end, however, there is a 56% chance of transition to ENSO-neutral (a period when La Niña and El Niño patterns are not present) between February and April 2023.[3] According to the National Weather Service Climate Prediction Center, the seasonal temperature outlook during the summer of 2023 makes predictions for above normal temperatures.[4]

The assessment of EOP annexes for hot and cold weather emergencies and hurricanes provides an indication of the preparedness of entities considering the upcoming weather predictions. Overall, electric cooperatives and electric utilities have the highest passing rates for hurricane preparedness around 75%.[5] Electric cooperatives and power generation companies received the highest scores with respect to hot and cold weather preparedness for generation facilities. Municipally owned utilities demonstrated excellent weather emergency preparedness for transmission or distribution facilities with an overall passing rate of 88%.[6]

EOP Best Practices

To strengthen emergency response and grid resiliency, Ascenttra recommended the following best practices be considered for incorporation into EOPs. The Commission will review and consider these best practices for implementation within the bounds of its statutory authority, as appropriate.

- Equipment weather design limits should be defined to identify key factors that lead to an EOP activation. Many electric cooperatives are already doing this.
- Single points of failure for critical assets should be documented in the EOP to identify vulnerabilities and determine support systems and mitigation plans for continuity of service. Similarly, it is important to plan to ensure an uninterrupted supply chain during a weather emergency and to inventory,

[3] National Weather Service, Climate Prediction Center, El Niño/Southern Oscillation (ENSO) Diagnostic Discussion.

[4] National Weather Service, Climate Prediction Center, Seasonal Outlooks Official forecast Jun-Jul-Aug 2023.

[5] This figure was derived from Ascenttra's work papers not included in this report.

[6] This figure was derived from Ascenttra's work papers not included in this report.

maintain, and strategically deploy critical supplies in a weather emergency for efficient equipment maintenance. The identification of single points of failure and linked vulnerabilities presents an opportunity for improvement from entities with generation facilities.

- EOPs should include procedures for plant personnel to periodically test the use of backup or alternative fuel to become familiar with the process if necessary, during an EOP activation. Many power generation companies are currently implementing alternative fuel testing as documented in the EOP.
- EOPs should include a plan to maintain appropriate staffing levels and ensure all surge capacity staff are trained. Many entities address adequate staffing in the EOPs and procedures to train and deploy both internal and contracted surge staff.
- EOPs should include procedures for regular updates to an EOP, especially following an exercise or activation based on lessons learned. 16 TAC §25.53 includes basic requirements for corrective action processes. Nearly a third of entities incorporated more comprehensive continuous improvement planning.

EOP Improvement Recommendations

Ascenttra's EOP assessment identified areas of strength in the EOPs and opportunities for improvements that may be considered by the entities and the Commission. Ascenttra's recommendations include:

- Develop a template. An EOP should be crafted from a comprehensive template that includes a repository for all relevant information and contains internal cross references to streamline documents submitted. Ascenttra recommends use of a template as a best practice rather than a requirement. Each EOP must address every section. Any section that is not applicable should be clearly labeled with an explanation as to why it is not applicable.
- In addition to maintaining a record of internal distribution, require each EOP to maintain a record of external distribution to local emergency management authorities.
- Customize the EOP, as necessary. The EOP should contain information that is relevant and addresses the specific facility characteristics An EOP should clearly identify specific facility information including geographic characteristics, location and function, staffing, and equipment. geographic characteristics, location and function, staffing, and equipment.
    - All critical staffing positions (denoting hazard type, if appropriate) must be listed.
    - All critical supplies (denoting hazard-type, if appropriate) must be listed, specifying locations of supplies as well as primary and alternate vendors for obtaining additional supplies.

  - Weather design limits and single points of failure must be identified so that mitigation strategies and specific response measures can be developed.

- Adopt an all-hazards approach to emergency management. 16 TAC §25.53(d) requires an entity's EOP to address both common operational functions that are relevant across emergency types and annexes that outline the entity's response to specific types of emergencies. However, Ascenttra noted that not all entity's EOPs followed this approach. All-hazards is an emergency management best practice that emphasizes capacities and capabilities rather than scenarios or event types. This type of EOP has a base plan that focuses on processes common to all emergencies such as purpose, planning assumptions, responsibilities, plan maintenance, and authorities.
  - Annexes are used to respond to a specific emergency type and build upon the fundamentals established in the base plan. Planning for specific hazards and vulnerabilities such as weather events or other known threats should be done in annexes.
  - Appendices are used to document areas needing more specificity than the base plan, as well as confidential or perishable information (for example, contact information, training records, and event participation logs). Whenever possible, sensitive information should be located in these sections.
- Utilize checklists. Each EOP should contain checklists that are easily accessible when responding to an emergency to expedite and reliably replicate preparedness for weather events.
- Identify local coordination efforts. Each EOP should document how to coordinate with representatives at the local and regional levels. Specifically, the EOP should include how the entity will implement Incident Command System (ICS) in coordination with local emergency response.
- Require equivalent responsibilities for alternate emergency managers. Both primary and alternate emergency managers should be designated to attend meetings, participate in training and exercises, and coordinate with the emergency preparedness community.
- Specificity in affidavits. Affidavits should affirm specific EOP details rather than boilerplate language. Ambiguity should not be introduced into the affidavit (for example, "will be or has been" or "as needed" qualifiers should be eliminated).

Recommended Commission Actions

Ascenttra recommended the Commission consider the following actions:

- Amend 16 TAC §25.53 to standardize entities' EOPs and require or encourage use of the characteristics noted above.[7]
- Amend 16 TAC §25.53 to conform to Homeland Security Exercise and Evaluation Program (HSEEP) nomenclature. For example, current language uses "drills," which is one of seven different exercise types under HSEEP.
    - For entities located in a hurricane evacuation zone, a mandatory annual hurricane exercise and an exercise for another scenario should be required to ensure entities are prepared to respond to a variety of vulnerabilities.
- Collaborate with TDEM to develop a recommended curricula for emergency managers, facilitate planning workshops, and support entities in completing thorough EOPs.
    - Consider options to support entities in finding training opportunities on weather awareness and EOP development to incorporate into their EOP planning and development processes.
    - Develop processes for receiving and disseminating forecasts.
    - Provide training to personnel regarding how to identify changes in weather conditions.

[7] Tex. Util. Code § 186.007 provides the Commission with limited rulemaking authority to impose requirements on EOPs. Fully implementing Ascenttra's rulemaking recommendations may require additional statutory authority.

TEXAS UNIVERSAL SERVICE FUND REPORT

Public Utility Commission of Texas
August 31, 2022

Executive Summary

In 2017, the Legislature created a new rate of return methodology to determine the amount of support available to small telecommunications providers from the Texas Universal Service Fund (TUSF). This new methodology is found in Public Utility Regulatory Act (PURA)[1] § 56.032. The support amounts calculated under it are set to expire on September 1, 2023.

The Public Utility Commission of Texas (Commission) was directed to:

> *1. Review and evaluate whether the rate of return methodology under PURA § 56.032, and any rules adopted to implement that section, accomplish the purposes of the TUSF and allow small telecommunications providers the opportunity to earn a reasonable return; and*
>
> *2. Review and evaluate whether changes in law to amend or replace the rate of return mechanism are necessary to achieve such purposes.*[2]

Upon review and evaluation, the Commission concludes that:

The rate of return methodology under PURA § 56.032 accomplishes the purposes of the TUSF and allows small telecommunications providers the opportunity to earn a reasonable return. However, changes may be necessary to achieve these purposes more efficiently.

As part of the review, the Commission was directed to submit a report to the Legislature by September 1, 2022, addressing four specific issues and any other relevant information the Commission deemed necessary for inclusion.[3] This report addresses the Commission's evaluation of PURA § 56.032 and the following issues:[4]

1. The continued appropriateness of using the FCC prescribed rate of return for the mechanism established under PURA § 56.032(d) if the FCC still prescribes a rate of return that may be used for that mechanism;

The Commission concludes that it is appropriate to continue to use the Federal Communications Commission's (FCC's) prescribed rate of return.

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[1] Tex. Util. Code §§ 11.001–66.016.

[2] Act of May 16, 2017, 85th Leg., R.S., ch. 1116 (S.B. 586), §2(b), 2017 Tex. Gen. Laws at 4303.

[3] *Id.*, § 2(d), 2017 Tex. Gen. Laws at 4303.

[4] Act of May 16, 2017, 85th Leg., R.S., ch. 1116 (S.B. 586), §§ 1-3, 2017 Tex. Gen. Laws 4301.

2. The efficiency and frequency of adjustment proceedings conducted under PURA § 56.032(h) and § 56.032(i);

The adjustment proceedings conducted under PURA § 56.032(h) and (i) to ensure small providers are afforded the opportunity to earn a reasonable rate of return provide an efficient process to adjust support amounts and are conducted on a proper frequency.

3. The frequency and efficiency of determinations made on reasonable and necessary expenses under PURA § 56.032(d)(4);

The process for determinations under PURA § 56.032(d)(4) is efficient as it affords small providers the opportunity to earn a reasonable rate of return but is too frequent for Commission Staff to adequately determine the reasonableness and necessity of expenses incurred by small providers.

4. The effect of changes in technology on regulated revenue and support needs or determinations made under PURA § 56.032; and

Changes in technology have had an indirect effect on regulated revenue and support needs or determinations made under PURA § 56.032.

5. Any other relevant information the Commission determines is necessary for inclusion in the report and is in the public interest.

Other than administrative efficiency issues related to applying the different rate of return methodologies to small providers, there is no other relevant information the Commission determines to be necessary or in the public interest for inclusion in this report.

Background—History of the TUSF

The Texas Universal Service Fund (TUSF) was established in 1987.[5] The purpose of the TUSF is to implement a competitively neutral mechanism to enable all residents of the State to obtain basic local telecommunications services needed to communicate with other residents, businesses, and governmental entities.[6] The TUSF is funded by a statewide uniform charge, or "assessment," payable by each telecommunications provider that has access to the customer base.[7] In most cases, the providers choose to recover their assessment via a fee to end users

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[5] *See* Act of May 23, 1987, 70th Leg., R.S., ch. 371 (SB 444), § 8, 70th Legislature, 1987 Tex. Gen. Laws 1809, 1813; repealed by Act of March 29, 1995, 74th Leg., R.S., ch. 9 (SB 319), § 2, 1995 Texas Gen. Laws 31, 87.

[6] *See* 2013 *Commission Report to the 83rd Texas Legislature - Review and Evaluation of the Texas Universal Service Fund Pursuant to Senate Bill 980*, 82nd Legislature, Regular Session at 2 ("The TUSF accomplishes this purpose by assisting telecommunications providers in providing [basic local telecommunications service] at reasonable rates to customers in high-cost rural areas and to qualifying low-income and disabled customers. The TUSF also funds another program identified by the Legislature in PURA § 56.028, which supports certain telecommunications services for schools and libraries."); *Id.*

[7] *See* Tex. Util. Code § 56.022.

as part of the package of surcharges assessed on their bills.[8] Telecommunications providers then receive distribution of the funds based on a rate of return prescribed by the Commission.[9]

Texas Universal Service is composed of 11 programs separated into three major categories: high-cost assistance programs, low-income or disability assistance programs, and schools and libraries assistance programs. Of the 11 programs, expenses for the High-Cost Support program and Small and Rural Incumbent Local Exchange Carrier program (Small and Rural Plan) comprise the greatest proportion, ranging between 60 to 90 percent of total expenditures from the fund. This report focuses solely on the rate of return mechanism for providers under the Small and Rural Plan.

In 1997, the Federal Communications Commission (FCC) established the federal Universal Service Fund (USF)[10] following the directives of the 1996 Telecommunications Act (FTA).[11] Under the FTA, state regulations regarding universal service must not be inconsistent with FCC rules "to preserve and advance universal service".[12]

In 2011, the FCC comprehensively reformed the USF and Intercarrier Compensation (ICC)[13] through the issuance of the USF/ICC Transformation Order (Transformation Order).[14] The same year, the Texas Legislature passed Senate Bill (SB) 2603, 82nd Regular Session, which codified a new rate of return methodology under PURA § 56.032. SB 2603, in accordance with the Transformation Order, required the Commission to consider the adequacy of basic rates to support universal services and authorized the Commission to revise monthly support amounts from the Small and Rural Plan.[15]

TUSF Support for Small Telecommunications Providers under PURA § 56.032

PURA § 56.032 – Rate of Return Adjustments

In 2017, the Legislature again changed the rate of return method that determines the amount of support to providers from the Small and Rural Plan.[16] This new method, found in PURA § 56.032, is the current methodology and the subject of this report and is set to expire on

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[8] *See* 2013 *Commission Report to the 83rd Texas Legislature - Review and Evaluation of the Texas Universal Service Fund Pursuant to Senate Bill 980*, 82nd Legislature, Regular Session at 2.

[9] *See* PURA § 56.023(a)(1); *see also* 16 TAC §§ 26.406 and 26.407.

[10] *See generally* FCC 97-157.

[11] *See generally* 47 U.S.C. 254.

[12] 47 U.S.C. 254(f).

[13] *Intercarrier Compensation*, FEDERAL COMMUNICATIONS COMMISSION, https://www.fcc.gov/general/intercarrier-compensation-0 (last accessed August 26, 2022). ("Intercarrier compensation (ICC) is the system of regulated payments in which carriers compensate each other for the origination, transport and termination of telecommunications traffic.").

[14] *See* FCC 11-161.

[15] 16 Tex. Admin. Code § 26.407.

[16] 16 Tex. Admin. Code § 26.407.

September 1, 2023. The Legislature directed the Commission to review this mechanism and related rules prior to expiration.

Under the current methodology, a qualifying *small provider*[17] may request that the Commission determine support in fixed monthly amounts based on an annualized support amount. The annualized support amount must be sufficient, when combined with regulated revenues, to allow the small provider to earn a return on invested capital that is reasonable.[18] As required in the legislation, the Commission adopted new 16 Texas Administrative Code (TAC) § 26.407 in October 2018 to implement a mechanism to determine the annualized support amount. The mechanism was required to have the following elements:

- Require an annual filing to establish a continued level of support for the provider or eligibility for support adjustments and to determine whether support levels allow the opportunity to earn a reasonable return;
- Provide requirements for the annual filing, which may include annual earnings reports and any underlying data that the Commission determines to be reasonably necessary for the purposes of Subdivision (1);
- Provide requirements and procedures for adjustment proceedings to ensure small providers are afforded the opportunity to earn a reasonable return; and
- Provide a procedure for the Commission to assess, as necessary, whether the reported return of a small provider is based on expenses that are not reasonable and necessary.

To assist the Commission in its review and preparation of this report, the Commission requested public comment. [19] Notice of the request was provided in the Texas Register.[20] The Commission received comments from Dialtone Services, L.P., AMA Techtel Communications, the Texas Cable Association, the Office of Public Utility Counsel, the Texas Telephone Association, Texas Statewide Telephone Cooperative, Inc., and CTIA-The Wireless Association.

Issue 1 – FCC Rate of Return

The continued appropriateness of using the FCC's prescribed rate of return for the mechanism established under PURA § 56.032(d), if the FCC still prescribes a rate of return that may be used for that mechanism.

The Commission concludes that it is appropriate to continue to use the Federal Communications Commission's (FCC's) prescribed rate of return.

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[17] PURA § 56.032(a)(2) (*Small provider* defined as "an incumbent local exchange company or cooperative that, on September 1, 2013, together with all local exchange companies affiliated with the company or cooperative on that date, served 31,000 or fewer access lines in Texas; or a successor company.").

[18] PURA § 56.032(c).

[19] *Review of Texas Universal Service Fund*, Project No. 53140.

[20] 47 *Texas Register* 1649 (Mar. 25, 2022).

The FCC's rate of return is used to determine whether a small provider's return is reasonable,[21] and to separate a small provider into one of three categories under the Commission's rule as described below. As of August 2022, the FCC prescribed rate of return was set at 9.75%.

Category 1	A rate of return of more than ***three percentage points below*** the FCC rate of return.[22]
Category 2	A rate of return ***within two percentage points above or three percentage points below*** the FCC rate of return.[23]
Category 3	A rate of return of more than ***two percentage points above*** the FCC rate of return.[24]

Review of the 2020 reports filed in September 2021 by the 43 small providers receiving proceeds from the Small and Rural Plan resulted in Commission staff recommending:

- 32 small providers for placement in Category 1 (under-earning providers);
- 8 small providers for placement in Category 2 (providers receiving a reasonable rate of return); and
- 3 small providers for placement in Category 3 (over-earning providers).

Discussion

Removing the requirement to use the FCC rate of return would not provide any benefit to the adjustment mechanism. If the FCC rate of return is not used, a new rate of return methodology would have to be devised by the Commission. This would require the Commission to research and investigate alternative rate of return methodologies, adopt a new methodology, and subsequently implement that new methodology for all affected companies. Such an effort would take a substantial amount of time and resources for uncertain benefit. Moreover, in the interim period prior to implementation of the new methodology, the FCC rate of return would have to be utilized.

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[21] PURA § 56.032(f); 16 TAC § 26.407(f)(3).

[22] A small provider whose return is more than three percentage points below the FCC's rate of return is classified as category 1 and may file an application to adjust its support or rates to a level that would bring the small provider's return into the reasonable range. *See* PURA § 56.032(h); 16 TAC § 26.407(f)(3), (g)(1).

[23] A small provider is classified as category 2 and the return is deemed reasonable if the return is within two percentage points above or three percentage points below the FCC's rate of return. A small provider placed into category 2 is not eligible to seek an adjustment to its support from the Small and Rural Plan and the Commission cannot institute a proceeding against it. *See* PURA § 56.032(f); 16 TAC § 26.407(f)(3), (g)(2).

[24] A small provider whose return is more than two percentage points above the FCC's rate of return is classified as category 3. Although they are not presumed to have an unreasonable return, the Commission may initiate a proceeding to review the small provider's support level and regulated revenues and adjust the provider's level of support or rates, if appropriate. *See* PURA § 56.032(i); *see also* 16 TAC § 26.407(h)(2)(C).

Issue 2 – Adjustment Proceedings

The efficiency and frequency of adjustment proceedings conducted under PURA § 56.032(h) and § 56.032(i).

The adjustment proceedings conducted under PURA § 56.032(h) and (i), to ensure small providers are afforded the opportunity to earn a reasonable rate of return, provide an efficient process to adjust support amounts and are conducted on a proper frequency.

The rate of return mechanism created by PURA § 56.032 requires two types of rate adjustment proceedings: one for small providers whose rate of return is below a low threshold and one for providers whose rate of return is above a high threshold. Under the first type, termed category 1, a small provider may seek an adjustment to its support from the Small and Rural Plan or an increase in its regulated rates. For category 3 providers, which have a rate of return above the high threshold, the Commission may review and, if necessary, reduce the provider's rate of return. In addition, under the Commission's rule, some providers may challenge a Commission staff adjusted rate of return and the underlying adjustments.

A small provider classified as a category 1 may apply to increase support such that the small provider would earn a reasonable rate of return. The increase is capped at 140% of the provider's earnings over the 12-month period prior to the application.[25] A rate increase must not adversely affect universal service.[26] Except for good cause, a small provider that files an application for adjustment may not file a subsequent application before the third anniversary of the original application.[27]

If a small provider is classified as a category 3, the Commission may initiate a proceeding to review and potentially adjust the support and revenues of the provider.[28] The rate of return for such a provider is not unreasonable simply because it exceeds the high threshold.

As discussed under Issue 3 below, prior to an adjustment proceeding, Commission staff review a small provider's annual report and may recommend adjustments to the rate of return based on the financial and other information in that report.[29] After that review, Commission staff separated small providers into rate of return categories.[30] If Commission staff make any adjustments to that information, it will calculate an adjusted rate of return,[31] which may place the provider in a different rate of return category. In certain instances, a provider may contest the adjusted rate.

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[25] PURA § 56.032(h); 16 TAC § 26.407(h)(4).

[26] PURA § 56.032(h).

[27] PURA § 56.032(h).

[28] PURA § 56.032(i).

[29] 16 TAC § 26.407(f)(2)(A).

[30] *See* 16 TAC § 26.407(f)(3)(A)–(C).

[31] 16 TAC § 26.407(f)(2)(B).

If a provider files an application for an adjustment proceeding, it must give notice to its customers.[32] The Commission must grant or deny an application for an adjustment (including a challenge to a Commission staff adjusted rate of return) within 120 days of the date the application is deemed sufficient.[33] After the Commission issues an order in an adjustment proceeding, a subsequent adjustment proceeding may not be initiated before the third anniversary of the date on which the provider's most recent application is initiated, unless good cause is proven.[34]

Original rate of return classification	Commission staff adjusted rate of return classification	May request for an adjustment to rate of return	May contest Commission staff adjusted rate of return
Category 1	Category 2 or 3	Yes	Yes
Category 2	Category 3	No	Yes
Category 3	n/a	No	No

Discussion

According to data gathered by the Commission for the 2020-2021 period, 43 small providers participated in the Small and Rural Plan. Of that number, ten small providers are eligible for adjustment proceedings in 2022.

The adjustment proceedings conducted under the Commission's rule are administratively efficient for the Commission. The reviews are a straightforward matter of verifying the provider's reported or adjusted rate of return (associated placement into category) and assessing the application using basic accounting principles. Similarly, the three-year waiting period between adjustment proceedings permits sufficient time for Commission Staff to evaluate whether an adjustment proceeding is necessary. The three-year waiting period also assists the Commission in using its limited resources more efficiently than would be the case with a shorter waiting period.

Issue 3 – Determinations of Expenses

The frequency and efficiency of determinations made on reasonable and necessary expenses under PURA § 56.032(d)(4).

The process for determinations under PURA § 56.032(d)(4) is efficient as it affords small providers the opportunity to earn a reasonable rate of return but is too frequent for Commission Staff to adequately determine the reasonableness and necessity of expenses incurred by small providers.

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[32] 16 TAC § 26.407(h)(3).

[33] 16 TAC § 26.407(h)(5).

[34] 16 TAC § 26.407(h)(6).

A small provider is required to submit an annual report to the Commission that includes certain financial information as well as the small provider's full and complete cost allocation manual.[35] Commission staff review the annual report and recommends adjustments to a provider's rate of return if expenses are not reasonable or necessary, if there are inappropriate affiliate transactions or cost allocation, or for other reasons specified in the rule.[36] If Commission staff make any adjustments, it must recalculate the provider's reported rate of return and provide an adjusted rate of return as discussed above.[37]

The annual report is due to the Commission by September 15 of each year for the previous calendar year.[38] Commission staff must complete the review of an annual report within 90 days of the date the annual report was filed.[39] During the 90-day period, Commission staff may send Requests for Information (RFIs) to small providers with a ten-day deadline to respond. If the provider does not timely submit requested information, it is deemed to be a category 3 provider.[40]

At the conclusion of its review, Commission staff must make a final recommendation on the small provider's rate of return and placement into a rate of return category.[41] Commission staff will classify a small provider into one of three rate of return categories discussed in Issue 1. A provider's annual report and any information the Commission requires from a small provider is confidential and not subject to disclosure under chapter 552 of the Texas Government Code.[42] Third party access to such confidential information is subject to a protective order.

Discussion

The annual report and corresponding assessment of reasonable and necessary expenses require substantial engagement from Commission staff to obtain needed information. Specifically, the assessment of reasonable and necessary expenses entails the issuance of RFIs to small providers to determine whether a given provider should receive proceeds from the TUSF, and if so, how much. While adjustment proceedings are not administratively burdensome as discussed in the response to Issue 2, the reasonable and necessary expense assessment is considerably more onerous for Commission staff and more closely resembles a contested case than a rate disclosure of information.

Commission staff file approximately 20 to 35 RFIs per small provider within the 90-day period which historically can take weeks to prepare and to analyze responses. For 2020-2021, 43 small providers receive TUSF proceeds under the Small and Rural Plan, meaning that 43 separate reviews for reasonable and necessary expenses are required. The significant amount of discovery needed to make the recommendation is burdensome on Commission staff,

[35] 16 TAC § 24.407(e).

[36] 16 TAC § 26.407(f)(2).

[37] 16 TAC § 26.407(f)(2)(B).

[38] 16 TAC § 24.407(e)(1).

[39] 16 TAC § 26.407(f)(1)(B).

[40] 16 TAC § 26.407(f)(1)(A).

[41] 16 TAC § 26.407(f)(4).

[42] PURA § 56.032(k).

particularly given the 90-day review period. Additionally, most providers file their annual reports on or just before the annual September 15 deadline, resulting in a substantial number of reports that must be reviewed concurrently.

For comparison, electric utilities submit an annual earnings report with no specific action needed from Commission staff. Rather, Commission staff simply monitor the earnings levels of utilities with the option to engage in a more detailed analysis and potentially recommend a company file an application for a new rate proceeding.[43]

A three-year, staggered report period would be more *administratively* efficient. As a point of comparison, the largest electric companies that the Commission regulates must apply for a rate review every ***four*** years. The smallest electric companies must provide some form of a rate filing every ***eight*** years.[44]

While the small provider annual report reviews are not rate cases, they serve as a proxy for a rate case. Thus, reviews staggered in three-year intervals would be appropriate. Furthermore, reducing the number of reviews required each year would allow the Commission to review providers more thoroughly within the 90-day deadline.

Procedurally, PURA § 56.032(d)(4) requires the Commission to "assess, as necessary" whether a small provider's rate of return is based on reasonable and necessary expenses. This assessment results in Commission staff recommending a small provider be categorized as a Category 1, 2, or 3 provider as discussed in Issue 1. Although it is permitted do so do, to date, the Commission has not initiated a contested case proceeding for a Category 3 provider for the reasons explained below.

Books and Records Access and Prudence Review

Commission staff do not have access to the full books and records of small providers. Only the ***intrastate*** portion of a provider's financial information is provided to the Commission. The ***interstate*** financial information is unavailable, making it impossible to perform a comprehensive review of the provider's books and records. Similarly, Commission staff cannot perform a prudence review of a provider's intrastate capital additions, which is a study of the underlying costs of capital improvements implemented by the small provider during the reporting period, without corresponding interstate information. It is difficult for Commission staff to determine whether the allocated portion of certain costs is reasonable and necessary

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[43] *See generally Year-end 2020 Electric Utility Earnings Reports in Accordance with 16 TAC § 25.73*, Project No. 51718, Memorandum (Nov. 10, 2021) (Electric Earnings Reports); and *Year-end 2020 Telephone Utility Earnings Reports in Accordance with 16 TAC § 26.73*, Project No. 51719 (Telecommunications Earnings Reports).

[44] *See generally Rulemaking proceeding to amend 16 TAC 25.247 to establish a filing schedule for non-investor-owned transmission service providers operating within ERCOT,* Project 48377, Order Adopting Amendment to §25.247 (November 9, 2018).

without seeing the total costs and mechanics of the allocation.[45] For the same reason, the Commission staff do not perform prudence reviews of capital costs of small providers.

Cost-effectiveness of Small ILEC Base Rate Proceedings

In most cases, conducting a full base rate review of a small provider would not be cost effective because the cost of the rate case would likely exceed any rate reduction. Moreover, given limited resources, it is not feasible for Commission staff to conduct full rate reviews of small providers. The time and cost of these proceedings would not only burden the resources of the companies and the Commission, there would be a net loss for customers. [46]

Commission Resources

Commission staff, particularly in the Rate Regulation and Legal Divisions, dedicate a significant portion of their time to electric utility base-rate proceedings and other contested cases. The limitations of interstate cost review and confidentiality, coupled with the likelihood that ratepayers' costs for a full base-rate proceeding could outweigh any cost savings, call into question the value of the considerable time resources that Commission staff must dedicate to the annual reviews.

Issue 4 – Changes in Technology

The effect of changes in technology on regulated revenue and support needs or determinations made under PURA § 56.032

Changes in technology have had an indirect effect on regulated revenue and support needs or determinations made under PURA § 56.032.

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[45] *See e.g.*, *Review of Telecommunications Providers Receiving Texas Universal Service Fund Support Under the Texas High Cost Universal Service Plan and Small and Rural Incumbent Local Exchange Company Universal Service Plan*, Project No. 51433, Eastex Telephone Cooperative, Inc.'s Response to Commission Staff's First Set of Requests for Information at 8-10 (Dec. 3, 2020). The responses to Commission staff's RFIs indicate that the company-specific cost allocation manuals and Part 36 cost separations study are the definitive authorities on compliance with applicable accounting and regulatory rules. *See* Project 51433, Item #26 at 8-10. Cost allocation procedures, which are documented in cost allocation manuals, are required by FCC rules and have been in place since at least the 1980s. Companies devote great time and expense to developing specific cost allocation procedures and associated cost allocation manuals to ensure compliance. Cost allocation manuals are subject to audit by the Universal Service Administrative Company and National Exchange Carrier Association and are reviewed annually by the Commission.

[46] Additionally, written testimony issued by Commission staff in support of settlements typically states "[Commission staff] believe[s] that implementation of the various terms in the Stipulation will result in a fair and reasonable outcome for [the utility] and other stakeholders. The Stipulation provides certainty on the resolution of a variety of issues, and it ensures an outcome that, in the aggregate, is at least equal to—and, in some instances, possibly better than—the outcome that would result from continued litigation of this proceeding."

Discussion

The transition from traditional landline telephone to internet and mobile wireless data has indirectly impacted the rate of return methodology. This impact is due to continuing investments in infrastructure and equipment that is not needed to provide "basic local telecommunications service", but which small providers have invested in to provide internet and mobile wireless service. The scope of Commission Staff's review of a small provider's annual report does not allow for a determination of the prudency, reasonableness, or necessity of disclosed investments. Therefore, Commission Staff cannot draw any conclusions on whether expenses on such investments were reasonable and necessary, which, in turn, subverts a meaningful review on the reasonableness of the rate of return on those investments.

Issue 5 – Other Relevant Information

Any other relevant information the Commission determines is necessary for inclusion and is in the public interest.

Other than administrative efficiency issues related to applying the different rate of return methodologies to small providers, there is no other relevant information the Commission determines to be necessary or in the public interest for inclusion in this report.

APPENDIX

Funding Prior to Adoption of PURA § 56.032

1987: TUSF established.

1997: FUSF established.

1997-1998: The Commission establishes the Small and Rural Plan as part of the TUSF. Support amounts are based on wire line count based on the study area of each small and rural ILEC.

2005: The Commission is authorized to revise the monthly per-line support amounts for the High Cost and Small and Rural Plan.

2011: The FCC reforms FUSF and the Commission adds two alternative methodologies for ILEC providers participating in the High Cost and Small and Rural Plan:

- The 2010 methodology: TUSF support adjusted to fixed monthly amounts based on total support received by the provider in 2010.
- The CPI methodology: TUSF support changed to a fixed monthly amount based on total support received by the provider in the prior year adjusted by the percentage change in the CPI for the most recent 12-month period.

2011: The Commission adopts amendments to its rule for the Small and Rural Plan to determine whether an ILEC was charging a reasonable rate for basic local telecommunications service.

2013: PURA § 56.032 is amended by the Legislature allowing the Commission to adjust monthly support amounts by any method, including support reductions from rate rebalancing efforts by the Commission in 2011.

2017: PURA § 56.032 is amended again to adjust monthly support amounts based on the FCC prescribed rate of return used for the FUSF.

2022 Report to the Lieutenant Governor and the Speaker of the House of Representatives

Texas No-Call List

Public Utility Commission of Texas

TABLE OF CONTENTS

I. INTRODUCTION

In 2001, the 77th Legislature created the Texas No-Call List by adoption of the Texas Telemarketing Disclosure and Privacy Act (Act). The Act required the Public Utility Commission of Texas (Commission) to "provide for the operation of a database to compile a list of names, addresses, and telephone numbers of consumers in this state who object to receiving unsolicited telemarketing or telephone calls."[1] The Act applies on a statewide basis to all telemarketers operating in Texas.

This report is filed pursuant to § 304.201 of the Texas Business and Commerce Code, which requires the Commission to provide a report to the lieutenant governor and speaker of the house of representatives on the Texas No-Call List on or before December 31 of each even-numbered year to report the following information for the two-year period ending on August 31 of that year:

1) a statement of the number of telephone numbers included on the Texas No-Call List, the number of lists distributed to telemarketers, and the amount collected from telemarketers for those requests and for distribution;
2) a list of complaints received by the Commission concerning activities regulated by this chapter[2] itemized by type;
3) a summary of any enforcement efforts made by the Commission; and
4) the Commission's recommendations for any changes in the enabling legislation.

The reporting period for this report is from September 1, 2020 through August 31, 2022.

II. OVERVIEW OF TEXAS NO-CALL LIST REQUIREMENTS

The Texas No-Call List applies to all telemarketers, including Retail Electric Providers, calling a Texas residential or wireless number. The Texas No-Call List must contain telephone numbers of each consumer who has registered for the list. Wireless phone numbers became eligible to be added to the No-Call List on September 1, 2003. The Texas No-Call List is updated and republished on January 1, April 1, July 1, and October 1 of each year.

Since September 24, 2004, online registration for the Texas No-Call List has been free. Consumers registering by phone or by mail must pay a registration fee of $2.25 for each residential or wireless phone number added to the list. Texas businesses can register for the Electric No-Call List at a cost of $2.55. Registered phone numbers remain on the list for three years. Consumers who provide an email address when they register for the Texas No-Call list are notified when their registration is about to expire. Registration for phone numbers may be

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1 Tex. Bus. & Com. Code Ann. § 304.051 (West 2009 & Supp. 2014).

2 The activities regulated under Chapter 304 of the Texas Business and Commerce Code are: 1) no call complaints, 2) facsimile solicitation complaints, and 3) complaints concerning interference with Caller Identification service.

renewed for successive three-year periods. A consumer may request deletion of his or her telephone number from the list in writing at any time.

The 79th Legislature enacted House Bill 210, which affected the Texas No-Call List in several ways. HB 210 re-defined the Texas No-Call List to include the names and telephone numbers of all consumers who have registered for the Texas No-Call List as well as the names and telephone numbers of all Texas consumers who have registered for the National Do Not Call Registry. This amendment enables the Commission to pursue enforcement under state law on behalf of any Texas resident that is improperly solicited regardless of whether the Texas resident had initially registered on the Texas No-Call List or the National Do Not Call Registry. HB 210 also allowed the Commission or its designee to share information on the Texas No-Call List with the administrator of the National Do Not Call Registry and permitted the names and telephone numbers on the Texas No-Call List to be placed on the National Do Not Call Registry. Finally, HB 210 codified free Internet registration for the Texas Do Not Call List, excepted from public disclosure under the Texas Public Information Act any information provided to or received from the administrator of the National Do Not Call Registry and amended Public Utility Regulatory Act § 39.1025 to reflect that the Electric No-Call List would apply only to nonresidential customers.

By statute,[3] the Texas No-Call List restrictions do not apply to telemarketers contacting consumers:

- with whom they have an established business relationship;
- if the consumer requests the contact;
- if the call is between a telemarketer and a business, other than by a facsimile solicitation, unless the business informed the telemarketer that the business does not wish to receive telemarketing calls from the telemarketer;
- to collect a debt;
- on behalf of a non-profit organization or charity, provided the call does not meet the definition of a "telephone solicitation" by attempting to make a sale or gather information that will lead to a sale; or
- if the telemarketer is a state licensee (*i.e.*, insurance or real estate agent, etc.) and:
  - the call is not made by an automated dialing device;
  - the solicited transaction is completed with a face-to-face presentation to finalize a sales transaction and make payment; and
  - the consumer has not previously told the licensee that the consumer does not wish to be called.

[3] Tex. Bus. & Com. Code Ann. § 304.004 (2-5) (West 2009 & Supp. 2014).

III. NUMBER OF PHONE NUMBERS REGISTERED, NUMBER OF LISTS DISTRIBUTED, AND AMOUNTS COLLECTED

A. Phone Numbers Registered on No-Call List

From September 1, 2020 through August 31, 2022, there were 116,847 telephone numbers submitted to the Texas No-Call.

B. Distribution

Pursuant to P.U.C. SUBST. R. 26.37, telemarketers are required to purchase the Texas No-Call List. During the reporting period, 512 No-Call Lists were purchased by telemarketers.

The Texas No-Call List is updated on a quarterly basis. Telemarketers that subscribe to the list have 60 days from the date the list is revised to update their internal databases and to stop calling customers who have registered in the database.

C. Amounts Collected

The Commission was not appropriated funds to operate the Texas No-Call List and, therefore, relies on consumer fees and distribution fees to operate the registry. State law allows the Commission to charge a reasonable amount not to exceed $3, for a request to place a telephone number on the list or to renew an entry on the list. During the reporting period the registration fee was $2.25 per registered residential or wireless telephone number. Texas businesses can register for the Electric No-Call list at a cost of $2.55. Since September 24, 2004, online registration for the Texas No-Call List has been free. In addition, the Commission may charge a fee, not to exceed $75, to distribute the Texas No-Call List to telemarketers. During the reporting period, a quarterly fee of $75 applied to telemarketers requesting the current version of the published Texas No-Call List. Telemarketers may also choose to receive a geographically customized list from the Texas No-Call List database for a charge of $75 per quarter. All fees collected for registration and distribution of the Texas No-Call List go directly to the database administrator to cover the costs associated with operating the list.

- **Total Amount Collected from Telemarketers** **$271,350.00**

IV. COMPLAINTS

A. Texas No-Call Complaints

Consumers may file complaints for violations of the Texas No-Call List with the Customer Protection Division (CPD) of the Commission. Consumers may file complaints by phone, fax, mail, or email, or through a complaint form available online at http://www.puc.texas.gov/consumer/complaint/complaint.aspx. Consumers can also file complaints with the Office of the Attorney General of the State of Texas (OAG).

Typically, if the Commission receives a complaint via telephone, Commission Staff asks questions to elicit the necessary company contact information. However, in some instances, complainants were unable to provide sufficient information because, for example, they did not answer the call or failed to remember the specifics of their conversation with the telemarketer. No further action was taken on complaints with insufficient company contact information.

From September 1, 2020 through August 31, 2022, the Commission received 4,031 consumer complaints related to the Texas No-Call List. The Commission received 19% fewer complaints than were received over the previous reporting period of FY 2018-2020.

B. Facsimile solicitation complaints

During the reporting period the Commission received 3 consumer complaints regarding facsimile (fax) solicitations. All of the fax solicitation complaints were referred to the OAG.

C. Interference with caller ID service complaints

During the reporting period, the Commission received 549 complaints concerning interference with Caller ID service. Pursuant to Tex. Bus. & Comm. Code Ann. § 304.151, telemarketers may not block the identity of the telephone number from which the telephone call is made to evade devices designed to identify telephone callers.

V. ENFORCEMENT

Chapter 304 of the Business and Commerce Code authorizes the Commission to investigate companies and assess administrative penalties for violations of that chapter except those involving licensees of other state agencies.[4] Additionally, Chapter 304 authorizes the Office of the Attorney General (OAG) to investigate complaints and file civil enforcement actions seeking injunctive relief, attorneys' fees and civil penalties for violations involving all entities except state licensees and telecommunications providers.[5]

Potential telemarketing violations under Chapter 304 of the Business and Commerce Code include Texas No-Call List violations, facsimile solicitation violations, and interference with caller ID service violations.

4 While the Commission does not have jurisdiction over other state licensees violating the Texas No-Call List, those agencies issuing licenses to violators may initiate enforcement proceeding. Section 304.253 (a) of the Texas Business and Commerce Code provides that "[a] state agency that issues a license to a state licensee shall receive and investigate complaints concerning violations of Subchapters B and C by the state licensee."

5 Tex. Bus. & Com. Code Ann. § 304.252 (West Supp. 2014)

A. Cooperation with the Attorney General

The Commission and the OAG have concurrent jurisdiction to handle No-Call List, facsimile solicitation, and interference with caller ID service violations in cases where the violator is not licensed by another Texas state agency or is a telecommunications provider. The Commission and OAG cooperate on these potential violations pursuant to a Memorandum of Understanding (MOU). Under this MOU, the Commission and OAG have agreed to cooperate, assist one another, and share information regarding these potential violations. Staff from the Commission communicate and coordinate regularly with the OAG Staff on Texas No-Call enforcement issues.

The Commission provides the OAG with a monthly summary of all telemarketing complaints, including the No-Call List complaints. The facsimile solicitation complaints and the interference with caller ID service complaints were referred to the OAG.

B. Commission processes for telemarketing (including the No-Call list) investigations and enforcement

Using the Customer Protection Division database, the Commission Staff runs queries each quarter to identify the number of Texas No-Call complaints for that quarter. For each of the companies having met the threshold for No-Call complaints in a quarter, the Commission Staff opens an investigation and determines which companies are licensed by another Texas state agency. Those that are licensed by another agency are referred to that agency.

For those not licensed by another agency, the Commission Staff investigates to determine the status and history of the company for the Texas No-Call complaints for the current quarter and past quarters. Based on the results of this analysis, the Commission Staff may send the company an information letter regarding Texas No-Call laws and rules, investigate whether the company has purchased the required No-Call list, or flag the company for additional review and potential enforcement action.

For the period of 09/01/2020 through 08/31/2022, one No-Call investigations were opened by Commission Staff. Of the one, it resulted in the Commission referring it to the OAG for further development, Commission staff was unable to locate the company.

PUCT Approved ERCOT Revision Requests
2021-2022

Public Utility Commission of Texas

Load Profiling Guide Revision Request (LPGRR)	
LPGRR069	Add Lubbock Zip Codes and Clarify BUSIDRRQ/BUSLRG (DG) Assignments

Nodal Protocol Revision Requests (NPRRs)	
NPRR995	RTF-6 Create Definition and Terms for Settlement Only Energy Storage
NPRR1005	Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
NPRR1058	Resource Offer Modernization
NPRR1063	Dynamic Rating Transparency
NPRR1073	Market Entry/Participation by Principals of Counter-Parties with Financial Obligations
NPRR1077	Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs
NPRR1078	Clarification of Potential Uplift
NPRR1079	Day-Ahead Market RRS / ECRS 48-Hour Report Clarification
NPRR1080	Limiting Ancillary Service Price to System-Wide Offer Cap
NPRR1081	Revisions to Real-Time Reliability Deployment Price Adder to Consider Firm Load Shed
NPRR1082	Emergency Response Service (ERS) Test Exception for Co-located ERS Loads
NPRR1083	Modification of Uplift Allocation Rules to Address Role of Central Counter-Party Clearinghouses
NPRR1084	Improvements to Reporting of Resource Outages, Derates, and Startup Loading Failures
NPRR1085	Ensuring Continuous Validity of Physical Responsive Capability (PRC) and Dispatch through Timely Changes to Resource Telemetry and Current Operating Plans (COPs)
NPRR1086	Recovery, Charges, and Settlement for Operating Losses During an LCAP Effective Period
NPRR1087	Prohibit Participation of Critical Loads as Load Resources or ERS Resources
NPRR1090	ERS Winter Storm Uri Lessons Learned Changes and Other ERS Items
NPRR1091	Changes to Address Market Impacts of Additional Non-Spin Procurement
NPRR1092	Reduce RUC Offer Floor and Limit RUC Opt-Out Provision
NPRR1093	Load Resource Participation in Non-Spinning Reserve
NPRR1094	Allow Under Frequency Relay Load to be Manually Shed During EEA3

NPRR1095	Texas SET V5.0 Changes
NPRR1096	Require Sustained Two-Hour Capability for ECRS and Four-Hour Capability for Non-Spin
NPRR1097	Create Resource Forced Outage Report
NPRR1098	Direct Current Tie (DC Tie) Reactive Power Capability Requirements
NPRR1099	Managing Network Operations Model Resource Nodes
NPRR1100	Allow Generation Resources and Energy Storage Resources to Serve Customer Load When the Customer and the Resource are Disconnected from the ERCOT System
NPRR1101	Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve
NPRR1102	ERCOT Discretion for Adjusting Non-Interval Data Recorder (NIDR) Backcasted Load Profiles·,
NPRR1103	Securitization –PURA Subchapter M Default Charges
NPRR1104	As-Built Definition of Real Time Liability Extrapolated (RTLE)
NPRR1105	Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
NPRR1106	Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
NPRR1107	Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees
NPRR1108	ERCOT Shall Approve or Deny All Resource Planned Outage Requests
NPRR1109	Process for Reinstating Decommissioned Generation Resources
NPRR1110	Black Start Requirements Update
NPRR1111	Related to SCR819, Improving IRR Control to Manage GTC Stability Limits
NPRR1112	Elimination of Unsecured Credit Limits
NPRR1113	Clarification of Regulation-Up Schedule for Controllable Load Resources in Ancillary Service Imbalance
NPRR1114	Securitization – PURA Subchapter N Uplift Charges
NPRR1115	Administrative Changes for February 1, 2022 Nodal Protocols - Update ERCOT Austin Office Address
NPRR1116	Remove Obsolete Reference to Market Information System (MIS)
NPRR1117	Related to SMOGRR025, Modifications to Line Loss Compensation Requirement for EPS Metering

NPRR1118	Clarifications to the OSA Process
NPRR1119	Removal of Extraneous Language Pertaining to the Calculation of Weekly Generation and Load Resource Capacity Forecasts
NPRR1120	Create Firm Fuel Supply Service
NPRR1121	Add a Posting Requirement to the Exceptional Fuel Cost Submission Process
NPRR1122	Clarifications for PURA Subchapter M Securitization Default Charges
NPRR1123	Clarifications for PURA Subchapter N Securitization Uplift Charges
NPRR1124	Recovering Actual Fuel Costs through RUC Guarantee
NPRR1125	Use of Financial Security for Securitization Default Charge and Securitization Uplift Charge Invoices and Escrow Deposit Requests
NPRR1127	Clarification of ERCOT Hotline Uses
NPRR1129	Posting ESI IDs of Transmission-Voltage Customer Opt-Outs
NPRR1130	Weatherization Inspection Fees Sunset Dale Extension
NPRR1131	Controllable Load Resource Participation in Non-Spin
NPRR1133	Clarify Responsibilities for Submission of Planning Model Data for DC Ties
NPRR1134	Related to RMGRR168, Modify ERCOT's Mass Transition Responsibilities
NPRR1135	Add On-Line Status Check for Resources Telemetering OFFNS for Ancillary Service Imbalance Settlements
NPRR1136	Updates to Language Regarding a QSE Moving Ancillary Service Responsibility Between Resources
NPRR1137	Updates to Section 1.1 to Modify the OBD List Review Timeline and Other Clarifications
NPRR1139	Adjustments to Capacity Shortfall Ratio Share for IRRs
NPRR1140	Recovering Fuel Costs for Generation Above LSL During RUC-Committed Hours
NPRR1142	ERS Changes to Reflect Updated PUCT Rule Changes re SUBST. R. 25.507

Nodal Operating Guide Revision Requests (NOGRRs)	
NOGRR210	Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
NOGRR223	Add Phasor Measurement Recording Equipment Requirement to Modified Generating Facilities in Interconnection Process
NOGRR227	Add Phasor Measurement Recording Equipment Location for Main Power Transformer for Intermittent Renewable Resource (IRR)

NOGRR229	Alignment Changes for September 1, 2021 Nodal Operating Guide – NPRR995
NOGRR231	Update ERCOT Regional Map
NOGRR232	Related to NPRR1093, Load Resource Participation in Non-Spinning Reserve
NOGRR233	Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3
NOGRR234	Related to NPRR 1098, Direct Current Tie (DC Tie) Reactive Power Capability Requirements
NOGRR235	Combining Greyboxes and Other corrections
NOGRR236	Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
NOGRR237	Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
NOGRR238	Alignment Changes for December 17, 2021 Nodal Operating Guide – NPRR1094, NPRR1105, NPRR1106
NOGRR239	WAN Data Protection Responsibilities
NOGRR240	Direct Current Tie (DC Tie) Ride-Through Requirements
NOGRR241	Related to NPRR1127, Clarification of ERCOT Hotline Uses
NOGRR242	Update POIB References
NOGRR244	Alignment Changes for December 1, 2022 Nodal Operating Guide – NPRR1127

Other Binding Document Revision Requests (OBDRRs)	
OBDRR030	Related to NPRR 1080, Limiting Ancillary Service Price to System-Wide Offer Cap
OBDRR031	Change Non-Spinning Reserve Service Deployment
OBDRR032	Non-Spin Changes Related to NPRR1093, Load Resource Participation in Non-Spinning Reserve
OBDRR033	ORDC Changes Related to NPRR1093, Load Resource Participation in Non-Spinning Reserve
OBDRR034	Related to NPRR 1099, Managing Network Operations Model Resource Nodes
OBDRR035	Related to NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve
OBDRR036	Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of EEA
OBDRR037	Power Balance Penalty and Shadow Price Cap Updates to Align with PUCT Approved High System-Wide Offer Cap

OBDRR038	Minimum Contingency Level Updates to Align with PUCT Order
OBDRR039	ORDC Changes Related to NPRR1120, Create Firm Fuel Supply Service
OBDRR040	ORDC Changes Related to NPRR1131, Controllable Load Participation in Non-Spin
OBDRR042	Related to NPRR1142, ERS Changes to Reflect Updated PUCT Rule Changes re SUBST. R. 25.507

Planning Guide Revision Requests (PGRRs)	
PGRR089	Planning Data and Information Updates for Planning Posting
PGRR091	FIS Application Completion 60-Day Limit
PGRR092	Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs
PGRR093	Replace Inadvertent Deletions in Section 5
PGRR094	Clarify Notification Requirement for Generator Construction Commencement or Completion
PGRR095	Establish Minimum Deliverability Criteria
PGRR096	Achieve Consistent Representation of Distributed Generation in Steady-State Models
PGRR098	Consideration of Load Shed in Transmission Planning Criteria
PGRR099	Revise GIM Process to Ensure Compliance with the Lone Star Infrastructure Protection Act
PGRR100	Steady-State Case Building Timeline Update
PGRR101	Related to NPRR1133, Clarify Responsibilities for Submission of Planning Model Data for DC Ties

Retail Market Guide Revision Requests (RMGRRs)	
RMGRR165	Modify ERCOT Pre-Launch Responsibilities in a Mass Transition
RMGRR166	Revising Timing for Switch Hold Extract Availability
RMGRR167	Switch Hold Removal Documentation Clarification
RMGRR168	Modify ERCOT's Mass Transition Responsibilities
RMGRR169	Related to NPRR1095, Texas SET V5.0 Changes
RMGRR170	Inadvertent Gain Process Updates

Resource Registration Glossary Revision Requests (RRGRRs)	
RRGRR025	Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
RRGRR028	Transformer Impedance Clarifications
RRGRR029	Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs
RRGRR030	Allow New Voltage Levels in Resource Registration Information
RRGRR031	Related to NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage

System Change Requests (SCRs)	
SCR813	NMMS Jointly-Rated Equipment Coordination Confirmation
SCR814	Point-to-Point (PTP) Obligation Bid Interval Limit
SCR815	MarkeTrak Administrative Enhancements
SCR816	CRR Auction Bid Credit Enhancement
SCR817	Related to NPRR1095, MarkeTrak Validation Revisions Aligning with Texas SET V5.0
SCR818	Changes to Incorporate GIC Modeling Data into Existing Modeling Applications
SCR819	Improving IRR Control to Manage GTC Stability Limits
SCR820	Operator Real-Time Messaging During Emergency
SCR822	Create Daily Energy Storage Integration Report and Dashboard
SCR823	ERCOT Mass System “County Name” File Updates for Texas SET V5.0 Implementation

Verifiable Cost Manual Revision Request (VCMRR)	
VCMRR032	Calculation of Average Running Hours per Start when Determining the Variable O&M for QSGRs

Settlement Metering Operating Guide Revision Request (SMOGRR)	
SMOGRR025	Modifications to Line Loss Compensation Requirement for EPS Metering