JANUARY 2025

PUBLIC UTILITY COMMISSION OF TEXAS

# BIENNIAL AGENCY REPORT

TO THE 89TH TEXAS LEGISLATURE

# Public Utility Commission of Texas

**Thomas J. Gleeson, Chairman**
**Lori Cobos, Commissioner (June 2021-December 2024)**
**Jimmy Glotfelty, Commissioner (August 2021-December 2024)**
**Kathleen Jackson, Commissioner**
**Courtney K. Hjaltman, Commissioner**

**Connie Corona, Executive Director**
**Barksdale English, Deputy Executive Director**

*Project Supervisor*
**Rama Singh Rastogi, Program Manager, Rules and Projects**

**Key agency divisions that contributed to this report:**

Agency Operations
Communications
Compliance and Enforcement
Consumer Protection
Critical Infrastructure Security and Risk Management
Energy Efficiency
Executive Counsel
Governmental Relations
Infrastructure
Legal
Market Analysis
Office of Public Engagement
Rate Regulation
Rules and Projects
Texas Energy Fund
Utility Outreach

## Who We Are

The Public Utility Commission of Texas (PUCT) regulates the state's electric, telecommunications, and water and sewer utilities. The PUCT is led by five full-time commissioners. These commissioners are appointed by the Governor and confirmed by the Texas Senate to serve staggered six-year terms. The Governor appoints one of the commissioners to be chairman of the commission.

**Mission:**
We protect customers, foster competition, and promote high quality infrastructure.

## What We Do

The PUCT regulates the electric, telecommunications, and water and sewer utility industries by:

- implementing related legislation through agency rulemaking,
- setting and regulating utility rates,
- approving and modifying ownership and territory changes for water and sewer providers,
- approving and modifying utility certification to operate equipment within the State of Texas,
- ensuring utilities comply with agency regulations and enforcing penalties when they don't, and
- protecting consumers by resolving complaints and issues.

The PUCT maintains oversight of the Electric Reliability Council of Texas (ERCOT), which operates the electric grid for approximately 90% of Texans and manages the state's wholesale electricity market.
The commission follows the statutes outlined in the Public Utility Regulatory Act (PURA) of 1975 and the Texas Water Code (TWC).

# Guide to this Report

This Biennial Agency Report is responsive to PURA § 12.203. The Biennial Agency Report includes:

- Scope of competition in the electric market: summary of commission action over the biennium that reflects changes to the industry and consumers in the regulated electric market,
- Scope of competition in the telecommunications market: summary of commission action over the biennium that reflects changes to the industry and consumers in the regulated telecommunications market,
- Water and sewer services market report, and
- Legislative recommendations to promote the public interest and for modifying and improving the commission's statutory authority for the improvement of utility regulation in general, including regulation of water and sewer service, and in the partially competitive electric and telecommunications markets.

All industry related data cited in the report is for the biennium September 1, 2022, through August 31, 2024, unless otherwise specified. Rulemakings and other significant commission actions covered in this report are for the period September 1, 2022, through December 31, 2024.

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# PUCT BY THE NUMBERS

SEPT 2022 - AUG 2024

## UTILITIES REGULATED

**403** WATER AND SEWER SERVICE IOUs *(Investor-Owned Utility)*

**189** ELECTRIC SERVICE PROVIDERS

**381** TELECOM SERVICE PROVIDERS

## 5 COMMISSIONERS

**Thomas J. Gleeson**
Chairman
Appointed
Jan 2024

**Lori Cobos**
Commissioner
Served
June 2021 - Dec 2024

**Jimmy Glotfelty**
Commissioner
Served
Aug 2021 - Dec 2024

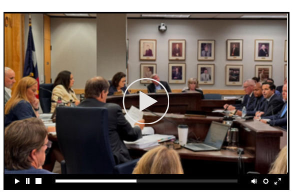
**Kathleen Jackson**
Commissioner
Appointed
Aug 2022

**Courtney K. Hjaltman**
Commissioner
Appointed
June 2024

## ENFORCEMENT

**217** INVESTIGATIONS CLOSED

**$5,017,945**
PENALTIES, REFUNDS, DONATIONS



**78** PUBLIC MEETINGS

**863** CONTESTED CASES

## RULEMAKINGS

**34**
PROPOSALS FOR ADOPTION

## ERCOT MARKET RULES APPROVED

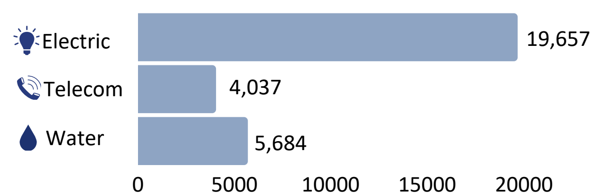
**179**

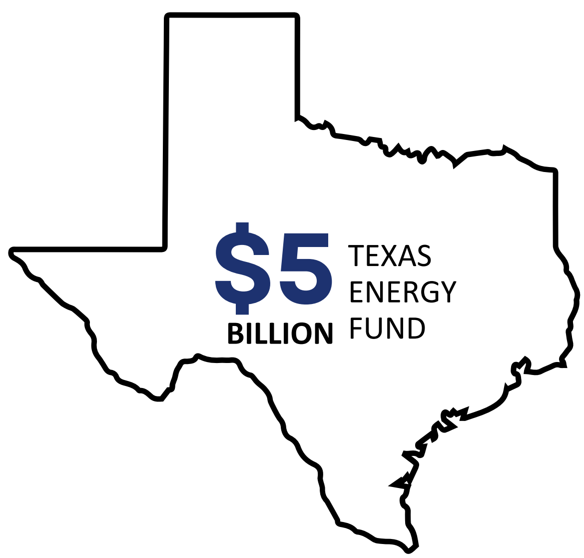
**256 FTE**

**44% GROWTH TO MEET ADDITIONAL DUTIES**

## CONSUMER PROTECTION

**29,378**
COMPLAINTS INVESTIGATED UNDER PUCT JURISDICTION



# I. Agency Highlights

The 2023-24 biennium was a period of significant growth and transition for the PUCT and great progress for Texas. This section highlights key milestones, with more information available throughout the report.

## New Commissioners and Executive Leadership

In January 2024, Governor Abbott appointed Thomas J. Gleeson, then the executive director of the agency, as chairman of the commission. Chairman Gleeson stepped into the position held by Interim Chair Kathleen Jackson, who had been appointed by Governor Abbott as interim chair in June 2023 upon the resignation of then-Chairman Peter Lake from the PUCT.

On May 23, 2024, Connie Corona was promoted to executive director of the agency by commission vote. She previously served as interim executive director and deputy executive director of the agency. Barksdale English, former director of the agency's Division of Compliance and Enforcement (DICE), was promoted to deputy executive director.

In late 2024, the PUCT created a Chief of External Affairs position to oversee the agency's external-facing divisions: Communications, Government Relations, Office of Public Engagement, Utility Outreach, and Consumer Protection. Lucy Nashed was hired to fill this position in December 2024.

Governor Abbott appointed Courtney K. Hjaltman, formerly chief executive and public counsel of the Office of Public Utility Counsel, as commissioner on June 24, 2024. Commissioner Kathleen Jackson continues her service as commissioner.

In late 2024, both Commissioner Lori Cobos and Commissioner Jimmy Glotfelty submitted to Governor Abbott their resignations from the PUCT, effective on December 31, 2024. Both had been appointed by Governor Abbott to the commission during the summer of 2021 in the aftermath of Winter Storm Uri.

## Hurricane Beryl

On July 8, 2024, Hurricane Beryl made landfall near Matagorda and caused major destruction as it moved inland, leaving more than 2.6 million Texans without power for several days in the Greater Houston area. At the direction of Governor Greg Abbott, the PUCT investigated the underlying causes of repeated and ongoing power outages in Houston and the surrounding communities. The PUCT submitted its findings with recommendations to the Governor and the Texas Legislature on November 21, 2024. Public documents related to the investigation and the investigation report are available on the PUCT's Interchange website under Project No. 56822.

## First Open Meeting and Workshop Outside Austin

The PUCT held its first-ever open meeting outside of Austin on October 5, 2024. The meeting was held in Houston along with a workshop on emergency preparedness and the extreme weather response of utilities in the Greater Houston region. The workshop was open to the public with more than 100 residents of the Greater Houston region attending. The five PUCT Commissioners heard from members of the Houston community, who shared their experiences with recent power outages during Hurricane Beryl and the May 2024 derecho and suggested potential policy and community outreach changes.

The commission received in-person comments from the Lieutenant Governor and other state lawmakers. Executive leadership from CenterPoint Energy provided an update on their ongoing efforts to improve the resiliency of their transmission and distribution systems. Experts from the Texas Division of Emergency Management, National Weather Service, Edison Electric Institute, MG Spoor Consulting, GridSky Strategies Inc., Texas A&M Forest Service, and Southeastern Electric Exchange presented on the strategies for responding to emergencies and hardening infrastructure so that electric delivery facilities and equipment will withstand extreme weather.

## Permian Basin Reliability Plan

In September 2024, the commission approved the long-term Permian Basin reliability plan that is required by PURA § 39.167 (HB 5066, 88R) to address increased need for transmission capacity to meet the growing future electricity needs of the Permian Basin Region. This landmark commission decision will result in significant transmission infrastructure buildout in the Permian Basin Region, which is a key participant in the nation's energy economy.

ERCOT forecasts electricity demand in the region will grow by approximately 26 gigawatts (GW) by 2038, which is equivalent to almost one third of the current summer demand of the entire ERCOT system. The plan approved by the commission includes two categories of transmission infrastructure to support the region's current and future power needs: new and upgraded local transmission projects to strengthen the area's transmission service and new import paths that will bring additional power to the region to serve the area's growing electricity needs.

## Reliability Standard

As part of the electric grid and market improvement initiatives and statutory requirements of PURA § 39.159, in August 2024 the commission approved an electricity reliability standard for Texas. Setting a standard for reliability in ERCOT will allow for regular assessments of the grid's ability to meet consumer demand and help the PUCT and ERCOT determine what market or reliability improvements could be necessary in the future.

The reliability standard is based on three criteria:

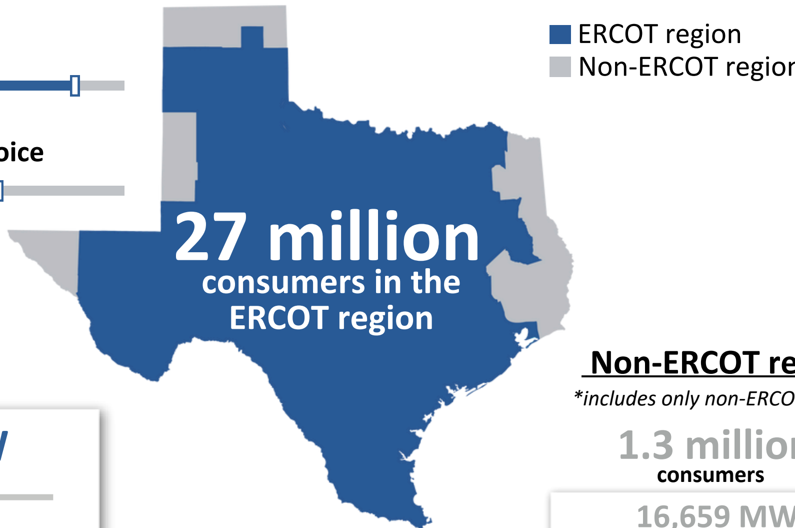
- **Frequency:** sets the expected loss of load events to be equal to or less than one event per ten years;
- **Duration:** sets the maximum expected length of a loss of load event, measured in hours, to be less than 12 hours; and
- **Magnitude:** sets the expected highest instantaneous level of load shed during an event, which is to be reviewed annually by the commission.

# ELECTRICITY BY THE NUMBERS

## ERCOT region

**90%** of Texas Load

**75%** of load has retail choice




**103,609+ MW**
Installed Capacity

**1,873+**
Active Market Participants

**85,508 MW**
Peak Demand *August 10, 2023*

## Non-ERCOT region

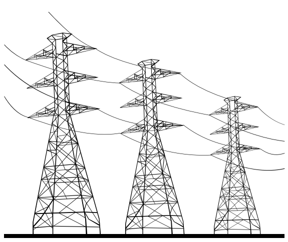
**includes only non-ERCOT IOUs*

**1.3 million**
consumers

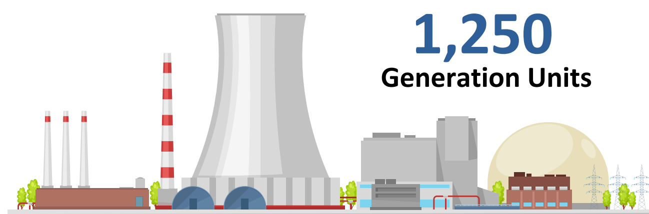
**16,659 MW**
Generation Capacity

**80**
Generation Units

**15,204 MW**
Peak Demand



**54,100**
miles of transmission lines



**1,250**
Generation Units

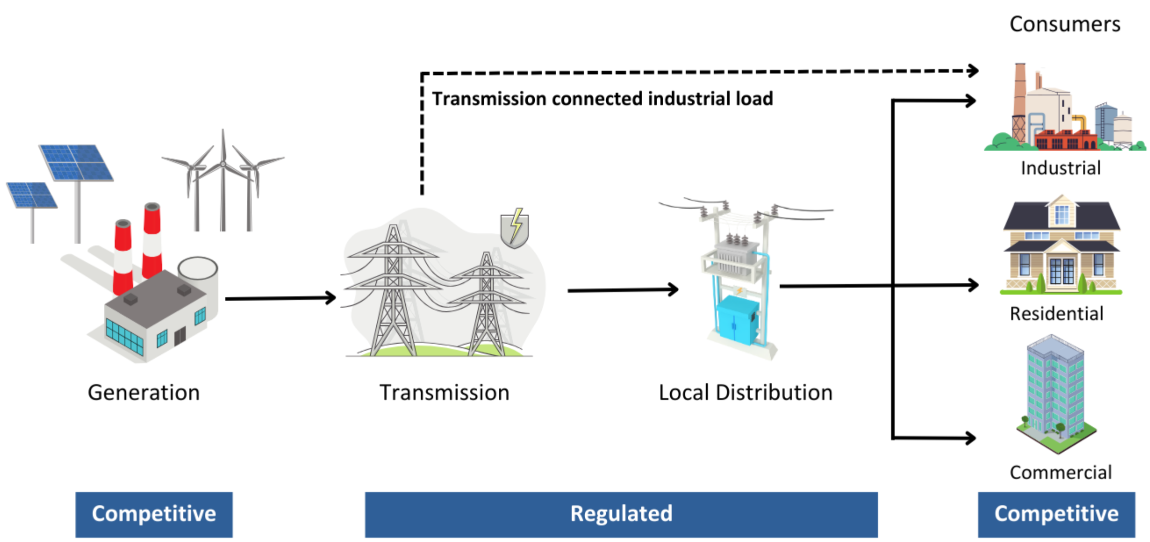
**299** Electric Service Providers (Texas)
**includes both regulated non-opt in entities*


Retail Electric Providers | Electric Cooperatives | Municipally Owned Utilities | IOUs

## II. Electricity – Scope of Competition

The continental United States is served by three major power grids: the eastern, western and Electric Reliability Council of Texas (ERCOT) interconnections. Texas is the only state in the country that is served by all three interconnections. However, a majority of the state is served by ERCOT.

There are three broad functions of the electricity industry: generation, transmission and distribution, and retail sale to the end-use consumers. Electricity is generated in power plants, moved across the state over transmission lines, delivered to end-use consumers through a distribution system, and ultimately sold to those consumers at a retail rate. In Texas, residential, commercial, and industrial consumers are served by one of four types of electricity service providers. Most are served by a retail electric provider (REP) of their choice in the competitive market within the ERCOT interconnection. Outside of ERCOT, consumers are generally served by the investor-owned, vertically integrated utilities authorized to serve their local area. Electric cooperatives (co-ops) and municipally owned utilities (MOU) can be found both inside and outside of ERCOT, and typically have monopoly status in their respective local areas. However, an MOU or co-op within ERCOT may choose to implement retail competition, as Lubbock Power & Light did in 2024. The Nueces Electric Cooperative has offered retail choice to its consumers since 2004.



## Electricity Service Providers

**Retail Electric Provider (REP)**
A REP is an entity that buys electricity in the wholesale market to sell to its retail customers in areas that are open to retail choice in Texas. A REP does not own or operate generation assets. It manages the retail relationship with the consumer, including billing and customer service. The term 'REP' does not include an entity that owns or operates equipment used solely to provide electricity charging service for consumption by an alternatively fueled vehicle, as defined by Section 502.004, Transportation Code.

**Transmission Service Provider (TSP)**
A TSP is an entity under the jurisdiction of the commission that delivers energy from resources to entities that ultimately serve end use consumers. TSPs own or operate transmission facilities in the Texas transmission grid. Transmission facilities include power lines, substations, and associated facilities, operated at 60 kilovolts (kV) or above. Transmission systems are commonly thought of as the highways of the grid.

**Distribution Service Provider (DSP)**
A DSP is an entity that owns or operates a distribution system to deliver electricity from the transmission grid to end consumers. The distribution facilities operate at under 60kV. The distribution systems are commonly thought of as the byways of the grid. A DSP is an electric utility, municipally owned utility, or electric cooperative that owns or operates for compensation equipment or facilities that are used for the distribution of electricity to retail customers.

**Municipally Owned Utility (MOU)**
A MOU is owned, operated, and controlled by a municipality or by a nonprofit corporation whose directors are appointed by one or more municipalities. A MOU may own or operate for compensation equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in Texas.

**Electric Cooperative (co-op)**
An electric cooperative is a non-profit organization that supplies electricity to homes and businesses. These are owned and governed by their community members. An electric cooperative may own or operate for compensation equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in Texas.

**River Authority**
A river authority is a conservation and reclamation district created under the Texas Constitution, article 16, section 59. A river authority may own or operate for compensation equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in Texas.

# Competitive Retail Market

## Retail Electric Providers

Texans in areas open to retail competition can choose electricity products or plans from a variety of retail electric providers (REPs). A REP buys electricity in the competitive wholesale market to sell to its retail customers. A REP also manages the retail relationship with the customer, including billing and customer service. The variety of plans available in the competitive retail market allows consumers to choose a plan that best fits their needs and budget.

During the 2023-24 biennium, the number of REPs and types of electricity plans or offers in the competitive market areas of ERCOT remained stable. As of September 2024, plans are available that offer 100% renewable electricity, time-of-use pricing such as free electricity on the weekends, excess solar generation buy-back, and prepaid plans. Contract terms vary from one month up to 60 months. There are 138 REPs authorized to sell electricity in the Texas competitive retail market.

| REP Certification | | | |
|---|---|---|---|
| Year | New | Relinquished | Total Certificated REPs |
| 2023 | 38 | 19 | 138 |
| 2024 | 14 | 14 | 138 |

REPs in the competitive market serve 7,139,850 residential premises, 1,190,620 commercial premises, and 5,139 industrial premises.[1] The average electricity prices available on powertochoose.org for a 12-month, fixed-rate plan across the transmission and distribution utilities' service territories in September 2024 ranged from 13.86 cents per kilowatt hour (kWh) to 15.88 cents per kWh. Power to Choose is a PUCT-managed website where certified electricity providers in Texas provide information about their electricity plans and offers for consumers to choose from.

| REP Consumers* | | | |
|---|---|---|---|
| Year* | Residential Premises | Commercial Premises | Industrial Premises |
| 2023 | 6,869,461 | 1,175,922 | 4,715 |
| 2024 | 7,139,850 | 1,190,620 | 5,139 |

*- March 2023 and March 2024

[1] ERCOT POLR Counts Energy 2024 Report, Sheet 2 (June 3, 2024).

### Electricity Brokers

Some consumers in the competitive retail market use an electricity broker to assist with shopping for a retail electricity plan. Brokers also provide supplementary services to their customers, such as energy management services or bill management services. As of September 1, 2024, there are 1,526 active brokers registered with the PUCT.

## Competitive Wholesale Market

The competitive wholesale electricity market is a marketplace where electricity is bought and sold in bulk. Within ERCOT, the competitive wholesale electricity market operates as an energy-only market. This means each generator is paid based on the energy and ancillary services it provides to the grid. In contrast, other independent system operators (ISOs) around the country utilize an additional capacity market where generators can also be paid for availability of generation capacity in the future, in addition to energy and ancillary services.

There are over 1,250 generation units and more than 150 different providers of retail electric service that participate in the ERCOT wholesale market. Like other competitive markets, owners and investors decide to invest in new generation units or retire existing generation units based on expected costs and profits.

### Wholesale Market Prices

The ERCOT wholesale market must meet the fluctuating demand for energy from consumers. Wholesale electricity prices are determined by the dynamics of supply and demand in the wholesale market while considering the engineering limitations of the transmission network.

ERCOT administers wholesale electricity trading in two markets. The first is the day-ahead market (DAM), which is a voluntary, financially binding forward energy market, where electricity is traded up to one day ahead of the day the energy is used. In this market, buyers and sellers can hedge their expected exposure to real-time electricity prices. The second is the real-time electricity market, where energy is traded every five minutes to maintain the balance between demand for and supply of electricity. Volatility in real-time wholesale electricity markets can occur because demand can change rapidly and the ability of supply to respond can be restricted by the physical limitations of the resources and the transmission network.

### Generators and Other Resources

The four primary resource types that participate in the wholesale market are thermal, renewable, energy storage resources (ESR), and load resources. Thermal generation includes energy produced from coal, natural gas, and nuclear energy, while sources of renewable generation include wind, solar, and hydroelectric dams. An ESR is a resource that can store energy received from the grid or another source and inject this energy back into the grid, as needed.

In recent years, there has been substantial growth of renewables in the market. ESRs are also experiencing steady growth as technology improves. Loads that can respond to ERCOT instructions can also participate in the energy and ancillary services markets. Energy storage resources and loads are discussed in the emerging issues section of this report.

Despite these latest trends, thermal units provide the largest share of electricity delivered to the ERCOT market today. Thermal units require fuel to produce electricity, making fuel costs a primary driver of wholesale market prices. In contrast, renewable resources have no fuel costs, which contributes to reducing wholesale prices.

## Power Marketers

A power marketer buys and sells electric energy in wholesale markets but does not own generation, transmission, or distribution facilities and does not have a certificated service area. Power marketers add liquidity to the electricity market by actively buying and selling electricity in the wholesale market. People planning to buy and sell electric energy at wholesale in Texas are required to register as power marketers. As of September 2024, there are 118 power marketers operating in Texas.

## Independent Market Monitor (IMM)

The Public Utility Regulatory Act (PURA) § 39.1515 requires the PUCT to contract with an independent entity to function as the wholesale electric market monitor, known as the independent market monitor (IMM). Potomac Economics, a consulting firm, currently serves as the IMM.

The IMM provides PUCT staff with information on potential instances of market power abuse as they occur. Market power abuse occurs when a business with a dominant or significant position in the market uses that position to weaken competition outside of normal competitive forces.

The IMM publishes an annual report on the state of the ERCOT market, including any changes made to the market that year. This report examines whether market power – the ability to control prices or exclude competition in a relevant market – exists and whether attempts are made to exercise it.

The IMM report[2] also identifies market inefficiencies and makes recommendations to improve the competitive performance and operation of the market. In addition, the IMM provides feedback and recommends changes to ERCOT Protocols and processes to improve market

[2] 2022 State of the Market Report for the ERCOT Electricity Markets (June 6, 2023). Last found at https://www.potomaceconomics.com/wp-content/uploads/2023/05/2022-State-of-the-Market-Report_Final_060623.pdf

efficiency. In both the 2022 and 2023[3] *State of the Market* reports for the ERCOT electricity market, the IMM found that the ERCOT wholesale market performed competitively.

## Transmission and Distribution Utilities

Within the ERCOT competitive market, transmission and distribution utilities (TDUs) are responsible for building and maintaining the infrastructure that delivers electricity to consumers. TDUs do not sell power to consumers. The electricity delivery infrastructure includes high-voltage transmission lines, substations, local distribution lines, and the consumer's meter.

In the ERCOT power region, the PUCT regulates and sets the rates for nine investor-owned utilities. Of these, four companies provide both transmission and distribution services:

- Oncor Electric Delivery,
- CenterPoint Energy,
- American Electric Power (AEP) Texas, and
- Texas-New Mexico Power (TNMP).

The remaining five IOUs provide transmission-only services:

- Electric Transmission Texas,
- Wind Energy Transmission,
- Lone Star Transmission,
- Cross Texas, and
- Sharyland Utilities.

The PUCT also sets transmission-service rates for 38 entities that provide wholesale transmission service in ERCOT, including electric cooperatives, municipalities, and river authorities.

## Outside ERCOT: Vertically Integrated Utilities

Outside the ERCOT region, four electric utilities remain vertically integrated. These utilities own and are responsible for each of the major functions of electricity service: generation, transmission and distribution, and retail sale to the end-use consumers. The PUCT sets retail rates for these vertically integrated utilities in comprehensive rate proceedings:

- Entergy Texas, Inc., which serves Southeast Texas;
- Southwestern Electric Power Company (SWEPCO), which serves Northeast Texas;
- El Paso Electric (EPE), which serves the El Paso area; and
- Southwestern Public Service (SPS, also known as Xcel Energy), which serves the Panhandle.

Together, these utilities serve more than 1.3 million consumers. The PUCT regulates the bundled retail rates of these utilities. The Federal Energy Regulatory Commission (FERC) has regulatory

[3] 2023 State of the Market Report for the ERCOT Electricity Markets (June 6, 2024). Last found at https://www.potomaceconomics.com/wp-content/uploads/2024/05/2023-State-of-the-Market-Report_Final.pdf

authority over interstate wholesale power sales and interstate transmission rates for these utilities. The PUCT retains outside counsel and consultants to help protect the interests of Texas consumers and stakeholders in FERC proceedings. These consultants participate in a variety of activities before FERC, including rulemakings and contested cases that may affect Texas utilities, consumers, and the state's jurisdictional rights.

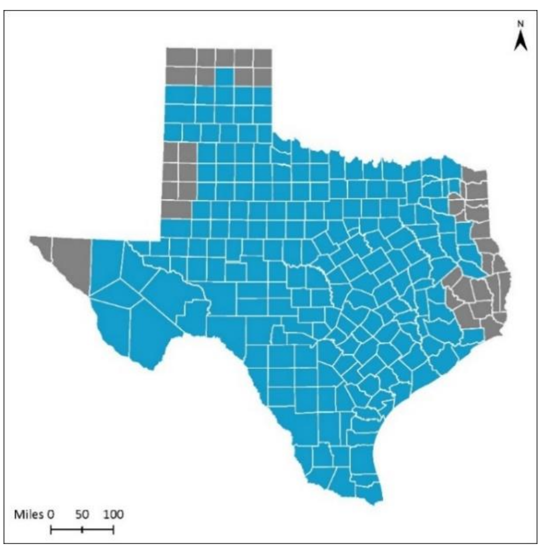
## Municipally Owned Utilities and Electric Cooperatives

Throughout the state, MOUs and electric cooperatives serve over 8.3 million consumers and businesses in Texas. There are 76 member-owned electric cooperatives in Texas, governed by elected boards that serve nearly three million consumers. Additionally, 72 municipalities own and operate utilities, including Austin Energy and CPS Energy in San Antonio. Together, these municipalities serve over 5.3 million consumers.

The PUCT does not have retail rate-setting authority 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.

## Regional Transmission Organizations

### ERCOT Region




*ERCOT Area in Texas*

ERCOT is the regional transmission organization (RTO) and the independent system operator (ISO) for the ERCOT region within the state. Its major responsibilities are:

- maintaining the reliability of the bulk electric system;
- facilitating competitive retail and wholesale electricity markets; and
- ensuring fair and open access to the bulk electric system.

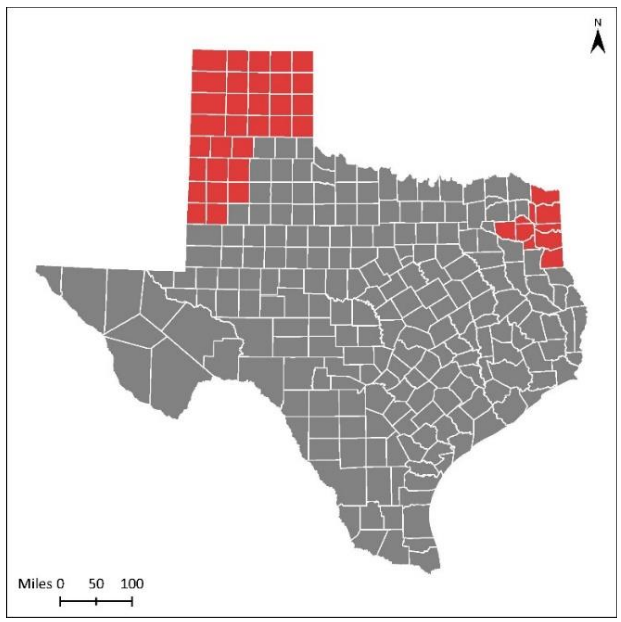
As the ISO, ERCOT manages the flow of electric power to more than 27 million Texas consumers, representing about 90% of the state's electric load.

An independent board of directors, subject to the oversight of the PUCT and the Legislature, governs ERCOT. ERCOT manages real time electricity demand and supply to maintain system frequency. The ideal frequency for the ERCOT bulk electric system is 60 Hz. Supply and demand of power must balance to maintain this frequency.

ERCOT routinely assesses electricity demand and the amount of generation needed to serve current and future load. ERCOT publishes these estimates in two reports. The *Capacity, Demand, and Reserves Report* (CDR) is published biannually. The CDR details generation capacity that is either currently online or has met certain milestones and is expected to be online in the coming years. ERCOT also publishes a *Monthly Outlook for Resource Adequacy* (MORA) that assesses the risk of outages going into the upcoming month.

## Southwest Power Pool (SPP)

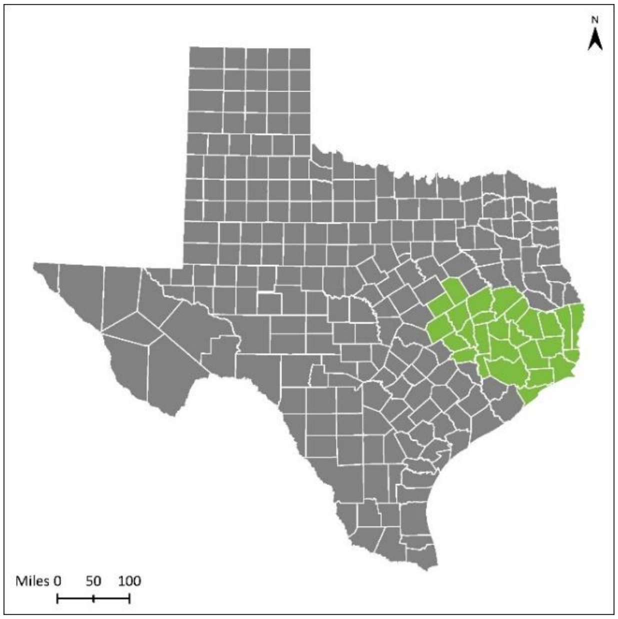
The Southwest Power Pool (SPP) is the Federal Energy Regulatory Commission (FERC)-authorized RTO and ISO for areas of Northeast Texas and the Texas Panhandle. SPP covers 14 states, including parts of Texas, Arkansas, Iowa, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Wyoming, and all of Kansas and Oklahoma. The SPP footprint for Texas includes SWEPCO, SPS, several electric cooperatives, and various MOUs. The PUCT participates in SPP meetings to ensure fair treatment of Texas consumers. The SPP's Regional State Committee (RSC) consists of one commissioner per state in the region. The RSC is the decision-making authority at SPP on issues such as the allocation of costs for transmission upgrades, the allocation of financial transmission rights, and generation resource adequacy. In both the 2022 and 2023 *State of the Market* reports, market monitoring unit concluded that SPP markets generally performed competitively.[4]




*Southwest Power Pool (SPP) Area in Texas*

[4] Southwest Power Pool Annual State of the Market Report 2023 (May 31, 2024). Last found at https://www.spp.org/documents/71645/2023%20annual%20state%20of%20the%20market%20report%20v2.pdf

## Midcontinent Independent System Operator (MISO)




*Midcontinent Independent System Operator (MISO) Area in Texas*

The eastern portion of Texas, served primarily by Entergy Texas, Inc. (Entergy), is part of the Midcontinent Independent System Operator (MISO) footprint. MISO is the largest RTO in North America, serving all or part of 15 states in the central United States and the Canadian province of Manitoba.

FERC has regulatory authority over wholesale power transactions and transmission rates for Entergy. FERC approves the MISO Tariff, which includes rules pertaining to transmission planning, resource adequacy, and energy market design. The MISO Tariff establishes the rules for how MISO market participants like Entergy operate. Changes to the MISO Tariff can have significant cost and reliability implications for Texas ratepayers in the Entergy footprint, making the PUCT's involvement in these proceedings critical. The PUCT collaborates with outside counsel on FERC proceedings about the MISO Tariff. Potomac Economics, the company that serves as the independent market monitor for MISO, concluded that the MISO energy and ancillary services markets generally performed competitively in 2023[5].

The Organization of MISO States (OMS) is the primary regional state committee for MISO. The OMS Board provides the broader state regulatory perspective and recommendations to MISO and FERC. The designated commissioner from Texas also serves on the Entergy Regional State Committee (ERSC) Board, which consists of regulators from Arkansas, Louisiana, Mississippi, Texas, and the Council of the City of New Orleans.

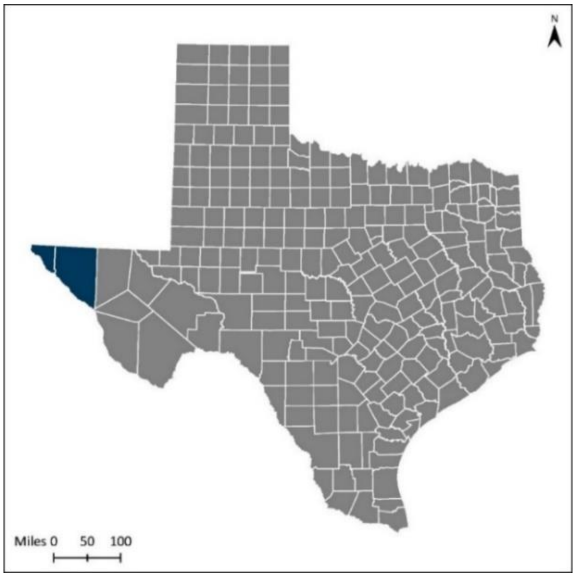
## Western Energy Imbalance Market (WEIM)

El Paso Electric (EPE) Company, the vertically integrated utility serving the western tip of Texas, joined the California ISO's (CAISO) Western Energy Imbalance Market (WEIM) on April 6, 2023. The energy imbalance market (EIM) is an energy trading function of CAISO's broader power markets that allows entities outside of CAISO to buy and sell excess generation capacity in real-time. The EIM benefits El Paso Electric's resource adequacy, reliability, and generation costs by allowing it to procure additional energy to balance load at short notice and at market-based prices. Commissioner Glotfelty represented Texas in the body of state regulators (BOSR) during

[5] 2023 State of the Market Report for the MISO Electricity Markets. Last found at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf

this past biennium. The BOSR provides a forum for state regulators to learn about the WEIM, the governing body, and related ISO developments that may be relevant to their jurisdictional responsibilities.

## Western Electric Coordinating Council (WECC)




*Western Electric Coordinating Council (WECC) Area in Texas*

The Western Electric Coordinating Council (WECC) is the regional entity responsible for bulk electric system reliability, associated compliance monitoring, and enforcement in the western interconnection. The WECC regional entity 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. EPE is the only electric utility in Texas that is a member of WECC.

## Interconnections

The ERCOT power region has four connections to adjacent grids: three DC ties and one Variable Frequency Transformer (VFT). DC ties can couple asynchronous Alternating Current (AC) system together by converting AC power from one system into DC power and back into AC power on the neighboring system. The interconnections allow for the transfer of power while maintaining a certain degree of electrical separation. The existing ERCOT-connected DC ties are back-to-back facilities meaning that the AC to DC conversion and DC to AC conversion occur at the same facility.

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 power grid Comision Federal de Electricidad (CFE), operated by Centro Nacional de Control de Energia (CENACE). For simplicity, all four facilities are referred to as "DC ties."

The four existing DC Ties details are provided in the table below:

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

There is one pending connection called the Southern Spirit Transmission Line (formerly Southern Cross Transmission Line). This would connect the ERCOT region to the MISO region and would permit the flow of approximately 2000 MW of power. The project received FERC approval in 2014 and the PUCT issued a CCN in 2017. ERCOT provides periodic updates on this project as it is pending regulatory approval from jurisdictions outside Texas.[6]

## Emergency-Use Interconnections

FERC has granted emergency-use only interconnections and related transmission service to the Eastern Interconnection. In the City of College Station, 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). Block load transfers allow load to be moved from being served by one grid to being served by another when one of the grids is not stable or is unable to supply power because of loss of a generator, transformer, cap bank, or transmission line. These ties cannot sync the ERCOT and Entergy transmission network that operates in the MISO region, but can be used only to pick up radially fed load from either side. This interconnection, like the DC tie connections discussed above, does not establish a synchronous interconnection between ERCOT and the Eastern Interconnect.

Entergy has a current capability to transfer up to 40 MW of block load from ERCOT to MISO at Dayton, Texas and up to 100 MW of block load transfer capability from ERCOT to MISO at College Station. While the block load transfer capability at Dayton was used in 2005 and in 2008, the capability at College Station has never been used.

## Legal and Jurisdictional Concerns

ERCOT and its market participants are generally not subject to the 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 the

[6] Compliance Project Related to Project No. 46304 (Oversight Proceeding Regarding ERCOT Matters Arising Out of Docket No. 45624), Project No. 54166.

transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce.[7] Each existing interconnection and the related transmission service has been authorized by FERC under Sections 210 and 211. The Southern Spirit tie is the most recent consideration of a new ERCOT interconnection by FERC.

## Utility Cybersecurity

The PUCT's Critical Infrastructure Security and Risk Management (CISRM) Division coordinates with electric utilities for cybersecurity, physical security, and emergency management resources. The PUCT and Paragon Systems held the second biennial Cybersecurity Symposium in October 2024 at the University of Texas at San Antonio. Utilities took part in a simulated cybersecurity threat on day one and received a full day of training and workshops on cyber topics to help improve their organization's overall cybersecurity posture. Symposium participants shared information to educate electric utilities on best business cybersecurity practices, emerging threat intelligence, and tabletop exercises to walk through their cyber incident response plans.

In 2023, CISRM kicked off the first Texas Division of Emergency Management (TDEM) regional outreach for electric utilities and local emergency management coordinators in Amarillo. The goal of this program is to bring electric utilities and emergency managers together during "blue sky" days – or normal, routine operating days – to collaborate and train on emergency procedures prior to an event taking place. In addition to Amarillo, CISRM has also hosted the program in San Antonio, El Paso, Fort Worth, and Houston.

## Electricity - Contested Caseload

The commission exercises regulatory authority over electric utilities and other regulated entities through contested cases. These cases address transmission and generation certificates of convenience and necessity (CCN), customer complaints, compliance with operating standards, and rate regulation. The commission currently has over 200 active cases relating to the regulation of the electric industry.

A significant portion of the commission's contested case workload is devoted to CCN applications for new electric facilities. These cases most often address the need for new electric transmission lines and where those lines will be sited. The Permian Basin Reliability Plan, for example, involves the construction of over 50 new electric facility projects, the majority of which will require CCN applications, all subject to a 180-day decision deadline. The CCN applications volume is expected to increase significantly resulting in increased caseload volumes for commission staff.

[7] Declaration of policy; application of subchapter, Use or sale of electric energy in interstate comments, 16 U.S.C. § 824(b)(1).

## Emerging Issues

The PUCT is monitoring emerging issues regarding specific technologies, growth areas, and events.

### Energy Storage

The total capacity of energy storage resources (ESR) in ERCOT continues to grow as technology improves and costs decrease. The ERCOT market treats ERCOT system users as either injecting power onto the grid (generation) or taking power from the grid (load). ESRs have the capability to do both. They act like a load when charging, then as a generation resource when injecting that power back into the grid. These resources can provide tremendous benefits to consumers but integrating them into the existing market must be thoughtfully managed. This challenge is not unique to the ERCOT market. Because ESRs are relatively new, many ISOs are still in the process of learning how to effectively manage them.

ERCOT is working closely with ESR owners to incorporate these systems effectively and increase their visibility and capability to ERCOT. In the future, ERCOT systems will incorporate the unique characteristics of ESRs being *both* load and generation, through real-time co-optimization (RTC). RTC is a market design feature that would allow optimizing the use of generation resources to meet both energy and ancillary service needs more economically in real-time. Since the initial RTC market design program, requirements have been enhanced to include functionality changes to account for the expansion of battery energy storage resources in the ERCOT market. This program is now referred to as the real-time co-optimization + batteries (RTC+B) program. With RTC+B, enhancements are expected to provide operational and reliability benefits to the ERCOT system as well as estimated annual wholesale market savings of approximately $2 billion.

### Distributed Energy Resources

The electricity market in the ERCOT region continues to see an increasing number of distributed energy resources (DERs). DERs are electrical generation facilities interconnected at the distribution level – at a voltage less than or equal to 60kV. Interconnection of DER facilities between 1 megawatt (MW) and less than 10 MW have been growing in the ERCOT region. DERs that participate in the wholesale energy and ancillary service market are required to register with ERCOT.

Smaller DERs on the distribution system include rooftop solar panels, conventional back-up generators, and small-scale batteries. These smaller DERs are not required to register at ERCOT but are required to interconnect with the local distribution service provider (DSP). There are no standardized interconnection processes among the various DSPs serving Texas consumers. Smaller DERs can aggregate and participate in the ERCOT market as part of the aggregated distributed energy resources (ADER) pilot.

The PUCT and ERCOT do not have complete visibility into the electricity distribution system. With higher penetration of DERs into the wholesale and ancillary service markets, DERs are becoming an integral resource that can have widespread implications on the grid as a whole. To better understand stakeholder issues related to DERs including interconnection standardization, PUCT held three workshops during the summer of 2023. Rulemakings are currently underway on DER interconnection standardization and technical standards at the PUCT. The rulemakings will address issues including timelines for interconnection, standardizing information required for utility studies, and interconnection cost allocation methodology. These rules will help with integrating the DERs effectively on the distribution system.

## Texas Advanced Nuclear Reactor Working Group

At the direction of Governor Greg Abbott, Commissioner Jimmy Glotfelty led the Texas Advanced Nuclear Reactor Working Group (TANRWG). The TANRWG evaluated the feasibility of advanced nuclear reactors (ANRs), identified financial incentives, and collaborated with stakeholders and market participants to examine issues related to development of advanced nuclear technology in Texas. The TANRWG included representatives from energy companies, advanced nuclear reactor manufacturers, nuclear subject matter experts from various Texas universities, members from ERCOT, and other entities from the engineering and manufacturing industries. The TANRWG submitted a report to the Governor and the Texas Legislature in November 2024. (Project No. 55421)

## Large Load Growth

Texas continues to experience significant growth in large-scale electricity demand. ERCOT forecasts load in the ERCOT region could grow by up to 76% to 150 GW over the next 7 years[8]. This growth is driven by electricity demand from data centers, virtual currency mining, hydrogen production, and other energy-intensive sectors. Of these loads, virtual currency mining operations are unique in that they can appear often within months, quickly scale up, or adjust planned location. The siting locations of these loads can shift in response to market conditions and technology trends. These unique load characteristics of virtual currency mining operations and large load growth, in general, create challenges for load forecasting and long-term grid planning, requiring ERCOT to consider different grid planning approaches[9]. ERCOT is continuing to proactively address the potential impacts of large load growth through its market rules. The

[8] *See* generally ERCOT Nodal Protocol Revision Requests numbers 1180, 1202, 1226, 1234, and 1238. (pending). Last found at https://www.ercot.com/mktrules/issues/nprr

[9] *See* ERCOT Nodal Protocol Revision Request 1188 (approved Nov. 21, 2024) last found at https://www.ercot.com/mktrules/issues/NPRR1188, and ERCOT Nodal Protocol Revision Request 1219 (approved Sept. 26, 2024) last found at https://www.ercot.com/mktrules/issues/NPRR1219.

commission is working closely with ERCOT to monitor the impact of these large loads on the grid. [10]

## Rulemakings

### Terms and Conditions of Access by a Competitive Retailer to the Delivery System of Certain MOUs and Electric Cooperatives

On March 23, 2023, the commission adopted new 16 Texas Administrative Code (TAC) § 25.219. The new rule and accompanying pro-forma tariff implement customer choice for Lubbock electricity consumers after May 1, 2023. **(Project No. 54212)**

### Review of Market Participant Qualifications and Reporting Requirements

On April 6, 2023, the commission repealed and replaced 16 TAC §§ 25.105, 25.107, and 25.109 as well as amended 16 TAC §§ 25.30, 25.485, and 25.495. The adopted rules ensure that the commission has current information on power marketers and power generation companies (PGCs). The rulemaking disallows certain persons from controlling retail electric providers and power generation companies and strengthens financial requirements for REPs. The amendments also change the complaint response period for entities from 21 days to 15 days. **(Project No. 52796)**

### Texas Backup Power Package Advisory Committee Rulemaking

On November 2, 2023, the commission adopted new 16 TAC § 25.515. The new rule implemented PURA § 34.0203 (SB 2627, 88R) by establishing an advisory committee to advise the PUCT on the administration of the Texas Backup Power Package Program. The rule establishes the purpose, duties, composition, membership, procedures, and term of the committee. **(Project No. 55407)**

### Emergency Pricing Program

On December 1, 2023, the commission adopted amendments to 16 TAC § 25.509. The amended rule implements PURA § 39.160 (SB 3, 87R) by establishing an emergency pricing program for the wholesale electric market. The amended rule describes the criteria and values of the high and low system-wide offer caps and requires ERCOT to administer an emergency pricing program during prolonged periods of elevated wholesale prices. **(Project No. 54585)**

### Review of Renewable Standard Portfolio

On November 30, 2023, the commission repealed and replaced 16 TAC § 25.173. The rule implements an uncodified requirement of HB 1500 (88R), Section 53, by shifting the mandatory renewable portfolio standard (RPS) to a temporary, mandatory, solar-only RPS, setting the

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[10] See generally ERCOT Planning Guide Revision Request 112 (approved July 25, 2024) last found at https://www.ercot.com/mktrules/issues/PGRR112.

termination date of the solar-only RPS, and creating a voluntary renewable energy credit (REC) trading program. Additionally, the rule directs ERCOT to continue to maintain an accreditation and banking system for awarding and tracking RECs voluntarily generated by eligible facilities. **(Project No. 55323**)

## Transmission and Distribution System Resiliency Plans

On January 18, 2024, the commission adopted new 16 TAC § 25.62. The new rule implements PURA § 38.078 (HB 2555, 88R) by establishing the requirements and procedure for an electric utility to submit a plan to the commission for enhancing the resiliency of its transmission and distribution system. **(Project No. 55250)**

## Generation Interconnection Allowance

On February 15, 2024, the commission adopted amendments to 16 TAC § 25.195. The amended rule implements PURA § 35.004 (HB 1500, 88R) by establishing a standard allowance for interconnection costs incurred by a transmission service provider to interconnect generation resources at transmission voltage to the transmission system within the ERCOT power region. Historically, interconnection costs within the ERCOT power region were paid for by load entirely. However, the 88th Texas Legislature sought to curtail excessive interconnection costs and encourage more economic siting discipline by generators. The amended rule accomplishes this objective by establishing a two-tiered allowance for interconnections based on voltage. **(Project No. 55566**)

## Texas Energy Fund In-ERCOT Generation Loan Program

On April 2, 2024, the commission adopted new 16 TAC § 25.510. The new rule implements PURA §§ 34.0104, 34.0106, and 34.0110 (SB 2627, 88R) by establishing procedures for applying for a loan for construction of dispatchable electric generation facilities within the ERCOT power region. The new rule also establishes evaluation criteria for the PUCT to use when reviewing loan applications, provides terms for repayment, and specifies performance standards in the terms of each borrower's loan agreement. **(Project No. 55826**)

## Texas Energy Fund Completion Bonus Grant Program

On April 25, 2024, the commission adopted new 16 TAC § 25.511. The new rule implements PURA §§ 34.0105 and 34.0106 (SB 2627, 88R) by establishing procedures for applying for a completion bonus grant award and terms for each annual grant payment. The new rule also specifies performance standards that an electric generating facility must achieve to obtain a completion bonus grant payment. **(Project No. 55812)**

## Review of Voluntary Mitigation Plan Requirements

On April 25, 2024, the commission adopted amendments to 16 TAC § 25.504. The amended rule implements PURA § 15.023 (HB 1500, 88R) by revising the standards, processes, and timelines under which voluntary mitigation plans are approved, reviewed, and terminated by the PUCT. The amended rule also clarifies that adherence to a PUCT-approved voluntary mitigation plan must be considered in a proceeding to determine whether a generation entity engaged in market power abuse and, if so, the appropriate administrative penalty to be assessed for the violation. **(Project No. 55948**)

## Review of Administrative Penalty Authority Related to Voluntary Mitigation Plans

On April 25, 2024, the commission adopted amendments 16 TAC § 25.8. The amended rule implements PURA § 15.023 (HB 1500, 88R) by increasing the authorized penalty for violations of market power abuse regulations in conjunction with not adhering to an applicable voluntary mitigation plan up to $1,000,000 per violation per day. Additionally, the amended rule aligns violation definitions across classifications, consolidates violation descriptions, and adds a new description for "special violations." **(Project No. 55955**)

## Review of §22.104 – Motions to Intervene

On April 25, 2024, the commission adopted amendments to 16 TAC § 22.104. The new rule implements PURA § 37.057 (SB 1076, 88R) by changing the intervention deadline from 45 days to 30 days for a proceeding involving a CCN application for a new electricity transmission facility that is subject to PURA § 37.057. **(Project No. 56253**)

## Reliability Standard for the ERCOT Market

On September 9, 2024, the commission adopted new 16 TAC § 25.508. The rule implements PURA § 39.159(b)(1) (SB 3, 87R) by creating a reliability standard for the ERCOT power region and identifying a process for the PUCT to review whether the ERCOT system is meeting that standard. **(Project No. 54584)**

## Goal for Reducing Average Total Residential Load in the ERCOT Region

On December 12, 2024, the commission adopted new 16 TAC § 25.186. The rule implements PURA § 39.919 (SB 1699, 88R) by establishing an average total residential load reduction goal for the ERCOT power region and authorizing REPs to meet that goal by offering responsive device programs to residential customers. These programs will be designed to reduce electricity consumption during an ERCOT peak demand period. **(Project No. 56966**)

### Temporary Emergency Electric Energy Facilities (TEEEF) and Long Lead-Time Facilities

On December 19, 2024, the commission adopted new 16 TAC §25.56 that established a process to allow a TDU to lease and operate TEEEF to aid in restoring power to the TDU's distribution customers during a significant power outage. The commission also adopted new 16 TAC §25.59, that established a process for a TDU to procure, own, and operate, or enter into a cooperative agreement with other TDUs to procure, own, and jointly operate, long lead-time transmission and distribution facilities that will aid in restoring power to the TDU's distribution customers following a significant power outage. The new rules also provide for the recovery of costs associated with TEEEF and long lead-time facilities. **(Project No. 53404)**

## III. Electricity Grid and Market Improvements

### Background

An unusually cold and windy weather pattern entered the southwest region of the United States on February 1, 2011 impacting generation resources through the morning of February 5, 2011. A total of 210 generation resources in the ERCOT region experienced a forced outage, derate, or failure to start during that period. System operators were required to order periodic, controlled load shed on February 2 and again on February 3. More than 3 million customers were affected.

In the wake of the storm, the commission worked with ERCOT and owners of generation resources to better prepare their facilities for winter weather events. Starting in December 2011, and each year thereafter, generation resource owners had to submit an attestation declaring that they were ready to manage winter weather conditions. This effort yielded decent results as the number of forced outages and derates due to winter weather conditions diminished over the rest of the decade.

In February 2021, Winter Storm Uri produced an unprecedented, extreme cold weather event across the Eastern, Central, and Southern United States. The severe winter weather escalated quickly through Sunday, February 14 into the early morning hours of Monday, February 15. Major load centers across Texas endured sustained and severe low temperatures. Electric generation units experienced forced outages as wind turbines froze and thermal generators tripped offline due to weather or limited fuel resources. To balance supply and demand on the grid, ERCOT ordered firm load shed, which electric utilities implemented with rotating outages. Many consumers were initially told to expect brief, temporary service outages. However, the controlled outage orders remained in place until early on Thursday, February 18. Some consumers remained without power because of storm-related damage to transmission and distribution infrastructure. ERCOT did not return to normal operations until mid-morning on Friday, February 19.

Immediately upon re-establishing normal grid operations, work began to determine what caused the severe and sustained outages and what the Texas Legislature, PUCT, and ERCOT needed to do to strengthen system reliability and resiliency.

In 2021, the Texas Legislature passed several bills related to the electricity industry, including Senate Bill 3 (SB 3). This legislation equipped the PUCT to implement landmark weatherization reforms. These reforms included:

- Requiring equipment and facility weatherization,
- Increasing financial penalties when utilities failed to meet weather emergency preparedness requirements,
- Providing ERCOT increased authority to manage planned power plant outages for maintenance and repairs, and
- Increasing collaboration between the PUCT and partner agencies to meet specific, statewide goals for increased safety and communication during inclement weather.

## Commission Action

### Requiring Equipment and Facility Weatherization

SB 3 authorized the PUCT to adopt and enforce weather preparation requirements for power generators and transmission service providers (TSPs). These requirements ensure facility owners take all necessary steps to prepare to sustain operations during both the extreme cold of winter and the extreme heat of summer. In the fall of 2021, the PUCT adopted a weather emergency preparedness rule (16 TAC § 25.55). This rule requires power facilities to prepare their facilities and file weather readiness reports confirming that their equipment is prepared for the upcoming winter or summer season. As addressed in more detail below, ERCOT annually conducts on-site facility inspections to verify compliance.

### Increasing Financial Penalties

In tandem with stronger weatherization requirements, SB 3 increased the maximum penalties for violation of those requirements from $25,000 to $1,000,000 per violation per day. In December 2021, the PUCT's Division of Compliance and Enforcement (DICE) proposed penalizing eight companies for failing to file winter weather readiness reports by the December 1, 2021 deadline.

### Providing ERCOT Increased Authority to Manage Power Plant Outages

For the first time, SB 3 provided ERCOT with the authority to proactively manage power plant maintenance and repair schedules. This planning ensures better system reliability because ERCOT can adjust the amount of generation offline at any given time. Before Winter Storm Uri, ERCOT Protocols required all generator outage requests submitted more than 45 days in advance to be accepted. In the summer of 2022 ERCOT adopted Nodal Protocol Revision Request 1108 (NPRR1108). This change allows ERCOT to reject a proposed outage no matter how far in advance it has been submitted. ERCOT now rejects an outage request when it determines the planned outage would cause total available generating capacity to fall below the level necessary to maintain system reliability. ERCOT publicly posts the total number of megawatts of planned outages available for each period of any given day, so that generators can plan and schedule their outages.

## Increasing Collaboration Between the PUCT and Partner Agencies

In 2021, new legislation outlined several areas where increased collaboration and communication between the PUCT and partner state agencies including Railroad Commission of Texas (RRC), Texas Department of Emergency Management (TDEM), Texas Department of Transportation (TxDOT) would better serve Texans during severe weather outbreaks. The commission continues to collaborate with these and other state agencies to effectively regulate the electric industry.

## Texas Electricity Supply Chain Committee and Map

Senate Bill 3 established the Texas Electric Supply Chain Mapping Committee to create and maintain the Texas Electric Supply Chain Map. The Mapping Committee is made up of members from the PUCT, RRC, ERCOT, TxDOT, and the Texas Division of Emergency Management (TDEM). The Committee identified and mapped critical infrastructure facilities throughout Texas, including electric generation plants and the natural gas plants that supply fuel to power the generators. The map is used during weather emergencies and natural disasters to allow for situational awareness and coordinated responses.

While the map is not publicly available for security reasons, as of November 1, 2024, it includes the following information:

- More than 12,740 facilities, including electricity generation plants powered by natural gas, electric substations, natural gas processing plants, underground gas storage facilities, oil and gas well leases, and saltwater disposal wells,
- More than 21,000 miles of gas transmission pipelines,
- Approximately 60,000 miles of electric transmission lines,
- Approximately 13,000 water and wastewater treatment plants, and
- A basemap layer of TxDOT roads.

## Critical Natural Gas Facilities

House Bill 3648 (87R) instructed the PUCT and the RRC to designate certain natural gas facilities as critical facilities during energy emergencies. Each agency enacted a rule to complete this requirement. The PUCT's rule (16 TAC § 25.52) requires critical natural gas production facilities to provide electric utilities with critical customer information. It also prioritizes critical gas facilities for restoration during an energy emergency event. The RRC's rule (16 TAC § 3.65) establishes critical designation criteria and timelines for critical natural gas facilities to provide information to electric utilities. It also designates critical gas suppliers and customers.

## Texas Energy Reliability Council

The Texas Energy Reliability Council (TERC) was also established by SB 3. TERC is a collaboration among the PUCT, the RRC, the Office of Public Utility Counsel (OPUC), the Texas Commission on Environmental Quality (TCEQ), the TxDOT, the TDEM, and ERCOT. The governor, the PUCT, and the RRC each nominate private citizens, including industry representatives from the electric energy and oil and gas sectors, to serve on TERC.

TERC enables a multi-industry perspective to better plan and coordinate emergency preparedness and response efforts. TERC enhances coordination and communication in the energy and electric industries so that the state meets high-priority human needs and addresses critical infrastructure concerns. SB 3 requires TERC to meet at least twice a year. However, TERC has met more frequently to better ensure open communication and address any issues that may arise in a timelier fashion.

## Power Outage Alert System

SB 3 required the adoption of a statewide Power Outage Alert system that works on both a regional and statewide level. The PUCT approved substantive rule 16 TAC § 25.57 in 2022 which outlines the criteria for issuing, updating, and terminating a power outage alert. ERCOT must notify the PUCT when its forecasts indicate that systemwide generation supply will likely be insufficient to meet demand within the next 48 hours. It must also notify the agency when it issues systemwide load shed instructions. TSPs in non-ERCOT regions are required to notify the PUCT if they receive system-wide load shed and load shed recall instructions from their applicable reliability coordinators. When the PUCT executive director recommends a Power Outage Alert, the Texas Department of Public Safety (DPS) issues the power outage alert message statewide or for one or more specific power regions in Texas. The alert is then passed to broadcasters and other entities for dissemination to the public.

## Consumer Complaints

Beginning in September 2023, the commission reduced the number of days it requires an electric utility to respond to consumer complaints from 21 to 15 days to ensure quicker resolution of consumer complaints. See 16 TAC § 25.485 for specific amendments.

## Ongoing Weather Preparation Efforts During Fiscal Years 2023-2024

Weatherization efforts remained a key priority for the commission in FY 2023 and 2024.

### Expanding Weather Preparation Requirements to Include Summer Weather and Weather Study Standards

At the beginning of fiscal year 2023, the commission expanded weatherization requirements for generators and TSPs to include summer weather preparation. Power facility owners were required to prepare their facilities and file winter weather readiness reports by December 1 each year and summer weather readiness reports by June 1 each year.

Amended 16 TAC § 25.55 sets specific, minimum weather-related standards to study for ten geographically distinct areas of the state. The rule establishes baseline daily and average 72-hour temperatures (both minimum and maximum), sustained wind speed, and wind chill in the region the operator is located. Each generator or TSP must prepare its facilities to be able to operate at those baseline factors. The rule provides specific guidance for ensuring operations during sustained wind chill temperatures.

To ensure weatherization requirements remain up to date, ERCOT must study historical weather data and file the results of that study in a report with the commission no later than November 1, 2026. ERCOT may add additional parameters to the study, and it must take into consideration weather predictions produced by the office of the state climatologist. It must update this study at least every five years.

### Weather Preparedness Planning

The PUCT and ERCOT conduct workshops and trainings before each winter and summer season to help market participants understand and comply with the weatherization standards. Market participants also share best practices for preparedness during these workshops. Since December 2021, the PUCT and ERCOT have conducted four workshops.

In FY 2024, ERCOT developed a weatherization and inspection portal that allows market participants to file their weather readiness reports. It also allows ERCOT to perform compliance checks to ensure weatherization standards are being met.

### Inspections and Cure Periods

Each generation facility is inspected at least once every three years. Between December 2021 and August 2024, ERCOT completed nearly 2,900 inspections of generators and transmission service providers. The requirement for winter inspections began in December 2021. Summer inspections began in the summer of 2023.

| Inspections | Generation Facilities | TSP Facilities | Total |
|---|---|---|---|
| Winter 2021-22 | 302 | 22 | 324 |
| Winter 2022-23 | 634 | 140 | 774 |
| Summer 2023 | 208 | 342 | 550 |
| Winter 2023-24 | 340 | 129 | 469 |
| Summer 2024 | 417 | 358 | 775 |
| Total | 1,901 | 991 | 2,892 |

The weatherization rule requires a "cure period" after an inspection is conducted. This cure period allows a facility to correct deficiencies within 72 hours of the on-site inspection. These cure periods have proven effective. Overall, ERCOT has issued 109 cure periods since winter weather inspections started in December 2021. Winter cure periods are down from an all-time high of 69 over the winter of 2022-23 to just five cure periods during the next winter of 2023-24. Summer cure periods are down from a high of 16 during the summer of 2023 to three during the summer of 2024.

| Cure Periods | Generation Facilities | TSP Facilities | Total |
|---|---|---|---|
| Winter 2021-22 | 10 | 6 | 16 |
| Winter 2022-23 | 20 | 49 | 69 |
| Summer 2023 | 12 | 4 | 16 |
| Winter 2023-24 | 4 | 1 | 5 |
| Summer 2024 | 3 | 0 | 3 |
| Total | 49 | 60 | 109 |

Entities with repeated or severe weather-related failures must undergo an independent assessment by a qualified professional engineer. Noncompliance with weatherization standards may result in enforcement actions and financial penalties. Between 2021 and 2023, the commission closed 29 weatherization compliance-related cases with assessed administrative penalties of approximately $800,000 on eight of these cases. As of November 2024, there are six open enforcement cases pertaining to weatherization.

## Firm Fuel Supply Service

As part of SB 3, the PUCT and ERCOT created a new Firm Fuel Supply Service (FFSS) to ensure generators have access to fuel at their plants if natural gas supplies are disrupted during extreme winter weather conditions. ERCOT contracts with participating generators to ensure access to at least 48 hours worth of backup fuel to be consumed during fuel scarcity events. ERCOT procures this service annually no later than August 1. The FFSS program is now in its third year. ERCOT procured 4,194.8 MW for the 2024-25 winter period.

## Weatherization Success

Since Winter Storm Uri in February 2021, the ERCOT grid has set several all-time, yearly, monthly, or daily peak demand records through multiple Arctic blasts and record-setting summer heat. The development and implementation of critical landmark grid weatherization reforms has kept the ERCOT grid operating without systemwide disruption or load shed through all these periods of record demand—ensuring the safe, reliable delivery of electricity to Texans. Ongoing vigilance is needed, however, as every new storm presents a new set of planning and operational challenges for the industry to confront.

## Market Design

The PUCT continues to implement wholesale electricity market design improvements to ensure reliability of the state's electric grid at a reasonable cost to rate payers. The commission adopted a two-phase blueprint for ERCOT wholesale electricity market design in its orders issued on January 13, 2022 (Phase 1) and January 19, 2023 (Phase 2).[11] The blueprint is a compilation of directives and market concepts designed to reform the wholesale electricity market.

The market design improvements include both legislative implementation and a proactive effort from the commissioners to identify potential improvements to the ERCOT grid and the competitive wholesale market design. The commission implemented several wholesale market design initiatives to enhance the operational reliability of the grid.

- **ERCOT Contingency Reserve Service (ECRS)** – ERCOT added a new ancillary service product in June 2023. ECRS mitigates real-time operational issues due to rapid changes in wind and solar output to keep electricity supply and demand balanced within the next 10 minutes.
- **Reliability Standard for the ERCOT Market** – In August 2024, the commission approved a reliability standard (16 TAC § 25.508) based on three criteria: frequency, duration, and magnitude of the loss of load events.
- **Value of Lost Load (VOLL)** – VOLL is a measure of the costs associated with interruptions in the supply of electricity. The commission approved a VOLL of $35,000/MWh for the ERCOT region. This estimate was developed based on a customer survey of Texas consumers by ERCOT.[12] Prior to the current value's adoption, VOLL in the ERCOT region had been set at $5,000/MWh since January 1, 2022, after being reduced from the previous value of $9,000/MWh.
- **Cost of New Entry (CONE)** – CONE is the levelized first year revenue that a resource needs to earn to incentivize construction of a new generation resource in the ERCOT region. The commission approved an updated CONE of $140,000 per MW-year based on a frame combustion turbine.

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[11] *Review of Wholesale Electric Market Design*, Project No. 52373, Approval of Blueprint for Wholesale Electric Market Design and Directives to ERCOT, AIS Item No. 336 (1/13/2022) and Order and Modified Memorandum, AIS Item No. 391 (1/20/2023).

[12] *Review of Value of Lost Load in the ERCOT Market*, Project No. 55837, ERCOT Value of Lost Load Study Final Report, AIS Item No. 12 (8/22/2024).

Below are the market design initiatives that the commission continues to work on:

**Demand Response** – The commission is pursuing market initiatives that allow for more targeted demand response to increase utilization of load resources for grid reliability. Demand response programs are intended to alter the timing of usage, type of demand, or the total electricity consumption. Demand response can refer to intentional actions taken by the customer or for the customer in response to conditions in the electricity market. Project No. 56966, 54445, and 53911 each address topics related to demand response.[13,14,15]

**Voltage Support Compensation** – In 2023, ERCOT conducted a study to evaluate whether voltage support compensation could be another revenue source for the dispatchable generators and help maintain grid stability as more inverter-based resources enter the market.[16]

**Performance Credit Mechanism (PCM)** – The PCM is a credit-based resource adequacy program. If the current market system is not meeting the established reliability standard, the PCM would provide additional revenues to generators to incentivize the entry of new resources. These revenues would come from a requirement for load serving entities to purchase performance credits from a centralized market. Eligible generators would be awarded PCs based on their availability during hours with the highest reliability risk. If the current system is meeting or exceeding the established reliability standard, the PCM would generate little to no additional revenues for existing generators and would provide no incentive, on its own, for additional generation to enter the market.

To evaluate the PCM program, as required by PURA § 39.1594 (d), ERCOT and IMM each conducted a cost-benefit assessment. For the purposes of conducting a cost-benefit assessment, the commission approved the PCM design parameters subject to guardrails as required in HB 1500.

At the December 19th 2024 open meeting, the commission approved Staff's recommendation to not move forward with the PCM at this time. As currently designed, it would not provide cost effective reliability benefits for the ERCOT market. The results of the cost-benefit analysis can be accessed in Project No. 55000.[17]

**Dispatchable Reliability Reserve Service (DRRS)** – ERCOT is currently developing a framework for implementing DRRS as a standalone ancillary service. Through DRRS, ERCOT would procure

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[13] *Goal for Reducing Average Total Residential Load in the EROCT Market, Project No. 56966.*
[14] *Review of Protocols Adopted by the Independent Organization*, Project No. 54445.
[15] *Aggregate Distributed Energy Resource (ADER) ERCOT Pilot Project*, Project No. 53911.
[16] *Voltage Support Compensation*, Project No. 56184, Staff memo, AIS Item No. 2 (2/5/2024).
[17] *Performance Credit Mechanism (PCM),* Project 55000, #45 ERCOT and E3 PCM Cost Benefit Analysis (12/6/2024) and #46 Revised IMM evaluation of PCM (12/10/2024)

dispatchable generation for reliability on a day-ahead and real-time basis to address electricity market uncertainty. DRRS is expected to be implemented after the real time co-optimization of energy and ancillary services is implemented in December 2025.[18]

**Review of Ancillary Services in the ERCOT Market** – PURA 35.004 (g) (SB3,87R) required the commission to review the type, volume, and cost of ancillary services (AS) and evaluate if additional ancillary services are needed for reliability in the ERCOT region. The commission conducted the AS study in collaboration with ERCOT and the IMM. At the December 19, 2024 open meeting, the commission adopted findings and recommended next steps pertaining to seven policy topics discussed in the AS study[19]. More information on the policy topics, AS study report, and related public proceeding can be found under Project No. 55845.

Emergency Pricing Program – The Emergency Pricing Program (EPP) is activated when the system-wide energy price has been at the high system-wide offer cap for 12 hours within a rolling 24-hour period.[20] While the EPP is active, the system-wide offer cap will be lowered to the Emergency Offer Cap until the EPP is terminated. The EPP would remain in effect for at least 24 hours after being activated, but it would not terminate until at least 24 hours after ERCOT exits any emergency operations without re-entering emergency operations.

Financial Improvements - Following Winter Storm Uri, market participants left billions of dollars in unpaid invoices with ERCOT. To protect consumers and the integrity of the market, the PUCT took additional steps to address credit requirements and required the REPs to put more money in security deposits. These steps were taken by the commission to ensure only financially strong REPs remained in the market.

In April 2023, the commission amended 16 TAC § 25.107 to broaden the financial requirements to obtain a REP certificate by increasing the amount required for letters of credit maintained by REPs to $1.5 million. Historically, a REP could use a $500,000 irrevocable letter of credit to demonstrate access to capital as part of the REP certification process. The commission also revised the requirement for REPs electing to meet the access to capital requirement via a standard form irrevocable guaranty agreement. A guarantor is currently required to have a tangible net worth greater than or equal to $100 million. The new REP financial requirements ensure adequate funds are available in the event a REP becomes insolvent or exits the market.

[18] ERCOT NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service (May 29, 2024).

[19] See AIS Project No.55845.

[20] Project 54585, Item #40 Order Adopting Amendments to 16 TAC § 25.509, AIS Item No. 40 (12/1/2024).

## Transmission and Distribution

### System Resiliency Plans

In February 2024, the commission implemented 16 TAC § 25.62 (HB 2555, 88R), allowing electric utilities to submit system resiliency plans. These plans are designed to help utilities prevent, withstand, mitigate, or recover more promptly from events such as extreme weather, wildfires, and cybersecurity or physical threats. Increasing system resiliency through these plans is expected to reduce long-term costs and improve overall service reliability for customers. Once approved, utilities may recover the costs of the improvements through the rates charged to customers. A utility can request to update its system resiliency plan every three years. The rule outlines guidelines for resiliency measures, including:

- Hardening and modernizing electric transmission and distribution facilities,
- Undergrounding electric distribution lines,
- Adopting measures to mitigate lightning strikes, floods, and wildfires,
- Vegetation management,
- Information technology,
- Cybersecurity and physical security measures.

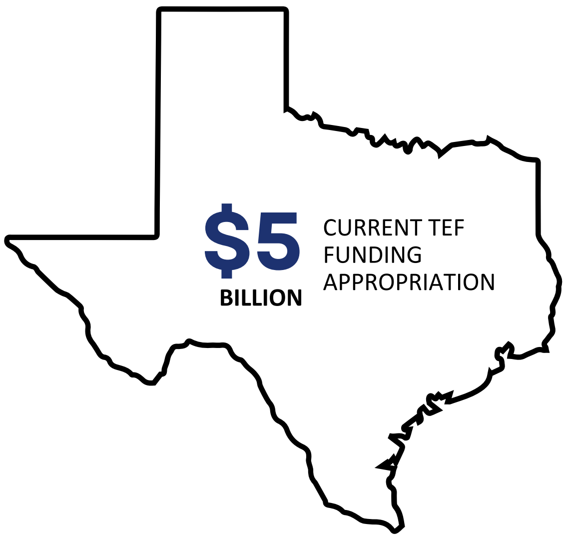
Seven electric utilities have filed system resiliency plans. These plans commonly include measures such as distribution hardening, wildfire mitigation, and vegetation management. For example, some utilities propose replacing wood poles with poles that meet new wind loading criteria and expanding vegetation management programs to include targeted inspections to identify and address wildfire risks. Five system resiliency plans—AEP Texas, TNMP, ETI, SPS, and Southwestern Electric Power Company (SWEPCO)—are in various stages of commission review and approval. Oncor's system resiliency plan was the first to be approved by the commission. CenterPoint Energy submitted a resiliency plan but later withdrew it in August 2024 following Hurricane Beryl.

### West Texas Transmission (Permian Basin)

Electricity demand in the Permian Basin in west Texas is growing rapidly as the oil and gas industry continues to electrify operations. The region’s electricity needs are evolving with the development of large commercial facilities including new data centers, cryptocurrency mining centers, and hydrogen production facilities. ERCOT forecasts electricity demand in the Permian Basin could grow to nearly 26 GW by 2038, equivalent to almost one third of the current summer demand of the entire ERCOT system. PURA § 39.167 (HB 5066, 88R) requires a reliability plan for the Permian Basin to address increased need for transmission capacity to meet the growing load in the region. In July 2024, ERCOT submitted a comprehensive transmission plan for the Permian Basin region that includes transmission projects local to the region as well as long-distance transmission projects that will import power from other regions of Texas into the Permian. This long-term plan will bolster transmission infrastructure to serve existing consumers and forecasted load growth in the Permian Basin through 2038. In September 2024, the PUCT approved the Permian Basin Reliability Plan.

The Permian Basin Reliability Plan consists of new and upgraded 138-kV and 345-kV transmission lines, substations, and equipment that will allow for the expansion of transmission service to new areas and will reduce interconnection times. The plan also provides new import paths that consist of 345-kV or EHV 765-kV transmission line options to increase access to available generation capacity.

# TEXAS ENERGY FUND BY THE NUMBERS




**In-ERCOT Generation Loan Program ***

**18**

**# of Applications undergoing Due Diligence**

**In-ERCOT Completion Bonus Grant Program**

**Application to open January 1, 2025**

**Outside-ERCOT Grant Program [1]**

**Application to open Summer 2025**

**Texas Backup Power Package Program [1]**

**Application to open Fall 2025**

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**In-ERCOT Generation Loan Program***

**9,720 MW**

**# of Megawatts under Due Diligence**

**$5.34 BILLION**

**$ TEF Funds Requested by Applicants under Due Diligence**

***1. Projected application open dates subject to change***

**** Projects advanced to due diligence do not guarantee an executed loan agreement. The PUCT may identify issues during due diligence that may disqualify applicants.***

# IV. Electricity - Texas Energy Fund

The Texas Energy Fund (TEF)—passed as Senate Bill 2627 during the 88th Regular Session of the Texas Legislature—supports the construction, maintenance, modernization, and operation of electric facilities in Texas. To ensure sufficient and reliable electric service, the TEF legislation directed the PUCT to implement and administer four loan and grant programs to support dispatchable electricity infrastructure throughout the state.

On November 7, 2023, Texas voters approved a constitutional amendment to create the $10 billion fund. To date, the Legislature has appropriated $5 billion to finance the four Texas Energy Fund programs. The PUCT oversees these programs with the assistance of various vendors, including Deloitte & Touche LLP, who provides primary consulting and administration services. Holland & Knight LLP provides legal services and Patrick Engineering, Inc. provides research and specifications for back-up power packages. The PUCT also anticipates procuring two additional TEF vendors for financial services in support of the four TEF programs, and back-up power technical and installation support.

## In-ERCOT Generation Loan Program

To stimulate the construction of new electric generation in ERCOT, PURA § 34.0104 authorizes the PUCT to use TEF funds to provide low-interest loans for the construction of new dispatchable generating facilities and upgrades for existing dispatchable generating facilities within the ERCOT power region.

These loans are available for projects that will add 100 MW or more of new dispatchable generation capacity per facility. TEF loans must have a 20-year repayment term at three percent interest, and the loan recipient can finance up to 60% of the estimated cost of the facility to be constructed. In March 2024, the PUCT adopted 16 TAC § 25.510 to establish procedures for applying for In-ERCOT loans as well as compliance terms for approved borrowers. The PUCT accepted loan applications between June 1, 2024, and July 27, 2024. Initial loan disbursements to approved applicants must be made by December 31, 2025.

In August 2024 the PUCT advanced 17 applications to undergo a due diligence review. One of the applications was denied in September 2024. On December 12, 2024, the PUCT advanced two additional applications to due diligence. Upon satisfactory completion of due diligence review, approved applicants will execute loan agreements with the PUCT and begin construction of their respective generation projects.

## TEF Timeline

| Step (Timing) | Explanation |
|---|---|
| **Notice of Intent to Apply (May 2024)** | Potential applicant submits notice that it intends to apply for a TEF In-ERCOT loan. |
| **Application Open (June 1 through July 27, 2024)** | Application presents project description and applicant attributes for Commission review. |
| **Application Review (July 27, 2024 – August 20, 2024)** | PUCT Staff and Consultant evaluate applications and present recommendation to Commission for projects to be advanced for due diligence and potential funding. |
| **Commission Order (August 29, 2024)** | Commission votes to advance first round of applications for due diligence review and potential funding. |
| **Due Diligence (Tentative: 4-8 months after Commission Approval vote)** | Consultants analyze project and applicant attributes to confirm suitability for approval of a TEF loan. |
| **Loan Execution (Prior to November 2025 to allow 1st disbursement by December 31, 2025)** | Applicant executes loan agreement and receives initial disbursement. |

### Completion Bonus Grant Program

To incentivize the prompt addition of new generation, PURA § 34.0105 authorized the PUCT to provide bonus grants for the completion and operations of new, dispatchable generating facilities in the ERCOT power region. In April 2024, the PUCT adopted 16 TAC § 25.511 to establish procedures and eligibility criteria for facilities to apply for a completion bonus grant.

New or expanded generation resources providing 100 MW or more of new capacity within the ERCOT Region may be eligible for a completion bonus grant. New generation interconnected before June 1, 2026, can receive a bonus up to $120,000 per MW of capacity (so, for example, up to $12 million for a 100 MW facility). For facilities interconnected after June 1, 2026, but before

June 1, 2029, the maximum bonus is $80,000 per MW of capacity (up to $8 million for a 100 MW facility). Grants will be paid in 10 installments over a 10-year period, subject to performance measures over an annual 12-month test period that runs between June 1 - May 31. The application for this program will open on January 1, 2025. Awards will be based upon funding availability.

## Outside ERCOT Grant Program

PURA § 34.0103 authorizes the PUCT to award TEF grants to transmission and distribution infrastructure and electric generation facilities outside of the ERCOT power region for infrastructure modernization, weatherization, reliability and resiliency enhancements, or vegetation management. Grants may not be used to make debt payments or pay for compliance with weatherization standards adopted before December 1, 2023. The PUCT anticipates the adoption of a rule to implement this program in early 2025 and the application for this program to open by summer of 2025.

## Texas Backup Power Package Program

To enhance critical facility resiliency throughout the state, PURA § 34.201 allows the PUCT to award grants and loans for backup power sources that can be used for islanding host facilities from the power grid for 48 hours or more. Qualifying host facilities are those that communities rely on for health, safety, and well-being.

In January 2024, the PUCT empaneled the Texas Backup Power Package Advisory Committee, which provided recommendations on criteria to employ in making grants and loans under this program on October 1, 2024.

The PUCT has procured a research entity, Patrick Engineering, Inc., to provide reports and specifications in support of the Backup Power Package Program.

The PUCT anticipates the commencement of a rulemaking project to implement the Texas Backup Power Package program in early 2025 and the program application to open by Fall of 2025.

# TELECOMMUNICATIONS BY THE NUMBERS

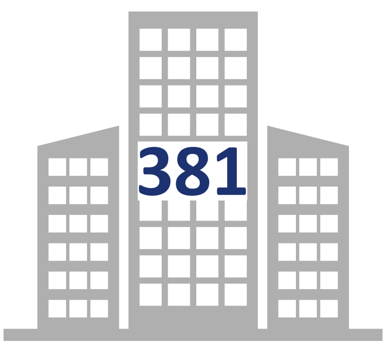
## CORE FUNCTIONS

### PUCT Regulated Services


- Regulates intrastate rates and services of landline telecom service
- Issues CCNs, COA, and SPCOA certificates

### PUCT Functions

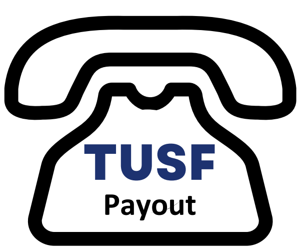
- **Cable and Video Services**: Issues a State Issued Certificate of Franchise Authority (SICFA)
- **Consumer Complaints**: Address telecom consumer complaints
- **Technical Assistance Programs**: Administers the TUSF assistance programs




**Total Regulated Telecom Companies**


**Total Certifications and Recertifications**


**Texas Universal Service Fund (TUSF)- Participating Telecom providers**




**$194,419,945**
**FY 2023**

**$184,549,094**
**FY 2024**

# V. Telecommunications – Scope of Competition

The telecommunications market in Texas includes voice, broadband, and cable and video services. The PUCT has regulated telecommunication services in Texas since 1975. With passage of the 1996 Telecommunications Act, the PUCT's jurisdiction was limited to the regulation of landline telecommunications service, with some exceptions. The agency currently regulates intrastate rates of landline service and issues certificates of franchise authority (CFAs). An entity must have a CFA to provide cable or video services in Texas. The PUCT does not regulate wireless or broadband services.

The PUCT regulates traditional voice services and intrastate rates offered by landline service providers that provide basic local exchange telephone service over landline. Basic Local Telecommunications Service (BLTS) is flat rate residential and business local exchange telephone service. BLTS includes primary directory listings, tone dialing service, access to operator and directory assistance services, as well as access to 911 service where provided by a local authority. The commission may require other services, after a hearing, to be included in basic local telecommunications service.

### Telecommunication Service Providers

**Incumbent Local Exchange Carrier (ILEC)**
An incumbent local exchange carrier is a telecommunication company that had a Certificate of Convenience and Necessity (CCN) on or before September 1, 1995. An ILEC provides only landline service within its service territory unless specifically approved by the PUCT to provide service outside its territory. ILECs provide critical physical telecommunications infrastructure especially, in rural Texas.

**Competitive Local Exchange Carrier (CLEC)**
A competitive local exchange carrier is a telecommunication company created by the telecommunications Act of 1996 that opened the traditional telecom market to competition. CLECs provide landline and other telecommunications services and may use facilities leased from ILECs.

## Jurisdiction

The PUCT regulates two main entities for voice services in the state, Incumbent Local Exchange Carriers (ILECs) and Competitive Local Exchange Carriers (CLECs). To provide local exchange telephone service, BLTS or switched access service in Texas, each ILEC must obtain a CCN, and each CLEC must either obtain 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. The PUCT also processes certifications for cable and video services. These are called State Issued Certificate of Franchise Authority (SICFA). A provider must obtain a SICFA to provide cable or video service.

## Incumbent Local Exchange Carriers (ILECs)

An ILEC has one of five distinct legal classifications, primarily based on the number of copper-wire lines they manage and whether the ILEC is fully regulated, partially deregulated, or fully deregulated. As of September 1, 2024, there are 61 active ILECs in Texas. The figure below provides details on the ILECs under PUCT jurisdiction.

| | **Fully Regulated** | **Partially Regulated** | | | **Deregulated** |
|---|---|---|---|---|---|
| **PURA Chapters** | **Chapter 52** | **Chapter 53** | **Chapter 58** | **Chapter 59** | **Chapter 65** |
| Type of Regulation | must maintain a tariff on file with the PUCT; must request PUCT review to change rates | (cooperatives only) must maintain tariff on file with the PUCT; can change rates with formal notice | pricing flexibility for existing services only; can change rates with informal notice | pricing flexibility for new and existing services; can change rates with informal notice. | do not maintain a tariff with PUCT; can change rates at own discretion |
| Number of lines served | ≤ 31,000 lines, typically serve rural areas | ≤ 31,000 lines, typically serve rural areas | ≥ 31,000 lines, typically serves urban areas | N/A | N/A |
| Number of ILECs | 44 | 3 | 11 | 0 | 3 |

## Competitive Local Exchange Carriers (CLECs)

A CLEC must obtain a COA or SPCOA to provide service. The PUCT processed 68 COA and SPCOA dockets during FY 2024. These included new applications and applications for amendments. As of September 1, 2024, there are 300 active CLECs in Texas.

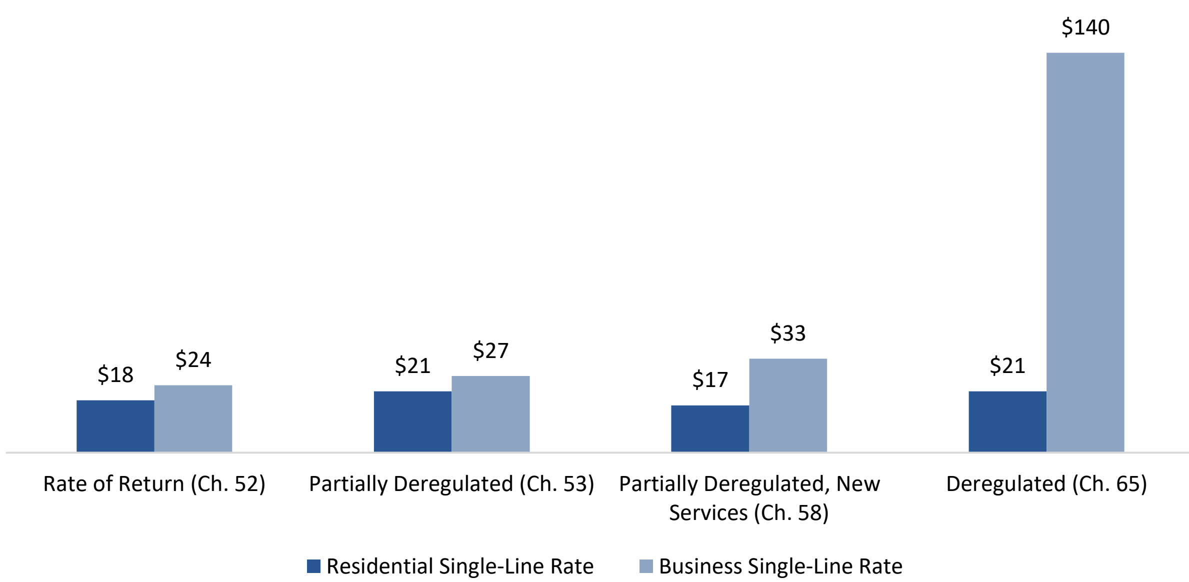
## Cable and Video Service

The PUCT issues certifications for cable and video service. PURA Chapter 66 designated the PUCT as the franchising authority for the provision of cable or video service. A State Issue Certificate of Franchise Authority (SICFA) replaced individual Cable and Video Municipal Franchises as they expired. As of September 1, 2024, there are 78 active SICFAs in Texas.

## Regulation and Rates Around the State

Fully regulated ILEC service areas are predominantly in rural Texas. Basic local telecommunication service rates in rural areas of the state are generally priced below the economic cost of providing service. The difference in the telecom service price and economic cost of providing service is subsidized through universal service fund mechanisms at both the state and federal levels.

Transitioning or deregulated ILECs mostly operate in urban areas. The rates charged by these companies tend to be higher. The figure below presents average telecommunication services rates by regulation type.




Eastex Telephone Cooperative, Inc., for example, offers residential landline service at $22.50 per month. Eastex is a fully regulated ILEC that serves consumers in small and rural areas of Northeast Texas.

Conversely, AT&T provides landline service in most of Texas' urban areas. It offers residential landline service at a rate of $51.00 per month. AT&T is a fully deregulated company, and its rates for local landline service, except for certain grandfathered rates, are uniform throughout its service territory.

The rates for single-line business service by rural ILECs are often less than those of ILECs in urban areas. For example, Frontier Communications charges a single-line business rate of $49.99 in urban areas. Conversely, West Plains Telecommunications, Inc., offers single-line business service in small and rural areas at a monthly rate of $22.18.

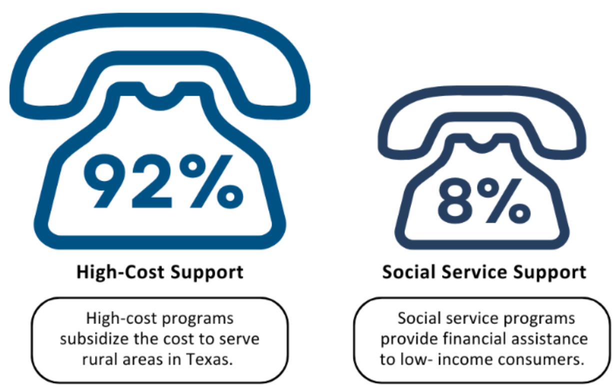
Frontier Communications is a deregulated company with pricing flexibility that is not available to fully regulated Chapter 52 companies, similar to other small and rural ILECs such as West Plains Telecommunications, Inc. Accordingly, fully regulated small and rural ILECs are limited in their ability to offer higher rates compared to companies that are not fully regulated (i.e., Chapter 58 and 65 companies).

## Texas Universal Service Fund (TUSF)

The TUSF was established in 1987 to enable all residents of the state to obtain Basic Local Telecommunications Service at an equitable rate. To accomplish this, the PUCT adopts and enforces rules requiring local exchange companies to establish universal service and administers the TUSF in a way that ensures reasonable rates for basic local telecommunications service.

### Programs Funded by TUSF

The TUSF has two programs, high-cost support programs and social service support programs. These programs together have nine service categories that fund 11 separate activities. The high-cost programs assist telecommunications providers that 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. The total TUSF funding was $194.41 million in 2023 and $184.54 million in 2024.




High-Cost Support program expenses comprise approximately 92.21% of the total TUSF expenditures. The following are payouts for high-cost and social service support.

## High-Cost Support Programs

| Program | Description | FY 2023 Payout | FY 2024 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. | $76,175,639 | $66,280,653 |
| **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. | $89,203,533 | $94,011,765 |
| **Additional Financial Assistance** | Additional revenue for ILECs drawing funds from the THCUSP or SRIUSP under certain conditions (PURA §§ 53.105, 53.151, and 53.406). Has never been used to seek additional support. | N/A | N/A |
| **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. (PURA § 56.025) | $11,955,528 | $9,561,565 |
| **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. | $138,314 | $124,402 |
| **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. | $202,034 | $198,269 |
| **Total** | | $177,675,047 | $170,176,654 |

## Social Service Support Programs

| Program | Description | FY 2023 Payout | FY 2024 Payout | FY 2024 Benefits Received |
|---|---|---|---|---|
| **Specialized Telecommunications Assistance Program (STAP)** | Reduces the costs of telephone equipment for consumers with speech or hearing disabilities. | $11,374,387 | $10,028,284 | 8,872 (No. of telephone equipment vouchers utilized for STAP program) |
| **Lifeline** | Reduces monthly voice rates for low-income consumers. | $4,051,418 | $2,928,791 | 489,003 (No. of total lifeline discounts received) |
| **Texas Relay Service** | Allows Texans with speech or hearing disabilities to communicate using specialized devices and operator translations. | $841,786 | $894,505 | 210,221 (No. of relay service conversation minutes used) |
| **Audio Newspaper Program** | Free telephone service that allows blind and visually impaired persons access to the text of newspapers by using synthetic speech. | $476,439 | $520,152 | 816,909 (No. of audio newspaper minutes used) |
| **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. | $868 | $708 | 82 (No. of Tel-Assistance support received) |
| **Total** | | $16,744,898 | $14,372,440 | |

### TUSF Funding

The TUSF is funded by a fee based on landline-based voice services along with voice portions of wireless carriers' billing. This is a fee telecom companies pay that is passed to Texas consumers. The fee is not based on data services. The number of traditional landline access lines has decreased over the years. This had led to reduced basic service portions related to voice service. Both these factors had led to a reduction in fee contributions made by the companies to the TUSF. Consequently, the TUSF could not collect enough money to fully fund the program, past January 2021. This in turn reduced reimbursements to carriers reliant on the TUSF.

On August 1, 2022, the Commission raised the TUSF surcharge assessment to 24% to fund TUSF obligation. This action resulted in fully funding TUSF obligations. Effective July 1, 2023, the Commission reduced the surcharge rate to 12%. The current TUSF fee of 12% is estimated to sufficiently fund the TUSF programs' expenditures. Emerging technologies, along with consumers converting to broadband services, requires the commission to monitor the TUSF to ensure a sufficient fund balance to cover all expenditure requirements.

## Emerging Issue

### Relinquishment of POLR Designation

Telecom companies are increasingly requesting to relinquish their provider of last resort (POLR) designation. Certificated telecommunications service providers including an ILEC or CLEC are obligated to be the POLR. A POLR telecom company is required to provide reasonably priced landline service to requesting consumers throughout its service territory, even if it is just for one consumer. To provide POLR services to all requesting customers, telecom companies may be required to maintain expensive telecom facilities.

Beginning 2015, telecom companies serving competitive areas and holding a COA are not required to fulfil the obligations of a provider of last resort, and could request to be relieved of their POLR obligation.[21] However, if more certificated telecom companies continue to relinquish POLR designation steadily, certain geographic areas may not be covered by a POLR company.

## Rulemaking

### Rule Review of Chapter 26 – Substantive Rules Applicable to Telecommunications Service Providers

On November 30, 2023, the commission repealed and replaced 16 TAC § 26.208 and adopted 16 TAC §§ 26.89,26.207, 26.209, 26.210, and 26.211 to implement PURA §52.251 as enacted by HB

[21] Public Utility Regulatory Act, Tex. Util. Code Ann. § 65.102

1597, 88R. The new rule and amendments clarify the requirements associated with filing and approval of telecommunications tariff with the commission.

The rulemaking amended 16 TAC §26.407 to implement PURA §56.032 as enacted by SB 1425, 88R to require small ILECs seeking adjustments to the TUSF high cost and small and rural plan, to publicly file with the commission their operational information, each year. The rule also amended 16 TAC §26.405 to implement PURA §56.023 as enacted by SB 1710, 88R to revise the eligibility criteria to receive TUSF support and require the commission to periodically review such criteria. Additionally, several minor and conforming changes were made to several rule sections throughout Chapter 26 as part of the Texas Administrative Procedure Act (APA) industry rule review that each state agency is required to conduct every four years. (**Project No. 54589)**

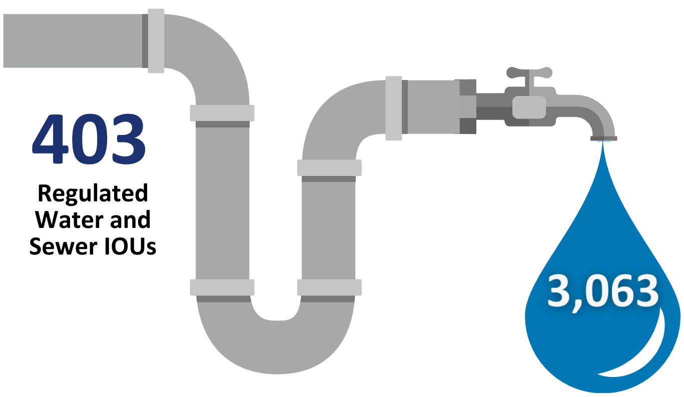
# WATER AND SEWER BY THE NUMBERS

## CORE FUNCTIONS

**Water and Sewer Industry Core Functions and Jurisdiction**

- CCNs*
- Water Rate Setting
- Consumer Complaints
- Registration of Entities**
- Non-functioning and Abandoned IOUs
- Industry Assistance Programs

*- Certificate of Convenience and Necessity, **-Submetered and Allocated billing

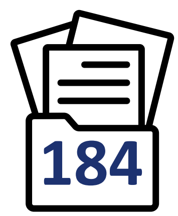



**403**
Regulated Water and Sewer IOUs

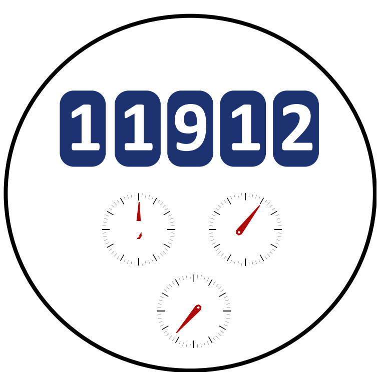
Water Retail Public Utilities

**Over 11 million Connections**

**441**
CCN Applications Processed




Water and Sewer Rate Reviews Performed




Registered Entities - Submetered and Allocated Billing


No. of industry assistance projects***

*** Industry assistance projects mainly include technical assistance provided to IOUs by an external contractor at the direction of the commission.

# VI. Water and Sewer Services

The PUCT regulates investor-owned water and sewer utilities (IOUs) in Texas. The PUCT's authority over IOUs is limited to financial and managerial operations of IOUs. The agency sets retail rates for IOUs and issues certificates of convenience and necessity (CCN) authorizing an IOU to provide water and sewer service in a specified service area. As of the end of FY 2024, there are 403 IOUs in Texas.

The PUCT also issues CCNs to water and sewer supply corporations (WSC), affected counties, and retail public utilities that plan to serve customers in an area already served by another provider. Affected counties are counties that meet certain economic criteria or are within 100 miles of the US-Mexico border. However, the PUCT does not set rates for these entities. Districts, counties, and municipalities can choose to obtain a CCN but are not required to hold a CCN to provide service. PUCT does not set water and sewer rates for services provided by municipalities, districts, and certain counties.

## Jurisdiction

The PUCT retains original authority over an IOU's retail water and sewer rates, which means that the commission must approve the IOU's rates.

The commission has appellate authority over water and sewer service providers other than IOUs. Appellate authority allows the PUCT to review rates set by other authorities, including a city, WSC, or district. Typically, an appeal from consumers or another interested party starts this review. The governing board of a city, WSC, or district approves the rate change for water or sewer service. Rates set by a city can be reviewed by the PUCT only if ten percent or 10,000 (whichever is less) of the affected customers located outside the city limits file an appeal. This appeal must be in the form of a petition.

The PUCT has no authority over setting the rates of an IOU that is within the city limits of a municipality. However, a municipality may choose to surrender its authority to review and modify the rates of the IOU to the PUCT. Seven municipalities, including the city of San Antonio, have surrendered authority to the PUCT.

*Municipalities that have surrendered water and sewer service authority to the PUCT*

City of Coffee City – effective December 4, 1993
City of Nolanville – effective April 18, 1996
City of Aurora – effective April 04, 1997
City of Arcola – effective May 05, 1998
City of Waco – effective February 07, 2012
City of San Antonio – effective January 30, 2014
Village of Jones Creek – effective December 04, 2014

# WATER AND SEWER INDUSTRY JURISDICTION

## CORE FUNCTIONS

**CCNs**

**PUCT approves service area for:**

- IOU
- Affected county
- WSC
- Certain retail public utilities[3]

**Water Rate Setting**

**PUCT sets rates for:**

- IOU outside City limits.
- Certain IOU inside City limits[4]

**PUCT has no authority[1] to set rates for:**

- IOU inside the city
- WSC[2]
- Affected county
- District

**No authority to set rates or service area**

- Exempt IOU[2]
- Exempt WSCs[2]
- IOU customers inside the city[2]
- County

**Notes**

**- IOU – Investor-owned utility, WSC- Water Supply and Sewer Corporation**

**1 - PUCT only has appellate authority on the retail rates for the service providers listed. The PUCT also has appellate jurisdiction over wholesale rates charged by an entity to a retail public utility.**

**2 - PUCT does not have rate setting authority, but these entities must file a tariff with PUCT**

**3 - Retail public utilities (RPU) that plan to serve in an area that is being lawfully served by another RPU**

**4 - IOUs that serve inside corporate limits of a city that surrendered jurisdiction to the PUCT**

## Primary Water and Sewer Service Provider Types

**District**

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

**River Authority**

River authorities are a type of district. 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.

**Municipally Owned Utility (MOUs)**

An MOU is a 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, an MOU must obtain a CCN if it intends to serve consumers in an area already served by another retail public utility.

**Water Supply Corporation (WSC)**

A WSC is a member-owned, member-controlled nonprofit businesses that offers sewer or potable water services. 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.

**Investor-Owned Utility (IOU)**

A private company that offers sewer or potable water services is an IOU. IOUs provide service for profit and range in size from small sole proprietorships or partnerships to large corporations. An IOU must hold a CCN to provide water or sewer services.

**Exempt Retail Public Water Utility**

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 that 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 an 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.

There are 3,183 active water and sewer service providers in the state. The table below provides a breakdown of the total active water and sewer service providers.

| Entity Type | Active Entities (#) |
|---|---|
| Districts | 1,012 |
| Municipally Owned Utility | 979 |
| Water Supply Corporations (WSCs) | 738 |
| Investor-Owned Utilities (IOUs) | 403 |
| Exempt Retail Public Water Utilities | 39 |
| Counties | 4 |
| Affected Counties | 8 |
| Total | 3,183 |

## Certificates of Convenience and Necessity (CCN)

A certificate of convenience and necessity (CCN) is a PUCT-issued certificate that identifies the geographic service area of a retail public utility. It grants the holder exclusive right to provide retail water or sewer utility service to a “certificated service area.” A CCN holder is required to provide continuous and adequate service to the area within its CCN boundary.

The PUCT has sole authority over water and sewer CCN regulations and issues CCNs to IOUs, affected counties, WSCs, and certain retail public utilities. IOUs, affected counties, and WSCs require a CCN to provide service to consumers. Political subdivisions such as municipalities, districts, and counties may obtain a CCN but are not required to unless they plan to provide service in an area where another utility is already lawfully serving. A political subdivision may also choose to obtain a CCN to protect its service area from encroachment by other service providers.

To obtain a new CCN, a utility must file an application with the PUCT. The PUCT reviews the filing entity’s financial, managerial, and technical capability to run a utility. The filing entity is required to submit a general location map, detailed map, and digital mapping data identifying the requested area in reference to verifiable man-made and natural landmarks and county, city, and town boundaries. The PUCT’s mapping team reviews any overlaps in a requested area with neighboring utilities, cities, or districts before granting the CCN. If the service area requires the construction of a new water system, the CCN applicant must also obtain approval for the engineering plan from the TCEQ. If the service area requires construction of a new sewer system, the CCN applicant must also obtain approval of a Texas Pollutant Discharge Elimination System from the TCEQ.

During FY 2023 and FY 2024, the PUCT finalized 441 CCN-related applications, including requests for new CCNs, amendments, decertification, and expedited release cases.

## CCN Amendments and Revocations

Any changes to a CCN must be approved by the PUCT. A CCN can be amended due to changes in ownership or the geographic area that is covered. The commission may also revoke a CCN if it determines a utility is not providing continuous and adequate service.

### Changes in Ownership

A utility may change ownership through a sale, transfer, or merger (STM) to consolidate businesses or to take over non-functioning utilities. This change requires approval by the commission. During an 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 show that the proposed STM is in the public interest.

### Changes in Service Area - Expedited Release

A landowner may petition the PUCT to receive water and sewer service from a different retail public utility through an expedited release proceeding if the CCN holder for that geographic area is not providing service. A prohibitively expensive cost to receive service may also qualify as a denial of service. To qualify for expedited release, a tract of land must be at least 50 acres, but the petition can include all or a part of the tract. The petition must name an alternative provider that can provide the scale of service that the landowner requests. The CCN holder can oppose the expedited release and may refute any information the petitioner gave. If the expedited release is granted, the landowner requesting must provide adequate and just compensation to the CCN holder. An expedited release can occur anywhere in the state except within cities with a population of more than 500,000, and the municipality or a municipally owned retail public utility is the certificate holder.

### Streamlined Expedited Release (SER)

The owner of a tract of land of at least 25 acres 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 33 counties under TWC § 13.2541.

## Comparison of Expedited Release and Streamline Expedited Release

| | **Expedited Release** | **Streamlined Expedited Release (SER)** |
|---|---|---|
| **Area** | **Owner of a tract of land at least 50 acres or more** | **Owner of a tract of land at least 25 acres or more** |
| **Qualification** | An expedited release can occur anywhere in the state, except within cities with a population of more than 500,000 and a municipality or a municipally owned retail public utility is the holder of the certificate.<br>When both of the following conditions are true: (1) the property is located within the boundaries or extraterritorial jurisdiction of a municipality with a population of more than 500,000, and (2) the certificate holder is the municipality or a municipally-owned retail public utility. | Limited to 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. |
| **New Provider requirement** | New provider must be named in the request | New provider information not necessary |
| **Compensation** | The landowner must provide adequate and just compensation to the CCN holder | The landowner must provide adequate and just compensation to the CCN holder |

## CCN Revocations

The PUCT can revoke the CCN and decertify a retail public utility if the CCN holder does not provide continuous and adequate retail water or sewer service. Reasons for this type of failure could include the utility's financial 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 plans to do so. Because a CCN grants the holder an exclusive right to provide utility service to a defined geographic area, a CCN revocation may become necessary for non-performing retail public utilities to ensure other potential service providers are not prevented from providing water and sewer service to consumers in that area.

The PUCT's Division of Compliance and Enforcement (DICE) conducts investigations to determine whether a CCN revocation is necessary.  DICE initiates proceedings to revoke the CCNs of non-functioning utilities to limit harm to consumers and ensure a qualified provider serves the area. Once a CCN has been revoked, the PUCT will typically work with one or more utilities to provide service within the previously certificated area.

There are 3,183 water and sewer service providers holding CCNs under the PUCT's jurisdiction. As of the end of FY 2024, these CCNs encompass 11,409,495 water connections serving residences and businesses in the state. 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 serve the rest of the population. Affected Counties and all IOUs, WSCs, and sewer service corporations must hold a CCN to provide water and sewer services.

## Water Rate Setting

The PUCT is charged with setting rates for water and sewer IOUs. 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 deliver safe, reliable customer service.

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 service cost. These include production, treatment, storage, collection, and distribution costs.

A utility may submit an application to the applicable regulatory authority to adjust its rates to reflect a change in its costs.

### Formal Ratemaking Proceedings

Before implementing a rate change, a utility must file its rate case with the regulatory authority that retains original jurisdiction over its retail water and sewer rates. Utilities can apply for a rate change no more than once in a 12-month period. Although homeowner associations (HOAs), property owners' associations (POAs), and cooperatives are nonprofit entities under Internal Revenue Service guidelines, the Texas Water Code (TWC) treats them similarly to IOUs for ratemaking purposes.

The rate-filing requirements for IOUs, HOAs, POAs, and cooperatives within the PUCT's authority vary based on the utility's size classification. The TWC classifies water or sewer utilities using the number of active connections served. When a utility serves both water and sewer customers, the number of water connections decides its classification.

The table below provides the IOU classification criteria.

| IOU Classification | Number of Connections | Number of Utilities* | # Connections Served |
|---|---|---|---|
| Class A | 10,000 - greater | 6 | 209,415 |
| Class B | 2,300 - 9,999 | 14 | 62,077 |
| Class C | 500 - 2,299 | 27 | 23,123 |
| Class D | 0 - 499 | 311 | 30,259 |
| Total | | 358 | 324,874 |

Note: *- Only water utilities

## Rate Application Filing Requirements by IOU Classification

| IOU Classification | Filing Requirements |
|---|---|
| **Class A** | • Provide cost of service information and complete all rate schedules<br>• Provide detailed financial information<br>• Provide information to support affiliate transactions<br>• Provide a proposed effective date the proposed rates will go in effect<br>• Notify affected customers, the applicable regulatory authority and the Office of Public Utility Counsel about a rate application and about the proposed effective date for the rate change<br>• Provide expert witness testimony to support its rate change request |
| **Class B & C** | • Provide cost of service information and complete fewer rate schedules<br>• Provide detailed financial information<br>• Provide information to support affiliate transactions<br>• Provide a proposed effective date the proposed rates will go in effect<br>• Notify affected customers, the applicable regulatory authority and the Office of Public Utility Counsel about a rate application and about the proposed effective date for the rate change<br>• Expert witness testimony to support its rate request is not needed unless commission staff or intervening parties request a formal hearing |
| **Class D** | • Class D IOU may implement a 5% rate increase no more than once each calendar year and no more than four times between comprehensive rate cases. To implement a rate change under this provision, a class D IOU has less burdensome requirements<br>  ◦ IOU is only required to submit a one-page form to request a rate change;<br>  ◦ No rate filing package is required;<br>  ◦ No expert testimony is required; and<br>  ◦ PUCT staff prepares a notice to be shared by the IOU with its customers<br>• For a rate increase greater than 5%, the Class D IOU must follow the filing requirements listed under Class B& C IOU |

### 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

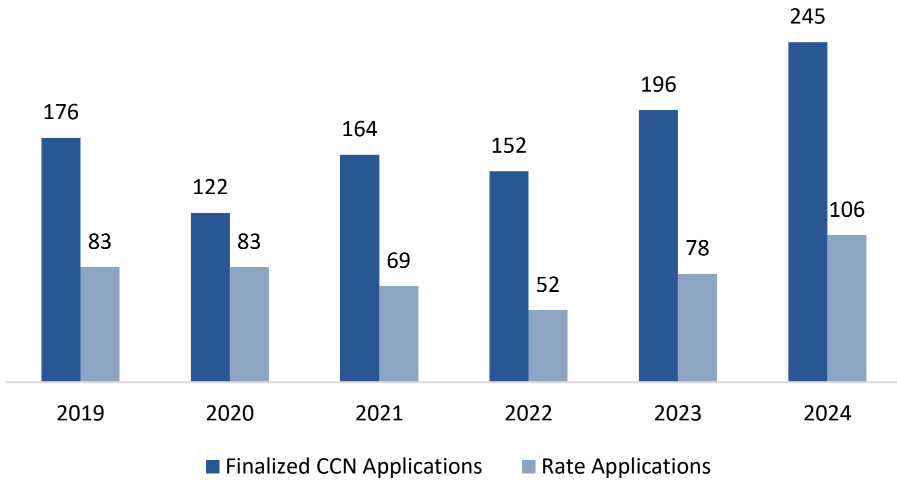
Alternative ratemaking provides utilities and the PUCT additional tools to implement rate changes outside intensive base rate proceedings. These methodologies include establishing a system improvement charge (SIC), using multi-step rates, the cash needs method, and the ability to request the addition of a new customer class. 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 in a comprehensive base rate case. The cash needs method is only available to a Class C or Class D utility, and the utility must provide documentation to support its use.

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. Any costs that are allowed through a SIC are to be reviewed for prudence, necessity, and reasonableness in the utilities' next comprehensive rate case. Also, once a SIC is granted, the utility is required to come in for a comprehensive rate case within a certain number of years, depending on utility's class.

## Water and Sewer CCN and Rate Application Processing

Water and sewer CCN and rate applications form a significant portion of the commission's legal case load. As of September 2024, 64% of the total cases with the Legal Division are for water and sewer services. The number of CCN and rate applications submitted with the commission has increased over the years, with a notable rise over the last biennium. The chart below tracks the number of CCN and rate applications processed by the commission from 2019 through 2024. The commission devotes considerable staff resources to processing these cases because they involve complex questions regarding operations and accounting.




## Additional Water and Sewer Industry Functions

| Consumer Complaints | PUCT addresses both formal and informal consumer complaints |
|---|---|
| Registration of Entities | • PUCT registers entities that submeter and allocate billing |
| Non-functioning Utilities | • Appoint temporary managers and supervisors<br>• Refer to OAG to appoint receivers<br>• Sets temporary and emergency rates for non-functioning utilities |
| Industry Assistance Programs | • PUCT provides assistance to utilities for rate filings and assists with other requests, as needed |

## Registration of Entities – Submetered and Allocated Billing

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. Apartment buildings with four separate housing units or less cannot register to submeter. 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 authority 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 tenants and ensure just and reasonable rates.

Property owners that submeter or allocate utility charges must register with the PUCT. There are currently 4,273 entities registered to submeter and 7,639 registered to allocate the water or sewer utility service charges to tenants.

## Non-functioning and Abandoned Utilities

Distressed water and sewer service utilities are utilities that fail to provide adequate and continuous services to consumers. Issues can include staff turnover, management changes, and stagnant rates, leading to diminishing the financial, managerial, and technical capabilities over time. 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.

The PUCT utilizes temporary management, supervision, and receivership to address abandonment issues in distressed utilities. These tools can help distressed utilities provide continuous and adequate service in compliance with PUCT and TCEQ regulations.

### Temporary Management

A temporary manager can be appointed to take over the operations of only a water or sewer IOU that is no longer functioning or has been abandoned by its owners. Both TCEQ and the PUCT have the authority to appoint a willing person, municipality, or political subdivision to manage a utility temporarily.

The goal for a utility in temporary management is to have an entity with sufficient financial, managerial, and technical capabilities take over the distressed utility's ownership and ensure continuous and adequate service to the consumers.

Since the beginning of FY 2023, the PUCT has appointed five temporary managers to abandoned water utilities covering 11 public water systems. As of the end of FY 2024, there were ten 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 utility. The OAG may seek a court-ordered appointment of a receiver to manage and operate a nonfunctioning water or sewer utility. Similar to a temporary manager, a receiver can be appointed to take over an abandoned or non-functioning utility. A receiver has more power over a utility than a temporary manager, including the ability to seek court approval to sell the utility contingent upon the PUCT's approval of the STM process. A receiver is also authorized to charge temporary rates set by the PUCT. Similar to temporary management, the long-term goal is to have an entity with sufficient financial, managerial, and technical capabilities take over the utility's ownership and minimize the amount of time that a utility stays in receivership. As of the end of FY 2024, six utilities were in receivership, one of which had its STM transaction completed.

## Temporary Management and Receivership Assistance

PUCT staff work closely with utility owners, customers, and necessary parties to facilitate the acquisition of a nonfunctioning utility.

On average, a nonfunctioning utility may remain under temporary management for two to four years and in receivership for five to ten years. 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.

During the 2023-24 biennium, the PUCT terminated temporary management appointments across six utilities, which collectively had ten systems. The PUCT has completed processing the transfer of three 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 service issues. With new owners, the systems have restarted regular operations.

*L and T Utility*

In 2022, L and T Utility faced significant operational challenges, serving 133 customer connections in Freestone and Henderson Counties. L and T operated the Athens Water System and the Moody Water System. L and T faced numerous service issues. Its customers reported that L and T's telephone numbers were disconnected, their local office was vacant, and some neighborhoods experienced prolonged water outages. One severe incident occurred on June 29, 2022, when the Athens Water System faced hours-long water service discontinuance due to an electric service disconnection from unpaid bills. In light of these persistent issues, the PUCT appointed Texas Water Utilities as the temporary manager to stabilize and manage L and T Utility. Texas Water Utilities immediately addressed critical operational deficiencies, improved customer communication, and ensured consistent water service. They submitted an STM application to formalize the transition of management and ownership. The STM was finalized, and on June 26, 2023, the temporary manager was formally dismissed.

## Comparison of Temporary Management and Receivership

| | Temporary Manager | Receiver |
|---|---|---|
| **Rules and Statutes** | TWC § 13.4132, TAC §§ 24.355, 25.357, and 24.363 | TWC §§ 13.412, 13.413, TAC § 24.363 |
| **Process to Appoint** | Appointed by order of the PUCT or TCEQ and accountable to the appointing agency. | Appointed by a state district court with Commission's referral and accountable to the state district court and the appointing agency. Either TCEQ or PUC can refer an entity to OAG for the appointment of a receiver. |
| **Eligibility** | May be a natural person, partnership, water supply or sewer service corporation, or corporation. | Must be an individual citizen of Texas – 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 state district court with Commission's referral and accountable to the state district court and the appointing agency. Either TCEQ or PUC can refer an entity to OAG for the appointment of a receiver. |
| **Reporting** | Must submit monthly reports to both TCEQ and PUCT. | Must submit monthly reports to the Court, TCEQ, and PUCT. |
| **Authority to Sell** | Can sell if the owner cannot be located or does not respond to an expedited STM application (which is available only to temporary managers that are Class A & B utilities) | May file a motion at the court and seek authorization to sell the utility. Can request expedited STM application if the receivers is an operator of a Class A & B utility. |
| **Compensation** | The appointing agency 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. |
| **Roles and Duties** | • Operational Management: Handles day-to-day operations of the utility to stabilize it and ensure compliance with regulations.<br>• Short-term Focus: Focuses on immediate Operational issues and quick improvements.<br>• Coordination: Works closely with PUCT or TCEQ, reporting regularly on progress and challenges. | • Asset Management: Takes control of all assets and operations to restructure the utility for long-term stability.<br>• Legal Authority: Has the Authority granted by the court to make significant changes, including selling the utility if necessary.<br>• Comprehensive Oversight: Provides reports to the court, PUCT, and TCEQ. |
| **Determining Need** | • When to Appoint: Used when the utility needs immediate operational support and there is potential for quick recovery with proper management.<br>• Factors Considered: Willingness of a qualified candidate, utility's compliance status, operational deficiencies, and financial stability. | • When to Appoint: Chosen when the utility is in severe distress, requiring significant restructuring, or when legal authority is needed to manage or sell assets.<br>• Factors Considered: Willingness of a qualified candidate, severity of non-compliance, financial insolvency, operational failures, and the need for long-term solutions that may include legal actions. |

### Supervision

The PUCT may place a utility under supervision if it has exhibited gross or continued mismanagement, gross or continued noncompliance with governing statutes or PUCT orders.

When a utility is placed under supervision, the PUCT may require the utility to comply with 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 payment priority and other financial obligations. Currently, there are no utilities under supervision.

## Industry Assistance Programs – Financial, Managerial, and Technical Assistance Contract

The PUCT has established a Financial, Managerial, and Technical (FMT) assistance program to support water and sewer retail public utilities across the state. Funded with state resources, this program enhances the financial stability and operational efficiency of utilities struggling to meet regulatory requirements or deliver consistent services to consumers.

The program includes a contract with a third-party consultant that conducts on-site visits to address the specific requirements of the IOUs referred by the commission. The contractor tailors support in critical areas such as billing, budgeting, business planning, and customer service. This, in turn, supports the long-term sustainability of water and sewer services, ensuring that utilities can continue to provide safe, reliable, and affordable services.

Financial, managerial, and technical assistance was provided to 60 water and sewer utilities over FY2023-2024.

## Emerging Issues

### Impact of Federal Legislation

In April 2024, the Environmental Protection Agency (EPA) issued a regulation of Polyfluoroalkyl Substances (PFAS) in the nation's drinking water supply. Under this new federal regulation, many retail public utilities must make substantial capital investments to follow these standards. The cost of infrastructure and equipment updates to follow the EPA's PFAS rule is expected to be a significant financial burden on many utilities. It could result in consumer rate increases and consolidation in the industry. In lieu of increasing their rates, many utilities have contacted the PUCT to express an interest in selling their utilities. This option allows utilities to transfer the financial and operational responsibilities to a more capable entity to manage the necessary investments. The PUCT works closely with retail public utilities looking for a viable entity to acquire, purchase, or consolidate their systems with another utility.

### Critical Water Facilities Registration

Senate Bill 3, enacted by the 87th Texas Legislature, requires “affected utilities” under TWC § 13.1394 to annually submit critical facility details for emergency preparedness. However, the definition of "affected utility" encompasses a wide range of entities, including any retail public utility, exempt utility, or provider of potable or raw water serving more than one connection outside of Fort Bend or Harris Counties. This broad scope creates challenges in identifying the total number of affected utilities required to comply, making it difficult to gauge compliance rates accurately. In addition to filing this information at the PUCT, the utilities are required to provide a copy to each electric utility 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. As of September 2024, the PUCT has received more than 2,191 critical water filings in the project created as a repository for the filings. The PUCT continues to conduct outreach activities to ensure that information about critical water and sewer facilities' location, critical load status, emergency contact information, and the utility’s address are up to date.

### Consumer Rate Increase After Utility Acquisitions

Since 2021, after the passage of HB 1484, (see details under rulemakings) which allowed existing tariffs of an acquiring utility to be charged to the acquired customers in an STM transaction, the commission has reviewed over 20 such applications. Of the total number of applications, nine were approved, and the acquired customers in a third of the approved applications filed protests against rate increases because of acquisition and requested for hearings. It is expected that a majority of STM cases in which the acquiring entity requests PUCT to allow their existing tariffs to be charged to their acquired customers could result in rate increases. PUCT continues to work with utilities to find rate resolutions where the impact of any rate increases on consumers is mitigated while maintaining their water and sewer service.

## Rulemakings

### Review of 16 TAC § 24.239, Sale, Transfer, Merger, Consolidation, Acquisition, Lease, or Rental

On March 9, 2023, the commission adopted amendments to 16 TAC § 24.239. The amended rule implements Texas Government Code § 1502.055 (HB 3717, 87R) by clarifying the entities to which the rule applies and instituting specific requirements for transactions involving the purchase of a municipal retail water or sewer utility system from an MOU. **(Project No.54046)**

### Review of 16 TAC § 24.101 - Water Rate Appeals

On September 14, 2023, the commission adopted amendments 16 TAC § 24.101. This rule implements Texas Water Code § 13.043 (SB 387 and HB 3689, 87R) by allowing ratepayers to appeal an increase in an MOU's water and sewer rates, including a rate increase resulting from a decision by the governing body of the municipality that takes over the provision of service to ratepayers previously served by another retail public utility. The amended rule also clarifies that in an appeal under this section, the PUCT will ensure that every appealed rate is just and reasonable. **(Project No. 54932)**

## Water and Sewer Utility Rates After Acquisition

On March 21, 2024, the commission adopted new 16 TAC § 24.240 relating to Water and Sewer Utility Rates after Acquisition. The new rule implements TWC § 13.3011 (HB 1484, 87R) by allowing an acquiring water and sewer utility to apply rates from an existing tariff to the customers of an acquired system without starting a new rate proceeding. To be eligible to apply, an existing tariff must be currently in force and filed with a regulatory authority for another water and sewer system owned by the acquiring utility. **(Project No. 53924)**

## Rates for Certain Recreational Vehicle Parks

On October 24, 2024, the commission repealed 16 TAC § 24.361 and adopted new 16 TAC § 24.50. This rulemaking implements TWC § 13.152 (SB 594, 88R) by requiring a retail public utility serving a recreational vehicle park to base its billing on actual water usage and prohibits the retail public utility from charging extra based on the number of RV or cabin sites in the RV park. The rulemaking also moved the text of the rule from the Enforcement subchapter to the Rates subchapter and made other minor and conforming changes. **(Project No. 56828)**

# ENFORCEMENT BY THE NUMBERS

**261**
ERCOT Reliability Monitor Referrals

**9**
Independent Market Monitor Referrals

November 1, 2022 through October 31, 2024

**217**
INVESTIGATIONS
CLOSED

Electric 185
Water 26
Apartments 5
Telecom 1

**$5,017,945**
PENALTIES, REFUNDS, DONATIONS

Penalties $4,748,091
Refunds $82,279
Donations $187,575

**16**
Temporary managers and Receivers appointed

# VII. Enforcement

The PUCT's Division of Compliance and Enforcement (DICE) focuses on violations of statutes and PUCT substantive rules, as well as Electric Reliability Council of Texas (ERCOT) protocols and market guides. Compliance efforts encompass regulated electric, water, sewer, and telecommunications service. DICE's mandate is protecting consumers and the reliability of the electric grid. DICE pursues investigations, audits, and enforcement actions to bring entities into compliance with applicable rules and statutes.

To effectively regulate utility service in Texas, DICE works with other PUCT divisions, the Office of the Attorney General, Texas Commission on Environmental Quality, ERCOT, the Independent Market Monitor (IMM), the ERCOT Reliability Monitor (ERM) and other state agencies. DICE analysts which provide technical expertise, and DICE attorneys which provide legal analysis work together to protect consumers and ensure the reliability of water, telecommunication, and electric service in Texas.

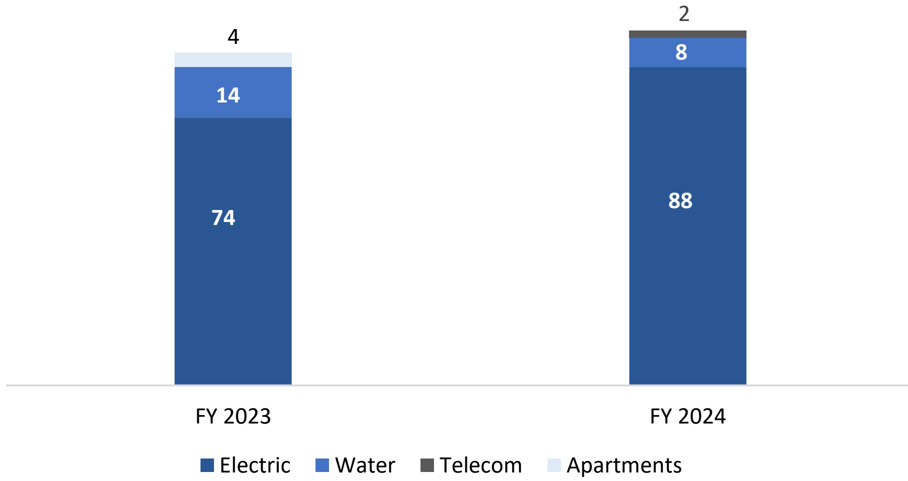
## Investigations

DICE initiates investigations based on consumer complaints, self-reported information from regulated entities, press reports, legislative inquiries, and referrals from ERCOT, the ERM, and IMM.

DICE works with the agency's Consumer Protection Division (CPD) and other agency divisions on investigations. CPD handles consumer complaints for electric, water, and telecom industry. It also investigates each incoming complaint and attempts to resolve complaints through the informal complaint investigation and resolution process.

An informal complaint investigation is not a legal proceeding. In instances where the complainant is not satisfied with the complaint resolution, the complainant is provided with an option to file a formal complaint with the agency that is taken up as a legal proceeding. CPD may refer complaints to DICE for further investigation on a case-to-case basis.

During the 2023 and 2024 fiscal years, DICE opened 190 investigations. The chart below provides a breakdown of investigations by type of utility.

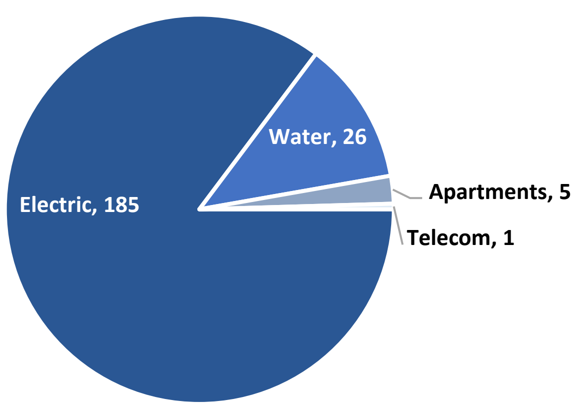



Note: There were no investigations for telecommunication in FY 2023 or for apartments in FY 2024

DICE investigations focus on ensuring electric, water, and telecom regulated entities comply with statute and PUCT rules. When necessary, non-compliance can result in punitive actions by DICE.

Most DICE investigations focus on the electric industry. Many of DICE's water-related enforcement actions involve non-functioning and abandoned water and sewer utilities that may require appointment of temporary managers for these struggling water utilities. Telecom enforcement actions are infrequent.

DICE resolves investigations primarily through settlement agreements, though litigation is sometimes necessary. In the 2023-2024 biennium, DICE closed 217 investigations related to the oversight of wholesale market participants. The chart below provides details about investigations closed by type of utility during the biennium.



## Penalties, Refunds, and Donations

Enforcement actions can result in penalties, consumer refunds, donations, and revocation of operating certificates. DICE pursues different outcomes depending on the type of violation. In instances where an entity has over-collected from customers, DICE works to ensure that entities return to customers the money that was overcharged.

Penalties in the 2023-2024 biennium totaled $4,748,091, which entities pay to the state's general revenue fund. Refunds to consumers in the 2023-2024 biennium totaled $82,279, and donations to customer assistance programs totaled $187,575. The commission also ordered market participants to return improperly collected revenues totaling $23,462. The return of improperly collected revenues is known as disgorgement. The dollars collected under disgorgement go toward reducing costs or fees incurred by retail electric customers. For those investigations resulting in a financial obligation, the distribution between penalty, donation, and refund is illustrated below.

| Penalties | | | | Refunds | Donations | Total |
|---|---|---|---|---|---|---|
| Electric | Telecom | Water | Apartments | | | |
| $ 4,408,091 | $ 0 | $ 20,000 | $ 320,000 | $ 82,279 | $ 187,575 | $ 5,017,945 |

The PUCT can also revoke a company's operating certificate either as the result of litigation or settlement. During the 2023-2024 biennium, 14 DICE investigations resulted in revocation. For investigations that do not rise to the level of revocation or financial obligation, DICE may issue a warning letter, which remains on file so that DICE is aware of patterns of violation. During the biennium, DICE issued 72 warning letters.

## Wholesale Electric Market Oversight

A critical function of DICE is ensuring Texas' wholesale electric market participants operate lawfully. The commission oversees the wholesale market through ERCOT, which operates the wholesale electricity market, and through the IMM. The IMM monitors wholesale market activity to detect market manipulation and power abuses by market participants. Both the ERCOT reliability monitor and the IMM gather and analyze wholesale market buying and selling data to determine if the market participants complied with the market rules. Market power abuse is engaging in predatory pricing, withholding of production, precluding entry, and collusion by market participants that have the ability to control prices or exclude competition in a relevant market.[22] Market power abuse can include deceptive trade practices, which may impact the

[22] 16 TAC § 25.504.

stability of the ERCOT power grid and affect the cost of electricity to consumers. If a violation of market rules and statutes is detected by ERCOT, IMM, or other sources, DICE investigates such violations and recommends suitable penalties.

## Weather Emergency Preparedness

DICE enforces commission rules for both winter and summer emergency preparedness. In the 2021-2022 Agency Report, DICE reported investigating eight entities for failure to comply with the commission's Weather Emergency Preparedness rule. All eight investigations were resolved during the 2023-2024 biennium, resulting in $9,600,000 in administrative penalties. DICE did not open any additional investigations of this kind during the 2023-2024 biennium.

## ERCOT Reliability Monitor

The ERM is tasked by the PUCT with monitoring entities that participate in the ERCOT power region. To facilitate these efforts, the ERM adopts rules to maintain reliable operation of the power grid. As part of its monitoring duties, the ERM refers matters to DICE for further investigation into instances of potential noncompliance. During November 1, 2022 through October 31, 2024, ERM referred 261 cases to the commission.

## Power Line Inspection and Safety (HB 4150, 86R)

All electric utilities, municipally owned utilities, or electric cooperatives that own or operate overhead transmission or distribution lines in the state of Texas must provide information to the public about the safety of their overhead equipment. In May 2019, the 86th Texas Legislature enacted House Bill 4150, creating reporting requirements regarding power line inspection and safety for these entities. The focus of these reports is on the vertical clearance and safety of power lines and safety training provided to employees.

To implement the requirements of HB 4150, the commission adopted 16 TAC § 25.97 in February 2020. Certain entities are now required to file up to three reports, which include annual reports, five-year reports, and employee training reports.

DICE received 52 reports regarding compliance with vertical clearance and safety requirements. From the reports received, staff initially identified 249 non-compliant spans of transmission and distribution lines owned by 12 entities. At the close of the biennium, only two lines remain noncompliant. Staff is receiving monthly progress reports, which are filed in Project No. 52667.

# VIII. Resources For Texans

The PUCT promotes a culture of continuous improvement by developing and implementing resources to inform, engage, and assist the public. The PUCT has many ways for the public to participate in its decision-making or get assistance with questions related to utility service. The PUCT also maintains an online, publicly accessible, searchable repository for all public documents filed with the PUCT.

## Consumer Assistance

The Consumer Protection Division (CPD) assists utility consumers by answering utility service questions and helping to resolve disputes with their utilities. Consumers are always encouraged to first contact their utility with questions about service, or to resolve a dispute, and then contact CPD if a satisfactory result is not reached.

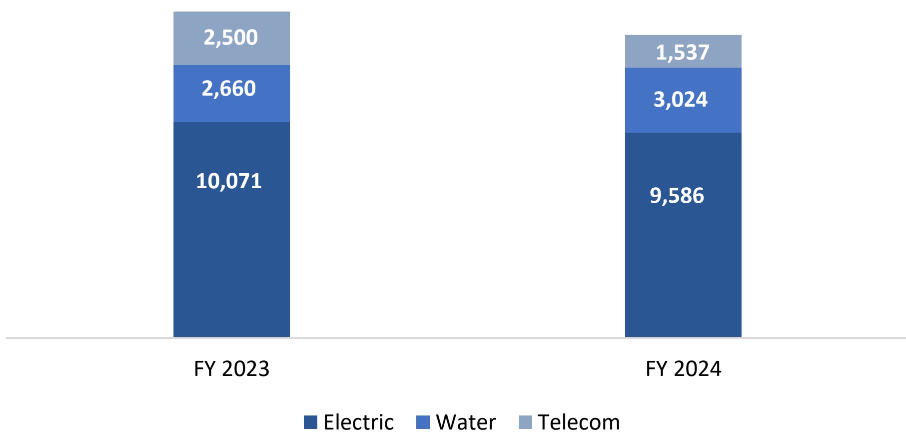
A common question CPD receives from consumers is how to read utility bills. The PUCT's public website has guides for consumers on how to read electric, water, and telecom bills, including explanation of charges. The website also has information and resources available for consumers facing utility service disconnections or outages. Additionally, the PUCT website provides information about "Storm Resources" to assist consumers with information about outages and other related information.

The CPD team answers questions about the PUCT's Power to Choose website, related to REPs electricity plans and offers for consumers. The information provided on the website helps consumers select a REP. CPD also accepts complaints regarding the Texas No Call list. The CPD team reviews complaints for alleged violations of the Texas No Call Lists. Texans may register a telephone number with the PUCT under "No Call Lists". This list allows a consumer to register their name, address, and telephone number to identify themselves as someone who does not want to receive telemarketing calls, and messages from telemarketers operating in Texas. The CPD team collects the No Call List complaint data and shares it with the Attorney General's office regularly. PUCT's Division of Compliance and Enforcement may review No Call List complaint data for enforcement investigations either internally or in conjunction with the OAG's office as circumstances warrant.

The CPD team assists consumers in investigating complaints related to inaccurate billing and has helped consumers in securing refunds and bill credits. During the 2023-2024 biennium, CPD helped consumers secure $1,028,663 in refunds and bill credits.

A consumer who has a dispute with their utility can submit an informal complaint to CPD for the CPD to open an investigation. A CPD investigator reviews information received from both the complainant and the service provider. The service provider is required to respond to a CPD investigation correspondence within 15 days. After investigation, a CPD staff provides a response to the complainant and service provider. The investigator may identify compliance issues and may recommend corrective actions as part of the response.

From September 1, 2022 – August 31, 2024, CPD received 29,378 complaints. The chart below provides details of the total consumer complaints received by the CPD with a breakdown by industry type.




## Office of Public Engagement

In August 2022, the Office of Public Engagement (OPE) was set up as a resource for the public to explain PUCT processes and facilitate participation of Texans in rulemakings, rate cases, hearings, transmission line siting and other important policy matters at the PUCT.  OPE is present to greet the public at open meeting and assist anyone who wishes to make public comment.

OPE engages with consumers directly through educational materials, the PUCT's public website and through hosting and participating in events that provide education to consumer about utilities across the state.

OPE has a multilingual team that receives questions from consumers via email, telephone, and social media. Generally, consumer questions are about pending water and electricity rate cases and how to participate in the rate case process. This team also provides translation of key PUCT communications from English to Spanish.

OPE has organized and attended events across Texas since the office was created. These events are usually in person, but virtual or hybrid participation can also be accommodated. Event size has ranged from an informal meeting with five homeowners to as large as hundreds of people.

## Digital Resources

The PUCT engages directly with Texans every day through the PUCT's public website and social media accounts. These digital resources allow the PUCT to inform the public about the agency's activities, responsibilities, rules and regulations, consumer tips, and emergency information.

### PUCurrenT

The PUCT's Communications Division launched PUCurrenT, a quarterly newsletter in English and Spanish, in September 2023. The newsletter contains updates on significant commission action related to regulatory policy, as well as important agency updates. Texans can subscribe to this newsletter on the PUCT website.

### PUCT Interchange (interchange.puc.texas.gov)

The PUCT Interchange is an online application accessible on the PUCT's public website. The Interchange is a document filing system for submitting and reviewing public documents filed with the PUCT. Documents can be searched by case style (the docket or project description), utility type, utility name, filing party, item type, filing description, and date range. PUCT Staff can be reached via email (centralrecords@puc.texas.gov) to answer questions about filing or locating documents in the Interchange.

### *Channel Oaks Water System*

Channel Oaks is a 45-home subdivision near Marble Falls whose water system was not providing reliable service. OPE and the PUCT's Division of Utility Outreach (DUO) attended two property owners' association meetings in May 2023 and June 2024 to educate residents about the situation. Customers were worried about their water service and the future of their community. PUCT staff provided information to consumers on actions taken by the commission and, next steps, and contacts to get more information. A temporary manager was appointed to the system in June 2023

### *Lubbock Retail Shopping Fair*

Lubbock Power & Light (LP&L) connected to the ERCOT grid in early 2024, adding approximately 107,000 customers to the competitive retail electricity market. This required thousands of customers to shop for retail electric plans, many for the first time. OPE staff took part in a retail shopping fair in Lubbock during the transition period. Staff answered questions and assisted consumers with shopping for a retail electric plan that would best suit their individual needs. OPE team assisted more than 400 customers who had questions about how to compare plans, how the PUCT protects customers, and how the competitive retail electricity market works.

## Social Media Accounts

The PUCT uses four social media platforms to share educational information, open meeting notifications, information on commission actions, and other resources. Over the course of the biennium, the PUCT's social media efforts to educate and engage consumers and utilities resulted in more than a 30% increase in total social media content views.

Public Utility Commission of Texas

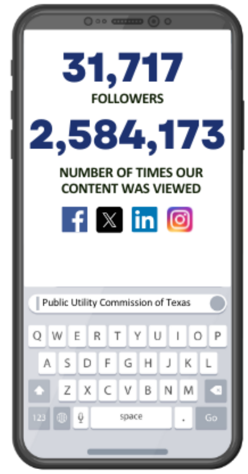
PUCTX

Public Utility Commission of Texas

PUCTX

Power to Choose

powertochoosetx




## PUCT Public Website

The PUCT's website serves as the "virtual front door" of the agency and has gone through a complete redesign over the past biennium. This redesign made the PUCT website more user-friendly, intuitive to navigate, and responsive to fit on any device that a user chooses to access it from.

The website features easily accessible information and digital tools for consumers, utility providers, and industry. The PUCT's website averages more than 255,000 page views per month. The most-visited pages include "Paying Your Bill," "Industry Filings," "Rules," and "Know Your Rights."

Additional resources and tools include:

- Online informal complaint filing for electric, telecommunications, water, and wastewater utility service issues;
- An outage resource section with contact information to report local electric utility service outages to providers and links to local outage maps to monitor outages;
- Access to information about electric, telecommunications, water, and wastewater utility service providers;
- Links to live internet broadcasts, agendas, and calendar for open meetings; and
- News releases and updates from the PUCT.

## Power to Choose (powertochoose.org)

The Power to Choose website is a free resource maintained by the PUCT that allows retail consumers in competitive areas to research, compare, and select the electric plan that best suit their needs. The Power to Choose site is available in English and Spanish. REPs are not required to post prices or rate plans on Power to Choose. However, most REPs choose to do so.

While the website is maintained by the PUCT, REPs are responsible for submitting and updating information on their plans. Consumers are encouraged to contact a provider directly with any questions about a specific plan.

## Map Viewers

The PUCT's online map viewers make it simple for the public to locate and view electric, telecom, water and sewer utilities and their service area boundaries. An individual can search by address to locate areas of interest in Texas and view industry data.

The ***Water and Sewer CCN Viewer*** enables users to search, view, and print the boundaries of retail public water and sewer certificates of convenience and necessity (CCN). Users search by address or CCN number. Utility companies can use the viewer to prepare maps to transfer a CCN.

The ***Electric Outages Viewer*** enables users to search by address to locate the name and contact information of electric utilities that maintain a company outage map on their website. The viewer is highlighted on the PUCT's "Storm Resources" webpage and is used by the PUCT's emergency management response staff for emergency management activities. The PUCT encourages the public to use these tools before and during emergencies or disasters to monitor outages.

The ***Electric Service Area Boundaries Viewer*** lets users search, view, and print the approximate, unofficial electric service area boundaries of investor-owned utilities, municipally owned utilities, and electric cooperatives (collectively, utilities). Individuals can use the viewer to search the name and contact information of a utility. It also shares links to utilities' outage maps and is used by the State Operation Center's Emergency Management Response Team.

The ***Energy Efficiency Programs and Tips of Electric Utilities Viewer*** enables customers to view energy efficiency tips and programs of electric utilities in Texas.

The ***Texas Electricity Supply Chain Map Viewer*** is a confidential viewer developed by PUCT staff, the ERCOT, RRC, TxDOT, TDEM, and all of Texas' electric utilities. Authorized users can search and view details about the connectivity of critical infrastructure necessary for maintaining natural gas supply to the state's generating facilities. The State Operations Center also uses the viewer to coordinate efforts during emergency response activities.

# IX. Legislative Recommendations

## Electricity

### Establish Minimum Standards for Transmission and Distribution Infrastructure

Electric utilities construct and operate transmission and distribution facilities in accordance with the voluntary, industry-defined guidelines, outlined in standards such as the National Electric Safety Code, National Electrical Code, and Rural Utility Service Standards. These include standards for pole design and construction. To assess standards adherence and identify poles for replacement, utilities operate inspection and testing programs. The PUCT has limited visibility into a utility's construction standards or its pole inspection and testing program and relies on self-reported information.

Texas currently has no mandatory minimum standards for pole infrastructure. Recent resiliency events, such as hurricanes and wildfires, have highlighted the criticality of designing pole infrastructure according to each Texas region's geography and weather patterns. The PUCT recommends setting minimum design, construction, and inspection standards that consider regional weather and vegetation risks. The standards would apply to replacement of current infrastructure as well as to new construction. To verify compliance, utilities should be required to obtain third-party audits of new construction and of pole inspection and testing programs. The PUCT would seek penalties for non-compliance based on the results of these audits.

### Nuclear Interconnection Allowance

Interconnection costs are the cost of connecting a generation resource to a substation so that the energy the resource produced can be transmitted throughout the electricity grid. Following the passage of HB 1500 in the 88$^{th}$ Legislative Session, a “standard allowance” was implemented to more appropriately allocate interconnection costs between ratepayers and generators. Generators are required to pay any costs that exceed this standard allowance. The PUCT recommends exempting advanced nuclear reactors (ANR) from paying costs that exceed the standard allowance.

### Enhance Background Checks for PUCT Personnel

Some PUCT personnel have access to critical information related to Texas’ electric grid. A background check is a simple tool to ensure that PUCT staff does not present a safety risk to Texas’ electric grid. To conduct background checks on state employees, a state agency must have explicit statutory authority. Currently, the PUCT has the authority to conduct a background check before an individual is hired, but not on current employees. The PUCT recommends that the Legislature grant this authority to conduct background checks on all employees to protect the Texas grid.

## Clarify Oversight of RV Park Billing Complaints

Owners of recreational vehicle parks often use submetering to bill tenants for electric service. Under this method, the park owner is the electric service customer of record. The park owner then charges tenants based on the readings of the submeters. PURA establishes how the PUCT regulates submetered billing for tenants of apartment complexes or detached dwellings, but the statute is unclear about the commission's jurisdiction over RV park submetering. When an RV park tenant files a complaint with the commission related to electric billing, resolving it requires a complex legal analysis involving three different sets of state law to determine the commission's authority. The ambiguity is directly related to the definition of a recreational vehicle. The Legislature could provide clarity for both owners and tenants of RV parks by establishing a clear definition of "recreational vehicle" in PURA.

# Water

## Expedite the System Improvement Charge (SIC) Timeline

Since the passage of SB 700 (86R), smaller water utilities have been able to apply for a system improvement charge to fund certain needed improvements to their systems more quickly than through a traditional rate case. The current statute requires the PUCT to issue a final order within 120 days after the application is determined to be sufficient. The PUCT recommends shortening the timeline from 120 days to 60 days to create more certainty for utilities and their consumers.

## Enhance Response to Distressed Water and Sewer Utilities

Distressed water or sewer utilities present a significant hazard to the health and wellbeing of Texans. The Legislature has provided the PUCT with clear authority to appoint a temporary manager over a distressed utility or to work with the Office of the Attorney General to seek appointment of a receiver over the utility through a district court proceeding. The Legislature could broaden the pool of available, qualified water and sewer operators who may be willing to take on the challenge of rescuing distressed utilities.

### *Expand Types of Entities That Can Serve as Temporary Manager or Receiver*

Chapter 13 of the Texas Water Code (TWC) states that the PUCT can appoint a person as a temporary manager. Chapter 64 of the Civil Practices and Remedies Code describes a receiver as a person, though the TWC is silent on this point. Under the TWC, a person does not include a municipally owned utility, district, or county. The Legislature could amend Section 13.4132 to make clear that the PUCT can appoint as a temporary manager a person, municipally owned utility, district, or county. Additionally, the Legislature could amend Section 13.412 to make clear that a person, as that term is currently defined, is not the only type of entity that may be appointed as a receiver of a distressed utility. By expanding the pool of available entities to serve in these critical roles, the Legislature would broaden the PUCT's ability to seek out and find qualified, willing entities and individuals who are capable of restoring essential water or sewer utility service.

#### *Expansion of the Expedited Sales Transfer or Merger Process*

Following the passage of SB 1965 (88R), Class A and B water utilities can acquire a utility in temporary management or receivership through an expedited sale, transfer, or merger (STM) application process. This ensures that struggling utilities are transitioned to capable operators more quickly. Currently, the expedited process only applies to temporary managers or receivers that are Class A or B utilities. As the second part of this recommendation to enhance the PUCT's ability to address distressed utilities, the PUCT recommends making the expedited STM process available to temporary managers that are municipalities, water supply or sewer service corporations, utility districts, river authorities or water control and improvement districts.

## Enforcement

The PUCT has identified three areas where statutory amendments would provide enforcement consistency and clarity and lead to more effective settlement outcomes.

### Authorize consistent administrative penalties for all regulated entities

The PUCT does not have clear authority to equally impose administrative penalties against all regulated entities. This authorization would clarify the PUCT's enforcement authority over wholesale market participants, including electric cooperatives, municipally owned utilities, and river authorities.

### Clarify that enforcement authority applies to both water and sewer utilities

The PUCT has clear authority to initiate enforcement action against a water utility if there is reason to believe there is an imminent threat to human health or safety. Amending this statute to include *sewer utilities* would provide clarity for the PUCT, consumers, and utilities. The PUCT recommends holding sewer utilities to the same enforcement standard as water utilities.

### Enhance enforcement settlement effectiveness through confidentiality

Informal settlement negotiations are a common practice at the PUCT and an important part of the PUCT's strategy to ensure full compliance with the law. Often, an entity involved in an enforcement case is willing to reveal sensitive or proprietary information or take accountability for certain behaviors when assured of confidentiality in a settlement negotiation. However, once the PUCT finally decides the outcome on the case, the confidentiality of those materials is no longer protected. The uncertainty around confidentiality can create a chilling effect on negotiations and make an entity less willing to provide information. Ensuring confidentiality to parties involved in enforcement cases would significantly increase the effectiveness of informal settlement negotiations. The PUCT recommends making investigation files explicitly confidential even after the case is resolved, as they are for some other regulatory agencies.

## Severe Weather Preparedness and Response

### Codify a customer's right to information about restoration times and the right to contact an electric service provider by phone.

All customers experiencing an outage should have reasonable access to information about their outage status and estimated restoration time. The Commission has launched an administrative rulemaking requiring IOUs to maintain functional and accurate public-facing outage trackers. However, the Commission lacks the authority to require the same of MOUs and co-ops. Additionally, customers should have the ability to contact their electric service provider to report outages and other electrical emergencies 24 hours a day.

The Legislature should consider adding these protections to the Public Utility Regulatory Act (PURA) Chapter 17, which outlines customer protections.

Further, critical loads, such as assisted living facilities and water utilities, must be able to contact their electric service provider directly during an emergency. The Legislature should consider codifying a critical customer's right to timely contact with utility representatives during significant power outages. Some of these customers reported waiting on hold for hours to speak to a customer service representative following Hurricane Beryl.

### Establish a framework and penalty structure to assess IOU service quality during major outage events.

The Commission oversees and enforces IOU compliance with service quality standards. However, since 1998, the Commission has excluded major events—extreme weather that disrupts power to at least 10% of customers—from these service quality calculations. The exclusion reflects concerns that including such events would misrepresent a utility's typical reliability. While it's reasonable to exclude hurricane damage from average service quality metrics, utilities should not avoid accountability for insufficient storm preparation or response.

The Commission recommends establishing a new standard to assess IOU system reliability and response during major events. The standard would be applied to a utility's service quality performance during major events over the course of a year, similar to how the Commission's current service quality rules are designed. For violations of this standard, the Commission should have the authority to pursue enhanced administrative penalties.

### Increase the penalty cap for electric service quality violations.

Vegetation-related outages generally represent 15% to 20% of system-wide forced-outages reported by IOUs in each reporting year (excluding major events like hurricanes). System-wide violations of electric service quality metrics are considered one violation for the entire reporting year and are capped at $25,000. To incentivize proactive measures to improve electric service quality, the Legislature could either increase the penalty cap or expand what may constitute a violation by placing a maximum threshold for forced-outages caused by vegetation-related issues. Enhanced penalties could apply if the utility crosses the threshold due to failure to trim circuits based on its trim cycle plan.

# Acronyms

AC – Alternating Current
ADER – Aggregate Distributed Energy Resource
AEP – American Electric Power
ANR – Advanced Nuclear Reactor
APA – Texas Administrative Procedure Act
BLTS – Basic local telecommunications service
BOSR – Body of State Regulators
CAISO – California ISO
CCN – Certificate of Convenience and Necessity
CDR Report – Capacity, Demand, and Reserves Report
CENACE – Centro Nacional de Control de Energia
CFA – Certificate of Franchise Authority
CISRM –Critical Infrastructure Security and Risk Management Division
CLEC – Competitive Local Exchange Carrier
COA – Certificate of Operating Authority
CONE – Cost of New Entry
CPD – Consumer Protection Division
DAM – Day-Ahead Market
DC – Direct Current
DER – Distributed Energy Resource
DICE – Division of Compliance and Enforcement
DPS – Texas Department of Public Safety
DRRS – Dispatchable Reliability Reserve Service
DSP – Distribution Service Provider
DUO – Division of Utility Outreach
ECRS – ERCOT Contingency Reserve Service
EED – Energy Efficiency Division
EHV – Extra High Voltage
EIM – Energy Imbalance Market
EPA – Environmental Protection Agency
EPE – El Paso Electric
EPP – Emergency Pricing Program

ERCOT – Electric Reliability Council of Texas
ERM – ERCOT Reliability Monitor
ERSC – Entergy Regional State Committee
ESR – Energy Storage Resources
FERC – Federal Energy Regulatory Commission
FFSS – Firm Fuel Supply Service

FMT – Financial, Managerial, and Technical Assistance Program
FPA – Federal Power Act
FTE – Full-Time Employee
FY – Fiscal-Year
GIS – Geographic Information System
GW – Gigawatt
HB – House Bill
LFL – Large Flexible Loads
LOLE – Loss of Load Expectation
LP&L – Lubbock Power and Light
MISO – Midcontinent Independent System Operator
MORA – Monthly Outlook for Resource Adequacy
MOU – Municipally Owned Utility
MW – Megawatt
MWh – Megawatt-hour
NPRR – Nodal Protocol Revision Request
OAG – Office of the Attorney General
OMS – Organization of MISO States
OPE – Office of Public Engagement
OPUC – Office of Public Utility Counsel

PCM – Performance Credit Mechanism
PFAS – Polyfluoroalkyl Substances
PGC – Power Generation Company
POA – Property Owners' Association
PUCT – Public Utility Commission of Texas
PURA – Public Utility Regulatory Act
REC – Renewable Energy Credit
REP – Retail Electric Provider
RPS – Renewable Portfolio Standard
RRC – Railroad Commission of Texas
RSC – Regional State Committee
RTC – Real-Time Co-optimization
RTO – Regional Transmission Organization
SB – Senate Bill
SER – Streamlined Expedited Release
SERC – Southeastern Electric Reliability Council
SIC – System Improvement Charge
SICFA – State-Issued Certificate of Franchise Authority
SPCOA – Service Provider Certificate of Operating Authority
SPP – Southwest Power Pool
SPS – Southwestern Public Services
STM – Sale, Transfer, or Merger
SWEPCO – Southwestern Electric Power Company
TAC – Texas Administrative Code
TANRWG – Texas Advanced Nuclear Reactor Working Group
TCEQ – Texas Commission on Environmental Quality

TDEM – Texas Division of Emergency Management
TDSP – Transmission Distribution Service Provider
TDU – Transmission and Distribution Utility
TEF – Texas Energy Fund
TERC – Texas Energy Reliability Council
TNMP – Texas-New Mexico Power

HOA – Homeowner’s Association
HVDC – High-Voltage Direct Current
ILEC – Incumbent Local Exchange Carriers
IMM – Independent Market Monitor
IOU – Investor-Owned Utilities
ISO – Independent System Operator
IT – Information Technology
kWh – Kilowatt-hour
TSP – Transmission Service Provider
TUSF – Texas Universal Service Fund
TWC – Texas Water Code
TxDOT – Texas Department of Transportation
VOLL – Value of Lost Load
WECC – Western Electric Coordinating Council
WEIM – Western Energy Imbalance Market
WSC – Water and Sewer Supply Corporation

# Appendix - Agency Updates (2023 – 2024)

The PUCT requested resources from the 88th Texas Legislature to strengthen the agency's ability to regulate the electricity, water, and telecommunications industries. This section gives updates on the status of the PUCT's implementation and use of those resources granted by the Legislature, as well as updates on implementation of other legislation.

## Update on Exceptional Items in the FY 2024-25 Budget

The PUCT requested and was granted $19 million in exceptional items for the FY 2024-25 biennium.

### New Full-Time Employees (FTEs)

In January 2023, the PUCT had 202 employees and a cap of 234 FTEs. The 88th Texas Legislature granted $4.5 million per year in funding for FTEs and increased the cap to 283. At the conclusion of FY 2024, the PUCT had 258 FTEs. The agency continues to post and fill vacancies for new positions in FY 2025.

The PUCT needed to add positions throughout the agency in response to an overall increase in workload across every division, including the contested caseload volume. These new hires also created new teams and divisions.

To keep pace with the growing workload related to contested cases, the Rate Regulation, Infrastructure, and Legal Divisions, as well as the Office of Policy and Docket Management, added staff. A special projects coordinator position was created to enhance data collection and reporting.

The PUCT expanded its Information Technology (IT) team to enhance its automation capabilities and replace outdated applications with modern tools and architecture. A Learning and Development team was also created to enhance training opportunities for all employees. This new team ensures that as the agency grows, new staff are onboarded and brought up to speed as effectively as possible.

### Market Data Analysis Team

The Market Data Analysis team was created using $955,000 per year granted by the Legislature. Currently, the team consists of a program manager, a project manager, and two economists with expertise in data analytics, economics, mathematics, and statistics. All employees on this team have advanced degrees. The PUCT also purchased upgraded computers and several technical tools to support their work, and the team is continuing to assess its technology needs in FY 2025.

During FY 2024, the team continued to work on specialized data analysis projects to support commission decision-making on significant policy issues, including the electricity market reliability standard, generation resource adequacy, long term transmission planning, transmission system resiliency plans, and Texas Energy Fund (TEF). In addition, the team supported the agency's Electric Reliability Council of Texas (ERCOT) oversight responsibilities by analyzing market operations-related changes, including analysis of proposed changes to ERCOT market rules and procedures developed through the ERCOT stakeholder process.

## Energy Efficiency Division

The PUCT established the Energy Efficiency Division in 2024 with $495,000 in funding for the biennium. The division oversees the energy efficiency programs administered by the eight investor-owned utilities and evaluates the programs to ensure these are effective in achieving energy efficiency goals. Energy efficiency programs are designed to reduce residential and commercial energy consumption and manage consumer energy costs. The team is currently working on rulemakings to implement requirements related to energy efficiency and demand response as provided in SB 1699 and HB 1500 (88R).

Additionally, the division collaborates with ERCOT to provide energy efficiency savings forecasts accounted for in the capacity, demand, and reserves assessments. It also collaborates with the Texas Commission on Environmental Quality and Texas A&M Energy Systems Laboratory on an annual report quantifying the reductions of energy consumption, peak demand, and associated air contaminant emissions.

## Information Technology (IT) and Cybersecurity

The 88$^{th}$ Texas Legislature appropriated $512,000 per year to the PUCT in additional funding for improvements to its internal cybersecurity and IT modernization efforts. The PUCT has implemented all the funded improvements.

Security enhancements include new security tools and a network firewall upgrade. The PUCT added a web application firewall to protect its websites. A security information and event monitoring (SIEM) system was implemented and combined with vulnerability management for greater visibility into security events and potential hazards. The PUCT has increased email security by adding tools to protect against phishing.

The PUCT procured and implemented a low-code development platform in FY 2024 to automate manual processes and enhance agency processes. The agency has used the low-code platform to develop a Customer Relationship Management application to track inquiries from external entities that come in through various PUCT divisions, including Communications, the Office of Public Engagement, the Division of Utility Outreach, and Government Relations. This tool helps staff consistently track and respond to inquiries from external parties.

The PUCT IT team is also working on a portal for utilities to use to submit compliance reports and documentation to the PUCT into a database. The new tool will increase data accessibility and availability to enable staff to track and analyze compliance data effectively and efficiently.

## Salary Increases

The 88th Texas Legislature granted the PUCT $1.2 million for staff salary increases in FY 2024 and 2025 to boost employee retention efforts. The Legislature granted a five percent increase to all PUCT staff and an additional five percent increase to licensed certified public accountants, attorneys, and professional engineers, because those are the hardest positions for the PUCT to recruit and retain. These salary increases were in addition to statewide salary increases approved by the Texas Legislature for all state employees.

The results from this exceptional item have been notable. The PUCT's turnover rate averaged 20.3% during FY 2017-21 with attorney turnover as high as 36%. After the salary increases for staff during the summer and fall of 2023, the PUCT's turnover has decreased to 10.4% in FY 2024.

## Professional Contracts

The PUCT was granted $2.28 million in funding for several new contracts for mapping and engineering support and digitization efforts. One of these contracts, for geographic information system (GIS) mapping resources, is in the procurement stage, and others are in various stages of planning, procurement, and implementation.

## Tools, Training, and Buildouts

With the $1.35 million in funding received for equipment, training, travel, and workspace for additional employees, the PUCT procured additional laptops, monitors, and other equipment for its employees. The agency also completed new cubicle buildouts to accommodate additional staffing on the 7th and 8th floors of the William B. Travis Building. The PUCT's employee training program has been expanded significantly, with development of a new department and expanded training opportunities for all employees to build utility knowledge and other skills.

## Office of Public Engagement

The Office of Public Engagement (OPE) is fully staffed and operational with three FTEs using $255,000 per year in funding from the 88th Texas Legislature. OPE participated in a broad range of events across the state. In FY 2024, the OPE responded to 865 calls and emails and conducted 39 presentations and meetings for citizen groups to expand understanding of the PUCT's processes and how Texans can engage with the agency.

The OPE team educated consumers about the electricity market and consumer protection issues in Lubbock when the city introduced retail customer choice for its electricity consumers. The team participated in town hall meetings with lawmakers and Texans dealing with water utility rate increases and other water service issues. OPE also provides assistance to Texans who need help submitting public comments at commission open meetings.

## Update on PUCT's Recommendations to the 88th Legislature

### Background Checks for PUCT Personnel (SB 1112)

The PUCT requested the authority to conduct background checks on PUCT employees to ensure they do not present a safety risk to Texas' electric grid. Senate Bill 1112, ( 88R), granted the PUCT the authority to obtain background and criminal history record information for new PUCT employees only, when they are hired. The PUCT does not have the authority to conduct background checks on current PUCT employees.

### Registration of Large Flexible Loads (SB 1929)

To limit grid reliability risks created by large flexible loads (LFL), which can be turned on or off within seconds, the PUCT requested the Legislature grant ERCOT the authority to require LFLs to register and follow standards on allowable behaviors.

Senate Bill 1929, 88R, directed the PUCT to require virtual currency mining facilities, which are a type of LFL, to register with the agency. They must provide related information that the PUCT may share with ERCOT. The bill, however, did not include other types of LFLs. The bill also did not grant authority to impose standards on allowable behavior of LFLs. In November 2024, the PUCT adopted 16 TAC § 25.114 to require virtual currency mining facilities larger than 75 MW to register with the PUCT.

### Aggregate Distributed Energy Resources (SB 1699)

An aggregate distributed energy resource (ADER) consists of distributed energy resources at multiple homes and businesses that can aggregate at the distribution level. Together, they effectively serve as one resource to provide power in response to ERCOT dispatch instructions.

To facilitate the development of ADERs, the PUCT asked the Legislature to clarify that a distributed energy resource (DER) is not required to register with the commission, if an aggregator that is a REP has registered the DER, and the aggregated DER is not a power generation company (PGC). The PUCT also recommended that it be authorized to establish simplified registration requirements for ADERs and its rules, jurisdiction, and authority extend to market participants' and consumers' participation in an ADER.

Senate Bill 1699, 88R, provided the PUCT with the authority to establish rules and registration requirements for ADERs. It clarified that a person that aggregates DERs is required to comply with PUCT rules, guidelines, and registration requirements, as well as comply with customer protection provisions laid out under PURA chapter 17, and other applicable statutes. Additionally, the statute clarified that a person aggregating DERs is not required to register as a PGC.

The PUCT is currently overseeing the implementation of Phase 2 of the ADER pilot project in the ERCOT power region. ADER participants take part in the wholesale energy market and certain ancillary services. Ancillary Services are purchased by ERCOT in the day-ahead market to balance the next day's supply and demand of electricity on the grid and mitigate real-time operational issues. Generators or consumers can both provide ancillary services to increase or decrease the supply of electricity in a matter of minutes or seconds. As of September 2024, two ADERs fully participate in the ERCOT market and provide both energy and ancillary services.

## Electricity Supply Chain Map (SB 1093)

The Electricity Supply Chain Map was created by the Texas Electricity Supply Chain Security and Mapping Committee (Mapping Committee) for effective coordination of preparedness and faster response time during weather emergencies. In its legislative recommendation, the PUCT recommended adding water facilities to bolster the map. It also recommended adding the TxDOT to the mapping committee and to allow transmission distribution service providers (TDSPs) access to their specific portion of the Electricity Supply Chain Map. Senate Bill 1093, 88R, amended PURA § 38.201 to include water and wastewater treatment plants as part of the electricity supply chain. It also added the executive director of TxDOT to the Mapping Committee and allowed TDSPs view-only access to their specific portion of the Electric Supply Chain Map.

The PUCT completed implementation of PURA § 38.201, as amended by SB 1093, in 2023. The commission enabled view-only access to the map for an electric utility, municipally owned utility (MOU) or electric co-op requesting access. The view-only access to the map is limited to the critical natural gas facilities on the map that are located in the requesting entity's service area. The commission also coordinated with the Texas Commission on Environmental Quality (TCEQ) to add water and wastewater treatment plants to the Electricity Supply Chain Map and added TxDOT to the mapping committee.

# Conflicts of Interest Report

**Responsive to Public Utility Regulatory Act § 39.167 (House Bill 1500, 88R)**

January 15, 2025

## Introduction

House Bill 1500, enacted by the 88th Legislature (R.S.) and codified at Public Utility Regulatory Act (PURA) § 39.167, requires the Public Utility Commission of Texas (PUCT) and ERCOT to annually review statutes, rules, protocols, and bylaws that apply to conflicts of interest for commissioners and for members of the governing body of the independent organization. The PUCT is required to submit an annual report to the legislature on the effects the statutes, rules, protocols, and bylaws have on the ability of the commission to fulfill its duties. The PUCT does not have bylaws and it does not adopt protocols. Accordingly, this report primarily addresses conflicts of interest provisions based in statutes and PUCT rules. However, under PURA § 39.151, two PUCT commissioners serve on the ERCOT board of directors. Conflicts of interest requirements established in ERCOT bylaws that are applicable to those two commissioners are addressed separately. ERCOT protocols govern the activities of market participants and therefore do not impact the official activities of PUCT commissioners.

The PUCT submits this "*conflicts of interest report*" in compliance with House Bill 1500. As described in more detail below, the PUCT is able to fulfill its duties with the current statutes, rules, and bylaws governing conflicts of interest applicable to commissioners.

## Statutory and Rule Requirements

The following Government and Penal Code provisions apply to all state employees and officers, including PUCT commissioners. The Utilities Code provisions, however, only apply to PUCT employees and commissioners. In many instances, the provisions of the Utilities Code may be more restrictive than those in the Government and Penal Codes.

Additionally, the Utilities Code conduct provisions only affect commissioner interaction with an electric or telecommunications public utility or affiliate.[1] Because the Texas Water Code does not contain restrictions similar to those in the Utilities Code, a commissioner's interaction with a water or sewer utility or affiliate is limited only by the general ethical standards in the Government and Penal Codes. This means that in all situations a commissioner may not engage in conduct unless such conduct is permissible under all applicable provisions of the Government and Penal Codes. In interactions with an electric or telecommunications public utility or affiliate, a commissioner must additionally comply with conduct restrictions in the Utilities Code.

[1] *See* Utilities Code §§ 11.003(2), 11.004, 31.002(6), and 51.002(8).

## Government Code Chapter 572

Government Code Chapter 572 serves as a guide for the official conduct of those persons owing a responsibility to the people and government of Texas in the performance of their official duties. The chapter not only sets the standards of conduct and disclosure requirements for state officers and employees, but also provides a basis for discipline for those who fail to meet its requirements.[2]

## Government Code § 572.001

Government Code § 572.001 provides that a state officer or employee may not have a "direct or indirect interest, including financial and other interests, or engage in a business transaction or professional activity, or incur any obligation of any nature that is in substantial conflict with the proper discharge of the officer's or employee's duties in the public interest."

This section establishes the primary conflict of interest standard applicable to all state employees and officers, including PUCT commissioners.

## Government Code § 572.051

Government Code § 572.051 prohibits state officers and employees, including PUCT commissioners, from:

- accepting or soliciting any gift, favor, or service that might reasonably influence the individual in the performance of his or her official duties;
- accepting other employment or engaging in other professional activity that could induce the individual to disclose confidential information acquired as a result of his or her official position;
- accepting other employment or compensation that could impair the individual's judgment in performance of his or her official duties;
- making personal investments that could create a substantial conflict between the individual's public and private interests; and
- accepting or soliciting any benefit as a result of performing the individual's official duties.

A state officer violating this section is subject to civil or criminal penalty if the violation also constitutes a violation of another statute or rule.

## Government Code § 572.054

Government Code § 572.054 prohibits state officials, including PUCT commissioners, from communicating to or appearing before an officer or employee in which the official served for two years after the official ceased his or her service, if the purpose of the communication or appearance is made with the intent to influence and is on behalf of any person seeking official action of the agency in which the former officer served.

[2] Texas Government Code § 572.001(b) and (c).

**Government Code § 572.069**
A former state officer who participated in a procurement or contract negotiation with a person may not accept employment from that person before the second anniversary of the date the contract is signed, or the procurement is terminated or withdrawn.

**Government Code §§ 572.021 and 572.026**
Government Code Chapter 572, Subchapter B contains several provisions related to personal financial statements for state officers. These sections require a state officer, including PUCT commissioners, to annually file a verified financial statement accounting for the financial activity of the individual[3] during the preceding calendar year.

**Government Code §§ 556.004 and 556.006**
These sections contain restrictions related to certain political activities and legislative lobbying. Under Government Code § 556.004, a state officer, including a PUCT commissioner, may not use his or her official authority or influence or permit the use of a program administered by the state agency of which the person is an officer to interfere with or affect the result of an election or nomination of a candidate or to achieve any other political purpose. A state officer is also prohibited from using a state-owned or state-leased motor vehicle for such a purpose. Government Code § 556.006 prohibits the use of appropriated money to attempt to influence the passage or defeat of a legislative measure.

**Government Code § 2152.064 and 1 Texas Administrative Code § 45.5**
These provisions contain restrictions related to state procurement and contracting. Government Code § 2152.064(a)(1) prohibits PUCT commissioners from having an interest in, or in any manner being connected with: (A) a contract or bid for a purchase of goods or services, including professional or consulting services, in connection with the charge and control of state buildings, grounds, or property; maintenance or repair of state buildings, grounds, or property; construction of a state building; or purchase or lease of state buildings, grounds, or property by or for the state; or (B) a recipient of state surplus or salvage property. Government Code § 2152.064(a)(2) prohibits PUCT commissioners from, in any manner, including by rebate or gift, accepting, or receiving, directly or indirectly, from a recipient of state surplus or salvage property or a person to whom a contract may be awarded, anything of value or a promise, obligation, or contract for future reward or compensation.

A violation of § 2152.064(a)(2) could result in the dismissal of the commissioner.

[3] *See* Texas Government Code § 572.023(a), also requiring an account of the financial activity of an individual's spouse and dependent children if the individual had actual control over that financial activity for the preceding calendar year.

### Penal Code Chapter 36

Penal Code Chapter 36 contains provisions of general applicability that relate to all state officials, including PUCT commissioners. In general, the chapter restricts the acceptance or solicitation of certain gifts and benefits. The Utilities Code contains similar, and in some cases, more restrictive provisions relating to commissioners' interactions with electric and telecommunications utilities. The Texas Water Code, however, does not contain such restrictions. As a result, the Penal Code provisions are most applicable to commissioners' interactions with water and sewer utilities. In all situations however, regardless of whether the Utilities Code provisions may also apply, PUCT commissioners must comply with the restrictions in the Penal Code. Further, violations of these provisions carry potential criminal liability.

### Penal Code § 36.02

Penal Code § 36.02 prohibits a person, including PUCT commissioners, from intentionally or knowingly offering, conferring, or agreeing to confer on another, or soliciting, accepting, or agreeing to accept any benefit as consideration for the individual's decision, opinion, recommendation, vote, or other exercise of discretion as a public official.

An individual may violate this provision even if the benefit is not conferred or accepted until after the decision, opinion, recommendation, vote, or other exercise of discretion has occurred or the individual ceases to be a public official.

### Penal Code § 36.07

A public servant, including PUCT commissioners, may not solicit, accept, or agree to accept an honorarium in consideration for services that the public servant would not have been requested to provide but for the public servant's official position or duties.

### Penal Code § 36.08

Penal Code § 36.08 generally prohibits a public servant, including a PUCT commissioner, from soliciting, accepting, or agreeing to accept any benefit from a person the individual knows to be subject to regulation, inspection, or investigation by the individual or his or her agency. Additionally, under this section, an individual who exercises discretion in connection with contracts, purchases, payments, claims, or other pecuniary transactions of the government may not solicit, accept, or agree to accept any benefit from a person the individual knows is interested in or is likely to become interested in any contract, purchase, payment, claim, or transaction involving the exercise of his or her discretion.

### Penal Code § 39.02 and Government Code § 2203.004

Penal Code § 39.02 prohibits a public servant, including a PUCT commissioner, from misusing government property, services, personnel, or any other thing of value belonging to the government that has come into the individual's custody or possession by virtue of his/her office or employment. Similarly, Government Code § 2203.004 requires state property to be used only for state purposes. An individual, including a PUCT commissioner, therefore, may not entrust state property to any other person if the property is not to be used for state purposes.

**Utilities Code Chapter 12**

The Utilities Code Chapter 12 sets out the eligibility requirements for PUCT commissioners and prohibits specified conduct for PUCT commissioners as it relates specifically to interacting with electric and telecommunications utilities. These restrictions do not apply to similar interactions involving water and sewer utilities because the Texas Water Code does not contain similar restrictions.

**Utilities Code § 12.053**

Utilities Code § 12.053(b) prescribes the eligibility requirements for PUCT commissioners.[4] A person is not eligible for appointment as a commissioner if he or she, at any time during the one year preceding appointment: (i) personally served as an officer, director, owner, employee, partner, or legal representative of a public utility regulated by the PUCT or of an affiliate or direct competitor of a public utility regulated by the PUCT; (ii) owned or controlled, directly or indirectly, more than a ten percent interest in a public utility regulated by the PUCT or in an affiliate or direct competitor of a public utility regulated by the PUCT; (iii) served as an executive officer listed under the Texas Constitution, Article IV, Section 1, other than the secretary of state, or a member of the legislature; or (iv) is not qualified to serve under Utilities Code §§ 12.151, 12.152, or 12.153.

**Utilities Code § 12.055**

Under Utilities Code § 12.055, a PUCT commissioner may not seek nomination or election to another civil office in Texas or the United States while serving as a commissioner.

If a commissioner does so in violation of this provision, the individual's office immediately becomes vacant.

**Utilities Code § 12.059**

This section requires all PUCT commissioners to complete a training program before beginning their service as a commissioner. The training program must include information regarding laws relating to disclosure of conflicts of interest, other laws relating to public officials in performing their duties, and any applicable ethics policies

[4] Utilities Code § 12.054 specifies the grounds for removal of a PUCT commissioner, including violation of a prohibition contained in § 12.053 or Chapter 12, Subchapter D (relating to prohibited relationships and activities).

adopted by the PUCT or the Texas Ethics Commission.

**Utilities Code § 12.152**

Section 12.152 contains specific conflict of interest provisions applicable to PUCT commissioners. Under § 12.152, a person is not eligible to serve as a commissioner if the individual serves on the board of directors of a company that supplies fuel, utility-related services, or utility-related products to regulated or unregulated electric or telecommunications utilities, or if the individual or the individual's spouse is employed by or participates in the management of a business entity or other organization that is regulated by or receives funds from the PUCT or directly or indirectly owns or controls more than a ten percent interest in certain specified business entities, utility competitors or suppliers, or mutual or retirement funds.[5]

**Utilities Code § 12.153**

Under Utilities Code § 12.153, a person may not serve as a PUCT commissioner if the individual is an officer, employee, or paid consultant of a trade association; or the spouse of an officer, manager, or paid consultant of a trade association.

**Utilities Code§ 12.154**

Utilities Code § 12.154 prohibits certain activities while an individual serves as a PUCT commissioner. Under Utilities Code § 12.154(a), during the period of service with the PUCT, a PUCT commissioner may not have a pecuniary interest in a public utility, a public utility affiliate, or a person a significant portion of whose business consists of furnishing goods or services to a public utility or affiliate. A PUCT commissioner may also not accept a gift, gratuity, or entertainment from a public utility, affiliate, direct competitor of a public utility, a person a significant portion of whose business consists of furnishing goods or services to public utilities, affiliates, direct competitors of public utilities; or an agent, representative, attorney, employee, officer, owner, director, or partner of those entities. Under § 12.154(b), a PUCT commissioner may not directly or indirectly solicit, request from, or suggest or recommend to a public utility or an agent, representative, attorney, employee, officer, owner, director, or partner of a public utility the appointment to a position or the employment of a person by the public utility or affiliate.[6] Under § 12.154(c), a PUCT commissioner may not accept a gift, gratuity, employment, or entertainment from a public utility; affiliate; a direct competitor of a public utility; a person who furnishes goods or services to a public utility, affiliate, or direct competitor of a public utility; or an agent, representative, attorney, employee, officer, owner, director, or partner of such entities.

**Utilities Code § 12.155**

This section prohibits a commissioner from being employed by a public utility that

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[5] Government Code § 12.152(a)(2)(D) and (b) prescribe permissible exceptions to the section's requirements.

[6] Utilities Code § 12.154(e)-(h) contain exceptions to these prohibitions.

was within the scope of the commissioner's official responsibility while serving as a commissioner. This is a two-year prohibition from the date the commissioner ceases to serve as a commissioner.Commissioners are also prohibited from representing any person before the PUCT, the State Office of Administrative Hearings or a court in a matter in which the commissioner was personally involved. This prohibition has no time limit. Finally, a commissioner may not be employed by an independent organization certified under Utilities Code § 39.151 until the second anniversary of the date the commissioner ceases to serve as a commissioner.

**Utilities Code §§ 12.060 and 12.151**

Under Utilities Code § 12.060, a former PUCT commissioner may not, before the first anniversary of the date the individual ceases to be a commissioner, engage in an activity before the PUCT that requires registration under the lobby provisions of Government Code Chapter 305. Similarly, under Utilities Code § 12.151, a person required to register as a lobbyist under Government Code Chapter 305 because of the individual's activities for compensation on behalf of a profession related to PUCT activities may not serve as a commissioner.

**16 TAC § 22.3(d) – Standards for Recusal of Commissioners**

PUCT rule 16 TAC § 22.3 governs standards of conduct for parties and decision makers in PUCT proceedings. Subsection (d) of this rule addresses three circumstances when commissioners must recuse themselves from deciding one or more issues in a proceeding: (1) the commissioner lacks impartiality or the commissioner's impartiality has been reasonably questioned; (2) the commissioner (or a relative of the commissioner) is a party, or has a financial or other interest in the subject matter of the proceeding; or (3) the commissioner (or a relative of the commissioner) has participated as counsel, advisor, or witness in the proceeding.

**ERCOT Bylaws Article 9**

Under PURA 39.151(g-1)(1), two PUCT commissioners serve as ex officio, nonvoting members of the ERCOT board of directors. While these commissioners do not vote on ERCOT board decisions, they are still bound by the ERCOT bylaws. ERCOT bylaws article 9 includes several conduct restrictions applicable to the two PUCT commissioners on the ERCOT board. First, the commissioners must disclose any actual or potential conflict of interest for any matter that comes before the board. If a PUCT commissioner has a significant financial or personal interest in a matter, then the commissioner must recuse himself from deliberations on the matter. Second, ERCOT may not loan money to the PUCT commissioners on the board, and any business transaction between ERCOT and PUCT commissioner must be fully disclosed. Finally, article 9 includes a list of prohibited conduct that generally prevents the PUCT commissioners from undertaking acts that may imperil ERCOT as an organization.

## Effects of Statutes and Rules on Ability of PUCT Commissioners to Perform Their Statutory Duties

The majority of restrictions discussed in this report apply equally to all state officers and are not unique to PUCT commissioners. Although additional restrictions in the Utilities Code also apply to PUCT commissioners, none of these provisions impair the commissioners' ability to fulfill their statutory duties. On the contrary, the provisions enable the Legislature and the PUCT to ensure that commissioners are qualified to serve in their positions. Additionally, commissioners are able to remain in compliance with the eligibility requirements, disclosure requirements, and conflict of interest requirements of Texas law during their terms of service. The post-employment restrictions in the Utilities and Government Codes also help ensure that PUCT commissioners do not use their position for personal benefit after their terms of service end. Further, the financial statements that must be filed annually with the Texas Ethics Commission by all state officers, including PUCT commissioners, also provide a means of monitoring commissioner compliance with both the financial disclosure requirements in Texas Government Code Chapter 572 and the investment restrictions in Utilities Code § 12.154. Finally, many of the Government and Penal Code provisions contain some exceptions for otherwise prohibited conduct, which lessens the burden of compliance.

On occasion, PUCT commissioners recuse themselves from participating in contested cases under 16 TAC § 22.3 because they represented parties to those cases before becoming commissioners. For example, two PUCT commissioners previously served as Public Counsel for the Office of Public Utility Counsel (OPUC). In that capacity, they represented OPUC as an intervenor party in numerous contested cases. The practice of these commissioners is to file a memo announcing that they will recuse themselves from participation as a decision maker if OPUC was a party to the case during their tenure as Public Counsel. However, these instances of recusal do not impact the PUCT's ability to decide contested cases because the remaining commissioners are empowered to render a decision in each contested case.

The ERCOT bylaws only bind the two PUCT commissioners who sit on the ERCOT board by statutory designation. The bylaws conflict-of-interest provisions prevent the PUCT commissioners from participating in deliberations where a relationship with another entity would compromise the commissioners' duties to ERCOT. These provisions do not impede the commissioners' ability to fulfill their responsibilities to the PUCT because recusal from an ERCOT deliberation does not force a commissioner to undertake any action related to PUCT duties.

PUCT ethics policies reiterate the applicable statutes and rules discussed in this report. Incoming PUCT commissioners receive training regarding these statutes and rules, and the PUCT's agency counsel is available to answer questions and provide guidance regarding commissioner compliance. Further, in an effort to ensure ongoing compliance with the statutes and rules, under Texas Utilities Code § 12.059, commissioners are provided a copy of the PUCT's training manual annually, and all commissioners are required to sign and submit to the executive director a statement acknowledging that they have received and reviewed the training manual.

| Statute | Prohibition/Requirement | Applicability |
|---|---|---|
| Government Code §§ 556.004 and 556.006 | Political activity/lobbying prohibition | General applicability |
| Government Code § 572.001 | Conflicts of interest | General applicability |
| Government Code §§ 572.051 and 2113.014 | Standards of conduct | General applicability |
| Government Code §§ 572.054 and 572.069 | Employment restrictions | General applicability |
| Government Code § 2152.064 and 1 Tex. Admin. Code § 45.5 | Contracting prohibitions | General applicability |
| Government Code §§ 572.021 and 572.026 | Financial statement requirements | General applicability |
| Penal Code § 36.02 | Bribery restrictions | General applicability |
| Penal Code § 36.07 | Honorarium restrictions | General applicability |
| Penal Code § 36.08(a) and (e) | Accepting/soliciting benefits from regulated entity or interested party | General applicability |
| Penal Code § 36.08(d) | Accepting/soliciting benefits from bidder or contracted entity | General applicability |
| Penal Code § 39.02 and Government Code § 2203.004 | Misuse of governmental property | General applicability |
| Penal Code § 39.06 | Misuse of official information/failure to report | General applicability |
| Utilities Code §§ 12.053 and 12.054 | Eligibility requirements | PUCT specific |
| Utilities Code § 12.055 | Nomination/election prohibitions | PUCT specific |
| Utilities Code §§ 12.059 and 12.156 | Training requirements | PUCT specific |
| Utilities Code § 12.060 | Lobbying restrictions (former commissioners) | PUCT specific |

| | | |
|---|---|---|
| Utilities Code § 12.151 | Lobbying restrictions (current commissioners) | PUCT specific |
| Utilities Code § 12.152 | Conflicts of interest | PUCT specific |
| Utilities Code § 12.153 | Trade association prohibitions | PUCT specific |
| Utilities Code § 12.154(a) | Pecuniary interests | PUCT specific |
| Utilities Code § 12.154(b) | Applying for job/job recommendations | PUCT specific |
| Utilities Code § 12.154(c) | Gift prohibitions | PUCT specific |
| Utilities Code § 12.155 | Employment restrictions | PUCT specific |

# Electric Industry Report

**Responsive to Public Utility Regulatory Act § 39.166 (House Bill 1500, 88R)**

January 15, 2025

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# I. Texas Electric Grid

The continental United States is served by three major power grids: the eastern, western, and Electric Reliability Council of Texas (ERCOT) interconnections. Texas is the only state in the country that is served by all three interconnections. However, most of the state is served by ERCOT.

There are three broad functions of the electricity industry: (1) generation, (2) transmission and distribution, and (3) retail sale to the end-use consumers. Electricity is generated in power plants, moved across the state through transmission lines, delivered to end-use consumers through a distribution system, and ultimately sold to those consumers at a retail rate.

In Texas, residential, commercial, and industrial consumers are served by one of four types of electricity service providers: Retail Electric Provider (REP), Electric Cooperative (Co-op), Municipally Owned Utility (MOU), or vertically integrated Investor-Owned Utility operating outside of ERCOT (Non-ERCOT IOU). A Non-ERCOT IOU is an electric utility that owns and operates generation, transmission and distribution lines, and is responsible for retail sale to end-use consumers.

Within the ERCOT region, consumers can be served by a REP, MOU, or Co-op. Most Texans are served by a REP of their choice in the competitive retail market within the ERCOT region. MOUs and Co-ops typically have a monopoly on retail services in their respective local areas and generally do not offer retail choice. However, a MOU or Co-op within ERCOT may choose to implement retail competition, as Lubbock Power & Light did in 2024. The Nueces Electric Co-op has offered retail choice to its consumers since 2004. Outside of the ERCOT region, consumers do not get to select their retail electric provider. These consumers are served either by a Non-ERCOT IOU, MOU, or Co-op.

## ERCOT Region

### Competitive Retail Market

Texans in areas open to retail competition can choose electricity products from a variety of REPs. A REP buys electricity in the competitive wholesale market to sell to its retail customers. A REP also manages the retail relationship with the customer, including billing and customer service. The variety of plans available in the competitive retail market allows consumers to choose a plan that best fits their needs and budgets.

During the 2023-24 biennium, the number of REPs and types of plans or offers in the competitive market areas of ERCOT remained stable. This biennium the PUCT certified 14 new REPs and 14 REPs relinquished their certificates to operate in Texas. There are currently 138 REPs authorized to sell electricity in the Texas competitive retail market. As of March 2024, REPs in the competitive market served 7,139,850 residential premises, 1,190,620 commercial premises, and 5,139 industrial premises.[1]

PUCT-certified REPs in Texas use the Power to Choose[2] website to provide information about their electricity plans and offers for consumers. The price available on Power to Choose for a 12-month, fixed rate plan across the transmission and distribution utility (TDU) service territories in September 2024 ranged from 13.86¢ per kilowatt hour (kWh) to 15.88¢ per kWh. As of September 2024, plans were available that offer 100% renewable electricity, time-of-use pricing (such as free electricity on the weekends), excess solar generation buy-back, and prepay optionality. Contract terms varied from one month up to 60 months.

## Competitive Wholesale Market

The competitive wholesale electricity market is a marketplace where electricity is bought and sold in bulk. Within ERCOT, the competitive wholesale electricity market primarily operates as an energy-only market, meaning each generator is paid only for the actual energy or electricity it provides to the grid. Generators also can participate in the ancillary services markets, which pay generators for reserving a portion of the capacity of their power plants to serve as an operating reserve. Ancillary services are reliability products used to support the transmission of energy to loads and the reliable operation of the electricity system.

In contrast, other power regions around the country incorporate an additional payment mechanism where generators can be compensated for availability of generation capacity in the future, in addition to payments for energy and ancillary services. There are over 1,250 generation units that participate in the ERCOT wholesale market. Like other competitive markets, owners and investors decide to invest in new generation units or retire existing generation units based on expected costs and profits.

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[1] PUCT , POLR Counts Energy 2024 Report. Last found at http://www.ercot.com/mktinfo/retail (March 2024)

[2] See powertochoose.org

### Transmission and Distribution Utilities

Within the ERCOT competitive market, TDUs are responsible for building and maintaining the infrastructure that delivers power to consumers. This infrastructure includes high-voltage transmission lines, substations, local distribution lines, and the end-use consumer meters. While the TDUs physically deliver electric power to consumers in ERCOT, they do not sell power to consumers. There are over 54,100 miles of high voltage transmission in the ERCOT region.

In the ERCOT power region, the PUCT regulates and sets the rates for nine IOUs. Of these, four companies provide both transmission and distribution services: Oncor Electric Delivery Company (Oncor), CenterPoint Energy (CenterPoint), American Electric Power Texas (AEP), and Texas-New Mexico Power Company (TNMP). The remaining five IOUs provide transmission-only services: Electric Transmission Texas, Wind Energy Transmission of Texas, Lone Star Transmission, Cross Texas Transmission, and Sharyland Utilities. The PUCT also sets transmission-service rates for 38 entities that provide wholesale transmission service in ERCOT, including electric co-ops, MOUs, and river authorities.

## Outside ERCOT Region

Outside the ERCOT region, four electric utilities remain vertically integrated. These Non-ERCOT IOUs own, operate, and are responsible for each of the three major functions of electricity service: generation, transmission and distribution, and retail sale to end-use consumers. These utilities are: Entergy Texas, Southwestern Electric Power Company (SWEPCO), El Paso Electric (EPE), and Southwestern Public Service Company (SPS, also known as Xcel Energy). In contrast, in the competitive ERCOT areas these functions are separated, and except for MOU or Co-ops, no single entity can be responsible for all three functions.

Together, the Non-ERCOT IOUs serve more than 1.3 million consumers. The PUCT sets retail rates for these vertically integrated utilities in comprehensive rate proceedings. The Federal Energy Regulatory Commission (FERC) has regulatory authority over interstate wholesale power transactions and interstate transmission rates for these utilities.

### MOUs and Co-ops

MOUs and Co-ops can be found both inside and outside the ERCOT region of Texas. There are 76 member-owned Co-ops in Texas, governed by elected boards, that serve nearly 3 million consumers. Additionally, 72 municipalities own and operate utilities, including Austin Energy and CPS Energy in San Antonio. Together, all MOUs serve over 5.3 million Texas consumers.

The PUCT does not have retail rate-setting authority over Co-ops or MOUs. However, the PUCT does have limited ability to review retail rates of the MOUs. Through its authority over wholesale transmission rates, the PUCT sets the wholesale transmission rates of MOUs and Co-ops in the ERCOT region and regulates reliability issues.

## Regional Transmission Organizations

Regional Transmission Organizations (RTOs) are organizations that administer the transmission grid on a regional basis throughout North America and Canada. In the United States, FERC regulates all RTOs except ERCOT. The PUCT regulates ERCOT. However, ERCOT is subject to some FERC jurisdiction over reliability related issues.

There are three RTOs that operate in Texas: ERCOT, Southwest Power Pool (SPP), and Midcontinent Independent System Operator (MISO).

RTOs are responsible for ensuring a reliable and adequate electric transmission network to meet system needs and to support load growth at a reasonable cost in their respective regions.

RTOs are also responsible for ensuring that there are sufficient generation resources available to generate power to serve expected peak electricity demand. To maintain resource and transmission adequacy, RTOs use various methods to track, plan, and forecast the need for generation and transmission capacity, taking into account resource mix, potential capacity shortages, transmission constraints, and expected demand. These methods are developed through extensive stakeholder processes. Stakeholders include generation and transmission owners, entities that serve consumers, and consumer representatives. RTOs in the non-ERCOT regions of Texas also include representation from states in their respective geographic regions. FERC approves the transmission and resource adequacy plans of the various non-ERCOT RTOs.

ERCOT, Inc. is the RTO for the ERCOT region that is entirely within Texas. ERCOT manages the flow of electric power to more than 27 million Texas consumers, representing about 90% of the state's total electric load. SPP is the FERC-authorized RTO for areas of Northeast Texas and the Texas Panhandle. SWEPCO, SPS, several Co-ops and MOUs operate within the SPP footprint. MISO is the largest RTO in North

America, serving all (or part) of 15 states in the central United States and the Canadian province of Manitoba. Entergy Texas serves a portion of southeast Texas that is part of the MISO footprint.

The PUCT participates in SPP and MISO meetings to ensure the fair treatment of Texas consumers.

### Western Electric Coordinating Council (WECC)

The Western Electric Coordinating Council (WECC) is the FERC-approved reliability entity responsible for reliability in 14 western states in America, two Canadian provinces, and northern Baja Mexico. It oversees compliance monitoring and enforcement in the western interconnection. Unlike an RTO, WECC does not control market operations or dispatch generation. EPE is the only electric utility in Texas that is a member of WECC.

## II. Generation Capacity

Planning for sufficient generation capacity across the state does not follow a uniform process. In the SPP, MISO, and WECC areas of the state, generation capacity planning occurs through centralized and federally-regulated procedures. The RTOs require electric utilities to maintain minimum levels of generation capacity and have developed economic and regulatory methods by which these capacities are procured. In ERCOT, however, generation capacity is driven primarily through market incentives. Investors assess whether and when to build new generation based on the future potential to earn a sufficient return on their investment.

The table below provides information about available generation capacity as of 2024. Texas had a generation capacity of over 120,000 megawatts (MW).

| Region | Generation Capacity (MW) |
|---|---|
| ERCOT | 103,609 |
| Non-ERCOT* | 16,659 |
| Total Texas | 120,268 |

Note: * Aggregates only non-ERCOT IOUs' data. Capacity data is an estimation of capacity and is subject to revision. The data excludes all the non-ERCOT IOUs' bilateral trade agreements used to serve load and fulfill capacity requirements in non-ERCOT regions.

## ERCOT Region

The operational generation capacity available during summer 2025 is forecasted at 115,596 MW. This includes 817 MW of electricity generation capacity that ERCOT has access to import from other power regions, using the direct-current ties to other interconnections. Planned new generation capacity available at the time of the summer 2029 peak load hour is forecasted to be at 30,001 MW.

Below is background information about resources that were aggregated to determine the generation capacity.

<u>Resources</u>

- At the time the May Capacity, Demand, and Reserves (CDR) report was prepared, ERCOT Protocols did not include a methodology for determining the capacity contribution of battery storage. Therefore, the contribution in the May 2024 CDR is reported as zero MW. Protocols now include a methodology for estimating the capacity contribution of battery storage systems. For the May CDR, ERCOT developed an interim capacity contribution methodology to show the impact on reserve margins. The summer 2025 capacity contribution percentage based on the interim method is 31% for the peak load hour.
- Recent changes to load forecast methods allow for the consideration of more load in the planning processes. In contrast, the policy governing the inclusion of planned generation resources in the planning models remains unchanged. Currently, planned generation resources can only be added to the planning models when they meet the requirements established in ERCOT's planning guides. ERCOT is currently developing a revision to its planning guide to adjust the criteria for adding generation resources to the planning models and will initiate stakeholder discussions on this topic in 2025.

<u>Significant Resource Status Changes</u>

ERCOT received Notifications of Suspension of Operations (NSOs) for three gas-steam units totaling 885 MW of installed capacity, with an indefinite suspension of operations beginning March 31, 2025.[3] ERCOT's reliability analysis determined that these generation resources are needed to support ERCOT system reliability. For the May 2024 CDR report, these units are reported as being available for the forecast period.

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[3] *See* generally ERCOT market rules. Last found at https://www.ercot.com/services/comm/mkt_notices/M-C031324-11.

The table below provides estimates for ERCOT's operational capacity as provided in the May 2024 CDR Report. [4]

**ERCOT – Operational Generation Capacity for Summer Peak Demand (MW)**

| Resources | 2025 | 2029 |
|---|---|---|
| **Installed Summer-rated Capacity, Thermal** | 66,107 | 66,107 |
| **Hydroelectric, Peak Average Capacity [1]** | 455 | 455 |
| **Switchable Capacity** | 3,680 | 3,680 |
| **Switchable Capacity unavailable to ERCOT** | -1,345 | -732 |
| **Available Mothballed Capacity[2]** | 136 | 136 |
| **Capacity from Private Use Networks** | 2,870 | 3,217 |
| **Coastal Wind[3], Panhandle Wind[4], Other Wind[5]** | 10,961 | 10,961 |
| **Solar Utility-Scale, Peak Average Capacity Contribution (76% of installed capacity)** | 17, 670 | 17,670 |
| **Storage, Peak Average Capacity Contribution** | 0 | 0 |
| **Operational Generation Capacity** | **100,533** | **101,493** |

Notes:1- Contribution at 80% of installed capacity, 2-Inactive but not decommissioned generating units, 3-Peak average capacity contribution at 60% of installed capacity, 4- Peak Average Capacity Contribution at 29% of installed capacity, 5- Peak Average Capacity Contribution at 22% of installed capacity.

**ERCOT Planned Generation Resources (MW)**

| Resources | 2025 | 2029 |
|---|---|---|
| **Planned Resources[6] with Signed IA, Air Permits and Adequate Water Supplies** | 694 | 972 |
| **Planned Coastal Wind, Panhandle Wind, and Other Wind with Signed IA** | 270 | 1,010 |
| **Planned Solar Utility-Scale[7]** | 13,281 | 28,019 |
| **Planned Storage[8]** | 0 | 0 |
| **Planned Generation Capacity** | **14,245** | **30,001** |
| **Non-Synchronous Ties** | **817** | **817** |
| **Total capacity** | **115,596** | **132,312** |

Notes: IA- Interconnection Agreement, 6- Excludes wind, solar or storage, 7- Peak average capacity contribution at 76% of installed capacity, 8- at peak average capacity contribution

[4] See Capacity, Demand and Reserves Report. Last Found at, https://www.ercot.com/files/docs/2024/05/24/CapacityDemandandReservesReport_May2024_Revised.pdf?utm_source=substack&utm_medium=email

### Non-ERCOT Region

As of 2024, the non-ERCOT regions had a total generation capacity of over 16,000 MW. The IOUs' generating capacity represents most of the generation capacity in the non-ERCOT region. Golden Spread Electric Co-op and East Texas Electric Co-op together have 3,700 MW of generation capacity, but it is spread over multiple power regions within the Co-ops' service areas. Thus, the capacity of these Co-ops was not included in the total generation capacity to prevent any double counting.

MOUs that operate in the non-ERCOT regions are usually smaller in size and typically have electric service agreements with IOUs. These IOUs consider the MOUs' load impacts on reliability constraints and need for generation capacity in their own generation expansion plans that they submit to the RTOs within which they operate.

| Non-ERCOT IOUs | Generation Capacity (MW) |
|---|---|
| SPS | 5,393 |
| Entergy | 3,955 |
| SWEPCO | 4,920 |
| El Paso Electric | 2,391 |
| Total | 16,659 |

Note: Generation capacity is subject to revision according to individual planning cycles of reporting entities

## III. Customer Demand

As of 2024, Texas had an electricity demand of over 100,000 MW for the ERCOT and non-ERCOT regions of the state. One MW of electricity is enough to serve about 250 residential consumers during ERCOT's peak hours.

| Region | Total Peak Demand (MW) |
|---|---|
| ERCOT | 85,199* |
| Non-ERCOT** | 15,204 |
| Total Texas | 100,403 |

Notes:* Peak demand on August 20, 2024. ** Only includes estimates from the non-ERCOT IOUs.

## ERCOT Region

ERCOT's recent load forecasts indicate that the ERCOT region is experiencing significant and rapid demand growth. ERCOT's maximum peak demand in 2024 was 85,199 MW on August 20, 2024. On August 10, 2023, ERCOT set an all-time peak demand record of 85,508 MW.

The forecasted total peak demand for summer 2025 is 87,962 MW, which does not account for reductions in energy consumption realized through energy efficiency and demand response programs. The summer 2025 peak demand forecast assumes that Large Flexible Loads (LFLs) will reduce their consumption to just 15% of their summer peak demand hours. It is important to note that the total peak demand forecast used in the May 2024 CDR report is based on weather conditions over the last 15 years, which explains why the total peak demand forecast for summer 2025 is lower than the actual summer total peak demand of 85,508 MW for 2023. The summer of 2023 was the second hottest summer on record, only exceeded by 2011.

However, the summer 2025 firm peak demand forecast is 80,639 MW. Firm peak demand accounts for the impact of incremental rooftop solar generation and load management programs, thereby indicating the amount of electricity that must be available to ERCOT to serve load reliably. By summer of 2029, the forecasted firm peak demand is expected to reach 82,677 MW.

The firm peak demand increases to 86,221 MW for 2025 and 103,713 MW for 2029 when including the newly contracted loads reported by transmission service providers (TSPs).

**Firm Peak Demand, May 2024 ERCOT CDR Report (MW)**

| | 2025 | 2029 |
|---|---|---|
| **Summer Total Peak Demand[1]** | 87,962 | 94,132 |
| **Energy Efficiency Program Savings Forecast** | -3,208 | -4,367 |
| **Rooftop PV, load resources providing ancillary services, ERS, and Load management programs forecast** | -4,115 | -7,088 |
| **Summer Firm Peak Demand** | **80,639** | **82,677** |

Notes:[1]- Peak demand before reductions from energy efficiency programs forecast 2. ERS=Emergency Response Service

### Non-ERCOT Region

As of 2024, the non-ERCOT region had a peak demand of just over 15,000 MW.

| Non-ERCOT IOUs | Total Peak Demand (MW) |
|---|---|
| SPS | 4,458 |
| Entergy | 4,072 |
| SWEPCO | 4,886 |
| El Paso Electric | 1,788 |
| **Total** | **15,204** |

The Non-ERCOT IOUs' electricity demand numbers in the table above exclude the total reported demand of approximately 2,900 MW from Golden Spread Electric Co-op and East Texas Electric Co-op to avoid double counting between the multiple power regions in which both cooperatives' service areas are located.

## IV. Transmission Capacity

Transmission capacity is the amount of power that can be moved through transmission infrastructure. Transmission capacity of the bulk electric system is location-specific and cannot be calculated for an entire transmission grid. An electric utility's transmission infrastructure is comprised of elements that have varying capacities to transmit power across the system. The capacity of a given transmission line to deliver power depends on factors such as transmission facility equipment's physical ratings or stability-related limits.

The Public Utility Regulatory Act (PURA) provides sufficient regulatory and policy guidance to ensure the transmission planning entities adequately address transmission capacity needs. PURA also gives the PUCT sufficient authority to address larger transmission plans and specific projects through timely, consumer-oriented procedures.

As the NERC registered planning coordinator, ERCOT is responsible for planning and operating the transmission network for the ERCOT region. For managing transmission capacity needs, non-ERCOT entities (IOUs, Co-ops, and MOUs) participate in transmission planning, either directly or indirectly, through SPP, MISO, and WECC. Details about ERCOT's assessment of transmission needs as well as the transmission planning processes of other RTOs can be found later in the report as well as in the detailed Report on Transmission and Generation Capacity.[5]

# V. Transmission and Distribution Constraints

## Transmission systems

Transmission systems are a network of power lines, substations, and associated facilities that are operated at 60 kilovolts (kV) or above. These are designed to move large amounts of electricity from generation sites to locations of demand as efficiently as possible.

However, a transmission system can experience constraints that prevent transmission lines from efficiently moving electricity. Transmission constraints occur when the physical limitation of the transmission equipment limits the amount of electricity flowing on the transmission line. When transmission constraints occur, it can create congestion on the transmission system. To resolve congestion, ERCOT may choose to dispatch a more expensive generation site that is closer to the location of demand instead of dispatching a farther, cheaper alternative. This choice may result in higher energy prices for some consumers buying their power from the generation units in the congested areas. This price difference between congested and not congested areas is described in simple terms as "congestion rent." To reduce congestion and to access generation from the cheaper units, transmission lines need to be built.

ERCOT's annual Constraints & Needs Report identifies and analyzes existing and potential constraints on the ERCOT transmission system.[6,7] The 2024 report noted findings from the Permian Basin Reliability Plan Study[8] and the 2024 Regional Transmission Plan (RTP)[9], and concluded that the ERCOT system continues to evolve with significant load growth, increased thermal generation retirement, rapid growth in

[5] See AIS Project No. 56335, ITEM 11. Last found at https://interchange.puc.texas.gov/search/documents/?controlNumber=56335&itemNumber=11

[6] *See* ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2024. Last found at https://www.ercot.com/files/docs/2024/12/20/2024-report-on-existing-and-potential-electric-system-constraints-and-needs.pdf, (Dec. 31, 2024).

[7] *See* PURA § 39.166(b)(1) and 16 Texas Administrative Code § 25.362(i)(2)(l) and § 25.505(c).

[8] Permian Basin Reliability Plan Study, July 25, 2024. Last found at https://www.ercot.com/gridinfo/planning

[9] Regional Transmission Plan, 2024. Last found at https://www.ercot.com/mp/data-products/data-product-details?id=pg7-048-m

transmission-connected wind, solar and energy storage resource (ESR) development, and distributed generation (DG).

Below are the key findings of the ERCOT 2024 Constraints & Needs Report:

- ERCOT continues to experience a rapid shift in the type and location of generation available to serve demand.
- The change in generation mix has resulted in increased distance between generation sites and demand centers. Generation mix, or fuel mix, refers to the various fuels that are used to generate electricity in the state. Historically, coal and gas generation was typically sited closer to large cities, whereas the most abundant wind and solar-rich regions tend to be in more distant locations.
- Majority of new planned resources which are expected to be installed by the end of 2025 will be wind, solar and battery energy storage.
- Coal and natural gas generation continues to be retired, with over 7,300 MW retired since 2018.
- ERCOT continues to improve DG integration processes as market penetration steadily increases. DG is an electrical generating facility with a capacity of 10 MW or less that is connected at a voltage less than or equal to 60 kV.

Additionally, the 2024 Constraints & Needs Report noted that ERCOT is critically evaluating its planning processes and pursuing changes necessary to meet challenges associated with the evolving grid. The report evaluated the top 10 constraints on the ERCOT system from October 2023 to November 2024, as well as the top 10 projected constraints on the ERCOT system for 2026 and 2029, which is based on economic analysis conducted for the 2024 RTP.

## Recent Transmission Constraints

The table below provides details about transmission constraints on the ERCOT system, ranked by the amount of congestion rent. Congestion rent indicates areas where economic transmission projects may be beneficial.[10]

[10] ERCOT Report of Existing and Potential Electric System Constraints and Needs, Recent Constraints (December 2024).

| Constraint | Congestion Rent (millions $) |
|---|---|
| Tonkawa Switch – Morgan Creek SES 345kV | 156 |
| West Texas Export Interface | 148 |
| Morgan Creek SES – Navigation Sub 138kV | 79 |
| Odessa EHV Switch – Yarbrough Sub 138kV | 57 |
| Hargrove – Twin Buttes 138kV | 55 |
| Panhandle Interface | 49 |
| Bell County – Salado Switch 138kV | 48 |
| Lamesa – Jim Payne Poi 138kV | 46 |
| North Edinburg to Lobo Interface | 45 |
| Burns Sub – Rio Hondo 138kV | 33 |

## Projected Transmission Constraints

The table below provides details about projected transmission constraints on the ERCOT system, based on economic analysis conducted for the 2024 RTP.[11] The constraints are ranked by projected congestion rent for 2026 and 2029.

| Constraint | Congestion Rent (millions $) | |
|---|---|---|
| | 2026 | 2029 |
| MacKenzie Substation – Northeast Substation 115kV Line | 15 | 181 |
| West Texas Export Interface | 178 | 49 |
| Panhandle Interface | 139 | 100 |
| Fowlerton – Tilden 138 Sub 138-kV Line | 108 | 19 |
| Farmland – Wett Long Draw 345-kV Line | 19 | 64 |
| Navarro – Richland 69-kV Line | 62 | - |
| Meadow – PH Robinson 345-kV Line | 54 | 42 |
| Stagecoach – Killeen Elm 138-kV Line | 49 | 24 |
| North – Houston Interface | 46 | 34 |
| Temple North – Pepper Creek Switch 138-kV Line | - | 40 |

[11] ERCOT Report of Existing and Potential Electric System Constraints and Needs, Projected Constraints (December 2024).

### Distribution systems

The distribution system is part of the electric delivery system operating under 60 kV. A distribution line begins at a substation and extends to an end-use consumer's meter. Distribution systems are located at (or near) the load centers.

Distribution systems are typically planned by distribution service providers (DSPs), including IOUs, MOUs, and Co-ops that are regulated either by the PUCT or their municipal or Co-op boards.

DSPs perform system analysis of their distribution networks to meet current and future load demand and to ensure reliable and efficient power delivery. When a DSP expects load growth in its service area, it is required to plan for expansion of its distribution systems to serve load reliably. DSPs can seek recovery of costs incurred for distribution system expansion through customer rates within their service territory.

ERCOT does not have sufficient visibility into the distribution system to analyze distribution-level constraints. Distribution networks are not represented in detail within the ERCOT network model. As such, ERCOT's visibility of distribution networks largely consists of how changes in the distribution system affect the flow through the modeled load points. The ERCOT network model does represent distribution-level generators that meet the qualifications and elect to participate in ERCOT markets. However, these generators are only "mapped" to the transmission load point and each generator's respective distribution connection is not represented.

## Alternatives for Meeting System Needs

There are several alternatives to building additional transmission lines that are broadly explored to meet system needs. These *non-wires* alternatives include reducing demand or increasing generation at strategic locations.

### Aggregate Distributed Energy Resources (ADER)

The Aggregate Distributed Energy Resources (ADER) Task Force is piloting the integration of distribution-side resources into ERCOT's operating models so that the resources could deploy as a potential alternative to some transmission build-out. An ADER pilot project consists of multiple homes and businesses that can aggregate as one resource at the distribution level to respond to ERCOT dispatch instructions. The PUCT is currently overseeing the implementation of Phase 2 of the ADER pilot project in the ERCOT region. ADER participants can take part in the wholesale energy market and provide certain ancillary services. As of September 2024, two ADERs fully participate in the ERCOT market. These two ADERs are capable of providing 14.5 MW of energy, 8.8 MW of Non-Spin, and 8.6 MW of ERCOT Contingency Reserve Service (ECRS)[12]. More information about ADER can be found in Project No. 53911.

### Demand Response (DR)

Demand response (DR) may also be considered as an alternative to transmission build-out in some cases. In December 2024, substantive rule 16 Texas Administrative Code (TAC) § 25.186 was adopted. The rule implements PURA § 39.919 (Senate Bill 1699, 88R) by establishing an average total residential load reduction goal for the ERCOT region and authorizing REPs to meet that goal by offering responsive device programs to residential customers. These programs are to be designed to reduce electricity consumption during an ERCOT peak demand period. Such programs may prove effective at reducing the need for additional transmission build-out and could be considered as an alternative for meeting system needs. More information about the new rule can be found in Project No. 56966.

### Institute of Electrical and Electronics Engineers (IEEE) Standards

The commission is in the process of considering rules that will adopt national standards promulgated by the Institute of Electrical and Electronics Engineers (IEEE-1547) by establishing ride-through criteria for DG. Hardening the distribution system against voltage fluctuations improves the reliability of the overall system and reduces the need for additional transmission redundancies to support system reliability in an area of widespread DG adoption. More information about this topic can be found in Project No. 54233.

### New Dispatchable Generation at Strategic Locations

Depending on circumstances in a region, new dispatchable generation can serve as an alternative for meeting transmission needs. The Texas Energy Fund, passed by the Legislature in the 88th Legislative Session, may result in additional dispatchable capacity that will help support reliability needs related to the transmission system. The PUCT considers the proposed location of new generation projects seeking Texas Energy Fund support to determine their respective impacts on ERCOT transmission constraints.

[12] See AIS Project No. 53911, ITEM 119

# VI. Key Findings of Reports

## 1. Grid Reliability Assessment Report

**Background**

PURA § 39.159 requires ERCOT to prepare a Grid Reliability and Resiliency Assessment (GRRA) on a biennial basis. The study addresses ERCOT system transmission needs under extreme weather conditions.

The 2024 GRRA is the inaugural biennial report. Due to the implementation timeline, the 2024 GRRA used the final reliability case from the 2023 RTP which did not incorporate the additional load driven by the load growth since the 2023 RTP and the new requirement (from House Bill (HB) 5066, 88R) to include load for which an electric utility has yet to sign an interconnection agreement. The GRRA process adjusts the load forecast based on the outcome of the extreme weather scenarios studied.

The 2024 GRRA addresses ERCOT system transmission needs under extreme weather conditions for year 2029. The assessment considers the impact of different levels of thermal and renewable generation availability; the impact of potential outages caused by extreme weather conditions on consumers; identifies areas of Texas within the ERCOT region that face significant grid reliability and resiliency issues; and proposes transmission projects to increase the grid's reliability or resiliency under such extreme weather conditions.

The GRRA is not intended to resolve any resource adequacy issues caused by such extreme weather conditions.

The resiliency criteria used by the 2024 GRRA focus on transmission projects that are necessary to:

1. Prevent cascading, instability, or uncontrolled islanding; and
2. Reduce the impact of outages on consumers.

The 2024 GRRA assesses the impacts of two extreme weather scenarios:

1. An extreme winter peak scenario that considers a weather condition similar to the 2021 Winter Storm Uri event but with the impacts of the PUCT's subsequent weatherization rules factored in; and

2. A hurricane scenario using information provided in Argonne National Laboratory's 2024 Hurricane Study for ERCOT for a worst-case scenario Category 5 hurricane making landfall near Houston.

**Key findings - 2024 GRRA**

- ERCOT found that additional transmission enhancements would be beneficial to increase the resiliency of the ERCOT transmission grid under both the extreme winter peak and hurricane scenarios studied.
- Reinforcement of the 345-kV transmission pathways from the Coast Weather Zone to Central Texas and the 345-kV pathways between South Dallas and Central Texas were found to be beneficial to increase the system resiliency under the extreme winter peak scenario. This reinforcement was also found to be needed for system reliability in the 2024 RTP.
- Substation hardening was found to have a critical role in increasing system resiliency under the hurricane scenario.
- Though distribution hardening was out of the scope of this assessment, a more resilient distribution system was deemed crucial to increasing overall system resiliency under the hurricane scenario.

The transmission projects identified in the 2024 GRRA do not represent ERCOT's endorsement of those projects. ERCOT intends to propose a new market rule to establish a process to determine whether a project that meets the proposed resiliency criteria provides sufficient benefit balanced with economic savings and reliability benefits to be endorsed, in accordance with 16 TAC § 25.101(b)(3)(A)(iii). This new ERCOT market rule is currently under development and will be brought to the stakeholder process in 2025. ERCOT will continue to work with stakeholders to identify areas of the state within the ERCOT region that face significant grid reliability and resiliency issues for inclusion in the 2026 GRRA. ERCOT will start engaging stakeholders in the extreme weather scenario development discussion in 2025 to identify the extreme weather conditions that may impose resiliency risks to the ERCOT system.

## 2. Report on Transmission and Generation Capacity[13]

**Background**

PURA § 39.9112 requires ERCOT and the PUCT to prepare a report on transmission and generating capacity in Texas. This inaugural report provides information about the existing generation capacity and about generation capacity shortfalls for both the ERCOT and non-ERCOT regions. The report provides background information to explain that transmission capacity of the bulk electric system is location-specific and cannot be calculated for an entire transmission grid. The report, however, provides details about transmission planning processes to assess the need for transmission capacity for both ERCOT and non-ERCOT regions.

**Summary -Report on Transmission and Generation Capacity**

ERCOT Region – Transmission

- ERCOT evaluates and provides recommendations to the PUCT about the need for new transmission facilities. ERCOT examines proposed transmission projects based on its planning criteria and NERC Reliability Standards and provides its assessment of increased transmission capacity need in various study reports including annual RTP, annual Constraints and Needs report, biennial Long Term System Assessment report, and special reports – Permian Basin Reliability Plan Study.

ERCOT Region – Generation

- ERCOT conducts several studies to evaluate the need for generation capacity in its assessment of resource adequacy. As the grid coordinator, ERCOT does not own generation, nor does it have the authority to direct new build of generation. Therefore, these assessments are critical in assisting policymakers in their evaluation of resource adequacy, as well as informing market participants of the current and expected generation build-out on the system.
  - *Monthly Outlook on Resource Adequacy (MORA)*
    - The MORA report is a monthly outlook that serves as an early indicator of the hour-by-hour risk that ERCOT may need to issue an

[13] See AIS Project No. 56335, ITEM 11. Last found at https://interchange.puc.texas.gov/search/documents/?controlNumber=56335&itemNumber=11

Energy Emergency Alert (EEA) or call for controlled outages to maintain grid reliability for the reporting month.
    - For calendar year 2024 and winter months January and February 2025, the MORA reports indicated that the risk of ERCOT declaring EEAs is less than 10% for each hour of the monthly peak load day. For the non-winter months, the hourly risk is concentrated in the early evening hours due to the ramping down of solar generation.
    - Over the course of 2024, there was a small EEA risk covering more hours of the day due to the addition of certain large loads, such as data centers, whose electricity consumption remains steady throughout the day.

  - *Capacity, Demand and Reserves (CDR) Report*
    - ERCOT publishes the CDR Report twice a year, in May and December, for the purpose of evaluating forecasted planning reserve margins for the ERCOT summer peak load seasons from June through September, and winter peak load season from December through February for the following year.
    - The firm summer peak demand for 2025 is forecasted to be 80,639 MW, and 82,677 MW for 2029. These estimates account for incremental rooftop solar generation and load reduction programs.
    - Total resource capacity available for summer 2025 peak load hour is forecasted at 115,596 MW. Planned new installed resource capacity expected by summer 2029 was estimated at 30,001 MW.

Non- ERCOT Region – Transmission and Generation

- Outside the ERCOT region, non-ERCOT IOUs, Co-ops, and MOUs are responsible for assessing the need for increased transmission and generation capacity to meet the demand in their respective service areas. These entities participate in generation and transmission planning in their respective RTOs, as applicable.
- MOUs do not own the threshold amount of generation or transmission assets to directly participate in regional or RTO-wide transmission planning. These entities' transmission and generation capacity needs are generally represented in the combined transmission and generation capacity needs requirements of

the IOUs with whom they typically have service agreements to provide electric service.

- SPP's footprint for Texas includes two IOUs (SWEPCO and SPS), several Co-ops, and various MOUs.
    - SPP uses the Integrated Transmission Planning (ITP) model, which is an annual process to assess the near and long term economic and reliability needs for the transmission system in its entire footprint over a 10-year horizon. Stakeholders participate in the SPP transmission planning processes, and SPP staff and market participants provide details such as forecasted load growth, reliability constraints, and generation resource changes to inform the need for increased transmission capacity within the region.
    - SPP has a generation capacity requirement which obligates all utilities that serve load in its footprint, to have access to enough generating capacity to serve their customers' peak demand, also known as Resource Adequacy Requirement (RAR). SPP establishes a mandatory planning reserve margin. Currently, SPP's projected summer planning reserve margin ranges from 15% to 17%, while the winter planning reserve margin ranges from 36% to 38%. To help assess future generation capacity needs and comply with SPP margin requirements, SWEPCO and SPS each develop an Integrated Resource Plan (IRP).
        - According to its IRP, SWEPCO may have a capacity shortfall of over 800 MW for its Texas region by 2030, and SPS may have a capacity shortfall of over 3,100 MW by 2030.

- MISO is the RTO for the southeastern portion of Texas, served primarily by Entergy Texas.
    - MISO evaluates near-term and long-term transmission needs to ensure a reliable and economic electric infrastructure for the MISO region over a span of 10 and 20 years. As part of this process, MISO reviews projects submitted by transmission owners that address local reliability issues, aging equipment, load growth, generator interconnection needs, regional and interregional reliability, and compliance with NERC standards.
    - Entergy Texas's need for generation capacity, both near-term and long term, starts with a review of its current capacity position. Base load

forecasts using historical sales volumes, customer counts, and temperature data, as well as future estimates for normal weather and energy efficiency, are applied to develop a load forecast.

        - According to the 2023 Strategic Resource Plan, Entergy Texas is expected to have a total load requirement of approximately 5,173 MW and an estimated capacity deficit of over 1,500 MW by 2030.

- WECC is the regional entity responsible for bulk electric system reliability in the El Paso region. EPE is part of regional and subregional WECC planning organizations.
    - EPE's participation in the planning organizations facilitates the coordination of its transmission plans with transmission providers and entities. As a part of its process to study the need for increased transmission, EPE conducts an annual System Expansion Plan (SEP) study, which is a technical evaluation of its bulk electric system performance over a 10-year planning horizon.
    - EPE participates in the WECC's generation planning. It compiles its supply, demand, and reserves information into its loads and resources ("L&R") documents on an annual basis. Its generation planning process begins with the development of its 20-year load forecast, together with consideration of planned retirements based on the age and condition of existing generation resources, to assess capacity needs on a 20-year planning horizon.
        - By the year 2030, EPE expects a total system demand of 2,235 MW in its Texas region and a total generation capacity of 2,579 MW.

# Enhanced Analytics Capabilities Report

**Responsive to the General Appropriations Act (House Bill 1) enacted by the 88th Texas Legislature**

December 1, 2024

# Executive Summary

The General Appropriations Act, (House Bill (HB) 1) enacted by the 88th Texas Legislature appropriated funds to the Public Utility Commission of Texas (PUCT) to create a data analysis team for enhancing the agency's policy research, data verification and analytics capabilities. The statute requires the PUCT to annually report the activities of this team to the Legislative Budget Board, the Sunset Advisory Commission, and the Legislature by December 1 each year. PUCT submits this report in compliance with HB 1.

The PUCT set up the data analysis team within the Market Analysis (MA) division in 2023. In FY 2024, the team added two FTEs. Currently, the team consists of a program manager, a project manager, and two economists with expertise in data analytics, economics, mathematics, and statistics. All employees have advanced degrees.

In FY 2024, the agency purchased hardware and software to fulfill the team's high performance computing requirements to enhance market data reporting, tracking, and analytics capabilities. Details of these purchases are provided under *Information Technology Tools* section of this report.

During FY 2024, the team continued to work on specialized data analysis projects to support commission decision-making on significant policy issues that have long term impacts on the Texas electricity markets. These included topical research on electricity market issues, data reviews, data verification, data reporting and tracking on important policy issues including electricity market reliability standard, generation resource adequacy, long-term transmission planning, transmission system resiliency plans, and Texas Energy Fund (TEF). In addition, the team supported the agency's Electric Reliability Council of Texas (ERCOT) oversight responsibilities by analyzing market operations-related changes, including analysis of proposed changes to ERCOT market rules and procedures developed through the ERCOT stakeholder process.

Below is a list of completed and ongoing projects with details on the role of the data analysis team in each of these projects.

# Data Analytics Projects

## Market Analysis and Topical Research

1) **Project No. 55845 – Review of Ancillary Services in the ERCOT Market** – As part of implementation of PURA § 35.004 (g) (SB3, 87R), the commission (1) reviewed the type, volume, and cost of ancillary services to determine whether those services will continue to meet the needs of the electricity market in the ERCOT power region, and (2) evaluated whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation.[1] Ancillary services are purchased by ERCOT in the day-ahead market to balance the next day's supply and demand of electricity on the grid and mitigate real-time operational issues. Generators or consumers can provide ancillary services to increase or decrease the supply of electricity in a matter of minutes or seconds.

   The data analysis team worked in close collaboration with ERCOT and the Independent Market Monitor (IMM) to conduct a comprehensive review of the current suite of ancillary services, including reviewing the types of risks for which each ancillary service is procured, the effectiveness of ancillary services in managing these risks, and the methodology for determining the procurement quantities of each ancillary service. The team reviewed ERCOT's and IMM's model inputs and assumptions. Additionally, staff prepared and filed questions for stakeholder comment[2] and hosted a workshop[3] to

[1] Public Utility Regulatory Act (PURA) § 35.004.

[2] *Review of Ancillary Services in the ERCOT Market*, Project No. 55845, Questions for Stakeholder Comment Related to Draft Study, AIS Item No. 14 (Oct. 7, 2024).

[3] Project No. 55845, Agenda for Oct 31, 2024 Staff Led Workshop, AIS Item No. 39 (Oct. 28, 2024).

solicit additional stakeholder feedback on related topics. The final report is provided in Project No. 55845 and as an appendix to the PUCT's Biennial Agency Report filed in Project No. 56335.

2) **ERCOT Stakeholder Process & Market Rules Revision Requests** – The data analysis team closely monitors various ERCOT market stakeholder committees where ERCOT market rules and policy issues are discussed to receive stakeholder feedback. These committees include Wholesale Market Subcommittee (WMS), all working groups under WMS, and the Real-Time Co-Optimization plus Batteries Task Force (RTCBTF), which reports to the Technical Advisory Committee. The team tracks the developments in these committees to stay apprised of technical details of any stakeholder proposals that have the potential to affect the normal and competitive functioning of the electricity markets. In particular, RTCBTF is presently working on many policy topics that may affect future outcomes in the market under real-time co-optimization of energy and ancillary services. This oversight responsibility also involves reviewing technical market rules including Nodal Protocol Revision Requests and other revision requests developed through these stakeholder groups.

3) **Project No. 55421 - Texas Advanced Nuclear Reactor Working Group (TANRWG)** At the direction of Governor Greg Abbott, the TANRWG was established on August 16, 2023, and operated under the leadership of PUCT Commissioner Jimmy Glotfelty. This group evaluated factors necessary for the growth of reliable and affordable power provided by advanced nuclear reactors. The TANRWG submitted a report with its findings and recommendations to Governor Abbott in November 2024. To assist with this report, the data analysis team closely monitored meetings of the TANRWG, reviewed and assessed the various market design proposals discussed, and drafted recommendations on each proposal for the working group's consideration.

# Data Analysis and Verification Support

## Rulemakings and Project Support

4) **Project No. 55837 – Review of Value of Lost Load in the ERCOT Market** – At the direction of the commission, ERCOT initiated a study to determine an updated value of lost load (VOLL) for the ERCOT power region. A VOLL study was necessary to support the commission's ongoing market design initiatives, particularly the development of a reliability standard. VOLL is a measure of consumers' willingness to pay for reliable electric service that is used as a proxy for the costs associated with interruptions in the supply of electricity. This study involved a review of existing literature estimating VOLL in various regions, an assessment of different research methodologies, and a survey of residential, commercial, and industrial customers in the ERCOT region to obtain a direct estimate of VOLL from respondents. The survey was sent out to nearly 150,000 consumers. Of these, nearly 5,000 responded. Those that responded included 2,991 residential consumers, 1,219 small commercial and industrial consumers, and 492 medium/large industrial and commercial consumers. The data analysis team worked closely with ERCOT and its contractors throughout this process, reviewing all survey instruments and statistical reports. The team reviewed the final VOLL report describing the results of the consumer survey and filed a memo that provided an overview of these results and a recommendation for the updated VOLL.[4] As a result of this effort, the commission adopted an updated VOLL of $35,000/MWh to be used in ongoing and future cost-benefit analyses and ERCOT planning models. Since January 1, 2022, VOLL in the ERCOT region had been set at $5,000/MWh, after being reduced from the previous value of $9,000/MWh.

[4] *Review of Value of Lost Load in the ERCOT Market*, Project No. 55837, Staff Recommendation Memo on VOLL, AIS Item No. 13 (Aug. 22, 2024).

5) **Project No. 54584 – Reliability Standard for the ERCOT Market** – PURA § 39.159(b)(1) (SB 3, 87R) required the commission to establish a reliability standard for the ERCOT power region and identify a process for the commission to periodically review whether the ERCOT system is meeting that standard. The data analysis team reviewed ERCOT analyses used to inform various decisions around the establishment of the reliability standard. In particular, the team reviewed results of modeling simulations and a report on the cost of new entry (CONE) conducted by ERCOT and its contractors. The analysis informed the commission's decision related to approval of a new CONE value that was set at $140,000 per MW-year based on a frame combustion turbine. CONE is the levelized first year revenue that a resource needs to earn to incentivize construction of a new generation resource in ERCOT region. Based in part on this analysis, the commission adopted a reliability standard which measures the magnitude, frequency, and duration of probability-based, modeled load shed events.

6) **Project No. 55000 – Performance Credit Mechanism (PCM)** – The data analysis team reviewed technical details and analyses provided by ERCOT and its contractor, Energy and Environmental Economics, Inc. (E3), and worked in close collaboration with ERCOT staff to establish a set of key parameters that define the PCM.[5] These parameters were foundational for the cost-benefit analyses required by PURA § 39.1594(d) (HB1500, 88R). The team reviewed the cost-benefit analyses conducted by ERCOT, E3 and the IMM.

7) **Project No. 55566 – Generation Interconnection Allowance** – PURA § 35.004 (HB 1500, 88R) required the commission to develop a reasonable allowance applicable to generation resources interconnecting directly with the ERCOT transmission system at transmission voltage after December 31, 2025. The data analysis team analyzed four years of data from the 12 largest transmission service providers (by 2022 revenue) to recommend establishing two different allowances based on the transmission voltage at

[5] *Performance Credit Mechanism (PCM)*, Project No. 55000, Staff PCM Design Recommendations, AIS Item No. 42 (Aug. 22, 2024).

the point of interconnection. One allowance applies to any generation resource interconnecting at a transmission voltage of 138 kV or less, and the other applies to those resources interconnecting at a transmission voltage higher than 138 kV. The rule that was adopted in FY 2024 incorporated the team's recommended two-tier generation interconnection allowance structure.[6]

8) **Project No. 55826 – Texas Energy Fund In-ERCOT Generation Loan Program** – PURA § 34.0104 (SB2627, 88R) required the commission to implement the TEF In-ERCOT Generation Loan Program.[7] The data analysis team, in collaboration with ERCOT, developed two quantitative metrics based on a resource's availability and performance that will be used to evaluate electric generating facilities availing TEF funds. These metrics, and their corresponding evaluation thresholds, were derived based on analyses of historical data from existing generation facilities in ERCOT.

9) **Project No. 55812 – Texas Energy Fund Completion Bonus Grant Program** – PURA § 34.0105 (SB2627, 88R) required the commission to establish a mechanism to provide a completion bonus grant for the construction of dispatchable electric generating facilities in the ERCOT region.[8] Completion bonus grants are to be dispersed in equal annual payments over a 10-year period; however, a disbursement may be discounted according to the recipient's performance during the 100 hours with the least quantity of operating reserves in each year. The data analysis team, in collaboration with ERCOT, developed two quantitative metrics that will be used to evaluate the availability and performance of resources during those 100 tightest hours. These metrics, as well as the framework for determining how they impact annual grant disbursements, were developed based on an economic and statistical analysis of historical data from existing generation facilities in ERCOT.

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[6] *See* 16 Tex. Admin Code § 25.195.
[7] PURA §§ 34.0104, 34.0106, and 34.0108.
[8] PURA §§ 34.0105 and 34.0106.

10) **Project No. 56966 – Goal for Reducing Average Total Residential Load in the ERCOT Region** – PURA § 39.919 (SB1699,88R) required the commission to establish goals to reduce the average total residential load in the ERCOT power region.[9] The data analysis team reviewed and analyzed historical residential electric consumption data to inform the determination of an appropriate goal and assisted with the development of rule language related to data collection and analysis for future reporting and assessment of this residential load reduction goal.

11) **Project No. 56969 – Report on Dispatchable and Non-Dispatchable Generation** – As part of implementation of PURA § 39.1591 (HB 1500, 88R), the commission is required to report on (1) the estimated annual costs incurred by load-serving entities to back up electric generation facilities (dispatchable and non-dispatchable) to guarantee a firm amount of electric energy, and (2) the cumulative annual costs for transmission of electricity from generation facilities (dispatchable and non-dispatchable) to load, to interconnect transmission level loads, and a breakdown of annual costs by each activity. The data analysis team collaborated with ERCOT and the Rules and Projects Division to advance this report with additional data and analysis, building on last year's report. The team conducted a qualitative review of ancillary services and various quantitative analyses, using historical ancillary services procurement data provided by ERCOT from January 2018 through December 2023. The team also analyzed interconnection cost data provided by transmission service providers. The final report is filed in Project No. 56335.

## Compliance and Enforcement Support

12) **Voltage Support Services (VSS) Investigation** – The data analysis team continued to assist the Division of Compliance and Enforcement to verify information related to potential violations by electricity market participants. The team used the computer program it wrote in 2023 to verify data provided by the ERCOT Reliability Monitor

[9] PURA § 39.919.

related to an enforcement investigation and potential violations of ERCOT protocols. The team also provided technical and data review support throughout the course of these investigations.

## Contested Cases Support

13) **Transmission and Distribution System Resiliency Plans** – In January 2024, the commission adopted a rulemaking related to Transmission and Distribution Resiliency Plans (Project No. 55250), to implement PURA § 37.078 (HB2555, 88R). The rule established requirements and procedures for an electric utility to submit a system resiliency plan (SRP) to enhance the resiliency of its transmission and distribution systems. Several utilities have submitted SRPs to the commission for review. The data analysis team participated in the SRP review and worked with the Infrastructure and Legal divisions at the commission. The team's evaluation of these SRPs focused on reviewing any quantitative or cost-benefit analyses and assessing proposed evaluation metrics intended to demonstrate realized benefits associated with the implementation of various resiliency measures included in the SRPs. The team filed testimony in the following dockets.
    1) Docket No. 56548, *Application of CenterPoint Energy Houston Electric, LLC for Approval of Its Transmission and Distribution System Resiliency Plan*,[10]
    2) Docket No. 56545, *Application of Oncor Electric Delivery Company LLC for Approval of a System Resiliency Plan*,[11]

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10 *Application of CenterPoint Energy Houston Electric, LLC for Approval of its Transmission and Distribution System Resiliency Plan*, Docket No. 56548, Direct Testimony of Tyler Nicholson Market Analysis Division of Public Utility Commission of Texas (Jul. 2, 2024).

11 *Application of Oncor Electric Delivery Company LLC for Approval of a System Resiliency Plan*, Docket No. 56545, Direct Testimony of Chris Brown, Market Analysis Division, Public Utility Commission of Texas (Jul. 17, 2024).

3) Docket No. 56735, *Application of Entergy Texas, Inc. for Approval of a System Resiliency Plan*,[12] and
4) Docket No. 56954, *Application of Texas-New Mexico Power Company for Approval of a System Resiliency Plan*.[13]

Additionally, the data analysis team is currently participating in the review of Docket No. 57057, *Application of AEP Texas Inc. for Approval of a System Resiliency Plan*, and Docket No. 57259, *Application of Southwestern Electric Power Company for Approval of a System Resiliency Plan* and may file testimony in these dockets.

### Market Operations Data Review

14) **Review ERCOT and Independent Market Monitor (IMM) Data and Reports –** The PUCT regularly receives summary statistics and reports related to market prices and system conditions from ERCOT and the IMM. The data analysis team reviews, verifies, and, in some cases, replicates this information to stay apprised of any important real-time developments related to the grid and electricity markets.

## Information Technology Tools

In FY 2024, PUCT purchased two desktop computers with increased computing power that have improved the computing capabilities of the data analysis team. PUCT also purchased Gartner technical professional licenses and Azure DevOps licenses for the team. The team primarily uses software that is either open-source or licensed by the PUCT.  It regularly uses

12 *Application of Entergy Texas, INC. for Approval of a System Resiliency Plan*, Docket No. 56735, Direct Testimony of Tyler Nicholson, Market Analysis Division, Public Utility Commission of Texas (Aug. 23, 2024).

13 *Application of Texas-New Mexico Power Company for Approval of a System Resiliency Plan*, Docket No, 56954, Direct Testimony of Jacob Bulzak, Market Analysis Division, Public Utility Commission of Texas (Oct. 29, 2024).

analytics software such as Python, Excel, and SQL Server as well as enabling tools, such as task boards and shared documents, within the Microsoft 365 Suite.

Additionally, the team is working with the Information Technology (IT) division to set up an internal database to improve data storage and access processes, which will increase effectiveness and efficiency in future data analysis projects.

The team is currently collaborating with ERCOT's IT team and the PUCT IT team to determine potential solutions that can provide the team with automated, direct access to ERCOT datasets without manual intervention to reduce staff processing time. Inter-agency coordination for data access can be time-consuming. This initiative may provide significant efficiency gains for both ERCOT and PUCT. Staff expects to provide an update on this initiative in its next report.

## Enhanced Analytic Capabilities Interim Impact

The data analysis team's analytics capabilities have created efficiencies at the agency. Specifically, the team's contributions related to policy research, data analysis, and data verification have informed commission policy decision making, particularly for the electricity market. In-depth analysis by the team has created more data-driven decisions for agency rulemakings, projects, and other initiatives, as detailed above under specific projects.

## Recommendations for Performance Measures

PUCT has no recommendations for future performance measures at this time. The data analysis team will continue to coordinate with commissioners' offices, PUCT executive offices, and various divisions within the agency to evaluate the data analytics needs of the agency and determine where the data analysis team can provide the most benefit to various commission initiatives.

# Market Manipulation Report

**Responsive to Public Utility Regulatory Act (PURA) §39.1515(i) (House Bill 1500, 88R)**

December 1, 2024

# Introduction

House Bill 1500, enacted by the 88th Legislature, added Public Utility Regulatory Act (PURA) § 39.1515(i) that requires the Public Utility Commission of Texas (PUCT) to annually report to the Texas Legislature the following information, by December 1 of each year.[1]

1. The number of instances in which the Independent Market Monitor (IMM) reported potential market manipulation to the commission or commission staff for the 12-month period preceding the report's submission;
2. The statutes, commission rules, and Electric Reliability Council of Texas (ERCOT) Nodal Protocols or Other Binding Documents alleged to have been violated by the reported entities; and
3. The number of instances reported under bullet point (1) for which the commission instituted a formal investigation on its own motion or commission staff initiated enforcement action.

The PUCT submits this annual report on market manipulation in compliance with the requirements of PURA § 39.1515 (i). This report covered the 12-month reporting period from November 1, 2023 through October 31, 2024.

# Market Manipulation Instances

Potomac Economics, serving as the IMM for the ERCOT power region, reported to the commission or commission staff one instance of potential market manipulation during the 12-month reporting period.

# Statutes, Commission, and ERCOT Rules

The following statutes, commission rules, ERCOT Nodal Protocols, or Other Binding Documents were implicated by the IMM's reporting:

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016.

a. 16 Texas Administrative Code § 25.503(f), related to duties of market entities;
b. ERCOT Nodal Protocols § 6.4.6, related to resource status; and
c. ERCOT Nodal Protocols § 6.5.7.9, related to dispatch instructions.

## Formal Investigation

Commission staff has initiated enforcement action on the potential market manipulation instance reported by the IMM during the 12-month period addressed in this report. The commission did not institute a formal investigation on its own motion.

# Public Utility Commission of Texas

# Strategic Communications Plan

**Responsive to Public Utility Regulatory Act § 12.205 (House Bill 1500, 88R)**

September 2024

## Summary

The Public Utility Commission of Texas' (PUCT) Strategic Communications Plan (Plan) identifies the agency's key audiences, communications tactics, and actionable strategies to inform and engage the Texans we serve. While this summary provides a high-level overview of the PUCT's Strategic Communications Plan, PUCT staff maintain the full Plan internally. It remains a living document to ensure it incorporates proven and evolving best practices in public communications – which include technological innovation, increasing use of integrated tactics, and changing demands for information by various audiences – and accurately reflects the communications priorities of the PUCT as they may change or evolve over time.

The Plan is designed to meet four principal goals:

- Inform and educate Texans about the duties, responsibilities, and actions of the PUCT to protect and advance the public interest and its importance to Texas.
- Strengthen the agency's reputation and credibility with Texans.
- Provide Texans with the consumer resources they need to make informed choices about certain utility services and assistance when in conflict with utilities under PUCT regulation.
- Serve as a critical source of information during an emergency, in close coordination with the Texas Division of Emergency Management and partner agencies to protect life, property, and the economy.

Proactive communications and rapid response efforts are emphasized throughout the Plan. This ensures timeliness of information for Texans and best positions the PUCT to tell its story. To further achieve this outcome, the Plan also emphasizes the use of plain language and non-technical jargon to reach the greatest number of people in a meaningful and understandable way.

The Plan contemplates the full use of standard public communications tactics, including, but not limited to, proactive and reactive media engagement; generating daily social media content; maintaining a dynamic, responsive, and up-to-date agency website; audio-visual production; and producing a wide variety of digital and hard copy infographics, documents, and internal and external newsletters.

It also serves as a guidance document in planning long-term communications efforts, articulating methodologies, and establishing standards to follow. This ensures consistency and uniformity in what and how information is developed and shared.

While the PUCT coordinates and partners with many agencies and organizations on a host of different issues, the PUCT and the Electric Reliability Council of Texas (ERCOT) share a unique relationship requiring more frequent and detailed collaboration in communications. The Plan outlines processes and responsibilities for each organization to best ensure the release of important information is uniform and consistent between them.

# Review of Ancillary Services in the ERCOT Market

# Commission Findings

**Responsive to Public Utility Regulatory Act § 35.004 (g) (Senate Bill 3, 87R)**

December 19, 2024

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## INTRODUCTION

The *Review of Ancillary Services in the ERCOT Market* (AS Study) was performed to assist the Public Utility Commission of Texas in meeting the requirements of PURA § 35.004(g) (SB3, 87R) which states, in relevant part, that:

> *The commission shall: (1) review the type, volume, and cost of ancillary services to determine whether those services will continue to meet the needs of the electricity market in the ERCOT power region; and (2) evaluate whether additional services are needed for reliability in the ERCOT power region while providing adequate incentives for dispatchable generation.*

The Commission initiated this study as a collaborative effort between ERCOT, the Independent Market Monitor (IMM), and Staff and approved the AS Study scope at the February 15, 2024 open meeting.[1] Over the course of the study, Staff, ERCOT, and the IMM met multiple times to collaborate, share study progress, and discuss interim results.

Stakeholder involvement was integral to the study as well, with ERCOT and the IMM providing opportunity for review and discussion of preliminary and final results at meetings of ERCOT's Technical Advisory Committee (TAC) this past summer.[2,3] On October 1, 2024, Staff filed a draft study report which included ERCOT's and IMM's analyses and recommendations.[4] Staff subsequently posted a set of questions for public comment and held a workshop to allow stakeholders additional opportunities to provide input to assist with finalizing Staff's recommendations.[5]

Staff filed its analysis, recommendations, and suggested next steps for this study on November 15, 2024.[6] These recommendations were intended to address the requirements of PURA § 35.004(g) and were structured around seven policy topics. At the November 21, 2024 and December 12, 2024 open meetings, the commissioners discussed these topics and Staff and ERCOT Staff answered questions and the IMM was also in attendance to assist as needed.

Based on the results of the AS Study, the Commission agreed at the December 19, 2024 open meeting on the following findings and next steps regarding how best to utilize the results of this study to benefit both the ERCOT power region and its wholesale markets and satisfy the requirements of PURA § 35.004(g). These findings are organized around the same policy topics as described in Staff's recommendations. Details on the policy topics, full AS study report, and related public proceeding can be found under Project No. 55845.

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[1] *See* Staff Memo and AS Study Scope, AIS Item No. 2 (Jan. 19, 2024).

[2] *See* Item 13, Other Business, June 24th TAC Meeting at www.ercot.com.

[3] *See* Meeting Materials, August 28th TAC Workshop for Ancillary Services Study at www.ercot.com.

[4] *See* AS Study Draft Report and Next Steps, AIS Item No. 13 (Oct. 1, 2024).

[5] *See* Agenda for Oct 31, 2024 Staff led Workshop, AIS Item No. 39 (Oct. 28, 2024).

[6] *See* Staff Recommendations, AIS Item No. 41 (Nov. 15, 2024).

## COMMISSION FINDINGS

### *TOPIC 1: SUFFICIENCY OF CURRENT ANCILLARY SERVICES*

**Finding** – The current set of AS, combined with the forthcoming Dispatchable Reliability Reserve Service (DRRS), provide ERCOT sufficient AS to comply with North American Electric Reliability Corporation (NERC) requirements and respond to inherent system variability and uncertainty.

**Next Steps** – ERCOT should continue to monitor the need for new AS. Staff should incorporate an update to this AS review into the 2026 reliability standard assessment.

### *TOPIC 2: PROVIDING ADEQUATE INCENTIVES FOR DISPATCHABLE GENERATION*

**Finding** – The reliability standard rule (16 TAC § 25.508) has defined a process for assessing and ensuring resource adequacy.

**Next Steps** – The first holistic reliability standard assessment in 2026 will include an assessment of whether incentives are adequate to support a sustainable level of dispatchable generation, and ERCOT should incorporate the impact of new market features such as Texas Energy Fund, DRRS, and real-time co-optimization plus batteries (RTC+B) into this assessment.

### *TOPIC 3: APPROPRIATE CRITERION FOR AS PROCUREMENT QUANTITIES*

**Finding** – ERCOT's current posture of maintaining AS quantities that minimize the chance of entering the pre-emergency operational condition of an Operational Watch should be maintained in order to balance system improvements made since Winter Storm Uri until additional data is available to support further Commission evaluation of this operating posture.

**Next Steps** – ERCOT should develop the capability to provide current estimates of costs and probabilities of experiencing a Watch, Emergency Alert, and Load Shed for several potential alternative target reserve levels as soon as practicable and no later than to support the Commission setting an objective, data-based procurement criteria for the 2027 AS Methodology.

### *TOPIC 4: DYNAMIC DETERMINATION OF AS QUANTITIES*

**Finding** – Tradeoffs exist between the certainty provided to market participants by calculating AS quantities primarily on an annual basis (as is done currently) and the efficiency of calculating some portion of AS quantities closer to the operating day.

**Next Steps** – ERCOT should work with stakeholders to explore a dynamic AS methodology that best balances these trade-offs.

### *TOPIC 5: PROBABALISTIC MODELING TO DETERMINE AS QUANTITIES*

**Finding** – ERCOT's current practice to determine AS quantities relies on a statistical analysis using historical operating conditions and outcomes. This methodology is no longer sufficient as myriad changes to the wholesale markets and operating conditions continue to impact reasonable forecasting needs. Changes such as incorporation of an unknown amount of TEF-supported capacity, how new large loads are integrated into grid operations, or the impact of new market designs present uncertainty for forecasting tools based exclusively on historical data.

**Next Steps** – ERCOT should develop a suitable probabilistic, forward-looking modeling capability, provide regular updates to TAC, and present options that can be incorporated no later than the 2027 AS Methodology.

### *TOPIC 6: DISPATCHABLE RELIABILITY RESERVE SERVICE (DRRS)*

**Finding** – DRRS is one of the tools in the market design toolbox that may assist in meeting the ERCOT reliability standard and need not be specially designated as a tool for resource adequacy to be utilized for this purpose in the future.

**Next Steps** – ERCOT should design DRRS to ensure that it meets its primary role as an ancillary service to mitigate operational risks in real time and reduce the use of Reliability Unit Commitment. ERCOT should also design flexibility into the mechanism for procuring DRRS so that, if the Commission determines that the price for or quantity of DRRS should be modified in the future to provide targeted additional generator revenue, this could be done without requiring significant additional system changes and without creating artificial scarcity or other detrimental effects on the market. ERCOT and stakeholders may have additional ideas to achieve this outcome that merit continued examination.

### *TOPIC 7: OTHER CONSIDERATIONS*

#### 7A. FIRM FUEL SUPPLY SERVICE (FFSS)

**Finding** – No changes to FFSS are warranted as part of this study as risks mitigated with FFFS do not overlap with risks mitigated by procuring AS.

**Next Steps** – FFSS has its own project and any improvements to that service will continue there.[7]

#### 7B. EMERGENCY RESPONSE SERVICE (ERS)

[7] See *Firm Fuel Supply Service*, Project No. 56000 (pending).

**Finding** – Opportunities to expand ERS or create related new demand response products should be pursued.

**Next Steps** – ERCOT should perform a holistic review of existing and potential voluntary and emergency-related DR programs, including ERS.

### 7C. INDIVIDUALLY PRICING AS SUB-TYPES

**Finding** – Creating separate clearing prices for different resource types that provide different sub-types of the same AS will likely benefit the ERCOT market, but it is not currently a top priority, given other market improvement efforts in-flight.

**Next Steps** – ERCOT and stakeholders should consider pricing AS subtypes separately after RTC+B has stabilized.

### 7D. DURATION REQUIREMENTS FOR ERCOT CONTINGENCY RESERVE SERVICE AND NON-SPIN RESERVE SERVICE.

**Finding** – Examining the length of response time required for these two AS will likely benefit the ERCOT market, but it is not currently a top priority, given other market improvement efforts in-flight.

**Next Steps** – ERCOT and stakeholders should revisit duration requirements for ECRS and Non-Spin after RTC+B has stabilized.

# Report on Dispatchable and Non-Dispatchable Generation Facilities

**Responsive to Public Utility Regulatory Act (PURA) §39.1591 (House Bill 1500, 88R)**

December 1, 2024

# Introduction

Public Utility Regulatory Act (PURA) §39.1591 (House Bill 1500, 88R) requires the Public Utility Commission of Texas (PUCT) to submit a report on costs associated with dispatchable and non-dispatchable generation facilities to the Legislature by December 1 each year. Specifically, the report must provide:

(A) the estimated annual costs incurred by load-serving entities associated with backing up dispatchable and non-dispatchable electric generation facilities to guarantee that a firm amount of electric energy will be available to the ERCOT power grid; and

(B) as calculated by ERCOT, the cumulative annual costs that have been incurred in the ERCOT market to facilitate the transmission of dispatchable and non-dispatchable electricity to load and to interconnect transmission level loads, including a statement of the total cumulative annual costs and of the cumulative annual costs incurred for each type of activity described above.

Part (A) of this report provides the required information for calendar year (CY) 2023 based on data available within ERCOT systems. For part (B), this report offers CY 2023 information provided by ERCOT and transmission service providers (TSP) in response to a request for information issued by PUCT Staff.[1]

The legislation also requires the PUCT to document the progress in implementing PURA Chapter 39, subchapter D requirements related to reliability, resilience and transparency of the electricity market and whether any regulations or ERCOT rules the PUCT has adopted as result of those statutes that have materially improved the reliability, resilience, and transparency of the electricity market. The PUCT's regular status reports on implementation of legislation found in subchapter D are attached as appendices.

Changes in laws or regulations take time to have material impact on the resiliency of grid operations. Whether due to the time it takes to develop and implement new systems software solutions or construct more robust infrastructure, enhancing operational reliability is a multi-year effort. As a result, starting in 2025, Staff will begin a review of subchapter D and provide an update on the status of regulations or ERCOT rules that may have materially improved reliability, resilience, and transparency of the electricity market.

[1] Report on Dispatchable and Non-Dispatchable Generation Facilities - CY 2024, Project No. 56969, *Staff Memo - Report on Dispatchable and Non-Dispatchable Generation Facilities*, AIS Item No. 2 (Aug. 29, 2024).

## A. Load-Serving Entities' Annual Costs to Back-up Dispatchable and Non-Dispatchable Electric Generation

ERCOT procures reliability services, which are energy products and services used to maintain grid stability and reliability. Each year, ERCOT – in consultation with market participants and under the authority of the PUCT – determines the minimum amount of each product or service needed for the upcoming calendar year using a risk-based assessment. ERCOT's methodology examines risks to the system's ability to maintain frequency at a steady state of 60 Hz and control system voltage within nominal ranges. Through its settlement systems, ERCOT allocates costs associated with procuring reliability services to qualified scheduling entities (QSEs) based on each QSE's load ratio share. Each QSE assigns these costs to the load serving entities (LSEs) that it represents, such as retail electric providers, electric cooperatives, or municipally owned utilities. LSEs pass these costs on to end-use customers. ERCOT does not have information about how the QSE assigns these costs to LSEs or how LSEs pass these costs on to customers. Each LSE may have different financial or physical hedging arrangements into which ERCOT has no visibility.

Below is a brief explanation of each of the reliability products and services procured by ERCOT and allocated to QSEs based on their load ratio share.

**Ancillary Services (AS)** are reliability products used to support the transmission of energy to load. These products are purchased by ERCOT to balance supply and demand of electricity on the grid and for mitigating real-time operational issues. A QSE may independently arrange to contract for its share of AS and report those amounts to ERCOT in a process known as self-arrangement. In 2023, QSEs self-arranged approximately 12% of AS, across all hours and AS products. Ancillary services can be provided by qualified generators or consumers (also referred to as 'load'), to increase or decrease the supply of electricity in a matter of minutes or seconds. Resources selected in the day-ahead market (DAM) to provide an ancillary service for a particular hour are paid the clearing price for that service for that hour. These payments are collected from the LSEs. There are four types of AS:

1. **Regulation Services (Reg-Up and Reg-Down)** are provided by resources that can respond to signals from ERCOT to adjust their output or consumption within five seconds to address rapid changes in system frequency.
2. **Responsive Reserve Service (RRS)** is provided by resources that can, within the first few seconds, arrest significant frequency deviations on the grid and, ultimately, help restore system frequency back to 60 Hz. One example of an event that would cause such a deviation is a large generation resource tripping offline.

3. **ERCOT Contingency Reserve Service (ECRS)** is provided by resources that can be available within 10 minutes and provide the service for at least two consecutive hours to cover errors in forecasting or replace deployed reserves.
4. **Non-Spin Reserve Service (Non-Spin)** is provided by resources that can be available within 30 minutes and provide the service for at least four consecutive hours to cover errors in forecasting, respond to forced outages, or replace deployed reserves.

Additional reliability products and services procured by ERCOT to support transmission of energy to load are described below.

**Black Start Service (BSS)** is provided by qualified generation resources contracted to be ready to start up without the support of the ERCOT transmission grid in the event of a system-wide or partial system outage.

**Emergency Response Service (ERS)** is provided by qualified generation resources and end-use customers (including aggregations) that are contracted to be deployed by either decreasing demand or increasing supply in the event of an emergency. ERS is procured for two different response times: responding within 10 minutes or responding within 30 minutes. ERCOT awards contracts for ERS four times per year.

**Firm Fuel Supply Service (FFSS)** is provided by qualified generation resources from November 15 through March 15. The generation resources must maintain sufficient back-up fuel and be able to follow ERCOT dispatch instructions during extreme winter weather if there is a disruption in natural gas supply. FFSS is established to mitigate risks in the natural gas supply chain.

**Reliability Must Run Service (RMR)** is provided by a resource entity with whom ERCOT contracts for capacity and energy from generation resources that otherwise would not operate and that are deemed necessary to provide voltage support, stability, or management of localized transmission constraints under applicable reliability criteria, where market solutions do not exist.

**Reliability Unit Commitment (RUC)** is a process to ensure that there is adequate resource capacity and ancillary service capacity committed in the proper locations to serve ERCOT's forecasted load. The portion of the RUC settlements (make whole payments to generators) not assigned directly to capacity-short entities is allocated to the QSEs based on load ratio share. The extra revenues clawed back from resources that receive RUC instructions (above their make whole payments) are paid out to QSEs on a load ratio share basis.

**Voltage Support Service (VSS)** is a service necessary to maintain transmission and distribution voltages on the ERCOT transmission grid within acceptable limits. Currently, no costs were incurred for this service.

Table 1 below delineates the charges allocated to QSEs from the ERCOT settlement systems for reliability services during CY 2023. ERS charges have been evenly allocated across the months of the respective contract periods. The charges reported here do not include any secondary cost impacts borne by the LSEs resulting from reliability deployment price adders. The ancillary services settlement data provided include the AS procured by ERCOT in the DAM and the self-arranged AS valued at DAM market clearing prices for capacity. In 2023, ERCOT had no RMR resources under contract; as a result, no costs were assigned to load.

### Table 1: Reliability Services Costs Incurred by Load-Serving Entities ($million, CY 2023)

| Month | AS[1] | BSS [1] | ERS[1] | FFSS | RMR Charge | RUC [2] | RUC[3] | VSS | TOTAL |
|---|---|---|---|---|---|---|---|---|---|
| Jan | $26.4 | $0.6 | $5.0 | $8.0 | $0.0 | $0.0 | ($0.8) | $0.0 | $39.1 |
| Feb | $29.9 | $0.5 | $5.0 | $9.7 | $0.0 | $0.0 | ($0.2) | $0.0 | $44.9 |
| Mar | $45.7 | $0.6 | $5.0 | $4.7 | $0.0 | $0.0 | ($0.2) | $0.0 | $55.8 |
| Apr | $44.2 | $0.5 | $1.0 | $0.0 | $0.0 | $0.0 | ($0.1) | $0.0 | $45.7 |
| May | $57.2 | $0.6 | $1.0 | $0.0 | $0.0 | $0.0 | ($0.4) | $0.0 | $58.4 |
| Jun | $310.7 | $0.5 | $6.3 | $0.0 | $0.0 | $0.0 | ($0.1) | $0.0 | $317.4 |
| Jul | $137.1 | $0.6 | $6.3 | $0.0 | $0.0 | $0.0 | ($0.2) | $0.0 | $143.8 |
| Aug | $909.7 | $0.6 | $6.3 | $0.0 | $0.0 | $0.0 | ($0.4) | $0.0 | $916.2 |
| Sep | $177.4 | $0.5 | $6.3 | $0.0 | $0.0 | $0.0 | ($1.0) | $0.0 | $183.2 |
| Oct | $68.4 | $0.6 | $2.6 | $0.0 | $0.0 | $0.0 | ($0.2) | $0.0 | $71.3 |
| Nov | $49.2 | $0.5 | $2.6 | $3.5 | $0.0 | $0.0 | ($0.0) | $0.0 | $55.8 |
| Dec | $18.4 | $0.6 | $8.8 | $7.3 | $0.0 | $0.0 | $0.0 | $0.0 | $35.0 |
| **TOTAL** | $1,874.1 | $6.6 | $56.1 | $33.2 | $0.0 | $0.0 | ($3.5) | $0.0 | $1,966.6 |

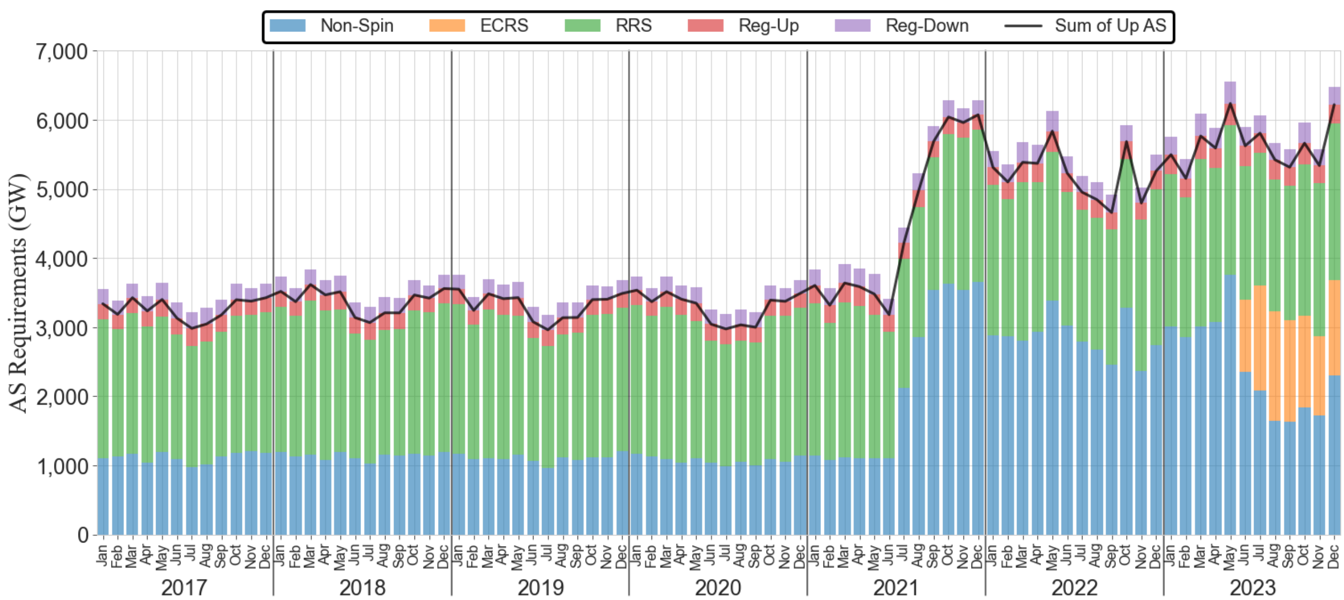
Notes: 1- Settlements, 2- Make Whole Uplift Charge, 3 - Claw Back Allocated to Load

The remainder of this section of the report restricts attention to ancillary services, which accounted for more than 95 percent of the total costs in CY 2023.

## Qualitative Review of Operational Risks and AS Quantities

ERCOT annually determines minimum quantities of each type of AS required to mitigate real-time operational issues. The calculation methodology includes a statistical analysis of the historical drivers for AS while factoring in expected system changes that may impact the needed quantities. Figure 1 below displays the total monthly ancillary service procurements from January 2017 through December 2023, broken down by AS type. The most notable change over this period was an increase in the quantities of some types of AS beginning in the latter half of 2021. This change reflects an operational posture that ERCOT adopted beginning July 2021 that requires more operating reserves to be online in real-time to effectively avoid entering emergency operations.

**Figure 1: Total Monthly Ancillary Service Requirements (GW)**




The risks that each AS covers and the adjustments to AS quantities that have been implemented to account for changes in the factors that drive each of these risks are examined below. Many of these services are designed to address risks and uncertainties related to net load, which is the system load for a given period less the amount of generation produced by photovoltaic generation resources (PVGRs) and wind generation resources (WGRs) for the same period.

Below is a brief explanation of the risks and uncertainties that each AS addresses.

*Regulation Services* are procured to cover risks associated with uncertainty from net load ramp, which is defined as changes in net load between consecutive time intervals. Quantities are primarily determined from an assessment of historical net-load ramp during the same month in the previous two years. Quantities may also be adjusted based upon annual incremental changes in installed wind and solar generation capacity.

*Responsive Reserve Service* is procured to ensure that sufficient capacity is available to respond to changes in frequency resulting from unit trips. The primary determinant of RRS quantities is the combined capacity of the power region's two largest units, both of which are dispatchable generation resources.

*ERCOT Contingency Reserve Service* is primarily procured to cover risks associated with intra-hour net load uncertainty, with quantities determined based on an analysis of historical intra-hour net load uncertainty during the same month and hour in the previous two years. Quantities may also be adjusted based on incremental growth in solar capacity. Additionally, ECRS may be deployed to restore frequency following a significant frequency deviation resulting, for example, from a large generation unit trip.

*Non-Spin Reserve Service* is procured to cover risks associated with hourly net load uncertainty, with quantities determined based on an analysis of historical, hourly net load uncertainty from the same month in the previous three years.

## Changes in AS Costs Over Time

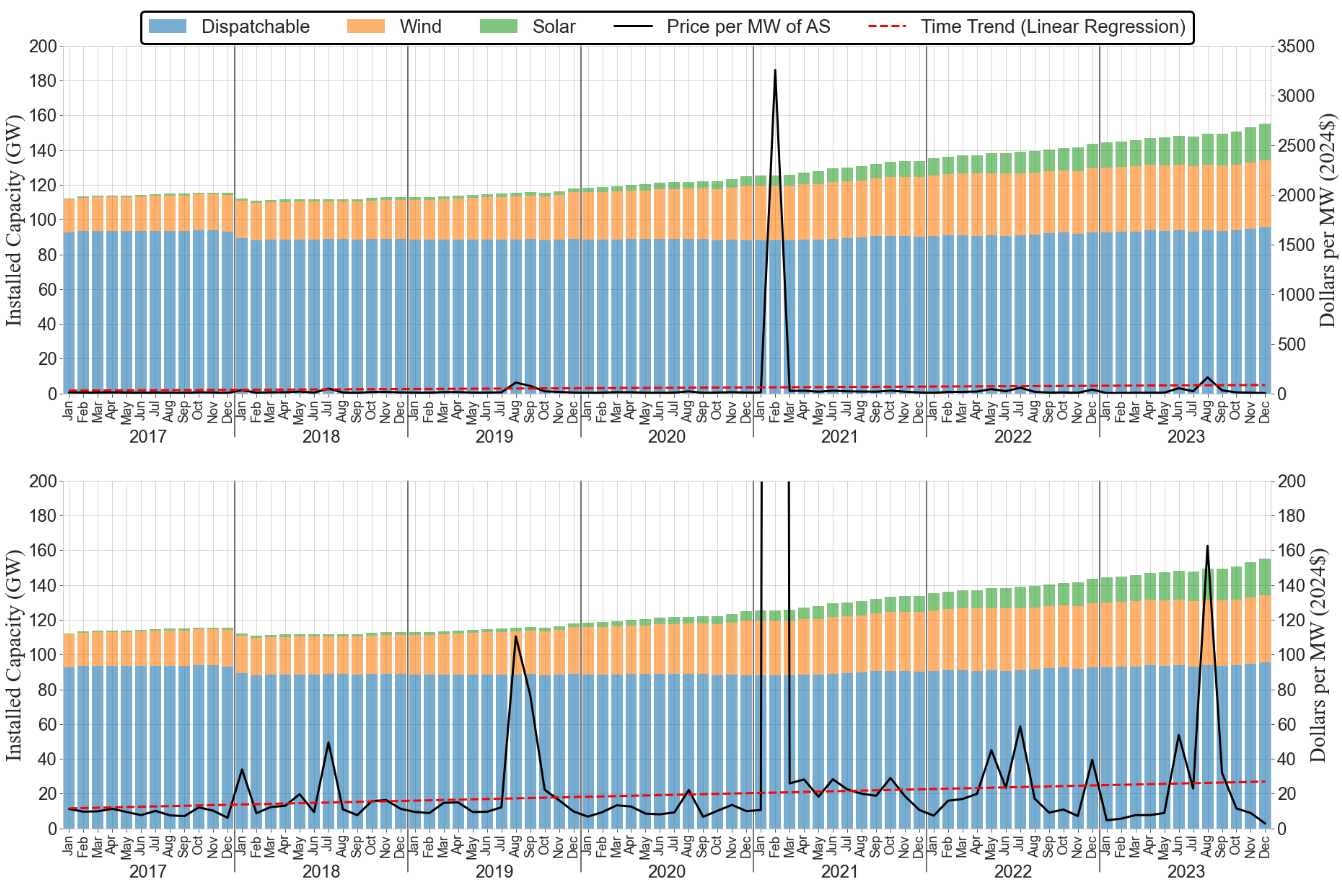
This section examines how AS costs have changed over time and whether any relationship exists between AS costs and installed capacity of non-dispatchable generation resources. Despite the fact that some AS quantities are adjusted to account for incremental growth in non-dispatchable capacity on the system and there has been considerable growth in the amount of non-dispatchable capacity in recent years, AS costs have not substantially increased on a dollar-per-MW basis, on average, during the period examined in this report (January 2017 through December 2023).

Figure 2 includes two graphs displaying total installed capacity, broken down by dispatchable, wind, and solar resources, and the total monthly cost of AS per MW procured from January 2017 through December 2023. The top graph in this figure is zoomed out to a scale that allows it to display all the data. Because of the substantial impacts of winter storm Uri, February 2021 is a considerable outlier in terms of total monthly AS costs. For this reason, the second graph is a zoomed in version of the top graph at a scale that provides a better picture of the AS cost data in all other months.

Each graph in this figure also includes a linear regression trend line that describes the average change in monthly AS costs over time on a dollars-per-MW basis. The regression time trend line displayed in the second graph (which is estimated on a subset of the data that excludes February 2021) indicates that AS costs have increased, on average, over this period. However, the estimated effect is only marginally significant (p-value = 0.071), and the magnitude of this increase is relatively modest at approximately $2.2/MW annually. A regression analysis estimating the effect of an additional GW of installed non-dispatchable capacity on the price per MW of AS indicates a marginally significant (p-value = 0.092) increase of \$0.35/MW of AS. Figure 2 also reveals that AS prices were unusually high in August 2023. Repeating similar regression analyses on a further restricted dataset that excludes August 2023 (in addition to February 2021), reveals a statistically insignificant (p-value = 0.309) annual increase in AS costs of \$0.93/MW, on average, over this period and a statistically insignificant (p-value = 0.470) increase of \$0.11/MW of AS per GW of additional installed non-dispatchable capacity.

In summary, while these analyses indicate that AS costs have moderately increased over time, on average, they do not establish a clear link between AS costs and the amount of non-dispatchable capacity on the system.

## Figure 2: Installed Capacities and Monthly AS Costs (\$ per MW)




Notes:

1. Dollar values are adjusted to 2024 dollars using U.S. Bureau of Labor Statistics Consumer Price Index (CPI) data.
2. The regression line in the first graph is estimated using all data points, while the regression line in the second graph is estimated on a restricted dataset that excludes February 2021 to eliminate the impact of this outlier.

As discussed under the qualitative review section, ERCOT procures AS to manage a varied set of system risks. This includes, but is not limited to, the risk of unit trips (for all generator types) as well as the risk of under-forecasting net load associated with variability of load and non-dispatchable resources that are weather dependent and prone to variability. It is important to note that regardless of the original intent for which the AS was procured, ERCOT may use an AS for any type of contingency faced in real time operations based on the underlying technical capabilities of the resources providing that AS.

The determination of some portion of AS quantities involves adjustments to account for incremental changes in the resource mix and the associated changes in the variability and uncertainty on the grid. However, AS quantities are not, by design, determined directly based on resource type. Additionally, uncertainty related to net load may inherently involve non-dispatchable resources but could as easily be attributed to load forecast error or dispatchable resource under-performance. As such, clear segregation of AS costs between dispatchable and non-dispatchable resources is inherently difficult. However, to comply with PURA §39.1591 (1) (A), Staff presents two approaches that attempt to disaggregate AS costs between three distinct categories: (i) dispatchable, (ii) non-dispatchable, and (iii) load. The following sections present estimates of the costs that can be allocated to each category under these approaches and discuss the short comings of each approach.

## I. AS Costs Distributed Based on Real-Time Generation Mix

This approach retroactively compares the AS quantities procured with proportions of the total amount of energy generated in real-time by respective resource types that the AS were backing up. Table 2 reports the results of this distribution methodology, which attributes 78.9% of overall AS costs to dispatchable generation and 21.1% to non-dispatchable resources. This approach, however, abstracts away some important aspects of how AS are determined and procured. First, AS quantities are determined in advance based upon historical analyses of the risks each service is designed to address and forecasts of future conditions. Second, some of the risks inherent to the system at any point in time are also driven by load uncertainty and fluctuations. This approach does not account for the impacts of forecasts, and it assigns all costs either to dispatchable or non-dispatchable generation, ignoring the effect that *load variability* has on AS costs altogether. The approach described under section II attempts to account for all three of these factors.

As shown in Table 2, a majority of all energy generated during 2023 came from dispatchable resources. Total energy generated aligns closely with the proportions of overall installed generation capacity in ERCOT. In December 2023, there was approximately 155 GW of total installed capacity on the system, with nearly 95 GW of dispatchable resources and 60 GW from non-dispatchable resources. Therefore, if annual costs were, alternatively, disaggregated according to the proportion of overall capacity from each category of resources, the results would likely be relatively similar.

**Table 2: Ancillary Service Costs Distributed Based on Real-Time Generation ($million, CY 2023)**

| Month | Regulation | RRS | ECRS | Non-Spin | All AS | DG (%) | NDG (%) | DG | NDG |
|---|---|---|---|---|---|---|---|---|---|
| Jan | $3.5 | $8.8 | $0.0 | $14.1 | $26.4 | 61.6 | 38.4 | $18.7 | $7.7 |
| Feb | $5.7 | $7.6 | $0.0 | $16.6 | $29.9 | 61.7 | 38.3 | $21.4 | $8.5 |
| Mar | $6.3 | $15.2 | $0.0 | $24.2 | $45.7 | 58.9 | 41.1 | $31.0 | $14.6 |
| Apr | $5.8 | $13.7 | $0.0 | $24.6 | $44.2 | 58.6 | 41.4 | $29.2 | $15.0 |
| May | $3.9 | $8.7 | $0.0 | $44.6 | $57.2 | 71.4 | 28.6 | $42.1 | $15.1 |
| Jun | $16.0 | $74.3 | $112.2 | $108.1 | $310.7 | 72.8 | 27.3 | $239.1 | $71.6 |
| Jul | $8.4 | $34.9 | $58.2 | $35.7 | $137.1 | 72.9 | 27.1 | $104.9 | $32.2 |
| Aug | $86.0 | $253.4 | $437.9 | $132.3 | $909.7 | 76.5 | 23.5 | $745.0 | $164.7 |
| Sep | $20.7 | $62.3 | $65.8 | $28.6 | $177.4 | 75.7 | 24.3 | $143.7 | $33.7 |
| Oct | $7.2 | $23.7 | $22.3 | $15.1 | $68.4 | 68.1 | 32.0 | $52.5 | $15.9 |
| Nov | $3.8 | $17.1 | $12.8 | $15.4 | $49.2 | 69.2 | 30.9 | $38.9 | $10.3 |
| Dec | $1.7 | $5.7 | $4.5 | $6.5 | $18.4 | 65.3 | 34.7 | $12.6 | $5.8 |
| **TOTAL** | $169.2 | $525.3 | $713.7 | $466.0 | $1,874.1 | 68.6% | 31.4% | $1,479.1 | $395.0 |

Notes: DG = Dispatchable generation, NDG = Non-dispatchable generation

## II. AS Costs Distributed Based on Forecasted Conditions and Covered Risks

This subsection discusses an alternative methodology that accounts for both wind and solar forecasting and load variability aspects of AS quantity determination. This approach disaggregates the costs associated with each AS into three categories—dispatchable (D), non-dispatchable (ND), or load (L)—based upon the types of risks that a product is intended to address and the discrepancies between forecasted and actual conditions.

Below is a brief description of how the cost of each AS is broken down into these categories.

*Regulation Services* – As discussed above, this service covers risks associated with variability in net load ramp. For each five-minute interval, the total error between forecast and actual net load ramp is calculated. This error is then split into load and non-dispatchable proportions based upon the amount that the ramp error of each category contributes to the overall net load ramp error. These five-minute values are averaged within each hour and costs for that hour are distributed between the load and non-dispatchable categories based on these average hourly proportions.

*Responsive Reserve Service* - Because the primary determinant of RRS quantities is the capacity of the two largest contingencies on the system, both of which are dispatchable generation resources, the entirety of RRS costs is assigned to the dispatchable category.

*ERCOT Contingency Reserve Service*– This service is procured to cover risks and uncertainty associated with intra-hour net load variability. For each hour, total net load error is calculated based on the difference between actual and 30-minute ahead forecasts of load, wind, and solar. This error is then split between load and non-dispatchable proportions based upon the amount that the error of each category contributes to the overall net load error. Costs for that hour are then distributed to the load and non-dispatchable categories based on these hourly proportions.

*Non-Spin Reserve Service* - Some portion of Non-Spin quantities are procured to account for the risk of forced unit outages, and the remainder is procured to cover risk associated with hourly net load uncertainty. For each hour, total net load error is calculated based on the difference between actual and six-hour ahead forecasts of load, wind, and solar. This error is then split between load and non-dispatchable proportions based upon the amount that the error of each category contributes to the overall net load error. The portion of costs associated with the forced outage adjustment is assigned entirely to the dispatchable category, while the remaining costs, which are associated with net load uncertainty, are distributed to the load and non-dispatchable categories based on the proportion of net load error attributable to each.

Table 3 reports the results of this cost distribution methodology. Overall, this approach results in 23.4% of costs being distributed to load, 34.6% distributed to dispatchable, and 42.0% distributed to non-dispatchable. This table also includes the relevant distribution totals and percentages for each individual service. It is noteworthy that approximately 47.9% of the total costs distributed to the load category and 64.0% of the total costs distributed to the non-dispatchable category were from ECRS, a new service launched in June 2023.

### Table 3: Ancillary Service Costs Distributed Based on Associated Risks ($million, CY 2023)

| Month | Regulation | | RRS | ECRS | | Non-Spin | | | All AS | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | L | ND | D | L | ND | L | D | ND | L | D | ND | Total |
| Jan | $1.2 | $2.2 | $8.8 | $0.0 | $0.0 | $5.0 | $2.4 | $6.7 | $6.2 | $11.2 | $9.0 | $26.4 |
| Feb | $1.8 | $3.9 | $7.6 | $0.0 | $0.0 | $7.3 | $2.8 | $6.5 | $9.2 | $10.4 | $10.3 | $29.9 |
| Mar | $2.1 | $4.2 | $15.2 | $0.0 | $0.0 | $9.9 | $4.3 | $10.0 | $11.9 | $19.5 | $14.3 | $45.7 |
| Apr | $1.8 | $4.1 | $13.7 | $0.0 | $0.0 | $7.8 | $4.8 | $12.0 | $9.6 | $18.5 | $16.1 | $44.2 |
| May | $1.3 | $2.6 | $8.7 | $0.0 | $0.0 | $15.4 | $8.4 | $20.8 | $16.8 | $17.1 | $23.4 | $57.2 |
| Jun | $4.8 | $11.2 | $74.3 | $26.2 | $86.1 | $44.6 | $33.5 | $30.1 | $75.5 | $107.8 | $127.4 | $310.7 |
| Jul | $2.8 | $5.6 | $34.9 | $15.8 | $42.3 | $13.6 | $9.4 | $12.7 | $32.2 | $44.3 | $60.6 | $137.1 |
| Aug | $29.1 | $56.9 | $253.4 | $130.2 | $307.7 | $48.1 | $36.4 | $47.9 | $207.4 | $289.7 | $412.6 | $909.7 |
| Sep | $6.9 | $13.8 | $62.3 | $20.1 | $45.7 | $7.2 | $9.4 | $12.1 | $34.1 | $71.6 | $71.6 | $177.4 |
| Oct | $2.6 | $4.7 | $23.7 | $10.3 | $12.0 | $5.0 | $5.0 | $5.1 | $17.8 | $28.8 | $21.8 | $68.4 |
| Nov | $1.6 | $2.2 | $17.1 | $5.6 | $7.2 | $5.3 | $5.4 | $4.7 | $12.5 | $22.6 | $14.1 | $49.2 |
| Dec | $0.6 | $1.1 | $5.7 | $1.6 | $2.9 | $2.4 | $1.4 | $2.6 | $4.6 | $7.1 | $6.6 | $18.4 |
| **TOTAL** | $56.7 | $112.5 | $525.3 | $209.8 | $503.9 | $171.5 | $123.2 | $171.2 | $438.0 | $648.5 | $787.6 | $1,874.1 |
| **Pct.** | 33.5% | 66.5% | 100% | 29.4% | 70.6% | 36.8% | 26.4% | 36.7% | 23.4% | 34.6% | 42.0% | 100.0% |

Although this cost distribution methodology improves upon the previous approach by better accounting for both the impacts of load and uncertainty on AS procurement quantities, it also has its shortcomings. Some AS products are procured to address multiple risks that may be related with different categories, and it is difficult to clearly disaggregate these quantities. For example, ECRS can be used in real time to address frequency deviations following large unit trips, and this portion of the quantity procured could plausibly be assigned to the dispatchable category. Therefore, while this method provides a better approach to distributing costs among these three categories, it is unable to fully account for every aspect of how AS quantities are determined.

## B. Annual Costs for Transmission of Dispatchable and Non-dispatchable Electricity to Load

Annual costs associated with transmission of electricity comprises costs associated with generation resource and load interconnections and costs associated with the use of bulk electric transmission network to deliver power from generators to loads.

In 2023, the total cost of transmission buildout to meet the system reliability and economic needs, was approximately $1.6 billion, as reported by TSPs to ERCOT in the *Transmission Project and Information Tracking (TPIT)* report. TPIT is used to track the status of transmission level projects (60 kV and above) that have a material impact to the flow of power in the ERCOT system. ERCOT, however, does not have access to direct costs for both generation and load interconnection buildout. Consequently, Staff issued a request for information (RFI) to collect direct annual costs to interconnect generation and transmission level load from all TSPs in the ERCOT region. In response to the Staff RFI, the ERCOT TSPs provided direct interconnection costs from 2019 onwards. Information for prior years can be accessed in Project No. 56969. This section of the report summarizes the TSP responses to the RFI to provide 2023 annual costs for interconnecting generation resources by resource type and the cost to interconnect transmission-level loads in compliance with PURA §39.1591(1) (B).

In 2023, the total cost of bulk transmission network buildout (excluding the load and generation interconnection) was approximately $1.16 billion. The ERCOT bulk transmission network is used to transmit energy from all available energy resource types to all loads. Hence, it is not possible to accurately allocate or assign bulk transmission network costs to a particular resource type or load.

However, transmission interconnection costs for generation resources can be broken down by resource type.

Table 4 provides a summary of generation resources interconnected to the ERCOT grid during CY 2023. A total of 11,273 MW of generation resources were interconnected to the grid, with interconnection costs approved in rate proceedings totaling $293.18 million. To segregate resources into dispatchable and non-dispatchable categories, all wind and solar generation resources were considered as non-dispatchable resource type. However, for any wind or solar generation resource sharing location with battery or storage resource with battery or storage capacity greater than 10% of the non-dispatchable generation capacity, the full capacity was considered as dispatchable. All conventional generation types and storage or battery resources were considered as dispatchable. The total costs in the table below also include any generation interconnection with multiple energization dates spanning between 2023 and the year prior.

### Table 4: Generation Interconnection Cost ($million, CY 2023)

| Generator Dispatch Type | Nameplate Capacity (MW) | Transmission Line (miles) | Interconnection costs | | | |
|---|---|---|---|---|---|---|
| | | | Estimated | Approved in rate proceeding | | |
| | | | | Transmission Line Built Out | Transmission Upgrades | Total Cost |
| Dispatchable | 3,728 | 5.62 | $84.07 | $19.86 | $48.86 | $68.72 |
| Non- Dispatchable | 7,545 | 31.15 | $268.85 | $74.08 | $150.38 | $224.46 |
| Total | 11,273 | - | $352.92 | $93.94 | $199.24 | $293.18 |

In 2023, 22 transmission-level loads were interconnected at various voltage levels across various TSPs. The total interconnection costs for these loads that were approved in rate proceedings was $81.49 million, which was made up of $50.91 million for line build out and $30.58 million for upgrades. Table 5, below, provides a summary of transmission-level load interconnection cost broken down by voltage level.

### Table 5: Transmission-Level Load Interconnection Cost ($million, CY 2023)

| Voltage Level (kV) | Transmission Line (miles) | Interconnection costs | | | |
|---|---|---|---|---|---|
| | | Estimated | Approved in rate proceeding | | |
| | | | Transmission Line Built Out | Transmission Upgrades | Total Cost |
| 69 | 0.40 | $0.00 | $0.00 | $0.00 | $0.00 |
| 138 | 22.85 | $91.04 | $49.67 | $30.58 | $80.25 |
| 345 | 0.21 | $1.28 | $1.24 | $0.00 | $1.24 |
| Total | - | $92.32 | $50.91 | $30.58 | $81.49 |

Table 6, below, provides a breakdown of generation resource types interconnected to the ERCOT grid during CY 2023. Some projects in this table have associated costs of $0.00 because they have not been submitted for recovery in a rate proceeding.

## Table 6: Generation Interconnection Cost by Resource Type ($million, CY 2023)

| Generator Type | Dispatch Type | Nameplate Capacity (MW) | Voltage Level (kV) | Transmission Line (miles) | Interconnection costs | | |
|---|---|---|---|---|---|---|---|
| | | | | | Estimated | Approved in rate proceeding | |
| | | | | | | Transmission Line Built out | Transmission Upgrades |
| Gas | D | 408 | 138 | 0.900 | $16.50 | $5.49 | $6.72 |
| Gas | D | 539 | 138 | 0.120 | $1.14 | $0.14 | $1.03 |
| Battery | D | 63 | 69 | 0.102 | $2.10 | $0.77 | $1.72 |
| Battery | D | 239 | 345 | 0.160 | - | $1.08 | $4.28 |
| Battery | D | 310 | 138 | 0.040 | $3.34 | $3.36 | - |
| Battery | D | 100 | 138 | 0.050 | $1.36 | $1.49 | - |
| Battery | D | 175 | 138 | 0.050 | $3.38 | $3.24 | - |
| Other | D | 150 | 138 | <0.1 | $2.10 | $0.00 | $2.10 |
| Storage | D | 150 | 345 | 0.000 | $0.00 | $0.00 | $0.00 |
| Storage | D | 221 | 345 | 0.000 | $4.48 | - | $4.48 |
| Storage | D | 30 | 345 | 0.000 | $0.00 | - | $0.00 |
| Storage | D | 151 | 138 | 0.000 | $0.00 | - | $0.00 |
| Storage | D | 101 | 345 | 0.000 | $0.00 | - | $0.00 |
| Solar and Battery | D | 187 | 138 | <0.1 | $12.96 | $0.00 | $12.96 |
| Solar and Battery | D | 203 | 138 | <0.1 | $5.29 | $0.00 | $5.29 |
| Solar and Storage | D | 409 | 345 | 0.700 | $14.57 | $4.29 | $10.28 |
| Wind and Storage | D | 292 | 345 | 3.500 | $16.84 | $0.00 | $0.00 |
| Solar | ND | 241 | 138 | <0.1 | $8.11 | $0.00 | $8.11 |
| Solar | ND | 203 | 345 | 0.200 | $0.00 | $0.00 | $0.00 |
| Solar | ND | 201 | 345 | 0.340 | $0.00 | $0.00 | $0.00 |
| Solar | ND | 155 | 345 | 0.300 | $6.99 | $1.21 | $5.78 |
| Solar | ND | 600 | 345 | 0.300 | $9.30 | $0.00 | $5.08 |
| Solar | ND | 240 | 345 | 0.200 | $10.42 | $2.27 | $8.15 |
| Solar | ND | 81 | 138 | 0.580 | $6.39 | $2.25 | $4.14 |
| Solar | ND | 323 | 345 | 1.120 | $3.10 | $3.10 | - |
| Solar | ND | 514 | 345 | 0.300 | $12.30 | $1.57 | $10.73 |
| Solar | ND | 452 | 345 | 0.100 | $17.78 | $3.26 | $0.76 |
| Solar | ND | 254 | 345 | 1.340 | $10.62 | $3.66 | $6.96 |
| Solar | ND | 29 | 138 | 0.200 | $1.02 | $1.02 | $0.00 |
| Solar | ND | 253 | 345 | 1.840 | $11.85 | $4.17 | $7.68 |
| Solar | ND | 204 | 138 | 0.500 | $3.69 | $1.25 | $2.44 |
| Solar | ND | 260 | 138 | 0.000 | $0.98 | - | - |
| Solar | ND | 320 | 345 | 1.650 | $27.37 | $7.87 | $19.50 |
| Solar | ND | 254 | 345 | 0.400 | $0.00 | $0.00 | $0.00 |
| Solar | ND | 50 | 138 | 0.310 | $5.44 | $0.92 | $4.52 |
| Solar | ND | 245 | 345 | 0.100 | $8.48 | $1.21 | $7.27 |
| Solar | ND | 252 | 138 | 0.700 | $6.38 | $1.81 | $4.57 |
| Solar | ND | 252 | 345 | 0.100 | $31.17 | $3.35 | $26.83 |
| Solar | ND | 200 | 138 | 0.700 | $11.54 | $4.10 | $7.41 |
| Solar | ND | 252 | 345 | 0.091 | $3.61 | $1.03 | $2.61 |
| Wind | ND | 182 | 138 | 0.000 | $0.18 | - | $0.18 |
| Wind | ND | 309 | 138 | 0.280 | $0.00 | $0.00 | $0.00 |
| Wind | ND | 293 | 345 | 17.000 | $47.69 | $30.05 | $17.64 |
| Wind | ND | 531 | 345 | 0.100 | $0.00 | $0.00 | $0.00 |
| Wind | ND | 140 | 138 | 0.100 | $0.00 | $0.00 | $0.00 |
| Wind | ND | 255 | 345 | 2.300 | $24.44 | $0.00 | $0.00 |
| Total | | 11,273 | | | $352.92 | **$93.94** | **$199.24** |

Table 7, below, provides a breakdown of transmission-level loads interconnected to the grid along with associated costs recovered in a rate proceeding. Some projects in this table have associated costs of $0.00 because these have not been submitted for recovery in a rate proceeding.

### Table 7: Transmission-Level Load Interconnection Cost by Voltage Level ($million, CY 2023)

| Voltage Level (kV) | Transmission Line (miles) | Interconnection Costs | | |
|---|---|---|---|---|
| | | Estimated | Approved in rate proceeding | |
| | | | Transmission Line Built out | Transmission upgrades |
| 138 | 0.024 | $7.00 | ($0.48)[1] | $0.01 |
| 138 | 0.1 | $3.11 | ($0.21)[1] | ($0.01)[1] |
| 345 | 0.21 | $1.28 | $1.24 | $0.00 |
| 138 | 0.5 | $0.00 | $0.00 | $0.00 |
| 138 | 0.15 | $0.38 | $0.38 | $0.00 |
| 138 | 0.17 | $2.26 | $1.68 | $0.59 |
| 138 | 0.81 | $1.87 | $1.87 | $0.00 |
| 138 | 0.00 | $0.00 | $0.00 | $0.00 |
| 138 | 0.03 | $2.01 | $1.42 | $0.59 |
| 138 | 0.30 | $3.68 | $2.01 | $1.66 |
| 138 | 0.50 | $0.00 | $0.00 | $0.00 |
| 138 | 0.20 | $2.90 | $2.16 | $0.74 |
| 138 | 0.40 | $6.63 | $0.91 | $5.72 |
| 138 | 0.70 | $2.12 | $1.70 | $0.42 |
| 138 | 0.50 | $4.06 | $2.05 | $2.02 |
| 138 | 0.10 | $1.33 | $1.33 | $0.00 |
| 138 | 0.00 | $0.00 | $0.00 | $0.00 |
| 138 | 1.00 | $4.07 | $1.71 | $2.36 |
| 138 | 15.72 | $34.60 | $20.54 | $14.06 |
| 69 | 0.40 | $0.00 | $0.00 | $0.00 |
| 138 | 0.00 | $3.39 | $0.97[2] | $2.42 |
| 138 | 1.67 | $11.62 | $11.62 | - |
| Total | | $92.32 | **$50.91** | **$30.58** |

Notes:1- Correction or reallocation of costs, 2- There was no new line buildout associated with this project but there were line costs associated with building a new point of delivery in an existing transmission line to provide service to the customer.

The 2023 interconnection costs above are already, or will be, included in wholesale transmission rates applicable to ratepayers across ERCOT, to be collected over a span of years. As of March 2024, the total wholesale transmission charges in ERCOT were approximately $5.6 billion per year. This represents an eight percent increase year-over-year. The aggregate effective annual ERCOT wide postage stamp transmission rate as of March 2024 was approximately $66.8 per kW.

# Appendices

- 88th Legislative Session PUCT Status Report -PowerPoint Presentation
- 87th Legislative Session PUCT Status Report -PowerPoint Presentation

See an up-to-date version of the Status Report here.

# Report on Transmission and Generation Capacity

**Responsive to Public Utility Regulatory Act § 39.9112 (House Bill 1500, 88R)**

December 31, 2024

## Introduction

House Bill (HB) 1500, enacted by the 88th Texas Legislature, Regular session (88R) and codified at Public Utility Regulatory Act (PURA) § 39.9112, requires the Public Utility Commission of Texas (PUCT or commission) and the Electricity Reliability Council of Texas (ERCOT) to study the need for increased transmission and generation capacity throughout the state and report to the legislature the results of the study and any recommendations for legislation.

The PUCT submits this report in compliance with HB 1500.

This report provides information about the need for increased transmission and generation capacity for both the ERCOT and non-ERCOT regions.

For the ERCOT region, this report summarizes the key findings from several of the ERCOT transmission planning and resource adequacy reports including, (i) the Regional Transmission Plan, 2024 which provides information about ERCOT transmission system needs for years 2026 through 2030; (ii) Constraints & Needs Report; (iii) biennial Long-term System Assessment (LTSA) which uses scenario-analysis techniques to assess the potential needs of the ERCOT transmission system up to 15 years into the future; (iv) the Permian Basin Reliability Plan (HB 5066, 88R) which addresses the increased need for transmission capacity to meet the growing future electricity needs of the Permian Basin region; (v) the Monthly Outlook on Resource Adequacy report which provides information about resource adequacy for the upcoming month; and (vi) Capacity, Demand and Reserves report which provides annual forecasted electricity demand, generation capacity and reserves for the ERCOT summer and winter peak load seasons. More details about these reports are provided later in the report.

For the non-ERCOT regions, this report presents information provided by non-ERCOT investor-owned utilities (IOUs), electricity cooperatives (Co-ops), and municipally owned utilities (MOUs). Additionally, the report includes analysis generated from responses to commission staff's informal requests for information and other resources, including resources from Regional Transmission Organizations, in which these non-ERCOT utilities are located.

# Transmission and Generation Planning

Regional Transmission Organizations (RTOs) are Federal Energy Regulatory Commission (FERC) regulated organizations that administer the transmission grid on a regional basis throughout North America and Canada. RTOs are responsible for ensuring reliable and adequate electric transmission network to meet system needs and to support load growth at a reasonable cost in their respective regions. There are three RTOs operating in Texas – ERCOT, Southwest Power Pool (SPP), and Midcontinent Independent System Operator (MISO). Additionally, the Western Electric Coordinating Council (WECC) is responsible for bulk electric system reliability in the El Paso region and oversees compliance monitoring and enforcement in the western interconnection.

In late 1990s, FERC took actions to increase competition in the interstate wholesale electricity markets and ensure there was no discrimination regarding access to the transmission systems by generators and loads. This new framework necessitated establishing RTOs. These organizations must be certified by FERC by meeting specific technical requirements to run the high-voltage transmission grid for transmission owners in their respective regions. RTOs are required to follow specific rules and standards for planning, operating, and maintaining the transmission network set by North American Electric Reliability Corporation (NERC). FERC has oversight over NERC.

While each state has the authority over resource adequacy, generation, and transmission siting, RTOs are responsible for ensuring that there are sufficient resources available to serve expected peak power demand. To maintain resource adequacy, RTOs use various methods to track and forecast available generation capacity, resource mix, potential capacity shortages, and expected demand. These methods are developed through extensive stakeholder processes. RTOs in the non-ERCOT regions, include representation from states in their respective footprints, and their resource adequacy plans are ultimately approved by FERC. These methods are specific to each RTO and explained later in this report.

# Summary of Findings

The commission summarizes the conclusions provided in this report below.

## A. Transmission Capacity

Transmission capacity of the bulk electric system is location-specific and cannot be calculated for an entire transmission grid. An electric utility's transmission infrastructure is comprised of elements that have varying capacities to transmit power across the system. The capacity of a given transmission line depends on factors such as physical ratings of equipment or stability related limits. PURA provides sufficient regulatory and policy guidance to ensure that the planning entities adequately address transmission capacity needs and that the commission address larger transmission plans and specific projects through timely, consumer-oriented procedures. Therefore, this report provides details about the transmission planning processes of three RTOs and one reliability entity that operate within Texas.

## B. Generation Capacity

Planning for sufficient generation capacity across the state does not follow a uniform process. In the SPP, MISO, and WECC areas of the state, generation capacity planning occurs through centralized and federally regulated procedures. The RTOs require electric utilities to maintain minimum levels of generation capacity and have developed economic and regulatory methods by which these capacities are procured. In ERCOT, however, generation capacity is driven primarily through market incentives. Investors assess whether and when to build new generation based on future potential to earn a sufficient return on their investment.

To gauge whether sufficient generation capacity exists in the state, the table below compares reported peak demand with available generation capacity. As of 2024, Texas had an electricity demand of over 100,000 MW and generation capacity of over 120,000 MW.

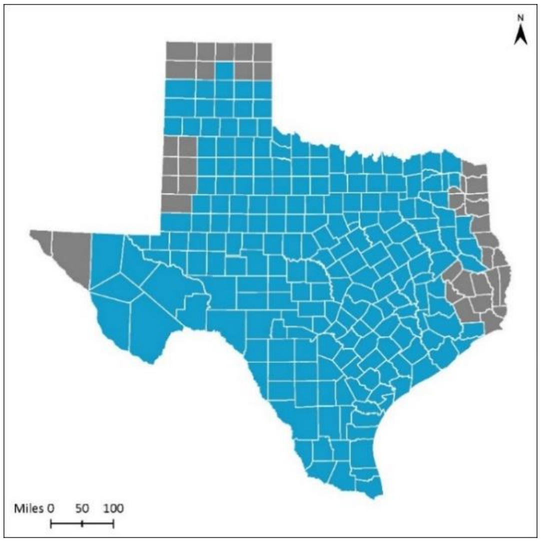
| Region | Peak Demand (MW) | Generation Capacity (MW) |
|---|---|---|
| ERCOT | 85,199[1] | 103,609 |
| Non-ERCOT* | 15,204 | 16,659 |
| Total | 100,403 | 120,268 |

Note: 1- August 20, 2024. * Aggregates only non-ERCOT IOUs data

The non-ERCOT IOUs provided estimated peak demand and generation capacity data for use in this report, and it is subject to revision according to their individual planning cycles. This data also does not include all the IOUs' bilateral trade agreements used to serve load and fulfill capacity requirements in non-ERCOT regions. Additionally, the non-ERCOT demand and capacity numbers in the table above exclude the total reported demand of approximately 2,900 MW and generation capacity of 3,700 MW from Golden Spread Electric Cooperative and East Texas Electric Cooperative to avoid double counting between the multiple power regions in which both cooperatives' service areas are located.

Available generation capacity in 2024 exceeded peak demand by about 20%. While this amount may suggest sufficient capacity exists statewide, those extra megawatts are not uniformly accessible by all consumers across the state due to limitations on electricity exports and imports across RTO boundaries. Moreover, and as the report will detail below, anticipated growth in demand for electricity may quickly outstrip these reserves, particularly as new commercial and industrial facilities can be built much more quickly than new generation can be installed. The commission's new reliability standard for the ERCOT region will help the state closely monitor generation capacity sufficiency and FERC standards will address any need for additional capacity in the non-ERCOT areas of the state.

# I. ERCOT Region




ERCOT Area in Texas

ERCOT is the RTO for the ERCOT power region within the state. ERCOT is the only RTO within the United States that is located wholly within the boundaries of the State of Texas.

ERCOT operates under the authority of the Public Utility Commission of Texas (PUCT). It manages the flow of electricity for 90% of the state and serves over 27 million electricity consumers in Texas and oversees more than 54,000 miles of transmission lines in the state.

## Transmission Planning Process

ERCOT supervises and exercises independent authority over the planning of transmission projects for the ERCOT system as outlined in the PURA and PUCT substantive rules. The commission's rules require ERCOT to evaluate and provide recommendations to the PUCT about the need for new transmission facilities. ERCOT examines the need for proposed transmission projects based on ERCOT planning criteria and NERC Reliability Standards. Once a project need has been identified, ERCOT evaluates project alternatives based on cost-effectiveness, long-term system needs, and other factors.

ERCOT conducts several extensive transmission planning studies in order to evaluate the need for increased transmission capacity: the Regional Transmission Plan, the Long-Term System Assessment, and the Constraints and Needs Report. Additionally, ERCOT has conducted other focused transmission studies like the Permian Basin Reliability Plan Study at the direction of the PUCT and the Texas Legislature. The following sections explain the purpose of these transmission studies and the process by which it evaluates the need for capacity and provide the key findings from the most recent reports conducted in 2024.

### *(i) Regional Transmission Plan (RTP)*

The RTP is performed by ERCOT annually and published in December of each year. The RTP addresses region-wide reliability and economic transmission needs. It includes the recommendations of specific planned improvements to meet those needs for the upcoming six years. Specifically, the scope of the RTP is to identify reliability needs and transmission upgrades and additions required to meet the system needs per criteria set in the ERCOT Planning Guide Sections 3 and 4 and the NERC TPL-001-05.1 Reliability Standard. Transmission Service Providers (TSPs) and other stakeholders in the ERCOT region review and provide input to the RTP. The 2024 RTP addresses ERCOT System transmission needs for years 2026 through 2030.

The reliability analysis was performed using a six-year planning horizon; years two through five representing the near-term horizon, and year six representing the long-term horizon. The reliability analyses in the 2024 RTP included:

- Steady-state contingency analysis to identify criteria violations based on NERC Reliability Standards and ERCOT planning criteria;
- Short-circuit analysis to identify circuit breakers that could fail to adequately protect the transmission system in the near-term planning horizon; and
- Cascading analysis to identify potential system cascading conditions.

Following the reliability assessment, and in collaboration with various TSPs, ERCOT developed Corrective Action Plans (CAPs) to address the reliability criteria violations identified in this assessment. These plans included, but were not limited to, upgrades or additions of new transmission facilities and new Constraint Management Plans.

#### Transmission Needs Driven by Load Growth

The ERCOT System is experiencing rapid changes, including trends of notable growth in demand and penetration of intermittent generation resources. In the ERCOT region, peak demand for the year 2024 was set on August 20, 2024 at 85,199 MW. This trend of rising demand is expected to continue, driven by factors such as further electrification of oil and gas processes in the Permian Basin and continued interest in connecting large loads to the ERCOT System. Sufficient transmission capacity plays a key role in ensuring system reliability while meeting the rapid growth in demand. While transmission typically requires from three to five years to be developed and energized, electricity demand is increasing at a faster pace.

Recognizing that the transmission infrastructure is not able to keep pace with the demand growth, the Texas Legislature enacted SB 1281 (87R) and HB 5066 (88R) that revised ERCOT's method to forecast future demand to include historical load, forecasted load growth, and additional load currently seeking interconnection, to give greater visibility of expected load. The Texas Legislature also enacted SB 1076 (88R) to speed up the regulatory approval process for electric utilities seeking to build new transmission infrastructure.

These new requirements combined with broad economic growth across the state led to a significant increase in the number of large loads, such as data centers, hydrogen and hydrogen-related manufacturing, and crypto mines being included in the 2024 RTP. The forecasted summer peak demand for 2030 exceeds 150 GW, of which approximately 50 GW is due to large loads. Close to 40 GW of that forecasted large load demand is related to the new rules permitting inclusion of additional, forecasted demand in the RTP without requiring the load to present an executed interconnection agreement.

While the new rules allow for the consideration of more load in the planning processes, the policy governing the inclusion of planned generation resources in the planning models remains unchanged. Currently, planned generation resources can only be added to the planning models when they meet the requirements established in paragraph (1) of the ERCOT Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models. Under this rule, the total available generation was less than 120 GW in the 2030 summer peak case, based on the 2024 RTP renewable and battery dispatch assumptions. This indicated a supply deficit of more than 30 GW to meet the demand. Additional steps outside of the current planning practices are needed to create planning models capable of accommodating the unprecedented load growth. To achieve balance between supply and demand, ERCOT incorporated generators that have not yet met the Planning Guide Section 6.9 requirements into the planning models and presented the assumptions at the May 2024 Regional Planning Group meeting. ERCOT is currently developing a Planning Guide Revision Request to adjust the criteria for adding generation resources to the planning models and will initiate stakeholder discussions on this topic in 2025.

In addition to the magnitude of the load growth, the constant manner by which large loads use electricity adds another layer of complexity to the assessment of whether sufficient generation exists or is planned to meet future demand requirements. Most of the large loads seeking interconnection are expected to maintain consistent electricity consumption regardless of season, day, or time. Ensuring reliable interconnection for these loads requires a generation resource mix capable of supporting their 24/7 electricity demand.

### *(ii) Constraints & Needs Report*

ERCOT's annual Constraints & Needs Report[1] identifies and analyzes existing and potential constraints on the transmission system.[2] The report noted the development of the Permian Basin Reliability Plan Study, the 2024 RTP, and concluded that the ERCOT System continues to evolve with significant load growth, increased thermal generation retirement, rapid growth in transmission-connected wind, solar and energy storage development, and distributed generation. Further, the 2024 Constraints & Needs Report noted that ERCOT is critically evaluating planning processes and pursuing changes necessary to meet challenges associated with the evolving grid. The report evaluated the top 10 constraints on the ERCOT system from October 2023 to November 2024, as well as the top 10 projected constraints on the ERCOT system for 2026 and 2029, which is based on economic analysis conducted for the 2024 RTP.

Constraints & Needs Report key findings are:

- ERCOT continues to experience a rapid shift in the type and location of generation available to serve demand.
- The change in generation mix has resulted in increased distance between generation sites and demand centers. Historically, coal and gas generation typically sited closer to large cities, whereas the most abundant wind and solar rich regions tend to be in more distant locations.
- Robust growth of inverter-based resources (IBR) continues with over 102 GW of transmission-connected wind, solar, and battery energy storage capacity that is expected to be installed by the end of 2025. Total IBR capacity has the potential to exceed 140 GW in 2027.

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[1] *See* ERCOT Report on Existing and Potential Electric System Constraints and Needs, December 2024. Last found at https://www.ercot.com/files/docs/2024/12/20/2024-report-on-existing-and-potential-electric-system-constraints-and-needs.pdf, (Dec. 31, 2024).
[2] *See* PURA § 39.166(b)(1) and 16 Texas Administrative Code § 25.362(i)(2)(I) and § 25.505(c).

- Coal and natural gas generation continues to retire with over 7,300 MW retired since 2018.
- ERCOT continues to improve distributed generation (DG) integration processes as DG penetration steadily increases.

### *(iii) Long-Term System Assessment (LTSA)*

ERCOT conducts the LTSA on a biennial basis every even-numbered year. The LTSA uses scenario-analysis techniques to assess the potential needs of the ERCOT system up to 15 years into the future. ERCOT conducted capacity expansion and retirement analyses for each of the following three future scenarios:

I. Current Trends,
II. High Large Load Adoption, and
III. High Load Growth and Environmental Regulations.

The role of the LTSA is to guide near-term planning decisions by providing a longer-term view of system reliability and economic needs.

The 2024 RTP forecasted unprecedented load growth due to continued interest in connecting large loads to the ERCOT system. The potential for this growth prompted discussions about introducing 765-kV facilities to the ERCOT transmission grid.

While incremental transmission improvements may appear to satisfy the RTP's six-year planning horizon, the LTSA's longer planning horizon typically reveals whether a more extensive project could be needed. A larger project may also be more cost-effective than multiple smaller projects—each being recommended in successive RTPs.

ERCOT studies different scenarios in its long-term planning process to account for the inherent uncertainty of planning the system beyond six years. The goal of using a variety of scenarios in the LTSA is to identify transmission upgrades that are robust across a range of potential outcomes or more economical than the upgrades that would be determined considering only near-term needs.

The ERCOT region is forecasted to experience tremendous electric demand growth in the next five to seven years, which drives the need for ERCOT to adapt and plan differently for the future. ERCOT's new planning approach focuses on ensuring all areas of system planning—from generation development and load interconnections to transmission plan development—can adapt to better serve the needs of the rapidly growing Texas economy. The 2024 LTSA provides insights on these new challenges the ERCOT region is experiencing.

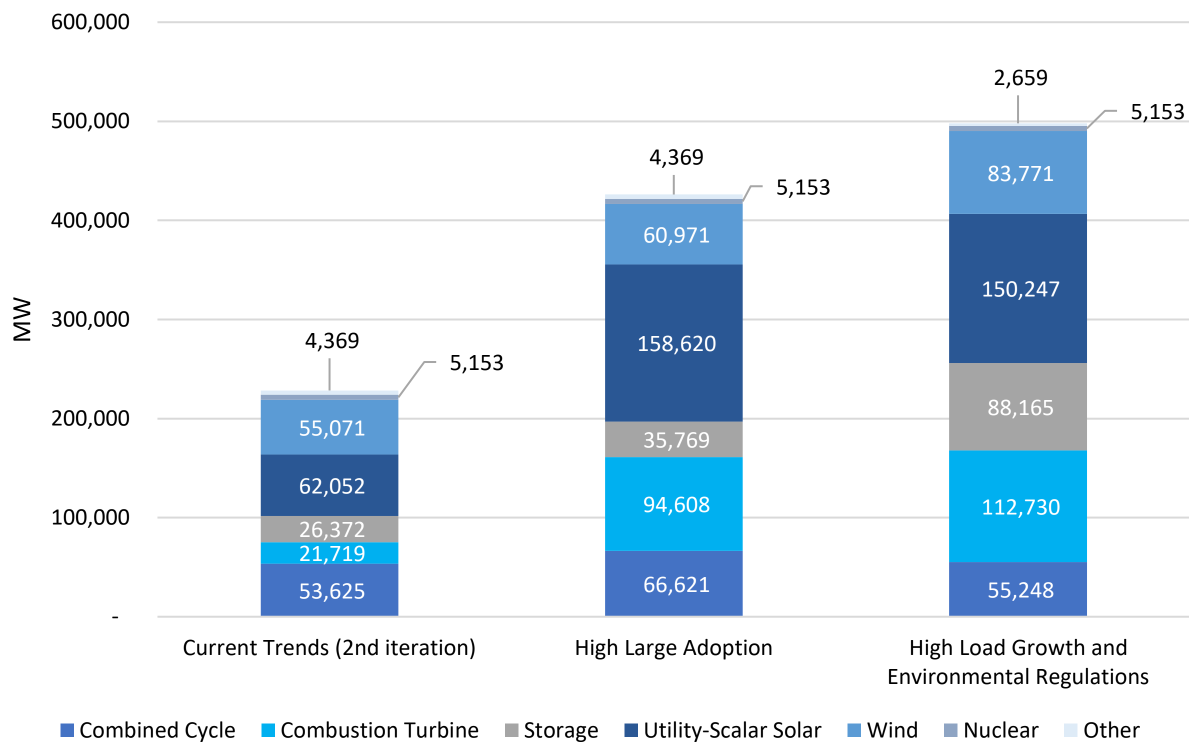
### LTSA Planning Process

Planning for transmission 10 and 15 years into the future requires ERCOT to make assumptions about the types of new resources that may be developed. As a biennial process, the 2024 LTSA study started in 2023 and used the 2023 RTP final reliability cases as the base case to develop the LTSA study cases for years 2034 and 2039. It did not incorporate the additional large loads included in the 2024 RTP because the reliability projects needed to support large load additions were not available at the time the 2024 LTSA was initiated in 2023. As a result, neither 2024 unprecedented load growth nor the associated 345-kV plan or the 765-kV plan from the 2024 RTP was included in the final study cases developed for the 2024 LTSA. Development of the 2026 LTSA will begin in 2025, which will use the 2024 RTP final reliability cases as the base case. The 2026 LTSA will incorporate the transmission needs evaluation if the commission decides to introduce 765-kV facilities into the ERCOT region.

LTSA report key findings are:

- Significant growth in wind, solar, natural gas, and battery energy storage resource types was found across all scenarios. These resources would replace retired coal and natural gas generation capacity to meet rising demand.
- Renewable resources were found to constitute a large portion of available capacity across all scenarios, introducing elevated operational risks due to the resources' intermittent output.
- Battery energy storage and combustion turbines resources were found to be critical in managing increased net load ramping challenges.
- The scale and geographic distribution of wind and solar generation additions depend on sufficient transmission capacity between resource-rich regions and demand centers.
- Transmission challenges were identified for both the export from the renewable-resource-rich regions and the import into the demand centers.

In all three scenarios, a mix of solar, wind, natural gas, and battery energy storage resource types was projected to be added to the system to serve growing demand and replace retired capacity. The chart below shows nameplate capacities in ERCOT projected in the year 2039 under three future scenarios. A significant increase is projected in net total solar capacity that ranged from 62,052 MW to 158,620 MW, and net total battery capacity that ranged from 26,372 MW to 88,165 MW under various scenarios. Conversely, more than 25,000 MW of existing coal and natural gas capacity was projected to retire by 2039 in all scenarios, although the timing of specific retirements varied.




Renewable resources were projected to comprise a large portion of the resource capacity to serve the demand across all three scenarios. This resource mix change would introduce elevated operational risks. Thermal and stability constraints on the transmission system, as well as operational considerations such as ramping limitations and minimum system inertia needs, are to be assessed further to ensure reliability under a high renewable penetration outcome. The study results showed a significant increase in the ramping needs across all scenarios, driven primarily by the amount of new solar generation that is projected to be added. Notably, scarcity hours in the summer will likely shift to later in the day, similar to results reported in previous LTSAs. However, stressed system conditions were observed at various times of day and in various days throughout the year. As renewable penetration on the ERCOT system continues to increase, possible system conditions outside of summer peak, including peak net load and winter peak conditions, are to be included in planning studies.

The increased development of battery energy storage and combustion turbines became increasingly important in managing the increased variability in generation and demand. The storage resources will be likely to charge when low-cost, surplus renewable generation is available and to discharge during peak net load periods, providing fast response ramping services. Traditionally, combustion turbines operate only during a limited number of hours each year. However, in both the High Large Load Adoption and the High Load Growth and Environmental Regulations scenarios, combustion turbines were required to be online more frequently, especially during night hours, to compensate for the rapid changes in net load.

Capacity expansion and retirement provided insight into the potential impacts of transmission limitations on new generation development. The inclusion of transmission constraints in capacity expansion and retirement analyses led to a shift of wind and solar resources away from the resource-rich regions in West and North Texas to areas closer to major demand centers. The primary cause of this shift was the inclusion of the West Texas Export and Panhandle interface limits, which were binding constraints during many hours. Transmission challenges were identified for both the export from the renewable-resource-rich regions and the import into the demand centers.

### *(iv) Permian Basin Reliability Plan Study*

On December 14, 2023, the commission issued an order[3] directing ERCOT to develop a reliability plan for the Permian Basin region. The order required ERCOT to submit the plan to the PUCT.

On July 25, 2024, ERCOT filed the completed Permian Basin Reliability Plan Study Report to identify the transmission needs and the transmission upgrades required to meet the forecasted electric demand in the Permian Basin region.

The Permian Basin Reliability Plan Study assessed transmission needs utilizing the S&P Global Permian Basin load forecast through 2038 and additional non-oil and gas load forecasts provided by the TDSPs serving loads in the Permian Basin region. The forecasts showed that, by 2030, transmission and distribution service providers (TDSPs) anticipate approximately 24 GW of load in the region, including 12 GW of oil-

[3] Project No. 55718 AIS Item 7

and-gas-related load and another 12 GW of additional load primarily attributable to data centers, crypto-mining, and hydrogen electrolysis facilities.

The study identified transmission upgrades necessary to reliably serve the projected loads in the Permian Basin region. The report proposed transmission upgrades that are categorized as local transmission upgrades and import paths. It also identified the need for projected load growth in 2030 and 2038 using three different import paths consisting of 345-kV import paths, 500-kV Extra-High Voltage (EHV) import paths, and 765-kV EHV import paths. Based on cost information received from TDSPs as well as publicly available data sources, ERCOT has initially estimated that, depending on the option selected by the commission, the total cost of the needed transmission facilities could range between $12.95 billion to $15.32 billion.

On October 5, 2024, the commission approved the Reliability Plan for the Permian Basin Region.[4] This order included approval of all the common local projects that are required to serve the region through 2038.

## Generation Capacity

ERCOT conducts several studies to evaluate the need for generation capacity on the system in its assessment of resource adequacy.[5] As the RTO, ERCOT does not own generation, nor does it have the authority to direct new build of generation. Therefore, these assessments are critical in assisting policymakers in their evaluation of resource adequacy, as well as informing market participants of the current and expected generation build-out on the system.

### *(v) Monthly Outlook on Resource Adequacy (MORA)*

The MORA report is a monthly outlook that serves as an early indicator of the hour-by-hour risk that ERCOT may need to issue an Energy Emergency Alert (EEA) or call for controlled outages to maintain grid reliability for the reporting month. The MORA report uses probability-based modeling to determine the likelihood that ERCOT will have insufficient operating reserves during monthly peak electric demand periods. The report also includes scenarios to show demand and resource availability for selected hours based on expected adverse grid conditions, focusing on low wind generation

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[4] Project 55718 AIS Item 52

[5] *See* ERCOT Resource Adequacy Reports. Last found at https://www.ercot.com/gridinfo/resource (Dec. 31, 2024).

and severe winter storm impacts. ERCOT uses the probabilistic MORA model, in consultation with the commission, to support seasonal capacity request for proposals (RFPs) to shore up shorter-term resource adequacy needs.

For calendar year 2024 and winter months January and February 2025, the MORA reports indicated that the risk of ERCOT declaring EEAs is less than 10% for each hour of the monthly peak load day. For the non-winter months, the hourly risk is concentrated in the early evening hours due to the ramping down of solar generation. For the winter months, the risk appears in the morning hours just before and during sunrise. A secondary hourly risk occurs in the early evening hours due to higher heating loads and minimal solar generation. Over the course of 2024, there has been a small EEA risk covering more hours of the day due to the addition of large loads, such as data centers, whose electricity consumption remains steady throughout the day.

### *(vi) Capacity, Demand and Reserves (CDR) Report*

ERCOT publishes the CDR Report twice a year, in May and December, for the purpose of evaluating forecasted planning reserve margins for the ERCOT summer peak load seasons from June through September, and winter peak load season from December through February for the following year. Specifically, the planning reserve margin represents the percentage of resource capacity, in excess of firm electricity demand, available to cover uncertainty in future demand, generator availability, and new resource supply. Firm demand accounts for load reductions available through interruptible load programs controlled by ERCOT as well as incremental load reductions from rooftop solar systems not accounted for in the load forecast model. The methodologies used to develop planning reserve margins and other elements of the CDR report are outlined in the ERCOT Nodal Protocols, Section 3.2.6. Major revisions to the CDR preparation methodologies were approved by the commission as part of Nodal Protocol Revision Request 1219.[6] Forthcoming CDR reports will reflect these revisions.

ERCOT's load forecasts are based on normal weather conditions and determined by publicly posted load forecast methodologies. Resource data comes from generation capacity developers and owners as reported in ERCOT's Resource Integration and

[6] *See* generally ERCOT Nodal Protocol Revision Request number 1219 (Adopted September 2024). Last found at https://www.ercot.com/mktrules/issues/NPRR1219.

Ongoing Operations (RIOO) system, as well as other data collection mechanisms described in the ERCOT Protocols. The CDR is not intended for characterizing the risk of capacity scarcity conditions from a real-time operations perspective.

CDR May 2024 Report key findings are:

### *Load and Resources*

Peak Load Forecast

- The forecasted base peak demand for summer 2025 is 84,754 MW and does not account for new contracted loads recently reported by TSPs to ERCOT. When accounting for the newly contracted loads, the peak load forecast increases to 90,336 MW. The summer peak demand forecast assumes that Large Flexible Loads (LFLs) will reduce their consumption to just 15% of their summer peak load hours. It is important to note that the peak demand forecast used in the CDR is based on weather conditions over the last 15 years, which explains why the base forecast for summer 2025 is lower than the actual summer peak load of 85,508 MW for 2023. Summer 2023 was the second hottest summer on record, only exceeded by 2011.
- The firm summer 2025 peak demand is 80,639 MW, which accounts for incremental rooftop solar generation and load reduction programs. The firm peak demand increases to 86,221 MW when including the new contracted loads reported by TSPs. By summer of 2029, the forecasted firm peak demand with new contracted loads is expected to reach 103,713 MW. The winter 2025-26 base peak demand forecast is 73,710 MW.
- The winter load forecast assumes that LFLs do not reduce their consumption during the winter peak load hours. To conform to the current ERCOT Protocols, ERCOT assumes LFLs will reduce consumption based on the real-time cost of electricity; however, it is assumed that LFL consumption during summer peak loads is not available as a Load Resource during potential emergency conditions. This is an interim accounting approach until ERCOT implements a forecast methodology for addressing Large Loads in the CDR report. ERCOT also continues with the policy of not identifying the generating units with co-located Large Loads in the CDR reports until formal reporting rules have been adopted.

Resources

- Total resource capacity available at the time of the summer 2025 peak load hour is forecasted at 115,596 MW. Planned new installed resource capacity expected by summer 2025 totals 29,357 MW.
- At the time the May CDR was prepared, ERCOT Protocols did not include a methodology for determining the peak-average capacity contribution of battery storage. Therefore, the contribution in the May 2024 CDR is reported as zero MW. Protocols now include a methodology for estimating the capacity contribution of battery storage systems. For the May CDR, ERCOT developed an interim capacity contribution methodology to show the impact on reserve margins. The summer 2025 capacity contribution percentage based on the interim method is 31% for the peak load hour. Applying this percentage to the summer 2025 forecasted storage capacity yields a capacity contribution of 5,029 MW. The inclusion of this storage contribution increases the summer 2025 Reserve Margin from 46.0% to 52.4%.

Significant Resource Status Changes

- Notifications of Suspension of Operations (NSOs) were received for three gas-steam units totaling 885 MW of installed capacity, with an indefinite suspension of operations beginning March 31, 2025. [7] ERCOT's reliability analysis determined that these generation resources are needed to support ERCOT system reliability. For the CDR report, these units are reported as being available for the forecast period.

Planning Reserve Margins

- The planning reserve margin for summer 2025 is forecasted to be 43.4%, representing a 3.4 percentage point decrease relative to the 46.7% margin reported in the December 2023 CDR report. This decrease is mainly due to delays of planned projects—mostly solar—that were previously expected to be in service by July 1, 2025. When including new contracted loads, the reserve margin drops to 35.2%. The reserve margin rises to 54.4% for summer 2026, reflecting the addition of planned solar capacity previously delayed to 2026.

[7] *See* generally ERCOT market rules. Last found at https://www.ercot.com/services/comm/mkt_notices/M-C031324-11.

With new contracted loads, the summer 2026 reserve margin drops to 38.2%. By summer 2029, the reserve margins without and with new contracted loads are 60.0% and 27.6%, respectively.

New Non-contracted Loads Reported by TSPs

- Based on HB 5066 (88R), ERCOT modified its transmission planning criteria to include certain forecasted loads without signed interconnection agreements. To show the respective reserve margin impacts of both updated contracted load growth and new prospective non-contracted load growth reported by the TSPs (for years 2025-29), the summer and winter evaluation reports these load forecast components and the associated cumulative reserve margin impacts. For this CDR report, the non-contracted load forecast is considered a forecast scenario given the greater uncertainty in the magnitude and timing of these loads relative to the contracted loads.
- This CDR report also includes new supplemental data that shows the total load forecast with all new contracted and non-contracted loads for the entire 10-year forecast period along with 90th percentile values to provide a reasonable upper bound on load forecast expectations.

The U.S. Environmental Protection Agency's (EPA) Final Green House Gas Emissions Rule for Fossil-Fueled-Fired Power Plants

- On April 25, 2024, the EPA issued its final rule on Greenhouse Gas (GHG) emission performance standards and emission guidelines for existing coal-fired and new gas-fired power plants. The GHG rule will be phased in over time, with specific requirements dependent on the type of technology (coal-fired versus combustion turbine), duty cycle for combustion turbines (base, intermediate and peaking) and the expected remaining lifespan of coal-fired units.
- This CDR report does not account for potential changes to coal unit retirement and natural gas unit investment plans resulting from rule compliance. The rule has been challenged in federal court.

### *Reliability Assessment*

The commission's substantive rule 16 TAC § 25.508 requires ERCOT to initiate an assessment to determine whether the bulk power system for the ERCOT region is meeting the reliability standard and is likely to continue to meet the reliability standard for three years following the date of the assessment. The commission's rule requires that this assessment be conducted at least once every three years, with the first assessment due to be initiated by ERCOT beginning January 1, 2026.

Before conducting the assessment, ERCOT is to file a comprehensive list of proposed modeling assumptions to be used in the reliability assessment, and these assumptions must include the number of historic weather years used in the model, the amount of new resources and retirements by resource type, the weatherization effectiveness, and other assumptions that would impact the modeling assumptions. The assessment will include review and analysis of the resource fleet, loads, and other system characteristics for the current year and three years out and will be filed with the commission when complete for its review in assessing the need for generation capacity in the ERCOT region. The rule also requires stakeholder feedback during the assessment process.

# II. Outside ERCOT Power Region

Outside the ERCOT region, IOUs, electric cooperatives, and MOUs are responsible for assessing the need for increased transmission and generation capacity to meet the demand in their respective service areas. All entities outside the ERCOT power region are vertically integrated, which means that they own and operate generation, transmission and distribution infrastructure, and provide retail electricity to the end-use consumers. The IOUs include Entergy Texas, Inc. (Entergy), which serves Southeast Texas; Southwestern Electric Power Company (SWEPCO), which serves Northeast Texas; El Paso Electric Company (EPE), which serves the El Paso area; and Southwestern Public Service Company (SPS, also known as Xcel Energy), which serves the Panhandle region. Together, these IOUs serve more than 1.3 million consumers.

Three electric cooperatives - Golden Spread Electric Cooperative (GSEC), East Texas Electric Cooperative (ETEC), and Northeast Texas Electric Cooperative (NTEC) which represent several smaller electric distribution co-ops, operate and serve in the non-ERCOT region of Texas and participate in generation and transmission planning in their respective regional transmission organizations (RTO), as applicable.

## East Texas Electric Cooperative Members

1. Cherokee County Electric Cooperative
2. Deep East Texas Electric Cooperative
3. Houston County Electric Cooperative
4. Jasper-Newton Electric Cooperative
5. Northeast Texas Electric Cooperative
6. Rusk County Electric Cooperative
7. Sam Houston Electric Cooperative
8. Wood County Electric Cooperative

## Golden Spread Electric Cooperative Members

1. Bailey County Electric Cooperative
2. Big Country Electric Cooperative
3. Coleman County Electric Cooperative
4. Concho Valley Electric Cooperative
5. Deaf Smith Electric Cooperative
6. Greenbelt Electric Cooperative
7. Lamb County Electric Cooperative
8. Lighthouse Electric Cooperative
9. Lyntegar Electric Cooperative
10. North Plains Electric Cooperative
11. Rita Blanca Electric Cooperative
12. South Plains Electric Cooperative
13. Southwest Texas Electric Cooperative
14. Swisher Electric Cooperative
15. Taylor Electric Cooperative

## Northeast Texas Electric Cooperative Members

1. Panola-Harrison County
2. Upshur Rural Electric
3. Bowie-Cass Electric
4. Deep East Texas Electric
5. Wood County Electric
6. Rusk County Electric

**Municipally Owned Utilities**

1. Brownfield (SPP)
2. Caldwell (MISO)
3. Electra (SPP)
4. Floydada (SPP)
5. Hemphill (MISO)
6. Jasper (MISO)
7. Kirbyville (MISO)
8. Liberty (MISO)
9. Livingston (MISO)
10. Newton (MISO)
11. San Augustine (MISO)
12. Timpson (MISO)
13. Tulia (SPP)

13 municipally owned utilities operate in the non-ERCOT region. These MOUs do not own the threshold amount of generation or transmission assets to participate in regional or RTO-wide transmission planning.

For managing both transmission and generation capacity needs, non-ERCOT entities (IOUs, Co-ops, and MOUs) either directly or indirectly participate in organized markets run by RTOs or independent system operators (ISO). MOUs typically have electric service agreements with IOUs, e.g. the City of Brownfield has an electric service agreement with AEP. The IOUs include in their forecasted load growth the MOUs they serve and consider the MOUs' load impacts on reliability constraints and need for transmission and generation capacity in their own transmission and generation expansion plans that they submit to the RTOs within which they operate.

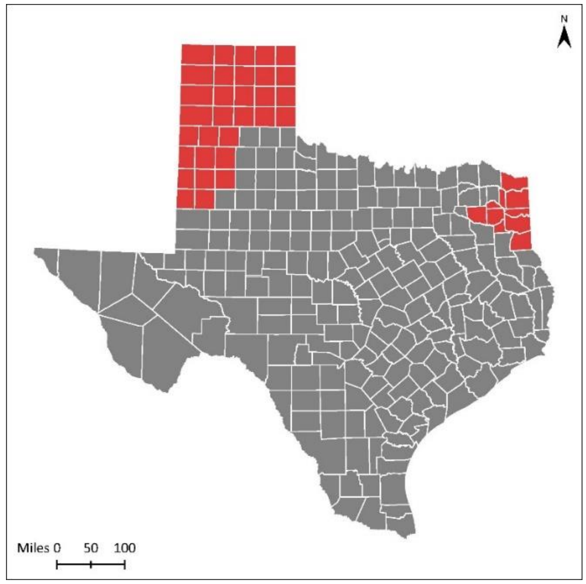
The table below provides electricity demand and generation capacity as of 2024 of the four IOUs operating in the non-ERCOT region.

| Non-ERCOT IOUs | Peak Demand (MW) | Generation Capacity (MW) |
|---|---|---|
| SPS | 4,458 | 5,393 |
| Entergy | 4,072 | 3,955 |
| SWEPCO | 4,886 | 4,920 |
| El Paso Electric | 1,788 | 2,391 |
| Total | 15,204 | 16,659 |

Note: The data in the table is subject to revision according to their individual planning cycles of each IOU. Additionally, the data does not include all the IOUs' bilateral trade agreements used to serve load and fulfill capacity requirements in non-ERCOT regions.

## Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) is the FERC authorized RTO for areas of Northeast Texas and the Texas Panhandle. 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 investor-owned utilities SWEPCO and SPS, several electric cooperatives, and various MOUs. The PUCT participates in SPP meetings to ensure fair treatment of Texas consumers. The SPP's Regional State Committee (RSC) consists of one commissioner per state in the region. The RSC is the decision-making authority at SPP on issues such as the allocation of costs for transmission upgrades, the allocation of financial transmission rights, and generation resource adequacy.




**Southwest Power Pool (SPP) Area in Texas**

IOUs, Co-ops, and MOUs provide electric service using the transmission system owned by individual utilities but planned, managed, and operated by SPP.

### Transmission Planning Process

SPP uses the Integrated Transmission Planning (ITP) model, which is an annual process to assess the near and long term economic and reliability needs for the transmission system in its entire footprint over a 10-year horizon. This annual assessment combines near term, 10 year and NERC planning assessments related to transmission expansion requirements.

Every five years, the ITP also provides a 20-year assessment that assesses the transmission expansion needs and targets a reasonable balance between long-term transmission investments and congestion costs to customers.

Stakeholders participate in the SPP transmission planning processes. SPP staff and market participants provide details such as forecasted load growth, reliability constraints, and generation resource changes to inform the need for increased transmission capacity within the region.

To determine the long-term transmission capacity need over a 10-year planning horizon, the SPP divides its footprint into six study zones. The Load Responsible Entities (LRE) within each study zone develop and submit a combined zonal load forecast that feeds into the ITP model. Each LRE is responsible for ensuring that there is sufficient generation capacity to meet its peak load plus its winter and summer reserve margin requirements. SPP applies both regional criteria and local or zonal planning criteria to determine when the system performance is inadequate and thus upgrades are needed. When these analyses identify a need for increased transmission capacity, projects are proposed to address the issue. The proposed projects are evaluated by the SPP planning staff in coordination with transmission owners and projects which are found to best address the issue are approved for construction.

SPS and SWEPCO submit their individual analyses that consider system operability and reliability, applicable regulatory requirements, and both short- and long-term least-cost impacts to their respective customers, while balancing the ability to deliver the expected level of service. SWEPCO, does not currently have any planned transmission projects in Texas. SWEPCO has approximately 2,152 miles of transmission lines, majority of which are 138 kV.

As an LRE in the SPP, GSEC also submits load forecasts on behalf of its members. However, neither GSEC nor its members perform separate studies to evaluate the need for increased transmission capacity.

GSEC relies upon the SPP transmission planning processes and transmission owners in the region to adequately evaluate and plan for the reliability of the transmission system and the sufficiency of available transmission capacity.

There is a distinction between networked and non-networked transmission facilities. This distinction impacts transmission planning. While GSEC is a transmission customer in the SPP and arranges network transmission service from transmission owners in the region to deliver power to its members, there are transmission lines required beyond the SPP network system to reach member consumers. These transmission lines are owned by GSEC members and are electrically interconnected with the SPP grid. These facilities, however, are radially connected to the SPP network transmission system, and are not considered SPP facilities. Consequently, these transmission facilities are not incorporated into the SPP planning processes.

A large portion of GSEC's load in SPP takes transmission service from SPS. SPS provides network integrated transmission service to several GSEC member delivery points at the end of the SPP transmission network. Then, member-owned radial transmission lines further carry the power to member consumers or retail customers.

GSEC as a transmission customer does not have visibility into the transmission capacity currently installed or projected to be installed on the grid in the future. As a transmission owner and the transmission provider, SPS compiles this information.

Co-ops ETEC and NTEC jointly participate in the planning processes of the SPP. Similar to GSEC and other IOUs, ETEC and NTEC provide their expected future peak loads and resources for the planning models used by the SPP. The SPP performs a variety of analyses, including power flow, stability, and short circuit analysis across the planning horizon.

ETEC, ETEC's members, and NTEC's members mostly own 138kV transmission lines. NTEC does not own any transmission lines.

## Generation Capacity

Unlike ERCOT, the SPP has a capacity requirement which obligates all Load Serving Entities (LSEs), which are entities that are responsible for supplying electricity to end consumers, to have access to enough generating capacity to serve their peak consumption, also known as Resource Adequacy Requirement (RAR). As part of this process, all entities submit to the SPP an annual load forecast that represents expected peak demand from their customers. The SPP integrates these load forecasts into its Loss of Load Expectation (LOLE) study to evaluate system-wide capacity and reliability requirements across the SPP footprint.

Based on the results of the LOLE study, SPP establishes a planning reserve margin, expressed as a percentage, which in turn defines the annual RAR that each LSE must meet on a seasonal basis for both winter and summer periods.

The RAR is calculated as the annual load forecast plus the applicable planning reserve margin. Currently, SPP's projected summer planning reserve margin ranges from 15% to 17%, while the winter planning reserve margin ranges from 36% to 38%.

SPS and SWEPCO develop an Integrated Resource Plan (IRP) to help assess future generation capacity needs. SPS's IRP is based on the best information available at the time of submission, stakeholder input, reasonable assumptions that could be useful in evaluating long-term system resource projects. Such information includes the IOU's studies, forecasts, and regulatory predictions and is combined with historical data, existing and potential resource capabilities, and generic costs associated with alternative generation resource expansion plans. However, the plan can be adjusted as new information and technologies evolve over the planning period.

By 2030, SPS estimates a capacity shortfall of over 3,100 MW to serve an estimated peak demand of 6,325 MW in Texas.

SWEPCO does not prepare state-specific generation resource planning. However, SWEPCO's most recently issued IRP, filed in Louisiana, includes a planning analysis for the entirety of SWEPCO's service area including Texas. Nearly 35% – 40% of SWEPCO's load is in Texas. By 2030, SWEPCO may have a capacity shortfall of over 800 MW for the Texas region. Though the IOU can draw on generation capacity provided by other SPP-interconnected entities to serve this potential gap, SWEPCO may seek to add to its existing resource fleet over the long run.

The cooperatives of ETEC and NTEC coordinate generation planning requirements. NTEC's generation needs are generally met through wholesale power agreements with ETEC and SWEPCO. Specifically, over the past two years, ETEC has conducted an IRP for its member systems which align with SPS's and SWEPCO's IRP processes to help assess generation capacity. By 2030, ETEC estimates a load requirement of over 2,000 MW for its entire service area, which is located in the SPP, MISO, and ERCOT regions. ETEC's cumulative winter resources through 2030 totaled to 1575MW.

ETEC's IRP results showed that diversity in the technology associated with generation provided pricing stability for its customers. The results also showed natural gas is needed to be the primary generation choice because of the capacity resource requirements of both the MISO and SPP markets. ETEC is a winter peaking cooperative and the winter capacity accreditation for solar and battery energy storage systems (BESS) is low. Wind is not a viable option for ETEC due to poor wind conditions in East Texas and the congestion risk from the wind-rich zones is high. To achieve the accredited capacity requirement, ETEC is planning to buy or build a combined solar and BESS resource.

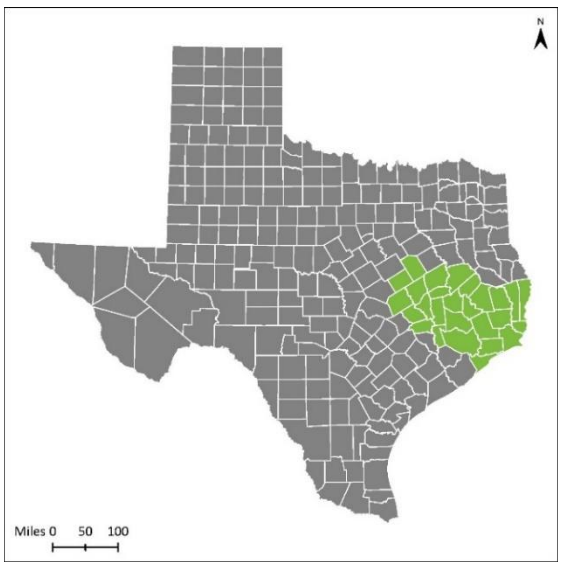
GSEC's resource planning process is guided by SPP's resource adequacy requirements, with the planning reserve margin serving as the primary determinant. For the 2025 planning year, and like all LREs, GSEC is to procure 100% of its forecasted peak load capacity, supplemented by an additional 15% to satisfy the planning reserve margin.

GSEC accounts for potential future increases in SPP's planning reserve margin and the anticipated impact of greater renewable energy integration in its long-term resource planning strategies. SPP's biennial LOLE study may also result in adjustments to capacity.

The SPP is considering significant changes in capacity accreditation methodologies in future. The proposed Performance-Based Accreditation (PBA) methodology has the potential to reduce the "accreditation" of resource capacity based, in part, on the historic performance of thermal resources. This approach will adjust the accredited capacity of thermal generators, reducing their contributions based on forced outage rates and ensuring a more accurate reflection of their availability and reliability. Future increases in the planning reserve margin are expected by market participants, alongside continued growth in renewable energy penetration. Increased renewable resources in SPP are expected to influence the accreditation of renewable resources within a resource portfolio, requiring strategic adjustments to ensure compliance and reliability.

The capacity accredited to GSEC's resource portfolio for planning year 2026 could decline driven by the implementation of SPP's PBA. By 2030, GSEC may have a capacity shortfall of over 150 MW for its service area located in both the ERCOT and SPP regions.

## Midcontinent Independent System Operator (MISO)




MISO Area in Texas

MISO is the largest RTO in North America, serving all or part of 15 states in the central United States and the Canadian province of Manitoba. The eastern portion of Texas, served primarily by Entergy Texas, Inc. (Entergy), is part of MISO footprint. FERC has regulatory authority over wholesale power transactions and transmission rates and approves the MISO Tariff, which includes rules pertaining to transmission planning, resource adequacy, and energy market design. The MISO Tariff establishes the rules for how MISO market participants like Entergy operate. Changes to the MISO Tariff can have significant cost and reliability implications for Texas ratepayers in the Entergy footprint.

## Transmission Planning Process

MISO evaluates near-term and long-term transmission needs to ensure a reliable and economic electric infrastructure for the MISO region over a span of 10 and 20 years. The annual MISO Transmission Expansion Plan (MTEP) identifies transmission projects needed for local, regional, and interregional reliability over a 10-year period. MISO also assesses its transmission needs in Long-Range Transmission Planning (LRTP) that spans over a period of 20 years. In December 2024, MISO approved the second phase of LRTP that develops a 3,631-mile 765 kV capacity transmission lines. Projects in the LRTP are targeted to go in service from 2032 to 2034.

MISO performs a variety of analyses, across different planning horizons. Regional and local or zonal planning criteria are applied to determine if the system performance is inadequate and if upgrades are needed. As part of this process, MISO reviews projects submitted by transmission owners that address local reliability issues, aging equipment, load growth, generator interconnection needs, regional and interregional reliability, and to ensure compliance with NERC standards.

Project submissions are reviewed through an 18-month process with stakeholder meetings, public subregional planning meetings, and additional technical study task force meetings. MISO members, including Entergy and ETEC, participate in this planning process. There are 9 non-ERCOT MOUs that are also a part of MISO, but most do not own sufficient transmission assets to directly participate in regional transmission planning.

Each year, Entergy conducts near- and long-term contingency analyses across multiple compliance years and seasons determined by the NERC TPL-001-5 Reliability Standard. In its long-term planning, Entergy monitors load serving capability for certain constrained areas called "Load Pockets" and conducts transfer studies to see how the pockets would perform under various future scenarios and load growth.

ETEC provides its expected future load requirements and resource capacity for the planning models that are in turn used by MISO for assessing transmission needs holistically for the MISO footprint.

## Generation Capacity

The process to study the need for increased generation capacity, both near-term and long term, starts with a review of market participant's current capacity position. Base load forecasts using historical sales volumes, customer counts, and temperature data, as well as future estimates for normal weather and energy efficiency, are applied to develop a load forecast. Calculations of future capacity surpluses or shortfalls by season utilize Entergy's peak load coincident to MISO peak load, account for transmission losses, and apply a planning reserve margin to develop Entergy's load requirement for each year.

In 2023, Entergy conducted a Strategic Resource Plan (SRP), to identify, evaluate, and select a portfolio of resources to meet its needs. Entergy develops a range of future scenarios it can reasonably expect to face to test how various iterations of commodity cost and load-growth assumptions affect future costs. The analysis is used to inform Entergy of the timing for resource additions and the types of resources that will be affordable, reliable, and sustainable over a range of potential future scenarios.

Entergy assesses its load and resource capability on an annual basis. The 2023 SRP noted the need for Entergy to add generation capacity beyond those resources already identified through previous long-term planning processes.

Based on a variety of considerations, the 2023 SRP analysis concluded that a portfolio consisting of a mix of dispatchable, and renewable resources represented the best option for addressing the long-term resource planning needs of Entergy's customers under the moderate load growth forecast that most closely resembles Entergy's 2024 forecast.

By 2030, Entergy's total load requirement is expected to be approximately 5,173 MW. To fulfil load requirements in 2030, Entergy may have a capacity deficit of over 1,500 MW.

## Western Electricity Coordinating Council (WECC)


WECC Area in Texas

The Western Electric Coordinating Council (WECC) is the regional entity responsible for bulk electric system reliability, associated compliance monitoring, and enforcement in the western interconnection.

WECC 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 14 western states in America. EPE is the only electric utility in Texas that is a member of WECC.

### Transmission Planning Process

EPE is part of regional and subregional WECC planning organizations. EPE's participation in these planning organizations facilitates EPE's coordination of its transmission plans with transmission providers and entities. EPE actively participates in WECC committees, including the WestConnect regional transmission planning process and the Southwest Area Transmission (SWAT) Subregional Planning Group that is comprised of transmission regulators (governmental entities), transmission users, transmission owners, transmission operators, and environmental entities. The SWAT addresses future transmission needs on a subregional basis.

As a part of its process to study the need for increased transmission, EPE conducts an annual System Expansion Plan (SEP) study, which is a technical evaluation of its bulk electric system performance over a 10-year planning horizon. The most recent 2024 Plan evaluated planning years 2025 through 2034. The SEP determines system facility additions and upgrades necessary to comply with WECC and NERC reliability rules. By year 2034, EPE's transmission capacity is expected to grow by almost 50%.

### Generation Capacity

EPE compiles its supply, demand, and reserves information into its loads and resources ("L&R") documents on an annual basis. The planning process begins with the development of its 20-year load forecast, together with consideration of planned retirements based on the age and condition of existing generating resources, to assess resource needs on a 20-year planning horizon.

The L&R documents show the balance or imbalance of EPE generating and purchased power resources versus expected loads and consider EPE's annual planning reserve margin. The reserve margin is necessary to reliably meet the resource needs of customers by taking into consideration transmission import constraints, operational risks of forced outages, and unforeseen load growth above forecast.

By the year 2030, EPE's total system demand is expected to be 2,235 MW in the Texas region with total net resources estimated to be 2,579 MW.

## III. Legislative Recommendations

The commission finds that PURA adequately addresses generation and transmission capacity needs in the state at this time. While the commission continues to study the possible use of extra high voltage transmission facilities in the ERCOT region, the Legislature may choose to provide guidance on specific factors the commission, ERCOT, and transmission service providers should consider in future transmission planning projects. However, PURA currently provides sufficient transmission system planning and construction policy guidance that the commission can use to consider any extra high voltage transmission project or plan. The commission will continue to address resource adequacy related issues in coordination with ERCOT and other relevant entities with its existing resources and authority.

# Texas Electricity Supply Chain Security and Mapping Committee Report

**Relating to Senate Bill 3, 87th Regular Session and Senate Bill 1093, 88th Regular Session Texas Legislature**

January 2025

# Introduction

As part of Senate Bill 3 from the 87th Regular Session (SB3), the Legislature created the Texas Electricity Supply Chain Security and Mapping Committee (the Committee). On January 1, 2022, the Committee submitted a report to the Governor, the Lieutenant Governor, the Speaker of the House of Representatives, the Legislature, and the Texas Energy Reliability Council on the activities and findings of the Committee.[1] In accordance with SB3, the 2022 report:

1) provided an overview of the Committee's findings regarding mapping the electricity supply chain and identifying sources necessary to operate critical infrastructure;

2) recommended a clear and thorough communication system for the Public Utility Commission (PUCT), the Railroad Commission of Texas (RRC), the Texas Division of Emergency Management (TDEM), Electric Reliability Council of Texas, Inc. (ERCOT), and critical infrastructure sources in Texas to ensure that electricity supply is prioritized to those sources during extreme weather events; and

3) included a list of established 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.

While SB 3 required only one Mapping Report from the Committee, the Committee committed to prepare an updated Mapping Report for the Legislature by January of each odd-numbered year. This schedule corresponds with the schedule for the PUCT's Biennial Agency Report as required by Public Utility Regulatory Act (PURA) § 12.203.

[1] Senate Bill 3, 87(R) added Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 38.204 (a) (West Supp. 2021), Mapping Report.

This Mapping Report takes a targeted approach and focuses on the Committee's efforts regarding the Electricity Supply Chain Map that have occurred since the initial report was submitted on January 1, 2022.

## Executive Summary

SB 3 created the Texas Electricity Supply Chain Security and Mapping Committee and included the executive director of the PUCT, the executive director of the RRC, the chief of TDEM, and the president and chief executive officer of ERCOT as members. Senate Bill 1093, 88th Regular Session, expanded the Committee to include the executive director of the Texas Department of Transportation (TxDOT).[2] The executive director of the PUCT serves as the chair of the Committee. Among its responsibilities, the Committee must map the electricity supply chain in Texas and identify the critical infrastructure sources in the electricity supply chain.

The completed electricity supply chain map identifies and connects the critical natural gas infrastructure needed to supply natural gas to natural gas dependent generators to the electric distribution and transmission system and provides information crucial to emergency management personnel during an emergency.

The Committee's mapping team used data from the PUCT, RRC, ERCOT, TDEM, U.S. Department of Homeland Security's Homeland Infrastructure Foundation-Level Data (HIFLD), S&P Global (a third-party vendor), electric utilities, and electric cooperatives to complete the initial electricity supply chain map, which was approved by the Committee and published in April 2022, several months ahead of the September 1, 2022 deadline set by SB 3. Although SB 3 requires the Committee to update the electricity supply chain map at least once each year, the Committee decided to make biannual updates to the map each year by December 1 in preparation for winter storm season, and by June 1 in preparation for hurricane season. Over the course of subsequent updates, data collected directly from electric utilities and electric

[2] PURA § 38.201(c).

cooperatives has gradually replaced third-party data initially acquired through HIFLD and S&P Global to cover the non-ERCOT regions of the state.

The initial electricity supply chain map included the following information:

1) TDEM regions and disaster districts;

2) electric transmission and distribution system infrastructure

   a. transmission and distribution lines, substations, electric generating facilities, electric service area boundaries;

3) critical natural gas infrastructure

   a. natural gas pipelines, compressor stations, processing plants, underground storage facilities, oil leases and natural gas wells, saltwater disposal wells;

4) electric service area boundaries;

5) 24/7 emergency contact information, owner and operator information, and unique identifying information; and

6) real-time weather information.

Passage of SB 1093 brought important updates to the map designed to provide decision makers with the information needed to coordinate between electric, gas, and water industries. This legislation also recognized the importance of passable roads to service critical infrastructure during emergency events by allowing TxDOT road crews to receive pertinent information during emergencies. Following passage of SB 1093, the mapping team updated the electricity supply chain map to include:

1) TXDOT-provided road layers,

2) water and wastewater treatment plants, and

3) electric service area boundaries provided by each electric utility, transmission and distribution utility, electric cooperative, and municipally owned utility (collectively "electric utilities").

The mapping team implemented updates required by SB 1093 in 2023, the same year the legislation passed. SB 1093 also permits:

1) an electric utility to request view-only access to the critical natural gas facilities in its service area; and

2) a natural gas facility operator to request view-only access to its infrastructure on the map. RRC provides operators with a list of their facilities that are on the map.

## RRC and PUCT Rules Related to the Electricity Supply Chain Map

RRC and PUCT rules provide the framework required to identify sources that serve critical infrastructure needed to create and update the electricity supply chain map. SB 3, sections 4 and 16, and House Bill 3648 from the 87th Regular Session required the PUCT to collaborate with the RRC to adopt a "process to designate certain natural gas facilities and entities associated with providing natural gas in this state as critical during energy emergencies."[3] The PUCT, RRC, ERCOT, and natural 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[4], both the RRC and PUCT adopted critical natural gas facility rules.

[3] PURA § 38.074(a).
[4] See PUCT, 16 Texas Administrative Code (TAC) § 25.52 and RRC, 16 TAC § 3.65.

## RRC Rule 16 Tex. Admin. Code (TAC) § 3.65-Critical Designation of Natural Gas Infrastructure

The RRC first adopted 16 TAC § 3.65 as required by HB 3648 and section 4 of SB 3 in 2021.[5] The rule was subsequently amended and became effective on November 21, 2022.[6] The rule establishes 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 TAC § 3.65 defines "energy emergency" and "critical customer information" and clarifies how to calculate gas volumes. It also designates the following facilities as "critical gas suppliers" during an energy emergency:

1. gas wells producing gas in excess of 250 Mcf/day;
2. oil leases producing casinghead gas in excess of 500 Mcf/day with some exception for enhanced oil recovery projects;
3. gas processing plants;
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.

[5] This legislation is codified at Tex. Nat. Res. Code § 87.073 and PURA § 38.074 (West Supp. 2021)
[6] 47 Tex. Reg. 7661 (Nov. 21, 2022).

16 TAC § 3.65 also defines "critical customers," which are a subset of "critical gas suppliers." Critical customers are critical gas suppliers who need electricity to operate. The rule requires a critical customer to send certain information, such as account number and premise identifying information, to its electric utility for load shed planning purposes during an energy emergency.

16 TAC § 3.65 permits facilities that are not designated as critical gas suppliers or critical customers to apply for critical designation if the facility's operation is required for another critical facility to operate. Additionally, a facility that is not designated as critical but is later included on the electricity supply chain map must apply to the RRC to be designated as critical.

Section 4 of SB 3 prohibits RRC from designating a facility as critical unless the facility is prepared to operate during a weather emergency. Critical gas suppliers shown on the electricity supply chain map published by the Committee must weatherize their facilities according to RRC's Weather Emergency Preparedness Standards Rule[7]. Under Rule § 3.65, only facilities not included on the electricity supply chain map may apply for an exception to this requirement. Additionally, 16 TAC § 3.65 requires operators of critical facilities to provide critical customer information to the RRC and the operators' electric delivery service providers. The RRC shares this information with the PUCT and ERCOT to support the creation of the electricity supply chain map.

## PUCT Reliability and Continuity of Service Rule - 16 Tex. Admin. Code (TAC) § 25.52

The PUCT amended 16 TAC § 25.52 to implement the provision in HB 3648 requiring 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.[8] The rule defines the terms "critical natural gas facility" and "energy emergency"

[7] 16 TAC § 3.66.
[8] *See* Tex. Nat. Res. Code § 81.073(a) (West Supp. 2021).

and clarifies that critical natural gas standards apply to each facility in Texas designated as a critical customer under the RRC's Rule § 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 electric delivery service providers and to ERCOT using RRC's form CI-D and any attachments.

The rule requires the PUCT to maintain a list of utility email addresses for critical natural gas facilities to communicate their critical customer information. If a utility's contact information changes or is inaccurate, the utility must provide the Commission with updates within five business days of the change or of becoming aware of the inaccuracy. The rule also requires utilities to evaluate critical customer information for completeness within ten days of receipt.

Each utility must provide written notice to an operator of a natural gas facility about its critical designation status, the date of its designation, and any additional classifications assigned to the facility by the utility. The utility must also inform the operator that its critical status does not guarantee an uninterrupted supply of energy.

Under PUCT Rule § 25.52, utilities or an independent system operator cannot release critical customer information without authorization by the PUCT or the operator of the critical 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 system operator or reliability coordinator for the power region in which the critical natural gas facility is located.

The rule also specifies that a critical natural gas facility is a critical load during an energy emergency. Utilities must treat facilities that self-designate as critical using the voluntary *Application for Critical Load Serving Electric Generation and Cogeneration form* as critical facilities, as circumstances require.

Finally, PUCT Rule § 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.

## Tiering Guidance for TDUs Serving Critical Natural Gas Facilities

Since Winter Storm Uri, electric utilities have experienced a substantial increase in the number of registrations from natural gas facilities seeking critical load designation. Transmission and Distribution Utilities (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 prioritization structure of critical infrastructure for load shed purposes. Natural gas industry market participants addressed the tiering concept for natural gas facilities in the RRC's initial critical designation rulemaking and in the PUCT critical designation rulemaking. The RRC also provided the PUCT with information outlining the facilities that the RRC knows are most important to the natural gas supply chain during an energy emergency.

The PUCT considered this input when issuing tiering guidance pursuant to the PUCT's jurisdiction and the requirements of SB 3 in PURA § 38.074(b)(2) and (3). The PUCT expects each electric utility to develop its own critical load classifications and criteria for prioritizing critical loads for power delivery and power restoration during energy emergencies based on the unique features of its system. The guiding consideration for these plans should be the safety and wellbeing of the public along with the preservation of critical facilities and infrastructure. Regarding critical natural gas facilities, during an energy emergency, utilities should strive to maximize the fuel supply to power generation facilities. PUCT staff provided the following guidance in January 2022 to the PUCT's regulated industry on the designation of load shed tiers during a weather emergency:

## Tier One

Tiers One and Two are subdivided into two groups. Tier One A is prioritized over Tier One B. Tier Two A is prioritized over Tier Two B.

A.

- Pipelines that directly provide natural gas to ERCOT identified Black Start Service facilities and other natural gas fired electric generation;
- Natural gas local distribution company critical pipelines or pipeline facilities;
- Underground natural gas transportation and storage facilities;
- Natural gas liquids transportation and storage facilities; and
- Associated pipelines, compressor stations, and control centers for facilities in Tier One A.

B.

- Natural gas wells and oil leases producing natural gas in excess of 5000 Mcf/day;
- Gas processing plants with a capacity of at least 200 MMcf/day;
- Associated pipelines, compressor stations, and control centers for facilities in Tier One B; and

- Associated saltwater disposal wells supporting the wells and leases for facilities in Tier One B.

## Tier Two

A.

- Natural gas wells and oil leases producing natural gas in excess of 1000 Mcf/day but no more than 5000 Mcf/day;
- Gas processing plants with a capacity of at least 100 MMcf/day but no more than 200 MMcf/day;
- Associated pipelines, compressor stations, and control centers for facilities in Tier Two A; and
- Associated saltwater disposal wells supporting the wells and leases for facilities in Tier Two A.

B.

- Natural gas wells and oil leases producing natural gas in excess of 250 Mcf/day but no more than 1000 Mcf/day;
- Gas processing plants with a capacity of at least 100 MMcf/day;
- Associated pipelines, compressor stations, and control centers for facilities in Tier Two B; and
- Associated saltwater disposal wells supporting the wells and leases for facilities in Tier Two B.

## Tier Three

- Natural gas wells and oil leases producing natural gas less than 250 Mcf/day;
- Associated pipelines, compressor stations, and control centers for facilities in Tier Three;
- Associated saltwater disposal wells supporting the wells and leases for facilities in Tier Three; and
- Any additional facilities identified as critical on Railroad Commission of Texas Form CI-D, including processing, metering, and similar support facilities and equipment.[9]

# Workflow and Individual Committee Member Updates

The Committee has met regularly since August 2021. Mapping and IT personnel from the PUCT, RRC, TDEM, ERCOT, and TxDOT work on multiple aspects of the electricity supply chain map, and Committee members have signed a memorandum of understanding (MOU) to establish a process to share confidential datasets between agencies.

To keep the electricity supply chain map current, the PUCT receives updated electric generation and transmission datasets securely from mapping and IT staff at ERCOT and electric utilities outside of the ERCOT region. Additionally, electric utilities securely provide electric distribution datasets on a regular, biannual, basis. The PUCT also receives updated critical natural gas infrastructure data securely from mapping and IT staff at RRC on a regular, biannual, basis. PUCT mapping staff converts information into a format that can be used by the PUCT's mapping software, and aggregates it into a single, reliable, database of integrated gas and electric industry information for inclusion in the electricity supply chain map.

[9] See Project No. 52345, Critical Natural Gas Facilities and Entities, Item No. 51, January 14, 2022.

## A. PUCT

PUCT shares regular, biannual updates for generation, transmission lines, and distribution lines, which are acquired from Texas utilities. Updates on water and wastewater treatment plants are acquired from the Texas Commission on Environmental Quality (TCEQ).

The Committee allows electric utilities, as permitted by SB 1093, to sign a Non-Disclosure Agreement for view-only access to the electricity supply chain map. The PUCT coordinates with each entity and provides the opportunity to securely view critical natural gas facilities on the map. An electric utility may only view critical natural gas facilities on the map located in its service area.

## B. RRC

RRC shares regular, biannual updates for eight critical infrastructure layers. These are the natural gas pipelines directly serving generation, gas processing facilities, pipeline compressor stations, off-lease compressor stations, saltwater disposal wells, gas wells, oil leases, and underground storage facilities.

## C. TDEM

TDEM works closely with staff representing the PUCT and RRC at the State Operations Center (SOC) 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. Additionally, TDEM provides updates to the map on a regular, biannual basis that results in streamlined communication and coordination with the appropriate TDEM personnel during an emergency. These updates include boundaries and emergency contact information for TDEM regions, disaster districts, and Councils of Government (COGs).

## D. ERCOT

ERCOT securely provides updates on power generation facility, transmission line, and substation data to the PUCT on a regular, biannual basis.

## E. TxDOT

The Committee uses TxDOT roadways in the electricity supply chain map. These are integrated with two TxDOT-customized basemaps made available to map users. TxDOT Maintenance Sections are also shared in the map. These sections show who is responsible for overseeing maintenance activities on TxDOT roadways within that section. The datasets provided by TxDOT are continuously and automatically updated to reflect changes in geospatial information and attribute data.

# Current Data Collection Challenges Related to the Electricity Supply Chain Map

A continuing challenge for the Committee is obtaining and mapping the electric distribution infrastructure that serves the critical natural gas infrastructure identified under RRC and PUCT rules. Because the PUCT lacks direct access to electric utility distribution level mapping data, the Committee must request this information from the electric utilities serving the infrastructure. To expedite this process, the Committee provides the electric utilities with lists of premise identifiers associated with the critical infrastructure sources identified by RRC. This information allows the electric utilities to 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 provide its premise identifier to the electric utility that serves the facility to be considered a critical load. The RRC must share this data with the Committee. The data is 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.

SB 1093 requires TDUs, Coops, and MOUs to submit service area boundary maps to the PUCT in a geographic information system (GIS) format. This has reduced the time required to link premise identifiers with electric distribution infrastructure, particularly in cases where data collection or data entry errors may have occurred. In those cases, the electric utilities use other clues in the data to help research the correct premise identifier, thereby linking the appropriate distribution-level GIS data. Operators are then asked to resubmit the correct premise identifier for the critical natural gas infrastructure to the RRC.

## Conclusion

The Committee has met statutory objectives. Continued participation by all Committee members will help ensure the electricity supply chain map continues to be a useful tool in emergency planning and response.