



Item 11.1: Strategic Discussion on Resource Adequacy and the Role of Demand Response

Keith Collins
Vice President, Commercial Operations

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Purpose

Discuss strategic challenges, issues, and approaches to addressing resource adequacy, focusing on the potential benefits of Demand Response to address short and mid-term supply limitations.

For information only

No action is requested; for discussion only.

Key Takeaways

- ERCOT system faces potential demand and supply imbalances as load grows.
- Supply chain challenges limit resource options in the short-run.
- Consider value of promoting demand response as a near-term solution to emerging resource adequacy challenges.

Strategic Challenges to ERCOT System

Even at the low end, loads are forecast to grow at significant rates in coming years



Supply chains limit short and mid-term options to meet growing demand



Combined, these challenges highlight the need for a range of solutions to ensure grid reliability and resource adequacy

ERCOT Strategic Approach – Long-Term Solutions

Promote effective and efficient long-term solutions

- Incentivize a balanced resource portfolio (e.g. NPRR 1310 – Dispatchable Reliability Reserves Service Plus (DRRS+))
- Enable growth of both supply and load throughout Texas (765kV expansion)

ERCOT Strategic Approach – Short-Term Solutions

Promote demand response solutions to help bridge gap to long-term solutions

- Enhance existing programs (ERS, ADER)
- Support development of large load response program Senate Bill 6 (SB6) and promote controllable load resources (CLRs)
- Reach untapped residential demand response potential as identified in Texas A&M Study (NPRR 1296)

Strategic Demand Response Questions

Can demand response help address near-term resource adequacy concerns?

Are current demand response incentives aligned with system needs?

Can residential demand response be efficiently tapped to help address reliability?

Can existing demand response programs be improved to enhance efficiencies and expand potential?

Why is demand response a good fit for ERCOT system?

Speed of deployment

- Can be developed in months versus years

Fills a specific resource gap

- Supply chain limitations creating resource availability gap

Cost effectiveness

- Comparable/lower cost than other markets depending on product

Untapped potential

- [Texas A&M study](#) identified gigawatts of untapped demand response

Enabled by emerging technologies

- Smart thermostats and home batteries enabling consumer participation

Key Takeaway: Several factors make demand response a viable and timely fit for ERCOT.

Examination of Short-Term Demand Response Solutions

Given the potential of demand response, ERCOT reached out to Charles River Associates to provide a high-level overview and examination of current and proposed programs within the ERCOT system, and to provide a comparison with other regions.

Key Challenges identified in Charles River Associates report

ERCOT system faces scarcity as demand is expected to outpace new generation.

The 4CP transmission cost allocation method drives most demand response in ERCOT but does not correspond to the system's highest net-load peaks.

Retail demand response programs exist in the ERCOT region but are not integrated with wholesale markets or operations.

Emergency Response Service (ERS) inclusion of highly price-sensitive resources (primarily crypto miners) is driving ERS clearing prices to potentially inefficiently low levels.

The Aggregate Distributed Energy Resource (ADER) pilot has broadened opportunities for distribution-connected DER aggregations to engage in ERCOT markets; however, technical and participation challenges are likely to slow wider implementation.

Key Takeaways from Charles River Associates report

Demand response offers a near-term solution to resource adequacy challenges.

Improved alignment of retail demand response could enhance reliability in nearer timeframes, especially given current needs.

ERCOT's proposed residential demand response (RDR) program fills a critical gap by systematically targeting net-load peaks across all seasons, addressing the absence of retail demand response programs focused on year-round system needs.

ERCOT's proposed RDR compensation rate (up to \$105,000/MW-year initially) is roughly comparable to retail demand response rates in CAISO, though the RDR is not a guaranteed-payment capacity product.

Protocol reforms may be needed for ERS to address self-deployment.

ERCOT Conclusions

Demand response could be a critical reliability bridge solution because load growth is forecast to outpace generation development.

- Demand response can be deployed faster than new most generation and is the most immediate tool available.

Current demand response is misaligned.

- The 4CP methodology drives large reductions during summer peak hours but not during net-load peaks — the intervals when the system is actually most stressed, including evenings and non-summer months. Additionally, these load reductions can not address needs in non-summer months.

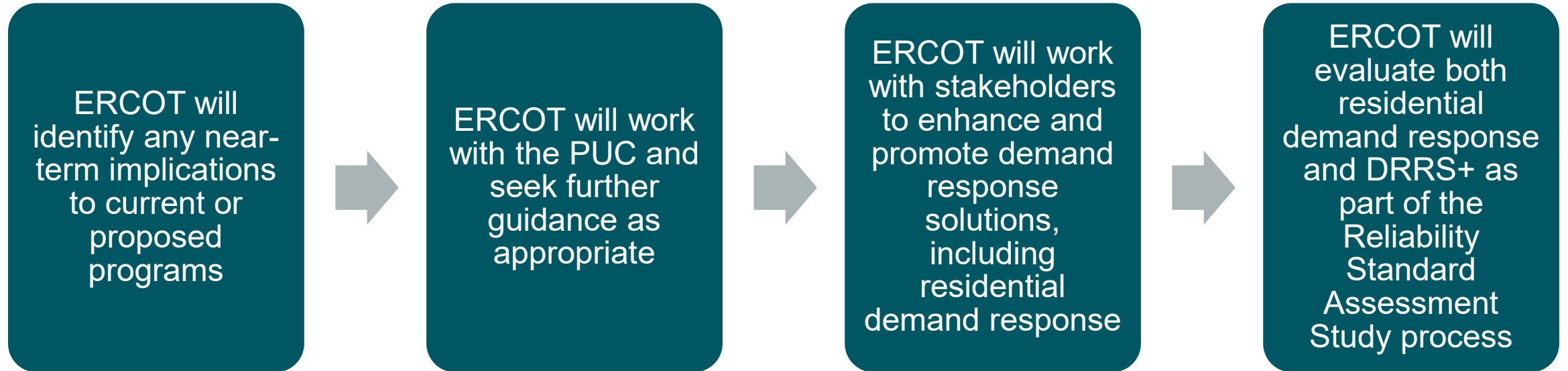
Existing programs such as ERS and ADER can be enhanced to improve efficiencies and effectiveness.

- Address inefficient ERS pricing caused by highly price sensitive resource participation.
- Enhance ADER pricing to better target congestion and codify program in Protocols.

Targeting and promoting residential demand response fills a gap in existing demand response programs.

- Charles River Associates supports the targeting of residential demand response.
- Charles River Associates noted that incentive premiums are warranted to overcome barriers to retail demand response participation in wholesale markets. Thus, continuing to incentivize retail demand response in the same way will likely not lead to meaningful growth in participation.

Next Steps



Key Takeaway: ERCOT intends to enhance and promote demand response programs with regulators and stakeholders.



Prepared for:

ERCOT

8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744

Assessment of load participation and demand response in ERCOT

Prepared by:

Emma Nicholson, Chris Russo, and Nirmal Bhatt

Charles River Associates
200 Clarendon Street
Boston, Massachusetts 02116

Date: April 2026

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1. Introduction

Load resources and demand response (DR) resources play an important role in reliably and affordably serving electricity demand in wholesale markets across the U.S. DR resources are particularly valuable today because they can be implemented much faster than generation resources, which take years to site, permit, construct, and interconnect to the transmission system. Some DR resources can also be implemented more cost-effectively than other resource types. Additionally, emerging customer-side technologies, such as smart thermostats, electric vehicles, and behind-the-meter battery storage, are expanding the potential for retail DR. New large loads also present opportunities for additional load flexibility and DR capability. Despite its value, DR participation in U.S. wholesale electricity markets is fairly low relative to its potential.¹

DR is especially valuable in ERCOT for two reasons. First, DR can be implemented quickly to help meet near-term energy needs and projected energy scarcity risks. Second, the evidence suggests there is an opportunity to expand retail DR participation in ERCOT to help meet future system needs, which will increase with projected load growth. ERCOT's residential DR proposal could expand DR participation in ERCOT and incent DR reductions during net peak load periods, which can have elevated scarcity risks.

ERCOT asked CRA to assess the current opportunities for load participation in ERCOT markets and how they interact with each other and other DR programs in the ERCOT footprint that ERCOT does not administer. ERCOT also asked CRA to identify options to expand DR participation in ERCOT and to assess the incentives its proposed Residential DR (RDR) program would offer and how it could interact with other ERCOT market products and retail DR programs.

CRA's key findings are as follows:

- ERCOT is facing near-term energy scarcity risks because projected load growth is outpacing the industry's ability to site, permit, build, and interconnect the new generation required to reliably serve the new loads. Given this need, ERCOT is appropriately considering near-term options, such as DR, to fill the gap.
- ERCOT provides several opportunities for load participation in ERCOT markets. Load Resources, including Aggregated Distributed Energy Resources (ADERs), can participate in energy and ancillary services markets or provide Emergency Response Service (ERS), provided they meet the applicable requirements.
- The four coincident peak (4CP) transmission cost allocation methodology, which is not designed to meet ERCOT's operational needs, currently provides the strongest incentive for load reductions in ERCOT, whether through formal retail DR programs or self-directed curtailments. 4CP cost allocation drives load reductions during anticipated coincident peak hours in summer, but these periods do not always align with the ERCOT system's periods of greatest need, such as net load peak periods throughout the year.
- Several retail DR programs exist in the ERCOT footprint that ERCOT does not administer. These DR programs are not directly integrated into the ERCOT market or operations, which is common across U.S. wholesale markets. Better aligning retail

¹ Energy Systems Integration Group, Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets, January 2025, at xiii.

DR programs with ERCOT's wholesale market and operational needs could increase reliability in ERCOT.

- ERCOT's proposed RDR program presents an opportunity to expand retail DR participation in ERCOT and by offering an incentive payment for DR reductions when they are needed most – during net load peaks. Retail DR programs in the ERCOT footprint and the incentives provided by 4CP cost allocation do not currently meet this need.
- ERCOT's currently proposed compensation under the RDR program, which is not guaranteed, is roughly comparable with compensation available to retail loads in other wholesale electricity markets.
- ERCOT has identified instances where extremely price-responsive ERS Resources self-deploy in response to high prices. If not addressed, this behavior could undermine the utility of the ERS product to the ERCOT system and drive ERS prices to inefficiently low levels.
- ERCOT's ADER pilot creates a pathway for aggregations of distribution-connected distributed energy resources to participate directly in ERCOT markets. Similar reforms are being adopted in other markets, though participation levels are low nationwide given the nascency of the programs, most of which are not fully implemented, the technical participation requirements involved, and other factors.

Section 2 provides information about DR programs and opportunities for loads to participate in the ERCOT footprint. Section 3 explains how load participation and DR programs impact the ERCOT system. Section 4 explains ERCOT's RDR proposal and the large load curtailment program required by Senate Bill 6 (SB6). Section 5 summarizes load side and DR participation in other wholesale electricity markets. Section 6 provides CRA's assessments and recommendations.

2. Current opportunities for load participation and DR in the ERCOT footprint

This section of the report provides background information on the current opportunities for load-side resources to participate directly in the ERCOT market or to provide DR through a retail DR program that is not administered by ERCOT. Subsection 2.1 describes ERCOT-administered programs: Emergency Response Service (ERS), load participation in ERCOT ancillary services markets, and the Aggregated Distributed Energy Resources (ADER) pilot. Section 2.2 describes DR programs and incentives that ERCOT does not administer: self-curtailment during 4 Coincident Peak (CP) intervals; Retail Electric Provider (REP) and Non Opt-In Entity (NOIE) administered DR programs, Transmission and Distribution Service Provider (TDSP) Load Management Programs, and self-directed price responsive load.

2.1. ERCOT-Administered DR programs

Load-side resources currently have three opportunities to participate directly in ERCOT through markets that ERCOT administers: load participation in ERCOT ancillary services markets, ERS, and the ADER pilot. These participation pathways are described further below.

2.1.1. Load resource participation in ERCOT Ancillary Services markets

Load Resources can participate directly in ERCOT markets and currently offer three ancillary service products: Responsive Reserve Service (RRS); Non-Spinning Reserve (Non-Spin); and ERCOT Contingency Reserve Service (ECRS). Although they are qualified to do so,

Load Resources do not currently provide regulation (i.e., Reg-Up or Reg-Down products). Load Resources can participate in ERCOT as either Controllable Load Resources (CLRs) or Non-Controllable Load Resources (NCLRs).²

Product specifications

The product specifications for ancillary service products are available in ERCOT's Nodal Protocols. Load Resources providing ancillary services must meet technical requirements that are comparable - but not identical to - generation resources. Such technical requirements include, but are not limited to, the ability to respond to dispatch instructions and telemetry requirements.

Generally, RRS resources are deployed to quickly maintain system frequency and must respond immediately to a deployment instruction and fully respond within ten minutes. CLRs use fast-acting control systems to respond to primary frequency deviations, similar to the governors on a conventional thermal plant. Load Resources capable of reducing their demand by a specified amount within 30 minutes and that are capable of running (or being interrupted) at a specified output level for at least four consecutive hours can qualify to provide Non-Spin. Load Resources that can respond within 10 minutes of deployment and sustain their response for at least two hours can qualify to provide ECRS.

Load Resources currently compete with generation resources to provide RRS, Non-Spin, and ECRS. ERCOT procures, settles, and clears these ancillary services and others through the day-ahead and real-time market clearing processes.³ ERCOT limits the proportion of RRS capacity provided by NCLRs to 60% for reliability reasons.

Participation, prices, and deployments

Table 1 presents load resource participation by type – NCLR and CLR – in ERCOT's ancillary service markets in 2025. Most Load Resources used the NCLR participation model to offer ancillary services, although a small number of Load Resources with sizeable capacity in aggregate participated as CLRs.

² NCLRs first became eligible to participate in the Non-Spin market in November 2022 after the implementation of NPRRs 1093 and 1101. See e.g., NPRR 1092: Load Resource Participation in Non-Spinning Reserve.

³ During the time period studied, ERCOT did not procure ancillary services in the real-time market.

Table 1: Load Resources qualified for ancillary services in 2025

	NCLR		CLR		Total Load Resources	
	Qualified Capacity (MW)	Num. of resources	Qualified Capacity (MW)	Num. of resources	Qualified Capacity (MW)	Num. of resources
RRS	7,568	340	252	6	7,820	346
Non-Spin	724	25	252	6	976	31
ECRS	3,831	168	282	6	4,113	174
Reg-Up	N/A	N/A	29	2	29	2
Reg-Down	N/A	N/A	29	2	29	2

ERCOT, 2025 Annual Report on Demand Response in the ERCOT Region, February 2025, Table 2.

Table 2 presents the average hourly ancillary services provided by NCLRs and CLRs in 2025; the majority of ancillary services were provided by NCLRs. In 2025, Load Resources showed a strong interest in providing RRS and were cleared for Non-Spin and ECRS in smaller amounts. While RRS and Non-Spin are deployed at times, public reports indicate that ECRS is rarely deployed. In 2025, there were no Energy Emergency Alert (EEA) events that resulted in the deployment of NCLRs providing ECRS or RRS.⁴

Table 2: ERCOT average cleared hourly ancillary service capability in MW by CLRs and NCLRs, 2025

Month	RRS	Non-Spin	ECRS
Jan 2025	1,221	71	160
Feb 2025	1,338	50	136
Mar 2025	1,505	72	133
Apr 2025	1,463	90	137
May 2025	1,179	99	219
Jun 2025	998	64	207
Jul 2025	959	59	238
Aug 2025	781	23	248
Sep 2025	839	37	249
Oct 2025	1,130	118	271
Nov 2025	1,357	65	265
Dec 2025*	1,035	17	162

Source: ERCOT, Monthly Demand Response from Load Resources, ERS and Ancillary Services. [link](#). Notes: DR resources did not provide Reg-Up or Reg-Down in 2025, RTC+B implemented in December 2025.

⁴ ERCOT, 2025 DR Report, at 8.

The average cleared quantities of RRS, Non-Spin, and ECRS cleared by month in the ERCOT system in 2025 are provided in the Appendix (Table 16). On average, Load Resources provided just over 40% of the RRS ERCOT procured in each hour, and about 15% of the average hourly ECRS procured. Load Resources provided only 2% of the average Non-Spin procured per hour in 2025. Table 3 summarizes average monthly prices for RRS, Non-Spin, and ECRS.

**Table 3: Average monthly ancillary service prices,
January 2025 - December 2025, \$/MW**

Year	RRS	Non-Spin	ECRS
Jan 2025	\$1.79	\$1.80	\$1.72
Feb 2025	\$2.99	\$3.01	\$3.11
Mar 2025	\$2.54	\$2.79	\$2.38
Apr 2025	\$2.69	\$3.21	\$2.61
May 2025	\$5.63	\$9.98	\$5.60
Jun 2025	\$2.90	\$3.12	\$2.40
Jul 2025	\$2.40	\$1.62	\$2.12
Aug 2025	\$2.79	\$1.32	\$2.66
Sep 2025	\$1.54	\$1.14	\$1.40
Oct 2025	\$2.17	\$2.31	\$1.94
Nov 2025	\$2.83	\$3.27	\$2.45
Dec 2025	\$2.34	\$4.98	\$2.18

Source: Potomac Economics, ERCOT Wholesale Electricity Market Monthly Report, January 10, 2026, p. 35, [link](#). Note: RTC+B implemented December 5, 2025.

ERCOT implemented the Real-Time Co-optimization Plus Batteries (RTC+B) reforms on December 5, 2025 and the Commission approved new Minimum Monthly Ancillary Service Requirements for ERCOT in 2026, both of which will change the dynamics of energy and ancillary services markets going forward.⁵

2.1.2. Emergency Response Service (ERS)

In March 2007, PUCT adopted 16 TAC §25.507 and directed ERCOT to implement an emergency demand response service.⁶ Over time, the regulations in §25.507 were revised and the product was renamed Emergency Response Service (ERS). The most recent reforms to §25.507 occurred in August 2022 when PUCT increased the annual ERS budget to \$75 million and permitted ERCOT to exceed this amount by up to \$25 million to renew ERS contract terms, if needed.⁷

⁵ ERCOT Notice M-A121925-01 2026 Minimum Monthly Ancillary Service Requirements, December 19, 2025, [link](#).

⁶ Public Utility Commission of Texas, Order Adopting New §25.507 as Approved at the March 20, 2007 Open Meeting. The name of the product was initially Emergency Interruptible Load Service.

⁷ Public Utility Commission of Texas, Order Adopting New 16 TAC as Approved at the August 4, 2022, Open Meeting.

Product specifications

The ERS product enables Load Resources to support electric reliability during emergencies by either reducing their electric load or relying on on-site back-up generation if deployed by ERCOT. Per ERCOT's Nodal Protocols, "ERCOT shall procure and deploy ERS with the goal of promoting reliability prior to and during energy emergencies."⁸ This language is consistent with ERS regulations specified in §25.507, which describe ERS as "a special emergency response service to be deployed by ERCOT to help prevent or alleviate an actual or anticipated Energy Emergency Alert".⁹ ERCOT purchases ERS through four Standard Contract Terms (SCT), with different cumulative deployment obligations, which are summarized in Table 4 below.

Table 4: Non-Weather Sensitive ERS Standard Contract Terms and Obligations

Standard Contract Term	Cumulative deployment obligation during contract term, in hours
December – March	24
April – May	12
June – September	12
October – November	12

Source: ERCOT Nodal Protocols, December 5, 2025, §3.14.3.1.
Notes: ERCOT procures ERS for eight Time Periods within each SCT.

For each SCT, ERCOT procures ERS within eight distinct Time Periods.¹⁰ There are four types of ERS resources: Non-Weather-Sensitive ERS with a ten-minute response time (ERS-10); Non-Weather-Sensitive ERS with a 30-minute response time (ERS-30), Weather-Sensitive ERS with a ten-minute response time (WS-ERS-10); and Weather-Sensitive ERS with a 30-minute response time (WS-ERS-30). ERCOT procures ERS-10 and ERS-30 in all SCTs but only procures Weather-Sensitive ERS in Time Periods that correlate with extreme weather.

ERS resources must meet their cumulative deployment obligations and when deployed by ERCOT, an ERS Resource must remain deployed until recalled by ERCOT. A Non-Weather Sensitive ERS Resource is obligated to provide ERS up to its maximum obligation in hours (see Table 4) during the SCT and Time Period for which it clears. Obligations can roll over to any subsequent ERS Contract Period the ERS Resource has with a remaining obligation.¹¹ ERCOT may choose to renew an ERS Resource's obligation once the resource's obligation is exhausted, subject to the consent of the ERS Resource and budget availability.

⁸ ERCOT Nodal Protocols, December 5, 2025, §3.14.3.1(1).

⁹ 16 TAC §25.507(b).

¹⁰ Time periods (TPs) are as follows: TP1 HE 6-9, Monday through Friday except ERCOT Holidays; TP2: HE 10-13, Monday thru Friday except ERCOT Holidays; TP3: HE 14-16, Monday-Friday except ERCOT Holidays; TP4: HE 17-19, Monday thru Friday except ERCOT Holidays; TP5: HE 20-22, Monday thru Friday except ERCOT Holidays; TP6 HE 6-9, Weekends and ERCOT Holidays; TP7 HE 16-21, Weekend and ERCOT Holidays; and TP8 All other hours.

¹¹ ERCOT Nodal Protocols, December 5, 2025, §3.14.3.1(17)(c).

Participation requirements

Two resource types can offer to provide ERS in ERCOT: 1) a single load or aggregation of loads; and 2) a dispatchable generator that is not registered with ERCOT as a Generation Resource, or an aggregation of such generators. An ERS Resource must be represented by a Qualified Scheduling Entity (QSE) and have a fifteen-minute interval meter. Weather-sensitive ERS must consist exclusively of residential sites while ERS Load must consist exclusively of non-residential sites.¹²

When deployed by ERCOT, ERS Loads must reduce their demand (or inject generation if applicable) relative to a baseline level established by ERCOT's DR Baseline Methodologies.¹³ Demand reduction is achieved through either the default "Drop-by" method (e.g., reduce demand by 2 MW upon deployment), or an alternative Maximum Base Load (MBL) "Drop-to" alternative (e.g., ERS Resource drops to its MBL upon deployment). The minimum sized offer for a WS ERS Load is 0.5 MW and the minimum size for ERS-10 and ERS-30 ERS resources is 0.1 MW. Non-Weather Sensitive ERS Resources may be aggregated to reach this requirement. A Load Resource may not offer to provide ERS if it participates in another DR program, including one administered by a TDSP.

Procurement method and settlement

ERCOT's procurement methodology for ERS, contained in Section 22 Attachment Q of the Protocols, specifies ERCOT's demand curve for ERS, which is downward sloping and has an \$80/MW-per-hour price cap. ERCOT procures ERS resources through a uniform clearing price auction for each SCT and Time Period. ERCOT procures ERS through a request for proposal (RFP) process that establishes a single clearing price (\$/MW) for all ERS product types and for each SCT and Time Period (i.e., 4 SCTs x 8 Time Periods = 32 procurements per program year). ERCOT maximizes the ERS quantity (in MW) procured subject to the expenditure limit for the applicable SCT and Time Period. ERCOT can spend a maximum of \$75 million in a 12-month period starting in December and allocates this budget across the four SCTs and Time Periods in proportion to ERCOT's assessment of the allocation of the risk of falling below the 3,000 MW Physical Responsive Capability (PRC) threshold.¹⁴ ERCOT may exceed the \$75 million cap by up to \$25 million for ERS contract renewals, if needed.

Participation, prices, and deployments

Table 5 and Table 6 summarize the ERS clearing prices and quantities, respectively, for ERS between the October 2024 - November 2024 and the December 2025 - March 2026 SCTs. ERS clearing prices have decreased and cleared quantities have increased in recent years. ERCOT reported on these trends in the 2025 DR Report.¹⁵

¹² ERCOT Nodal Protocols, December 5, 2025, §3.14.3.1(5).

¹³ ERCOT, Demand Response Baseline Methodologies, [link](#).

¹⁴ ERCOT 2024 Demand Response Report, at 8. See also, ERCOT Nodal Protocols Section 22, Attachment Q: Emergency Response Service Procurement Methodology, September 1, 2025, §D, "ERCOT will assign a high (H), moderate (M), or low (L) risk designation to each ERS Time Period and will assign a risk-weighting factor (a value from 1 to 100 with 1 being the lowest risk value and 100 being the highest risk value) for each risk designation. ERCOT's risk assessment will consider a number of factors, including, but not limited to, forecasted operating reserves, forecasted Load, Resource outage information, and the obligated cumulative deployment time for an ERS Contract Period as specified for the ERS Standard Contract Term in paragraph (18)(b) of Section 3.14.3.1, Emergency Response Service Procurement."

¹⁵ ERCOT 2025 DR Report, at 11-12, and Graph 4.

Table 5: ERS clearing prices (\$/MW), October 2024 – March 2026

	TP1	TP2	TP3	TP4	TP5	TP6	TP7	TP8
	Weekdays HE 6-9	Weekdays HE 10-13	Weekdays HE 14-16	Weekdays HE 17-19	Weekdays HE 20-22	Weekend+ Holiday HE 6-9	Weekend+ Holiday HE 16-21	All other times
Oct 24 - Nov 24	\$5.20	\$0.35	\$0.35	\$5.92	\$5.20	\$4.03	\$4.36	\$0.37
Dec 24 - Mar 25	\$26.87	\$4.67	\$4.67	\$17.46	\$17.70	\$8.20	\$0.32	\$2.60
Apr 25 - May 25	\$2.68	\$0.17	\$0.17	\$1.67	\$2.70	\$0.20	\$0.25	\$0.18
Jun 25 - Sep 25	\$1.73	\$1.72	\$10.36	\$18.69	\$18.08	\$0.19	\$13.68	\$0.18
Oct 25 - Nov 25	\$1.13	\$0.10	\$0.10	\$1.28	\$1.28	\$0.87	\$0.87	\$0.10
Dec 25 - Mar 26	\$11.92	\$2.14	\$2.05	\$7.75	\$7.75	\$3.57	\$0.12	\$1.05

This table summarizes prices for Non-Weather Sensitive ERS-10 and ERS-30 and Weather Sensitive ERS-10 and ERS-30. Source: ERCOT.

Table 6: Cleared ERS capability in MW, October 2024 – March 2026

Standard Contract Term	TP1	TP2	TP3	TP4	TP5	TP6	TP7	TP8
	Weekdays HE 6-9	Weekdays HE10-13	Weekdays HE 14-16	Weekdays HE 17-19	Weekdays HE 20-22	Weekend+ Holiday HE 6-9	Weekend+ Holiday HE 16-21	All other times
Oct 24 - Nov 24	1,251	1,375	1,357	1,281	1,253	1,202	1,162	2,333
Dec 24 - Mar 25	1,450	1,502	1,502	1,446	1,431	1,354	1,119	1,349
Apr 25 - May 25	1,777	1,779	1,775	1,789	1,696	1,605	1,568	1,741
Jun 25 - Sep 25	2,215	2,228	2,089	1,792	2,004	1,876	1,960	2,080
Oct 25 - Nov 25	2,609	2,519	2,755	2,650	2,478	2,529	2,505	2,530
Dec 25 - Mar 26	2,668	2,843	2,885	2,745	2,595	2,580	2,323	2,558

This table summarizes cleared capability for ERS-10 and ERS-30, and Weather-Sensitive ERS-10 and ERS-30. Source: ERCOT.

ERCOT only procures small amounts of Weather-Sensitive ERS-30. For example, during the December 2025 - March 2026 SCT in Time Period 1, ERCOT procured 5.3 MW of Weather-Sensitive ERS-30, or 0.2% of the total quantity procured for this interval. ERCOT also procured 83.7 MW of Weather-Sensitive ERS in the June 2025 - September 2025 SCT during evening and late-night hours (Time Periods 4, 5, and 7), which amounted to about 4% of ERS procured at these times. In interviews with CRA, ERCOT staff indicated that incorporating Weather-Sensitive ERS Resources in the ERS program is burdensome to administer.

ERCOT’s ERS procurement is budget-driven and ERCOT procures as much ERS capacity as the \$75 million annual budget will allow in each SCT and Time Period, with purchases weighted by the relative risks in each SCT and Time Period. This means that all else equal, lower ERS offer prices result in increased procurement quantities. The highest risk SCTs are in winter, particularly in the Time Periods with hours ending (HE) 6-9, 17-19, and 20-22, and summer (June-September) in the time periods that cover HE 14 through HE 22. Given this increased risk, ERCOT has a higher budget and willingness to pay for ERS during these periods, which is why these periods tend to have the highest clearing prices. ERS offer prices can also be higher during these periods to reflect the increased likelihood of deployment, which also contributes to higher clearing prices in these SCTs and Time Periods.

ERCOT does not deploy ERS often, which is not surprising given that ERS is only deployed in emergencies or prior to anticipated emergencies.¹⁶ As shown in Table 7, ERCOT has only deployed ERS Resources six times since 2011, with multiple instructions per deployment. Weather-Sensitive ERS has only been deployed twice.

Table 7: ERS deployments, February 2011- February 2026

Year	Number of deployments	ERS	
		Product Types	Deployment Month(s)
2011	2	ERS-10	Feb. and Aug.
2014	2	ERS-10 & ERS-30	Jan.
2019	4	ERS-10 & ERS-30	Aug.
2021	6	ERS-10, ERS-30, & WS	Feb.
2022	2	ERS-10, ERS-30, & WS	Jul.
2023	2	ERS-10 & ERS-30	Aug. and Sep.

Source: ERCOT ERS Event History, Sep 12, 2023. WS: Weather-Sensitive.

The last ERS deployments were in August and September 2023. ERCOT also relied on ERS during Winter Storm Uri, with a total of six ERS instructions on February 15, 2021. Summer deployments tend to be shorter than winter deployments.¹⁷

To align ERS deployments with ERCOT's energy-only market construct, ERCOT adds a Real-Time On-Line Reliability Deployment Price Adder to energy prices when it deploys ERS.¹⁸ ERCOT determines this adder in the Security Constrained Economic Dispatch (SCED) run to approximate the price impact ERS deployments. This adder addresses price formation concerns during ERS deployments because ERS deployments could depress prices and send price signals that are inconsistent with real-time system needs.

Current issues

The quantity of ERS supply offered to ERCOT has increased significantly in recent years, and this new capacity is being offered at lower prices. Together, these trends have lowered ERS clearing prices (see Table 5 and Table 6). ERCOT's 2025 DR report notes the recent ERS price declines and explains that the types of resources that participate in the ERS program have shifted over time. Crypto mining loads have grown as a share of ERS Resources. In the December 2025 - March 2026 SCT solicitation, crypto mining loads made up 64% of the ERS Resources procured.¹⁹ ERCOT staff presented an analysis at the January 2026 Wholesale Market Subcommittee that showed 60% of ERS resources self-deployed prior to ERCOT's instruction on September 6, 2023, the last time ERS was deployed.²⁰ As discussed further in section 6.1, self-deployment could raise reliability concerns and inefficiently depress ERS prices.

¹⁶ ERCOT, ERS Event History, [link](#).

¹⁷ *Id.* The longest ERS deployment in summer was 4 hours, while winter deployments were approximately 100 hours on average during Storm Uri and ranged from one to 28 hours during other winter events.

¹⁸ The Time On-Line Reliability Deployment Price Adder is also used to address other reliability deployments, such as resources committed through the Reliability Unit Commitment process.

¹⁹ ERCOT, Agenda Item #4: ERS/Crypto Mining Load, WMS Meeting, January 7, 2026, at 2.

²⁰ ERCOT, Agenda Item #4: ERS/Crypto Mining Load, WMS Meeting, January 7, 2026, at 5.

2.1.3. ADER

In October 2022, the ERCOT Board of Directors, at the direction of the Commission in Project No. 53911, launched a pilot project to explore whether ADERs can “support reliability, enhance the wholesale market, incentivize investment, potentially reduce transmission and distribution investments, and support better load management during emergencies.”²¹ ERCOT’s ADER pilot program is comparable in many ways to the Federal Energy Regulatory Commission’s (FERC) Order No. 2222, which sought to encourage ADER participation in FERC-jurisdictional wholesale markets.²² The ADER pilot has proceeded in phases and is currently in Phase 3; which ERCOT expects to run through at least June 2026 (a minimum of one year).

Product specifications

ADERs participating in the Phase 3 program compete with other ERCOT resources to provide energy, Non-Spin, and ECRS; all of which are procured in the day-ahead and real-time markets.

Participation requirements

An ADER is defined as any combination of distribution-connected generation, energy storage, or a controllable load. An ADER consists of multiple premises or devices with the ability, in aggregate, to respond to ERCOT dispatch instructions. An ADER aggregation must have the capability to provide at least 100 kW of response (demand response capability plus injection capability) and each Premises can provide at most 1 MW of response (demand response capability plus injection capability).²³ ADERs participate in the ERCOT energy and ancillary services market through existing ALR and NCLR participation models, with certain exceptions specified in the ADER Phase 3 Pilot Governing Document.²⁴

Under both the ALR and NCLR participation models, the ADER may contain premises that inject energy into the distribution system and may provide a net injection on an aggregated basis; ERCOT will consider net injections as Demand Response under the Protocols and other ERCOT rules.²⁵ The ADER must be registered and associated with a QSE. Known limitations relevant to the distribution service provider, such as Premise injection limitations, must be reflected in the registration. Identified limitations on the distribution system will not explicitly be enforced by ERCOT’s systems when awarding or dispatching the ADER. Further, the telemetry validation procedures and metrics in the ADER pilot differ from other resources that offer ancillary services in ERCOT.

ADERs participating as ALRs or NCLRs must comply with ALR metering and telemetry requirements. A QSE representing an ADER must send resource-level real-time telemetry to ERCOT every two seconds and comply with applicable ERCOT protocols.²⁶ Premises in an

²¹ ADER Pilot Project Governing Document Phase 3.1, Approved June 23, 2025, Updated October 24, 2025, at 3.

²² Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators, Order No. 2222, 172 FERC ¶ 61,247 (2020), 172 FERC ¶ 61,247 at P 204.

²³ ADER participants must submit a Details of the Aggregation (DOTA) form, among other things, to be qualified. The DOTA requires information about ERS and TDU commercial & residential load management programs.

²⁴ ADER Phase 3.2 Pilot Governing Document, at 21.

²⁵ For settlement purposes, ADER injections are treated as negative load in the Phase 3 pilot. For real-time telemetry, a static MW offset is applied to make it appear to ERCOT systems that these are always net load on the system.

²⁶ ADER Pilot Project Governing Document Phase 3.2, Approved June 23, 2025, Updated February 27, 2026, at 15, [link](#). (ADER Phase 3.2 Pilot Governing Document).

ADER are required to have 15-minute interval meter data; electric service identifier (ESI ID) data in a competitive choice area, and revenue-quality meter data in a NOIE service territory.²⁷ The QSE must provide ERCOT allocation factors that represent the fraction of the ERCOT-issued instruction to the ADER that is being provided by each metered Premise in the aggregation, which can be static in Phase 3 and does not need to be provided in real-time.²⁸ Regardless of participation model, an ADER is not permitted to present statistical sampling for performance evaluation.

ALR Participation model

An ADER using the ALR participation model is modeled as a Load Resource belonging to an aggregation of premises, but all the sites must be located in a single Load Zone and have the same Load Serving Entity (LSE) and Distribution Service Provider (DSP). ADERs participating as ALRs are subject to ALR participation rules with certain exceptions. The telemetry validation procedures and metrics for ADERs differ from those for ALRs. However, like all ALRs, ADERs participating as an ALR must qualify to participate in SCED.

NCLR Participation model

ADERs participating as an NCLR may be an aggregation of load-only sites. ADER baseline determinations involve meter readings prior to deployment and similar readings during the sustained response period for performance measurement. The NCLR ADER participation model allows aggregations that cannot incrementally follow SCED basepoints to provide ECRS and Non-Spin, but not RRS. Aggregated NCLRs can use third-party QSE aggregation and premises above 100 kW are not required to have the same LSE.²⁹

Procurement and settlement

In Phase 3 of the ADER pilot, systemwide participation limits were increased to 500 MW for energy dispatch, and 100 MW for ECRS and Non-Spin. However, a single QSE may not register ADERs with capability above 90% of the systemwide limits for each product. Qualified ADERs may offer Non-Spin or ECRS and are cleared and settled in accordance with the ERCOT Protocols regarding ALR energy settlement, and the Load Zone price will be used for settlement of energy. Premises in the ADER that inject into the distribution system are treated as negative load for purposes of settlement.

Historical participation, prices, and deployments

ADERs are currently qualified to provide Non-Spin and ECRS to ERCOT. As of February 2026, a total of 13 ADERs are registered to participate in the pilot, but only seven ADER resources are qualified to participate. The seven qualified ADER resources have a total qualified capacity of 107.7 MW that is qualified to provide ECRS or Non-Spin.

Table 8: ADER participation and qualification, February 2026

Qualified Resources	ECRS qualified capacity	Non-Spin qualified capacity	Total qualified capacity
7	49.7 MW	35.4 MW	107.7 MW

Source: ERCOT, February 2026.

²⁷ ADER Phase 3.2 Pilot Governing Document, at 15.

²⁸ ADER Phase 3.2 Pilot Governing Document, at 21.

²⁹ ADER Phase 3.2 Pilot Governing Document, at 6.

ERCOT does not post information about the quantity of ECRS and Non-Spin capacity that ADER resources have cleared in ancillary services markets, but it does publish the number of intervals each ADER resource was cleared to provide each ancillary service, along with other information.³⁰

Table 9 shows the percent of real-time intervals where at least one ADER resource was cleared to provide either Non-Spin or ECRS. Resources in the ADER pilot have provided ancillary services in at least half of the intervals in the twelve-month period ending October 2025.

Table 9: Percent of real-time intervals with cleared ADER resources,

November 2024 – October 2025		
	Non-Spin	ECRS
Nov 2024	63%	0%
Dec 2024	63%	0%
Jan 2025	56%	2%
Feb 2025	52%	0%
Mar 2025	50%	18%
Apr 2025	55%	49%
May 2025	67%	58%
Jun 2025	73%	58%
Jul 2025	69%	56%
Aug 2025	12%	13%
Sep 2025	25%	58%
Oct 2025	66%	56%

Source: ERCOT, ADER Monthly Reports.

Current issues

Expanding the ADER program may require additional design modifications because ADER is currently procured at the system level, without regard to local constraints or congestion impacts. The ADER Governing Document identified this as a Phase 3 issue to study and directed ERCOT to evaluate how dispatching and settling ADERs at the zonal level—rather than at the nodal level—affects congestion management.³¹ ERCOT plans to remain in Phase 3 of the ADER pilot this year and will, among other things, continue to assess ADER resource performance, monitor participation limits, consider zonal and nodal dispatch and settlement models, review the ADER registration processes, and make targeted improvements.³²

2.2. DR programs not administered by ERCOT

Several types of DR programs and incentives exist in the ERCOT footprint that ERCOT does not administer. These DR programs are instead the result of individual customer financial incentives or retail DR programs and rate incentives administered by REPs, NOIEs, and TDSPs. This section begins with a summary of DR deployments and self-curtailments driven

³⁰ ERCOT posts this information about the ADER pilot [here](#).

³¹ ADER Phase 3.2 Pilot Governing Document, at 4, 22.

³² ERCOT, ADER Transition from Pilot to Protocols, April 1, 2026, [link](#).

by incentives to avoid transmission charges under the 4CP transmission cost allocation methodology. These actions to reduce transmission charges in the subsequent year drive the majority of DR program deployments and self-curtailements in ERCOT.

2.2.1. 4CP self-curtailements

ERCOT's 4CP intervals are defined as the highest four 15-minute gross load intervals in each of the four summer months of June, July, August, and September. A customer taking service at 700 kV or higher and individual NOIE transmission charges in a given year depend on their contribution to the 4CPs in the prior year. The 2025 rate to recover the ERCOT system's annual transmission revenue requirement was \$68.55/kW-year, creating a significant incentive for loads and NOIEs facing these 4CP charges to estimate when 4CP intervals will occur and curtail loads during those intervals. Pursuant to requirements in SB6, the Commission is evaluating whether the wholesale 4CP cost allocation rules are reasonable (Project No. 58484). Any changes the Commission orders to transmission cost allocation as a result of that proceeding will have a significant impact on load behavior and incentives in ERCOT.

Incentives to self-curtail

ERCOT loads that take service at 700 kV and above and individual NOIEs have a strong incentive to reduce loads during 4CP intervals because their transmission charges in the following year depend directly on their consumption during 4CP intervals. For example, according to NRG Energy, Inc., load reductions during 4CP intervals can yield savings as high as \$10,000 to \$21,000/MW *per interval*, depending on the customer's DSP.³³ Given the significant potential transmission cost savings involved, large customers do not need a formal DR program to incent self-curtailements during 4CP intervals.

By contrast, residential customers and small commercial loads do not have strong individual financial incentives to reduce consumption during 4CP intervals because REPs and NOIEs generally collect transmission charges from these customer classes on a per-kWh basis. However, NOIEs themselves have incentives to lower future transmission charges and as a result, many NOIEs design DR programs to reduce residential and small commercial loads during 4CP intervals. In the competitive areas, transmission costs are allocated at the TDSP level, and REPs pass transmission costs through directly to residential and small commercial customers. However, some REPs in competitive areas offer 4CP advisory services and other programs to loads subject to 4CP cost billing to help them manage transmission costs.³⁴

Although the 4CP transmission cost allocation methodology has the greatest impact on DR program deployments and self-curtailements in ERCOT, these load reductions do not necessarily align with ERCOT's system needs or market signals. For example, 4CP intervals do not coincide with intervals when load reductions would provide the most relief to the ERCOT system, such as during system net peaks or tight conditions in non-summer months.

2.2.2. REP and NOIE DR programs

As noted above, REPs and NOIEs administer their own DR programs independent of ERCOT. ERCOT does not play a role in these DR programs and does not procure, deploy, or directly compensate loads that participate in these programs. These DR programs include Indexed Real-Time, Indexed Day-Ahead, Critical Peak Pricing, Peak Rebates, Time of Use pricing, Free Days and/or Hours programs, other direct load control, and other voluntary DR

³³ NRG Energy, Inc., Comments in response to Public Utility Commission of Texas Staff's August 5, 2025 Questions, Project No. 54884, at 9.

³⁴ See e.g., Reliant 4CP advisory service offerings, [link](#).

products.³⁵ The REP and NOIE retail DR available to residential and commercial customers vary by administrator and a variety of program types and incentive structures are offered in the ERCOT footprint.

Residential DR programs

REP and NOIE residential DR programs available in ERCOT tend to have the same general structure, but the individual rates and incentives vary by program. Many REP and NOIE DR programs provide a thermostat rebate to lower infrastructure costs and incent the installation of smart thermostats. These are one-time rebates that can be applied to eligible thermostats selected by the program administrator. REPs and NOIEs have partnerships with different smart thermostat manufacturers and provide customers with lists of eligible thermostats to choose from for installation. While some administrators do not offer thermostat rebates, others provide a thermostat rebate or a smart thermostat free of charge.^{36, 37, 38}

Once a smart thermostat has been installed, customers may also receive an incentive to join the administrator's voluntary DR program with another potential one-time rebate for enrollment. While some administrators may not provide a rebate, others may provide rebates up to \$85.^{37,39,40} This range is based on review of a small sample of REP and NOIE programs and does not reflect every DR program available in ERCOT.

Finally, program administrators can also provide a recurring payment to customers to encourage continued participation in the DR program. Administrators have varying methods to provide monetary benefits to customers enrolled in the program. Some REPs, for example, do not provide an explicit payment, but create savings for customers by reducing their electricity use during peak periods.³⁹ On the other hand, certain REPs provide an annual payment (e.g., \$30) for continued enrollment, whereas other administrators provide more consistent monthly payments of up to \$15.^{40,41} Some REPs provide an energy discount of \$0.60/kWh for every kWh of demand reduced compared to baseline demand.⁴² Finally, some REPs provide enrolled customers with a half cent per kilowatt hour (\$0.005/kWh) discount on their electricity rate instead of a one-time or recurring payment.³⁶

Despite the varied structure of the programs, all administrators aim to incentivize adoption and continued participation. Table 10 summarizes the incentives of some of the programs discussed above. Some programs limit thermostat adjustments to a maximum of 4°F and aim to cap load reduction events at 25 times per year.⁴¹ Customers are also able to opt-out of a DR deployment by simply adjusting their thermostat. By contrast, some DR administrators do not limit the number of DR events they can call annually and only allow program participants to override three events.³⁸ The large variation in program rules and ability of customers to override DR reductions can be a source of uncertainty about how much residential DR is available to deploy during an event.

³⁵ ERCOT 2024 DR Report, at 13-14.

³⁶ E.g., Amigo Energy Stat Rewards Program [link](#).

³⁷ TXU's Connected Conservation Program [link](#).

³⁸ Rhythm Energy's Peak Payback Demand Response Program [link](#).

³⁹ Intelligent Octopus, [link](#).

⁴⁰ CPS Energy's WiFi Thermostat Rewards, [link](#).

⁴¹ Austin Energy Power Partner Thermostats, [link](#).

⁴² Reliant Energy's Degrees of Difference Rewards Program [link](#).

Table 10: Summary of select Residential REP and NOIE Smart Thermostat Programs

Administrator	Program Information		Incentive Structure		
	Program Name	Seasonality	Thermostat Rebate	Enrollment Bonus	Recurring Incentive
Austin Energy	Power Partners	Primarily Summer, can call all-year	\$50	\$75	\$30/year
CPS Energy	Wi-Fi Thermostat Rewards	Primarily Summer, some Winter	-	\$85	\$30/year
Octopus Energy	Intelligent Octopus	All-year	-	-	Bill savings during event
NRG (Reliant)	Degrees of Difference	All-year	-	\$50 (Smart Thermostat)	\$0.60/kWh discount for energy reduced compared to baseline (Manual thermostat), Bill credits (Smart thermostat)
Amigo Energy	Stat Rewards	All-year	-	\$50	\$0.005/kWh discount
Rhythm Energy	Peak Payback	All-year	Full Coverage	-	Up to \$15/month
Vistra (TXU)	Connected Conservation	All-year	-	\$50, up to \$150 if additional products bought	Bill savings during event

Commercial DR Programs

In addition to residential DR programs, REPs and NOIEs also offer DR programs to retail commercial customers in the ERCOT footprint. Similar to residential DR programs, the commercial DR programs do not follow a single program or incentive structure, but many share the same general structure. Unlike residential DR programs, many REP and NOIE commercial DR program administrators do not provide upfront incentives to install additional equipment beyond smart meters, nor do they offer upfront incentives to enroll in the program. However, upon enrollment in the commercial DR program, some administrators install advanced meters at no cost to the customer to closely monitor energy usage and encourage program participation.⁴³

Commercial DR programs may lack the direct incentives included in residential DR programs because many commercial DR programs do not require participants to possess advanced devices (e.g., controllable thermostats) that allow the program administrator to directly control the commercial customer's electricity usage. DR programs that require a smart meter may

⁴³ Austin Energy. Commercial Demand Response, [link](#).

also allow commercial customers to manually adjust their electricity consumption during a DR deployment event.⁴⁴ Some incentive structures are based on a peak kW reduction, whereas others are based on a kWh reduction.^{43,44} Incentives can range from \$50-80/kW of peak reduced and administrators may also provide energy-based incentives, such as a payment of \$0.6 per kWh reduced compared to baseline demand.^{43,44} Some program administrators also provide additional incentives if additional equipment is installed and allowed to be used for automatic DR.⁴³ The incentive for reducing DR can be as high as \$10-15/kW higher for commercial customers that have installed advanced meters and allow the administrator to automatically reduce energy consumption.⁴³ Some commercial DR programs even provide a \$210-\$215/kW increase in incentive for the first year to increase adoption of advanced metering.⁴³

Most commercial DR programs are active in the summer between June and September, and administrators can provide advanced notice as late as 10 minutes prior to the event through email, text, or phone to notify customers of a DR curtailment.^{43,44} In addition to providing program time periods, some commercial DR programs give customers the number of times they will be curtailed in a certain time period. Other commercial DR programs may call on customers throughout the year.⁴⁴ Although DR program incentives and rate structures vary across administrators, they all aim to reduce commercial consumption during peak events. Most events rely on voluntary participation during the peak event, and customers have the ability to avoid large load reductions. The voluntary nature of event participation and the different program designs create uncertainty about how much commercial DR capability will be available during a given event.

2.2.3. TDSP Load Management Programs

Table 11 shows the summer and winter TDSP load management programs in 2025, which totaled approximately 290 MW in summer and 120 MW in winter. Under the existing Memorandum of Understanding that ERCOT has with the TDSPs, ERCOT can request the deployment of TDSP summer and winter load management programs prior to or during an EEA 2 or EEA 3 event. ERCOT did not deploy TDSP load management programs in 2025.

Table 11: Summer and Winter TDSP Load Management programs

TDSP	Program Duration	Operational Hours	Estimated Demand Savings (MW)	Capacity* MW
AEP Texas**	June 1-September 30	1-7pm*	20.7-40.3	35
CenterPoint	June 1-November 30	24/7	138	137
Oncor	June 1-November 30	24/7	101.9	106
TNMP	June 1-September 30	1-7pm*	8.5	9
AEP Texas	December 1-February 28	24/7	16.2	11
CenterPoint	December 1-February 28	24/7	50	26
Oncor	December 1-May 31	24/7	53.5	77
TNMP	December 1-May 31	24/7	7.4	7

Source: ERCOT, 2025 Demand Response Report, Table 7. *Excludes weekends and federal holidays. **Includes ERCOT holidays. **AEP Texas Summer TDSP programs are shown as a range because some load management programs are only available in August and September while others are available in all of the months shown.

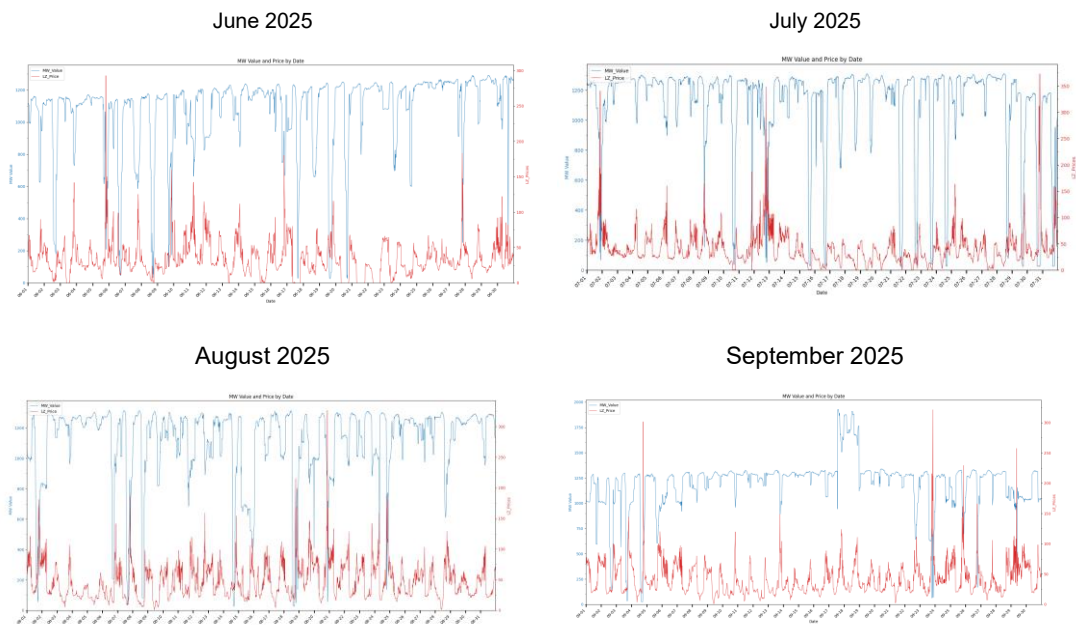
*Capacity figures shown are for Summer 2025 and Winter 2025.

⁴⁴ Reliant Energy. Business Degrees of Difference, [link](#).

2.2.4. Self-directed price-responsive demand

Many ERCOT loads respond to price signals outside of anticipated 4CP intervals and without being part of a formal DR program. Instead, they vary their load independently based on their own economics and the prevailing locational marginal price (LMP). For example, ERCOT provided information in a January 2026 Wholesale Market Subcommittee meeting showing that crypto mining loads are extremely price sensitive. As shown in Figure 1, crypto mining loads that also provide ERS in the West zone, are highly price sensitive, and rapidly reduce load (blue line) when prices spike (red line). These price responses appear to be almost instantaneous.

Figure 1: Crypto mining price sensitivity in West Zone, June - September 2025



Source: ERCOT, Agenda Item #4: ERS/Crypto Mining Load, WMS Meeting, January 7, 2026, at 6-9.

ERCOT also found that the price sensitivity of these crypto mining loads increased as LMPs increased. Specifically, ERCOT found that crypto mining loads are less price sensitive at prices at or below LMPs of approximately \$50/MWh. However, their price sensitivity increased with prices and a clear inverse relationship was apparent at LMPs above \$88/MWh.⁴⁵

3. Collective impacts of DR programs on ERCOT markets

Taken as a whole, the majority of the DR programs in ERCOT are targeted at load reductions during 4CP intervals. In 2024, these load reductions reached almost 5,000 MW through programs largely targeted at likely 4CP intervals. As noted above, 4CP intervals may not

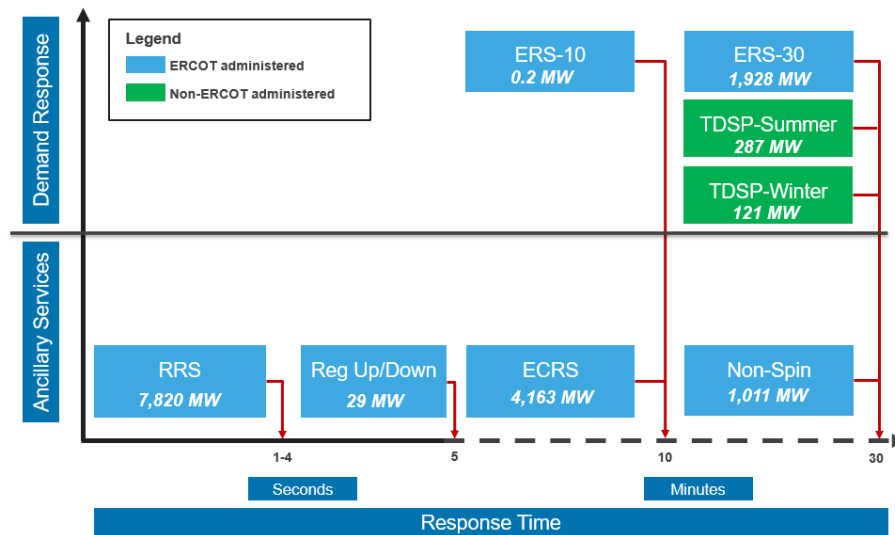
⁴⁵ ERCOT, Agenda Item #4: ERS/Crypto Mining Load, WMS Meeting, January 7, 2026, at 23, [link](#).

align with the ERCOT highest-risk periods when energy shortages can arise, such as during net peak periods.

In 2025, 4.5% of REP and NOIE customers participated in DR and 4CP load reduction program; with REP and NOIE participation rates of 8.7% and 2.1%, respectively.⁴⁶ DR also occurs outside of 4CP intervals, but such reductions are less frequent. ERCOT reported that most DR participants in indexed pricing programs, which are not permitted for residential and small commercial customers, tend to respond to price signals above \$200/MWh. LMPs do not exceed \$200/MWh in ERCOT often. For example, LMPs in the Central load zone exceed \$200/MWh in 0.5% of 15-minute intervals in 2025 (178 intervals total). However, these intervals also tend to be the intervals where DR and generation resources could offer the most value. Load reductions also occur outside of formal DR programs because certain loads are extremely price-sensitive and often self-curtail when LMPs exceed approximately \$70/MWh.⁴⁷ ERCOT referred to such loads in the 2025 DR Report as “super responders”.⁴⁸

Figure 2 summarizes the qualified Load Resources that ERCOT could deploy, or request deployment of in the case of TDSP programs, in 2025. It includes response times and whether the load response is provided through an ancillary service product, ERS, or a TDSP program. The figures in each box represent the average cleared ERS capability in 2025, TDSP capability, and the CLR, NCLR, and ADER capacity qualified to offer ancillary services in ERCOT.

Figure 2: Qualified Load Response and DR in ERCOT by product type and response time, 2025



Regarding TDSP load management programs, ERCOT has only made one request to deploy these programs to date. ERCOT made this request on September 6, 2023 during an EEA 2

⁴⁶ ERCOT 2025 DR Report, Table 9.

⁴⁷ ERCOT 2025 DR Report, at 18.

⁴⁸ ERCOT 2025 DR Report, at 18.

event.⁴⁹ ERCOT can only request that TDSPs deploy their load management DR capability, and ERCOT operators do not have information about the amount of DR capability (in MW) that is deployed in response to a deployment request.⁵⁰

It is also informative to examine time periods with the greatest load reductions due to DR programs. DR program administrators do not deploy load reductions on a routine basis throughout the year. Most DR deployments in ERCOT tend to occur in the summer months during intervals where 4CP intervals are likely to occur. For example, ERCOT reported that during the summer of 2023, one or more REPs deployed their responsive device DR programs on only 33 unique days.⁵¹

ERCOT's 2024 DR report contained a survey and analysis of the hours in Summer 2024 with at least 2,500 MW of load reduction in HE 17 (i.e., the hour ending at 5pm), where 4CP intervals are common (referred to herein as "high load days"). ERCOT's survey, summarized in Figure 3, included 24 days and shows load reductions from REP- and NOIE-administered 4CP DR programs and load reduction from other DR programs. Load reductions in the Summer of 2024 reached as high as 4,949 MW. ERCOT's analysis clearly demonstrates that the majority of load reduction in ERCOT is driven by 4CP cost allocation. Much lower amounts of load reduction from "Other" DR programs (shown in green).⁵²

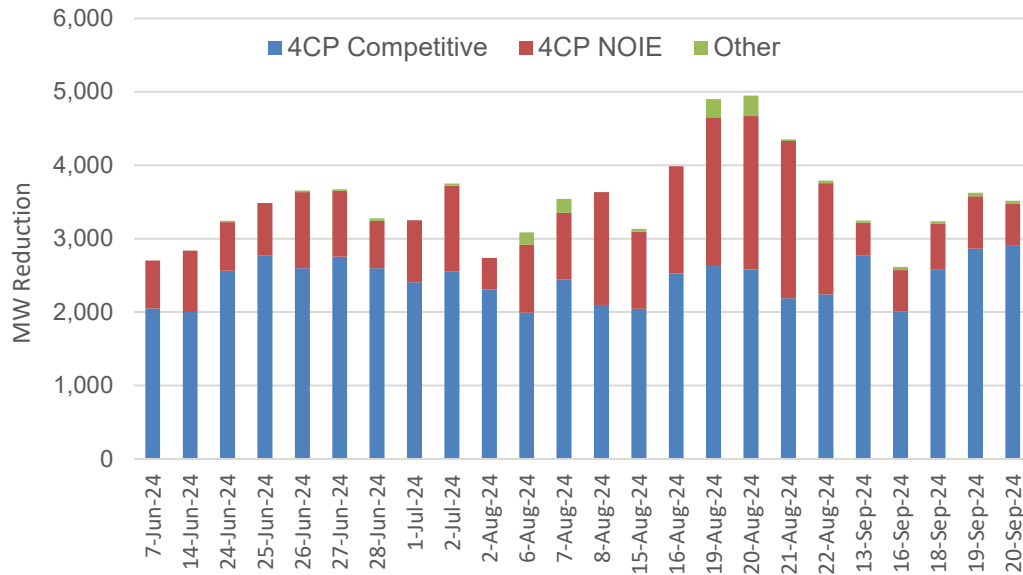
⁴⁹ ERCOT issued an EEA 2 alert on September 6, 2023. ERCOT News Release, Sep 6, 2023, *ERCOT Has Initiated Energy Emergency Alert Level 2 (EEA 2), Conservation is Critical* [link](#). See also ERCOT Response to Commission Staff's First Request for Information to ERCOT, Questions RF1-1 through RF1-8, Project No. 56517, April 3, 2025, at 10 (response to Staff RFI 1-5).

⁵⁰ See also ERCOT Response to Commission Staff's First Request for Information to ERCOT, Questions RF1-1 through RF1-8, Project No. 56577, April 3, 2025, at 10 (response to Staff RFI 1-5) and 12 (response to Staff RFI 1-6).

⁵¹ ERCOT Comments, Public Utility Commission of Texas, Project No. 56966, at 5, September 27, 2024.

⁵² ERCOT DR Report, February 2025, Table 16. "Other" is defined as the sum of load response associated with indexed day-ahead and real-time prices, NOIE price response, peak rebate, other direct load control, and ERS minus any capacity that participated in multiple programs (referred to as Overlap)

Figure 3: Summer 2024 demand reduction in HE 17 by program type



Source: ERCOT 2024 DR Report, Table 16. Note "Other category" is the sum of non-4CP programs minus customers participating in multiple programs, referred to as "Overlap" in the survey. Graph only includes days with at least 2,500 MW load reduction.

Load reductions from REP-administered DR programs averaged 2,436 MW in 2024 during the 24 high load days in HE 17 and ranged from 1,992 MW to 2,902 MW. Load reductions from NOIE-administered 4CP DR programs averaged 1,019 MW and ranged from 430 MW to 2,142 MW. Overall, load reduction from DR programs in the competitive areas accounted for 71% of the total load reduction on these summer days, on average, and load reductions in NOIE areas accounted for the balance. These ratios roughly align with the 2025 4CP Load Ratio Shares shown in Table 12 below.

These 2025 4CP values will form the basis for 2026 transmission cost allocation. Competitive areas will be allocated for 70% of transmission charges via the 4CP method, and NOIEs will be allocated the balance (30%). This table gives an indication of how ERCOT's transmission charges will be allocated to the competitive areas and NOIEs with a Load Ratio Share above 3% in 2026.

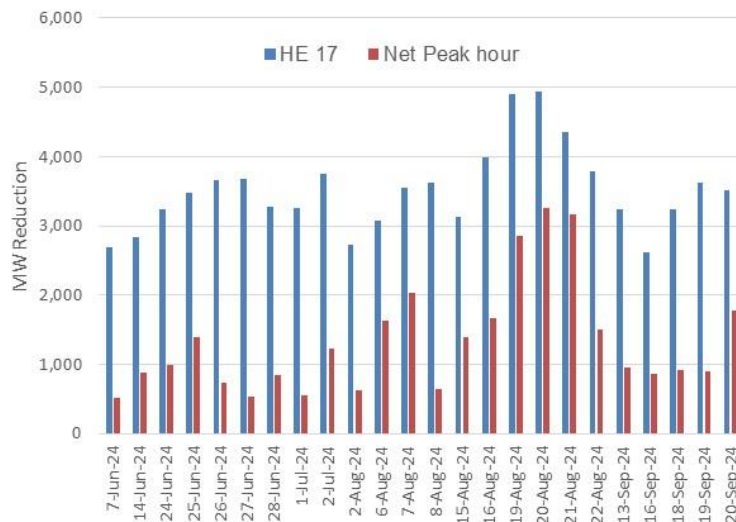
Table 12: 2025 4CP Values in ERCOT, MW

	June 6/19/2025 17:00	July 7/30/2025 17:00	August 8/18/2025 17:00	September 9/04/2025 17:30	Average 4CP Load	Load Ratio Share (%)
AEP Texas	5,014	5,285	5,559	5,340	5,300	6.6%
Oncor	27,203	29,484	29,873	28,148	28,677	35.5%
CenterPoint	19,857	20,154	20,747	19,962	20,180	25.0%
TNMP	2,392	2,616	2,349	2,333	2,423	3.0%
Competitive subtotal	54,467	57,539	58,529	55,783	56,580	70.0%
CPS Energy	4,846	4,885	5,362	5,151	5,061	6.3%
City of Austin	2,644	2,678	2,892	2,757	2,743	3.4%
NOIEs < 3% of Avg. 4CP	15,529	16,806	17,186	16,385	16,477	20.4%
NOIE subtotal	23,019	24,369	25,439	24,293	24,280	30.0%
ERCOT Total	77,486	81,908	83,968	80,076	80,860	100.0%

Source: ERCOT.

An important aspect of the incentives created by 4CP cost allocation is that load curtailments – whether through formal DR programs or through self-curtailment – are much greater in anticipated 4CP hours than in other hours. Summer coincident peak hours typically occur in the afternoon, with the 4CP hour often occurring in hour ending 17 (i.e., HE 5pm). The net load peak, defined as load minus the output of wind and solar resources, typically occurs at different times of the same day. For example, ERCOT also estimated DR load reductions on the same Summer 2024 high load days during the net peak hour, which predominantly occurred in HE 20 and 21. A comparison of load reductions during the peak hour and net peak hour on the sample of Summer 2024 days is shown in Figure 4 below. Load reductions during the net peak load hour tended to be much lower than during the peak hour.

Figure 4: DR load reduction on Summer 2024 high load reduction days, difference between HE 17 and daily net peak hour



Source: Derived from data provided in the ERCOT 2024 DR Report.

Specifically, the average load reduction on the 24 high load days in was 3,509 MW during the HE 17, a likely 4CP hour, and 2,178 MW higher than the average DR load reduction during the net peak load hour on the same day (1,331 MW).

An analysis ERCOT performed on a small sample REP-administered DR programs in 2023 showed the same dynamic – significantly higher load reductions during anticipated or likely 4CP intervals than during daily net load peaks. ERCOT analyzed the load reductions of approximately 30,000 residential customers enrolled in REP-administered residential DR programs in 2023.⁵³ ERCOT indicated that the REP-administered DR deployments were attributable to responsive devices, such as thermostats.

ERCOT selected the four summer days in June, July, August, and September 2023 with the highest net peak loads in each month.⁵⁴ On these days, ERCOT calculated baselines for the residential customers and estimated their aggregate load reductions during deployment. ERCOT found that the average premise-level load reduction during the net peak load hour on these days ranged from -0.48 kW to 1.25 kW.⁵⁵ Figure 5 plots load reductions from these residential customers (green line) relative to their estimated baseline loads (blue line) on one of the selected days; June 20, 2023. The residential load reductions during the net peak hour on June 20, 2023, which occurred in HE 20, was 17.08 MW, a reduction of 3.45% relative to the baseline estimate from these customers (500.06 MW). The highest load reduction on

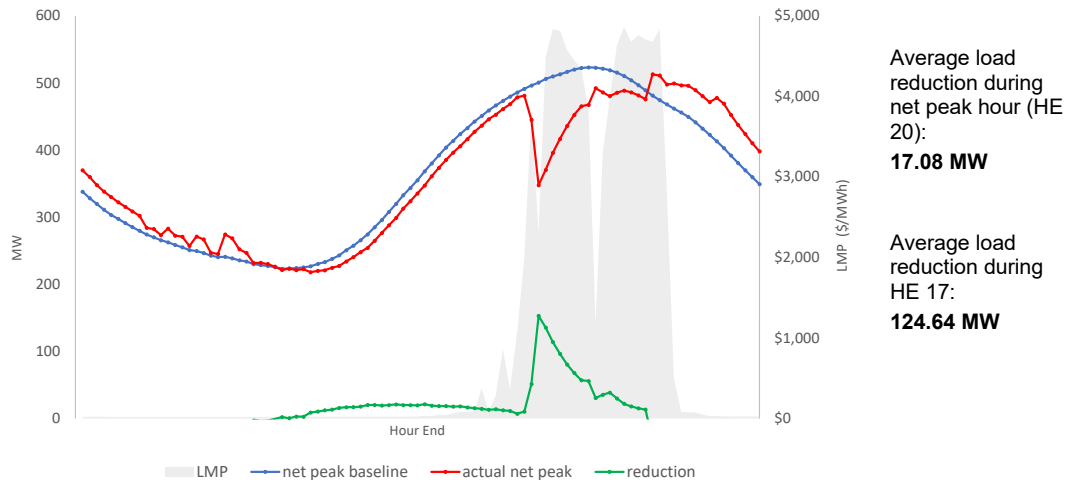
⁵³ ERCOT comments, Public Utility Commission of Texas Project No. 56966, at 1-2. ERCOT relied on information from its annual DR survey to perform this analysis.

⁵⁴ The dates ERCOT selected in 2023 were June 20, July 31, August 25, and September 6. These dates differed from the dates when the 4CP occurred in these months.

⁵⁵ ERCOT explained that these estimates were typically due to responsive devices, such as thermostats. The observed load increases, were due to REP deployments ending (e.g., thermostats reverting to prior settings), near the beginning of the peak hour.

June 20, 2023 occurred in HE 17, an hour when a 4CP interval is likely to occur. The average load reduction in HE 17 was 124.64 MW, a reduction of 25% relative to the baseline.

Figure 5: Estimated residential load reductions from REP-administered DR programs, June 20, 2023



Source: Attachment to ERCOT comments, PUCT Project No. 56966

Similar trends occurred on the other three days ERCOT analyzed, and although the information was not a complete sample of all 2023 retail DR programs, the data are consistent with the trend observed in ERCOT’s 2024 DR survey. ERCOT explained to the Commission that current REP-administered DR programs, “[do] not necessarily guarantee that deployment will occur during the highest net peak load hour or for the entirety of those hours.”⁵⁶ ERCOT further explained that many DR programs may not require curtailment, or may allow customers to cease curtailment after a specified time, and that there was an imperfect correlation between high LMPs and net peak loads for the full hour of peak net load. Finally, ERCOT noted that REPs could misestimate high-priced intervals, or have hedge positions that could reduce a REP’s incentives to curtail its customers in a given high-priced interval.

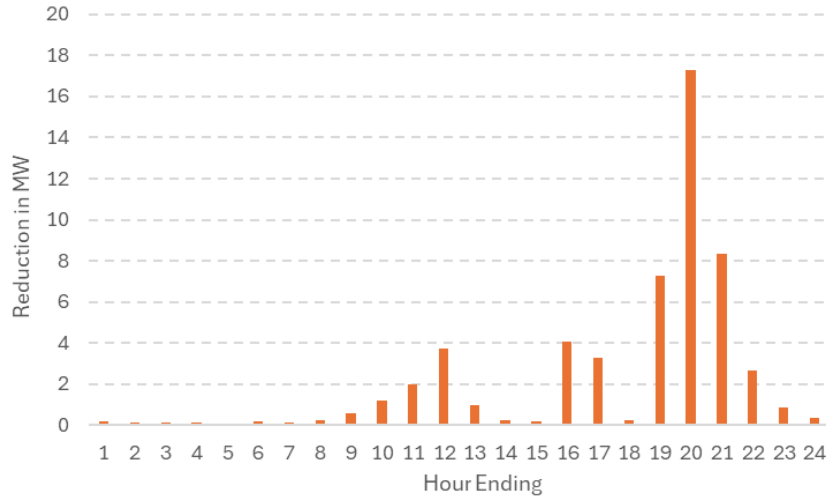
As such, the current REP- and NOIE-administered DR programs in ERCOT do not appear to be targeting the system’s greatest needs for load reductions, which often occur during net peak periods. The retail DR programs that ERCOT does not administer are not in conflict with each other and do not appear to be causing operational challenges or impairing the functioning of the ERCOT market, but there is an opportunity to increase the benefit of retail DR by better aligning them with ERCOT’s system needs. As discussed further below, ERCOT’s DR participation rates are fairly low and would likely increase if additional financial incentives are provided to retail DR program participants.

ERCOT provided CRA with summary information of DR deployments from REP-administered DR programs classified as “other direct load control programs” where at least 1,000 ESIIDs were recorded as being deployed in the summer months of June, July, August, and September 2025. These deployments occurred across the competitive areas in ERCOT

⁵⁶ ERCOT comments, Public Utility Commission of Texas Project No. 56966, September 27, 2024, at 3.

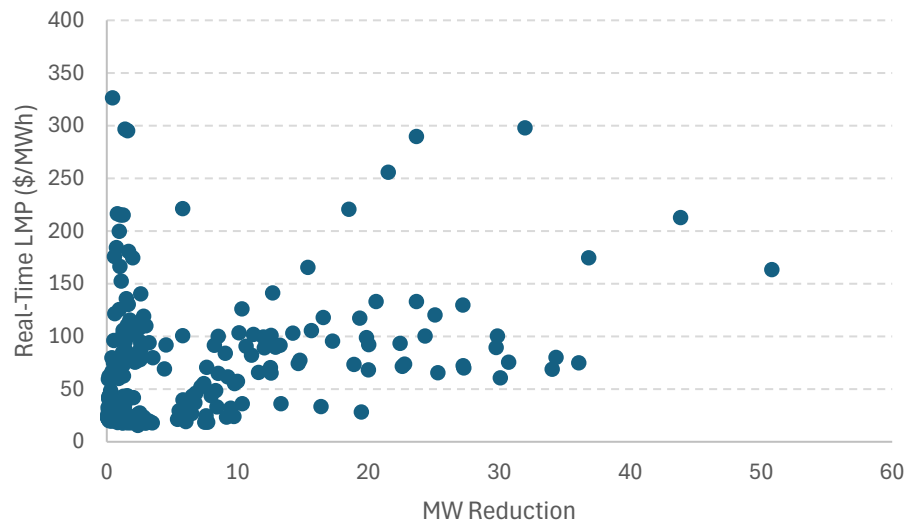
footprint. CRA analyzed the intervals where DR deployment was 5% or more below ERCOT’s calculated DR baseline for the associated ESIDs, which amounted to 247 15-minute intervals on 22 individual days. The average load reductions by hour are shown in Figure 6 below.

Figure 6: Summer 2025 sample of residential REP DR program reductions from Other Direct Load Control programs



The average residential load reduction from the load control programs on these days was 6.3 MW, but the maximum deployment was 50.8 MW. The average percentage reduction relative to ERCOT’s estimated demand baseline for the ESIDs was 17%, and the maximum percent reduction was 57%. These REP-administered retail DR deployments, which do not represent all DR deployments and were *not* associated with 4CP DR programs, tended to occur just before and during net peak hours (HE 20 and 21). Twenty percent of the intervals (50 out of the sample of 247 intervals) occurred during the net peak hour, and these reductions were also the highest in terms of MW. The average and maximum load reduction amounts from these direct load control DR programs do not represent load reductions from all DR programs and as a result, are much lower than typically occur in ERCOT during likely 4CP intervals. ERCOT has not released its analysis of 2025 load reductions from all DR programs, including those focused on 4CP intervals, as of the publication date of this assessment.

The amount of load reductions (in MW) associated with these DR programs was positively correlated with prices, with higher DR reductions occurring at higher prices, but the relationship was not linear. For example, there were several instances of high prices and relatively low DR reductions, as shown in Figure 7 below. This shows that DR reductions are not purely price driven, which indicates that REPs likely consider several factors when deploying DR, and may have financial positions that can make the REP less sensitive to prevailing real-time prices. Another factor may be that some DR reductions are achieved through a customer-sited PV installation or a combination of customer-sited PV and storage, which can limit when DR capability is available for deployment.

Figure 7: 2025 Sample load reductions and indicative Real-Time LMP

Additionally, energy consumption increased relative to the baseline after the deployment, most likely to restore temperatures to pre-deployment levels. However, the REP DR deployments resulted in net energy savings overall relative to ERCOT's estimated baselines.

4. ERCOT DR programs looking forward

Pursuant to SB6, enacted by the 89th Texas Legislature, ERCOT is required to add a new DR product available to loads at or above 75 MW.⁵⁷ ERCOT also proposed a DR product that would provide incentive payments for load reductions from residential customers during net peak periods (NPRR 1296).⁵⁸ SB6 and ERCOT's RDR proposal are discussed in turn below.

4.1. SB6 large load curtailment service

SB6 directs the Commission to require ERCOT to "develop a reliability service to competitively procure demand reductions from large load customers with a demand of at least 75 MW to be deployed in the event of an anticipated emergency condition."⁵⁹

SB6 further requires that the service: 1) specify the periods when the service may be used to assist with maintaining reliability during extreme weather events; 2) ensure that ERCOT provides at least a 24-hour notice to large load customers and requires each large load to remain curtailed for the duration of the energy emergency alert event or until the load can be recalled safely; and; 3) prohibit participation by any large load customer that curtails in response to the wholesale price of electricity, as determined by ERCOT, or that otherwise participates in a different reliability or ancillary service.⁶⁰ Finally, SB6 requires ERCOT to

⁵⁷ TX Senate Bill 6, 89th Texas Legislature, §39.170, [link](#).

⁵⁸ NPRR 1296, Residential Demand Response Program, [link](#).

⁵⁹ SB6, §A39.170(a).

⁶⁰ SB6, §A39.170(b).

include a deployment adder and calculate price adjustments when it deploys the service.⁶¹ The Commission is currently considering how to design this reliability service in Project No. 58482.

4.2. ERCOT RDR proposal

In December 2024, the Commission established an average residential load reduction goal for ERCOT that focused on reducing residential electric consumption during “ERCOT peak demand periods” pursuant to legislation enacted by the 88th Texas Legislature.⁶² The Commission created a residential DR program to help achieve the goal through responsive devices, referred to herein as the §25.186 program because the PUCT regulations that govern the program are contained in 16 TAC §25.186. REPs are eligible to receive funding to administer the §25.186 program through TDSP energy efficiency incentive programs established under 16 TAC §25.181.⁶³ As part of the §25.186 program, REPs must submit quarterly reports to ERCOT to help the Commission monitor §25.186 program performance.⁶⁴ As discussed further below, ERCOT has proposed to use this reporting as a vehicle to incent and expand residential load reductions in ERCOT, in both competitive and NOIE areas.

In 2025, ERCOT proposed an RDR program under NPRR 1296⁶⁵ that would leverage QSE reporting to ERCOT that would occur through the §25.186 program.⁶⁶ ERCOT is currently refining the RDR proposal and incorporating stakeholder feedback. PUCT regulations prohibit residential customers that participate in the §25.186 program from participating in the ERS program or TDSP load management programs.⁶⁷

Details of ERCOT’s proposed Residential DR program

ERCOT is proposing a program that would make incentive payments to QSEs (that represent a NOIE or REP DR program administrators) to compensate NOIEs and REPs for residential load reductions achieved through controllable devices, such as thermostats. ERCOT’s proposed RDR program would use the reporting established under PUCT’s §25.186 program to monitor performance and calculate incentive payments for residential load reductions. ERCOT would not issue deployment instructions under the proposal. Instead, ERCOT would provide incentive payments after-the-fact. As discussed further below, the incentive payments would not be guaranteed. According to ERCOT, the proposed RDR program will “expand the utilization of smart devices at households to provide DR to assist in meeting the peak system Net Load throughout the year.”⁶⁸

⁶¹ SB6, §A39.170(c).

⁶² Public Utility Commission of Texas, Order Adopting New 16 TAC §25.186, Project No. 56966, December 12, 2024, [link](#)

⁶³ 16 TAC, §25.186(f).

⁶⁴ Public Utility Commission of Texas, Order Adopting New 16 TAC §25.186, Project No. 56966, December 12, 2024, at 43. See also ERCOT, Instructions for Quarterly Residential Demand Response Data Submission by Transmission and Distribution Service Providers, [link](#).

⁶⁵ NPRR 1296, Residential Demand Response Program, [link](#).

⁶⁶ 16 Texas Administrative Code (TAC), §25.186(c), [link](#).

⁶⁷ 16 TAC, §25.186(c)(2)(D).

⁶⁸ ERCOT, NPRR 1296, at 1.

Performance assessment and price adder

Under the RDR proposal, ERCOT would review meter data provided by QSEs, on behalf of REPs/NOIEs, and calculate the highest hourly load reductions for each season during the applicable number of top net peak hours in each season, as noted in the “Assessment hours” column in Table 13. For example, for the summer season, ERCOT would calculate a REP/NOIE participant’s highest six load reductions during the eight highest net load hours in summer. ERCOT would then compensate NOIE/REP’s QSE at the seasonal RDR compensation rate, discussed further below.

Table 13: Proposed RDR seasons, assessment hours, and participation caps

Season	Assessment hours	Cap (MWh)
Summer (Jun – Sep)	highest 6 load reduction hours of the highest 8 net load hours	1,500
Fall (Oct – Nov)	highest 3 load reduction hours of the highest 5 net load hours	3,000
Winter (Dec – Feb)	highest 6 load reduction hours of the highest 8 net load hours	1,500
Spring (Mar – May)	highest 3 load reduction hours of the highest 5 net load hours	3,000

Source: NPRR [1296](#), Residential Demand Response Program, Aug. 26, 2025, §3.26.4(1).

Some stakeholders expressed concerns that the RDR proposal would suppress prices during net peak hours because the incentive payments would be paid outside of the real-time market. Based on this feedback, ERCOT proposed to include a Reliability Deployment Price Adder (RDPA) to address price formation concerns. The proposed RDPA would be triggered in hours when net load exceeds a pre-defined threshold. ERCOT reasoned that this adder would effectively capture the expected hours of RDR participation while also providing a reasonable degree of stability to the market. ERCOT is considering thresholds that would trigger the RDPA and recently proposed seasonal triggers based on seasonal net load peaks in the prior two years.⁶⁹

Participation requirements

ERCOT’s proposed RDR program would be open to QSEs that represent both REPs and NOIEs. Participating QSEs would submit interval data for all days in the Assessment Period and for other Unique Meter IDs selected by ERCOT from the initial population files that NOIE LSEs would be required to submit. The RDR program would require a minimum of 2,000 participants per NOIE or REP. Participating NOIE LSEs would also be required to assign Unique Meter Identifiers (UMIs), analogous to ESIDs, to premises. Individual entities participating in a TDSP’s Standard Offer Load Management Program implemented under 16 TAC §§25.181-183, ERS, or the ADER program would not be eligible to participate in the RDR program. ERCOT expects to apply the Matching Sites methodology to calculate baseline levels for RDR program participants, but may consider using the Statistical Regression baseline method if deemed necessary.

⁶⁹ ERCOT, NPRR1296: Residential Demand Response (RDR) Program – Reliability Deployment Price Adder (RDPA) Analysis, Wholesale Market Subcommittee (WMS) March 4, 2026, [link](#).

Proposed RDR incentive rate and program caps

ERCOT proposed an initial RDR compensation rate based on the lower of \$140,000/MW-year, and the historical 3-year rolling average of the Peaker Net Margin divided by the number of events per year, which is 18 as currently proposed.⁷⁰ The initial rate has since been adjusted to \$105,000/MW-year. If the RDR response (in MWh) exceeds the seasonal caps (see Table 13), then the RDR compensation rate would be commensurately reduced so as not to exceed the compensation caps (e.g. if 500 MW cap was exceeded by 10% in a season, the compensation would be reduced by 10%). ERCOT also considered and sought feedback on the proposed 500 MW seasonal participation cap for the RDR proposal.⁷¹ See the Appendix for additional details about the current RDR proposal, which as noted above is currently under development.

5. Load participation in other U.S. RTOs/ISOs

Although differences exist across markets, Load Resource and DR participation rates in ERCOT are comparable to participation in other U.S. wholesale electricity markets – the California ISO (CAISO), ISO New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM) and the Southwest Power Pool (SPP). This assessment collectively refers to these wholesale markets as FERC-jurisdictional RTOs/ISOs. As in ERCOT, load resources can participate in energy and ancillary services markets in FERC-jurisdictional RTOs/ISOs. Load resources can also participate in capacity markets, if they exist.⁷²

Load and DR resources in FERC-jurisdictional RTOs/ISOs earn the majority of their market revenues from capacity markets. For example, in PJM in 2024, capacity market revenue accounted for 76.4% of all revenue received by load resources, 7.25% came from participating in energy markets (economic DR), 9.1% of revenues came from regulation, and 7.2% came from synchronized reserves.⁷³ Additionally, in CAISO, the \$/kW-year rates available to load resources for capacity are at least ten times those available for providing ancillary services.⁷⁴ Given the difference in profitability, load resources tend to make up a small share of ancillary service markets in FERC-jurisdictional RTOs/ISOs, with rates comparable to those observed in ERCOT. Load resources rarely participate in FERC-

⁷⁰ The Peaker Net Margin as the cumulative difference between real-time energy prices and peaker's operating costs across settlement intervals, calculated starting from a value of zero on January 1 of each calendar year. ERCOT reasoned that the initial incentive rate would provide a predictable financial incentive to participants calibrated to market conditions. ERCOT, Residential Demand Response Workshop I, May 2, 2025, at 14, [link](#).

⁷¹ ERCOT, Residential Demand Response Workshop II, June 16, 2025 at 22, [link](#).

⁷² FERC-jurisdictional RTOs/ISOs are subject to FERC Order No. 745, which generally requires that DR resources must be eligible to offer into RTO/ISO product markets provided they meet the applicable technical and operational requirements and pass a net benefits test.

⁷³ Monitoring Analytics, 2024 State of the Market Report for PJM, March 13, 2025, at 345. Capacity resources that provide Emergency DR earn revenue from the capacity and emergency energy revenues.

⁷⁴ For example, net energy market revenues of Utility Proxy Demand Resources in 2024 were \$1.59/kW-year while available capacity revenues were \$96/kW-year in the RA program (85th percentile price) and \$206.42/kW-year in the Demand Response Auction Mechanism. See CAISO Department of Market Monitoring, Demand response issues and performance 2024, February 20, 2025, Table 3.2.

jurisdictional RTO/ISO markets as energy resources.⁷⁵ Table 14 summarizes the DR capacity that participated in RTO/ISO-administered capacity markets in 2024.⁷⁶

Table 14: DR Participation in RTO/ISO capacity markets, 2024

DR type		Capability (MW)
MISO*	Load Modifying Resource (LMR)	12,978
	LMR-BTMG	4,143
	LMR-DR	8,109
NYISO	Total Special Case Resources	1,435
	Special Case Resources – Capacity	1,433
	Emergency DR (SCR)	2
	Total Demand Capacity Resources	3,674
ISONE	Active Demand Capacity Resources	431
	Passive Demand Resources	3,243
PJM	Demand Response Capacity Resource	8,065

Source: Potomac Economics, MISO 2024 State of the Market Report, Table 17, and Monitoring Analytics, PJM 2024 State of the Market Report, Table 6-8 (PJM figure reported in UCAP MW).

CAISO does not administer a capacity market, but the California Public Utilities Commission (CPUC) administers a capacity construct called the Resource Adequacy (RA) Program. The RA Program is integrated into CAISO's day-ahead and real-time energy markets. In the summer of 2024, DR capacity (1,414 MW) accounted for about 2.6% of CAISO's total system RA capacity. The majority (about 1,150 MW) of the DR capacity used to meet RA Program requirements comes from retail DR programs administered by investor-owned utilities (IOUs) that are jurisdictional to the CPUC. An IOU's RA capacity is subtracted from its RA obligations.⁷⁷ Just over half of this DR capacity (54%) is from Reliability Demand Response Resources, which are primarily deployed in emergency conditions after CAISO issues a system warning. Third-party DR programs provide the remainder (approximately 20%) of DR capacity sold in the RA Program.

Table 15, which was prepared by FERC, shows the share of DR capability as a percent of peak demand in 2024. The figures include DR resources that do and do not participate in capacity markets, and DR capability ranges from a low of 1.7% in ISO-NE to a high of 10.6% in MISO. FERC relied on ERCOT's 2024 DR Report to estimate that DR resources in ERCOT constituted 4.8% of ERCOT's 2024 peak demand.

⁷⁵ Exceptions exist, such as in PJM, but this program involves a load resource offering a strike price into the Day-Ahead market that tends to be high. PJM can also deploy these resources in emergencies.

⁷⁶ SPP does not administer a capacity market but penalizes LSE that fail to meet their seasonal (summer and winter) capacity requirement.

⁷⁷ Capacity from IOU DR is scheduled into CAISO markets but not subject to CAISO's adequacy availability incentive mechanism (RAAIM), which rewards or penalizes RA resources based on their availability.

Table 15: RTO/ISO DR as a percent of peak, 2024

RTO/ISO	DR Resources (MW)	Percent of peak demand
CAISO	4,373	9.0%
ERCOT	4,099	4.8%
ISO-NE	431	1.7%
MISO	12,954	10.6%
NYISO	1,921	6.10%
PJM	8,526	5.7%
SPP	968	1.8%

Source: FERC, 2025 Assessment of Demand Response and Advanced Metering, December 2025, Table 3-3.

FERC-jurisdictional RTOs/ISOs also currently permit or plan to permit distribution-connected DER aggregations to offer energy, ancillary services, and capacity, where applicable, pursuant to requirements specified in FERC Order No. 2222. FERC Order No. 2222 is comparable to ERCOT's ADER pilot in many respects, although most FERC-jurisdictional RTOs/ISOs have not fully implemented the requirements. No FERC-jurisdictional RTO/ISO offers a DR product that is only available to residential customers. Instead, with limited exceptions, DR is procured and compensated through market products that all qualifying resource types can participate in (i.e., energy, ancillary services, and capacity).

Switching the focus to DR participation in energy markets, in FERC-jurisdictional RTOs/ISOs, DR resources that participate in the energy market are eligible to be compensated at LMP. This compensation is required by FERC Order No. 745.⁷⁸ Several stakeholders opposed compensating at LMP and argued that DR resources were an “unexercised call option on spot market energy”, which has a value equal to the LMP minus the “strike price,” which many argued was the retail rate.⁷⁹ Based on this rationale, many argued that DR resources should be compensated at the LMP minus the generation component of the retail rate (often referred to as “LMP minus G”). Commenters also argued that failing to account for the savings retail customers realize from load reductions – which enables those customers to avoid the retail rate - would overcompensate certain DR resources. FERC's Order 745 was upheld by the Supreme Court and governs how DR energy resources are compensated in FERC-jurisdictional RTO/ISO energy markets.⁸⁰

5.1. Lessons Learned from FERC-jurisdictional RTOs/ISOs

Although DR resources have successfully competed in FERC-jurisdictional RTO/ISO markets and provided system benefits, RTOs/ISOs have encountered issues that may prove informative to ERCOT as it considers designing new DR products. MISO's recent experience related to dual participation, DR baseline calculations, and ensuring and verifying DR performance may be instructive to the Commission, ERCOT, and stakeholders as they consider addressing pre-deployment issues with ERS, and the SB6 large load curtailment service, and the RDR proposal.

For example, MISO filed three sets of market rule changes with FERC, which FERC approved in July 2025, to address manipulation associated with payment for nonexistent or overstated curtailments; inaccurate or inflated baselines on which DR curtailments are based;

⁷⁸ *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (2011).

⁷⁹ *Id.*, at 24. DR resources must also provide a net benefits test.

⁸⁰ FERC v. Electric Power Supply Association (2016).

and the fraudulent registration of DR resources.⁸¹ ERCOT's Independent Market Monitor (IMM) Potomac Economics, which is also the IMM for MISO, was instrumental in identifying this behavior and helping MISO revise market rules to prevent similar behavior in the future. Manipulative behavior by DR resources in MISO resulted in two settlements with FERC's Office of Enforcement.⁸² Potomac Economics said these FERC settlements "illustrate the inherent problems of allowing demand to participate as supply in the market."⁸³

The first set of market rule changes clarified in the MISO tariff that DR resources must take actions (i.e., curtail load or increase behind-the-meter generation) after receiving instructions from MISO. These tariff changes also clarified that failing to respond to MISO instructions would violate the MISO tariff.⁸⁴ MISO explained to FERC that the second set of market rule changes were needed to determine accurate and verifiable baselines for MISO DR resources. The changes required certain DR resource types to attest in writing that a load reduction was made in direct response to MISO's instructions, and to ensure that the market participant understands it must respond to MISO's instructions to fulfill its obligations. The changes also required DR resources to submit meter data to MISO before final settlement charges and credits were billed.⁸⁵ The third set of market rule changes required market participants offering LMRs in MISO to attest they have the legal title and ability to deploy the LMR.⁸⁶ MISO explained that collectively, the three sets of market rule changes will provide MISO with the information it needs to verify DR performance and to adjust payments to DR resources for failure to respond to MISO instructions.

MISO's experience here could be instructive to ERCOT as it seeks to address issues discussed further below related to the self-deployment of ERS resources prior to emergency events. They also speak to the importance of establishing clear expectations of load side resources in the ERCOT tariff. Finally, MISO's reforms demonstrate the need to verify DR performance ex post for settlement purposes, adjusting payments if necessary. Such reforms also increase incentives for load resources to perform when called upon.

MISO also experienced challenges from load resources simultaneously providing two types of market products, often called dual participation. MISO proposed and received FERC approval for changes that prohibited certain load resources from participating in MISO markets as both an Emergency DR resource and as an LMR. MISO explained the changes were necessary because permitting such dual participation could enable certain DR resources to earn market revenues for potential DR deployments that MISO would never make in practice.⁸⁷

⁸¹ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,060 (2025), at P 7.

⁸² *Big River Steel LLC & Entergy Ark. LLC*, 184 FERC ¶ 61,111 (2023) and *Linde Inc. and N. Ind. Pub. Serv. Co. LLC*, 186 FERC ¶ 61,009 (2024).

⁸³ Potomac Economics, 2024 State of the Market Report for MISO Electricity Markets, June 2025, at 100.

⁸⁴ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,060 (2025), at P 8.

⁸⁵ *Id.*, at P 9. The new rules required DRRs without behind the meter generation to provide hourly meter data for all hours of every day by the 53rd calendar day from the Operating Day of the deployment or be treated as having not performed. DRRs with behind the meter generation were required to provide hourly meter data for all event and non-event hours for the previous five days after each Operating Day it received a deployment instruction. Load Modifying Resources were required to report hourly meter data for all hours in the 15 days prior to the event date, on the event day, and 15 days after the event date within 53 Calendar Days from the event date.

⁸⁶ *Id.* at P 18.

⁸⁷ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,059 (2025) at P 10.

Dual participation does not appear to be an issue in ERCOT as ERCOT's market rules generally prohibit dual participation in DR and load resource participation programs. However dual participation may not be problematic if the programs serve different needs and are unlikely to be deployed at the same time. Notably, MISO's dual participation reforms only address instances when dual participation was infeasible. Dual participation rules that are too stringent can needlessly limit DR participation. For example, ERCOT recently explained in comments to the Commission that, "In ERCOT's opinion, overlapping participation in REP Free-Days/Hours or Time-of-Use programs and ERS or TDU load management programs does not have an impact on the reliability benefits of either ERS or the TDU load management programs."⁸⁸ However, ERCOT also noted that other types of dual participation could impact reliability, such as dual participation in other REP DR programs and the ERS program or a TDSP load management program. As discussed further below, ERCOT's current market rules for Load Resources appear to address dual participation in instances where it could be problematic.

RTOs/ISOs have also had challenges calculating the reliability value of DR resources that provide capacity in RTO/ISO capacity markets.⁸⁹ This calculation can be challenging for all resource types because a variety of assumptions must be made to accredit capacity resources of all types. RTOs/ISOs with capacity markets have recently refined capacity accreditation techniques and now use resource adequacy models, along with other assumptions, to accredit capacity resources. These complex capacity accreditation techniques attempt to more accurately estimate the individual contribution each capacity resource makes to meeting the RTO/ISO resource adequacy requirement.⁹⁰ Given their complexity, resource accreditation can change from year-to-year given changes in the resource fleet, the periods when the system experiences its highest resource adequacy risks, and other factors. ERCOT does not have a capacity market so capacity accreditation is not needed, but DR accreditation techniques could be helpful for other purposes. For example, ERCOT currently uses capacity Effective Load Carrying Capacity accreditation techniques for inverter-based resources in its Capacity, Demand and Reserves Report (CDR Report) and could also consider ELCC or another accreditation approach for ERS resources or large loads that provide curtailments under the SB6 curtailment service.

5.2. Challenges integrating retail DR programs with RTO/ISO markets

DR capability from retail DR programs is offered into wholesale markets, but this is most effective when the retail DR programs are aligned with wholesale market products and operations, which is rarely the case in FERC-jurisdictional markets. For example, NYISO's IMM Potomac Economics observed that load reductions from utility DR programs is not considered in NYISO's day-ahead forecasts, which has led to unnecessary reliability commitments and out-of-market actions on high load days. The NYISO IMM further observed that, "to enhance market efficiency, it would be beneficial for NYISO to collaborate with [transmission owners] to evaluate the feasibility and appropriateness of including utility demand response deployments in its market scheduling and pricing processes."⁹¹

⁸⁸ PUCT Project No. 56517, ERCOT Response to Commission Staff's First Request for Information to ERCOT, Questions RF1-17, April 3, 2025.

⁸⁹ See e.g., Energy Systems Integration Group, Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets, January 2025, at 26-27. (ESIG DR Report, 2025).

⁹⁰ Examples of these methods include Marginal Reliability Impact accreditation, currently used in NYISO and planned in ISO-E; the Effective Load Carrying Capability used in PJM, and the Direct Loss of Load method accepted for future use in MISO.

⁹¹ Potomac Economics, 2024 NYISO State of the Market Report, at 25.

Additionally, in a 2025 report Energy Systems Integration Group (ESIG) noted the misalignment between retail and wholesale electric rates as a barrier to DR participation in wholesale electricity markets.⁹² ERCOT's proposed RDR would attempt to better align retail DR programs with ERCOT's system needs and real-time price signals.

CAISO is a notable exception to this trend because several retail DR programs in the CAISO footprint are specifically designed to align with CAISO market rules and the CPUC's RA program, which is integrated into the CAISO market. This direct alignment is intentional and the result of California state policies and initiatives, CPUC regulations, and DR program development and refinement over time.⁹³ For example, California IOUs Pacific Gas & Electric Company (PG&E) and Southern California Edison (SCE) offer retail DR programs that are designed to work within CAISO's wholesale market and the RA program for wholesale capacity. For example, PG&E and SCE both offer residential customers a Capacity Bidding Program (CBP), where retail DR aggregators can receive capacity payments in certain months (May - October). These DR compensation rates are guaranteed, change monthly, and average \$12.71/kW-month (\$152,520/MW-year) in PG&E and \$13.00/kW-month in SCE (\$156,000 per MW-year).^{94,95} PG&E also administers the Automated Response Technology (ART) program for residential customers that uses controllable devices, such as smart thermostats, to achieve load reductions during peak periods.⁹⁶ Unlike the CBP, ART is offered year-round, with current monthly rates that range from a low of \$1.57/kW-month in March to a high of \$28.83/kW-month in September. The average annual rate under the ART is \$10/kW-month, which is equivalent to \$120,000/MW-year. Although these rates are not directly comparable to the service provided under the RDR proposal, these rates reflect the retail DR rate incentives available to retail customers in CAISO. They are also roughly in line with the initial RDR incentive rate given the fact the RDR incentives are not guaranteed and would involve more deployments than a CAISO retail DR capacity resource.

6. CRA assessments and recommendations

Below, CRA presents its assessments of ERS, the ADER pilot, and ERCOT's RDR proposal.

6.1. ERS

The trends of ERS self-deployment and declining prices ERCOT identified raise several concerns. First, ERS self-deployment could give ERCOT operators a false sense of security that ERS Resources are available for deployment when they are not. Such situations could present reliability challenges during emergency events. Second, an ERS Resource portfolio comprised of highly price-responsive loads, such as crypto miners, is likely to continue to drive down ERS clearing prices, which could undermine the utility and purpose of the ERS product. ERS prices could be driven to inefficiently low levels and drive out less price-responsive ERS Resources that are still needed to address emergency conditions, particularly as ERCOT load grows. Finally, if these trends continue, paying highly price-

⁹² ESIG DR Report, 2025, at 39-40.

⁹³ See e.g., CPUC, Guiding Principles for Demand Response in California, Energy Division Staff Proposal, September 8, 2025, [link](#).

⁹⁴ PG&E Capacity Bidding Program Tariff Schedule, [link](#).

⁹⁵ SCE Capacity Bidding Program Tariff Schedule, Election Option 3 prices shown which has the highest trigger price and lowest \$/kW-month rate, [link](#).

⁹⁶ PG&E Automated Response Technology Program, [link](#).

responsive ERS resources for load reductions that they would have done for free is not a good use of customer funds.

Addressing self-deployment may require ERCOT Protocol reforms. For example, ERCOT could consider reforms similar, though not identical, to the MISO DR reforms discussed above to clarify ERS performance obligations after deployment. Claw-back provisions for non-performance could also be evaluated as a way to strengthen ERS performance incentives. However, any ERS reforms would need to balance the economic benefits associated with price-responsive loads in ERCOT against the operational objectives of the ERS product.

ERCOT's expenditure-based procurement approach for ERS resources fully expends ERCOT's pre-specified ERS budget to procure ERS Resources across SCTs and Time Periods based on relative risks rather than procuring specific MW quantities needed to meet a prespecified reliability target or goal. Notwithstanding issues related to self-deployment, ERCOT's expenditure-based procurement framework is reasonable under current conditions, given the system's growing need for energy. However, an ERS procurement approach based on MW quantities, rather than spending a set dollar amount (where expenditures could still be capped), would make it easier to align future ERS procurements with new DR products, such as the curtailment service required by SB6.

As noted in section 2.1.2 above, Weather-Sensitive ERS participation in ERS is quite low, at most 4%, and only occurs in certain seasons (summer and winter SCTs). ERCOT indicated that the Weather-Sensitive ERS program is burdensome to administer. Given these burdens and the low participation rates, eliminating the Weather-Sensitive ERS program could reduce burdens for ERCOT with little apparent downside because these residential customers can instead participate in the retail DR programs currently available in ERCOT, or potentially a future RDR program.

Finally, ERS is procured on a systemwide basis without consideration of transmission constraints. This raises the risk of procuring ERS capability that is unable to meet system needs due to not being deliverable. ERCOT indicated to CRA that interzonal constraints have not impacted ERS deliverability to date. ERCOT also noted that incorporating geographic location (e.g., zonal procurement) into ERS procurements could affect some ERS Resources that are aggregated across zones. Nonetheless, stakeholders could evaluate the potential benefits of establishing a Far West Texas ERS sub-zone as conditions have shifted with expected transmission limitations in the coming months.

6.2. ADER

The ADER pilot has succeeded in expanding the opportunities for distribution-connected resources to participate in ERCOT markets and increase supply in ERCOT. CRA advises ERCOT to consider expanding the types of ancillary services ADERs are eligible to offer, provided they are technically capable and their participation would not create reliability issues. However, technical challenges remain across RTOs/ISOs related to reliably integrating ADERs and enabling them to participate in wholesale electricity markets.⁹⁷ Given these complexities, only two of the six FERC-jurisdictional RTOs/ISOs will be fully compliant

⁹⁷ See e.g., Energy Systems Integration Group, Distributed Energy Resources Task Force, January 2022, DER Integration into Wholesale Markets and Operations. January 2022. See also, Berkeley Lab, , State Regulatory Opportunities to Advance Distributed Energy Resource Aggregations in Wholesale Markets, January 2025, [link](#).

by the end of 2026; CAISO is already compliant and ISO-NE should be in compliance by late 2026.⁹⁸

The current participation rates of ADER in other RTOs/ISOs are quite low given the nascency of the technology, the time required to design, test, and implement RTO/ISO software changes, and the operational and communication protocols needed on the distribution and transmission systems to reliably integrate ADERs into wholesale markets. Program participation will likely increase over time as FERC Order No. 2222 reforms are implemented and DER aggregators and RTOs/ISOs gain experience. However, as noted above, selling capacity tends to be the most profitable for DR resources in FERC-jurisdictional ISOs/RTOs, so it is not clear whether DER aggregations will participate in energy and ancillary services markets at scale. If ADER participation reaches ERCOT's current program caps (i.e., 500 MW for energy dispatch, and 100 MW for ECRS and Non-Spin), ADER participation levels would far exceed those in other RTOs/ISOs.

Certain stakeholders may question the value of devoting additional ERCOT resources to expand the ADER pilot because other resource types may be more efficient at providing energy and ancillary services than ADERs. There is still value in pursuing reforms that allow new and non-traditional resources, such as ADERs, to compete to provide services in ERCOT because it could increase competition, foster innovation, and reduce prices. However, given the technical challenges involved, ERCOT will have to balance such efforts with other priorities, many of which are mandated by statute.

As the ADER program expands, ERCOT may experience challenges by procuring and clearing ADERs at the zonal level rather than a more granular level that recognizes local transmission constraints. FERC Order 2222 requires RTOs/ISOs to establish locational requirements for DERs to participate in aggregations that are as geographically broad as technically feasible.⁹⁹ This technical challenge is often referred to as multi-nodal aggregation and FERC-jurisdictional RTOs/ISOs have developed approaches to address them. For example, SPP enabled multi-nodal aggregation by examining historical congestion and constraints to determine whether the DER sites within a given aggregation were located at different but "electrically similar" nodes that could be included in the same DER aggregation without threatening reliability or undermining LMP price formation.

SPP deems two nodes to be electrically similar – and thus nodes that can safely accommodate a multi-nodal DER aggregation – if the difference in shift factors two nodes have on a list of historically binding constraints is less than 1%.¹⁰⁰ SPP's analysis found that many of the electrically similar nodes were at the same substations and had the same kV voltage level. Other RTOs/ISOs used a similar approach and analyzed historical congestion patterns to identify groups of nodes that could safely host a multi-nodal DER aggregation. ERCOT could consider using similar methods as it studies the impacts ADERs have on congestion management.

⁹⁸ Charles River Associates, *Grid Under Pressure: Flexibility-centered large load policies overlook recent lessons*, February 2026, [link](#). ADERs can currently participate in some FERC-jurisdictional RTOs/ISOs through participation models developed independently of FERC Order No. 2222.

⁹⁹ *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), 172 FERC ¶ 61,247 at P 204.

¹⁰⁰ *Southwest Power Pool, Inc.*, 192 FERC ¶ 61,231 (2025), at P 72-78. SPP calculated the shift factors by analyzing ten years of historical real-time prices and congestion data and identifying transmission constraints that were loaded at 95% or more. SPP then compared all nodes' shift factors for those transmission constraints in that interval. Next SPP compared each node's shift factor relative to the constraint in that interval. Nodes with shift factors within 1% of each other were considered to be electrically similar.

6.3. RDR proposal

CRA agrees with ERCOT that increased residential DR participation would provide benefits to the ERCOT system and encourages ERCOT to work with the Commission and other stakeholders to explore ways to increase DR participation in ERCOT, such as residential DR, given the system's near-term projected load growth and energy shortage risks. DR resources of all types offer unique value at this time because they can be implemented much faster than utility-scale generation resources.

Public reports indicate ERCOT's need for additional electric generation (or equivalently, load reductions) in the near-term in net peak periods – the time periods the RDR proposal would target. For example, ERCOT's December 2025 CDR Report indicates that ERCOT's summer net peak load will grow by 55% over the next four years (through 2030), from a projected 81,411 MW in 2026 to 126,198 MW in 2030. The CDR Report also projects negative reserve margins during peak and net peak periods in both summer and winter by as soon as 2028.¹⁰¹ Additionally, the North American Electric Reliability Corporation's 2025 Long-Term Reliability Assessment for ERCOT projects elevated risks of expected unserved energy in ERCOT in the early morning and late evening hours, which are outside of ERCOT's typical peak demand periods when the greatest load reductions tend to occur.¹⁰² DR programs targeted to reduce loads in higher risk net peak periods could enhance reliability in ERCOT in the near term.

Based on CRA's review, the RDR proposal would not overlap with the products ERCOT currently procures from load resources. The RDR proposal is designed to meet system needs during net peak hours throughout the year. Current DR programs, whether administered by ERCOT or by others, do not meet this need. As discussed above, retail DR programs and self-curtailments currently focus load reductions during likely 4CP periods in the summer months. Commission staff made a similar observation in a March 2026 report on the 4CP cost allocation methodology.¹⁰³

There is no indication that the RDR program as proposed would interfere or overlap with the ancillary services markets that CLRs, NCLRs, and ADERs participate in. As discussed further below and in the Appendix, some ADER resources may choose to participate in a future RDR program if they are eligible to participate. The RDR proposal would meet different system needs than the emergency capacity shortages the ERS program is designed to address. Instead, the RDR proposal would be deployed more frequently in non-emergency conditions and during net peak periods. Similar to ERS, the load curtailment service required by SB6 would only be deployed in emergencies and would thus meet different system needs to the proposed RDR program. Importantly, the 2025 CDR Report indicates that ERCOT's projected reserve margin shortages already account for large load curtailments associated with SB6, which also indicates no overlap.¹⁰⁴ Finally, by design, the Dispatchable Reliability Reserve Service will meet ERCOT system needs during net peak periods, but not before the new dispatchable resources this future product is designed to incent reach commercial operation, which will take years.

Expanding the level of residential DR in the ERCOT above current levels would require increasing financial incentives for residential load reductions. As a general matter, a premium

¹⁰¹ ERCOT, Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2026-2030 December 19, 2025, at 4.

¹⁰² NERC, 2025 Long-Term Reliability Assessment, January 2026, at 130, [link](#).

¹⁰³ PUCT, Draft Evaluation of Transmission Cost Recovery, Project No. 58484, March 16, 2026, at 6-8, [link](#).

¹⁰⁴ ERCOT, Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2026-2030 December 19, 2025, at 4. The projects account for SB6 on a preliminary basis given the large load curtailment service is not yet finalized.

is warranted to increase retail DR participation in ERCOT given the insufficient financial incentives from DR programs currently available in the ERCOT footprint. The Energy Systems Integration Group noted weak financial incentives as a key barrier to expanding DR participation in wholesale electricity markets, particularly from retail customers given the misalignment between wholesale and retail rates.¹⁰⁵ For example, the prohibition against charging residential and small commercial customers rates indexed to real-time LMPs is designed to protect customers but contributes to the misalignment between wholesale and retail rates. Additionally, the cost of the equipment required to participate in retail DR programs can be several hundred dollars per installation including labor, another factor that weakens financial incentives.¹⁰⁶

As such, incentive payments to overcome these barriers are warranted to increase DR participation and help meet ERCOT's acute and near-term operational needs. ERCOT's proposed RDR incentive rate is likely to increase residential DR participation given the financial incentives it would offer.¹⁰⁷ The proposed RDR program is also likely to expand DR participation in the ERCOT footprint because it would have a low administrative burden for program administrators as it would use reporting that REPs are already subject to under the §25.186 program. Some REPs also supported the RDR proposal because it would not require an affirmative obligation to curtail loads, which reduces REP program implementation risks from retail customer switching.

Based on the currently proposed 500 MW participation cap and \$105,000/MW-year maximum compensation rate, the RDR program could have an initial cost of up to \$52.5 million per year, (i.e., 500 MW x \$105,000/MW-year), about two-thirds the annual cost of the ERS program. The actual cost would likely be lower given the rate will also be based on the lower of \$105,000/MW-year and the rolling average of the Peaker Net Margin.

The currently proposed maximum \$105,000/MW-year initial incentive rate, if paid, would also pay customers at a rate that could significantly exceed prevailing LMPs during net peak intervals, the compensation paid to ERCOT generation resources that also meet system needs in the same interval. However, as noted above, retail customers typically require a premium to provide DR capability given the misalignment between retail and wholesale rates. The \$105,000/MW-year rate is unlikely to be achieved in practice, and the average rate paid for residential load reductions on a per-MW basis will likely be much lower. ERCOT's proposed initial RDR rate is roughly comparable to rates paid to retail DR capacity resources in CAISO. Although these rates aren't directly comparable because the programs differ. However, the CAISO retail DR rate is also guaranteed, and deployments are capped and expected to be infrequent. By contrast, RDR resources can expect to be deployed multiple times per season at rates that are not guaranteed. The RDR program could change incentives for other ERCOT load resources. Appendix IV presents an analysis that shows that the program as currently proposed is likely to attract customers away from the ADER program, provided ADER pilot participants are eligible to participate in the RDR.

CRA agrees with ERCOT and others that there is untapped DR potential from residential customers in ERCOT. For example, the Energy Information Administration (EIA) collects survey information from utilities about their DR customers by customer class and the load reductions they achieve. According to that survey, six percent of residential customers in ERCOT participated in a DR program in 2024, and Texas ranks 24th among the 49 states with

¹⁰⁵ ESIG DR Report, 2025, at 39.

¹⁰⁶ ESIG DR Report, 2025, xii.

¹⁰⁷ See e.g., The Brattle Group, An Assessment of ERCOT's Proposed Residential Demand Response Program, January 2026, [link](#).

utility survey respondents (see Appendix III). Other researchers, such as The Brattle Group,¹⁰⁸ and Texas A&M¹⁰⁹ also estimate that ERCOT has untapped DR potential.

As noted in section 5.1 above, it is essential to establish accurate baselines for DR resources to avoid undue payments to DR program administrators and prevent gaming. ERCOT staff explained to CRA that it could be challenging to establish baselines for residential customers that do not have an easily predictable load profile, such as customers with batteries that are operated by third parties. Finally, expanding the eligibility of the RDR program to include small commercial customers could also expand retail DR participation in ERCOT. Although the §25.186 program reporting ERCOT intends to use is only applicable to residential customers in competitive areas, ERCOT could consider extending participation to small commercial customers in both competitive and NOIE areas in future years if the RDR program is implemented.

¹⁰⁸ The Brattle Group, An Assessment of ERCOT's Proposed Residential Demand Response Program, January 2026, [link](#).

¹⁰⁹ Texas A&M University, Demand Response and Energy Efficiency in ERCOT, October 2024, PUCT Project Nos. 38578 and 55999.

Appendix

I. ERCOT's RDR Proposal, as of March 2026

Certain formulas from ERCOT's current proposal for the Residential Demand Response Program are included below for reference. Note, the initial incentive rate has been updated to reflect the planning Cost of New Entry (CONE) estimate, based on guidance from ERCOT.

Residential Demand Response Rate

- (1) The Residential Demand Response Rate for the year shall be calculated as follows:

$$RDRR_a = \text{Min} (IRDRR, HRAPNM_a) / N$$

- (2) The Residential Demand Response Rate for the Season shall be capped by the program limits as described in Section 3.26.4, Residential Demand Response Program Cap. The Seasonal Residential Demand Response rate shall be calculated as follows:

$$CRDRR_s = [(SRCAP_s) / \text{Max} (SRCAP_s, RDRTOT_s)] * RDRR_a$$

Where:

$$RDRTOT_s = \sum_q RESDR_{q,s}$$

The above variables are defined as follows:

Variable	Unit	Description
$RDRR_a$	\$/MWh	<i>Residential Demand Response Rate</i> – The Residential Demand Response Rate, before any adjustments made for program limits, for the year a .
$CRDRR_s$	\$/MWh	<i>Capped Residential Demand Response Rate</i> – The Residential Demand Response Rate, adjusted for program limits, for the Season s .
$HRAPNM_a$	\$/ MW-Year	<i>Historical Rolling Average or Peaker Net Margin</i> – The historical 3-year rolling average of Peaker Net Margin (PNM) for the previous 3 calendar years ending December 31 of the year before the current program year start date of the Residential Demand Response Program Year.
$RDRTOT_s$	MWh	<i>Residential Demand Response Total</i> – The total ERCOT-wide Demand response for Season s .
$RESDR_{q,s}$	MWh	<i>Residential Demand Response Quantity per QSE per Season</i> – The MWh Demand response for QSE q for Season s .
N	None	<i>Number of events per year</i> – The total of the largest load reduction hours for the year for the RDR Program as defined in Section 3.26.3, Assessment Periods.
$SRCAP_s$	MWh	<i>Seasonal Response Cap</i> – The MWh cap for RDR for Season s as defined in Section 3.26.4, Residential Demand Response Program Cap.
$IRDRR$	\$/MW-Year	<i>Initial Residential Demand Response Rate</i> – The Residential Demand Response Rate, before comparison to

		the historical 3-year rolling average of Peaker Net Margin. Value is to \$105,000 \$/MW-Year
Q	None	A QSE.
A	None	The year of the RDR Program, as described in paragraph (1) of Section 3.26.5, Residential Demand Response Program Commencement.
S	None	The Season in the Residential Demand Response Program.

Residential Demand Response Payments

- (1) ERCOT shall pay the QSEs participating in the Residential Demand Response (RDR) Program as follows:

$$\mathbf{RDRPAMT}_{q,s} = (-1) * \mathbf{CRDRR}_s * \mathbf{RESDR}_{q,s}$$

Where:

$$\mathbf{RESDR}_{q,s} = \sum \mathbf{RESDRLSE}_{l,q,s}$$

The above variables are defined as follows:

Variable	Unit	Description
$\mathbf{RDRPAMT}_{q,s}$	\$	Residential Demand Response Payment per QSE per Season – The Residential Demand Response payment to QSE q for the Season s.
\mathbf{CRDRR}_s	\$/MWh	Capped Residential Demand Response Rate per Season – The Residential Demand Response Rate, adjusted for program limits, for the Season s.
$\mathbf{RESDR}_{q,s}$	MWh	Residential Demand Response Quantity per QSE per Season – The MWh demand Response for QSE q for Season s.
$\mathbf{RESDRLSE}_{l,q,s}$	MWh	Residential Demand Response Quantity per QSE per LSE per Season – The MWh Demand Response for QSE q, for LSE l and Season s.
Q	None	A QSE.
S	None	The Season in the Residential Demand Response Program.
L	None	An LSE.

ERCOT will calculate the MWh load reduction for each interval of each of the hours specified in Section 3.26.3 as follows:

$$\mathbf{RESDRDEP}_{l,s,i} = \mathbf{RDRPBASETOT}_{l,s,i} - \mathbf{RDRPACTTOT}_{l,s,i}$$

II. Average ancillary services requirements in 2025

Table 16 provides the average hourly ancillary service requirement, by month, in 2025.

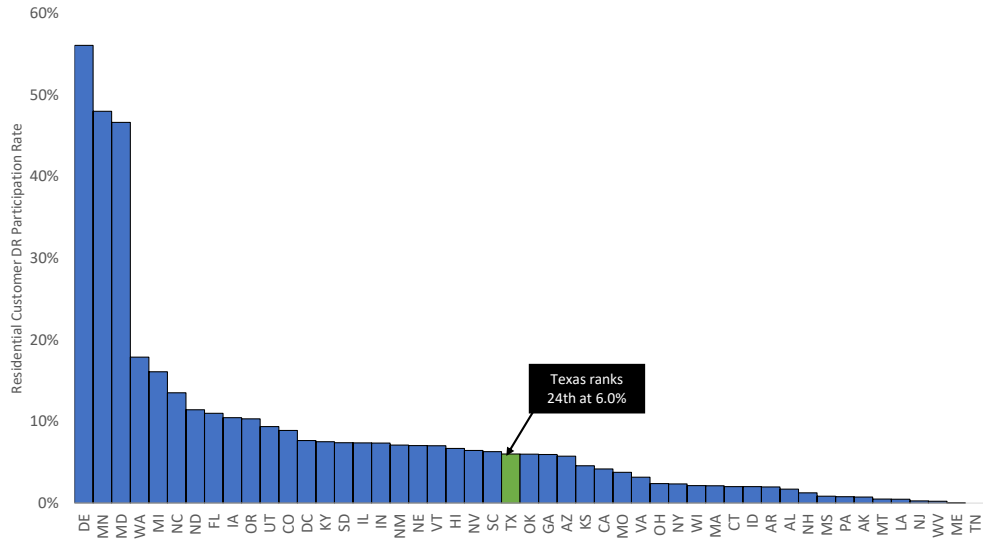
Table 16: Average hourly ancillary service requirements, 2025

Year	RRS (MW)	Non-Spin Reserve (MW)	ECRS (MW)
Jan 2025	2,892	3,163	1,216
Feb 2025	3,073	2,944	1,240
Mar 2025	3,065	2,814	1,411
Apr 2025	3,045	2,734	1,422
May 2025	2,635	3,933	1,874
Jun 2025	2,440	3,027	1,582
Jul 2025	2,396	2,968	1,619
Aug 2025	2,300	2,394	1,575
Sep 2025	2,389	2,167	1,506
Oct 2025	2,766	2,559	1,213
Nov 2025	2,986	2,661	1,265
Dec 2025	2,916	3,236	1,060

Source: Potomac Economics, ERCOT Wholesale Electricity Market Monthly Report for December 2025, January 10, 2026, p. 33, [link](#). Note RTC+B was implemented in December 2025.

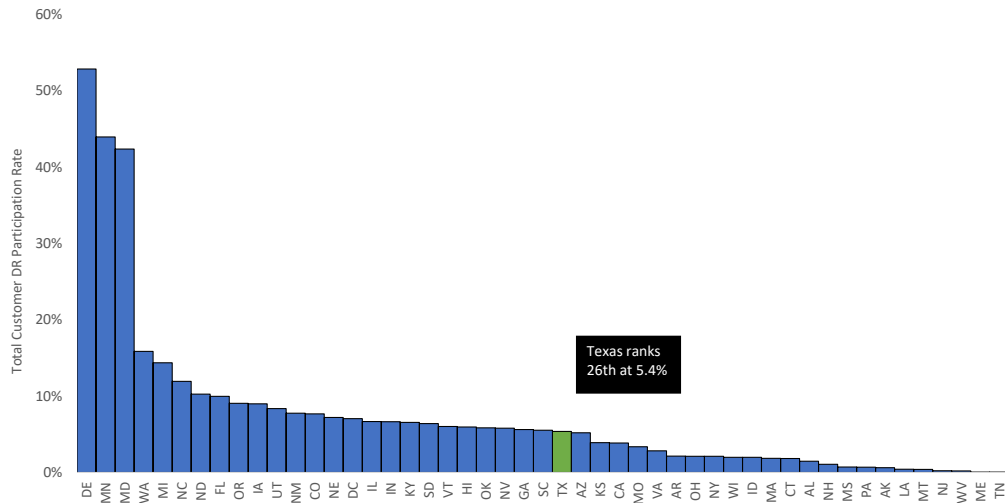
III. EIA survey of 2024 DR participation rates by State

Figure 8: Residential customer DR participation rate by state (% of residential customers)



Source: EIA 860 Data, 2024. Information based on survey responses of utilities in the ERCOT footprint and does not include all utilities.

Figure 9: Total customer DR participation rate by State (% of residential customers)



Source: 860 Data, 2024. Information based on survey responses of utilities in the ERCOT footprint and does not include all utilities.

IV. Analysis of revenues available under proposed RDR program

Market participants are typically profit maximizing and seek the most profitable use of their assets. This behavior must be considered when designing and compensating resources, whether the product is procured within or outside of ERCOT's day-ahead and real-time markets. Table 18 below presents a rough estimate of the annual revenues available to qualifying load resources under the ERS, the ancillary service market (example of an ADER or a load resource providing RRS), and the RDR program as currently proposed. These programs and markets are not directly comparable, but it is informative to compare alternatives available to the RDR. The RDR program is only available to residential customers with controllable devices, but aggregations of residential sites can participate in the ADER pilot or as a Weather-sensitive load in the ERS program. Further, the IMM and others have expressed concerns that the RDR program could attract loads away from the ADER pilot. More recently, the IMM expressed concerns that the proposed RDR incentives are too low to attract participation.

Focusing on Table 18, the estimated revenues from load participation in the ERS program are based on the most recent 12 months available (April 2025 - March 2026) and reflect the number of hours and clearing prices for each SCT and Time Period. The analysis also includes ERS prices and revenues from SCTs to better reflect historical ERS prices, prior to the recent declines. A qualifying Non-Weather sensitive ERS Resource with 1 MW of reduction capability¹¹⁰ could earn up to \$29,209 per MW-year based on the April 2025 – March 2026 prices if it cleared in all hours, and approximately \$26,288/MW-year if participated in 90% of the hours in a given year, which is less than the maximum potential revenue available from the proposed RDR program. However, as proposed, RDR revenues are likely to be lower. If ERS prices from the December 2022 - November 2023 period are used, ERS revenues almost double, to \$58,925/MW-year, making ERS revenues more comparable, and likely higher than the expected revenues under the proposed RDR program.¹¹¹

The revenue estimate from participating in the ancillary services market is based on 2025 average prices for RRS and Non-Spin. ADERs are not currently eligible to provide RRS but RRS is included because it is the ancillary service product load resources participated in most in 2025. If an ADER resource were ever permitted to offer RRS, it could earn an estimated \$21,425/MW-year, on average, if it were cleared to provide RRS in 70% of the hours of the year, and commensurately lower amounts if it cleared in a lower proportion of hours (i.e., 50% or 30%). These rates are roughly commensurate with the proportion of intervals ADER resources in the Phase 3 pilot are cleared to provide ancillary services (see Table 9). Alternatively, an ADER resource could provide Non-Spin, which it is currently eligible to do, and earn between \$4,704 and \$14,112 per-MW-year depending on the percent of hours it clears the ancillary services market.

¹¹⁰ This estimate is for comparison purposes only. It is unclear whether a residential customer with a controllable device could participate in the ERS program year-round.

¹¹¹ Weather-Sensitive ERS Resources are typically not procured outside of the summer and winter SCTs, potentially because they are not available (e.g., associated with AC and space heating loads). As such, a Weather-Sensitive ERS Resource would make less than a year-round ERS program participant and would thus also earn more revenues under the RDR program.

Table 17: Estimated annual revenues for ADER, ERS, and RDR based on 2025 prices

ERS 2025 revenues, Apr. 2025 - Mar. 2026 prices		
ERS hourly-weighted average price \$/MW per hr.		\$3.33
Assume 24x7 participation \$/MW-yr		\$29,209
Assume participation in 90% of hours		\$26,288
ERS 2025 revenues, Dec. 2022 - Nov. 2023 prices		
ERS hourly-weighted average price \$/MW per hr.		\$6.73
Assume 24x7 participation \$/MW-yr		\$58,925
Assume participation in 90% of hours		\$53,033
Ancillary Services		
	Non-Spin	RRS
2025 monthly avg. price, \$/MW per hr.	\$1.79	\$2.72
Clear in 70% of hours, \$/MW-yr	\$10,976	\$16,664
Clear in 50% of hours, \$/MW-yr	\$7,840	\$11,903
Clear in 30% of hours, \$/MW-yr	\$4,704	\$7,142
*ADER resources are not currently eligible to provide RRS		
RDR proposal		
Initial annual compensation - \$/MW-yr		\$105,000 (maximum possible)
Actual revenues will vary based on RDR rate and participant performance		Unknown

The currently proposed maximum and initial RDR incentive payment for residential load reductions during the Assessment periods is \$105,000/MW-year, but the actual compensation, and thus effective incentive payments, will depend on how many of the target hours the REP/NOIE participant achieves load reductions in, the total of reductions (in MW) in each season. The proposed RDR incentive rate would also fall if the Net Peaker Margin fell below \$105,000/MW-year.

In practice, the realized revenue from any RDR program would be uncertain, potentially with many load reductions being uncompensated, because ERCOT would only compensate RDR participants for load reductions in certain net peak hours in each season. At the currently proposed initial RDR rate, the RDR program appears more attractive than the ADER from a revenue perspective, but the RDR revenues would have to be discounted given the uncertainty involved, as payments are not guaranteed. The ancillary services revenues available under the ADER are more sustained and less uncertain than the RDR. However, providing ancillary services, including through the ADER pilot, requires more expensive equipment (e.g., telemetry), requires market expertise and sophistication to prepare bids, and involves more administrative burdens (e.g., registering with ERCOT, etc.) than the RDR.

Based on the rough approximations in Table 17, an ADER resource would prefer to participate in the RDR program if it expected to capture only 16% (i.e., \$16,664/\$105,000) of the maximum potential revenues available from the proposed RDR program. If the ADER can only provide Non-Spin, an ADER resource would prefer to participate in the RDR program if it expects to earn just 9% of the maximum potential revenues available from the RDR. These estimates are arguably conservative because they do not consider the costs and administrative burdens of ADER participation (e.g., telemetry and the duty to respond to

deployment instructions). Although each ADER will make different calculations based on their unique circumstances, at the currently proposed maximum incentive rate, the RDR program may draw participants away from the ADER program and towards the RDR program, provided they are eligible to participate. Such a switch is not necessarily a bad outcome if the load reductions during net peak periods under the RDR program provide more value to the system than the ancillary services provided by ADERs. ERCOT is in the best position to make that assessment.