

An Assessment of ERCOT's Proposed Residential Demand Response Program

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Notice

This report prepared for NRG and Google. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

Any wholesale market characterizations herein are not intended to be predictive of a future grid state, rather they are baseline assumptions used to assess the price impact of demand response.

We would like to thank Bill Barnes and Travis Kavulla (NRG) and Easar Forghany and Chris Matos (Google) for helpful input and insight throughout this study.

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I. Summary

A System Need For Available and Affordable Resources

ERCOT is experiencing [dramatic load growth](#) that is expected to exceed the pace at which conventional sources of supply can be added to the market. This dynamic is introducing [near-term concerns](#) about system reliability.

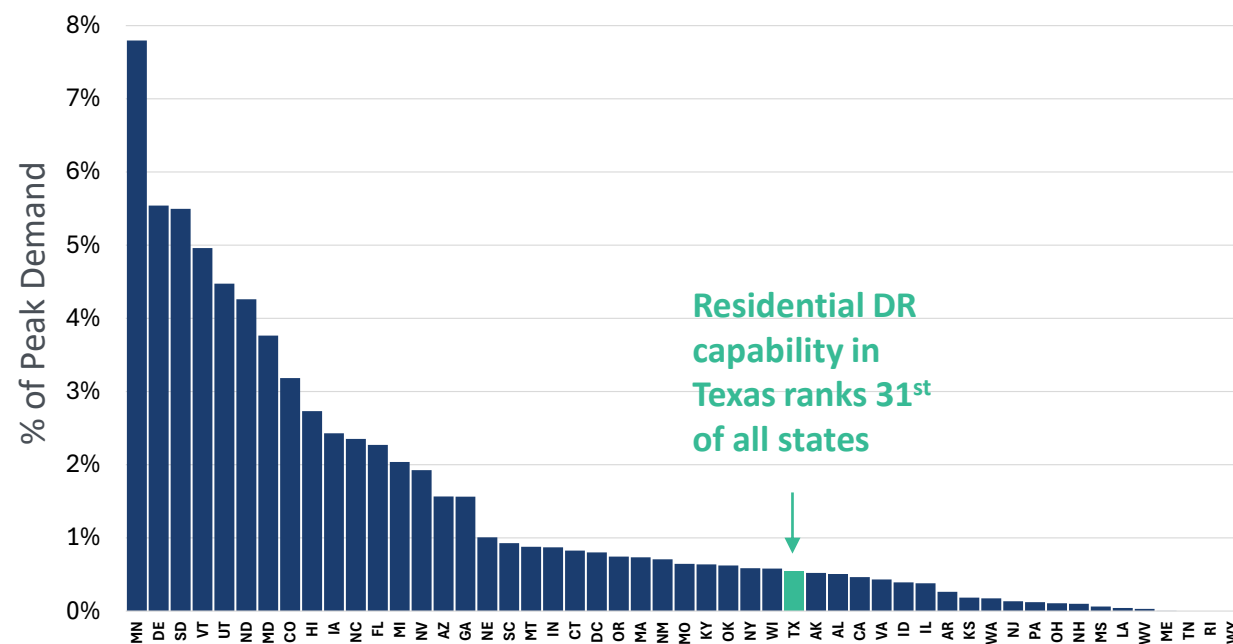
Meanwhile, residential demand response (DR) opportunities remain relatively untapped in ERCOT, despite large air-conditioning load. While many factors influence DR capability, Texas ranks in the bottom half of all U.S. states when expressing residential DR as a percentage of system peak (see figure at right).

In other markets, cost-effective participation compensation and effective program design have led to residential DR participation rates in excess of 20%. Nationally, there is 10 GW of residential DR in utility programs.

ERCOT's proposed Residential DR (RDR) program is designed to provide Retail Electricity Providers (REPs) with a price signal to develop programs that tap into latent residential flexibility to address reliability concerns.

Our study analyzes the extent to which the proposed RDR program is likely to increase residential DR capability and the impacts the program may have on market prices.

Residential Demand Response Capability, by State



Note: Data from [Form EIA-861](#), 2024. Accessed November 2025.

A More Competitive Residential DR Offering

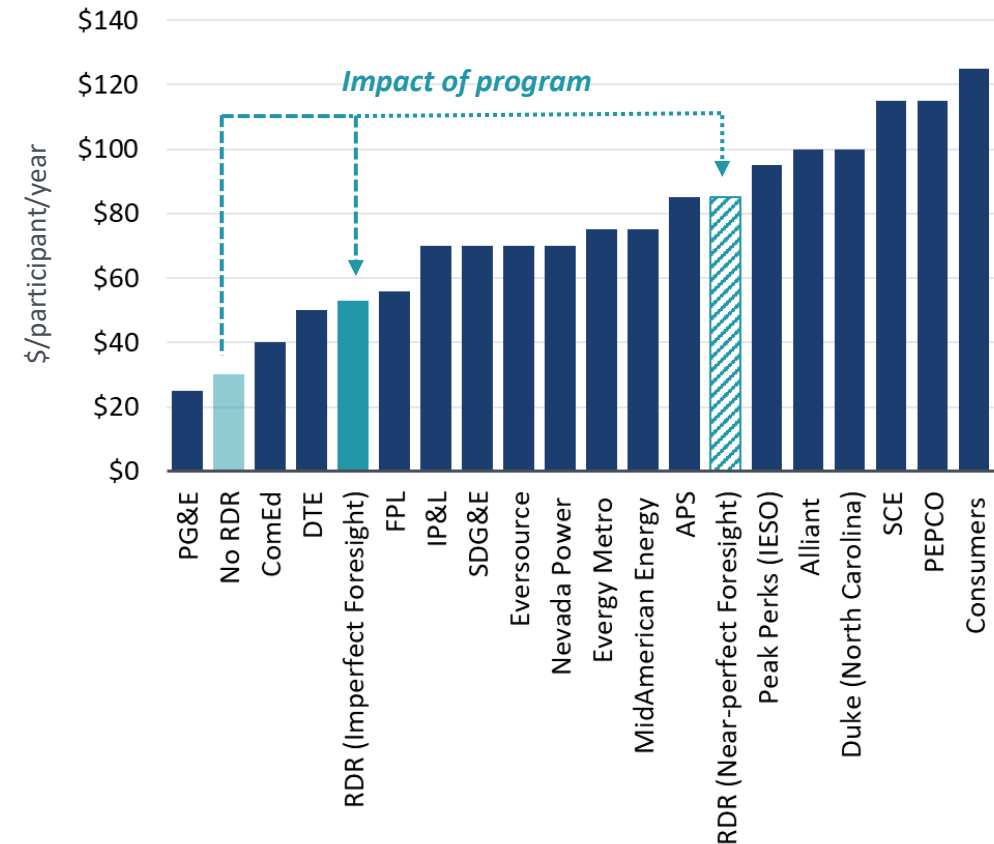
Currently, despite tightening reserve margins in ERCOT, the monetizable value of residential DR to REPs is limited. As a result, REPs can only offer relatively low incentive payments to attract participation. These payment levels are below those observed in successful program offerings in other jurisdictions.

ERCOT's proposed RDR program would significantly increase the monetizable value of residential DR to REPs. Our analysis indicates that the increased revenue from RDR would allow REPs to offer cost-effective compensation to participants that is 2x to 3x the levels currently supported by the market. The range varies depending on the DR technology being targeted and the extent to which REPs are able to accurately forecast system conditions and market prices.

This increase in DR incentive payments would align future offerings in ERCOT with levels that have supported significant enrollment in utility programs in other jurisdictions.

The result would be larger bill savings opportunities for participants, which should lead to greater DR deployment and adoption in ERCOT (see next page).

Incentive Payments Offered in US Utility Programs
Smart Thermostat Program Example



Note: Utilities shown offer the largest residential air-conditioning direct load control programs in the US, based on Brattle analysis of EIA-861 data. Estimates based on Brattle review of utility tariffs and modeling. The two ERCOT program cases shown assume imperfect foresight (low) and near-perfect foresight (high).

The Potential Impact of the RDR Program on DR Adoption

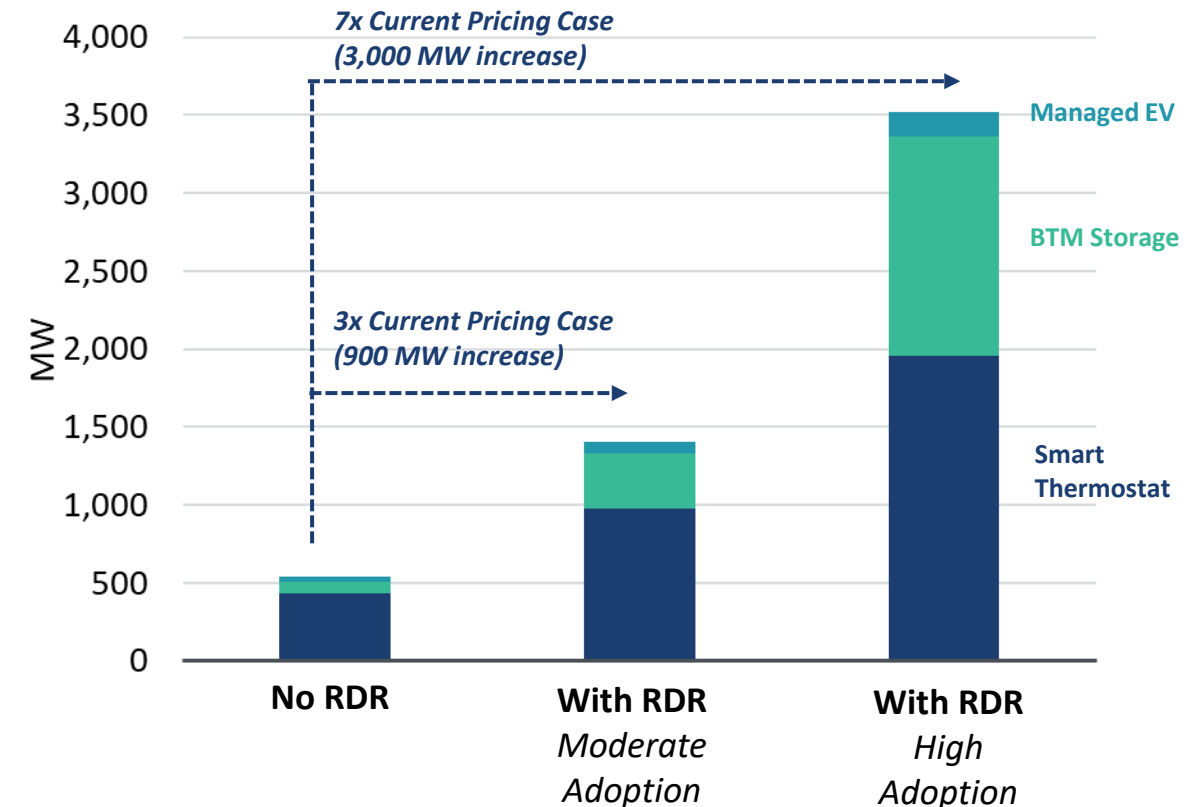
By offering participation compensation at levels observed in other jurisdictions, ERCOT's DR program could reach its 500 MW enrollment cap within a few years.

To illustrate the potential impact of increased incentives offered through the residential DR program, we modeled three scenarios.

- **No RDR:** Future DR adoption limited to low end of what has been achieved in other jurisdictions.
- **With RDR (Moderate Adoption):** With higher, industry-standard incentives supported by implementing the RDR program, we assume DR enrollment could increase to levels achieved by successful utility offerings in other jurisdictions.
- **With RDR (High Adoption):** When coupling higher incentives with the removal of other DR deployment barriers, we assume adoption could reach maximum levels observed in a review of various DR planning studies.

As currently proposed, compensation for participation in RDR is capped at 500 MW. If participation exceeds that level, compensation becomes diluted across participants (e.g., at 1,000 MW of participation, compensation would be cut in half on a per-MW basis). As a result, we do not expect that RDR participation would significantly exceed the cap but should largely be additive to other DR not participating in the RDR program.

2030 ERCOT Residential DR Capability



Note: Our analysis focuses on DR offerings that would be supported by direct reduction of energy and ancillary costs and contributions to residential DR accreditation hours. It does not account for alternative DR compensation opportunities in Texas, such as the ADER pilot. Further market research would be valuable to establish a direct relationship between incentives and likely DR participation.

The Potential Impact of the RDR Program on Market Prices

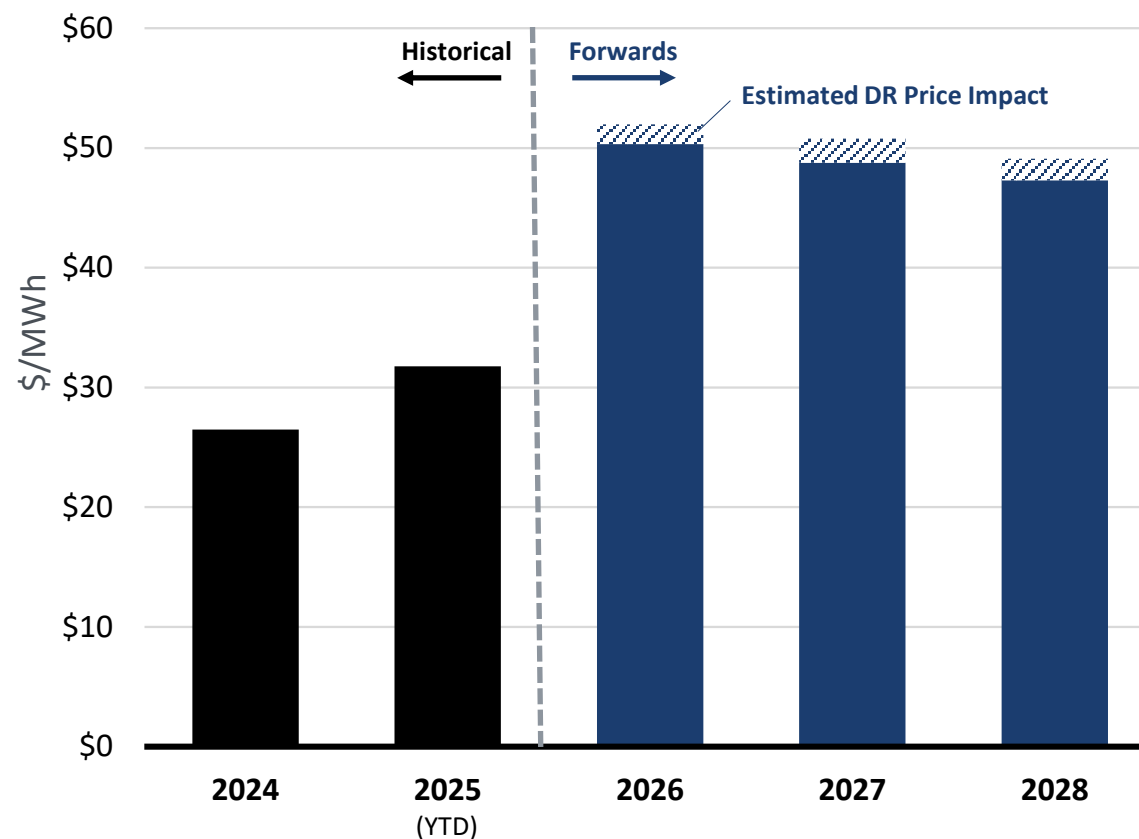
We conducted statistical analysis of historical market prices and reserve levels to better understand the magnitude of the impact that the RDR program could have on future market prices. Our analysis captures the fundamental relationship between changes in reserve levels and changes in market prices.

With the 500 MW participation cap, we do not expect the RDR program to lead to significant price suppression relative to increasing forward prices.

- ERCOT energy forwards indicate that prices will **increase +\$15-20/MWh from recent historical prices by 2028**.
- Our modeling suggests **prices would still increase nearly as much if the RDR program is implemented** (absent a price adjustment mechanism, but with a 500 MW cap).
- The impact of the RDR program could be on the order of a **3-4% reduction** in average annual prices, or **less than \$2/MWh on average**.

Note: These figures are not intended to be predictive of a future grid state, rather they are baseline assumptions used to assess the price impact of demand response.

Annual Average ERCOT Market Prices (Historical and Forwards)
With and without RDR impact





II. Introduction

Purpose and approach

Study background

- ERCOT is facing dramatic load growth that could outstrip the pace of supply additions and lead to system reliability challenges.
- ERCOT's recently proposed Residential Demand Response (RDR) program seeks to enable greater DR capability from the largely untapped residential customer segment to support system resilience and reliability.

Study purpose

- NRG and Google commissioned Brattle to analyze the potential impacts of ERCOT's proposed RDR program if it is adopted
- Focus on potential impacts in next 3 to 5 years

Research questions

- Is the RDR program likely to lead to an increase in residential DR capability?
- How will the RDR program impact market prices?

Organization of the report

The remainder of the report provides an overview of enrollment methodology in [Section III](#), RDR enrollment impacts in [Section IV](#), details on the market price effect in [Section V](#), with final takeaways in [Section VI](#) and a [Supplemental Appendix](#).

Study Approach

Define residential DR offerings utilizing smart thermostats, home batteries, and EV managed charging

Estimate monetizable DR value with and without RDR program compensation

Assess implications for higher participation incentive payments and greater ERCOT-wide DR capability

Analyze potential market price impacts of the Residential DR program at the 500 MW cap

An Overview of ERCOT's Proposed RDR Program

On August 26, 2025, ERCOT submitted Nodal Protocol Revision Request (NPRR) 1296 to propose the Residential Demand Response (RDR) Program, which would expand the utilization of smart devices at households to address system peak net load conditions throughout the year.

Participation

- REPs and Non Opt-In Entities (NOIEs) can enroll residential customers in DR programs that would be dispatched at REP/NOIE discretion (under mutually agreed upon terms).
- REPs/NOIEs will call events during predicted peak seasonal net load hours.
- Participating REPs/NOIEs register enrolled customers in the RDR program by reporting verified load reductions during event hours to earn program compensation.

Compensation

- Market participants can earn up to \$140/kW-yr or a 3-year rolling average of Peaker Net Margin for the accredited reductions during top net load hours, averaged across all seasonal accreditation hours.

Accreditation

- At the end of each season ERCOT will identify the top eight (Summer and Winter) or five (Fall and Spring) system net load hours for each season to quantify reductions.
- REPs/NOIEs are compensated based on their highest hourly load reductions during 6 of 8 (Summer and Winter) and 3 of 5 (Fall and Spring) hours in each of the four seasons.

Program Participation Cap

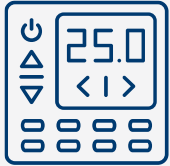
- ERCOT limits total RDR participation to a specified seasonal MWh cap. Compensation is effectively capped at 500 MW in each season (3,000 MWh in Summer and Winter; 1,500 MWh in Fall and Spring) across all ERCOT participants.
- As currently structured, there is no advanced registration at the start of a season. If participation exceeds the cap, incentives will be reduced accordingly across participants.
- The incentive cap restricts the impact on price formation. We explore the extent to which market prices are impacted with the introduction of the DR and alternative mechanisms (in [Section V](#)).



III. Modeling Enrollment Impacts

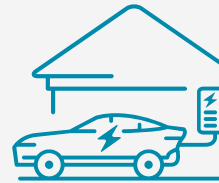
The Modeled DR Options

We model three residential technologies to illustrate DR opportunities in ERCOT.



Smart Thermostats

- **Smart thermostats** can be adjusted remotely to reduce air-conditioning load during DR event hours.
- Pre-cooling strategies, constraints on setpoint adjustments, and a cap on the number of events limits potential loss of customer comfort.
- Roughly [83%](#) of homes in Texas have central air-conditioning and could be incentivized to adopt a smart thermostat.
- Air-conditioning is a dominant driver of system peak demand in ERCOT.



Residential Electric Vehicle Charging

- **Residential electric vehicle (EV) charging** can be managed remotely to shift charging load to low-cost hours overnight.
- Our modeling does not include vehicle-to-grid capability, which could provide additional value once technically and commercially viable.
- Forecasts indicate that there could be [1 million light-duty EVs](#) on the road in Texas by 2030.



Residential Batteries

- **Residential batteries** can be discharged during high-priced or DR event hours and charged during low-priced hours, in addition to providing backup generation and bill savings to owners.
- Residential battery adoption is growing in ERCOT, and REPs are beginning to develop retail plans to pay customers for battery performance.
- Under NPPR 1296, batteries are only compensated for self-consumption (i.e., not grid injection) dispatch unless paired with distributed solar. We model standalone batteries in this study.

Features of the Analysis

We simulate DR dispatch to estimate maximum monetizable value from a REP's perspective, accounting for realistic DR operational constraints to maintain customer comfort.

Operational constraints

- Technology-specific limits on number of DR dispatch events/year and hours/day (e.g., for cooling load control, max 15 calls per year and 4 consecutive hours per call)
- Account for load building outside of event hours (e.g., due to pre-cooling or post-event load snapback)

Value-maximizing dispatch

- DR value to REP includes combination of real-time energy, A/S procurement, and RDR compensation
- REPs target program dispatch during seasonal net peak hours to earn maximum accreditation (top 6 of 8 in Summer/Winter and top 3 of 5 in Spring/Fall)

Realistic accounting for foresight

- Imperfect foresight scenario: REP targets 10x the top net load hours with program dispatch, receives lower accreditation
- Near-perfect foresight scenario: REP targets 2x the top net load hours, receives higher accreditation

Actual market data

- Simulations and value estimates based on 2019-2024 market prices and currently proposed RDR compensation level

Note: See appendix for additional methodological detail.

DR Modeling Approach Overview

We model DR economics with and without ERCOT's proposed RDR program.

1. Establish operational parameters of each DR offering

Smart thermostat	1 kW per-customer load reduction for 4 hours per day, June – September from 12 pm-9 pm (up to 15 events, 60 hours/yr). Lower reductions (0.9 kW) possible in May and October on high temperature days. Pre- and post-event load building to maintain participant comfort.
Residential battery	4.5 kW per participant discharged during up to 200 hours of year, maximum 3 hours per day (assumes 13.5 kWh energy storage capacity per participant).
Electric vehicle	90% of hourly average home charging load shifted out of up to 50 hours per month, maximum 4 hours per day (~0.45 kW per customer shifted out of top hours).

2. Estimate value of REP-operated DR without ERCOT's RDR program

- Real-time energy value for 2019 through 2024
- Reduced ancillary services (AS) cost for same historical period

3. Estimate value of REP-operated DR with RDR program (two foresight scenarios)

- Additional payment (\$140/kW-yr) from RDR program. At the end of each season, ERCOT determines the top 5 (Spring, Fall) to 8 (Summer, Winter) hours of net load. REPs will get credit for their top performance during 3 of 5 (Spring, Fall) or 6 of 8 (Summer, Winter) hours.
- We model two foresight cases to account for the difficulty REPs may face predicting top net load hours each season:
 - **Near-perfect foresight:** REPs must reduce demand in double the accreditation hours to earn full accreditation (e.g., 12 in the summer instead of 6). REPs forecast 2x potential net load hours.
 - **Imperfect foresight** REPs must reduce demand in 10x hours to earn full accreditation (e.g., 60 instead of 6 in the summer). The 10x ratio is informed by [near-4CP days](#) relative to 4CP days.
- Same real-time energy and ancillary services value opportunity without program enrollment. Dispatch simulation accounts for tradeoffs in net load-targeted dispatch.

4. Estimate impact of ERCOT's DR program on DR participation

- Calculate maximum cost-effective incentive payment that REPs could offer participants as the total program value less program implementation costs and additional value maintained by REPs for administering the DR program.
- Benchmark the incentives against offerings across other jurisdictions and estimate the impact of resulting higher incentive payment on DR participation and program potential (MW).

DR Dispatch Simulation

Our dispatch simulations maximize the monetizable value of the DR resource from a REP's perspective, accounting for realistic operational constraints that maintain customer comfort.

Each DR technology is dispatched to reduce load when the REP would be exposed to high real-time energy prices or ancillary services costs, without RDR.

Our dispatch simulations consider the sum of the real-time energy price and per-MWh ancillary service costs to which a REP would be in each hour of each year from 2019 through 2024.¹

To ensure participant comfort is maintained, we assume technology-specific limits on the number of DR dispatch events per year and hours per day. Our simulations account for load building outside of the VPP dispatch event hours.

With RDR, we forecast top net load hours (TNL) under two foresight scenarios. The REP will dispatch in predicted top net hours if available.² If the DR program is not available during the top net load hours, the RDR program accreditation is reduced, reflecting an expected value over time.

Total monetizable value of the DR program, when registered with RDR, is the avoided energy, ancillary services, and RDR revenues to the REP. See appendix for further discussion.

Notes: [1] The ancillary service cost is calculated as the hourly system-wide AS procurement cost (DA AS Plan quantity times DA clearing price, for all AS products) divided by divided by hourly load.

[2] REPs are credited for performance in the top X of Y seasonal net load hours. We model two foresight cases to capture REPs ability to predict top net load hours. Imperfect foresight scenario: REP targets 10x the top net load hours with program dispatch, receives lower accreditation. Near-perfect foresight scenario: REP targets 2x the top net load hours, receives higher accreditation.

Illustrative DR Dispatch (Imperfect Foresight RDR Case) Residential Electric Vehicle Program

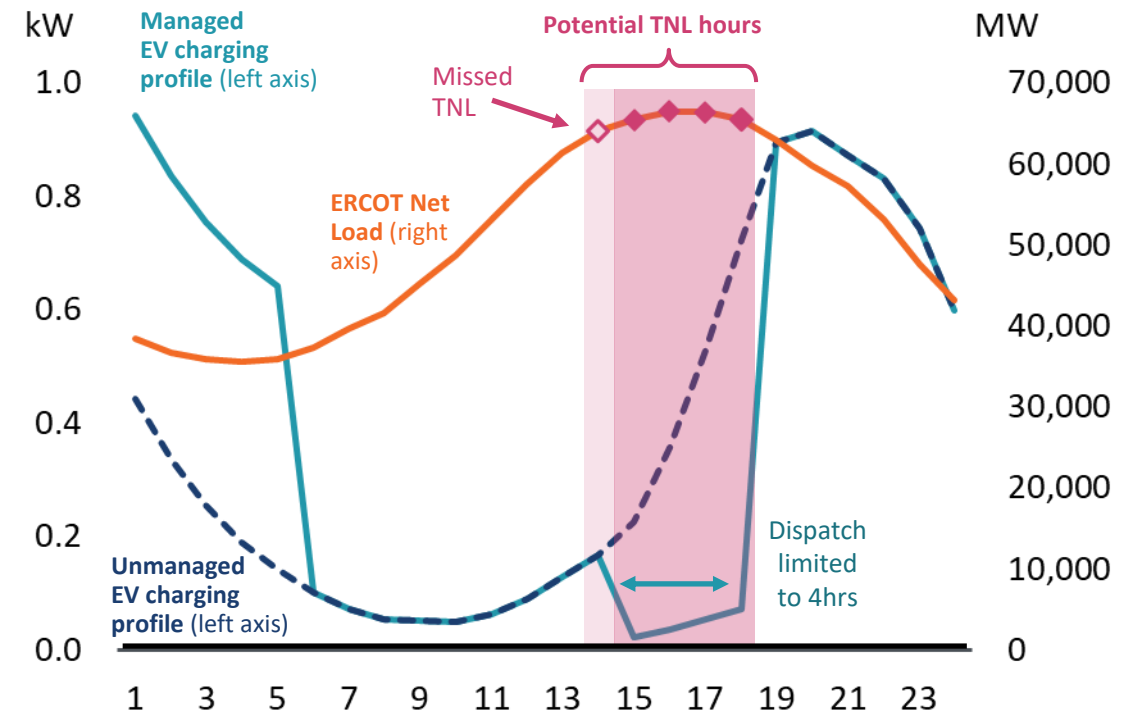


Figure notes: EV [charging profile](#) is average across a portfolio of EVs. EV managed charging assumed to only curtail charging up to 4 hours per event day and therefore cannot dispatch during all potential TNL hours if more than 4 occur on the same day. In the example above, 5 potential TNL hours occur on a single day. See appendix for technology-specific DR dispatch constraints and additional source materials.

Accounting for REP Foresight into System Conditions

Our analysis includes two scenarios representing different degrees of accuracy that REPs would have when forecasting system conditions and dispatching DR programs.

The proposed RDR program parameters will accredit reductions in the top performing “x of y” net load hours each season, specifically the top 6 of 8 in Summer (Jun – Sep) and Winter (Dec – Feb) and top 3 of 5 in Spring (Mar – May) and Fall (Oct – Nov). Net load is defined as gross demand less renewable output, before accounting for generator outages.

REPs will target DR dispatch during seasonal net peak hours to earn maximum accreditation. Since the top net load hours are determined at the end of a season, REPs cannot perfectly predict when those hours will occur.

To represent this imperfect foresight in our modeling, we identify a larger number of hours known in advance to have the *potential* to be the top net load hours, and then assign value based on the extent to which the REP can curtail load during all of those hours. The box at right describes the two scenarios we modeled.

For example, to receive full summer accreditation under the “imperfect foresight” scenario assumptions, the REP would need to be able curtail load during 60 of 80 identified “near peak” hours (i.e., 10x the proposed “6 of 8” hours). If the REP only has the capability to curtail load during 30 of those 60 hours, accreditation would be reduced by half.

Modeled Foresight Scenarios

Near-perfect foresight (higher value), where the REP must reduce demand in double the accreditation hours in order to earn full accreditation.

Imperfect foresight (lower value), where REPs must curtail load during 10x the number of accreditation hours in order to earn full accreditation (e.g., 60 instead of 6 in the summer). The 10x ratio is informed by ERCOT’s identification of the number of [near-4CP days](#) relative to 4CP days.

Notes: ERCOT Reports [~40 “near miss” 4CP days](#) for 2022 (10 per summer month), identified as days with more than 1,000 MW of total system DR. These are days that customers targeted as potentially being a 4CP day. Correspondingly, our dispatch targets 10x the top ERCOT system load hours in each season.



IV. The Enrollment Impact of ERCOT's Proposed RDR Program

Section Overview

This section summarizes the findings of our analysis of the potential impact of the RDR program on DR enrollment.

The section begins by presenting the value that REPs could monetize by operating DR programs with and without support from the proposed RDR program. We illustrate the value across three residential customer end-uses: smart thermostats, electric vehicles, and battery storage.

Then we demonstrate the change in incentive levels that REPs could offer customers with the RDR program. We benchmark these incentive offerings against cost-effective participation incentives offered across other jurisdictions.

Next, we illustrate the growth in DR enrollment that could be attributed to increased customer incentive payments, based on participation levels that have been achieved in other jurisdictions in similar timeframes.

Illustrating RDR Impact on Monetizable Value: Smart Thermostat Example

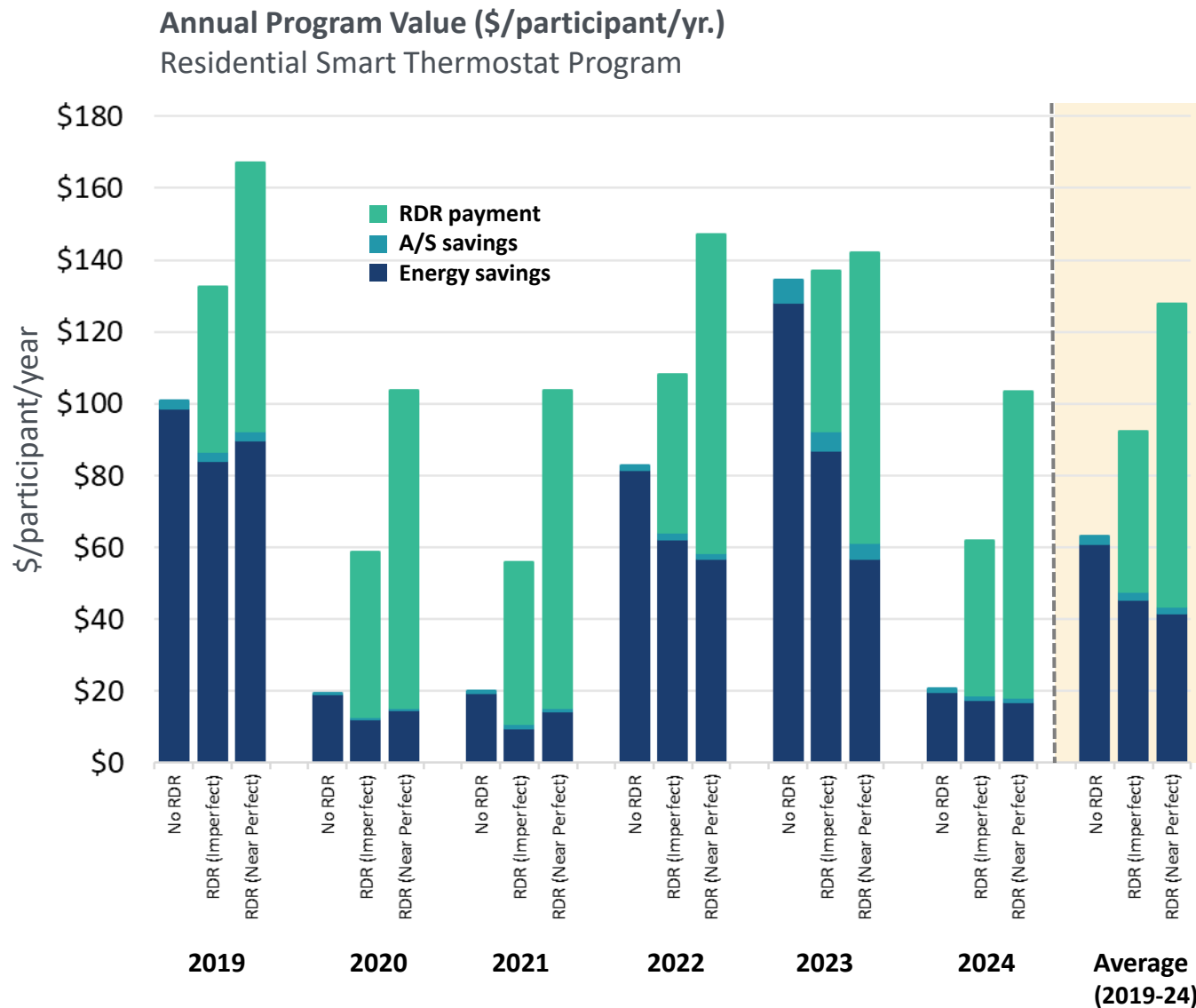
The RDR program increases the monetizable value of a smart thermostat program to REPs, which in turn would enable higher participation offers to customers.

Without the RDR program, smart thermostat demand reductions provide \$63/participant on average in annual energy and ancillary value (2019-2024).

With the RDR program, REPs could earn an additional \$29 to \$64/participant on average for targeted dispatch during peak net load hours, depending on accuracy of foresight into market conditions. Smart thermostats are not assumed to be able to earn RDR compensation in winter or shoulder seasons.

Earning compensation in the RDR program requires modest tradeoff with energy and ancillary services revenue that would otherwise be achieved.

Significant annual variation in the energy value highlights a challenge for the REP DR business model in ERCOT. The more consistent year-to-year benefit from RDR helps to mitigate that challenge to a degree.



The Impact of RDR on Cost-Effective Incentive Payments

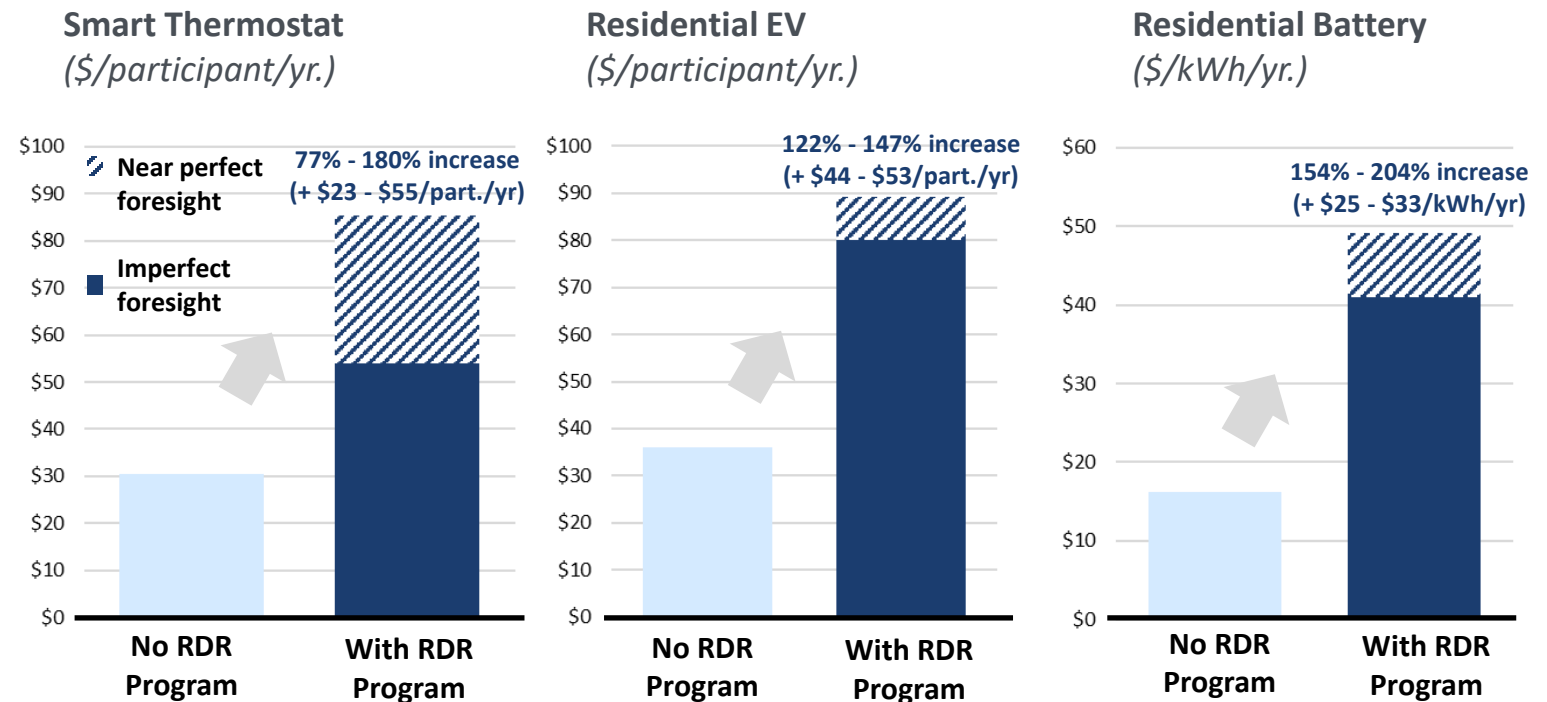
Increased revenue from RDR means participants could be offered cost-effective compensation payments that are 2x to 3x the levels currently supported by the market.

The maximum incentive payment that can be offered by REPs to participants is the monetizable DR value minus both DR implementation costs and the share of the value retained by the REP for facilitating the DR opportunity.

DR implementation costs account for marketing, program administration, and incremental DERMS fees. See appendix for details.

In our analysis, maximum incentive payments increase by between 77% and 204% with the introduction of ERCOT's proposed DR program, depending on the DR technology.

Maximum Cost-Effective DR Participation Incentive

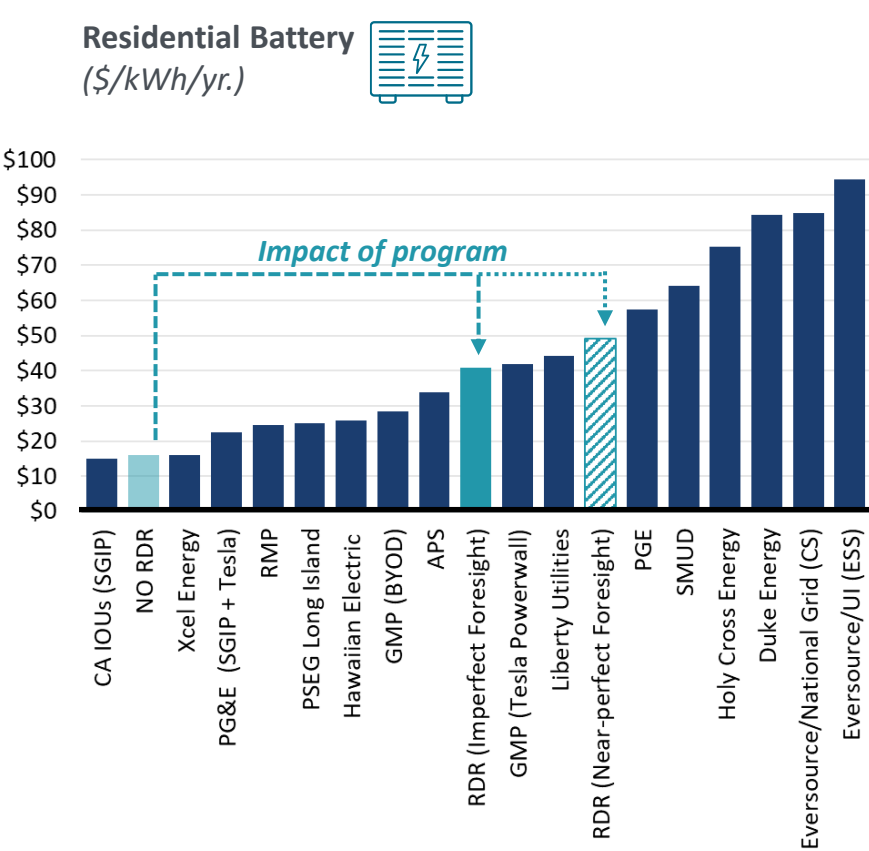
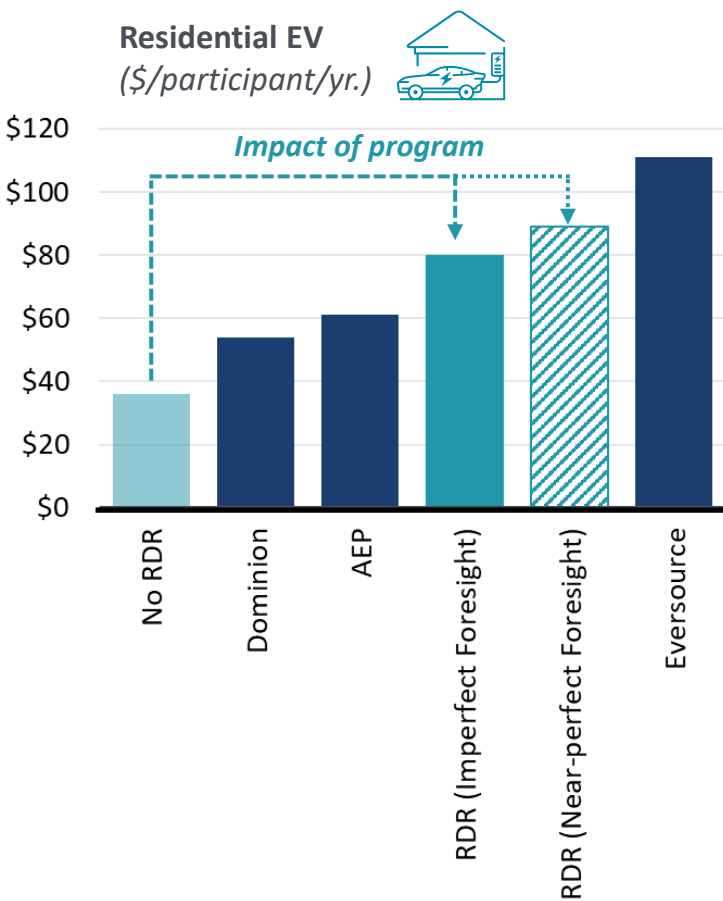
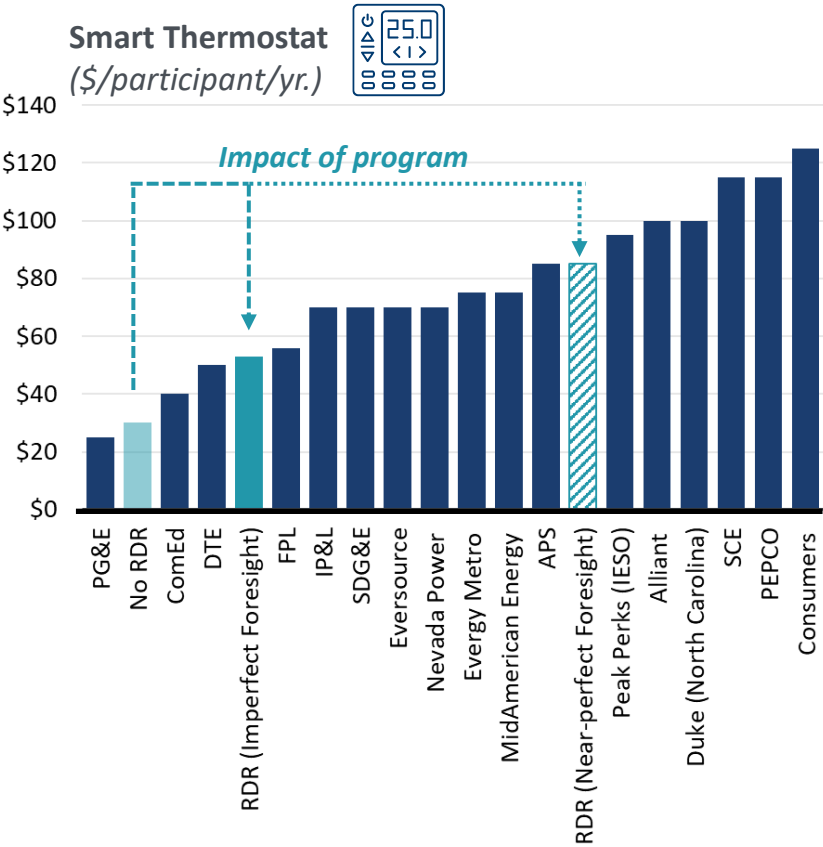


Note: Battery dispatch is not credited for exported energy, but could be if paired with distributed solar.

Benchmarking the DR Incentives to Other Jurisdictions

ERCOT’s RDR program could increase cost-effective DR participation incentives offered in ERCOT’s competitive retail market to levels that have supported significant enrollment in utility programs in other jurisdictions.

Benchmarking Against Participant Incentives Offered in Reviewed Utility Programs



The Potential Impact of the RDR Program on DR Adoption

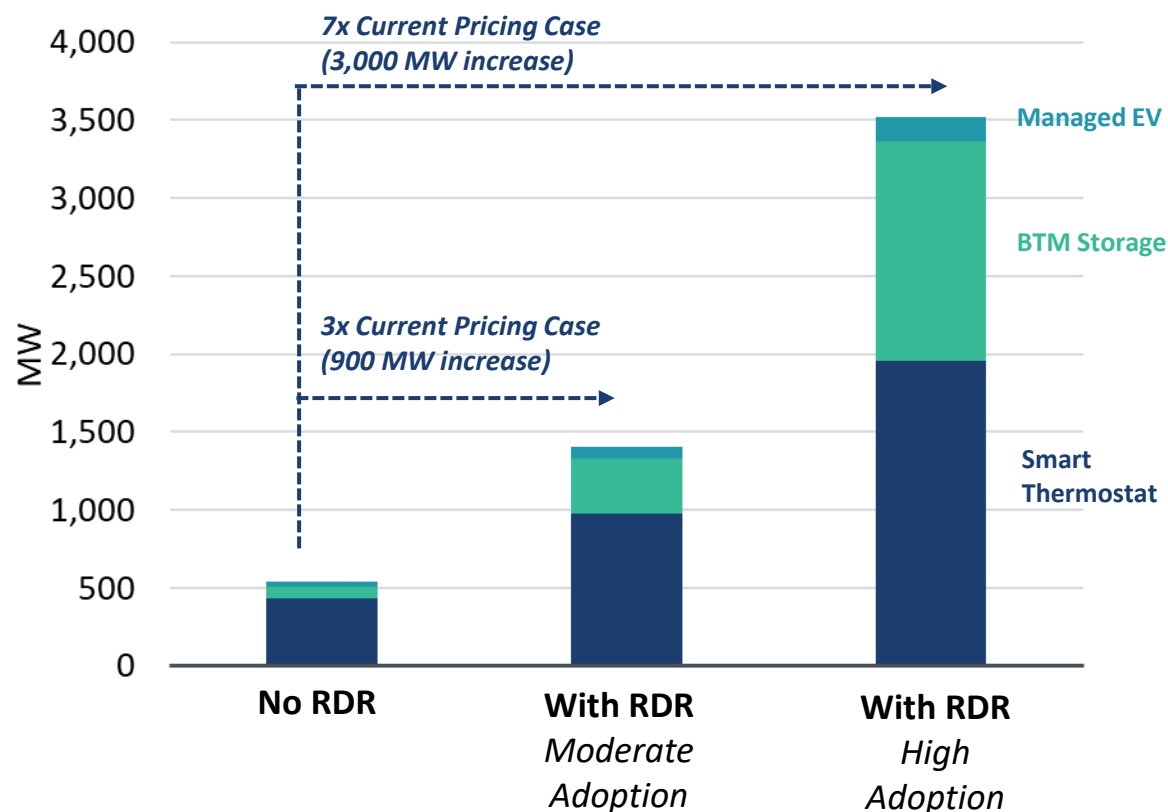
With competitive participation compensation, the RDR program could reach its 500 MW enrollment cap within a few years.

To illustrate the potential impact of increased incentives offered through the residential DR program, we modeled three scenarios.

- **No RDR:** Future DR adoption limited to low end of what has been achieved in other jurisdictions.
- **With RDR (Moderate Adoption):** With higher, industry-standard incentives supported by implementing the RDR program, we assume DR enrollment could increase to levels achieved by successful utility offerings in other jurisdictions.
- **With RDR (High Adoption):** When coupling higher incentives with the removal of other DR deployment barriers, we assume adoption could reach maximum levels observed in a review of various DR planning studies.

As currently proposed, compensation for participation in RDR is capped at 500 MW. If participation exceeds that level, compensation becomes diluted across participants (e.g., at 1,000 MW of participation, compensation would be cut in half on a per-MW basis). As a result, we do not expect that RDR participation would significantly exceed the cap but should largely be additive to other DR not participating in the RDR program.

2030 ERCOT Residential DR Capability



Note: Our analysis focuses on DR offerings that would be supported by direct reduction of energy and ancillary costs and contributions to residential DR accreditation hours. It does not account for alternative DR compensation opportunities in Texas, such as the ADER pilot. Further market research would be valuable to establish a direct relationship between incentives and likely DR participation.

The Achievable Pace of Program Growth

Existing residential HVAC control programs across the U.S. demonstrate that achieving 500 MW of smart thermostat capability (i.e., 8% participation rate) could be feasible for ERCOT in the next 3-5 years

Around 3% of ERCOT customers currently participate in a smart thermostat DR program, based on EIA-861 (2023) data.

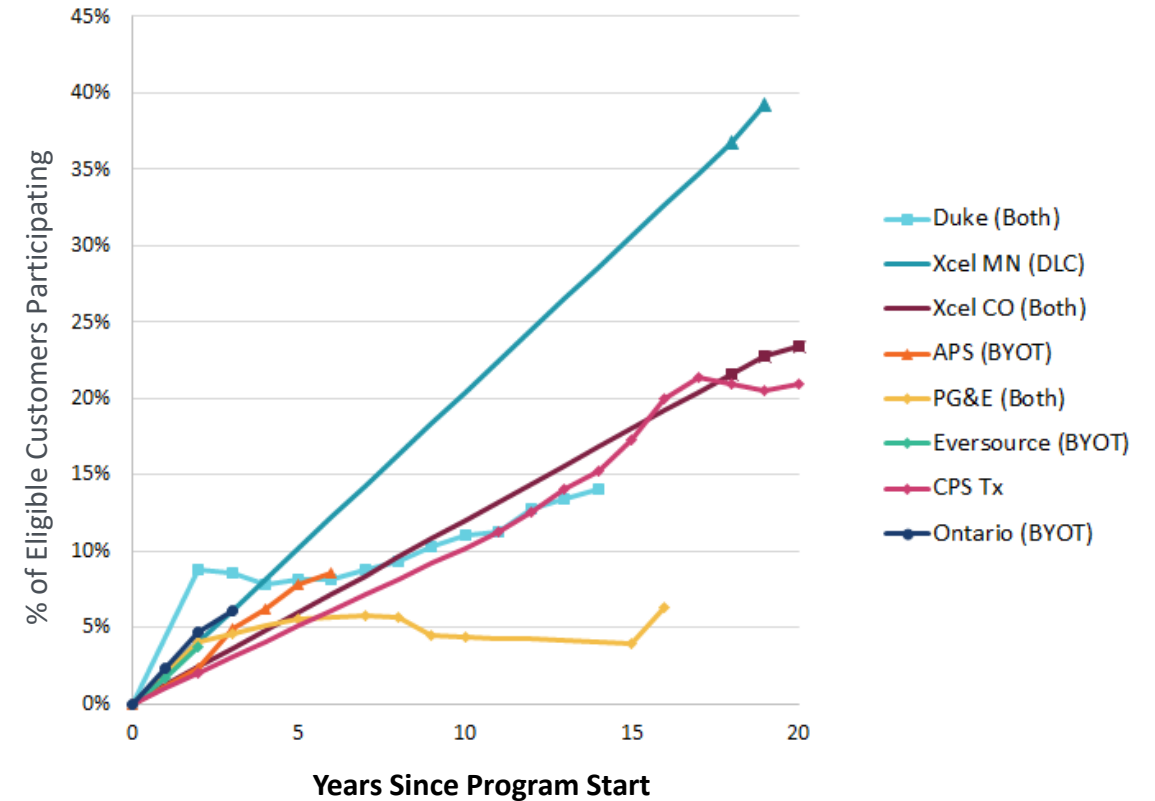
If participation increase to 8%, residential smart thermostats alone could provide more than 500 MW of new DR capability in ERCOT. Based on experience in other jurisdictions, ERCOT could expect to reach 8% participation within the next 3-5 years.

This growth could further be accelerated relative to other jurisdiction experience due to the following factors:

- Advancements in online marketplaces and digital marketing practices could boost enrollment rates relative to historical trends in legacy programs
- Organic adoption of smart thermostats has established an eligible customer base that did not exist in early years of comparable programs
- Smart thermostat programs have already been offered in ERCOT for over 10 years

HVAC Control Program Participation Rates

Direct load control (DLC) and bring-your-own-thermostat (BYOT)



Notes: Program participation collected from utility program evaluation reports. Both direct load control (DLC) and bring your own thermostat (BYOT) programs were included. Data points without markers indicate year where extrapolation was needed due to lack of available data.



V. Market Price Effects

Market Price Impact Approach Overview

We develop a regression-based approach to quantify the price impact of the RDR program relative to forwards.

Question

How much will the proposed 500 MW RDR program impact the projected energy price increase relative to today's prices given forecasted additions of non-firm supply and firm demand in ERCOT?

Hypothesis

Without a price adjustment mechanism, the RDR program will reduce prices relative to a case with no RDR program (all else equal)

Approach

1. **Develop series of regression models** to establish a relationship between hourly reserves, gas prices, and settlement prices
2. **Forecast hourly reserves** under projected supply and demand additions, calibrated to forwards
3. **Compare the impact of the RDR program** on average annual prices to ERCOT energy forwards

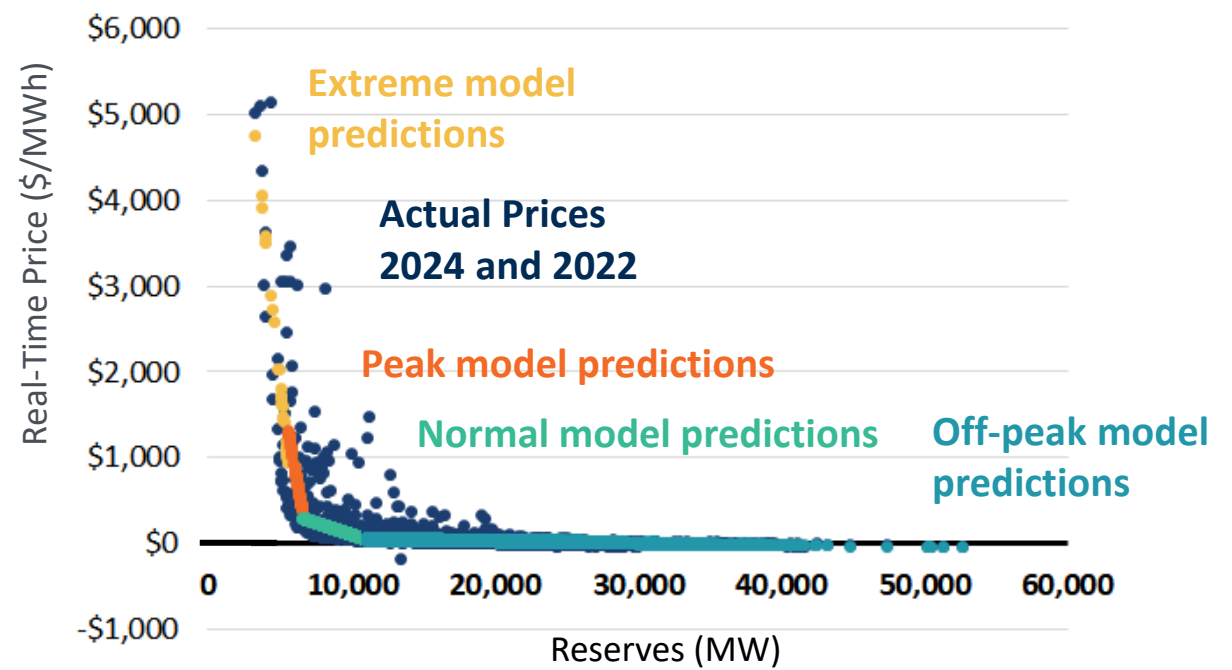
Note: See appendix for additional detail on approach.

Building a Simplified Pricing Model

Our pricing model uses regression analysis to relate prices to hourly online and offline reserves as well as monthly gas prices, based on data from 2022 and 2024.

- We develop four regression models using historical hourly reserve levels to predict prices across different periods.
- Prices are the dependent variable, with hourly reserves as the primary independent variable and gas prices only included as a second independent variable in the off-peak model.
- Implicitly, the extreme model captures effects of the ORDC. Extreme conditions are most relevant for analyzing DR dispatch.

Benchmarking Regression Models with Actual Hourly Prices
2022 and 2024



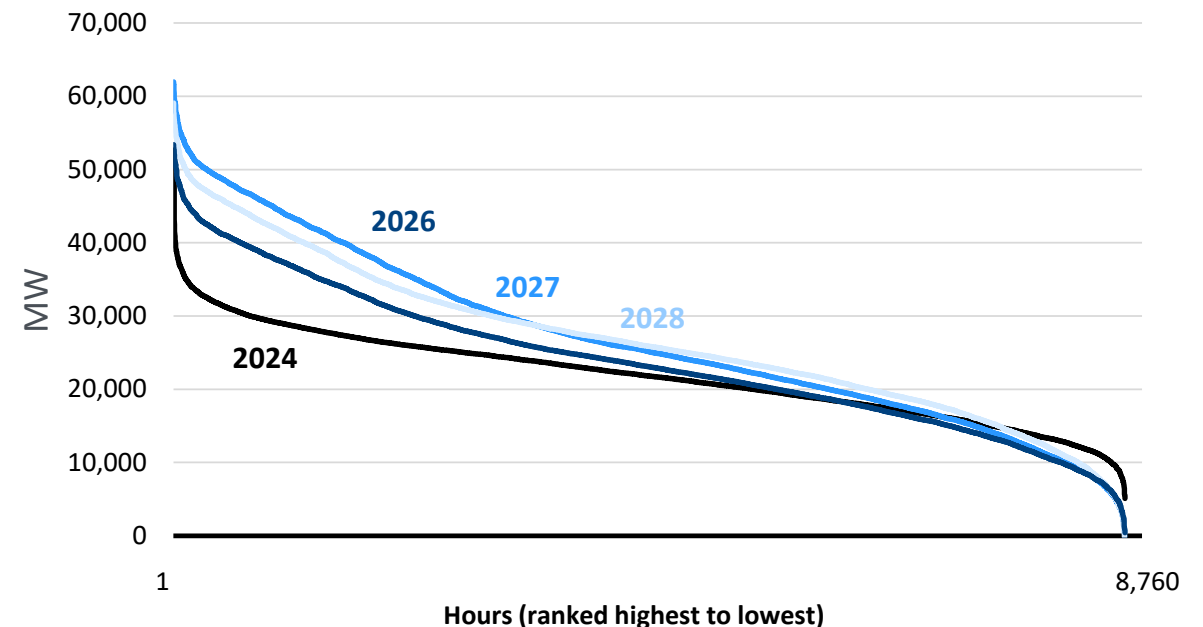
Note: 2023 was excluded due to anomalous price patterns that would skew predictions.

Projected Hourly Reserves with and without DR Dispatch

To project hourly operating reserves, we adjust historical hourly reserve levels by forecasts of incremental supply and demand and calibrate to forward prices in each forecast year. Then, we represent DR dispatch as added reserves during REP-targeted top net load hours and re-estimate prices.

- **We forecast hourly operating reserves** using 2022 – 2024 reserves plus weather-consistent incremental supply & demand; with load growth, the tightest hours may be tighter (rightmost part of duration curve), while many daytime hours have higher reserves due to expected additions of PV and other resources.
- **We apply reserves to the pricing model** (and calibrate annual new load and resources until annual average prices match forwards).
- Finally, to **estimate the DR program's price impact**, we:
 - Assume a residential DR program composed primarily of smart t-stat participants, dispatched up to 60 hours/year (May-Oct), with behavioral limits.
 - Adjust the hourly operating reserves by the DR program cap (500 MW), which conservatively assumes peak load reduction only.
 - Compare the estimated prices to those without the DR.
 - This analysis is *without* modeling any RTRDPA price adjustment.

Projected Reserves Duration Curve Compared to Historical



Note: These figures are not intended to be predictive of a future grid state, rather they are baseline assumptions used to assess the price impact of demand response.

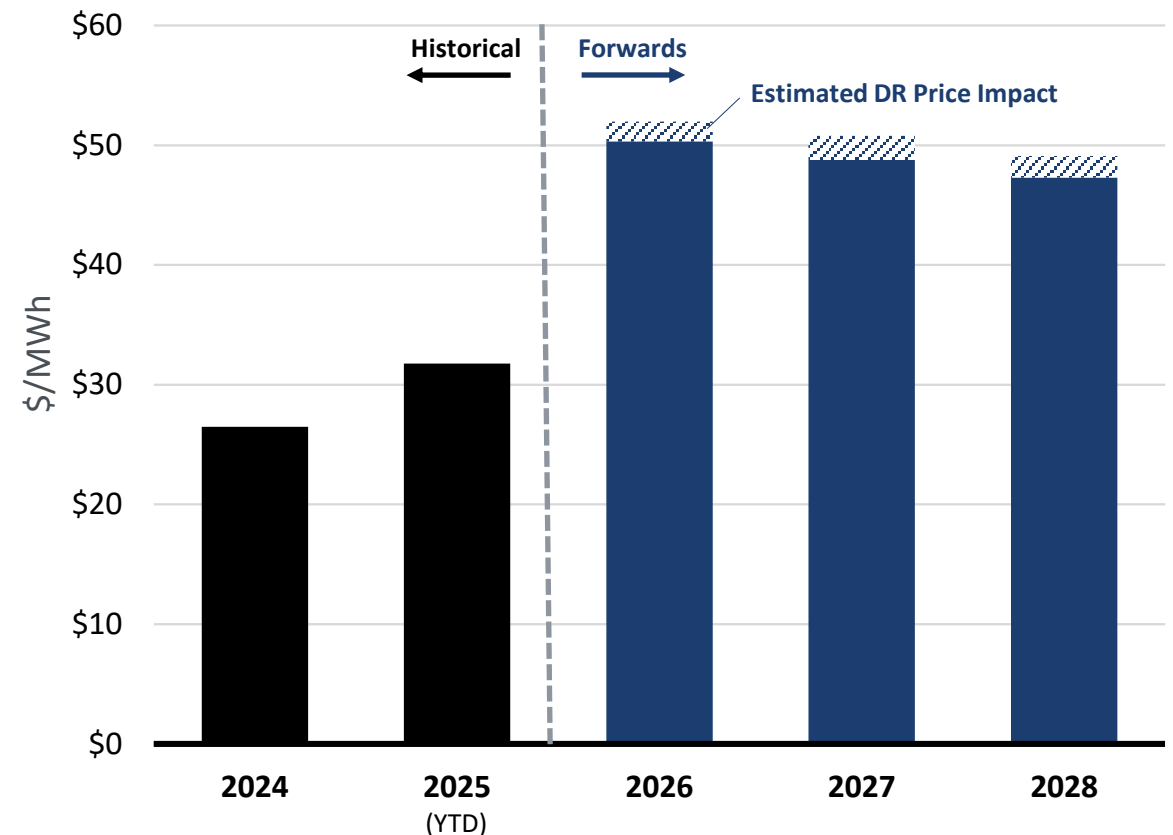
ERCOT RDR Program Effect on Market Prices

With the 500 MW participation cap, ERCOT's proposed Residential DR program will not lead to significant price suppression, relative to increasing forward prices

- Independent of the RDR program, ERCOT energy forwards indicate that, by 2028, prices are expected to **increase +\$15-20/MWh from recent historical average spot prices**.
- The RDR program could contribute up to **500 MW of supply** in high net load hours, with the current proposed cap. This would reduce demand in the highest priced hours.
- Our modeling results suggest **prices would still increase nearly as much with the DR program as proposed** (absent a price adjustment mechanism, but with a 500 MW cap).
- The RDR program, capped at 500 MW, could reduce prices by **3-4% reduction** on average, which is **less than \$2/MWh** on an annual average basis.

Note: These figures are not intended to be predictive of a future grid state, or upcoming market design changes such as Real-Time Co-optimization. Rather, they are baseline assumptions used to assess the price impact of demand response. Declining forward prices from 2026 to 2028 aligns with forecasted decline in natural gas prices during that period.

Annual Average ERCOT Market Prices (Historical and Forwards)
With and without RDR impact





VI. Conclusion

Key Takeaways

This study demonstrated that ERCOT's proposed RDR program could lead to significant growth in demand response capability, with notable favorable design features.

- Customer incentives offered by REPs could **double or triple** with the introduction of the RDR program.
- Increased incentives could lead to the **500 MW RDR cap being reached within a few years** from residential smart thermostats, EVs, and batteries.
- ERCOT is anticipating significant demand growth and tightening of reserves through 2030. The RDR program allows the **mobilization of dispatchable capacity** in the market.
- RDR has the **potential to exceed the cap** if it is eventually lifted.
- In addition to relieving a strained supply-demand balance in the near term, RDR could improve residential customers' familiarity, experience, and capability with respect to DR, creating a **foundation for a more price responsive residential customer base**.
- The introduction of DR as proposed could **lower prices by 3-4% relative to forwards**, which is substantially less than the price increase expected from tightening reserve margins.

Longer-term Opportunities to Enhance Program Design

Based on our review of the proposed RDR program, the following are potential opportunities to enhance its design following initial experience.

Annual accreditation: Most of ERCOT's highest risk hours occur during summer months (see appendix). While the RDR program compensates load reductions proportionally across all four seasons (based on performance), summer demand reductions will provide the highest value. In the future, ERCOT could explore modifications that more closely align performance payments in summer months.

Price adjustments: As shown in this study, the 500 MW program participation cap effectively mitigates the risk of significant price suppression, particularly relative to rising prices due to tightening reserve margins. In the longer term, a price-adjustment mechanism that offsets the price suppression effect would provide a more durable solution and allow the program to scale beyond the 500 MW cap.

Compensation uncertainty: RDR compensation effectively declines with the amount of enrolled DR beyond the 500 MW cap. This introduces risk to market participants, who do not have foresight into the level of program participation and cannot price participation incentives accordingly. Mechanisms that provide compensation certainty will support DR deployment.

Other barriers: To maximize residential DR, additional barriers will need to be overcome. While beyond the scope of this study, those may include inability to monetize location-specific distribution value of DR, volatility in year-to-year monetizable value and participating customer base, interoperability and communications challenges, and an inability of REPs to monetize the transmission value of residential peak demand reductions.



Appendix A: Enrollment Impact Analysis Detail

Appendix A: Overview

This appendix provides additional detail behind the methodology, assumptions and data sources that support the enrollment impact analysis, including:

- Market characteristics
- RDR top net load hours program foresight
- DR dispatch modeling constraints
- DR program cost assumptions
- DR participation assumptions
- DR incentive benchmarking

Market and RDR Characteristics

Without RDR Program

Each DR technology is dispatched to reduce load when the REP would be exposed to high real-time energy prices or ancillary services costs.

- Hourly Houston zone Settlement Point Prices (SPPs), calculated as simple hourly average of 15-min SPPs, sourced from ERCOT for 2019-2024
- Ancillary services cost recovery rates calculated based on day-ahead Ancillary Services Plan quantities and clearing prices allocated to hourly ERCOT-wide native load. Load, Ancillary Services Plan, and pricing data sourced from ERCOT for 2019–September 2023
- DR value is determined by the avoided cost to the REP during curtailment hours, less the increased cost associated with load building in other hours.

With RDR Program

REPs are additionally compensated (at CONE \$140/kW-yr) for top performance during 5-8 net load hours in each season. We capture the tradeoff between targeting net load hours and high priced hours. At the end of a season, ERCOT will determine the top 5 (Spring, Fall) to 8 (Summer, Winter) hours of net load. REPs will get credit for their top performance during 3 of 5 (Spring, Fall) or 6 of 8 (Summer, Winter) hours.

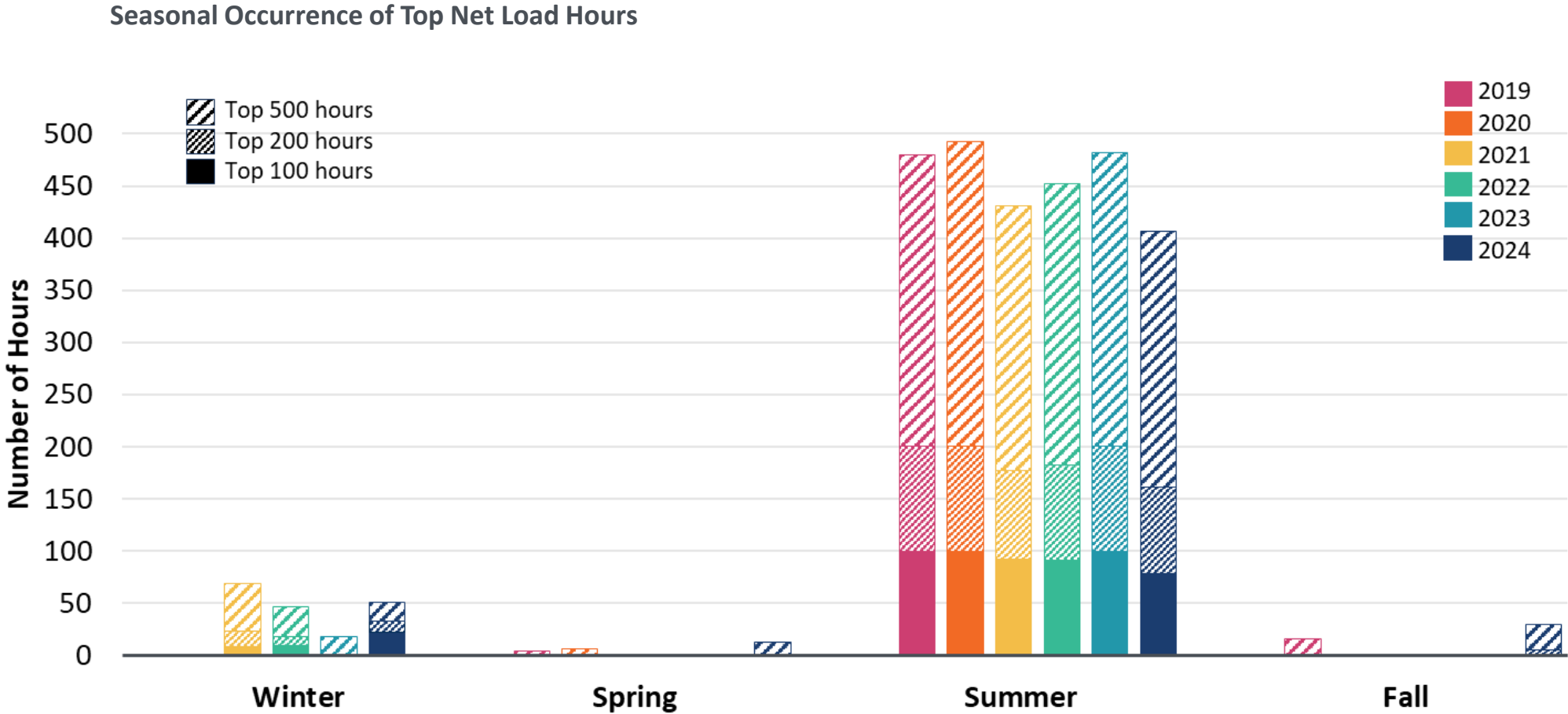
We model two foresight cases to account for the difficulty REPs may face predicting top net load hours each season:

- **Near-perfect foresight** case where the REP reduces demand in double the accreditation hours in order to earn full accreditation (e.g 12 in the summer instead of 6). REPs forecast 2x potential net load hours.
- **Imperfect foresight** case where REPs must call events in 10x the top net load hours each season to earn full accreditation (e.g., 60 instead of 6 in the summer). The 10x ratio is informed by [near-4CP days](#) relative to 4CP days.

The seasons are defined as: Dec – Feb (Winter), Mar – May (Spring), Jun – Sept (Summer), and Oct – Nov (Fall)

Seasonal Top Net Load Hours

The top 90% of net load is concentrated in Summer. The RDR program targets hours in all four seasons.



DR Dispatch Modeling Constraints

	Smart Thermostat	Residential Battery	Electric Vehicle
Event frequency	60 hours/yr (15 days with 4-hr events)	200 hours/yr	50 hours/month (600 annually)
Curtailment impact	1 kW/customer in Summer months (consistent with many utility smart thermostat program impacts), 0.9 kW/customer in May/Oct.	4.5 kW/customer (assuming on average 1.5 batteries per customer, each with 9 kWh capacity and 3 hours duration based on standard BTM storage specs). Batteries are not compensated for exports (but could be if paired with solar).	90% of expected hourly charge for EV portfolio accounting for opt-out (~0.45kW). Hourly charge pattern sourced from NREL EVI Pro Lite for Houston area, accounting for weekday and weekend patterns. Impact based on review of existing programs (AEP , Dominion , Eversource , Exelon)
Load shifting assumptions	1.5 hours of increased load per hour of curtailment, with 1/3 of those hours occurring immediately prior to event and 2/3 immediately after. Total added load equal to 40% of curtailed load	Charging happens in the lowest priced hours before 6 am and accounts for 90% round trip efficiency losses. Battery charges for same number of hours as dispatched during an event	Charging happens in lowest priced hours (midnight to 5 am) such that the vehicle is charged by 5 am, in order to preserve participant convenience
Curtailment restrictions	Up to 4 hours of thermostat load curtailment per event with max 1 event/day (hourly must be contiguous); limited to 12–9 pm and June–September	Up to 3 hours of storage dispatch per day, assuming a maximum of one full cycle per day	Up to 4 hours of curtailed charging per day (consistent with existing EV managed charging programs, e.g. Dominion's EV Charger Rewards)

DR Program Cost Assumptions

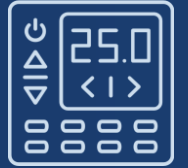
The maximum incentive payment that can be offered to participants is the monetizable DR value minus both REP costs to implement the DR offerings and the share of the value that is retained by the REP for facilitating the DR opportunity. DR implementation costs account for marketing, program administration, and incremental DERMS fees.

DERMS fees	We assume a fee of roughly \$2/kW-month for each participating DR technology, based on a review of vendor information. As such, the DERMS fee is higher in aggregate for technologies with larger controlled load. The fees amount to \$24/participant/year (smart thermostat), \$162/participant/year (residential battery), and \$11/participant/year (EV).
Administrative cost	We assume a cost of \$1/participant/year to cover program administrative costs such as staff salaries and general administrative expenses.
Marketing	We assume REPs are able to leverage existing marketing initiatives to create awareness of the DR opportunity with their customers, and do not incur substantial marketing costs beyond the participation incentive payment.
Cost share	After subtracting the above costs from the average annual monetizable value of the DR offering, we assume 20% of that remaining net value is allocated by the REP to non-participants. This is an illustrative assumption. The remaining 80% of the net value is assumed to be available to customers in the form of cost-effective participation incentive payments.

DR Participation Assumptions

We used the following assumptions to illustrate the potential impact of increased participation incentives on DR deployment and adoption.

Smart Thermostat DR Offering



- **Eligibility:** All residential REP customers in ERCOT with central air-conditioning (83%), assuming 7.5 million residential REP customers in 2030, based on assumed 1.5% annual growth.
- **No RDR:** Without the proposed RDR program, cost-effective participation incentives are lower than the range of incentives offered in successful utility programs. At this low level of incentive, we assume **3%** of eligible customers will participate. This participation is consistent with the lower-end of utility air conditioning direct load control programs in the US and is similar to estimates of enrollment in existing NOIE direct load control programs in ERCOT.
- **With RDR (moderate adoption):** The DR program payment could bring incentive payments within the range of offerings in the largest utility A/C DLC programs in the US. We assume **15%** of eligible customers will participate; this level of enrollment has been achieved in large utility residential air-conditioning load control programs with robust participation.
- **With RDR (high adoption):** Coupled with the removal of other potential barriers to DR deployment, we assume compensation from the proposed RDR program could contribute to smart thermostat DR participation rates of **30%** in the high enrollment case. This has been identified as a best practice participation level in Brattle's meta-analysis of demand response planning studies.

DR Participation Assumptions (cont'd)

We used the following assumptions to illustrate the potential impact of increased participation incentives on DR deployment and adoption.

Residential Batteries



- **No RDR:** Without the proposed RDR program, cost-effective participation incentives are unlikely to support discounts on the up-front purchase of a battery, but could enable limited support in a bring-your-own-battery program. In this case, we assume that 1% of residential households in ERCOT will have a battery by 2030, based on analysis of battery attachment rates to rooftop solar in other jurisdictions. Assuming 20% of those customers enroll in the program, **0.2%** of ERCOT households would participate in aggregate.
- **With RDR (moderate adoption):** The DR program payment would raise cost-effective DR incentive payments to the level offered in more mature battery programs, such as the program offered by Green Mountain Power. In this case, we assume **1%** of all ERCOT households would enroll a battery in the DR, consistent with the current level of participation in Green Mountain Power's program for its service territory.
- **With RDR (high adoption):** Green Mountain Power is expanding its residential battery program and plans to have at least 4% of its residential customers enroll in BTM storage programs by 2030. To illustrate what may be feasible at higher incentive levels with significant participation in a battery DR offering, we adopt Green Mountain Power's low case adoption estimate of **4%** for residential households in ERCOT by 2030.

DR Participation Assumptions (cont'd)

We used the following assumptions to illustrate the potential impact of increased participation incentives on DR deployment and adoption.

Residential EV Charging



- Without the proposed RDR program, cost-effective participation incentives for home EV managed charging are modest and below the range of incentives offered in four emerging active managed charging utility programs in the US. The proposed RDR program could bring that cost-effective incentive payment within the range of the other utility programs.
- Given the nascent state of active managed charging DR programs, there is not direct empirical support for achievable enrollment rates. Given that the magnitude of incentives offered in the managed charging programs is similar to those of smart thermostat programs, and that EV charging load is flexible, we assumed the same participation rates that we assumed for the smart thermostat DR: **3%** for the no RDR case, **15%** for the with RDR with moderate adoption, and **30%** for the with RDR with high adoption. This is an illustrative assumption and could be refined as additional information about customer propensity to participate in active managed charging programs becomes available.
- The assumed participation rates apply to EV owners who charge their EVs at home. By 2030, we assume that there will be approximately one million light-duty EVs on the road in ERCOT, based on recent [Brattle analysis](#) for ERCOT. Of those, we assume 80% will [charge at home](#). By 2030, we assume that all participating EVs would have the necessary communications capability, whether through a connected charger or on-board telematics.

Notes on DR Incentives Benchmarking Analysis

We made the following assumptions to establish comparable estimates of each of the utility program incentive payments presented in the incentives benchmarking section of this report.

Residential battery programs

- Surveyed utility programs with sufficient publicly available data on participant incentives and participation requirements
- Assumed participant has two Tesla Powerwall batteries (10 kW / 27 kWh) unless otherwise specified in program description
- Assumed 10 years of participation where applicable
- PGE up-front incentive is only available to customers in specific locations
- When retention incentives are a function of battery output, we assume the maximum amount of discharge available under program limits
- Assumed discount rate for annualizing up-front program incentives is based on discount rate implied in Green Mountain Power lease (i.e., difference between up-front versus monthly payment plan offerings). It is approximately 1.8%/year
- Estimates of battery cost savings to participant in leasing programs based on pre-tax incentive battery cost without installation

Smart thermostat programs

- Using 2022 EIA-861 data on demand response programs, we selected utilities with the highest residential DR enrollment that had more than 100,000 residential customers and specifically offer smart thermostat demand response programs
- Calculated customer incentives based on 1 year of participation

Electric vehicle active managed charging programs

- Calculated customer incentives assuming 10 years of participation where applicable
- Assumed discount rate for present value calculation is based on discount rate implied in Green Mountain Power storage lease, as noted on prior slide
- For AEP, assumed 5 high demand events per year
- For Eversource, accounted for up-front enrollment and ongoing incentives from direct managed program only (not the time-varying rate benefits). Up-front enrollment incentive assumes on-board vehicle telematics, consistent with modeling assumptions



Appendix B: Price Impact Analysis Detail

Appendix B: Overview

This appendix provides additional detail behind the methodology, assumptions and data sources that support the price impact analysis, including:

- Market price impact analysis assumptions
- Projected demand
- Projected supply

Market Price Impact Analysis Assumptions

	Description	Sources
Demand	Adjust 2022 and 2024 load profile by forecasted peak load to keep weather year consistency	ERCOT, Peak Load Forecast (2025); ERCOT, Hourly Adjusted Load Forecast (2025)
Supply: Storage	ICAP from CDR eligible units, treated as dispatchable in hourly reserves calculation	
Supply: Wind	ICAP from CDR eligible units decreased by policy impact, adjusted by hourly ERCOT-wide historical capacity factor for 2022 and 2024 for hourly reserves calculation	IEA, Renewables 2025 (October 2025)
Supply: Solar	ICAP from CDR eligible units decreased by policy impact, adjusted by hourly ERCOT-wide historical capacity factor for 2022 and 2024 for hourly reserves calculation	IEA, Renewables 2025 (October 2025)
Supply: Thermal	ICAP from CDR eligible units, increased by TEF units not already in CDR-eligible units list, adjusted by monthly estimation of thermal outage rate	Estimated using Pfeifenberger, SPP Future Energy and Resource Needs Study (FERNS): Land Use Analysis Approach (June 2024)
Supply: Market entry adjustment	Calibrated forecasted supply based on the market entry assumption that: 1. ERCOT Market Equilibrium Reserve Margin is 13.75% 2. Marginal CC entering the market would earn more than CONE (~\$290/kW-year)	ERCOT, Resource Adequacy reports MERM 13.75%
Supply: Calibration with Forwards	Calibrated forecasted supply to annual average forward energy prices	Forwards as of August 25, 2025 for Houston sourced from S&P Global Market Intelligence, MI Forward Full Value Future/Forward, Monthly term
Prices: Price Cap	\$5,000/MWh price cap applied for all years where Peaker Net Margin < 3x CONE, otherwise \$2,000/MWh price cap applied	
Demand Response Dispatch	DR dispatched at 500 MW in top 60 net load hours between May and October	

Projecting Demand Growth for Market Price Impact Analysis

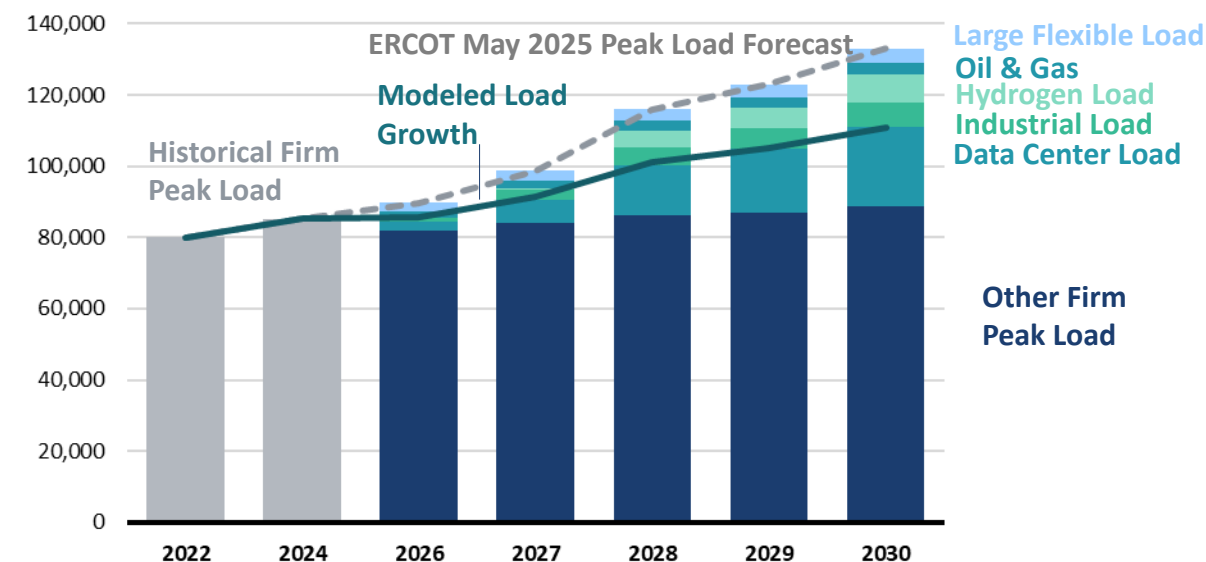
ERCOT forecasts that demand could grow by 40% by 2030 primarily driven by new large loads. We account for policy impacts on load forecast and estimate 23% growth by 2030.

Our “Modeled Load Growth” scenario is based on ERCOT’s May 2025 load forecast and adjusted downward for a variety of reasons such as limited interconnection pace, due to new policies like TX SB 6

- ERCOT’s most recent (May 2025) firm peak load forecast reduces new data center requests by ~50% and takes other peak load reducing measures to reflect a more realistic demand forecast, but does not account for more recent policy and economic conditions
- **SB6 requires large new loads >75 MW to:**
 - Bring emergency-only backup gen (or load shed), which would *not* moderate prices due to rare deployment and ERCOT price adjustments
 - Or bring dispatchable generation; if this is used frequently (with low variable costs), it could largely negate the load’s market impacts
 - Or not enter at all
- Implication may be **less upward pricing pressure** than ERCOT’s Adjusted Load Forecast alone suggests. The degree will depend partly on how new loads behave, the pace of interconnection, and the characteristics of new supply, which can be explored through scenarios

Peak Load Forecast by Load Type (May 2025)

Select Years 2022-2030



Sources: ERCOT, [Capacity Demand and Reserves Report](#) (May 2025); ERCOT, [ERCOT’s Adjusted Demand Forecast](#) (April 2025). **Note:** ERCOT’s adjustment to TSP-provided forecasts include: 180-day delay for Contracts and Officer Letter Load, all new data center requests are reduced to 49.8% of the original request. All Officer Letter Load requests are reduced to 55.4% of the original request. Large Flexible Loads follow price responsive profile as noted in Figure 2, ERCOT, [Long-Term Load Forecast Report](#) (2025).

Projecting Supply Additions under Tightening Reserve Margins for Price Analysis

We estimate ERCOT's capacity additions based on ERCOT-provided CDR-eligible units, with adjustments to account for U.S. policy changes, units supported by the Texas Energy Fund, reasonable market entry based on ERCOT's Market Equilibrium Reserve Margin and Cost of New Entry, and calibrated to average annual forward energy prices

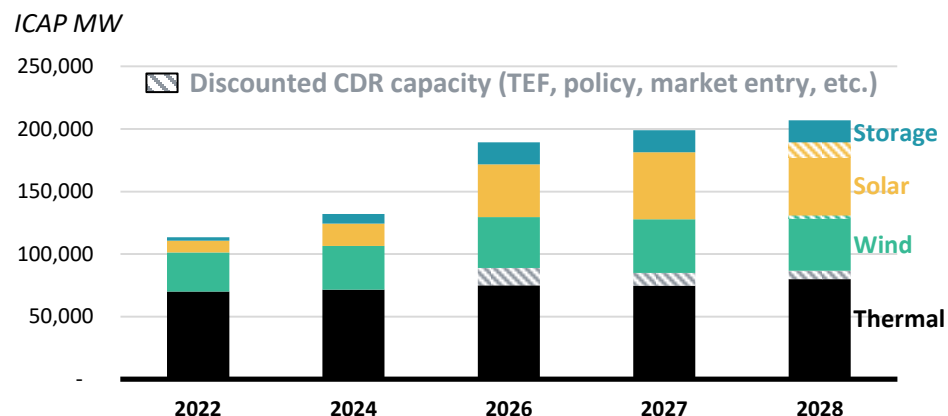
ERCOT's CDR report indicates +35 GW of non-firm supply (over half from solar) and +18 GW of firm load growth by 2028, which will change the profiles of net load and prices.

More non-firm supply brings more periods of low prices from lower cost renewables (captured in our model as high amount of reserves) as well as **more periods with higher prices** during the times with higher peak load.

Our projected capacity mix is based on ERCOT's provided CDR-eligible units list and adjustments include:

- **Policy (-):** Solar and wind planned supply cut by 43% and 60% respectively in 2028 due to U.S. policy changes (earlier tax credit phaseout, import limits, offshore leasing suspensions, and onshore permit restrictions)
- **Dispatchable units (+):** Add TEF-funded resources not already included in the CDR
- **Supply Adjustment (-):** Iteratively determines the capacity additions that enter the market based on ERCOT's 13.75% MERM, \$290/kW-year CONE, and calibrated against annual average forward energy price

Projected Supply Mix
Select Years 2022-2028



Note/Source: Supply forecast from CDR-Eligible Units list from ERCOT, [Capacity Demand and Reserves Report](#) (May 2025). Cumulative supply adjustment includes decrease in planned supply based on U.S. federal policy changes as reported by IEA, [Renewables 2025](#) (October 2025), addition of TEF Units not currently in CDR Approved Units, and adjustment for market entry from ERCOT, [Resource Adequacy](#), 2025. Capacity values shown before further calibration to forward prices.

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Serena specializes in electricity system modeling and policy. In her work at Brattle, she supports US regional trade organizations (RTOs) and independent system operators (ISOs), trade associations, and developers in addressing energy and ancillary service market design challenges. Ms. Patel has expertise in developing custom optimization and simulation models to assess the economic impacts of market design decisions and their implications for broader bulk power system goals such as reliability, affordability, and sustainability.