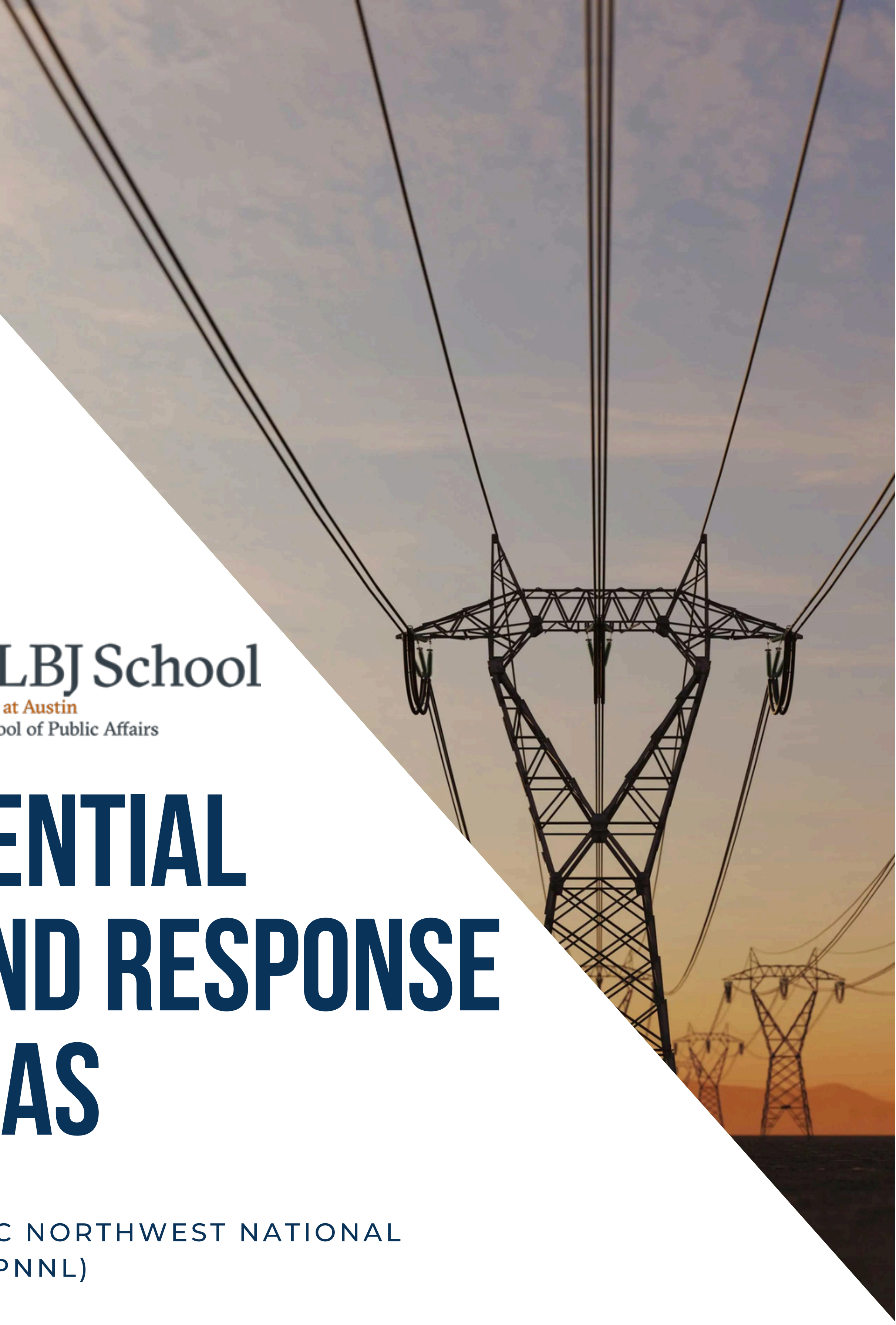

TEXAS LBJ School
The University of Texas at Austin
Lyndon B. Johnson School of Public Affairs

RESIDENTIAL DEMAND RESPONSE IN TEXAS

CLIENT: PACIFIC NORTHWEST NATIONAL LABORATORY (PNNL)

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MEET THE LBJ TEAM

TEXAS LBJ School
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In August 2023, the Pacific Northwest National Laboratory (PNNL) presented a research proposal on Residential Demand Response (RDR) to Professor Steven Pedigo's Professional Research Report class at the Lyndon B. Johnson (LBJ) School of Public Affairs at the University of Texas at Austin. A group of five LBJ graduate students, listed below, selected this research project and developed the following report, which explores the policies, market structures, and conditions that enable energy providers to create, implement, and expand successful RDR programs in Texas.

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EXECUTIVE SUMMARY

Climate change poses significant challenges to nearly every aspect of our lives, from national security and food supply to public health and foreign policy. Human activity, particularly burning fossil fuels and releasing greenhouse gases (GHGs) into the atmosphere, has driven global warming. This has resulted in more frequent and severe weather events, increasing the demand for electricity and straining the electric grid. Recent examples, such as Texas' Winter Storm Uri and record-breaking heatwaves, underscore the profound impact of climate change on critical infrastructure.

In Texas, the significant growth in population and energy-intensive industries exacerbates the issue, causing demand for electricity to approach or outpace the available supply. To meet peak energy demands, energy providers are often forced to rely on costly and environmentally harmful peaker plants. Despite such measures, energy demand can still outstrip supply, risking blackouts that could endanger citizens and heighten inequalities. This emphasizes the urgent need for solutions to mitigate electric grid imbalances.

Demand response (DR) initiatives aim to address the demand side of the equation by incentivizing consumers to change electricity consumption during periods of peak demand. As such, they offer a promising and cost-effective avenue for reducing grid stress. Most DR programs have historically targeted the commercial and industrial sectors. However, given that the residential sector is the largest consumer of electricity in the U.S., there exists an opportunity to develop and scale residential demand response (RDR) programs.

This report explores the policies, market structures, and conditions that enable energy providers to create and implement RDR programs in Texas. More specifically, it seeks to answer two key research questions:

1. What are the most important factors that affect how energy providers conduct demand-side management?
2. What are the enabling factors to implementing RDR programs?

We developed and employed a rigorous methodology to address these questions. This consisted of a comprehensive review of existing research on demand response programs and policies, with a focus on the residential sector. It also included two phases of semi-structured interviews with subject matter experts, energy providers, industry practitioners, and oversight entities.

A qualitative analysis of the interviews provided findings, patterns, and themes, yielding best practices and actionable recommendations for policymakers, energy providers, and researchers in Texas. Specifically, we propose the following recommendations, further detailed in later sections of the report:

1. The Public Utility Commission of Texas (PUCT) should update peak demand reduction and energy savings goals and reframe its cost-effectiveness standard by requiring the portfolio of

programs be net positive instead of each program and by adding avoided transmission and distribution benefits in its calculation methodology.

2. The PUCT should establish a demand response task force at the Office of Public Utility Counsel and the Office of Public Engagement to represent residential DR efforts.
3. Texas should financially support the development, implementation, and adoption of RDR programs through the Texas Energy Fund.
4. The Electric Reliability Council of Texas (ERCOT) or the Texas Energy Fund should provide state-level funding to ensure that successful components of DR pilot programs can be maintained and scaled.
5. Texas should develop complementary, state-level incentive and rebate programs to capitalize on IRA funding.
6. The PUCT should convene stakeholders and conduct an analysis to determine interoperability standards.
7. The Pacific Northwest National Laboratory (PNNL) should evaluate ERCOT's 4 Coincident Peak (4CP) program to better understand its relationship with residential demand response.

We recognize that combatting such multifaceted challenges as grid stability and the climate crisis will require a comprehensive strategy, and RDR is just one tool available in this broader matrix of solutions. Our findings emphasize the role of RDR as a cost-effective solution to grid stress and a complementary factor to decarbonization efforts. In support of these findings, our recommendations address the funding, policy, and future research necessary to expand the adoption of effective RDR programs across Texas. As the state progresses toward a more reliable and decarbonized electric grid, other states and regions can learn from Texas's unique set of regulatory and policy structures and the strategies that energy stakeholders can deploy to advance RDR.

KEY TERMINOLOGY

The following key terminology section defines frequently referenced terms throughout our report. Each definition is composed from our research or cited policy and scientific articles, papers, or websites.

Direct load control (DLC)
Direct load control is a demand-side management strategy that is when a consumer electricity load can be interrupted during a peak demand period by the control of the utility system operator.[1]

Distributed energy resource (DERs)
Distributed energy resources are a diverse set of devices and technologies, such as energy storage, electric vehicles, and micro-grids, that connect with an electricity system at the distribution level, whether they are connected to utility wires or behind the meter.[2]

Distributed energy resource management system (DERMs)
A distributed energy resource management system is a technology that helps control the flow of electricity from various distributed energy resources where the utility can better manage this flexible resource.[3]

Deregulated market
A deregulated energy market allows for customer choice when choosing an energy provider. Additionally, a utility cannot own all aspects of the value chain ie. generation, transmission and distribution, and retail.

Demand response (DR)
Demand response refers to the balancing of demand on power grids by encouraging customers to shift electricity demand to times when electricity is more plentiful or other demand is lower.[4]

Demand-side management (DSM)
Demand-side management are various programs consisting of the planning, implementing, and monitoring activities of electric utilities designed to encourage consumers to modify their level of electricity consumption.[5]

Energy efficiency cost recovery factor (EECRF)
An energy efficiency cost recovery factor enables an electric utility to "timely recover the reasonable costs of providing a portfolio of cost-effective energy efficiency programs."[6]

Electric cooperatives (ECs)
An electric cooperative provides electric services to its members like any other utility; however, the Co-op is owned by the government it serves.

Energy Reliability Council of Texas (ERCOT)
The Energy Reliability Council of Texas is a nonprofit corporation that manages the flow of electric power to over 26 million Texas customers in the ERCOT region. ERCOT is regulated and overseen by the Public Utility Commission of Texas and the Texas legislature.[7]

Federal Energy Regulatory Commission (FERC)
The Federal Energy Regulatory Commission is an independent agency that oversees and regulates the interstate transmission of electricity, natural gas, and oil.[8] Texas is not regulated by FERC.

Independent system operator (ISO)
An independent system operator is a federally regulated entity that was established to coordinate regional transmission in a "non-discriminatory manner and ensure the safety and reliability of the electric system."[9]

Independent third-party providers
An independent third-party provider is an ancillary business that offers demand response services to other business, utilities, and residential customers. This includes businesses such as Uplight, Tesla, and Google Nest.

Interoperability
Interoperability is the capability of two or more networks, systems, devices, applications, or technology components to effectively work together, and to securely exchange and readily use information.[10]

Investor-owned utilities (IOU)
An investor-owned utility is a privately owned electric utility who owns their own operation and is rate regulated.[11]

Load shift
Load shift or load shifting is a grid management technique where utilities shift energy demand from peak hours to off peak hours.

Load shed
Load shed or load shedding is a grid management technique that is an intentional reduction of energy demand on the electric grid by utilities to reduce grid strain in peak demand periods.

Municipally-owned utilities (MOUs)
A municipally-owned utility is owned and operated by the municipality it serves; generally these utilities maintain the wires, poles, meters, and finds power supplies for its consumers.[12]

Oversight entities
An oversight entity is an organizational or regulatory body who is responsible for the monitoring, evaluation and regulation of their members ensuring their compliance with all regulatory and policy responsibilities.

Peaking power plants (Peaker Plants)
Peaking power plants or peaker plants are low use and high greenhouse gas emitting power plants that grid operators call upon during times of peak energy demand.[13]

Public Utility Commission of Texas (PUCT)
The Public Utility Commission of Texas is the state agency that regulates the state's electric, telecommunication, water and sewer utilities while also implementing legislation and providing consumer assistance in complaint cases.[14]

Residential demand response (RDR)
Residential demand response is a set of strategies that encourage residential consumers to decrease energy consumption during periods of peak demand typically through prices or monetary incentives.

Retail energy provider (REP)
A retail electric provider buys wholesale electricity, delivery services, and additional services to then price and sell that electricity to retail customers in a given region.[15]

Regional transmission organization (RTO)
A regional transmission organization is an electric power transmission system operator that coordinates and monitors the transmission grid, on a regional basis, across North America.[16]

Supply-side management
Supply-side management involves various strategies to ensure that generation, transmission and distribution of electricity is conducted efficiently. [17]

Transmission and distribution utilities (TDU)
A transmission and distribution utility owns, constructs, and maintains the wires used to transmit wholesale power while also providing and operating the wires between the transmission system and end-use customer.[18] TDUs are commonly referred to as IOUs in Texas.

Virtual power plants (VPP)
A virtual power plant is a collection of small-scale energy resources that are aggregated together in order to provide additional reliability and economic value to the grid like traditional power plants.[19]

Wholesale electric power market
The wholesale electric power market functions as the marketplace where the purchase and sale of electricity for generators and retail electric providers occur. [20]

4 Coincident Peak (4CP)

4 Coincident Peak is a charged fee based on how much electricity a utility or business consumes during a defined peak consumption period in the previous year; ERCOTs peak period is during the summer months of June, July, August, and September.[21]

PROJECT CONTEXT

Climate change is one of the defining challenges of our generation. As the climate warms due to increasing amounts of greenhouse gases (GHGs) emitted into the atmosphere, extreme weather phenomena are becoming more frequent, more severe, and longer lasting.[22] These droughts, heatwaves, hurricanes, and flash floods pose significant financial, economic, social, and security risks to individuals and critical infrastructure.

President Biden and the U.S. Congress appear emboldened to combat this crisis. The President has signed into law a number of climate bills including the Creating Helpful Incentives to Produce Semiconductors (CHIPS) Act, the Infrastructure Investment and Jobs Act (Bipartisan Infrastructure Deal), and the Inflation Reduction Act (IRA). These bills are meant to incentivize GHG reduction policies, projects, and financing and laws. They constitute the largest investment in climate mitigation ever enacted in the U.S.[23]

How the U.S. strategically invests these resources is a critical question. For reasons noted below, the electric grid poses significant potential. First, the energy sector is one of the largest sectoral emitters of GHGs, accounting for 25% of total U.S. emissions.[24] These emissions stem from thermal power plants that burn fossil fuels like coal and natural gas to create energy. This process releases GHGs and other toxic air pollutants into the atmosphere, outcomes contrary to the President's climate goals. And yet, for several decades, grid operators have sought to meet increasing energy demand by building new thermal power plants (i.e., increasing supply). We note that although renewable energy resources are growing as a substitute fuel source, nascent battery technology is unable to store that renewable energy for long periods when demand is still needed, such as at night when solar power is at its lowest or in the midday when wind power is at its lowest.[25] This problem of intermittency and battery storage means that today, renewable energy alone cannot sustain the demand on the electric grid; said another way, thermal plants are still necessary to meet demand.

Second, extreme weather events across the country induced by anthropogenic climate change are straining the capacity of the electric grid. In particular, extreme heat and cold are causing sudden spikes (peaks) in energy demand that push it dangerously close to energy supply. In certain states and/or regions like Texas, growing populations and energy-intensive industries exacerbate this issue, narrowing the margin even more. Should demand exceed supply, dangerous, costly blackouts can occur, jeopardizing economic activity and disrupting the livelihoods of millions of Americans. This reality poses serious questions: build more polluting thermal plants? Continue to operate and maintain costly legacy peaker plants? These approaches assume supply must rise to demand. Practitioners, scholars, and regulators alike have begun to consider an alternative: instead of increasing supply, efforts are made to decrease demand such that new supply is no longer necessary. These proposals are considered demand-side solutions.

Demand-side solutions are often more cost-effective and have historically consisted of energy efficiency (EE) improvements for individual customers and demand response (DR) for commercial and industrial (C&I) customers.[26,27] EE improvements reduce the amount of energy needed to complete the same task. For example, an insulated (i.e., weatherized) home requires less AC to cool as cold air cannot escape as easily. DR solutions seek to shed load, shift load, or use on-site energy (such as a solar array or battery) in moments of tight supply-demand conditions to provide time-sensitive relief to the grid.[28] For those looking to maximize demand savings, C&I customers are a preferred market segment because a shift or shed commitment can result in a large net reduction in demand minimizing the chance of a blackout. This is because C&I is inherently more energy-intensive than residential homes or apartments. Consequently, policy, funding, and market structures have often omitted, or at best undervalued, resident participation in demand response.

Failure to meaningfully enroll and engage residential customers in DR is akin to leaving the "chips on the table." It unnecessarily limits tools and techniques that could help the U.S. meet its climate commitments. In fact, a 2021 Environmental Protection Agency (EPA) analysis found that the residential sector consumed 39% of national electricity, while the commercial sector consumed 35% and the industrial sector 26%.[29] Furthermore, the growing prevalence of Wi-Fi-enabled devices (e.g., smart thermostats) and the transition to electric-based vehicles and household infrastructure (e.g., heat pumps) have catalyzed innovation in the market. Automated technologies can now aggregate multiple smart devices across homes to shift specific loads to off-peak hours or shed loads while maintaining residents' comfort. The possibilities of residential demand response (RDR) are only growing, as is its potential as a grid management solution.

In Texas, this potential is somewhat muddied by complexities of its energy market. The Texas energy market is deregulated, meaning no one company can own generation, transmission, and distribution.[30] By disallowing energy monopolies, deregulated markets provide opportunity for competition in energy provision in an attempt to lower retail prices. Additionally, Texas operates its own grid, the Electric Reliability Council of Texas (ERCOT, named also for the oversight entity), independent of other states and regions; it is the only state in the contiguous U.S. to do so. As such, there are many actors in the Texas market, several of whom have different and competing priorities that make implementing RDR challenging. Table 1 below outlines the various utility models and key actors in Texas.

Table 1: Overview of Utility Models in Texas

Type	**Description**	**Motive**	**Service Level**	**Regulators**	**Examples**
Investor-owned utility (IOU)	• Generation assets sell power the wholesale market • Retail energy providers (REPs) purchase power in the wholesale market • Transmission and	Profit	~300 REPs, 6 ERCOT TDUs, 4 non-ERCOT, regulated (vertically integrated) IOUs; 28	PUCT, ERCOT, FERC	ERCOT TDUs: Oncor, CenterPoint, AEP Texas North, AEP Texas Central,

	distribution utilities (TDUs) transport high-voltage power through transmission towers and distribution lines to the consumer ● REPs interact with customers by selling power at a higher rate than what they purchased it; they facilitating billing		million Texans served		Texas-New Mexico Power, and Lubbock Power & Light REPs: TXU Energy, Ambit Energy Texas, Gexa Energy
Municipally-owned utility (MOU)	● Can own generation assets and transmission towers, often own distribution lines ● Participate in wholesale market ● Can enter into retail (competitive) market if desired	Reliable, affordable electricity rates	72 MOUs in Texas; 5.1 million Texans served	City Council (Utility) Committee, ERCOT	Austin Energy, CPS (San Antonio), Denton Municipal Energy
Electric cooperative (EC)	● Generation and transmission (G&T) ECs own and operate generation assets transmission towers ● Distribution ECs transport power to the consumer	Rural electricity provision	67 Distribution and 9 G&T ECs; 3 million+ Texas members	Elected Board of Directors, ERCOT	Bandera EC, Bryan EC, Pedernales EC

In the Texas investor-owned utility (IOU) model, hundreds of different retail energy providers (REPs) purchase power sold by generation assets in the wholesale market. REPs rely on transmission and distribution utilities (TDUs) to transport this high-voltage power to residential and C&I customers via transmission towers and distribution lines.[31] This capital infrastructure and the TDUs that operate them are often referred to as "poles and wires." In Texas, there are six ERCOT TDUs: Oncor, CenterPoint, AEP Texas North, AEP Texas Central, Texas-New Mexico Power (TNMP), and Lubbock Power & Light (LP&L).[32] Some TDUs are regulated by the Public Utility Commission of Texas (PUCT) but are outside ERCOT; they are connected to other grids, such the Southwest Power Supply (SWW), Midcontinent Independent System Operator (MISO), or the Western Electricity Coordinating Council (WECC).[33] As such, they are nationally regulated by the Federal Energy Regulatory Commission (FERC). As a result of deregulation, TDUs cannot sell energy directly to customers, so REPs do. REPs charge customers at a rate ideally higher than what they paid for it in the wholesale market (i.e., their profit margin) based on the customer's rate plan. In doing so, they facilitate billing and the majority of customer service (with the exception of outages that TDUs oversee). ERCOT and the PUCT conduct oversight over both ERCOT TDUs and REPs. ERCOT primarily oversees reliability whereas the PUCT primarily oversees ratemaking.

Municipally-owned utilities (MOUs) and electric cooperatives (ECs) also exist throughout Texas. MOUs that opt not to participate in the competitive retail market retain aspects of vertically integrated utilities.[34] This means they often own portions of generation, transmission, and distribution. They are, however, required to participate in the wholesale market. They are governed not by the PUCT but by their local city council. These utilities exist not to make a profit, such as with IOUs, but to provide stable, low-cost rates to their customers. There exist 72 MOUs that provide power to over 5.1 million Texans, representing approximately 15% of the state's population.[35]

ECs are similar in that they are also locally managed, but by an elected board of directors. ECs have a rich history of serving rural communities spurred by Roosevelt's New Deal era's Rural Electrification Act. Today, the Texas Electric Cooperatives association represents the interests of 67 distribution and nine generation and transmission cooperatives totaling more than three million members throughout the state.[36] Like MOUs, the PUCT only performs EC oversight in enacting transmission charges on its members.

The numerous utility models, actors, incentives, and market dynamics underscore the Texas energy market's complexity and uniqueness. For scholars, this makes the ERCOT market an interesting, applicable, viable DR study within the scope of a broader, national strategy to reduce GHG emissions and mitigate climate change's effects.

PROJECT SCOPE

These variations in utility ownership, regulations, and market structures across Texas (and the nation) present challenges to understanding, comparing, and analyzing residential demand response (RDR) programs. However, given that RDR represents a significant opportunity for climate mitigation through demand-side management solutions, it is crucial to understand the factors that enable or inhibit its implementation. It is in this vein that a subsidiary of the Department of Energy (DOE), the Pacific Northwest National Laboratory (PNNL), presented a research proposal on RDR to Professor Steven Pedigo's Professional Research Report (PRP) class at the Lyndon B. Johnson (LBJ) School of Public Affairs at the University of Texas at Austin in August of 2023.

In response to PNNL's proposal, our report explores the policies, market structures, and environments necessary to enable energy providers to offer and scale residential DR programs in Texas. More specifically, we seek to answer two key research questions:

1. What are the most important factors that affect how energy providers conduct demand-side management?
2. What are the enabling factors to implementing RDR programs?

To address these questions, we first provide a Scholarship and Policy Review that analyzes existing research on demand response policies and programs, focusing on the residential sector. This is followed by a Methodology section, which describes our two-phased process for conducting interviews and analyzing qualitative data. In the Findings section, we outline the key themes we observed in each project phase. Our Recommendations section provides a deep dive into the seven recommendations listed above, while the Best Practices section summarizes some of the technical findings that arose in interviews aimed at the development and implementation of successful RDR programs. We then discuss some Limitations and Future Research needs identified throughout our project, leading to the report's Conclusion. Lastly, a series of appendices provide the reader with additional information.

SCHOLARSHIP & POLICY REVIEW

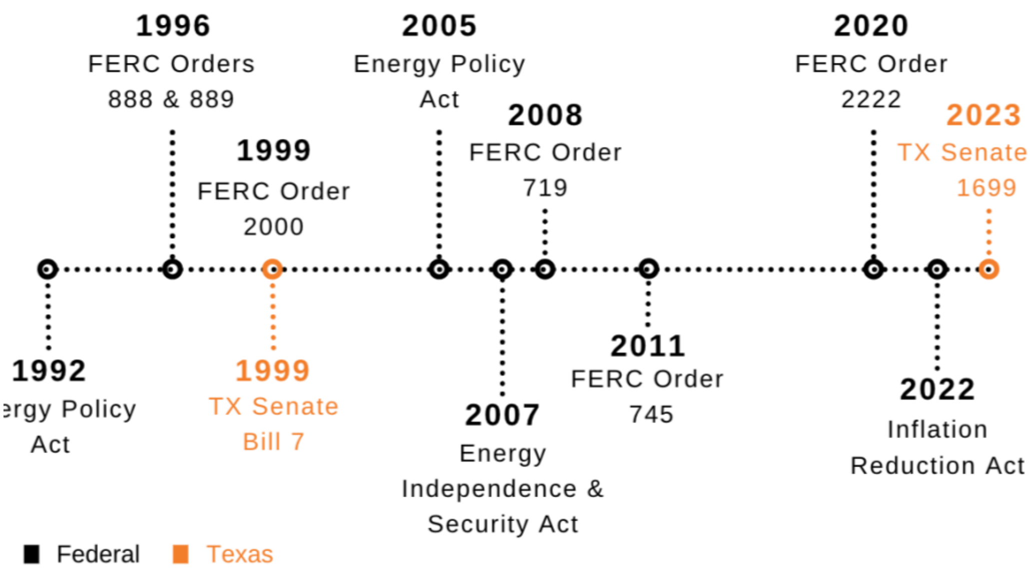
Much of the literature surrounding demand response (DR) explores its history, methods, processes, and impact. However, few papers analyze the factors that have led to the increased focus on and development of DR. Shen et al. (2014) addressed this research gap by creating an analytical framework that shows how certain factors interact to enable the development of DR.[37] They identify three key driving forces: 1) law and regulation, 2) market changes, and 3) technological advancement. More specifically, they argue that certain policies and regulations drove market changes that in turn accelerated technological advancement. The literature also addresses other factors that impact the adoption and success of DR programs, specifically behavioral economics, resident demographics, and communication strategies.

The following scholarship and policy review further explores these forces and their impacts on the development and expansion of DR in the U.S. electricity industry. This analysis does not focus on the history or processes of demand response. Instead, it expands on Shen et al.'s (2014) framework to include more recent literature with a focus on residential demand response (RDR). The following sections identify and review six key enabling factors: 1) policy and regulation, 2) market changes, 3) technological advancement, 4) behavioral economics, 5) resident demographics, and 6) communication strategies.

Policy & Regulation

Basic forms of DR have been present in the U.S. electricity industry since the 1970s, and several policies and regulations have contributed to its expansion and advancement over the last 50 years.[38] By the 1990s, several U.S. industries had undergone restructuring, wherein some economic activities were deregulated by the federal government and reconfigured to allow for more competition. In the energy sector, many states moved to deregulate their statewide electricity industries with the goal of increasing competition, providing consumer choice, and reducing market inefficiencies given the volatility of energy prices. States acted individually to set up competitive wholesale energy markets, leading to variation in the restructuring of utilities and policies that regulated the electricity industry in each state. Electricity deregulation typically involves the decoupling of energy generation from the transmission and distribution of electricity, although exceptions exist across states and regions. Many states still have regulated, vertically integrated electricity frameworks, while others contain a mix of regulation and deregulation.[39] With this restructuring came competitive regional wholesale electricity markets. Since generation, transmission, and distribution were no longer controlled by the same entity, DR became an economically viable alternative to supply-side energy management which could be used to stabilize the electric grid and bring down energy costs. The following paragraphs provide an overview of the key federal milestones that enabled the inclusion of DR within competitive wholesale electricity markets. They are also illustrated in Figure 1 below.

Figure 1: Key State and Federal Policy Milestones in Demand Response



The passing of the 1992 Energy Policy Act allowed independent power producers to participate in energy markets across the US. Four years later, the Federal Energy Regulatory Commission (FERC) Orders 888 and 889 established that all energy suppliers, including independent power producers, should have equal access to energy markets. These reforms required open access to transmission lines, created an open-access same-time information system, and encouraged regional planning for increased electric reliability. In 1999, FERC Order 2000 encouraged the development of Regional Transmission Organizations (RTOs), also referred to as Independent System Operators (ISOs), to eliminate discrimination in grid access and ensure reliability by balancing energy supply and demand.[40] These policies focused on increased competition, allowing more power generation assets to participate equally in wholesale markets. Because load management via DR could meet the same technical requirements as supply-side energy management, these policies also enabled DR programs to participate in wholesale energy markets as alternatives to new power plants.[41]

The potential for DR in the energy sector was recognized at the federal level with policies such as the Energy Policy Act of 2005, which codified the inclusion of DR programs within national energy policy, calling for the Department of Energy (DOE) to work with states and utilities to "identify and address barriers to the adoption of DR programs."[42] Shortly after, the Energy Independence and Security Act of 2007 directed FERC to conduct a National Assessment of Electricity Sector Demand Response and develop a National Action Plan on Demand Response, which identified gaps in technical assistance, research, and tools needed by states and utilities to optimize DR programs.[43] FERC Order 719 in 2008 eliminated some of the barriers to DR participation in wholesale energy markets by requiring ISOs to accept bids for DR "on a basis comparable to other resources," and by allowing load aggregators to bid DR directly into wholesale markets on behalf of retail customers.[44]

FERC Order 745 established the process by which DR providers must be compensated for the services they provide in balancing supply and demand in an organized wholesale energy market, requiring they be compensated at the wholesale energy market rate, or the locational marginal price of energy. This ruling was foundational to how energy markets incentivize DR and provided a basis for demand-side management to be valued equally to supply-side solutions to grid stress.[45]

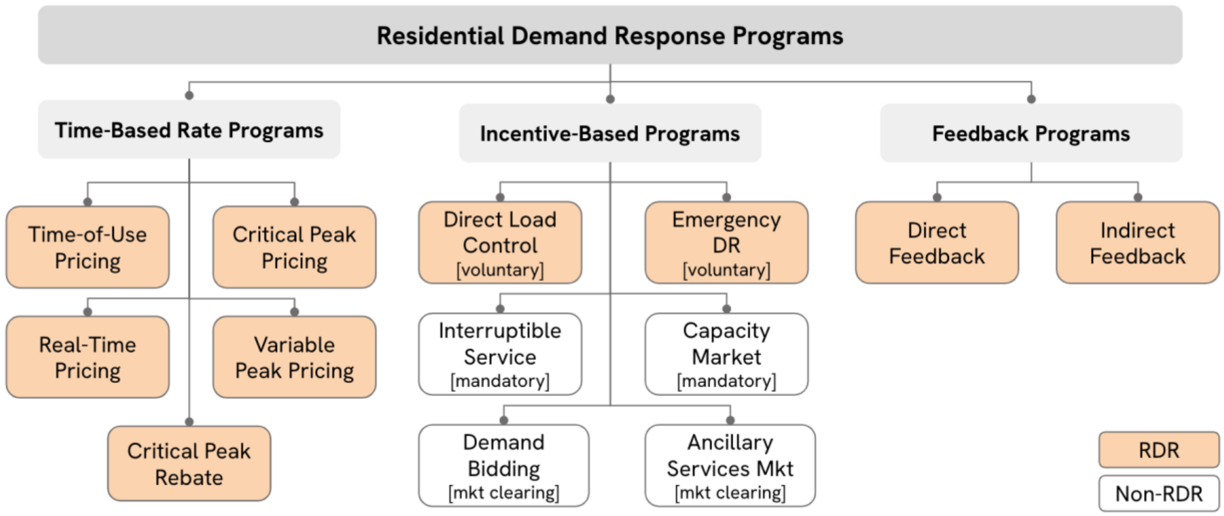
In 2020, FERC issued Order 2222, which facilitated the participation of distributed energy resources (DERs), which encompasses DR technologies and programs, within regional wholesale electricity markets. By allowing smaller reduction units to participate in wholesale markets, this order created additional flexibility and opportunity for DR implementation.[46] This scholarship and policy review further elaborates on DERs and their application within the context of DR implementation in the Technological Advancement section. The Inflation Reduction Act (IRA) also includes incentives aimed at expanding DR program adoption, including at the residential level. The IRA's tax credits for energy efficiency and electrification measures, like installing heat pumps or solar panels, are expected to increase the integration of DR programs in utilities' planning processes.[47]

There are also many state-level policies that have been implemented to advance DR, including energy efficiency standards and other regulations. Because this report focuses primarily on the policy enablers and inhibitors of DR in Texas, it is important to note the Texas-specific policies that have shaped DR adoption over the last few decades, highlighted in orange in Figure 1. In 1999, Texas became the first state to establish an energy efficiency resource standard through the passing of Senate Bill (SB) 7, which also restructured the Texas electricity industry.[48] This restructuring decoupled energy generation from electricity transmission and distribution, and required that investor-owned utilities, now only responsible for transmission and distribution, to meet specific energy efficiency goals each year. These efficiency goals have been increased several times by the Texas legislature, starting from the requirement that electric utilities offset 10% of demand growth in 1999 to 30% in 2013. Since then, the energy efficiency goal has been changed to focus on actual peak demand rather than demand growth, requiring each utility to achieve a 0.4% reduction in peak demand.[49] The Public Utility Commission of Texas (PUCT) also administers grants to fund energy efficiency programs, with the goal of achieving reductions in energy consumption, peak demand, and emissions.[50] In Texas, DR programs are included under the umbrella of energy efficiency, and are reported on annual energy efficiency reports by each electric utility. In 2023, the Texas Legislature also passed SB 1699, which requires the PUCT to establish residential load reduction goals, encouraging the development and expansion of residential RDR programs.[51]

Market Changes

The policies and regulations described above have both changed the electricity market and promoted DR.[52] As a result, there now exist a variety of DR program types that aim to reduce demand for electricity. These programs are labeled and categorized differently across the literature, making it difficult to fully understand the landscape. Further, most studies and reports account for DR programs at large without indicating which are specific to the residential sector. Figure 2 below combines various DR categorization models and filters strictly for programs that can be applied to the residential sector.

Figure 2: Residential Demand Response Programs



In accordance with the Energy Policy Act of 2005, FERC made one of the earliest attempts at organizing existing DR programs in its first annual Assessment of Demand Response and Advanced Metering report.[53] This report organizes DR into two overarching categories: time-based rate programs and incentive-based DR programs. The distinction is based on the interaction between customers and system operators/load serving entities (LSEs) such as utilities.[54]

Time-Based Rate Programs

Time-based rate programs, also known as dynamic pricing programs, alter the price that customers pay per kilowatt hour of electricity consumption. Historically, most customers pay a flat rate based on the average cost of electricity production.[55] However, cyclical changes in demand, unpredictable events, and capacity availability make the marginal cost of production highly variable.[56] Many argue that flat rates insulate consumers from the true underlying costs of production, thereby encouraging overconsumption. Time-based rate programs aim to address the inefficiencies that result from the disconnect between marginal costs and time-averaged, fixed rates. Instead of paying a flat rate (i.e., $0.05/kWh at all hours), customers pay rates based on the marginal cost (i.e., $0.04/kWh during normal hours, $0.12/kWh during peak hours).

The goal of such programs is to nudge consumers through price signals to voluntarily change their energy consumption. The idea is that "if the price differentials…are significant, customers can respond…with significant changes in energy use, reducing their electricity bills if they adjust the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher".[57] While FERC argues that it is often difficult to predict or measure customers' response to prices, various researchers have found ways to determine whether households reduce peak demand in response to price signals.[58]

FERC's first annual report specified three time-based rate program types: time-of-use pricing (TOU), critical peak pricing (CPP), and real-time pricing (RTP). Its later reports include two additional programs: variable peak pricing (VPP) and critical peak rebate (CPR).[59] The Lawrence Berkeley National Laboratory further subdivides RTP into day-ahead real-time pricing (DA-RTP) and real-time real-time pricing (RT-RTP).[60] Table 2 below describes these programs, as defined by the U.S. Energy Information Administration in its Annual Electric Power Industry report.[61]

Table 2: Time-Based Rate Programs

Time-Based Rate Program	**Definition**	**Example**
Time-of-Use Pricing (TOU)	A program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedule is fixed and predefined, based on season, day of week, and time of day.	Appendix A [Pedernales Electric Cooperative Time-of-Use Rates]
Critical Peak Pricing (CPP)	A program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10-15 per year). Prices can be 3-10 times as much during these few hours. Typically, CPP is combined with a TOU rate, but not always.	Appendix B [Sacramento Municipal Utility District Critical Peak Pricing Rate]
Real-Time Pricing (RTP)	A program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.	Appendix C [ComEd Hourly Pricing Program]
Variable Peak Pricing (VPP)	A program in which a form of Time-Of-Day (TOD) pricing allows customers to purchase their generation supply at prices set on a daily basis. Standard on-peak and off-peak time-of day rates are in effect throughout the month. Under the VPP program, the on-peak price for each weekday becomes available the previous day (typically late afternoon) and the customer gets billed for actual consumption during the billing cycle at these prices.	Similar to the TOU example, except that the on-peak price changes daily. The other prices do not change daily. Oklahoma Gas & Electric SmartHours Program

Critical Peak Rebate (CPR)	A program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure the energy provider can call event days (often limited to 10-15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.	Issuing customers a bill credit of up to $1.00 for every kWh saved compared to the average of the previous five days. Ambit Energy Texas Power Payback Program

According to FERC (2023), between 2018 and 2022, retail customer enrollment in time-based rate programs increased by 5.4 million, or 58.8%.[62] In 2021, total customer enrollment across the U.S. was approximately 14.6 million, a 20.1% increase from 2020. Despite increases at the national level, enrollment in the West South Central Census Division, which encompasses the state of Texas, decreased by 1.3% during this period. FERC did not provide context or reasons for these changes. It is worth noting that these numbers likely include non-residential customers.

Incentive-Based Programs

Incentive-based programs offer customers a monetary incentive in exchange for reducing or shifting their consumption during peak periods.[63] FERC considers these programs a "more active tool" since they do not depend on the response of customers to price signals. These incentives are not tied to the retail electricity rate.[64] Instead, they are provided to customers when they reduce their load in response to DR events, which typically occur when grid reliability is compromised or when the market price of electricity is too high.[65]

FERC identifies six types of incentive-based programs, which it now refers to as "demand-side management programs" or "retail demand response programs": 1) direct load control (DLC), 2) emergency demand response programs (EDRP), 3) interruptible/curtailable rates (I/C), 4) capacity market programs (CAP), 5) demand bidding/buyback programs (DB), and 6) ancillary-service market programs (A/S).[66] Across the literature, these programs are also referred to as "reliability programs", highlighting the idea that they are utilized to address grid reliability issues.[67]

Other researchers further classify these programs into three sub-categories: voluntary, mandatory, and market clearing programs.[68] They consider DLC and EDRP voluntary programs because customers are not penalized for failing to curtail consumption. On the other hand, mandatory programs such as I/C and CAP do impose financial penalties on enrolled customers. Lastly, DB and A/S are considered market clearing programs through which "large customers are encouraged to offer or to provide load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices”.[69]

CAP, DB, and A/S are considered wholesale DR programs, and are therefore not applicable to the residential sector.[70] I/C programs are largely offered only to large industrial or commercial customers.[71] Therefore, DLC and EDRP are the only incentive-based program types available to residential customers. Table 3 below describes each of these programs, as defined by the Department of Energy.

Table 3: Incentive-Based Programs

Incentive-Based Program	**Definition**	**Example**
Direct Load Control (DLC) [Voluntary]	A program by which the utility or system operator remotely shuts down or cycles a customer’s electrical equipment (e.g. air conditioner, water heater) on short notice to address system or local reliability contingencies. Customers often receive a participation payment, usually in the form of an electricity bill credit. A few programs provide customers with the option to override or opt-out of the control action. However, these actions almost always reduce customer incentive payments. Direct load control programs are primarily offered to residential or small commercial customers.	CPS Wi-Fi Thermostat Rewards Program Offers residential customers an $85 rebate for enrolling a thermostat, $30 for each year enrolled in the program, and a one-time $20 bill credit.
Emergency Demand Response Program (EDRP) [Voluntary]	Programs that provide incentive payments to customers for measured load reductions during reliability-triggered events. Customers can choose to forgo the payment and not curtail when notified. If customers do not curtail consumption, they are not penalized. The level of the payment is typically specified beforehand.[72]	Austin Energy Power Saver Program Notifies program participants in advance of an Energy Action Day, asking them to save energy from 1 - 7pm.
Interruptible/Curtailable (I/C) Service [Mandatory]	Curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.	Alliant Energy Interruptible Program Provides large commercial customers with discounts on pricing in exchange for reducing consumption during periods of extreme demand.

Capacity Market Programs (CAP) [Mandatory]	Customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so.	PJM Demand Response in Capacity Market DR participants must reduce load when requested by the system or receive a financial penalty.
Demand Bidding/Buyback Programs (DB) [Market clearing]	Customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt [MW] and over).	PG&E Capacity Bidding Program Aggregators submit monthly curtailment commitment nominations and face penalties if they fail to deliver committed load reductions.
Ancillary Services Market Programs (A/S) [Market clearing]	Customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.	ERCOT Ancillary Services Market Approved resources can bid into the day-ahead market to provide ancillary services.

Between 2018 and 2022, customer enrollment in these incentive-based programs increased by over 740,000 (7.6%) across the nation.[73] However, enrollment decreased by 10.1% between 2020 and 2021. Based on the latest FERC survey data, there were nearly 10.5 million customers enrolled in incentive-based programs in 2021, a 1.2 million decrease from 2020. The West South Central Census Division, which encompasses Texas, actually saw a 0.6% increase in customer enrollment during this period. FERC did not provide context or reasons for these changes. At both the national and West South Central Census Division levels, there are more customers enrolled in dynamic pricing programs than in incentive-based programs. As noted previously, these estimates likely include non-residential customers.

Other Program Types

Another study considers a third overarching category of DR programs, which it refers to as "customer feedback programs".[74] This includes two types of feedback methods: direct and indirect. Direct feedback programs utilize some sort of technology (i.e., in-home display devices, internet dashboards, smart meters, etc.) to provide customers with consumption and cost information. Indirect feedback methods include bills, periodic usage reports, usage disaggregation, and other customer data that is processed by a utility.

When comparing the average conservation effect of each of these program types, King et al. (2005) found that dynamic pricing programs reduce total consumption by 4%, incentive-based programs by 0.2%, and feedback programs by 11%.[75] While these findings are slightly outdated, they show the importance of providing feedback to residents. However, given that elements of feedback programs are now largely used in conjunction with dynamic pricing and incentive programs, this report will not consider "feedback programs" as a separate category of RDR programs.

Market Expansion

Shen et al. (2014) argue that two key changes in the electricity market paved the way for the development of DR. The first involves expansion of the wholesale market and the second is the entrance of new market participants. In addition to establishing wholesale energy markets, the deregulation of the U.S. energy industry also integrated other types of markets, such as ancillary services and capacity markets. Unlike energy-only markets, which compensate only for produced energy, ancillary services and capacity markets compensate for the capacity to supply energy. Ancillary services are designed to maintain reliable transmission of electricity throughout the grid by regulating short-term energy supply and demand to maintain the frequency of the energy system. These also include maintenance of operating reserves, which are energy resources that can go online within specified time increments (10-30 minutes) and are deployed if there are any deficiencies in expected energy supply.[76] Most RTOs/ISOs also have capacity markets, which ensure longer-term grid reliability. In a capacity market, grid operators run capacity auctions based on projected energy needs up to three years into the future. In capacity markets, LSEs pay energy producers for the investment costs they will incur to develop new power plants to cover projected energy demand plus a reserve margin.[77]

Both ancillary services and capacity markets provide additional opportunities for DR to participate in wholesale electricity markets since DR resources can be deployed to meet the technical requirements of either market. In the case of ancillary services, DR can be used to regulate short-term energy demand in the same way that operating reserves are kept on standby to cover imbalances between demand and supply. In the case of capacity markets, DR providers can bid into capacity auctions in the same way that energy producers can, with expected demand reductions compensated in place of future energy generation capacity. DR resources deployed for either short-term ancillary service requirements or long-term grid reliability are compensated through capacity payments, which ensure necessary investments in DR.[78]

In the residential sector, changes in policies and regulations also expanded market participants beyond utilities and residents.[79] Many utilities now outsource the provision of RDR services to emerging, third-party entities such as demand response aggregators, technology providers, or software companies. These entities not only help utilities meet demand reduction goals, but also mitigate three key challenges of applying DR mechanisms to the residential sector.[80] First, utilities would derive most of the benefit due to a resident's limited negotiation power. Second, the sheer number and widespread distribution of households presents utilities with significant scalability issues. Lastly, utilities generally lack the expertise required to design and implement DR mechanisms at this scale.

Aggregators address these challenges by acting as mediators between utilities and residential customers. These entities "combine several…customer demands into a unique 'pool' of aggregated controlled demand and offer it as a specific asset."[81] The literature references two types of aggregators: load aggregators and DR aggregators. Load aggregators are entities that aggregate forecasted demand for electricity among their customers, purchase the forecasted amount from the wholesale market, and then sell it to their customers.[82] These aggregators typically exist in deregulated markets, where residents cannot directly purchase electricity from the wholesale market. On the other hand, DR aggregators are entities that aggregate reductions in electricity demand.[83] These entities allow residential customers to participate in the DR market.

Currently, most DR aggregators pool demand reduction from the commercial and industrial sectors, where they are also referred to as "curtailment service providers."[84] However, over the past decade researchers have begun proposing models and strategies for how DR aggregators could participate in RDR markets. These include a hierarchical market model,[85] a bottom-up model,[86] a multi-agent optimization structure,[87] optimal bidding strategies[88], and an online transfer learning-based DR potential forecasting model.[89] While these proposed models, structures, and strategies have been validated using real-world datasets, there is a lack of studies evaluating existing RDR aggregator programs.

Technological Advancement

Along with regulatory reforms and market changes, Shen et al. (2014) identify technology as a key factor in enabling the development and expansion of DR.[90] Key technologies that facilitate DR include smart meters, communication networks, and data management systems, which together represent the main components of advanced metering infrastructure (AMI). AMI consists of meters that regularly measure, record, and report usage data to energy companies and consumers, with one-way or two-way communication capabilities.[91] Of the 162.8 million meters across the U.S. in 2021, an estimated 111.2 million were advanced meters.[92] This represents a 68.3% penetration rate, up from 4.7% when FERC first began to collect this data in 2008. The West South Central Division, which includes Texas, has the highest advanced meter penetration across all customer classes. The residential sector leads the charge, with an 86.7% penetration rate.

Networking technologies such as Wi-Fi represent another technological advancement that have enabled the expansion of Home-Area Networks (HANs), which now connect most home devices (i.e. thermostats, AC systems, heaters, electric vehicles, etc.).[93] HANs are allowing energy providers to manage residents' smart devices through internet or AMI network connections. Researchers argue that consumer indifference, equipment cost, data privacy concerns, and lack of technology standards hinder the potential use of HAN for RDR.

Automation technologies have played an increasingly important role in DR. Various studies have found that simply providing customers with feedback on their energy consumption does not result in energy savings.[94] This highlights a need for automated devices that are pre-programmed with a resident's preferences. Automation decreases the effort required by a resident to participate in DR, which some argue presents a large hurdle. It also simplifies a utility's role in DR by automating notification, confirmation, and monitoring. More importantly, in combination with AMI, automation allows utilities to initiate load control of residential devices.

Evidently, these technologies rely on and build upon one another. For this reason, a recent analysis recommends viewing and promoting these innovations as a mutually-supportive "technology cluster."[95] The DR technology cluster includes smart metering, storage technologies, automation technologies, dynamic pricing, and other DR services. This framework conveys the idea that these components deliver "greater benefits for the individual, environment, and society when combined."

The emergence of DR aggregators and recent technological advancements have led to the creation of virtual power plants (VPPs). VPPs are "aggregations of distributed energy resources (DERs)" such as electric vehicles, battery storage, smart thermostats, and solar generators.[96] They provide utilities and aggregators with an opportunity to increase grid flexibility by balancing both demand and supply of electricity. Independently, DERs can be used to shift demand, shed demand, and shape consumption. Currently, most VPPs are considered demand-shaping, meaning that they are used to manage demand as opposed to exporting power to the grid. However, they have the capacity to do both.

Many of the same factors that have spurred the growth of DR are currently driving the growth of VPP deployments. More specifically, these include the declining cost of DERs, advancements in algorithms for managing DERs, IRA incentives, FERC Order 2222, growing model availability, and an increased focus on decarbonization.[97] A 2023 report by The Brattle Group found that VPPs "leveraging commercially-proven residential load flexibility technologies could perform as reliably as conventional resources." Providing resource adequacy through VPPs yields a net cost to utilities equal to 40-60% the cost of conventional options. Further, VPPs have the potential to provide over $20 billion in societal benefits over 10 years. While VPPs are relatively new, some argue that they have existed for decades as DR programs.

While The Brattle Group report highlights the huge potential of VPPs, they also identify three key barriers to their development: technology, markets, and regulation. It is worth noting that these mirror the three enabling factors identified by Shen et al. (2014). At the technological level, they argue that a lack of communication standards and uncertainty surrounding DER adoption pose serious challenges; this is discussed in detail below. In regards to the market, the barriers include complexities in the wholesale market and a lack of DER incentivization through retail rates and program design. Finally, in terms of regulation, they argue that current utility regulatory models do not financially incentivize VPPs and that policy and planning decisions fail to consider the full value of VPPs. It is worth noting that these factors are quite similar to those identified by Shen et al. (2014) almost a decade ago.

One of the most pressing challenges facing VPP scalability–and by extension, RDR–is interoperability, or “the ability of two information systems to exchange and consume data transparently.”[98] This is because DERs–the building blocks of VPPs–consist of different, or diverse, devices, often manufactured by different companies.[99] For example, Google may sell smart thermostats while a different firm, such as Ford, may manufacture EVs. To maintain market competitiveness, each firm often uses its own proprietary communication interface with its own data types, fields, and schemas to communicate energy data to end-users and to maintain competitive advantage. Without information and communication technology (ICT) standardization to connect DERs across the electrical chain, VPP devices are challenging to integrate and therefore aggregate load across systems.[100]

Further, additional “costs of system development, integration, and installation with different technical configurations” increase overall transaction costs, often incurred by customers and utilities.[101] For customers, managing multiple devices complicates and decreases VPP enrollment. The penetration of more Wi-Fi, Bluetooth, and cellular data-enabled DERs exacerbates the problem. For utilities and third-party aggregators, barriers to data sharing obstruct accurate needs assessments, forecasting, and performance measurement and verification.[102] Standardization across ICT will allow customers “to better manage their energy use, enable businesses to build new applications and offer better products and services, and benefit utilities who could perform data analytics for better managing their programs.”[103] To realize these benefits, Shen et al. (2014) describe how the U.S. National Institute of Standards and Technology (NIST) is “developing interoperability specification for standardized signals related to the application of DR and distributed energy resources to allow further automation and improve DR capabilities across the grid.” OpenADR is one such open-source solution currently in pilot in California.[104]

Behavioral Economics

When designing RDR programs, it is important to consider human psychology, which impacts decision-making and behavior change. The complexities of behavior change present a common barrier to the adoption, retention, and success of DR programs, particularly in the residential sector. While the literature suggests that financial incentives can be a valuable tool in RDR program development, there exist challenges in determining the right price to elicit long-term behavior change. Trust between residents and utilities also plays an essential role in program participation and success. For this reason, understanding how trust is gained and lost in RDR is necessary when designing a successful program. Some of these barriers can be addressed with automation and other technologies because they reduce the need for active behavior change and make participation in programs more convenient.

Pricing & Financial Incentives

Time-based rate programs that require people to frequently change their energy usage based on price signaling can be burdensome. While some evidence suggests that consumers change energy consumption based on pricing on an aggregate level, more detailed studies show that most households do not respond to price signals.[105] For example, Belmans et al. (2014) conducted two research trials and found that people were unlikely to shift the time of day during which they used household appliances based on price signals.[106] It is important to consider that the burden of frequent behavior change may not be the only barrier to successful price signaling; some households may not be able to change their energy behaviors, regardless of their potential desire to reduce energy consumption.[107] Although, many people simply do not want to engage in behaviors that disrupt or add inconvenience to their daily routines, regardless of price.[108]

Incentive-based programs that provide financial motivation in the form of rebates, direct payments, or bill discounts can have more success than those that rely on consumers to shift their energy consumption based on price signals.[109,110] While financial incentives can be a successful tool for energy-related behavior change, finding the right price to motivate individuals to change their behavior over the long term can be challenging. A study in California found that offering direct payments for energy reduction was crucial to the initial success of an RDR program. Yet, marginal increases in incentives proved ineffective in the long run, leading to a decrease in retention rates.[111] Program retention is a common barrier to success if program incentives are inadequate.[112] Typically, residents' willingness to participate in a program increases as financial incentives increase. However, there is evidence that many residents are motivated to participate in programs for reasons other than personal financial benefit.[113,114,115]

Trust

Residents' lack of trust in utilities, energy providers, or independent RDR program providers may hinder program adoption. Lack of trust can stem from various factors, including unfamiliarity with DR. Residents unfamiliar with DR programs can become wary of the company's motivations.[116,117] Further, negative experiences with programs that use automation technology or direct load control, like faulty equipment or poor communication with program operators, can erode trust and result in poor program retention.[118] This lack of trust can also lead to concerns about privacy regarding the type of data collected, its use, and the potential for unauthorized access.[119,120] Hall et al. (2016) found that providing information about DR through an independent source can help eliminate the barrier of mistrust and allows program providers to regain trust and credibility.[121]

Automation & Other Technologies

Despite trust issues surrounding technology, automation devices can reduce the “perceived complexity, effort, and risk” associated with RDR programs.[122] Certain technologies, such as smart thermostats, can reduce inconvenience by automating a household’s heating, ventilation, and air conditioning while reducing energy consumption.[123] A study of two different RDR events concluded that automation is essential to maintain high DR efficiency in the long-term.[124] Automation devices can also help utilities implement direct load control programs effectively. However, some people perceive installing and utilizing new technology in the home as too complex, which can also hinder program adoption.[125]

Many residential customers fear the loss of control associated with direct load control programs and prefer utilizing automation technology without enrolling in direct load control programs because it allows them to retain greater control over their homes.[126,127] Another enabling technology is smart-metering, which provides better energy consumption data for utilities and consumers, allowing both groups to monitor energy consumption more accurately in real-time and utilities to communicate demand response events efficiently. Smart metering also gives consumers more control over their energy use and bills, making it easier to respond to time-of-use pricing models.[128,129,130,131]

Resident Demographics

In addition to considering human psychology in RDR program design to effectively incentivize behavior change, strategically targeting programs to certain demographic groups may also prove beneficial. Targeting specific demographics provides an opportunity for future RDR program success. Research has found a positive correlation between residents' educational attainment, income level, and participation in RDR programs.[132,133] These correlations could be due to the relationship between higher income and ownership of enabling technologies like solar panels, air conditioning, and electrified vehicles.[134] Faruqui and George (2005) found that people who did not own air conditioning reduced consumption between 8 and 15%, while those who did own air conditioning reduced their consumption by 25 to 30%.

Bird (2015) found a lack of correlation between energy reduction and traditional socio-demographic groups.[135] He argues that identifying residents with specific *characteristics*, like having a flexible work schedule and thus the ability to respond to price signaling readily, may prove effective.[136] Similarly, Gattaciecca et al. (2020) found that "energy-engaged" customers (people who own automation devices and enabling technologies) had the most significant reductions in energy use. Similarly, technologies such as air conditioning or dishwashers give residents more capacity for energy-reduction behaviors.[137]

Other research has found that households with children behave differently than those without children. Friis and Haunstrup Christensen (2016) found that families with small children or dependents had more difficulty adapting to some aspects of RDR programs, like shifting usage of “wet goods” (washing machines, dishwashers, and tumble driers).[138] Similarly, a study in the UK found that households without children were more likely to respond to time-of-use pricing than those with children.[139] Other research indicates that time spent in the home predicts RDR program success. Studies have found a negative correlation between time spent outside the home and RDR program participation. Therefore, time spent in the house acts as an enabler of program success.[140]

Communication Strategies

Different communication strategies provide opportunities for future RDR program design. Studies have found that messaging during DR events is most successful when it focuses on the consumer's financial benefit (i.e., cost savings and rebates).[141,142] Moral messaging around public health and environmental concerns is typically less effective at reducing demand.[143] However, there is evidence that focusing the messaging on energy supply security and environmental concerns information can induce desired behavior change that is as effective as financial benefit messaging.[144] Further, Shultz et al. (2015) found that sending messages with neighborhood energy use statistics to high use households decreased their electricity consumption; however, they found an inverse or "boomerang"effect with low use households.[145] This unintended negative response from low use households was successfully curtailed when communications included "a message of approval" for their initial responsible energy consumption.[146] These findings highlight the importance of crafting messages that are tailored to a resident's electricity consumption patterns.

Because residential electricity demand is aligned with human needs more so than operational processes or business requirements, the messaging type, design, and delivery of DR communications are increasingly important to a program's success.[147] Mohit Jain et. al (2015) analyzed various methodologies for effective DR messaging and developed a set of guidelines.[148] The study evaluated four aspects related to DR messaging including notification messaging, message type, associated incentive, and participation feedback. With regards to notification messaging, the report suggests using a combination of a tablet-based wall display for conveying DR alert messages and SMS for the notification of the arrival of a new DR message.[149] Additionally, the researchers suggest that messages should include specific tasks and actions on how to reduce demand while indicating their progress to help achieve their reduction targets.[150]

A 2020 report by the UCLA Luskin Center for Innovation analyzed the effectiveness of DR messaging based on its timing and frequency.[151] This report compared the effectiveness of low-frequency and high-frequency messaging across a 10 week time period. The researchers found that low-frequency messaging (once per week) is slightly more effective when using economic benefit messages or moral messages.[152] However, high-frequency messaging is more effective when there are no financial incentives. The high-frequency treatment included three messages in the first two weeks followed by one per week for the remaining time.[153] This research demonstrates that there may not be one consistent messaging strategy that is most effective. However, the UCLA researchers were able to conclude that 5:00pm was the most effective time for DR events.[154]

METHODOLOGY

The scholarship and policy review above comprehensively outlined existing research on demand response programs and policies, particularly in the residential sector. As such, it served as the foundation of the two-phased methodology we developed to comprehensively answer our research questions. Findings from the scholarship and policy review helped inform two phases of semi-structured interviews that we conducted with subject matter experts, energy providers, industry practitioners, and oversight entities. Additionally, findings from Phase I helped us fine tune our scholarship and policy review and influenced our Phase II interview questions. The sections below describe the methodology for both Phase I and II in greater detail.

Phase I Methodology

Phase I of our engagement addressed the following research question: **What are the most critical factors that affect how energy providers conduct demand-side management?** This question served several purposes. First, it aimed to bolster our team's technical knowledge of the complex U.S. energy landscape. For this reason, Phase I focused broadly on the concept of demand-side management as it is foundational to a clearer, holistic understanding of residential demand response (RDR). Second, this phase also served to identify gaps in current academic literature and inform our Phase II research questions and methodology. Finally, Phase I helped us understand how policies, laws, and regulations influence RDR adoption. This was critical as it helped narrow our research scope to a geographic region, Texas. It also allowed us to familiarize ourselves with recent events, such as court cases and legislative or rulemaking decisions that affect the energy market and, therefore, RDR adoption.

Semi-Structured Interviews

Our team conducted six semi-structured interviews with SMEs to meet our Phase I goals. These SMEs included energy scholars, policy consultants, and private sector actors from Texas. The questions that we posed to the interviewees are available in Appendix D. After we completed all six interviews and finalized the notes, we coded the interviews and organized the codes into a codebook. The final codebook for Phase I contained 35 unique codes. We then conducted a qualitative analysis of the codebook to identify themes and patterns across all six interviews.

Phase II Methodology

The second phase of the project aimed to address our second research question: **What are the enabling factors to implementing RDR programs?** At a high level, this question allowed us to develop a better understanding of the RDR program landscape within Texas. More specifically, it helped us identify the key factors (i.e. policies, regulations, structures, etc.) that mandate, encourage, or prevent energy providers, regulators, and independent third parties from adopting RDR programs. Lastly, it provided us with details about successful program implementation, opportunities, challenges, and best practices. This question shed insight into how energy providers can scale a quick, cost-effective, and viable grid management solution.

Semi-Structured Interviews

In Phase II, our team identified 22 interviewees at organizations including energy providers with RDR programs, energy providers without RDR programs, independent third parties, and oversight entities. Examples of independent third parties include Google Nest and EnergyHub. These entities do not provide energy to customers but instead offer technology, platforms, and solutions that allow for the implementation of RDR programs.

We also classified interviewees by their role in the energy market. These roles include: retail electricity providers (REPs), transmission and distribution utilities (TDUs, frequently referred to as investor-owned utilities or IOUs in Texas), municipally-owned utilities (MOUs), and electric cooperatives (ECs). We aimed for an equal distribution of interviews from each interviewee type, and Table 4 below provides a breakdown of our Phase II interviewees based on these categories.

Table 4: Phase II Interviewees

<table>
<tr><th colspan="4">ENERGY PROVIDERS</th></tr>
<tr><th>MOUs</th><th>IOUs/TDUs</th><th>ECs</th><th>REPs</th></tr>
<tr><td>Austin Energy
Bryan Texas Utilities
CPS</td><td>CenterPoint
El Paso Electric
Oncor</td><td>Bandera Electric Cooperative
Pedernales Electric Cooperative</td><td>Green Mountain Energy
NRG
Octopus Energy</td></tr>
<tr><th colspan="4">INDEPENDENT THIRD PARTIES</th></tr>
<tr><td colspan="2">EnergyHub
Google Nest
Nationwide Energy Partners
OhmConnect</td><td colspan="2">Recurve
Tesla
Uplight</td></tr>
<tr><th colspan="4">OVERSIGHT ENTITIES</th></tr>
<tr><td>Austin City Council</td><td>ERCOT</td><td>PUC Texas</td><td></td></tr>
</table>

Based on our Phase I findings, our team developed five sets of interview questions specific to each type of interviewee: energy providers with RDR, energy providers without RDR, oversight entities for MOUs, oversight entities for IOUs, and independent third parties. Questions between the five groups of interviewees varied but were guided by the same overarching research question: What are the enabling factors for implementing RDR programs? These interview questions are available in Appendix E.

Data Analysis

After we completed all 22 interviews and finalized the notes, we coded the interviews and organized the codes into a codebook. Our team utilized a semi-inductive coding process to analyze the data. We coded interviews at different times so team members could view existing codes in the codebook to inform their analysis. The final codebook contained 302 unique codes. Our team then conducted a content analysis where we identified sub-themes in the data, which we later grouped into overall themes that reflected patterns across the interviews. These themes, described in greater detail in the following section, informed our policy recommendations.

FINDINGS

Through the two phases of our project, we aimed to 1) understand the role of residential demand response (RDR) within the context of the Texas energy industry and 2) identify the key policy enablers of its expansion. In Phase I, we conducted interviews with six subject matter experts, who discussed some of the broad policy, economic, and behavioral challenges associated with RDR. During Phase II, we conducted interviews with 22 energy industry players, including transmission and distribution utilities (TDUs), municipally-owned utilities (MOUs), electric cooperatives (ECs), retail energy providers (REPs), independent third-party providers, and oversight entities. This group discussed a variety of enablers and inhibitors of RDR, both at the policy and program levels. The following section highlights the findings from each phase of this project, organized into high-level themes. Throughout this section, we synthesize broad ideas discussed in interviews and in some cases use quotations to indicate phrases from direct quotes.

Phase I Findings

Phase I aimed to answer the following question: what are the most critical factors that affect how utilities conduct demand-side management? After data collection via semi-structured interviews and a thorough qualitative analysis, six themes emerged from the data:

1. Behavioral and residential engagement
2. The role of technology
3. Financial incentives
4. Market influence and regulation
5. Issue framing
6. Stakeholder influence

The following sections summarize and describe our findings associated with each theme in greater detail.

Behavioral and Residential Engagement

Two common patterns emerged in this theme: 1) many RDR programs require customers to engage in active behavior change, which can be challenging, and 2) RDR program success hinges on the relationship between energy providers and customers. The term "behavioral economics" came up frequently in these interviews, both as a suggestion of something the team might explore further and as a strategy for energy providers wanting to implement RDR programs. Behavior change can be complicated, and thus, it is important to understand how customers make decisions and what incentivizes them to do so. Similarly, interviewees argued that it is crucial to find the right financial incentive to elicit behavior change.

Additionally, "cultural values" also impact customers' behaviors and thereby, the success of an RDR program. For example, in the U.S., residents are used to having "what they want when they want it", which makes the idea of reducing energy consumption at prescribed times a foreign concept. Lastly, interviewees discussed the fact that many energy providers lack strong relationships with their customers, posing challenges in the implementation of RDR programs. If customers do not have a trusting relationship with their energy provider, it is unlikely they will participate in an RDR program.

The Role of Technology

SMEs expressed consensus that technology can overcome some of the behavioral challenges highlighted earlier. To this end, automatic devices that eliminate the need for consistent behavior change may increase RDR program adoption. Further, for RDR programs to succeed, energy providers must have access to a lot of data, which can be challenging. Information on real-time energy consumption and reduction is critical. Therefore, technology such as smart meters can increase data availability, making the proliferation of RDR programs more feasible. Lastly, interviewees believe that technological advancement will shape the future RDR programs. In most interviews, interviewees mentioned that virtual power plants (VPPs), electrification, and other devices that increase home automation will influence the design of new RDR programs.

Financial Incentives

The market incentivizes actors in the energy landscape to implement RDR programs differently. For example, a private industry actor may be motivated to implement an RDR program for financial gain, whereas a utility may be motivated by stabilizing and lowering its customers' energy bills. How actors are motivated can pose challenges; for example, when running a traditional cost-benefit analysis, utilities may not see value in implementing an RDR program because it is seen as unreliable and not cost-effective. One reason for this is that DR is not valued “properly” as a resource. SMEs frequently brought up the challenge of DR being improperly valued against generation, diminishing its value and impeding its widespread adoption. On the other hand, market forces can also act in DR’s favor. Given the rise of Environmental, Social, and Governance reporting, many companies are striving to achieve decarbonization goals, and RDR programs can be part of that larger strategy.

Market Influence and Regulation

The SMEs we interviewed viewed Texas' energy market structure as both an enabler and a barrier to widespread RDR program adoption. According to interviewees, Texas' deregulated market often creates division between who owns, transports, and sells energy to customers, making it challenging to know which entity is best suited to implement RDR. Interviewees also discussed the impact of rate setting and design. In Texas, customers are shielded from wholesale market pricing, which SMEs viewed as a positive, protective measure that disincentivizes residents from participating in RDR programs. Additional challenges arise when trying to financially incentivize RDR because Texas does not have a capacity market, which SMEs view as an enabler of successful RDR programs. Lastly, the market's regulatory frameworks incentivize various stakeholders, utilities, REPs, and third-party aggregators differently. For example, 4 Coincident Peak (4CP) pricing incentivizes utilities to implement RDR programs because reducing energy consumption at a prescribed time can lower their energy bills for the entire subsequent year.

Issue Framing
The way that energy providers and other stakeholders frame RDR programs impacts its perception and potential. In other words, how entities market their RDR programs to their customers can influence the rate of enrollment and participation. Some residents may be more likely to participate if energy providers describe RDR as an essential tool for grid stability. Others may be more drawn to messaging that ensures residents that they will not lose "control" over the devices in their homes. Further, interviewees argued that framing RDR in political spaces is equally important. Texas has strong cultural values and has historically not made decisions based on environmental concerns. Therefore, positioning RDR as a tool for competitive market innovation may bode well compared to describing RDR as a decarbonization measure. Overall, SMEs expressed consensus that RDR has the potential to stabilize the grid and increase reliability, all while being affordable and environmentally friendly. However, they highlight that the success of RDR hinges on how it is framed to different stakeholders.

Stakeholder Influence
SMEs frequently recommend investigating the financial incentives or other motivations that drive different stakeholders in the energy market to implement DR programs. Multiple SMEs referred to the lack of proper incentives as the reason that more utilities do not have RDR programs for their residents. Another recurring sentiment in the interviews was that due to the competitive market in Texas, the private sector is leading in technological innovation in the RDR space and responsible for its advancement. Private companies' incentive is their desire to capitalize on an "emerging market financially." SMEs mentioned Tesla by name on numerous occasions.

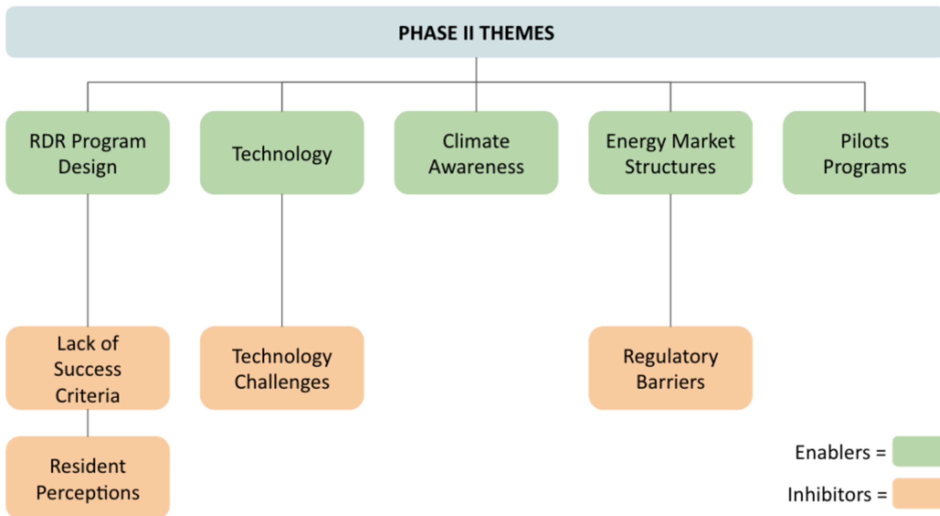
Phase II Findings

During the second phase of our research, we asked interviewees about existing RDR programs at their organization (if such programs exist), challenging aspects of implementing and scaling RDR programs, program success criteria, and policies that would enable the expansion of RDR, among other topics. A qualitative analysis of the data from these interviews revealed numerous enablers and inhibitors of RDR, which we organized into five key themes:

1. RDR program design
2. Technology
3. Climate awareness
4. Energy market structures
5. Pilot projects

The following subsections provide further detail on these themes using examples discussed in interviews. As shown in Figure 3, due to the nuances of the issues highlighted by interviewees, each theme discusses challenges in context with their associated enabling conditions. For example, the RDR Program Design theme includes a number of findings that are enabling factors for RDR, as well as two associated inhibiting factors (i.e., lack of success criteria and resident perceptions).

Figure 3: Phase II Themes: Enablers & Inhibitors of RDR



RDR Program Design

The first major theme that arose in our Phase II interviews is related to the design of RDR programs, specifically best practices. We have created an inventory of these technical findings, which can be accessed in the Best Practices section of this report. This particular section on RDR program design will detail some of the elements that interviewees expressed as having a significant impact on RDR program success more generally, including some inhibitors in this area.

A major aspect of program design is the need to enable ease of enrollment and participation in RDR programs. Interviewees overwhelmingly expressed this sentiment, whether related to implementing programs that minimized resident "discomfort", offering a variety of programs personalized to different types of residents, or enabling better program management through automation technology. One interviewee discussed having success in implementing multiple types of program offerings, noting that some residents are wary of ceding control to utilities and instead prefer to participate in RDR programs that offer more customer control. Despite this general preference, interviewees discussed their success in implementing both utility and customer control models of RDR programs, and emphasized that customers are not a monolith.

Many interviewees reported residents' negative perceptions of RDR programs as an inhibitor to RDR success, especially relating to residents' overall lack of trust in utilities and the electric grid system. The "big brother" aspect of automated or direct load control programs can create a sense of distrust among residents, as well as raise privacy concerns related to data sharing. Further, the increased duration and number of RDR events can cause fatigue among residents, dampening their perception of the program and leading them to unenroll. For this reason, many interviewees were prompted to limit the number of times they call RDR events to help with customer retention.

Despite residential concerns over control and privacy, most interviewees agreed that automation technology is appealing because it removes the behavioral aspect of customer participation. Some interviewees discussed the option of automatically enrolling residents participating in smart thermostat rebate programs into RDR. In essence, residents in these programs would not have to actively adjust their thermostats to participate in RDR, but would have the option to opt out of the event by simply adjusting their thermostat. However, there exist several challenges with this concept. The first is that some thermostat manufacturers do not allow for automatic enrollment into programs. A second challenge is related to how energy providers market and message these programs to residents so as to mitigate concerns over privacy and control.

Many interviewees expressed the need to emphasize the voluntary nature of RDR programs and the options to override and opt-out at any moment. Additionally, they discussed the importance of helping residents understand the billing around RDR events, demonstrating that their participation results in financial savings. This highlights an overarching barrier to RDR – lack of resident education. Many energy providers discussed the need for intentional educational efforts to build trust with customers and maintain transparency. Beyond education, some interviewees mentioned that notifying residents ahead of call events also helps foster trust and thereby increase participation.

Another key element of program design is incentivization. Interviewees overwhelmingly discussed the importance of incentivizing enrollment and participation, whether through rebates, avoided costs, gamification, pay for performance structures, or other rewards. These financial incentives encourage greater customer participation. One interviewee noted that having more resources to offer as RDR program rewards would help make a transition from customer indifference to participation.

Lastly, interviewees varied in their evaluation of RDR program design and success. Energy providers mentioned a variety of success metrics, including customer enrollment numbers, load reductions, event participation rates, customer satisfaction rates, customer awareness, percentage of device-driven customers versus behavior-driven customers, and customer opt out frequency. Some energy providers had such small participation in their RDR programs that efforts to measure success seemed perfunctory. Others argued that RDR evaluations should be conducted by third parties to ensure unbiased assessments. Further, we also identified the use of varying terminology to describe similar concepts among many energy industry players. For example, some referred to load reductions as “kW/MW savings” while others called it “load shifting” or “reduced demand.” The inconsistency in success metrics and terminology used throughout the industry makes tracking successful RDR program implementation difficult, which could potentially hinder the growth of new programs.

Technology

Next, we observed that the growth of automation technologies in households has spurred a movement from behavior-based to device-based programs. Most of the energy providers we interviewed rely heavily, or almost exclusively, on smart thermostats to conduct RDR, highlighting this shift. Electrification, as well as emerging technologies such as battery storage, electric vehicles (EVs), and heat pumps, also came up as factors that are expected to enable the expansion of RDR. Because these technologies shift previously gas-powered systems to electricity, a larger proportion of energy load is now available for energy providers to shed or shift during peak demand periods, which provides more flexibility to the electric grid.

Many interviewees expressed interest and hope in the emerging role of aggregation technologies, which allow energy providers and residents to aggregate energy load from multiple sources into a single hub, and adjust during peak demand periods. This concept applies at the utility and grid level in the form of virtual power plants (VPPs), also called aggregated distributed energy resources (ADER), which allow for more flexible load shifting in response to variable energy resources in the grid. In addition, VPP programs can include residential sources of energy such as EV charging equipment or solar panels, giving residents the opportunity to make money by selling unused energy to the electric grid. Interviewees noted that these aggregation technologies have a growing presence within the energy market, and can have significant impacts on the future adoption of RDR. Aggregation technologies can also be applied at the resident level in the form of home energy management systems, which allow residents to aggregate and enroll multiple devices into VPP programs. Multiple interviewees discussed the benefit of deploying these systems to set customer preferences to prioritize which devices should be adjusted during RDR events. Coupled with RDR programs, home energy management technologies can allow for load reductions with little to no customer discomfort. Although these residential-level aggregation technologies exist, they are not widely adopted due to their high cost for residents.

While many interviewees discussed the benefits of technology in RDR programs, they also identified a series of challenges. These include a lack of technology expertise among energy providers, issues with interoperability between devices, and data concerns. Most energy providers do not have the in-house expertise necessary to aggregate and manipulate energy load from multiple sources into one system. Therefore, they must rely on independent third party providers to obtain these services. However, there are several challenges associated with contracting out certain resident-facing program operations. Firstly, interviewees noted that some independent third party providers have a limited number of RDR events they can call, which can create impediments for utilities trying to meet certain goals or target through their RDR programs. Secondly, interviewees expressed concern over the data sharing and customer relationship aspects of contracting independent third party vendors, noting the importance of third parties maintaining the utilities' reputation during their interactions with customers.

Another challenge that arises with the increased reliance on technology for RDR is interoperability, which refers to the communication between home devices and platforms used to aggregate energy load at the utility level. Apart from technology standards and protocols, interviewees also mentioned other interoperability challenges due to regulatory requirements or manufacturer settings that make certain devices ineligible for use in RDR programs. There exist many third parties that provide DR/RDR management platforms for utilities, as well as many different technology companies that create devices for use in RDR. However, not all platforms can communicate with all devices used in DR/RDR, which poses limitations for utilities implementing and scaling such programs as well as customers participating in them. Interviewees argued that implementing interoperability standards would provide energy providers with more flexibility by making devices more interchangeable, avoiding stranded investments, and increasing competition among DR/RDR platform providers and technology companies. One example of the competition aspect of interoperability came up with respect to newer devices, such as EVs and EV charging equipment, with some interviewees noting that certain manufacturers of these technologies have been resistant to allowing utilities to connect with these devices for curtailment during RDR events. Interviewees noted that manufacturers cite privacy concerns as their reasoning for restricting access, but they believe that in reality the resistance is due in part to manufacturers' desire to maintain their competitive advantage by "owning the customer and the data".

The third technology challenge that arose relates to data concerns, with many interviewees noting either a lack of data availability or an excess of data as challenges to developing and monitoring RDR. Some interviewees, especially TDUs, expressed frustration with massive amounts of data associated with RDR, which requires time and staff bandwidth to collect, manage, and analyze. On the other hand, REPs noted that lack of data availability creates barriers to their implementation of effective RDR programs.

Climate Awareness

Throughout Phase II, interviewees recognized RDR as an effective tool for grid resilience, especially in the wake of Winter Storm Uri and growing efforts to enhance the reliability of the Texas electric grid. Many energy providers, independent third party providers, and oversight entities acknowledged the need to expand RDR to help stabilize the grid during heat waves in the summer and cold snaps in the winter. Underlying this idea was the concept that the penetration of renewable energy resources into the Texas electric grid complements the growth of RDR, and vice versa. For example, RDR programs can help optimize the use of renewable energy by shifting demand to periods when more renewable energy resources are available in the wholesale electricity market. Interviewees have seen a simultaneous growth in RDR programs as more renewable energy resources have come online in Texas. Some believe that this relationship between DR/RDR and renewable energy growth enables the use of DR/RDR beyond emergency events, such as three-digit degree weeks in the summer. Because energy providers are responding to the availability of renewable energy resources in the grid, they can use RDR programs to continuously adjust energy load for longer periods of time rather than just during grid emergencies.

More generally, awareness of climate-driven extreme weather patterns was a driving force for RDR among many energy providers in Texas. Several interviewees mentioned climate-related goals such as reducing greenhouse gas emissions, decarbonizing of their fuel mix, meeting customer preferences for "green" solutions, and other general sustainability goals in the context of their motivation to implement RDR programs or offer RDR services. One utility oversight entity mentioned that the costs associated with RDR program adoption must be balanced against reliability of the electric grid and the climate impact of the business-as-usual approach to load management. Many interviewees expressed a need to value RDR against new generation and expressed the challenges of conducting cost benefit analyses for RDR programs, especially given the differences between dispatchability of RDR versus traditional power plants. One interviewee, an independent third party provider, experienced greater adoption of RDR programs in states with climate policies that allocated resources for RDR implementation among utilities. Many interviewees also acknowledged that federal funding around decarbonization enables RDR program adoption and participation by providing financial benefits to utilities and customers for energy efficiency upgrades that complement RDR.

Most interviewees discussed the intersection between DR/RDR and energy efficiency, noting the need to distinguish between the two concepts despite their interdependencies. Energy efficiency moderates the effectiveness of RDR by enhancing residents' ability to participate in RDR programs. For example, better insulated homes can go longer without turning on the heat in cold months or kicking up the AC in hotter months. On the flip side, residents in less weatherized homes experience more discomfort when their smart thermostat is manipulated by their energy provider, a burden felt more so in lower income communities who participate in RDR since they are less likely to afford weatherization upgrades.

Energy Market Structures

A fourth major theme that arose in our interviews relates to energy market structures. Within the Texas energy market, interviewees observed that the competition enabled by deregulation breeds technological innovation, and therefore, the expansion of RDR programs. Multiple technology companies mentioned their ability to test new business models and technologies, such as battery storage deployment, in Texas as opposed to other geographies due to favorable market structures. As mentioned in Phase I interviews, Tesla is a major player in the DR/RDR space due to their expansion of EVs, EV charging, and battery storage technology across the state and their role in pushing regulators to enable further technological innovation. Competition among technology companies and other third-party actors offering RDR services also spurs innovation at utilities, who rely on third parties to implement RDR programs.

Market conditions in Texas create a variety of motivations for energy industry players to offer RDR programs, providing benefits to all forms of energy providers in addition to residents. For example, 4CP pricing was acknowledged as both a factor enabling RDR program adoption as well as a limitation to program expansion. The majority of interviewees expressed that 4CP pricing motivates TDUs, MOUs, and ECs to offer DR/RDR programs to lower their energy costs throughout the year and pass on savings to their customers. Several interviewees even identified 4CP pricing as the explicit financial reason for conducting RDR. However, given the focus on the 4CP pricing model during the summer, many interviewees voiced concern that this limits RDR and that concentrating all events into four months of the year leads to resident fatigue and lack of participation over time.

Another interesting market interaction with respect to RDR is the relationship between REPs and TDUs. In Texas, TDUs are prohibited from offering services directly to customers, which means that the customer relationship is owned by REPs, who rely on TDUs to distribute energy from power plants to their customers. TDUs are motivated to conduct RDR to avoid high energy rates from the 4CP pricing mechanism and also because they receive annual energy efficiency budgets through the Public Utilities Commission of Texas (PUCT), which can be used for aspects of DR/RDR program implementation. REPs are motivated to implement RDR programs because RDR can be used as a hedging strategy for financial risk mitigation. For example, REPs can purchase energy on the day-ahead energy market, call an RDR event the next day, and sell back excess energy in the real-time energy market, typically at a higher rate than what they purchased. Several interviewees discussed this interaction, with many believing that REPs and TDUs should work together since REPs have the customer relationship and TDUs receive funding to implement RDR. However, interviewees also voiced limitations with PUCT energy efficiency funding, with PUCT requirements that qualifying RDR interventions be cost-effective and not interfere with competition in the Texas energy market.

Many interviewees also noted ratemaking structures as major challenges to RDR implementation and participation. Most residential customers in Texas are insulated from energy market price volatility, and many see this as a barrier to RDR since the residential sector is not motivated to reduce their energy demand during peak periods. However, policy structures and news stories around some customers paying extremely high energy prices around Winter Storm Uri have made it difficult to change residential rates. We heard many perspectives on this issue, with some arguing that shielding customers from wholesale market pricing is more equitable, while others believe that exposing residents to the real price of energy would encourage a paradigm shift in energy consumption, prompting more people to participate in RDR programs. Time-of-use pricing was brought up as one of the most prevalent rate structures used to motivate RDR participation. However, this model depends heavily on resident behavior.

Interviewees also mentioned general policy barriers to RDR adoptions, including Texas policy favoring supply-side load management and lack of education on RDR benefits among Texas policymakers. One interviewee also mentioned a lack of external policy incentives for DR/RDR adoption among ECs, given the independent structure of cooperatives compared with other energy providers. In the case of MOUs, which are managed by city council oversight committees, the slow pace of government can also pose limitations for RDR adoption.

Pilot Projects

The final theme revealed throughout our Phase II interviews was the role of pilot projects in advancing RDR program adoption across Texas. In 2022, the PUCT directed ERCOT to begin the development of an Aggregated Distributed Energy Resources (ADER) pilot program and taskforce, which is aimed at understanding the benefits and challenges of allowing aggregated distributed energy resources to bid into the wholesale energy market. The ADER pilot and taskforce was a prominent point of conversation among many interviewees, who mentioned the intersection with the pilot and the concept of DR/RDR. As alluded to in the technology theme of this section, aggregation technologies are emerging as a way to scale RDR for greater impact on the electric grid. By combining load reductions from multiple small sources, RDR programs can be scaled to a level where they become comparable to new power generation. Several energy providers mentioned their participation in and tracking of the ADER pilot and taskforce, with some ready to see regulatory changes as taskforce conversations progress. Many also noted that energy providers are often wary of trying new programs, which is why the ADER pilot is an important signal. Pilot programs, both those led by oversight entities as well as individually at the utility level, are important for testing the viability of projects related to DR/RDR.

RECOMMENDATIONS

Based on a qualitative analysis of the interview findings detailed above, we have identified a series of recommendations that aim to enable the development, implementation, and success of RDR programs in Texas. These recommendations highlight funding gaps, policy solutions, and future research needs, emphasizing that RDR is a cost-effective tool to manage grid stability. We propose the following recommendations to policymakers, energy providers, and researchers in Texas:

1. The Public Utility Commission of Texas (PUCT) should update peak demand reduction and energy savings goals and reframe its cost-effectiveness standard by requiring the portfolio of programs be net positive instead of each program and by adding avoided transmission and distribution benefits in its calculation methodology.

2. The PUCT should establish a joint demand response task force at the Office of Public Utility Counsel and the Office of Public Engagement to represent residential DR efforts.

3. Texas should financially support the development, implementation, and adoption of RDR programs through the Texas Energy Fund.

4. The Electric Reliability Council of Texas (ERCOT) or the Texas Energy Fund should provide state-level funding to ensure that successful components of DR pilot programs can be maintained and scaled.

5. Texas should design coordinated federal and state-level funding to expand the adoption of enabling technologies of RDR.

6. The PUCT should convene stakeholders and conduct an analysis to determine interoperability standards.

7. The Pacific Northwest National Laboratory (PNNL) should evaluate ERCOT's 4 Coincident Peak (4CP) program to better understand its relationship with residential demand response.

Below, we expand upon each recommendation in detail.

1. **The Public Utility Commission of Texas (PUCT) should update peak demand reduction and energy savings goals and reframe its cost-effectiveness standard by requiring the portfolio of programs be net positive instead of each program and by adding avoided transmission and distribution benefits in its cost benefit methodology.**

   Context:
   In 1999, Texas became the first state to adopt energy efficiency resource standards (EERS) for its investor-owned utilities (IOUs) (i.e., transmission and distribution utilities (TDUs); due to deregulation, TDUs in Texas are often referred to as IOUs).[155] EERS set energy

savings goals, which vary in magnitude and type between states. Some examples, as documented by The American Council for an Energy-Efficient Economy (ACEE), include:

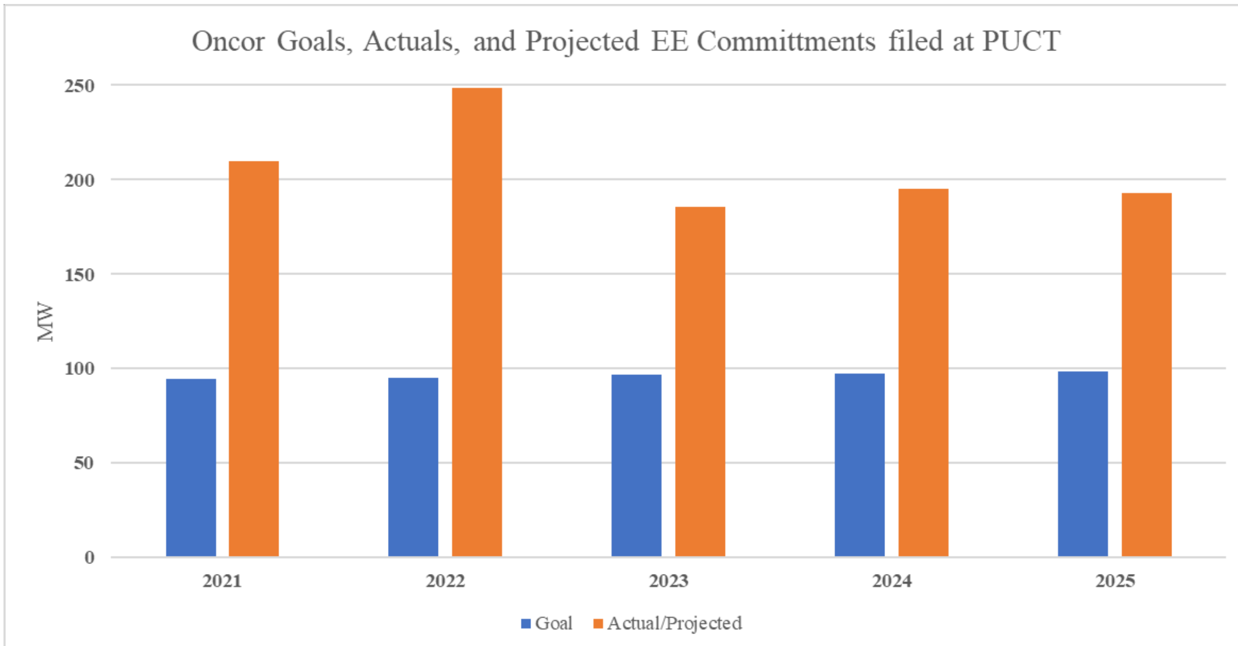
- Arkansas: 1.2% savings targets of 2018 baseline sales for electric utilities
- California: incremental savings targets average about 1.6% (gross) of retail sales from 2020-2025
- Colorado: 5% peak demand reduction and 5% energy savings by 2028 for demand-side management programs implemented during 2019 through 2028 compared to a 2018 baseline (the Commission ruled in Proceeding No. 17A-0462EG that PSCo's goal for annual energy savings for 2019-2023 be 500 GWh)
- Illinois: 1.77% of sales from 2018 to 2021, 2.08% from 2022 to 2025, and 2.05% from 2026 to 2030 (these metrics are an average and thus vary slightly utility to utility)
- Iowa: incremental electricity savings of 0.89% per year (these metrics are an average and thus vary slightly utility to utility)
- Maryland: 0.2% increase in savings per year, leveling out at 2% incremental savings per year as a percent of 2016 weather-normalized gross retail sales and electricity losses

It is worth noting that Alabama, Georgia, Idaho, Kansas, Kentucky, Louisiana, Mississippi, Montana, North Dakota, Ohio, Oklahoma, and South Carolina, West Virginia, and Wyoming do not have EERS. Other states have standalone and/or voluntary EE goals, like Florida, Indiana, Missouri, Nebraska, South Dakota, and Tennessee.[156]

In Texas, the PUCT requires IOUs to meet two types of goals each year: demand reduction goals (MW) and energy savings goals (MWh). The demand reduction goals are tiered in that once a utility meets the requirements of the first goal, it moves to the second, and so forth. Appendix F details the three tiers in Texas Administrative Code (TAC) §25.181-1 (e)(1). In short, the majority of large IOUs in Texas must offset 0.04% of summer weather-adjusted peak demand for the combined residential and commercial customers from the previous year through its energy efficiency (EE) programs (paragraph C tier). For energy savings goals, the PUCT requires that Texas IOUs "administer a portfolio of energy efficiency programs designed to meet an *energy savings* goal calculated from its demand savings goal, using a 20% conservation load factor".[157] To derive the energy savings goal, the demand reduction goal is converted to MWh and multiplied by 20%. Together, these goals constitute EE goals for Texas IOUs.

Despite Texas' original EERS leadership, regulators have not revisited or amended these demand reduction and energy savings goals since 2012. As such, many of these goals are outdated and therefore, too low and too easily achieved. For example, Texas IOUs must file their EE goals each year with the PUCT, reporting on future estimates and most recent actuals. Using Oncor's April 2024 Energy Efficiency Plan and Report filing as an example, we note their 2021-2025 demand reduction goals (MW), actual demand reduction achieved (reported and verified savings at meter, MW), and in the case of 2024 and 2025, projected demand reductions (MW) in Figure 4.[158]

Figure 4: Oncor 2024 Energy Efficiency Plan and Report filing



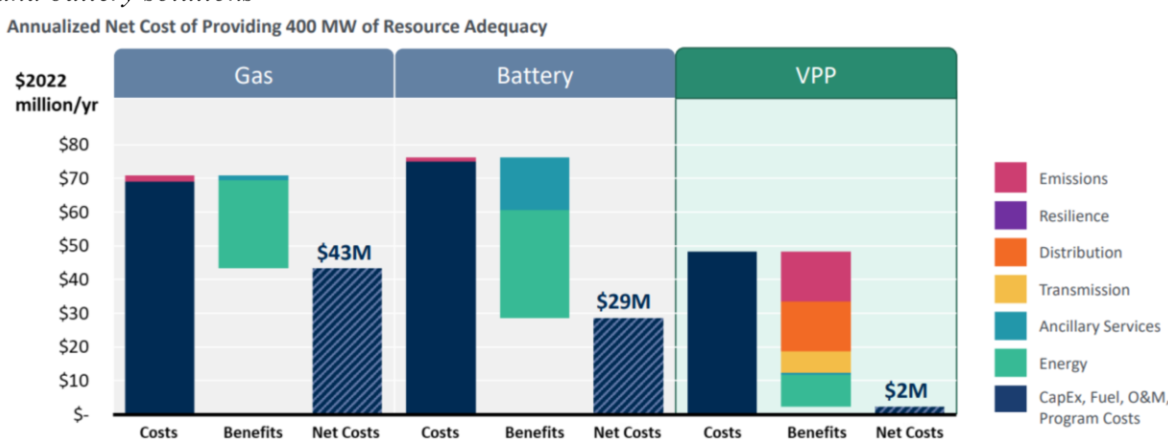
This demonstrates that the demand reduction goals required by the PUCT are incredibly low compared to the actual demand reduction achieved or projected by the IOU. Further, with the exception of 2021 to 2022 actual demand reduction, year over year change is minimal and in some cases, even negative. Although we note only Oncor above, Dr. Cyrus Reed, the Conservation Director of the Texas chapter of the Sierra Club, notes in an August 2022 petition for rulemaking filing to the PUCT that similar patterns across all Texas IOUs exist.[159]

Updating demand reduction and energy savings goals are important to reflect reality and to prompt Texas IOUs to invest more materially in EE. Doing so will also help limit the bonuses that IOUs reap as a result of exceeding such low goals. TAC §25.182 details the Energy Efficiency Cost Recovery Factor (EECRF) submission process, which allows IOUs "to timely recover the reasonable costs of providing a portfolio of cost-effective energy efficiency programs" through a charge on residential and commercial customers.[160] In short, this provision allows an IOU to reimburse itself for "forecasted annual energy efficiency program expenditures, the preceding year's over- or under-recovery including interest, municipal and utility EECRF proceeding expenses, any performance bonus earned, and EM&V [evaluation, measurement, and verification] costs allocated to the utility by the Commission".[161] Specifically, "a utility that exceeds 100% of its demand and energy reduction goals shall receive a bonus equal to 1% of the net benefits for every 2% that the demand reduction goal has been exceeded, with a maximum of 10% of the utility's total net benefits."[162] Given the PUCT goals are so low, utilities easily achieve them and earn a substantial performance bonus. In Oncor's 2024 EECRF filing, it requested a budget of $72,339,769. The performance bonus for meeting 2022 EE goals was $20,545,284, or roughly 28% of its entire budget.[163] It is important to note that the EECRF is only available to IOUs, not retail electricity providers (REPs).

To calculate the program costs of various EE efforts reported in the EECRF, PUCT rule §25.181 outlines how to calculate avoided capacity and avoided energy use. TAC §25.181(d), the Cost Effectiveness Standard, states that "utilities are encouraged to achieve demand reduction and energy savings through a portfolio of cost-effective programs".[164] This implies that the programs must all be cost effective. In other words, newer, more innovative demand solutions like RDR might be disallowed as initial ramp-up implementation may be cost-prohibitive despite existing within a net-positive, cost effective portfolio. As such, this provision encourages IOUs to continue investment in the same measures year over year.

Secondly, the benefit calculation stated in TAC §25.181(d)(2-3) omits avoided transmission and distribution costs.[165] For RDR programs, this is particularly problematic. Per a 2023 Brattle Report, avoided transmission and distribution costs account for a large portion of virtual power plant (VPP) benefits, lowering overall net cost relative to a thermal gas plant and battery solution.[166] Figure 5 demonstrates this advantage. In failing to account for these avoided costs in the PUCT rules, the benefit of RDR programs such as VPPs are understated, making them appear at best less cost-effective, at worst, cost-prohibitive and thus, not permitted as an EE demand measure.

Figure 5: 2023 Brattle Report on net cost of RDR virtual power plant (VPP) program vs. gas and battery solutions



Recommendation:
We recommend that the PUCT consider the following three policy changes:

- Increase demand reduction (MW) and energy savings (MWh) goals. These changes would encourage IOUs to adopt more/new RDR programs to achieve the newly set goals. Although it is outside the scope of this report to prescribe what the goals should be, we note that Dr. Cyrus Reed, the Conservation Director of the Texas chapter of the Sierra Club, is in support of a 0.7% peak demand reduction goal (MW, equivalent to roughly 50% of annual load growth) and a 1% energy savings goal (MWh).[167] His recommendation is based on a 2010 study conducted by Itron, a energy consulting firm, that the Texas state legislature commissioned to provide EE recommendations to the PUCT. Regardless of the exact metric, we recommend that intermediary, staggered goals be set to give IOUs time to adjust.

- Change rule §25.181(d) language from "utilities are encouraged to achieve demand reduction and energy savings through a *portfolio of cost-effective programs*" to "utilities are encouraged to achieve demand reduction and energy savings through a *cost-effective portfolio of programs*." In changing the syntax, IOUs can invest in programs that may be initially cost-prohibitive (i.e., not a cost effective program) so long as their portfolio of EE programs is cost effective. This will broaden EE program offerings, minimize new program risk that IOUs incur, and incentivize the adoption and maturity of RDR technologies while maintaining fiscal responsibility.
- Add avoided cost of transmission and distribution provisions to TAC §25.181(d). This will more accurately reflect the large, expensive capital cost of transmission tower and distribution line expenses avoided by many DR solutions, including RDR. The benefits of RDR programs will become more accurate (larger) and will thus lower the net cost. The cost effectiveness of these solutions will rise and prompt more IOUs to invest in them as EE solutions.

Further, we recommend that PNNL conduct further research regarding:

- The impact of allocating a portion of EECRF PUCT budget to compensate REPs for their EE programs, which could include RDR. Today, only IOUs submit EECRF requests for reimbursement; REPs cannot. This becomes problematic as IOUs in Texas cannot directly sell energy to customers due to deregulation. As such, RDR programming becomes difficult for IOUs as they must either provide programs indirectly through independent parties or through REPs in their territory. REPs have more potential to implement RDR programs given their direct relationship with residents, yet they lack access to the reimbursement mechanism from the PUCT. By distributing some portion of EECRF PUCT money, REPs can subsidize their RDR programs and expand their offerings while IOUs can continue with non-RDR EE initiatives and still receive sufficient financial support.
- The impact of cost-caps (EE dollars per customer class) set by the PUCT, which could limit IOU EE expenditures necessary to meet these goals. We recommend particular emphasis on increasing commercial caps so not to inequitably burden certain residential users.
- The impact of requiring industrial customer class participation. As a result of extensive lobbying in 2007 over provisions in House Bill 3693, industrial consumers are exempt from contributing to or participating in EE programs and thus, receive no

rate-payer fee assessed as part of IOU delivery charges on their bill. The South-central Partnership for Energy Efficiency as a Resource (SPEER) summarizes the grounds of their opposition, noting:

> That they invest in efficiency, as a matter of course, because of their internal incentive to improve their own bottom line and competitiveness, and are not motivated by utility incentives. Energy efficiency programs are funded through a rate-payer fee assessed as part of a customer's delivery charge, and the industrial customers also argued that the companies that invested their own capital should not have to subsidize their competition.[168]

2. The Public Utility Commission of Texas (PUCT) should establish a joint demand response task force at the Office of Public Utility Counsel and the Office of Public Engagement to represent residential DR efforts.

Context:

ERCOT has established a Demand Side Working Group (DSWG) to aid in identifying and implementing DR programs. This team works on "promoting various opportunities for demand-side resources to participate in the ERCOT market".[169] However, the responsibilities and goals of this group are heavily technical and industry led, lacking consumer representation, input, and education. As a group, the DSWG reports to the Wholesale Market Subcommittee (WMS) and operates on an open forum led by a Chair and Vice Chair. Listed are two examples of the DSWG goals: 1) evaluate new operational opportunities and needs of DR/DG in ERCOT and 2) the assessment of technical strategies, such as DR and retail rate structures, and their reflection in ERCOT documents.[170] The average residential customer would not be able to easily or readily participate in such a technical discussion, therefore additional forums, designed with residential customers in mind, should be developed.

In our Phase II interviews, energy providers discussed growing concerns about residential consumers' participation in RDR programs. This included consumers' hesitancy to enroll, utilities' ability to educate consumers, and consumer feedback. Additionally, the responsibility of educating and advocating for residential consumers was widely spread amongst energy providers. This makes the chain of information difficult for residential consumers to follow, while hindering their ability to participate and be represented in any DR development process. This demonstrates a need for an organization, such as the PUCT and its subsidiaries, to take on the responsibilities of informing its constituents of RDR programs, services, and benefits with minimal confusion and mistrust.

Recommendation:

We recommend the establishment of a joint DR task force at the Office of Public Utility Counsel (OPUC) and the Office of Public Engagement (OPE) to represent RDR efforts. Below are some details:

- The joint DR task force can function similarly to a consumer advisory council, such as the one at the Pennsylvania Public Utility Commission. The purpose of the council is to represent the public in advising the Commissioners on matters relating to the public's interest, so long as it is under the Commission's jurisdiction.[171]

- The DR taskforce, however, would be internally run by the PUCT and its subsidiaries, but its goal is to represent and advocate for residential consumer interests. The task force would function as a central access point to DR specific information, that is easily accessible to residential customers.
- Due to the complexity of DR and the energy market, OPUC and OPE would jointly lead the DR task force, providing a level of expertise that is accessible to everyday Texans. OPUC currently provides a combination of policy, regulatory, legal, and technical expertise to represent, protect, and promote consumer interests.[172] The OPE helps the public participate in PUCT efforts while educating residents on the activities of the PUCT.[173]
- The joint DR task force can offer a wide range of services on behalf of residential consumers interests. This can include the creation and provision of educational materials, lists of DR providers, and consulting services to help utilities tailor DR programs to residential consumers.

3. Texas should financially support the development, implementation, and adoption of RDR programs through the Texas Energy Fund.

Context

On November 7th, 2023, Texas voted through a constitutional election (SB 2627) to create the Texas Energy Fund (TEF). TEF is a $5 billion fund housed in the PUCT that supports developing and maintaining electric generation projects in Texas, both in and outside of the ERCOT region.[174] The fund supports projects that build or expand dispatchable electric generating facilities, create new transmission and distribution infrastructure, or install backup power packages that support communities during grid strain or failure emergencies. The Texas Legislature proposed this fund in response to Winter Storm Uri, a severe winter storm that left millions of Texans without power and exposed the undependability of the Texas electric grid. The mission of TEF is to develop a more reliable, dispatchable power grid that protects Texans from future climate disasters. While new generation is an effective method for increasing grid stability and dispatchability, DR and RDR can provide similar results and are a cheaper and cleaner alternative to a new generation.

Recommendation:

We recommend that the PUCT seek to amend the TEF program criteria to include RDR programs or that the Texas legislature appropriate additional funds for the TEF, specifically for RDR programs.

- This would allow energy providers to apply for financial support to implement or sustain RDR programs.
- There is undeniable value in having reliable, dispatchable resources that new generation infrastructure provides; however, a diverse portfolio of resources, ranging

from new generation and energy storage to RDR, is a cost-effective and resilient alternative to mass production of new generation facilities.
- Allowing energy providers, excluding TDUs, to access TEF funds for RDR will increase RDR adoption, support the grid, and protect communities in Texas.

4. **The Electric Reliability Council of Texas or the Texas Energy Fund should provide state-level funding to ensure that successful components of DR pilot programs can be maintained and scaled.**

Context:
Energy providers, oversight entities, and independent third-party providers conduct pilot projects to experiment with innovative energy technologies and programs. For ERCOT, pilots present opportunities to test projects on a small scale. This helps them uncover insights into what aspects of the pilot are successful while learning how to pursue full-scale implementation.[175] In Texas, ERCOT manages all energy-related pilot programs, which allows them to validate any performance claims of novel technologies and review how those resources perform in various operational and market scenarios.[176]

In Phase II interviews, numerous individuals emphasized an ongoing ERCOT pilot project, the Aggregate Distributed Energy Resource (ADER) pilot. This project aims to assess the involvement of ADERs in the ERCOT wholesale market. An ADER is a resource consisting of multiple individual metered sites connected at the distribution system level.[177] Our Phase II findings demonstrated that this ADER pilot was a novel DR-related pilot project that involved virtual power plants (VPPs), with many stakeholders interested in its success.

The ADER pilot was established through the PUCT project No. 53911 and began on August 22, 2023.[178] The pilot is led by a 20 member taskforce established by the PUCT and its commissioners. Currently, only two ADERs are qualified to participate in the pilot, with seven additional ADERs waiting on registration and qualification acceptance.[179] Of the two ADERs currently participating, both are VPPs, one led by Tesla's Powerwall and the other by CenterPoint Energy. This pilot is conducted in two phases, with ERCOT expecting the pilot to continue for a minimum of two additional years from project adoption. The goal of this ADER pilot is to understand how VPPs can aggregate energy and also participate in the electric market by either providing or consuming electricity.

Additionally, interviewees shared concerns around information access and dissemination with regards to DR pilot efforts. Unless a stakeholder is involved in the pilot itself, accessing updates on the pilot's success can be challenging. Despite ERCOT's robust documentation regarding the ADER pilot in terms of governing documents, technical reports, and meeting notes, identifying overarching pilot evaluation and success metrics is lacking. In order to make DR more accessible to the public, ERCOT must simplify access to this information and clearly outline how they are evaluating pilot projects. Therefore, this recommendation focuses on the post-pilot evaluation process, including the necessary funding to continue exploring pilot project successes and distributing its findings.

Recommendation:

We recommend that either ERCOT or the Texas Energy Fund provide state-level funding to ensure that successful components of DR pilot programs can be maintained and scaled.

- This financial support will allow for the development of a post-pilot evaluation process that is easily accessible to the public and energy providers. A dedicated web page on pilot success metrics and evaluation criteria can also be developed to help enhance clarity on how ERCOT handles pilot projects once completed.
- ERCOT can use these funds to develop a broader post-pilot evaluatory team at ERCOT to determine what information can be shared with stakeholders and which new technologies are ready for implementation.
- Lasty, ERCOT can distribute these additional funds to DR providers, so that they can readily participate in future DR pilot projects. This would help accelerate the distribution and implementation of innovative DR technologies, such as VPPs.

5. Texas should design coordinated federal and state-level funding to expand the adoption of enabling technologies of RDR.

Context

Many interviewees noted the emerging role of enabling technologies as an opportunity for RDR program advancement. These technologies expand electrification, creating a larger proportion of energy load which can be shed or shifted during peak demand periods, adding more flexibility to the electric grid. Interviewees placed particular emphasis on the proliferation of battery storage, EVs, and heat pumps as enabling technologies of RDR. In addition, smart thermostats and home energy management systems use automation to make RDR more efficient and comfortable for residents, while enabling utilities to aggregate and remotely control smaller energy loads.[180] However, investment in these technologies can be cost prohibitive for residents and utilities. Over the last few years, many of these technologies have grown, notably in the Texas market, though the adoption of some continues to lag.[181] Tax credits and utility-level rebates for many of these technologies exist, including through the Inflation Reduction Act (IRA). Yet, eligibility limitations allows some of these energy market gaps, particularly those related to expanded RDR adoption, to persist.[182]

In March 2023, the State Energy Conservation Office (SECO) announced that Texas plans to apply for nearly $700 million in energy efficiency rebates via the IRA.[183] Federal funding will flow to state energy offices or designated agencies responsible for developing programs and administering rebates to residents. Texas will request funding for two IRA programs: the Home Electrification and Appliance Rebate program and the Home Efficiency Rebate program. Home Electrification and Appliance Rebates provide discounts for electrification projects such as heat pumps or EVs. Home Efficiency Rebates support HVAC updates, insulation projects, and weatherization projects that reduce home energy usage. Both programs support the widespread adoption of RDR by increasing the proliferation of electrification appliances, which enable RDR and weatherization of homes, making homes better candidates for RDR programs. The Office of State and Community Energy Programs, which administers the funding from both programs to states, leaves the specifics of program design and eligibility for state administrators to decide. This allows states to design effective programs that address market gaps and make sense for the relevant communities.

To capitalize on these funds, other states have established complementary, state-level incentive and rebate programs. For example, Colorado offers up to $7,500 in tax credits for EVs, pairing with federal tax credits to increase the proliferation of clean technology and “help ensure electric cars aren’t luxury items”.[184] Similarly, Pennsylvania is working to pass legislation to create The Solar for PA Schools Grant Program. This program would allow state funds to cover 50% of the cost of solar panel installation at Pennsylvania schools; the additional 30-50% of costs would be covered by available IRA funding, making a once-expensive technology much more affordable.[185]

Recommendation:
We recommend that Texas design coordinated federal and state-level funding to expand the adoption of enabling technologies of RDR.

- Firstly, Texas administrators of Home Energy Rebates should design program structure and eligibility requirements that effectively address Texas’ unique energy market gaps, prioritize enabling technologies for RDR, and provide the maximum possible benefits to Texas residents.
- Secondly, the state should establish complementary, state-level incentive and rebate programs that capitalize on IRA investments.
- To ensure that federal and state-level funding acts in concert, the state should further invest in SECO by creating new positions responsible for managing the coordination of federal and state rebate programs. New staff members would provide technical assistance to local governments and other relevant stakeholders, operationalizing IRA funding and state rebates at the residential level to maximum capacity.
- By providing price supports, these programs would help spread the adoption of EVs, battery storage, heat pumps, smart thermostats, home energy management systems, and other energy efficiency updates, increasing RDR program participation across Texas.

6. The PUCT should convene stakeholders and conduct an analysis to determine interoperability standards.

Context:
The growth of distributed energy resources (DERs) within the energy industry has opened new opportunities for renewable energy penetration, demand-side load management, and customer participation in the wholesale electricity market. Aggregating these smaller energy sources, which include rooftop solar, battery storage, smart thermostats, and EV charging

equipment can improve grid reliability by adding flexibility to the electric grid during periods of peak demand. However, aggregated DERs, also referred to as virtual power plants (VPPs) require the communication of many different systems and devices, including demand response management systems (DRMS) and other networks used to aggregate and manage energy load across the grid.[186]

Energy providers, oversight entities, and technology companies that participated in this project overwhelmingly reported the lack of interoperability standards among RDR program technologies as a major challenge. Within the Texas energy market, there exist many independent third-party providers that offer RDR aggregation services and software platforms for utilities. Similarly, residents can choose from a variety of household devices, including smart thermostats, water heaters, EV charging equipment, and pool pumps. However, the interoperability between these different devices, applications, networks, and systems, is becoming a limitation for RDR programs, especially as technology innovation brings new devices to the market.

Many interviewees discussed the benefits of adopting interoperability standards at the PUCT, including increased competition among device manufacturers and technology companies that offer aggregation and DRMS platforms. Such standards could lead to a landscape where all devices and load management systems could be interchangeable, reducing the risk of asset stranding for energy providers and customers as emerging DER/RDR technologies come online. Increasing the flexibility of aggregated DERs allows for more opportunities for residents to manage their energy consumption and get compensated for load reductions and injecting on-site generation into the electric grid. Efficient communication between grid operators and load aggregation systems would also lead to more responsive demand-side management, enhancing grid reliability.

Although the adoption of interoperability standards at the PUCT could induce many benefits, questions remain about which standards should be adopted. The section of the Texas Administrative Code pertaining to distributed energy resources was last updated in December 1999, and does not include standards relating to the interoperability of DER management systems or equipment.[187] Amid engagement with Texas energy stakeholders through the ADER Pilot and its associated taskforce, in November 2022 the PUCT released draft proposed changes to Substantive Rules 25.212 regarding the technical and operational requirements of distributed energy resources included in the electric grid.[188] While the proposed language includes requirements that DER equipment meet the applicable parts of IEEE Standard 1547-2018, this stipulation has been criticized as vague, leaving too much room for interpretation by device manufacturers and aggregation platforms.[189] Apart from IEEE 1547-2018, which pertains to performance, operation, testing, safety, and maintenance of DERs, other interoperability standards exist.[190] Another standard, IEEE 2030.5-2018, pertains to utility management of devices associated with demand response and distributed generation, and many other related communications standards and protocols exist by other standards-making entities.[191]

Recommendation:
We recommend that the PUCT convene stakeholders and conduct an analysis to determine their interoperability challenges and identify standards that best address the needs of the energy industry and consumers.

- The ADER Taskforce has highlighted interoperability challenges related to devices participating in the ADER Pilot Project as a policy question for consideration in future workshops by the Taskforce.[192] This proposed stakeholder convening would ensure that potential rule changes encompass the needs of all energy market stakeholders and also allow for consumer flexibility with respect to devices enrolled in the RDR components of ADER.
- Findings from this convening should inform a technical analysis of interoperability among equipment used in ADER and VPPs, including DR/RDR devices and management systems, to ensure the adoption of robust interoperability standards.

7. PNNL should evaluate ERCOT's 4 Coincident Peak (4CP) program to better understand its relationship with residential demand response.

Context:
In an effort to allocate the transmission costs associated with using the grid during periods of peak demand, ERCOT charges transmission and distribution service providers (TDSPs) a 4CP fee. TDSPs are regulated by the PUCT and refer to any entity that owns or operates "the equipment / facilities to transmit and/or distribute electricity in Texas".[193] This includes transmission and distribution utilities (TDUs), municipally-owned utilities (MOUs), and electric cooperatives (ECs). To assess the fee, ERCOT first identifies the four coincident peaks (4CP). This refers to the "four 15-minute Settlement Intervals corresponding with the highest ERCOT Load in each of the four summer months (June, July, August, and September)".[194]

After identifying the 4CP, ERCOT calculates each TDSP's average 4CP load and bills them based on their cost responsibility. For example, in 2023, Austin Energy's load during 4CP was 2,805.17 MW in June; 2,889.3 MW in July; 2,996.57 MW in August; and 3,022.68 in September, resulting in an average 4CP load of 2,928.42 MW.[195] The total average 4CP load across all TDSPs was 83,556.85 MW, meaning that Austin Energy's load share ratio was 3.5%. Consequently, Austin Energy will pay 3.5% of the total transmission charges on the grid. TDSPs pass on these costs to their large customers, typically commercial and industrial customers with peak demands greater than 700 kW.[196] Each customer's monthly 4CP fee is based on its average demand during the 4CP, which can account for nearly 30% of an organization's monthly bill.[197] In essence, 4CP functions as a demand response program that incentivizes TDSPs and large entities to reduce their demand for electricity during anticipated periods of peak demand to save money.

As highlighted in our findings, 4CP came up often in both our Phase I and Phase II interviews. The TDUs, MOUs, and EC's that we interviewed utilized RDR programs almost exclusively for 4CP savings, with the goal of saving their customers money. To this end, 4CP acts as an enabler of RDR programs. However, given that RDR is viewed as a financial tool for 4CP, energy providers narrow their limited number of RDR events to the summer months. This limits the use of RDR throughout the rest of the year, which is problematic given the rise of extreme weather year round. Further, it can cause fatigue among residents in the summer months. Therefore, 4CP also inhibits RDR to an extent.

It is worth noting that most residents in Texas are currently serviced by a Retail Electricity Provider (REP) and therefore do not face 4CP charges. Instead, they pay for their consumption of energy, at rates based on the average cost of electricity. Therefore, residents are largely protected from both their demand during peak periods and the true cost of electricity.

Recommendation:
We recommend that PNNL or ERCOT conduct an evaluation of the relationship between the 4CP program and RDR. This analysis should consider exploring:

- The extent to which 4CP enables or inhibits RDR programs;
- The impact of increasing the number of coincident peaks beyond four, as is done in other states; and,
- The effect and feasibility of imposing demand charges on residents in conjunction with consumption charges.

BEST PRACTICES

Our Phase II interview findings yielded a set of 11 best practices for the development, implementation, and evaluation of residential demand response (RDR) programs. Given that energy providers typically partner with independent third parties to conduct RDR programs, these best practices are aimed at both groups. The goal is for these practices to guide the creation of RDR programs that maximize program participation, protect resident comfort and control, and ultimately stabilize the electric grid by reducing peak demand. While our project has largely focused on RDR in Texas, the best practices detailed below are likely applicable across the nation.[i]

1. **Hire or acquire the technical expertise and IT capabilities necessary to manage an RDR program.** Of the 11 best practices, this one is exclusively geared toward energy providers. Generally, these entities' primary purpose and expertise is the distribution and/or provision of electricity. Therefore, they often lack the software, IT, and technical expertise to administer seamless, aggregated, and user-friendly RDR programs. To this end, many partner with independent third parties such as EnergyHub or Uplight to meet these needs. Other energy providers may decide to develop these skills in-house. Regardless, it is critical for energy providers to identify the platforms and systems they will utilize to administer and manage RDR programs.

2. **Offer a "suite" of RDR programs that provide options for different types of customers.** Unlike commercial and industrial customers, residential customers vary widely in their electricity needs and preferences. As a result, a "one size fits all" approach to RDR is not very effective. To address this, energy providers and independent third parties should consider offering multiple RDR programs that appeal to residents' differing preferences.

   One way to do this is to offer both behavioral-based and device-based RDR programs. Behavioral-based programs target residents who wish to maintain full control of their devices, as well as those who may not have smart devices. These programs notify residents of an upcoming RDR event and request that they manually decrease their consumption of electricity during a certain period of time. On the other hand, device-based programs target residents with smart devices who value the convenience of automatic participation. With these programs, often referred to as "direct load control (DLC)," energy providers can control a resident's devices during peak periods to decrease their consumption of electricity. Residents should always be able to opt out of the program or override DLC settings.

   Given the increased reliance on devices to conduct RDR, it is also important to allow the participation of different devices beyond smart thermostats. These include EVs, batteries, water heaters, and pool pumps. While these devices may not be as invasive or noticeable as thermostats, it is also important to offer behavioral-based participation for those residents

[i] The order of the best practices does not indicate priority level or sequence

who value control more than automation. Lastly, it is worth exploring time-based rate programs such as time-of-use rates for those residents who are responsive to price signals.

3. **Market RDR programs to residential customers that are more likely to participate.** While offering a suite of RDR programs will likely yield higher enrollment rates than a "one size fits all" approach, some residents are simply more likely to participate in these programs. For this reason, many energy providers and independent third parties target certain types of residents through their marketing efforts. These include residents who own smart devices, live in more urban areas, and are environmentally conscious. It can also include residents seeking opportunities to save money or those who do not have small children in the household. Our scholarship and policy review above consolidates existing research into residential demographics that are more likely to participate in RDR programs.

   Once target audiences are identified, it is important to develop a marketing strategy that utilizes messaging and mediums that appeal to these groups. For example, energy providers may consider partnering with device manufacturers such as Honeywell or Google Nest to market their RDR programs to customers who are purchasing smart thermostats. Not only does this strategy directly target residents who are more likely to participate in RDR, but it could also potentially serve as an opportunity to more easily enroll residents.

4. **Educate residents on RDR through marketing and communications.** One of the key issues with RDR is that residents generally do not think about their electricity consumption unless they have an issue. As a result, residents are unfamiliar with concepts such as RDR, making education a critical element to the success of RDR programs. Energy providers and independent third parties should develop an educational plan to help residents understand the basics of RDR and its personal, societal, and system benefits. These educational efforts should be embedded in marketing strategies (before enrolling residents in an RDR program) and in communication strategies (after enrolling residents in an RDR program). This gives residents greater transparency into RDR programs, which can help mitigate concerns over control, fatigue, and privacy.

5. **Make enrollment and participation in RDR programs simple and easy.** Once residents make the choice to enroll in an RDR program, energy providers and independent third parties should ensure that signing up for the program is a straightforward and quick process. Utilizing well-designed websites and/or mobile applications can help with this, as can limiting the number of steps to enroll in the program. Once enrolled, participating in RDR programs should also be easy and simple, as should the process of opting out or unenrolling. Overall, residents should know exactly how and where to receive information on and make decisions about their participation in RDR programs.

6. **Incentivize enrollment and participation in RDR programs.** Few residents choose to participate in RDR programs without receiving some sort of compensation. For this reason,

energy providers and independent third parties should explore ways to incentivize or reward enrollment, decreased energy consumption, and continuous participation. To encourage enrollment in RDR programs, many energy providers offer discounts or rebates for smart devices that can participate in RDR. Others offer an initial bill credit for enrollment. While residents who participate in an RDR event should see lower energy bills as a result of their participation, most energy providers have found it helpful to provide additional incentives in the form of bill credits or reward points. Some also aim to make the experience engaging by gamifying participation. While difficult, it is important to identify the right incentive or reward amount to ensure that these incentives are encouraging program participation without resulting in a financial loss.

7. **Mitigate resident discomfort by making participation in RDR as un-noticeable as possible.** Resident discomfort is one of the key inhibitors of a successful RDR program. Not only are RDR events typically called on the hottest or coldest days of the year, but they also largely rely on residents changing their household's temperature. This can result in physical discomfort, which can in turn lead to lack of participation in an RDR event or disenrollment from the program altogether. To this end, it is important to mitigate discomfort and make participation in RDR events as un-noticeable as possible.

   One way to do this is by allowing the participation of non-thermostat devices (ex: EV chargers, water pumps, batteries) in RDR programs. In non-behavioral-based programs, energy providers and independent third parties should provide residents with the ability to share their preferences regarding the order in which their devices are tapped for program participation. For example, a resident might indicate a preference for their EV charging station to participate in an RDR event before their thermostat. In this case, the thermostat would only participate in an RDR event if the decreased consumption from the EV charging station is not enough to offset the peak. This requires that energy providers have access to technology with the capability to directly control electricity consumption based on order of residential preference.

8. **Call RDR events often enough to keep residents engaged, but not too much to cause fatigue.** RDR programs typically call events during periods of peak electricity demand, which have historically occurred during the summer months. As a result, residents can become easily fatigued with participation in RDR programs, as programs may call on them to participate multiple days in a row. On the other hand, this clustering of RDR events can also lead residents to disengage with RDR programs during the rest of the year. While many energy providers increasingly rely on RDR during the winter months, there is a need to strike a balance between resident fatigue and disengagement. To address this, some energy providers and independent third parties have limits on the number of RDR events they can call during a certain period. Others have started calling a few RDR events during off-peak seasons to remain engaged with their residents.

9. **Stagger RDR events across residents to avoid snapback peaks.** One potential unintended consequence of calling an RDR event is a "snapback peak." This occurs when all the thermostats and devices that decreased consumption during an RDR event suddenly turn back on at the same time, causing another peak. Some energy providers stagger their RDR events across their residents to avoid this. For example, a third of residents may receive a notification to decrease consumption (or have their consumption directly curtailed) starting at 5:00 pm, with the next group kicking in at 5:30 pm and the third group at 6:00 pm.

10. **Establish a data plan to outline data collection, data analysis, and data privacy.** To best serve their customers and evaluate the success of their programs, energy providers and independent third parties need to understand their customers' energy behaviors and patterns. This depends on collecting and analyzing relevant resident data, which begets the need for a well-designed data plan that outlines some key features. These include: 1) what type of data needs to be collected, 2) why that data needs to be collected, 3) who will collect the data, 4) who will analyze the data, 5) who will have access to the data, and 6) how the data will be protected. To develop such a plan, an energy provider must first identify its success metrics based on the data it is able to collect. This process can help mitigate the overcollection or lack of irrelevant data. Further, it prioritizes the resident by proactively creating data privacy policies, which can help reduce concerns over control and privacy.

11. **Hire a third party to conduct an evaluation of RDR programs.** Lastly, energy providers and independent third parties should engage in regular program evaluations to understand the impact of their RDR programs. Ideally, these evaluations should be conducted by an objective third party. While these evaluations will largely help determine if the RDR program results in decreased energy consumption during peak periods, providers can also use them to analyze other aspects of the program. This includes the effectiveness of marketing campaigns, communications strategies, incentives, and rewards. Overall, these evaluations should refine and iterate RDR programs to better serve residents, energy providers, and the electric grid.

LIMITATIONS & FUTURE RESEARCH

In detailing the scope and findings of our report, it is important to acknowledge limitations encountered within our methodology, data collection, and scholarship and policy review. In Phase II of our methods, we attempted to conduct an equal number of interviews across each energy category. However, a more significant proportion of independent third-party providers were interviewed, totaling approximately seven interviews compared to the average of three. Our access and connections to industry experts influenced this. Because of this, our Phase II findings are potentially more reflective of the opinions of independent third-party providers. Our qualitative coding process attempted to alleviate any biases in sample size and interpretation within our findings, however, some biases may remain.

We developed and disseminated a quantitative survey to all interview participants to quantify the information collected in our qualitative interviews. The quantitative surveys are shown in Appendix G. We designed three different surveys for each stakeholder category an interviewee fell into, such as utilities with RDR, utilities without RDR, and independent third-party providers. This portion of our research aimed to develop quantitative data points that reflected industry opinions on RDR. However, due to a low respondent rate and lack of statistical significance, we discarded the responses to the surveys from this project.

Additionally, given the novelty of the research surrounding RDR, there was difficulty in obtaining updated and recent literature on this topic. This is particularly true as it applies to our findings that analyze the policy enablers that can expand and scale RDR programs. Consequently, our policy and scholarship review closely followed the structure of a singular paper by Shen et al. (2014). However, the content of our policy and scholarship review is comprehensive. Moreover, emerging concepts within the DR field are still in the process of being fully documented, such as four coincident peak (4CP) and virtual power plants (VPPs).

Lastly, further analysis is needed to understand how policy enables the rapid expansion of RDR. This includes factoring in the various regulatory and market structures in the energy industry across the U.S. Currently, much of the DR literature focuses on commercial and industrial sectors but lacks attention to residential consumers.

CONCLUSION

This report explored the policies, market structures, and conditions that enable energy providers to create and implement RDR programs in Texas. Residential demand response (RDR) is a novel and growing demand management strategy employed by utilities in Texas and throughout the U.S. Given RDR’s administrative and technical challenges, it presents more significant difficulties to study and implement compared to its application in the commercial and industrial sectors. Because of this, DR providers have encountered challenges in scaling and implementing DR programs for residential consumers.

We recognize that combatting such multifaceted challenges like grid stability and the climate crisis will require a comprehensive strategy. RDR is one such tool in a broader matrix of energy solutions. Our research emphasizes RDR's effectiveness in alleviating grid stress at a reasonable cost while complementing efforts to reduce carbon emissions. In support of these findings, our seven recommendations highlight the funding gaps, policy solutions, and future research necessary to offer and scale RDR programs in Texas. As the state progresses toward a more reliable and decarbonized electric grid, other states and regions can learn from Texas's unique regulatory and policy structures and strategies to advance RDR.

APPENDIX

Appendix A: Time of Use Rate Example[198]

Base Power Cost Rates			
Season	**Rate Schedule**	**Hours**	**Rate ($/kWh)**
Non-Summer (Jan - May & Oct - Dec)	Super Economy	2:01 am - 4:00 am	$0.040910
	Economy	11:01 pm - 2:00 am 4:01 am - 5:00 am	$0.050270
	Normal	8:01 am - 4:00 pm 7:01 pm - 11:00 pm	$0.055120
	Peak	5:01 am - 8:00 am 4:01 pm - 7:00 pm	$0.061710
Summer (June - Sept)	Super Economy	3:01 am - 5:00 am	$0.039440
	Economy	11:01 pm - 3:00 am 5:01 am - 7:00 am	$0.041440
	Normal	7:01 am - 12:00 pm 8:01 pm - 11:00 pm	$0.045910
	Peak	12:01 pm - 2:00 pm 6:01 pm - 8:00 pm	$0.059100
	Super Peak	2:01 pm - 6:00 pm	$0.119310

Appendix B: Critical Peak Pricing Example[199]

Season	Rate Schedule	Hours	Days	Rate ($/kWh)
Summer (June - Sept)	Off-Peak	12:00 am - 12:00 pm	Mon - Fri All day on weekends & holidays	$0.1150
	Mid-Peak	12:00 pm - 5:00 pm 8:00 pm - 12:00 am	Mon - Fri	$0.1664
	Peak	5:00 pm - 8:00 pm	Mon - Fri	$0.3279

	CPP Peak	Event based	NA	+$0.5000

Appendix C: Real-Time Pricing[200]

Real-Time Hourly Prices for August 15, 2023	
Price for the Hour Ending	**Hourly Price (¢/kWh)**
12:00 am	2.2¢
1:00 am	1.9¢
2:00 am	2.0¢
3:00 am	1.5¢
4:00 am	1.6¢
5:00 am	1.9¢
6:00 am	2.0¢
7:00 am	1.5¢
8:00 am	2.5¢
9:00 am	2.9¢
10:00 am	2.4¢
11:00 am	2.7¢
12:00 pm	3.6¢
1:00 pm	5.7¢
2:00 pm	3.0¢
3:00 pm	4.2¢
4:00 pm	4.5¢
5:00 pm	3.0¢
6:00 pm	2.9¢
7:00 pm	3.2¢
8:00 pm	3.5¢

9:00 pm	3.4¢
10:00 pm	2.9¢
11:00 pm	2.0¢

Appendix D: Phase I Interview Questions

1. Can you describe the most important parameters/contextual conditions (i.e. legal, policy, regulatory, etc.) that affect how utilities conduct demand side management?
    a. Of these, which do you believe would be particularly worthwhile for us to focus on in regards to RDR?
2. In order to scope this project, would you recommend that we focus on policies in certain states, adoption of certain (R)DR programs, or practices at specific utilities?
3. We get the sense that RDR is not widely adopted yet. Are there any policies/conditions that support / incentivize / encourage utilities to offer RDR programs?
    a. Are there any policies / conditions that discourage RDR programs?
4. What would you suggest are the most important questions to ask utilities / oversight entities / employees when researching 'enabling factors' of RDR?
5. What are some non-technical gaps you see in the RDR research space?
6. Are there any RDR policy scholars/ experts and also are there any data sources you have?

Appendix E: Phase II Interview Questions

Energy Providers with RDR:

1. How does your organization define demand response?
2. What prompted your organization to begin implementing RDR?
    a. Are there any policies (federal, state, local), regulations, initiatives, etc. that encouraged this?
3. What RDR programs do you (or any third-party providers) offer and why? How often do you call on these programs?
4. Do you administer RDR with your customers directly or do you use a third party provider?
    a. What factors influenced that decision?
5. What technology services or platforms do you leverage to provide these programs?
6. Are there emerging innovations or technologies that give increased confidence in RDR adoption?
7. How do you measure RDR success? And, how have your customers responded to these programs?
8. What have been the most challenging aspects of implementing and scaling RDR?
9. What policies, state of Texas and/or federal, would help your organization grow your RDR program(s)?
10. In your experience, do you find it is easier or harder to implement commercial/industrial DR vs. RDR programs? Why?

11. To what extent is single-family vs. multi-family considered in your RDR programs?
12. Is there anything else about RDR that you would like to share with us?

Energy Providers without RDR:

1. How does your organization differentiate between energy efficiency and demand response?
2. How does your organization define demand response?
3. Based on our research, it does not seem that your organization currently offers residential DR programs. Is this accurate?
    a. During times of high/peak energy demand, what strategies does your utility use to balance supply and demand?
4. Are there any factors that have kept your organization from implementing residential DR programs? If so, what are they?
5. Has your organization had conversations about implementing residential DR? Are there plans or goals to administer residential DR programs in the future?
    a. Have you had any residential DR programs in the past?
6. If your organization is interested in residential DR, what information, assistance, or guidance would you want or need to implement such programs?
7. Are there any policies, state of Texas and/or federal, that would enable or incentivize your organization (or others) to adopt residential DR programs?
8. Are there emerging innovations or technologies that give you increased confidence in residential DR adoption?
9. Does your organization offer any commercial/industrial DR programs? If so, what prompted you to implement them?
10. Does your organization have residential energy efficiency programs? If so, what are they and what are the goals they aim to achieve?
11. Is there anything else about residential DR that you would like to share with us?

Independent Third Parties/REPs:

1. How does your organization define demand response?
2. Who are your customers (utilities, businesses, residents)? Do you have a regional concentration?
3. What RDR programs do you provide?
4. What is your most effective RDR program?
    a. What is your most popular RDR program? Why do you think this is?
5. What technology services or platforms do you leverage to provide these programs?
6. What role, if any, do you see automation and VPPs playing in your RDR solution offerings?
    a. What are their biggest risks/rewards?
7. What other innovations or technology give you hope or increased confidence in RDR adoption?
8. What policies, state of Texas and/or federal, would help you expand your RDR programs/customer base?

9. In your experience, what factors do you think most strongly persuade(d) or dissuade a utility/consumer from adopting RDR programs such as the ones your company offers?
10. In your experience, do you find it is easier or harder to implement commercial DR vs. RDR programs? Why?
11. Is there anything else about RDR that you would like to share with us?
12. To what extent is single-family vs. multi-family considered in your RDR programs?

Oversight Entities (IOUs):

1. How do you/your organization define demand response?
2. Could you explain how your organization conducts oversight regarding residential DR?
3. Why is RDR important to you as a regulator?
4. In your experience, what factors do you think most strongly persuade(d) or dissuade a utility from adopting RDR programs? For those that have RDR, (1) what do you see as having been the most difficult aspects of implementing and scaling RDR and (2) what initially prompted them to begin offering RDR?
5. Are there any policies, state of Texas and/or federal, that would enable/incentivize RDR program adoption?
    a. Are there any policies inhibiting DR efforts?
6. What innovations or technology give you hope or increased confidence in RDR adoption?
7. In your experience, do you find it is easier or harder to implement commercial DR vs. RDR? Why?
8. Is there anything else about RDR that you would like to share with us?

Oversight Entities (Municipalities):

1. How do you/your organization define demand response?
2. Could you explain how your committee (or council) conducts oversight regarding residential DR?
3. Who initiated RDR implementation efforts? The utility you oversee? Your council/committee?
    a. If you, what prompted you to do so?
    b. If you, what were the most important considerations and guiding principles used to begin that process?
    c. If the utility, what prompted them to do so?
4. What have been the most challenging aspects of overseeing RDR efforts / programs?
5. How does your council/committee measure RDR success?
    a. How have your constituents responded to these programs?
    b. What do you view as the largest inhibitor to increased enrollment?
6. What innovations or technology give you hope or increased confidence in RDR adoption?
7. Are there any policies, state of Texas and/or federal, that would enable/incentivize RDR program adoption?
8. In your experience, do you find it is easier or harder to oversee commercial DR vs. RDR? If so, why?

9. To what extent is single-family vs. multi-family considered in your RDR programs?
10. To what extent is equity considered in RDR programs?
11. Is there anything else about RDR that you would like to share with us?

Appendix F: PUCT Demand Reduction Goal Tiers for TDUs

A. Beginning with the 2013 program year, until the trigger described in subparagraph (B) of this paragraph is reached, the utility shall acquire a 30% reduction of its annual *growth* in demand of residential and commercial customers (i.e., if demand is growing by 1.5% per year, the target is to operate programs that reduce demand by 0.45%).
B. If the demand reduction goal to be acquired by a utility under subparagraph (A) of this paragraph is equivalent to at least four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year, the utility shall meet the energy efficiency goal described in subparagraph (C) of this paragraph for each subsequent program year.
C. Once the trigger described in subparagraph (B) of this paragraph is reached, the utility shall acquire four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year.[201]

Appendix G: Quantitative Survey

Survey 1: Energy Providers with RDR

1. Is your utility municipally-owned, investor-owned, or an electric cooperative?
    a. Municipally-Owned
    b. Investor-Owned
    c. Electric Cooperative
    d. Other
2. Does your utility operate in a deregulated or regulated energy market?
    a. Deregulated (i.e. customers have utility choice)
    b. Regulated (i.e. customers do not have utility choice)
3. Which of the following best describe(s) your utility? Select all that apply.
    a. Generation Utility
    b. Transmission and Distribution Utility
    c. Retail Electricity Provider
    d. Other
4. Approximately how many customers does your utility service?
    a. Residential Service Size Total (Number)
    b. Commercial Service Size Total (Number)
5. Which department houses your residential DR programs?
    a. Open response
6. In what year did you begin offering residential DR programs/services?
    a. Open response

7. Approximately how many of your residential customers are currently enrolled in demand response programs?
    a. Open response
8. Approximately what percentage of your residential customers are currently enrolled in demand response programs?
    a. Open response
9. Is attrition a problem in your residential demand response program?
    a. Yes
    b. No
    c. Not sure
10. What is your approximate opt-out rate?
    a. Open response
11. Which of the following factors influenced your organization's decision to offer RDR programs? Select all that apply.
    a. Monetary Saving
    b. Grid Stability
    c. Innovation
    d. Customer Interest
    e. Climate Commitments
    f. Administrative Compliance
    g. Other
12. How difficult was it to implement a residential DR program?
    a. Extremely difficult
    b. Somewhat difficult
    c. Neither easy nor difficult
    d. Somewhat easy
    e. Extremely easy
13. Have any of the following challenges inhibited your organization's ability to expand RDR program(s)? Select all that apply.
    a. Cost
    b. Administrative Inconvenience
    c. Lack of Residential DR Awareness
    d. Technology Barriers
    e. Policy/Regulatory Challenges
    f. Data Challenges
    g. Other
14. Which of the following options most closely aligns with how your utility measures RDR program success?
    a. Customer Enrollment
    b. Cost Savings
    c. Net Energy Reduction
    d. Customer Retention

    e. Other
15. What is the estimated cumulative demand reduction achieved during peak hours through your residential DR programs? Please provide an annual estimated range in MW.
    a. Open response

Survey 2: Energy Providers without RDR

1. Is your utility municipally-owned, investor-owned, or an electric cooperative?
    a. Municipally-owned utility
    b. Investor-owned utility
    c. Electric cooperative
    d. Other
2. Does your utility operate in a deregulated or regulated energy market?
    a. Deregulated (i.e. customers have utility choice)
    b. Regulated (i.e. customers do not have utility choice)
3. Which of the following best describe(s) your utility? Select all that apply.
    a. Generation Utility
    b. Transmission and Distribution Utility
    c. Retail Electricity Provider
    d. Other
4. Approximately how many customers does your utility service?
    a. Residential Service Size
    b. Commercial Service Size
5. Does your organization hope or plan to implement any residential DR programs in the future?
    a. Yes
    b. Maybe
    c. No
6. Which of the following factors currently inhibit your organization from offering residential DR programs? Select all that apply.
    a. Cost
    b. Administrative inconvenience
    c. Lack of residential DR awareness
    d. Technology barriers
    e. Policy/Regulatory challenges
    f. Concerns over customer participation
    g. Other
7. In terms of technological infrastructure, how prepared is your utility to support residential DR programs?
    a. Highly Prepared
    b. Moderately Prepared
    c. Neither Prepared or Unprepared
    d. Somewhat Unprepared
    e. Not Prepared

8. If your utility were to offer an RDR program, what would be your main motivation for offering such a program?
    a. Monetary Savings
    b. Grid Stability/Reliability
    c. Innovation
    d. Customer Interest
    e. Climate Commitments
    f. Other

Survey 3: Independent third-party providers

1. Who are your primary customers?
    a. Utilities
    b. Residents
    c. Commercial
    d. Other
2. What percent of your residential DR program customers are in regulated vs deregulated markets?
    a. Deregulated
    b. Regulated
    c. Other / Not Sure
3. In what year did you begin offering **residential** DR programs/services?
    a. Open response
4. Is attrition a problem in your residential demand response program?
    a. Yes
    b. No
    c. Not sure
5. What is your approximate opt-out rate?
    a. Open response
6. Which of the following concerns do **your utility customers** have regarding residential DR?
    a. Financially Challenging (1)
    b. Uncommon / Too Novel (2)
    c. Technical Limitations (3)
    d. Scalability Challenges (4)
    e. Regulatory/ Policy Complications (5)
    f. Lack of Trust (6)
    g. Politics (7)
    h. Other (8)
7. Which of the following concerns do **your residential customers** have regarding residential DR?
    a. Cost (1)
    b. Lack of knowledge (2)
    c. Lack of trust (3)

    d. Politics (4)
    e. Lack of technology (5)
    f. Other (6)
8. Which of the following concerns do **your commercial customers** have regarding residential DR?
    a. Cost (1)
    b. Lack of knowledge (2)
    c. Lack of trust (3)
    d. Politics (4)
    e. Lack of technology (5)
    f. Other (6)
9. Have any of the following challenges inhibited your organization's ability to expand RDR program(s)? Select all that apply.
    a. Cost (1)
    b. Administrative Inconvenience (2)
    c. Lack of Residential DR Awareness (3)
    d. Technology Barriers (4)
    e. Regulatory Challenges (5)
    f. Politics (6)
    g. Other (7)
10. Which of the following options most closely aligns with how your organization measures RDR program success?
    a. Customer Enrollment (1)
    b. Cost Savings (2)
    c. Net Energy Reduction (3)
    d. Customer Retention (4)
    e. Other (5)
11. What is the estimated cumulative demand reduction achieved during peak hours through your residential DR programs? Please provide an annual estimated range in MW.
    a. Open response
12. How optimistic are you about the future growth and sustainability of the residential DR market?
    a. Not optimistic (1)
    b. Somewhat not optimistic (2)
    c. Neither agree nor disagree (3)
    d. Somewhat optimistic (4)
    e. Strongly optimistic (5)
13. After indicating your level of optimism, please provide additional details or insights on why you feel this way about the future growth and sustainability of the residential DR market.
    a. Open response

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