TEXAS ADVANCED ENERGY BUSINESS ALLIANCE

THE VALUE OF INTEGRATING DISTRIBUTED ENERGY RESOURCES IN TEXAS

Prepared by Demand Side Analytics

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TEXAS ADVANCED ENERGY BUSINESS ALLIANCE

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TEXAS ADVANCED ENERGY BUSINESS ALLIANCE

EXECUTIVE SUMMARY

Few industries have as deep a connection to the U.S. economy, policy, and innovation as the energy industry. Today, new technologies and business models are fundamentally changing the way we produce, manage, and use energy. These technologies are "advanced energy," and they are leading us toward a prosperous future powered by secure, clean, and affordable energy.

Advanced energy encompasses a broad range of technologies, products, and services that constitute the best available technologies for meeting energy needs today and tomorrow. In recent years, distributed energy resource (DER) technologies have emerged as an additional means of producing power, managing electricity demand, and providing valuable grid services. These resources are smaller, flexible, located within load centers, typically connect to the distribution grid and are capable of decreasing net electricity demand either by injecting power locally or by reducing demand. This report, prepared by Demand Side Analytics, quantifies the value of integrating DERs into transmission and distribution planning and better incorporating them into existing wholesale markets.

Currently, DERs are not considered for their potential contributions to the grid in open, transparent transmission and distribution (T&D) planning processes and generally are not allowed to participate as supply resources in ERCOT markets. Planning processes and market rules have been designed for large generators and industrial customers, and thus present barriers to DER participation. By functionally excluding DERs from consideration, Texas is forgoing opportunities to lower consumer costs that arise from allowing DERs to compete side-by-side with traditional generators and T&D solutions.

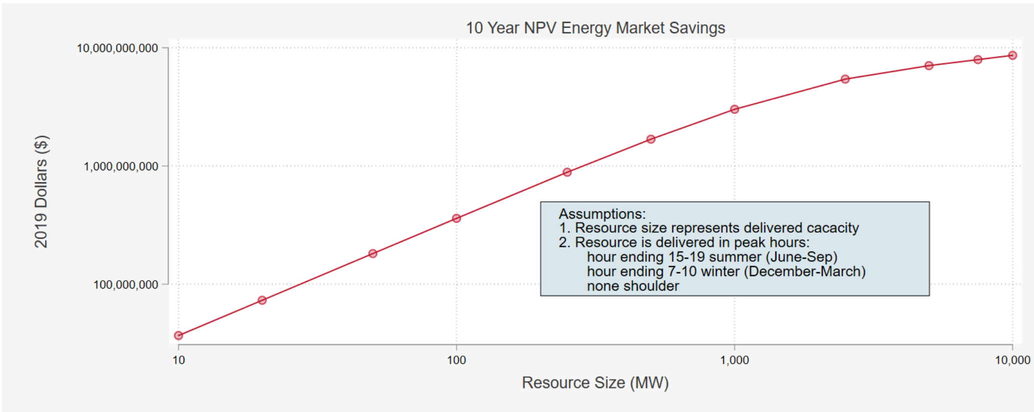
Texas utilities spent $40.6 billion on T&D infrastructure capital investment in the past 10 years. While some of these expenditures are unavoidable, T&D infrastructure expansion due to peak load growth can be reduced, deferred, or avoided by DERs that either inject power locally or reduce demand.

We estimate the value of T&D deferral in Texas by incorporating DERs at $344 million per year or $2.45 billion over 10 years ($2019 Present Value). On an annual basis, this represents 8.5% of total T&D infrastructure costs.

DER resources also can provide Texas valuable services by enhancing wholesale market competition and mitigating price spikes in ERCOT. Technology providers are capable of aggregating fleets of DERs into scalable grid resources. A large share of electricity costs is due to price spikes that occur in a limited number of hours. For example, in 2019, real-time prices exceeded $9,000 per MWh during a system peak, whereas the ERCOT-wide load-weighted average prices were only $35.63 per MWh across the year. The high price signals are designed to encourage the construction of new resources and motivate existing resources to produce power. Nearly all price spikes occur in the afternoon when net system loads (gross loads minus intermittent renewables) are high and in spring months when generators engage in maintenance.

To quantify the effect of adding resources on electricity costs, the relationship between wholesale market prices and net loads in ERCOT was modeled for 2014-2018. Next, different amounts of technology-agnostic resources were introduced to assess the impact on wholesale market prices.

Figure E-1: Wholesale Energy Market Savings by Resource Size (10 Year NPV)



Size (MW)	Value ($)
10	36,800,000
20	73,100,000
50	182,000,000
100	361,000,000
250	886,000,000
500	1,690,000,000
1,000	3,020,000,000
2,500	5,430,000,000
5,000	7,060,000,000
7,500	7,940,000,000
10,000	8,630,000,000

Adding 1,000 MW of DER resources into the supply stack (less than 1.2% of peak load) can decrease electricity costs for Texas consumers by $3.02 billion over 10 years if those resources can deliver reductions when prices spike. (Figure E-1)

The main conclusion of the study is that Texas consumers would benefit substantially by better integrating DER resources into T&D planning and wholesale energy markets. The total value of better integration is $5.47 billion over a 10-year period ($2019 Present Value), or $456 per household.

In the past 20 years, the grid and the technologies for generating and managing energy have evolved substantially. A larger share of generation is variable and, as a result, operators increasingly have less control over supply resources. By contrast, the ability to manage flexible loads and behind-the-meter DERs is expanding rapidly. Texas has a substantial amount of existing DERs and the penetration of connected devices, battery storage, distributed solar, energy efficiency, and other advanced technologies are expected to grow. However, absent changes to make the T&D planning process more transparent and competitive and to allow third-party participation in wholesale energy markets, the benefits of incremental DER resources will be untapped.

Better integration of DERs will require:

- Transparent, competitive T&D planning processes where DERs can compete based on their ability to meet grid needs.
- Modifying wholesale market rules to allow third-party DER providers to directly participate in ERCOT wholesale markets.

The status quo leaves considerable resources and efficiencies untapped, limiting competition, and leading to higher costs for Texas consumers. Ultimately, competition and markets will determine the magnitude, location, and mix of DERs. The fundamental question is whether Texas will take action to foster markets and competitive processes and allow DERs to fully compete.

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1 INTRODUCTION

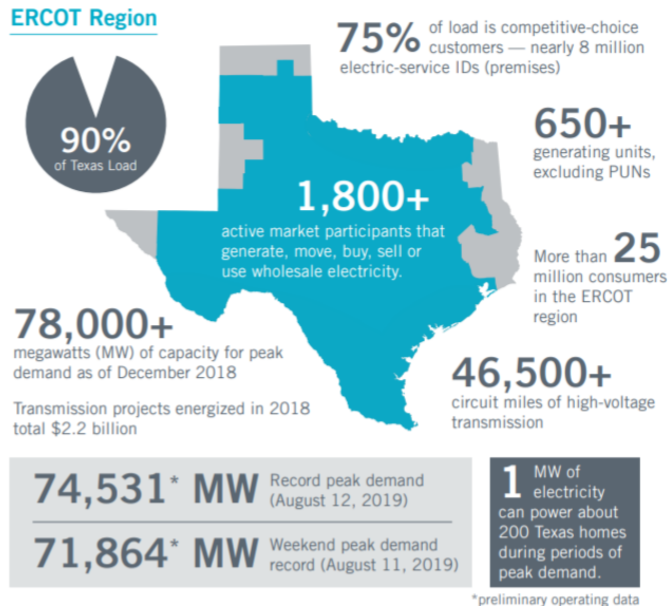
With a population approaching 29 million, Texas has approximately 12 million electric customers, a peak electricity demand over 74,000 MW, and spends $32 billion per year on electricity production and delivery. It has over 46,500 miles of transmission lines and over 15,000 feeder circuits. Over the 10-year period from 2009 to 2018, Texas spent approximately $40 billion in transmission and distribution investment. Figure 1 summarizes facts from the Electric Reliability Council of Texas (ERCOT), the nonprofit entity that oversees the state's competitive wholesale electricity market.[1]

In Texas currently, power is produced mainly by large generators and delivered over high voltage transmission lines and then via low voltage distribution networks. A total of five investor-owned utilities and over 140 municipal utilities and electric cooperatives are responsible for the transportation of power from where it is produced to where it is used. The electricity system has traditionally followed a one-way flow, from large scale, centralized power generation through the electric grid to the end-user.

ERCOT plays a crucial role in planning, operations, administering competitive markets and ensuring reliability. It manages the flow of electricity to customers representing about 90 percent of the state's electric load, coordinates a competitive market, and dispatches generation on an electric grid that connects more than 46,500 miles of transmission lines and 600+ generation units.

One of ERCOT's core functions is to balance supply and demand at all times. Historically, due to the cost of storing electricity, reliability has been ensured by sizing infrastructure so enough electricity can be produced and delivered when demand use is forecasted to be at its highest—peak demand. The amount of generation and transmission capacity is typically tied to ERCOT system peaks, while distribution capacity is based on location-specific peak demand connected to the relevant substation, feeder circuit, line segment, or transformer.

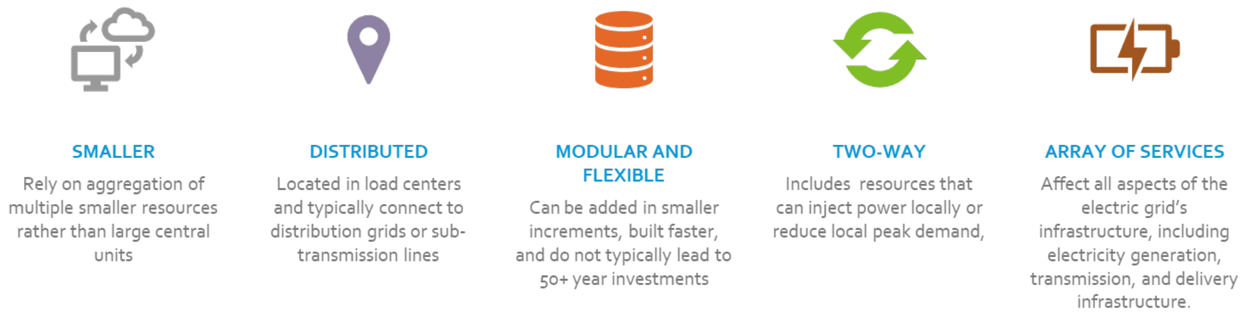
Figure 1: ERCOT Quick Facts



http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_8.20.19.pdf

This general approach has served us well for many years. However, planning and operation of the electric grid are evolving due to rapid technological change. In recent years, distributed energy resources (DERs) have emerged as an additional means of producing power, managing electric demand, and delivering grid services. These resources are smaller, flexible, located within or near load centers, typically connect to the distribution grid and are capable of decreasing net demand (as seen by the bulk power sysem) either by injecting power locally or by reducing demand. DERs include a broad range of technologies – including distributed solar, battery storage, thermal storage, customer-owned generation, connected devices such as smart thermostats, electric vehicles, demand response, and energy efficiency.

Figure 2: Characteristics of Distributed Energy Resources



DERs have the potential to influence all aspects of electricity grid infrastructure, including electricity generation, transmission, and local delivery. They are capable of providing a broader array of grid and energy services than bulk power generation and transmission equipment or distribution network equipment. The ability to impact both the bulk power system and the local distribution system stands in contrast to investments such as large-scale generators, transmission lines, and distribution transformers.

Each DER technology has a unique set of characteristics and operating constraints, but because of their modularity, DER portfolios can be tailored to meet a range of energy and infrastructure needs. They can be customized to deliver the exact amount of energy and/or capacity needed at a given location and can serve multiple needs.

In many cases, DER portfolios can offer more cost-effective solutions than expanding traditional infrastructure. By injecting power into the distribution grid or reducing demand, DERs can reduce, defer, and sometimes avoid the need for T&D investments. DERs can also increase available capacity when the net system load and prices are high and produce power, provide grid balancing, or operating reserves to help the Texas electric grid function.

DERs are not explicitly considered for their potential contributions to the grid in open, transparent transmission and distribution (T&D) planning processes and generally are not allowed to participate as supply resources in ERCOT markets. Planning processes and market rules have been designed for large generators and industrial customers, and thus present barriers to DER participation. This leaves considerable resources and efficiencies untapped. By functionally excluding DERs from consideration, Texas is forgoing potential opportunities to lower consumer costs that arise from allowing DERs to compete side-by-side with traditional generators and T&D solutions. The current state of DER integration raises two essential questions:

- How much money is left on the table by the failure to include DERs in T&D planning?
- How much money would consumers save by ensuring DERs are able to compete in ERCOT wholesale energy markets in full?

The magnitude, location, operating characteristics, and mix of DERs should ultimately be determined by competition and markets. The fundamental question is whether Texas will take action to foster markets and competitive process and allow DERs to compete in full.

The remainder of this report addresses each of these questions. In Section 2, we discuss and quantify the potential benefits of integrating DERs into T&D planning. In Section 3, we quantify the potential consumer savings from allowing DERs to compete in energy markets.

2 BENEFITS OF INTEGRATING DISTRIBUTED ENERGY RESOURCES INTO T&D PLANNING

DER portfolios are currently being used in multiple jurisdictions to reduce, defer, and avoid T&D infrastructure expansion driven by growth in local peak demands.[2, 3] This application of DERs to target periods when the system is at or near peak conditions is often referred to as non-wire solutions (NWS), and the T&D deferral value is often simply called the locational value of DERs.

Multiple factors drive the locational value of DERs, including the magnitude of growth-related T&D investments, peak load growth rates, the amount of existing T&D capacity available to accommodate additional growth, and the expected deferral period.

In this section, we focus on five key questions:

1. How do DERs reduce T&D expansion costs?
2. How much does Texas spend on T&D infrastructure?
3. What share of T&D costs are growth related and avoidable?
4. How long can DERs defer T&D infrastructure investments?
5. What is the value of T&D deferral in Texas?
6. How sensitive are the results to input assumptions?

By design, the answers to the initial four questions inform the assumptions used to quantify the value of integrating DERs into T&D planning in Texas.

2.1 HOW DO DERS REDUCE T&D EXPANSION COSTS?

T&D infrastructure investments occur for several reasons, including replacement of aging or failing equipment, the need to improve reliability, the connection of new buildings to the electric grid, grid modernization, and connecting new generation. Many of these investments cannot be avoided and must take place. However, as a general rule, infrastructure expansion due to peak load growth can be reduced, deferred, or avoided by reducing local peak demand through either injecting power locally or reducing demand using DERs.

As loads grow, the distribution capacity cushion that ensures reliability dwindles. If a customer helps reduce coincident peak demand (i.e., when the local distribution system peak occurs), either by injecting power into the distribution grid or by reducing demand, the unused distribution system capacity can then accommodate load growth elsewhere in the local system.

Transmission expenditures are often driven by growth in overall system peak demand and corresponding congestion. On a more local scale, growth-related sub-transmission and distribution expenditures are driven by specific load pockets with expanding population or economic activity, rather than evenly across a service territory.

When the use of existing T&D infrastructure is prolonged by managing peak demand, Texas consumers save money. Effectively, the utilization of existing capital-intensive assets is improved while investments in new assets are deferred or avoided.

T&D capital projects are identified during utility planning processes, but these processes are not open and transparent, and the selected T&D solutions typically do not compete against alternatives. There are no price signals to drive competition. Often, the decision to build distribution infrastructure is not subject to regulatory approval directly as regulators make approvals in rate cases, but don't oversee individual projects. Once investments are made, the T&D capital costs are generally amortized over the life of the capital equipment, converted into revenue requirements, and collected through rates.[4] In some jurisdictions, the maintenance costs are included in the amortization. Because T&D infrastructure tends to have a long useful life, typically exceeding 50 years, the infrastructure costs are often amortized and collected through customer rates for multiple decades.

Deferral or avoidance of T&D capital expenditures thus translates directly into reduced rate pressure for consumers. It also allows utilities to assess better if peak load growth at a given location is a temporary phenomenon or a long-run trend before making irreversible, multi-decade investments.

2.2 HOW MUCH DOES TEXAS SPEND ON T&D INFRASTRUCTURE?

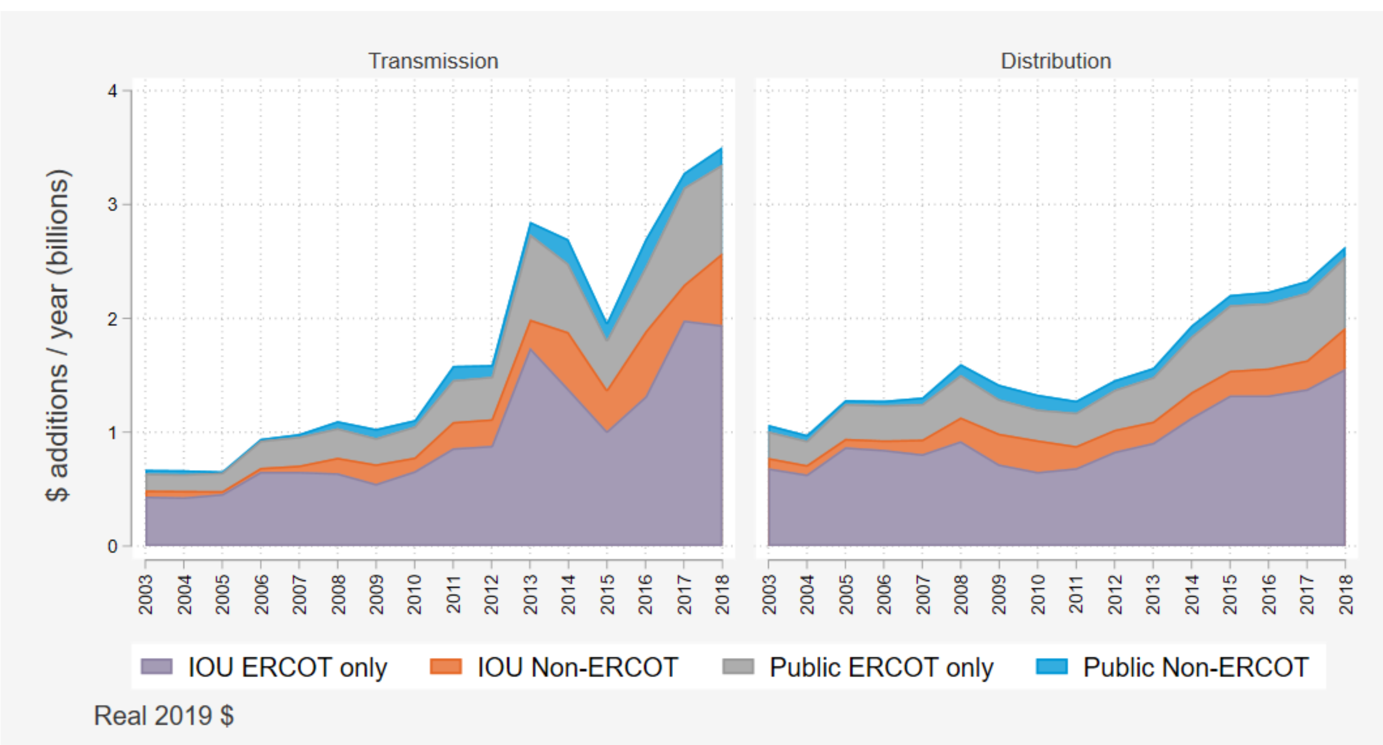
The magnitude of T&D expenditures varies by state and utility and is driven by a mix of population growth, economic growth, and technology adoption. In assessing T&D expenses, it is crucial to distinguish between historical and potential future costs. By definition, costs for historical investments are sunk and have already been approved and incorporated into electric rates. These investments cannot be avoided or deferred. In contrast, future investments can be reduced, deferred, or avoided. Nevertheless, past expenditure trends can help inform estimates for future investments.

There is a large amount of publicly available data describing historical T&D investments[5]. Figure 3 summarizes annual T&D spend by Texas utilities over the past 16 years. Appendix B includes detailed tables of historical expenditures with and without inflation adjustments.

Historical cumulative spend on T&D capital expenditures has been $25.5 billion ($2019) over the past five years and $40.6 billion ($2019) over the past 10 years. Investments have been trending upwards over time with only a small slowdown in distribution spending during the post-financial crisis recession. Though both transmission and distribution investments have been growing, transmission spending has been uneven, with substantial investments beginning in 2013 to connect low-cost wind generation resources to population centers.

Traditional factors such as economic and population growth, as well further electrification (electric vehicles, smart devices) in Texas drives both peak demand

Figure 3: Annual T&D Investment Additions Made by Texas Utilities, 2003-2018



growth and transmission and distribution expenditures. Between 2003 and 2018, the Texas economy grew by 60%[6], the state's population grew by over 30%[7], and electricity sales grew by about 35%. Both transmission and distribution capital expenditures grew faster than the population and electricity sales.

2.3 WHAT SHARE OF T&D COSTS ARE GROWTH-RELATED AND AVOIDABLE?

As noted earlier, not all T&D investments are tied to load growth or otherwise avoidable. Key examples include system maintenance, replacement of aging or failed infrastructure, and grid modernization investments (e.g., sensors, smart meters, data recording and transmittal, automated load transfer switches). Moreover, not all investments due to load growth are avoidable. For example, new home construction often requires connecting customers, adding distribution line segments, adding transformers, and connecting sites. Even if an existing substation can service the added load, some T&D investments are required.

While many utilities report on overall expenditures, few utilities separately report costs driven primarily by peak demand growth. This data limitation creates a challenge for identifying the portion of investments which are growth-related and avoidable. Table 1 summarizes the public information available for multiple jurisdictions[8]. Notably, the sources are varied, each with a different investment description. They do, however, indicate that growth-related investments tend to range from about 10% to 30%.

For context, Table 2 shows population and economic growth rates for Texas and the states where we identified public information about growth-related investments. Across these utilities and states, over the past five years, Texas generally has higher GDP growth, higher population growth, or both, compared to the other states. Thus, the share of growth-related investments in Texas is likely to fall in the upper end of the range.

Table 2: GDP and Population Growth for Selected Benchmark States (2014-2018)

State	GDP (current $)	Population growth
Texas	13%	6%
California	24%	2%
New York	17%	-1%
Georgia	21%	4%
New Mexico	8%	0%
Washington	19%	7%

Table 1: Estimates of Growth-Related Investment Percentages for Selected Jurisdictions

Utility	% Growth related	Source
Con Edison (NY)	7%	2016 DSIP Appendix F: "Expansion"
Con Edison (NY)	26%	2016 DSIP Appendix F: "Expansion + New business"
National Grid (NY)	9%	5 year capital forecast, Distribution System Capital Expenditure by Spending Rationale: "System Capacity"
SCE (CA)	32%	2018 GRC - System Planning Summary "System Improvement"
PNM (NM)	20%	2018-2022 Capital Plan, "Transmission Expansion" as portion of "Trans Expansion + Core T&D"
Southern Company (GA)	24%	earnings call citation. "Growth" expenditures for 2017-2021
Washington State (various)	26%	State of Washington 2017 Distributed Energy Resources Report Appendix

2.4 HOW LONG CAN DERS DEFER T&D INFRASTRUCTURE INVESTMENTS?

The ability to defer T&D investments – and, thus, avoid new costs – is tied to the rate of peak demand growth and the magnitude of DER resources that can be added to a location. More resources enable utilities to avoid growth-driven infrastructure for more extended periods. However, when peak demand is growing at a rapid pace, it is difficult to avoid or defer infrastructure upgrades by managing peak demand. When the pace of growth is moderate or low, it is possible to defer infrastructure upgrades for longer periods and, in some cases, avoid them altogether.

Table 3 shows the relationship between deferral period length (in years), percent load growth (rows), and the magnitude of flexible resources introduced (columns) as a percentage of the T&D equipment operating limit.[10] For example, if peak loads are growing at a 2% annual rate and enough DERs are introduced to shave peak demand by 20%, it is possible to defer infrastructure expansion for 9.2 years, after taking into account compound growth. By contrast, if growth is higher, say 10%, the same amount of resources can delay the upgrade for only 1.9 years. Lastly, the timing of the deferral, but not the duration, is influenced by the capacity available to accommodate additional growth.

Table 3: Deferral Duration as a Function of Annual Peak Growth and DER Magnitude[9]

Annual Growth Rate	Resource Magnitude (% of operating limit)				
	5%	10%	15%	20%	25%
0.0%	N/A	N/A	N/A	N/A	N/A
0.5%	9.78	19.11	28.02	36.56	44.74
1.0%	4.90	9.58	14.05	18.32	22.43
1.5%	3.28	6.40	9.39	12.25	14.99
2.0%	2.46	4.81	7.06	9.21	11.27
2.5%	1.98	3.86	5.66	7.38	9.04
3.0%	1.65	3.22	4.73	6.17	7.55
3.5%	1.42	2.77	4.06	5.30	6.49
4.0%	1.24	2.43	3.56	4.65	5.69
4.5%	1.11	2.17	3.18	4.14	5.07
5.0%	1.00	1.95	2.86	3.74	4.57
5.5%	0.91	1.78	2.61	3.41	4.17
6.0%	0.84	1.64	2.40	3.13	3.83
6.5%	0.77	1.51	2.22	2.90	3.54
7.0%	0.72	1.41	2.07	2.69	3.30
7.5%	0.67	1.32	1.93	2.52	3.09
8.0%	0.63	1.24	1.82	2.37	2.90
8.5%	0.60	1.17	1.71	2.23	2.74
9.0%	0.57	1.11	1.62	2.12	2.59
9.5%	0.54	1.05	1.54	2.01	2.46
10.0%	0.51	1.00	1.47	1.91	2.34

As a general rule, we assumed that the expected deferral must exceed two years for a non-wires solution to be viable. However, it is not possible to indefinitely prolong the life of existing, functional devices – eventually, equipment ages and decays.

Because growth rates are tied closely to grid expansion and locational value, it is critical to understand how

Figure 4: Texas Indexed 2010-2017 Population Growth for Metro and Micro Areas

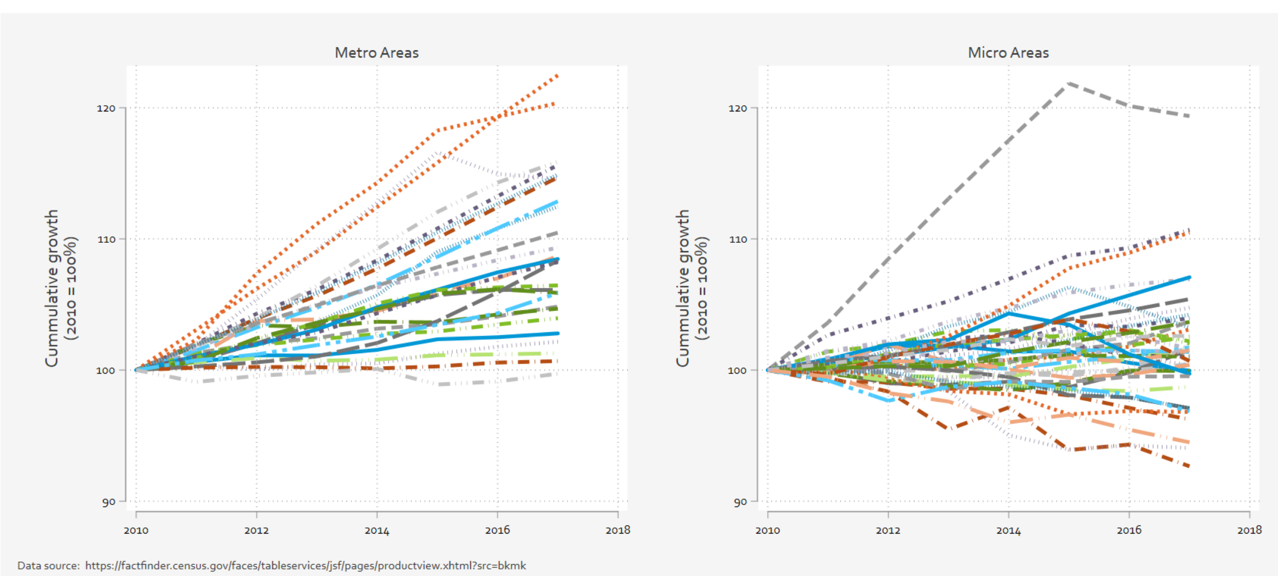
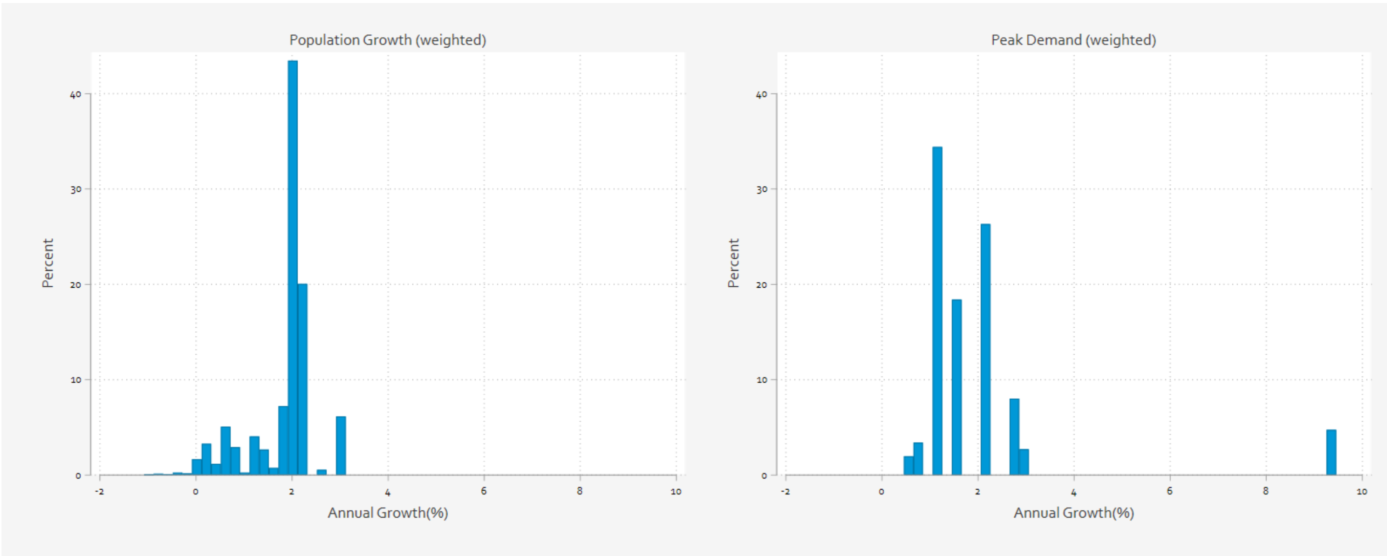


Figure 5: Distribution of Population and Peak Demand Growth in Texas



growth rates vary across Texas. Most utility service territories have pockets where population and peak demand are fast-growing and areas where growth is stagnant or even declining. A quick way to illustrate the diversity in growth is to use population data for Texas. The U.S. Census Bureau has public data on population changes from 2010-2017 for 27 metro areas and 47 micro areas in Texas. We indexed growth to the 2010 population, allowing a side-by-side comparison of different areas. Figure 4 shows the diversity in growth rates for larger metro areas (left panel) and smaller micro areas (right panel).

To better understand the diversity of growth rates in Texas, we analyzed population data for metro areas (more than 50,000 inhabitants) and micro areas (10,00-50,000 inhabitants) and demand data for each of the ERCOT zones. The population data had more geographic granularity, while the ERCOT load data allowed us to estimate peak demand growth directly.

Figure 5 shows the resulting distribution of population and peak load growth in Texas. The left panel shows a population-weighted histogram of annual growth rates for all Texas metro and micro areas. The population-weighted average growth rate was 1.8%, and the median growth rate was 2.0%. The right panel shows the load-weighted peak demand growth rates across the various ERCOT zones. On average, peak demand growth is 2.0%, similar to average population growth, but the median growth rate is lower at 1.5%. The one distinct outlier is the Permian Basin (ERCOT Far West), where annual growth rates exceed 9%, mainly due to a boom in the oil and gas industry.

Transmission and distribution upgrades do not occur randomly across geographic areas but are more likely to occur in areas with above-average growth and/or highly loaded grid components. In practice, a deferral may not be feasible in locations with exceptionally high growth rates. Nevertheless, it will be possible to defer and, in some cases, altogether avoid infrastructure expansion in many situations. Absent granular load data for specific circuits, feeders, distribution substations, and transmission pockets, the distribution of load and population growth rates were used here to inform the analysis of deferral potential.

2.5 WHAT IS THE VALUE OF T&D DEFERRAL POTENTIAL IN TEXAS?

We now turn to the fundamental question: how much money is left on the table by the failure to proactively consider DERs as potential non-wires solutions in a transparent T&D planning process, such that DERs would lead to traditional T&D investment deferral? As discussed earlier, by managing loads and continuing to optimize functional, existing T&D assets, Texas customers avoid the incremental costs for early replacement of infrastructure (and associated finance charges). Because T&D capital investments are amortized and collected through rates, delaying replacement or expansion of functional T&D infrastructure translates directly into reduced rate pressure for consumers.

Table 4 summarizes the key assumptions used in estimating the value of T&D deferral. The calculation equations and simplified examples are included in the appendices. The assumptions are based on the earlier analysis regarding the magnitude of T&D investment, the share of growth-related investments, the distribution of growth rates, and the relationship between growth rates and deferral duration.

A few inputs are worth further explanation.

- The annual T&D annual costs included are lower than the total historical expenditures in Texas in the past five years. Specifically, we assumed $1.05 billion of transmission capital expenditures per year, which is the inflation-adjusted average over the five years (2006-2010) immediately preceding the expansion of the transmission grid for competitive renewable energy zones (CREZ). For distribution expenditures, we used the average of 2014-2018 annual spending, $2.32 billion per year. The data was based on distribution expenditures reported by Texas investor owned utilities in FERC-Form 1 filings, scaled for municipal utilities and cooperatives. Given the overall scale of historical T&D investments, we believe these assumptions to be relatively conservative.

- We assumed that 20% of T&D expenditures are due to load growth, given the above-average economic and population growth in Texas (as discussed in Section 2.3).

- We assumed T&D investments generally take place in areas with higher peak load growth than Texas as a whole. The assumption of higher growth rates leads to shorter deferral periods and lower deferral values. Figure 6 shows the distribution of annual growth used in the deferral valuation calculation.

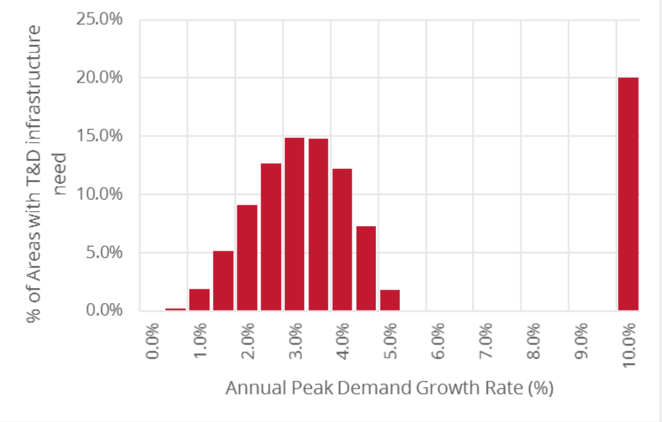
Inputs	Value	Source/Notes
Annual T&D expenditures	$3.37 Billion ($2019)	FERC Form 1 Distribution: 2014-2018 Average Transmission: 2006-2010 (Pre-CREZ)
% growth related	20.0%	Based on the review of growth-related investments as a percentage of T&D expenditures (See Table 1)
Peak load growth Distribution (in T&D areas)	See Figure 6	Based on peak load growth distribution for Texas plus the assumption that areas with T&D investments have higher growth rates overall (leading to shorter deferral periods and deferral value) a more conservative assumption.
Net-to-Gross Multiplier	142.9%	Capital costs are scaled up to account for federal, state, local, and property taxes as well as other carrying costs such as depreciation and insurance. Total carrying costs were assumed to be 30%, based on non-public data from 3 utilities that implemented T&D deferral studies. $Multiplier = \frac{1}{1 - carrying\ costs\%}$
Asset life	50 Years	T&D equipment life varies by component but based on ASCE Infrastructure Report Card, generally lasts 50 years.[11]
Weighted Average Cost of Capital	8.5%	Review of utility filings
Inflation rate	2.1%	The Gross Domestic Product deflator is employed because it reflects inflation for both business and residential customers.

Table 4: Deferral Value Results

Output Metric	Value	Units
Present value without deferral	$1,044.7	$2019 Million per year
Present value with deferral	$700.4	$2019 Million per year
Deferral value (per year)	$344.4	$2019 Million per year
Deferral value over 10 years	$2,451.6	$2019 Million per year

In total, the cost of growth-related T&D expansion to Texas consumers is $1.045 billion per year. By deferring growth-related T&D expansion, the costs can be reduced to $700.4 million per year. Thus, the T&D deferral potential is $344.4 million per year. Over the course of 10 years, the value of T&D deferral is $2,451.6 million. The potential for reducing costs by incorporating DERs into T&D planning is substantial. On an annual basis, it represents 8.5% of total T&D infrastructure costs.

Figure 6: Annual Peak Demand Growth Distribution Employed



2.6 HOW SENSITIVE ARE THE RESULTS TO INPUT ASSUMPTIONS?

Sensitivity analysis is a systematic process for identifying and ranking the inputs that most affect the results. Sensitivity analysis serves several functions. It helps:

- Identify the assumptions and inputs that have the most influence on the results;
- Assess the degree by which results change due to changes in input assumptions;
- Focus on inputs and assumptions that drive results;

The standard process for sensitivity analysis is to vary each input one at a time while holding other factors constant. Typically, each factor is changed by ±20%. The process allowed us to identify the assumptions which have the most influence.

Figure 8 shows the results of the sensitivity analysis. The chart shows which inputs most influence the estimate of T&D deferral, ranked in order of influence. The most striking observation is that the T&D deferral savings are large even when key inputs are changed. In other words, the the magnitude of T&D deferral value is not highly sensitive to the base inputs. The four main drivers of T&D deferral value are (i) the share of T&D investments that are driven by load growth, (ii) the estimate of annual T&D spending, (iii) the net-to-gross multiplier for taxes, and (iv) the magnitude of DER resources that can be deployed in target areas.

Based on the initial sensitivity analysis, the two factors worth exploring further are the percentage of T&D costs that are growth-related, and the magnitude of DER resources that can be deployed in target areas. Figure 7 shows how the T&D deferral value varies as a function of these two factors.

As noted earlier, relatively few jurisdictions publicly report the share of T&D capital expenditures that are related to growth. Thus, the percentage of growth-related costs could deviate significantly from the assumption that 20% of T&D costs are growth-related.

The effect of the size of DER resources is non-linear. The magnitude of DERs needs to be large enough to deliver a meaningful deferral of T&D expansion. Most T&D planning teams will not consider deferral unless

Figure 7: Sensitivity to % T&D Growth-Related Costs and Magnitude of DER Resources

% Growth Related	Distributed Energy Resources (% of operating limit)				
	5.0%	10.0%	15.0%	20.0%	25.0%
10%	$134.3	$724.5	$1,002.9	$1,225.8	$1,542.4
11%	$147.8	$796.9	$1,103.2	$1,348.4	$1,696.6
12%	$161.2	$869.4	$1,203.4	$1,470.9	$1,850.8
13%	$174.6	$941.8	$1,303.7	$1,593.5	$2,005.1
14%	$188.0	$1,014.3	$1,404.0	$1,716.1	$2,159.3
15%	$201.5	$1,086.7	$1,504.3	$1,838.7	$2,313.6
16%	$214.9	$1,159.2	$1,604.6	$1,961.2	$2,467.8
17%	$228.3	$1,231.6	$1,704.9	$2,083.8	$2,622.0
18%	$241.8	$1,304.1	$1,805.2	$2,206.4	$2,776.3
19%	$255.2	$1,376.5	$1,905.5	$2,329.0	$2,930.5
20%	$268.6	$1,449.0	$2,005.7	$2,451.6	$3,084.7
21%	$282.1	$1,521.4	$2,106.0	$2,574.1	$3,239.0
22%	$295.5	$1,593.9	$2,206.3	$2,696.7	$3,393.2
23%	$308.9	$1,666.3	$2,306.6	$2,819.3	$3,547.5
24%	$322.4	$1,738.8	$2,406.9	$2,941.9	$3,701.7
25%	$335.8	$1,811.2	$2,507.2	$3,064.5	$3,855.9
26%	$349.2	$1,883.7	$2,607.5	$3,187.0	$4,010.2
27%	$362.7	$1,956.1	$2,707.7	$3,309.6	$4,164.4
28%	$376.1	$2,028.6	$2,808.0	$3,432.2	$4,318.6
29%	$389.5	$2,101.0	$2,908.3	$3,554.8	$4,472.9
30%	$403.0	$2,173.5	$3,008.6	$3,677.3	$4,627.1

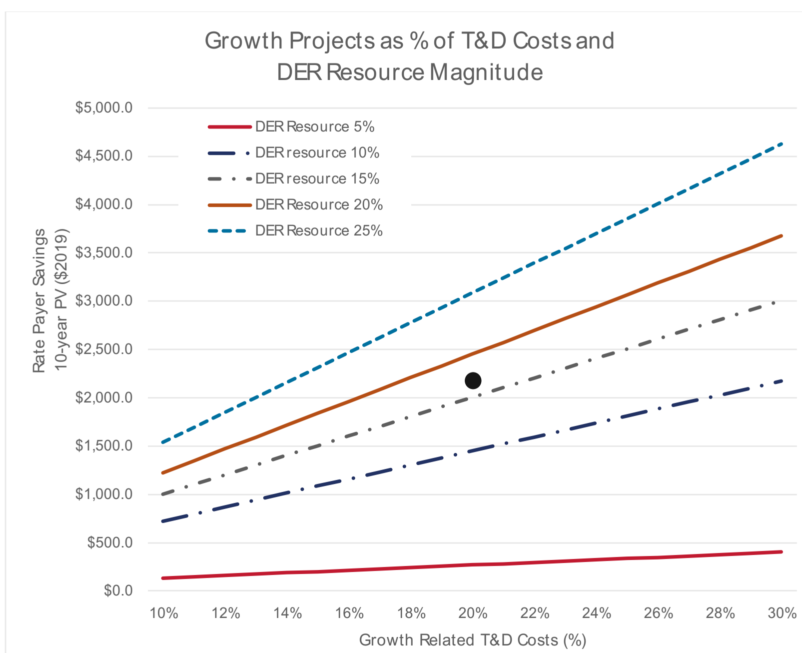
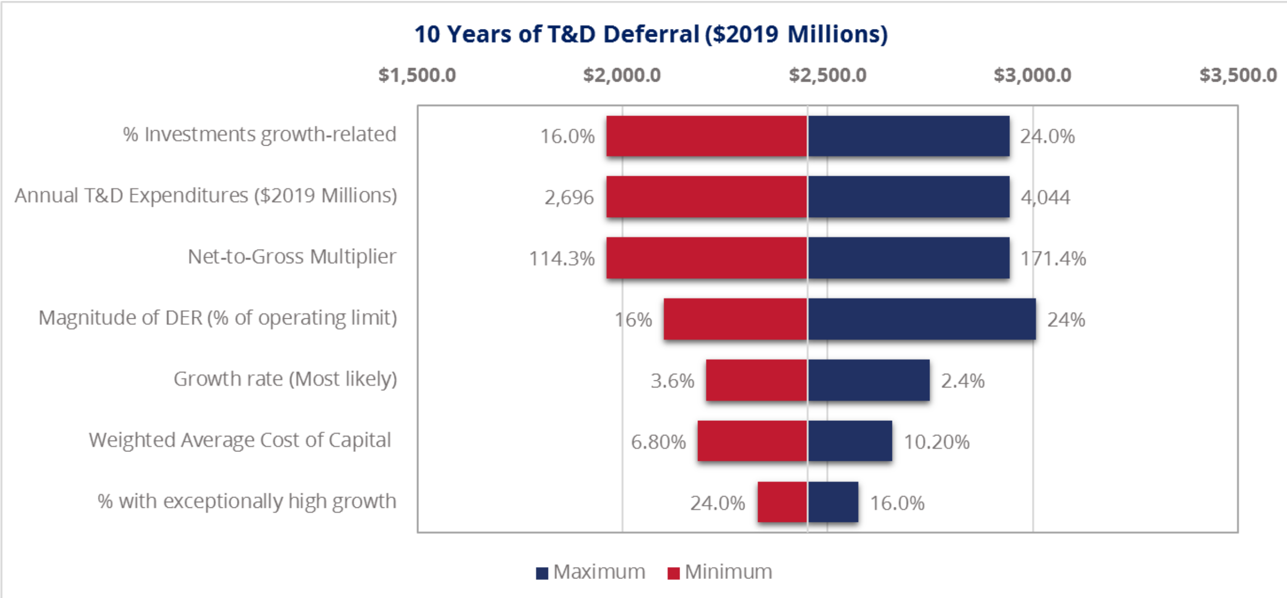


Figure 8: T&D Deferral Potential Sensitivity Analysis (±20%)



Bar labels show the test range for each input variable

resources are large enough to defer the project for two or more years. When the magnitude of DER resources is a small share of the feeder capacity, say 5%, the deferral period may be insufficient at most locations to defer T&D expansion in practice. Thus, the value of DER resources depends in part in identifying high-value locations.

2.7 KEY FINDINGS AND CONCLUSIONS

The study of T&D deferral value in Texas produced several insights, including:

- Infrastructure expansion due to peak load growth can be reduced, deferred, or avoided by DERs that either inject power locally or reduce demand.
- Texas has spent $40.6 billion ($2019) on T&D infrastructure capital costs in the past ten years.
- Growth-related investments tend to range from about 10% to 30% of T&D capital expenditures.
- The value T&D deferral is approximately $344 million per year, or $2,452 million over 10 years (present value), the equivalent of $220 per household over 10 years.
- The sensivity analysis indicates that the T&D deferral savings are large even when key inputs are changed. In other words, the magnitude of T&D deferral value is not highly sensitive to the base inputs.

The T&D deferral potential represents a cap on the DER locational value. In practice, DERs are not cost-free, but substantial savings can be attained by allowing them to compete with traditional solutions. While this chapter focuses on T&D value, DERs create value beyond locational value, including grid resilience (which is critical during hurricanes), cleaner air, more competition, and customer savings.

The potential T&D benefits of DER, however, will not occur without an initiative to integrate DER into T&D planning and create transparent, competitive processes that explicitly consider non-wires solutions. Another option is to make modifications to distribution utility rate designs to reflect DERs benefits or to develop other mechanisms to support DER deployment. In order to avoid or defer distribution investments, incremental distributed energy resources need to be procured in advance at the right locations and target the right hours. The magnitude of DERs introduced also needs to be large enough to prolong the use of existing equipment. Thus, to unlock the locational value of DER resources, it is necessary to identify the high-value locations so DER resources can be concentrated.

Specifically, we recommend establishing processes to:

- Identify locations that are highly loaded (e.g., loading factor above 90%);
- Define the magnitude and timing of resources needed for each forecast year;
- Collect competitive bids for DER resources (non-wire solutions); and
- Implement the least cost solution, whether it is a DER solution or an expansion of the T&D system.

3 BENEFITS OF INTEGRATING DISTRIBUTED ENERGY RESOURCES INTO WHOLESALE MARKETS

When the ERCOT market was initially designed, grid operators had extensive control over generators and limited (or no) control over loads and behind-the-meter generation or energy storage. In the roughly 20 years since the creation of ERCOT, however, the grid and the technologies for generating and managing energy have evolved substantially. A larger share of generation is variable (solar and wind) and, as a result, operators increasingly have less control over generation. In contrast, the ability to manage flexible loads and behind-the-meter DERs is expanding rapidly.

DER resources are able to provide the ERCOT market with valuable services by enhancing competition, mitigating price spikes, and responding to wholesale price signals. Technology and service providers are capable of aggregating fleets of residential and small commercial smart devices such as water heaters, HVAC systems, electric vehicle chargers, solar inverters, distributed batteries, and energy management systems into single grid resources and operate them as virtual power plants.

ERCOT has adjusted rules and procedures to allow loads to deliver grid services, either directly or through the aggregation of retail customers. Many DERs can and do participate via mechanisms available for load participation but are not incorporated into the supply stack, and dispatch is limited to emergency conditions.

The full potential of DERs has not been realized, however; more DER capacity would be installed and made available to wholesale markets if the T&D services were more open to competition and if DERs could more easily participate in wholesale markets. DERs can deliver incremental resources to wholesale markets when prices spike and additional resources are needed. This section estimates how much money consumers could save from allowing DERs to compete in existing wholesale energy markets.

In this section, we investigate the following:

1. How is the ERCOT energy market structured?
2. How do DERs reduce electricity costs?
3. What Does the Electricity Supply Curve Look Like in Texas?
4. What is The Value of Additional DER Resources to Texas Consumers??

3.1 HOW IS THE ERCOT ENERGY MARKET STRUCTURED?

Table 5 summarizes the existing ERCOT energy markets and the function they serve.

ERCOT differs from many other organized wholesale markets in that it functions as an energy-only market. There is no forward capacity market to provide financial compensation to peaking plants whose purpose is to meet peak load obligations. Furthermore, ERCOT does not have a resource adequacy reliability standard or reserve margin requirements. In other words, the economic signals from the energy and ancillary service markets alone dictate decisions to invest in additional generating resources. This design lends itself to more extreme fluctuations in the price of energy, particularly during peak load periods. For example, in 2019, real-time prices exceeded $9,000 per MWh during a system peak, whereas the ERCOT-wide load-weighted average price was $35.63 per MWh across the year[12]. In August of 2019, prices exceeded $9,000 per MWh again.

The real-time market is subject to operational and reliability constraints (security constrained economic dispatch ensures supply equals demand and transmission limit are not exceeded), and prices may exhibit significant volatility. Consequently, only a fraction of energy is bought and sold in the real-time market. The day-ahead market and bilateral contracts are used to manage risk and hedge against exposure to real-time price spikes. The real-time energy prices typically determine expectations for prices in the day-ahead market where the majority of transactions occur. If the markets are functioning correctly, prices in the

Table 5: ERCOT Wholesale Market Products and Services

Service	Key Function	Competitive Mechanisms and Products
Energy Production	What mix of resources can produce electricity at the lowest cost?	Day-Ahead Market Real-Time Market
Frequency Regulation / Load Balancing	Can the bulk system respond quickly enough (<4 seconds) to match supply and demand and maintain frequency in the target range?	Regulation Up ($/MW) Regulation Down ($/MW)
Operating Reserves	Does the grid have the ability to withstand system shocks (e.g., forced outages or unforecast changes in resources or demand?	Responsive Reserve Service ($/MW) Non-Spinning Reserve Service ($/MW)
Emergency Service	Maintain grid stability during emergency conditions and reduce the likelihood of the need for rotating outages	Emergency Response Service (ERS)

forward markets should be directly related to the prices in the real-time market; otherwise participants could engage in arbitrage. However, there is a risk premium associated with the day ahead market which results in slightly higher average prices in the day-ahead market. In 2018, the day-ahead market price averaged $3 per MWh more than the real-time market.

Because nearly two-thirds of the energy transactions occur in the day-ahead market, we use the historical day-ahead market prices as the basis for this analysis. The settlement prices in the market reflect locational marginal prices, meaning that they include the costs of the energy itself and any congestion costs associated with delivery. The settlement occurs at either a resource node, a load zone or a hub and may differ slightly across these settlement points to reflect the locational specific load, generation and delivery resources available in that portion of the ERCOT territory. We utilize the ERCOT hub average price in this analysis to capture the general price trend, but recognize this may mask some variation at a more granular level. Thus, while day-ahead market prices may be higher than average real-time prices, we believe that the values derived in the following analysis represent conservative estimates of DER potential as these resources would likely target periods of higher volatility and locations with higher than average energy and congestion prices.

Table 6 summarizes the participation of flexible loads and distributed generation in various ERCOT services. With few exceptions, DERs in ERCOT are not incorporated into the energy market supply stack.

Most DER participation in ERCOT is in delivering responsive reserve service (RRS), where, by rule, loads are can only deliver up to 60% of responsive reserves[13]. As a result a significant amount of DER capacity that is offered into the summer months during the peak time periods is not awarded. In August 2018, for example, the amount of RRS capacity awarded to DERs during the peak hours from 15:00 to 16:00 was 28.7% of the capacity offered.[14]

Table 6: DER participation in ERCOT[13]

Service	MW	Incorporated into energy market supply stack
Responsive Reserve Service	1,472	Indirectly
Emergency Response Service 10-minute (Average Hour Ending 14:00 to Hour Ending 19:00)	142	No
Emergency Response Service 30-minute	675	No
Transmission/Distribution Service Provider Load Management Proggram	251	No
Distributed Generation Price Response	286	Yes

DERs can also participate in Emergency Response Service (ERS) to be deployed in the late stages of a grid emergency. However these resources are not incorporated into the energy market supply stack and participation by weather-sensitive loads is limited to 12 out of 817 MW (1.5%).[13]

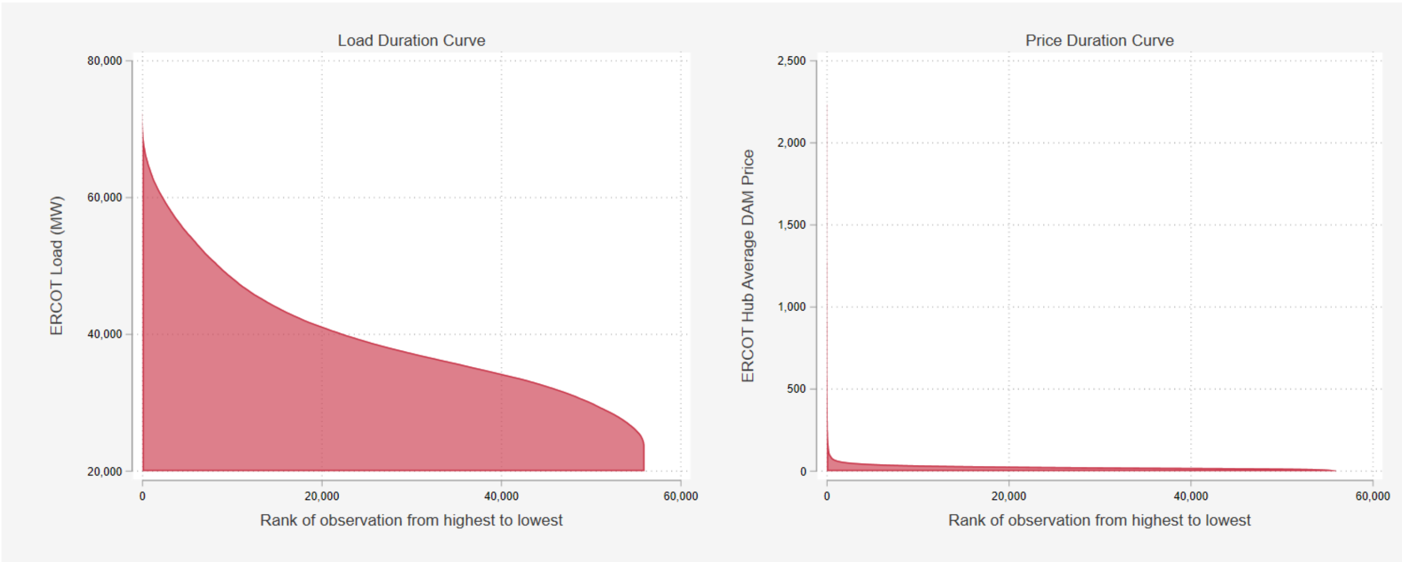
Distributed generation price response is incorporated into the supply stack but these resources typically constitute large back-up generation systems such as on-site gas turbines. It does not include distributed solar and wind generation or any flexible loads.

Most smaller DERs cannot bid directly into the energy markets, even when aggregated, and are limited to participating indirectly as load modifying demand via a Transmission or Distribution Service Provider (TDSP). TDSP resources are not incorporated into the energy market supply stack and are only dispatched under emergency conditions. A third party capable of operating a virtual power plant by controlling connected DERs is unable to bid into ERCOT unless they are a load-serving entity or partner with one.

3.2 HOW DO DERS REDUCE ELECTRICITY COSTS?

Electricity prices in Texas can reach extreme values when demand is high, resources are offline, or an unexpected event occurs – e.g., transmission outages, generator outages, or unforecasted changes in load or solar or wind production. The extreme prices that occur in ERCOT are generally limited to a small number of hours but account for a substantial share of costs. By design, the high price signals encourage existing generators to produce power as well as the construction of new resources. Both extreme prices and peak loads occur during only a small fraction of hours in each year with the timing of each varying from year to year. Figure 9 shows the ERCOT load and price duration curves using data from 2014-2018.

Figure 9: Load and Price Duration Curves



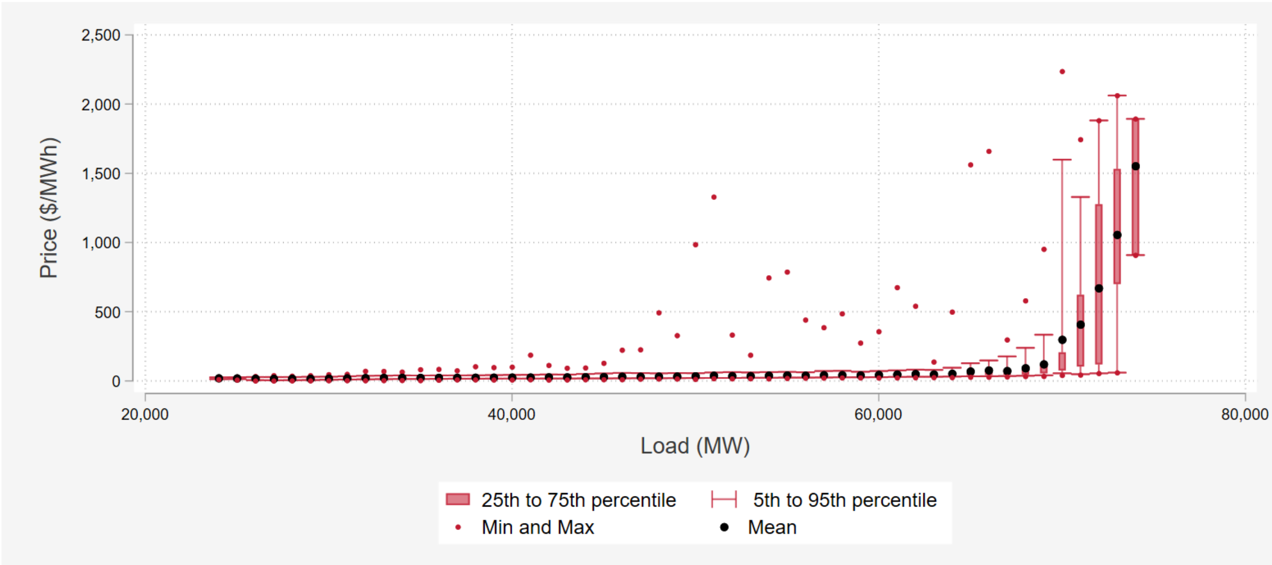
Duration curves rank the hours based on price or load from highest to lowest and are useful for understanding how frequently high prices or high loads occur. The ERCOT peak load approached 80,000 MW in this timeframe. However, less than 5% of hours were within 20% of the peak load. The price duration curve in Figure 9 demonstrates that price spikes are even more infrequent than high loads.

The vast majority of settlement prices in the day ahead market are under \$50/MWh with peaks approaching \$2,500/MWh. Despite the fact that peak prices occur less often than high load conditions, there is a clear relationship between peak loads and peak prices.

Figure 10 shows the relationship between load and price and captures the typical "hockey stick" supply curve. Prices are low and relatively consistent across low loads, but increase sharply when demand levels are high. Outlier high prices can occur even when demand is relatively low for multiple reasons: generators may be offline for maintenance, or a large generator or transmission line can unexpectly go out of service. However, the majority of extreme prices occur when net loads (system demand minus wind and solar) are high.

Figure 10 displays five years' (2014-2018) worth of hub average, day-ahead market settlement prices with the corresponding ERCOT loads in that hour. The data are aggregated in 1,000 MW load bins. The black point represents the mean price for that load tranche. The boxes show the 25th to 75th percentile of prices in that tranche and the capped whiskers the 5th to 95th percentile. The small red dots show the minimum and maximum values. During peak load conditions, demand outpaces supply and prices in the market rise to reflect the changing market conditions. There is also much greater price volatility during peak loads.

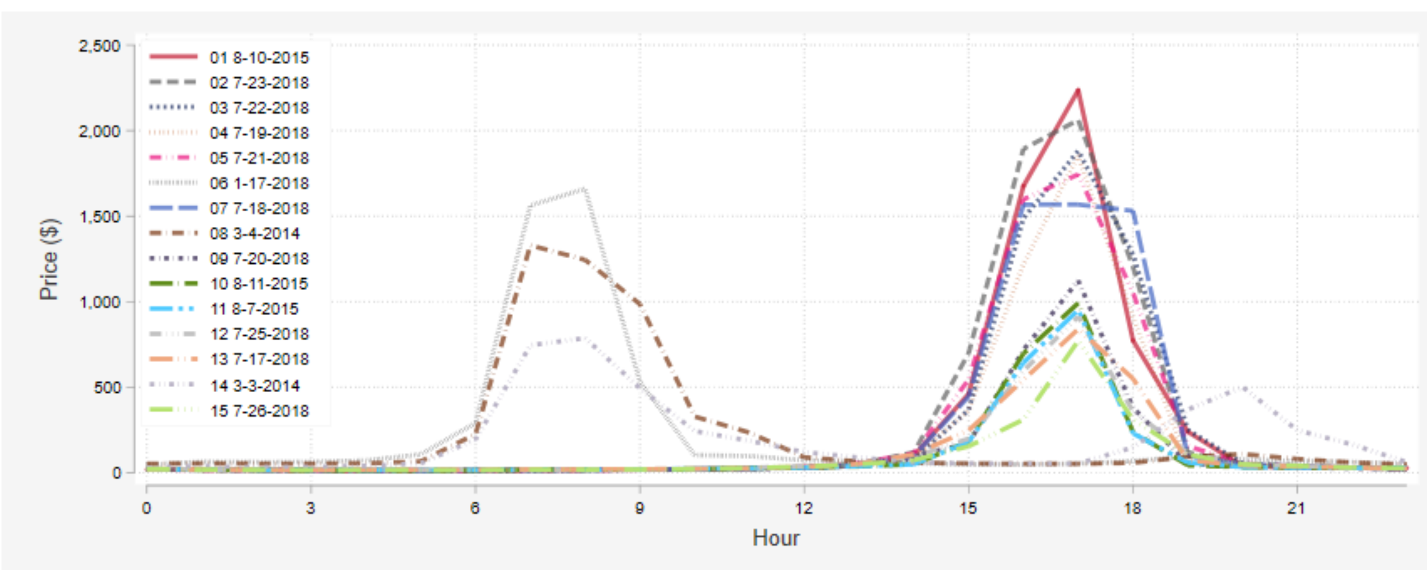
Figure 10: Relationship between Day Ahead ERCOT Price and Load in 1,000 MW bins (2014-2018)



While price spikes are relatively rare, they are orders of magnitude greater than typical prices and usually occur in periods when the largest amount of energy must be procured. As such, these peak hours can be large drivers of electricity costs. Figure 11 shows the day-ahead hourly prices for the 15 days with the highest prices and demonstrates that the duration of peak prices is relatively short, with high prices abating within a few hours.

The majority of the peak pricing hours occurred during the summer months in the late afternoon, consistent with the expectations for peak load. However, there were also some instances of peak prices during morning hours in winter and shoulder months.

Figure 11: Price by Hour (day-ahead market) during 15 Highest Load Days



A wide variety of DER technologies are able to deliver energy or reduce load with short notice when extreme prices occur. In addition, the modular, diverse nature of DERs lends itself nicely to the construction of a portfolio which can be deployed when, where, and in the amount needed to serve the peaks. Bulk generation, on the other hand, is added in larger increments and requires significant investment for a resource that may be idle or uneconomical for the majority of the time (depending on the type of technology deployed). DER resources do not need to operate in energy markets for hundreds of hours per year to recover costs. They can save customers money by reducing utility bills, and if they can be dispatched to deliver grid services when needed can also provide significant grid value.

3.3 WHAT DOES THE ELECTRICITY SUPPLY CURVE LOOK LIKE IN TEXAS?

The ability of DERs to reduce electricity production costs is tied to their ability to mitigate peak prices by supplying resources when they are needed most. In cases where prices are high, even a slight shift in the supply curve (or a reduction in net energy demand) can have a substantial effect on the market-clearing price during that hour. Aggregating these impacts over time allows us to estimate the value associated with further participation of DER resources in market price-setting.

Adding resources that produce power (or reduce demand) at these critical times, shifts the supply curve outwards (or demand curve inward), changing the market-clearing price and lowering costs for all Texas consumers. The fundamental question is by how much do consumer costs decrease by adding additional resources? Many DERs have near-zero marginal costs for dispatching resources quickly, meaning they enter near the bottom of the supply stack and can place downward pressure on the market equilibrium.

To quantify the effect of this resource addition on electricity costs, we introduce a technology-agnostic resource that delivers the stated capacity during the periods most frequently associated with peak prices (Summer hours 3pm to 7pm , Winter hours 6am to 10am). In practice, to deliver capacity reliably during these periods would require composing a portfolio of resources (such as solar+storage, demand response, fuel cells, etc.). We defined these hours as peak pricing periods. Using the five years of historical data for 2014-2018, we then iterate through each hour of every year and perform the following steps:

1. Add the resource (if applicable in that hour) to the base of the supply curve (shift curve right).
2. Calculate the new price at the historical level of load.
3. Subtract the new price from the actual price in that hour to get the price differential.
4. Multiply the price differential by the load to estimate energy cost savings.

3.4 WHAT IS THE VALUE OF ADDITIONAL DER RESOURCES TO TEXAS CONSUMERS?

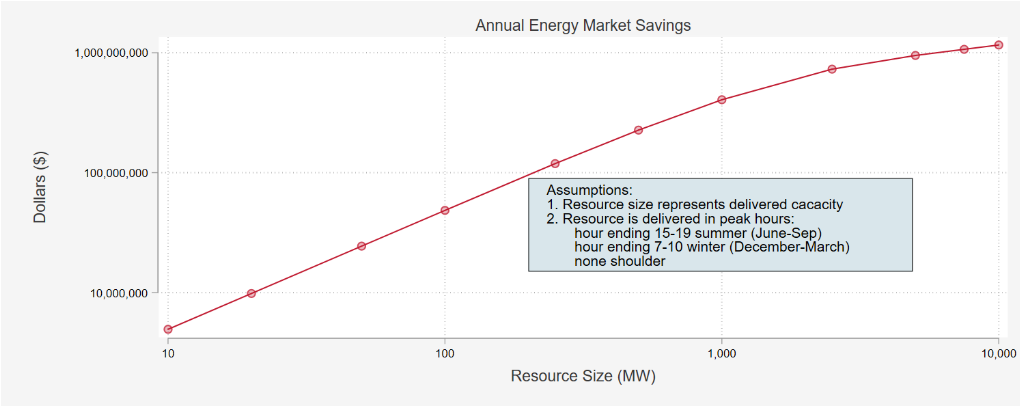
With an hourly estimate of savings, we sum across all hours of each year to produce annual savings. The average annual savings across the five years of data is calculated to produce our estimates of the annual cost savings.

Figure 12 shows the annual cost savings estimates assuming incremental resource addition between 10 and 10,000 MW. Both axes are presented on a logarithmic scale due to the wide range of values included in the analysis.

By design, we modeled delivered, not nameplate capacity because DERs encompass a wide range of technologies with different characteristics, including but not limited to availability, speed of response, load shape, and maximum dispatch duration.

As would be expected, the total annual savings associated with electricity costs increase with the size of the resource. More resources lead to larger shifts in the supply curve and larger decreases in electricity costs. However, the per MW savings decrease as the resource

Figure 12: Annual Savings by Resource Size



Size (MW)	Value ($)
10	5,000,000
20	9,800,000
50	24,400,000
100	48,500,000
250	119,000,000
500	227,000,000
1,000	406,000,000
2,500	730,000,000
5,000	950,000,000
7,500	1,070,000,000
10,000	1,160,000,000

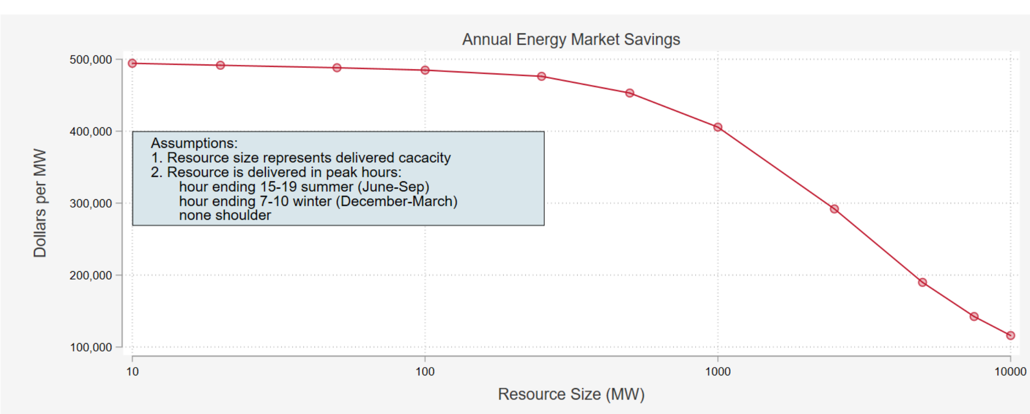
size increases, as shown more clearly in Figure 13. The per MW benefits start diminishing more markedly when over 1,000 MW (roughly 1.4% of historical peak load) of resources are added.

Over multiple years, the value of including additional DER resources in the Texas electricity market is substantial. Figure 14 shows an estimate of the 10 year present value for various increases in resources. Adding 500 MW of effective DER resources can decrease electricity costs by $1.69 billion over ten years – a saving of $3,380 per incremental kW. Adding 1,000 MW of effective DER resources can decrease electricity costs by $3.02 billion over ten years – a savings of $3,020 per incremental kW.

DERs can also reduce electricity costs by participating in ancillary service markets. Ancillary service market prices are highly correlated with the day-ahead market energy prices, especially when loads are high. Further discussion of the ancillary service markets can be found in Appendix F.

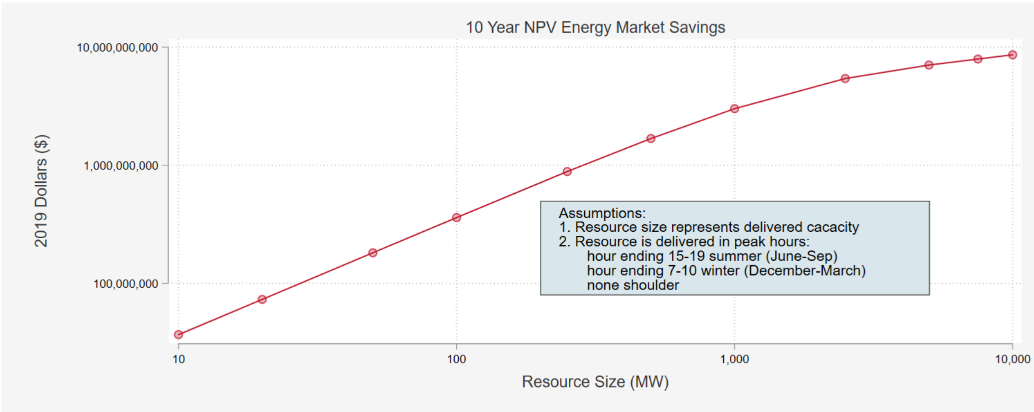
Participation in either market increases the amount of power available when those resources are needed most, leading to lower market prices. Thus, policies to allow more participation of DERs in the ancillary service market also lowers electricity costs to Texas consumers.

Figure 13: Annual Savings Per MW by Resource Size



Size (MW)	Value ($)
10	494,344
20	491,675
50	488,247
100	484,895
250	476,285
500	453,087
1,000	405,675
2,500	292,008
5,000	189,908
7,500	142,422
10,000	116,057

Figure 14: 10 Year NPV by Resource Size



Size (MW)	Value ($)
10	36,800,000
20	73,100,000
50	182,000,000
100	361,000,000
250	886,000,000
500	1,690,000,000
1,000	3,020,000,000
2,500	5,430,000,000
5,000	7,060,000,000
7,500	7,940,000,000
10,000	8,630,000,000

3.5 KEY FINDINGS AND CONCLUSIONS

The analysis of wholesale markets in Texas produced several insights, including:

- ERCOT market prices signal the need for additional resources on a limited number of hours that occur when:
  - Demand is high or variable generation production is low
  - During shoulder seasons when generators schedule maintenance
  - When the grid experiences unexpected transmission outages, generator outages, or large un-forecasted changes in load or intermittent generation
- While several initiatives to incorporate DERs into wholesale markets have been made[15], most DERs are not part of the supply stack and participation is functionally limited to larger sites.
- Adding incremental resources that deliver during those hours leads to reductions in electricity costs to Texas customers.
  - Adding 500 MW of delivered DER resources can decrease electricity costs by $1.69 billion over the course of 10 years (present value).
  - Adding 1,000 MW of delivered DER resources into the supply stack can decrease electricity costs for Texas consumers by $3.02 billion over ten years (present value).

The adoption of DERs is expanding at a rapid pace and represents a significant resource that is, for the most part, not directly incorporated into the ERCOT energy market supply stack. More value can be delivered if they can respond and be compensated during price spikes. To date, participation by DER resources is limited and third-party providers are unable to deliver resources independently. Texas consumers would benefit substantially, saving billions of dollars, by better integrating DER resources into the energy supply stack.

APPENDIX A: FERC FORM-1 DETAILS

Figure 15 shows an excerpt from FERC Form-1[16] which is an annual filing requirement for all "major" IOUs. According to FERC, "major" is defined as having (1) one million megawatt-hours or more of annual sales; (2) 100 megawatt-hours of annual sales for resale; (3) 500 megawatt-hours of annual power exchange delivered; or (4) 500 megawatt-hours of annual wheeling for others (deliveries plus losses)."

The Form-1 field "Additions for Electric Plant in Service (Transmission and Distribution)" was the primary data source for annual T&D expenditures for this study[17,18,19]. Only the line items outlined in orange were included. The others were excluded given their clear ties to individual service connections. In the case of "Land and Land Rights" for Transmission Plant, 50% of additions were allocated for inclusion in the study to reflect cases where utility right-of-way or land ownership needed for new projects has already been procured.

Figure 15: FERC Form-1 Detailed T&D Expenditure Categories

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)			
Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights		
49	(352) Structures and Improvements		
50	(353) Station Equipment		
51	(354) Towers and Fixtures		
52	(355) Poles and Fixtures		
53	(356) Overhead Conductors and Devices		
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)		
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights		
61	(361) Structures and Improvements		
62	(362) Station Equipment		
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures		
65	(365) Overhead Conductors and Devices		
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices		
68	(368) Line Transformers		
69	(369) Services		
70	(370) Meters		
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)		

APPENDIX B: TEXAS HISTORICAL T&D EXPENDITURES

Table 7 summarizes the T&D capital expenditures in Texas and is based on FERC Form 1 data. However, FERC Form 1 only includes data for investor-owned utilities and does not separate investments by state. To scale the investment for Texas, we relied on the Energy Information Administration's Form 861 sales data, which includes information for all investor-owned utilities, municipal utilities, and cooperatives by state. The volume of energy sales (GWh) was used to pro-rate investor-owned utility expenditures for Texas (e.g., CenterPoint has territory outside of Texas) and to scale for municipal utilities and electric cooperatives which are not included in FERC Form 1 data. Table 8 includes the detailed estimates of T&D capital expenditures for Texas territory inside and outside of ERCOT and by type of utility ownership.

Table 7: Texas Historical T&D Capital Expenditures

	No inflation adjustment		With inflation adjustment	
Year	Transmission ($)	Distribution ($)	Transmission ($2019)	Distribution ($2019)
2003	$491,774,112	$781,107,072	$670,565,738	$1,065,089,901
2004	$502,359,808	$736,093,184	$666,858,509	$977,128,336
2005	$509,663,296	$994,709,504	$657,173,666	$1,282,605,391
2006	$754,754,496	$1,022,897,088	$942,267,124	$1,277,027,566
2007	$810,697,856	$1,074,655,616	$985,255,111	$1,306,047,537
2008	$920,222,592	$1,340,278,272	$1,098,265,446	$1,599,592,671
2009	$870,456,128	$1,198,337,280	$1,029,581,140	$1,417,401,088
2010	$947,338,944	$1,137,832,704	$1,107,613,333	$1,330,335,549
2011	$1,381,858,944	$1,114,806,912	$1,582,994,905	$1,277,072,214
2012	$1,413,757,824	$1,295,569,536	$1,590,447,423	$1,457,488,118
2013	$2,576,832,512	$1,415,861,504	$2,849,781,497	$1,565,835,536
2014	$2,486,343,424	$1,789,028,608	$2,694,427,444	$1,938,753,807
2015	$1,834,058,240	$2,058,075,136	$1,965,469,148	$2,205,536,932
2016	$2,538,262,528	$2,105,057,024	$2,694,848,416	$2,234,918,384
2017	$3,137,937,408	$2,230,672,896	$3,277,114,343	$2,329,609,929
2018	$3,446,145,536	$2,587,925,760	$3,505,330,705	$2,632,371,597
2014-2018 (5-year average)	**$2,688,549,427**	**$2,154,151,885**	**$2,827,438,011**	**$2,268,238,130**
Pre-CREZ 5-year average (2005-2009)	**$773,158,874**	**$1,126,175,552**	**$942,508,497**	**$1,376,534,851**

Table 8: Detail on Texas Historical T&D Expenditures

Geography	Ownership type	Year	Utility sales (MWh)	Transmission ($)	Distribution ($)	Transmission ($2019)	Distribution ($2019)
Non-ERCOT	IOU	2003	17,422,027	38,712,703	66,371,680	$52,787,269	$90,502,069
		2004	17,644,221	43,200,333	62,102,135	$57,346,366	$82,437,601
		2005	25,126,830	20,106,520	57,423,807	$25,925,891	$74,043,813
		2006	25,760,791	27,048,785	66,107,227	$33,768,836	$82,531,031
		2007	25,901,987	45,189,988	105,318,294	$54,920,173	$127,995,142
		2008	26,793,297	114,284,802	175,103,325	$136,396,401	$208,981,971
		2009	26,344,679	144,559,859	228,327,140	$170,986,336	$270,066,818
		2010	27,373,412	103,121,225	237,703,060	$120,567,664	$277,918,564
		2011	27,580,752	201,056,509	169,374,407	$230,321,214	$194,027,635
		2012	27,458,696	207,525,053	170,581,453	$233,461,262	$191,900,499
		2013	27,620,544	223,352,082	168,955,057	$247,010,478	$186,851,490
		2014	27,871,941	459,648,860	205,641,060	$498,117,231	$222,851,321
		2015	27,560,921	340,294,795	202,968,559	$364,677,035	$217,511,327
		2016	27,147,093	537,504,296	224,780,085	$570,663,036	$238,646,811
		2017	27,104,942	298,965,472	242,624,760	$312,225,488	$253,385,896
		2018	46,430,020	622,801,728	354,834,783	$633,497,917	$360,928,825
	Public	2003	10,983,594	24,406,150	41,843,556	$33,279,361	$57,056,389
		2004	10,731,458	26,275,036	37,771,372	$34,878,848	$50,139,682
		2005	11,331,826	9,067,741	25,897,282	$11,692,191	$33,392,657
		2006	12,008,249	12,608,640	30,815,516	$15,741,154	$38,471,381
		2007	11,642,459	20,312,056	47,338,604	$24,685,593	$57,531,423
		2008	12,230,562	52,168,548	79,930,888	$62,262,016	$95,395,759
		2009	12,445,362	68,290,824	107,862,920	$80,774,828	$127,580,960
		2010	12,840,380	48,372,328	111,502,272	$56,556,142	$130,366,649
		2011	14,942,319	108,925,616	91,761,328	$124,780,243	$105,117,614
		2012	12,041,885	91,009,160	74,807,712	$102,383,365	$84,157,082
		2013	12,186,856	98,548,376	74,547,080	$108,987,036	$82,443,422
		2014	12,010,060	198,063,360	88,611,032	$214,639,437	$96,026,958
		2015	11,466,081	141,571,744	84,440,352	$151,715,408	$90,490,532
		2016	11,477,320	227,247,488	95,033,120	$241,266,428	$100,895,731
		2017	11,201,335	123,549,888	100,266,632	$129,029,696	$104,713,758
		2018	11,201,335	150,252,160	85,604,600	$152,832,637	$87,074,800
ERCOT	IOU	2003	180,706,203	319,711,071	501,874,078	$435,946,677	$684,337,694
		2004	182,446,907	322,726,673	474,318,398	$428,404,152	$629,634,885
		2005	187,823,398	354,985,697	673,334,532	$457,728,178	$868,215,793
		2006	190,321,951	523,489,008	677,862,370	$653,545,602	$846,271,773
		2007	181,719,320	536,893,362	664,275,066	$652,495,778	$807,304,964
		2008	182,668,696	536,297,305	772,137,406	$640,059,051	$921,529,030
		2009	177,955,000	462,574,088	606,453,223	$547,135,624	$717,316,796
		2010	186,810,562	562,582,213	557,479,841	$657,762,002	$651,796,391
		2011	193,849,496	750,572,206	597,775,620	$859,821,463	$684,784,626
		2012	188,963,976	783,346,308	737,659,181	$881,247,902	$829,850,858
		2013	192,297,248	1,576,762,509	819,772,886	$1,743,779,855	$906,606,693

Geography	Ownership type	Year	Utility sales (MWh)	Transmission ($)	Distribution ($)	Transmission ($2019)	Distribution ($2019)
		2014	196,744,888	1,274,811,235	1,042,067,818	$1,381,501,182	$1,129,279,286
		2015	200,785,272	942,683,194	1,234,423,590	$1,010,226,772	$1,322,870,468
		2016	202,620,272	1,238,174,629	1,246,366,056	$1,314,557,853	$1,323,254,610
		2017	205,653,488	1,898,153,644	1,319,610,443	$1,982,342,452	$1,378,139,124
		2018	220,416,520	1,907,005,949	1,532,034,782	$1,939,757,459	$1,558,346,421
	Public	2003	61,577,125	108,944,176	171,017,728	$148,552,415	$233,193,709
		2004	62,275,429	110,157,760	161,901,248	$146,229,134	$214,916,128
		2005	66,403,981	125,503,336	238,053,904	$161,827,403	$306,953,155
		2006	69,661,856	191,608,032	248,111,952	$239,211,492	$309,753,352
		2007	70,502,967	208,302,432	257,723,632	$253,153,544	$313,215,983
		2008	74,073,318	217,471,968	313,106,624	$259,548,016	$373,685,877
		2009	75,029,727	195,031,376	255,693,968	$230,684,373	$302,436,480
		2010	77,457,170	233,263,184	231,147,584	$272,727,533	$270,254,007
		2011	82,983,021	321,304,672	255,895,568	$368,072,053	$293,142,351
		2012	80,057,633	331,877,280	312,521,184	$373,354,867	$351,579,672
		2013	82,707,542	678,169,600	352,586,432	$750,004,189	$389,933,876
		2014	85,472,472	553,820,096	452,708,640	$600,169,732	$490,596,179
		2015	87,222,599	409,508,512	536,242,688	$438,849,939	$574,664,662
		2016	87,604,732	535,336,160	538,877,760	$568,361,147	$572,121,229
		2017	88,546,097	817,268,416	568,171,008	$853,516,721	$593,371,096
		2018	88,546,097	766,085,632	615,451,584	$779,242,624	$626,021,540

APPENDIX C: T&D DEFERRAL CALCULATIONS

Because growth rates influence the duration and value of deferral, the deferral calculations were implemented based on a distribution of growth rates. Table 9 includes the annual deferral value results and weights for each growth rate bin. The locational value was not included when the expected deferral duration was less than two years, to ensure consistency with T&D planning practices.

Table 9: Detailed Annual Deferral Year Calculations

				Book Life Costs without Deferral		Book Life Costs with Deferral		
Peak Demand Growth Rate	Cummulative Distribution	Distribution (weight)	Expected Deferral Years	NPV of capital cost (over book life)	NPV of O&M (over book life)	NPV of capital cost (over book life)	NPV of O&M (over book life)	Avoided cost
0.0%	0.0%	0.0%	20.0	$0.00	$0.0	$0.0	$0.0	$0.0
0.5%	0.2%	0.2%	36.6	$2.42	$0.0	$0.1	$0.0	$2.3
1.0%	2.1%	1.9%	18.3	$19.83	$0.0	$4.4	$0.0	$15.4
1.5%	7.3%	5.1%	12.2	$53.63	$0.0	$19.8	$0.0	$33.9
2.0%	16.3%	9.1%	9.2	$94.92	$0.0	$44.8	$0.0	$50.1
2.5%	29.0%	12.7%	7.4	$132.41	$0.0	$72.5	$0.0	$59.9
3.0%	43.9%	14.9%	6.2	$155.21	$0.0	$93.8	$0.0	$61.4
3.5%	58.7%	14.8%	5.3	$154.85	$0.0	$100.5	$0.0	$54.4
4.0%	70.9%	12.2%	4.6	$127.34	$0.0	$87.2	$0.0	$40.2
4.5%	78.2%	7.3%	4.1	$76.16	$0.0	$54.3	$0.0	$21.8
5.0%	80.0%	1.8%	3.7	$19.01	$0.0	$14.0	$0.0	$5.0
5.5%	80.0%	0.0%	3.4	$0.00	$0.0	$0.0	$0.0	$0.0
6.0%	80.0%	0.0%	3.1	$0.00	$0.0	$0.0	$0.0	$0.0
6.5%	80.0%	0.0%	2.9	$0.00	$0.0	$0.0	$0.0	$0.0
7.0%	80.0%	0.0%	2.7	$0.00	$0.0	$0.0	$0.0	$0.0
7.5%	80.0%	0.0%	2.5	$0.00	$0.0	$0.0	$0.0	$0.0
8.0%	80.0%	0.0%	2.4	$0.00	$0.0	$0.0	$0.0	$0.0
8.5%	80.0%	0.0%	2.2	$0.00	$0.0	$0.0	$0.0	$0.0
9.0%	80.0%	0.0%	2.1	$0.00	$0.0	$0.0	$0.0	$0.0
9.5%	80.0%	0.0%	2.0	$0.00	$0.0	$0.0	$0.0	$0.0
10.0%	100.0%	20.0%	1.9	$208.95	$0	$208.9	$0.0	$0

APPENDIX D: PEAK LOAD GROWTH

The peak load growth was estimated for each ERCOT zone using data from 2013 to 2018. The goal was to estimate the annual percent change in peak demand after controlling for year-to-year variation in weather. We relied on an econometric model and used the natural log of the zonal demand as the dependent variables. Thus, the coefficient of the year variable estimated the percentage in peak hour demand. The general form of the models was:

$$\ln(MW) = a + b \cdot Year + c \cdot W + \sum_{m=1}^{12} e_m \cdot month_m + \sum_{dow=1}^{5} f_{dow} \cdot day\ of\ week_{dow}$$

Where:

a-f	Are model coefficients. The variable of interest is *b* since it represents the annual % peak growth.
Year	It is a continuous variable ranging from 2013 to 2019. The values in partial years were index by dividing by 365 (e.g., July 1, 2015, equals 2015.5)
W	It is a set of variables to reflect weather conditions. The out-of-sample testing focused on different ways to model weather.
Month$_m$	Are indicator (dummy) variables. One for each month.
Day of week $_{dow}$	Are indicator (dummy) variales. One for each day of the week. Note that modeling focused on Monday to Friday.

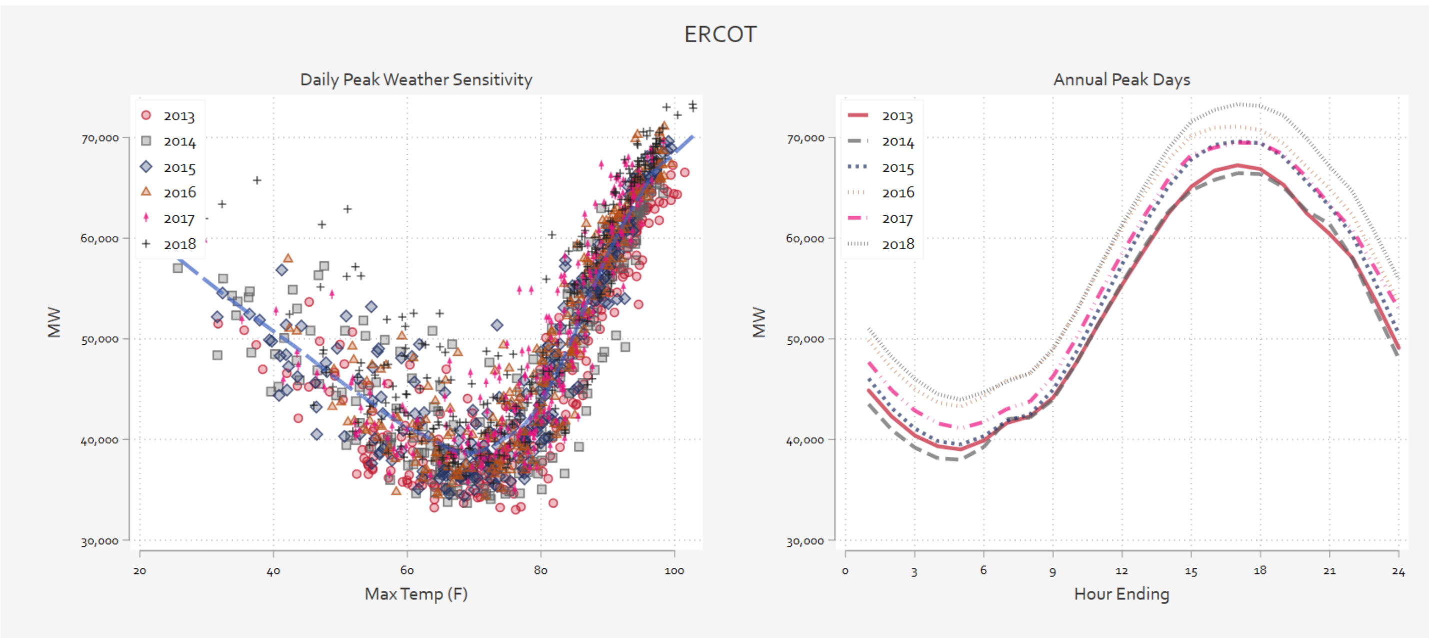
Because multiple models are plausible, we used an out-of-sample selection process to identify the best model for each zone. Our process relied on:

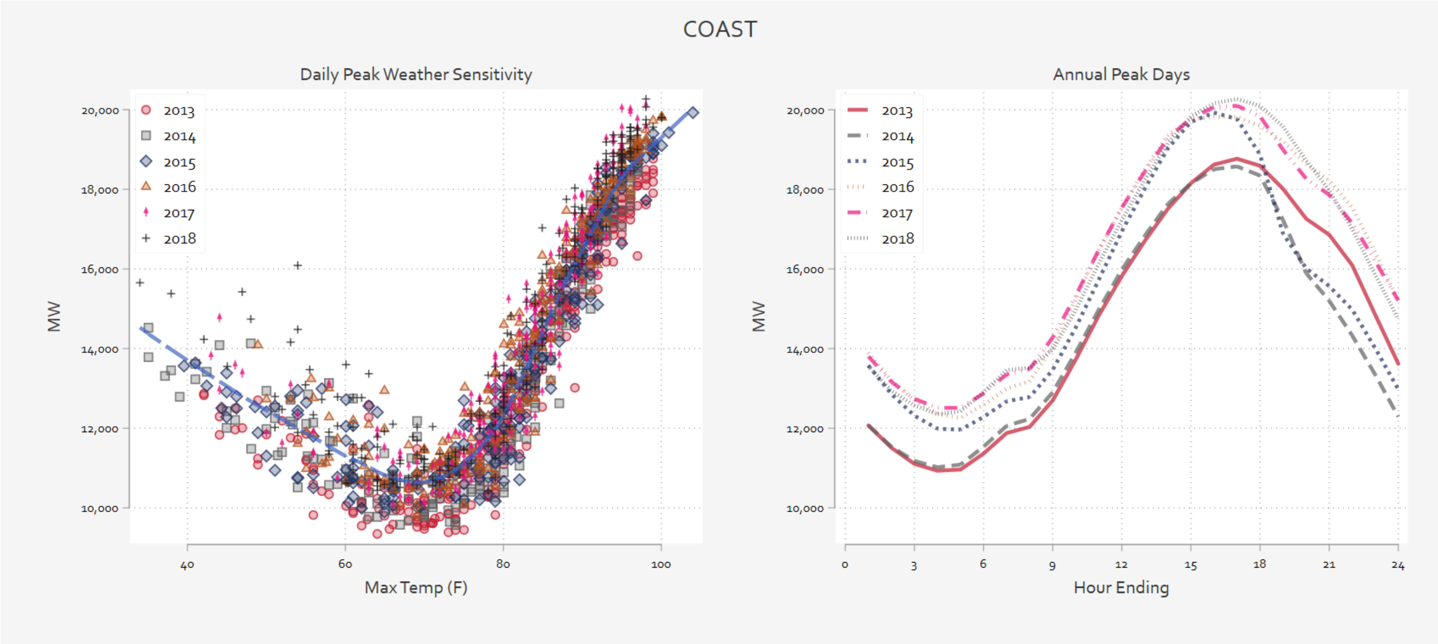
1. Splitting the data into testing and training days
2. Defining ten plausible model specifications.
3. Running each of the models using the training data.
4. Predict out-of-sample loads for the testing days.
5. Assessing the out-of-sample bias and fit by comparing predictions to actual electricity use on the testing days.
6. Identifying the best performing model using a two step process for each zone. First, the candidate models were narrowed to the three with the least absolute percentage bias (or an absolute percentage bias of less than 1%). Second, we selected the model with the best fit as defined by the normalized root mean squared error.
7. The best performing model was then applied to all days and used to estimate the annual growth rate.

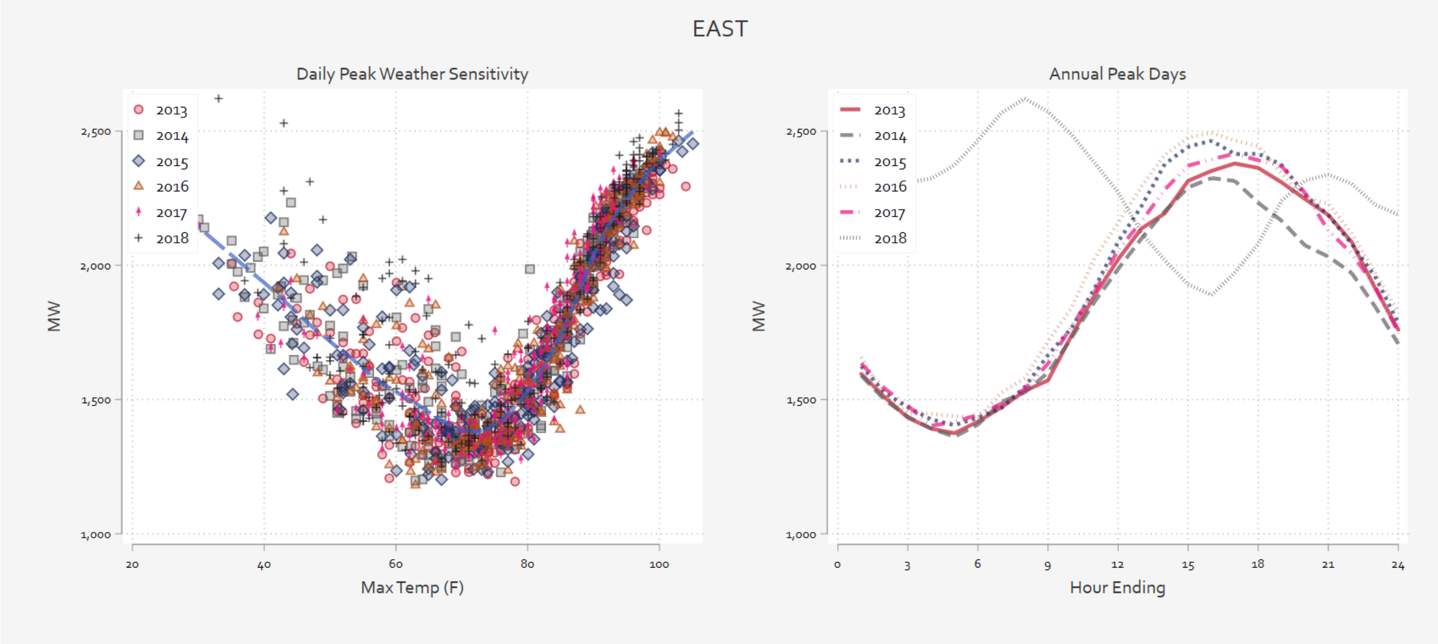
Table 2 summarizes the actual peaks in each year and zone and includes the estimated annual growth rate. Note that in two zones – East and South – annual peaks occurred in both summers and winters. The figures summarize the relationship between weather and peak load and the hourly annual peak load for each zone.

Table 10: Annual Peak Demand and Growth Rates by Zone

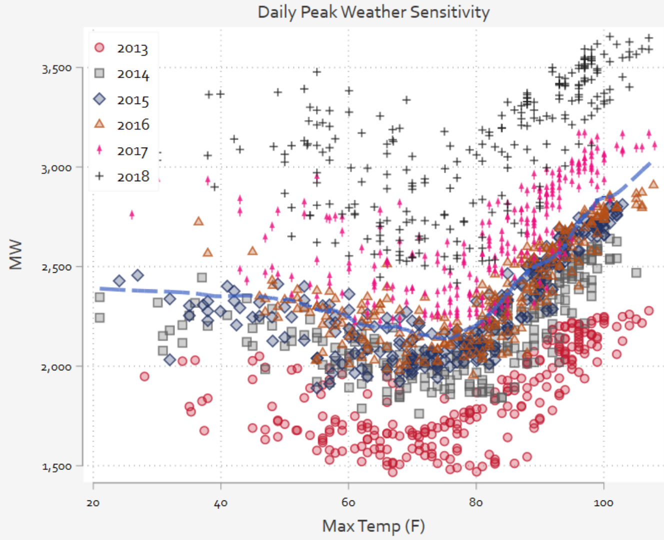
Zone	Annual Peak Demand (Actual) 2013	2014	2015	2016	2017	2018	Annual Peak Growth (%)	Std. Error
COAST	18,770	18,578	19,929	19,826	20,101	20,270	**2.33%**	**0.10%**
EAST	2,379	2,325	2,464	2,494	2,416	2,621	**1.22%**	**0.13%**
FAR WEST	2,279	2,688	2,812	2,909	3,164	3,655	**9.98%**	**0.15%**
NORTH	1,483	1,408	1,452	1,440	1,394	1,522	**0.47%**	**0.11%**
NORTH CENTRAL	24,421	23,446	24,581	25,282	24,313	26,499	**1.32%**	**0.11%**
SOUTH	5,207	5,352	5,455	5,787	5,845	6,176	**2.99%**	**0.13%**
SOUTH CENTRAL	11,433	11,452	12,033	12,345	11,970	14,167	**1.75%**	**0.10%**
WEST	1,862	1,853	1,884	1,899	1,902	2,084	**3.10%**	**0.14%**
ERCOT	**67,253**	**66,464**	**69,620**	**71,093**	**69,496**	**73,308**	**2.43%**	**0.11%**

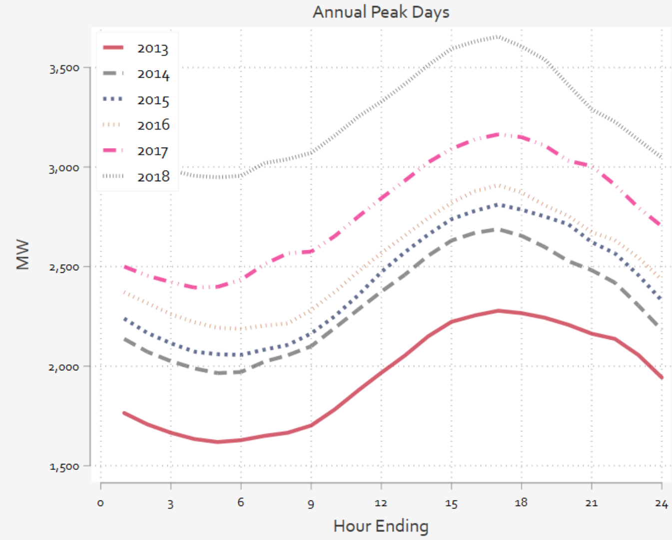



COAST
Daily Peak Weather Sensitivity
2013
2014
2015
2016
2017
2018
MW
Max Temp (F)
Annual Peak Days
Hour Ending

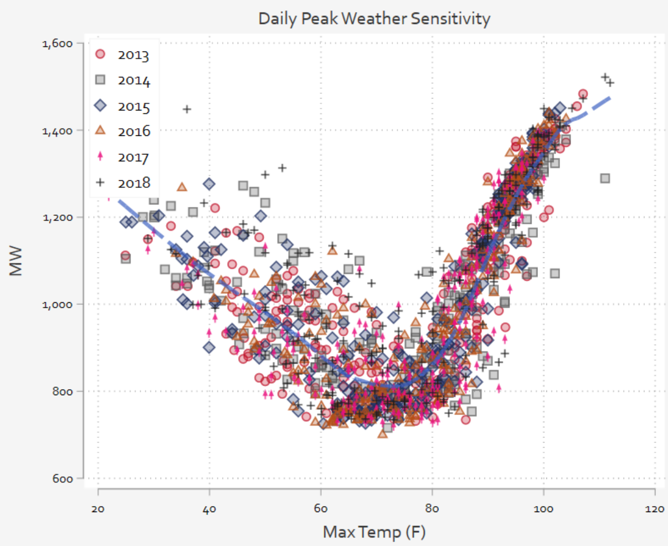

EAST
Daily Peak Weather Sensitivity
2013
2014
2015
2016
2017
2018
MW
Max Temp (F)
Annual Peak Days
Hour Ending

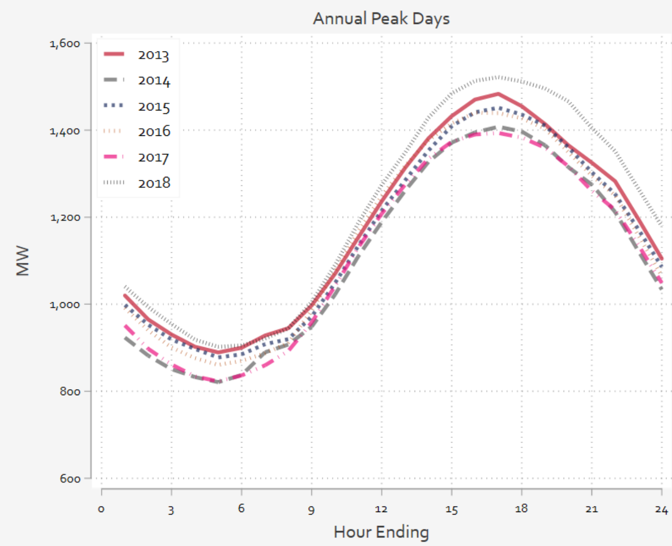
FAR WEST

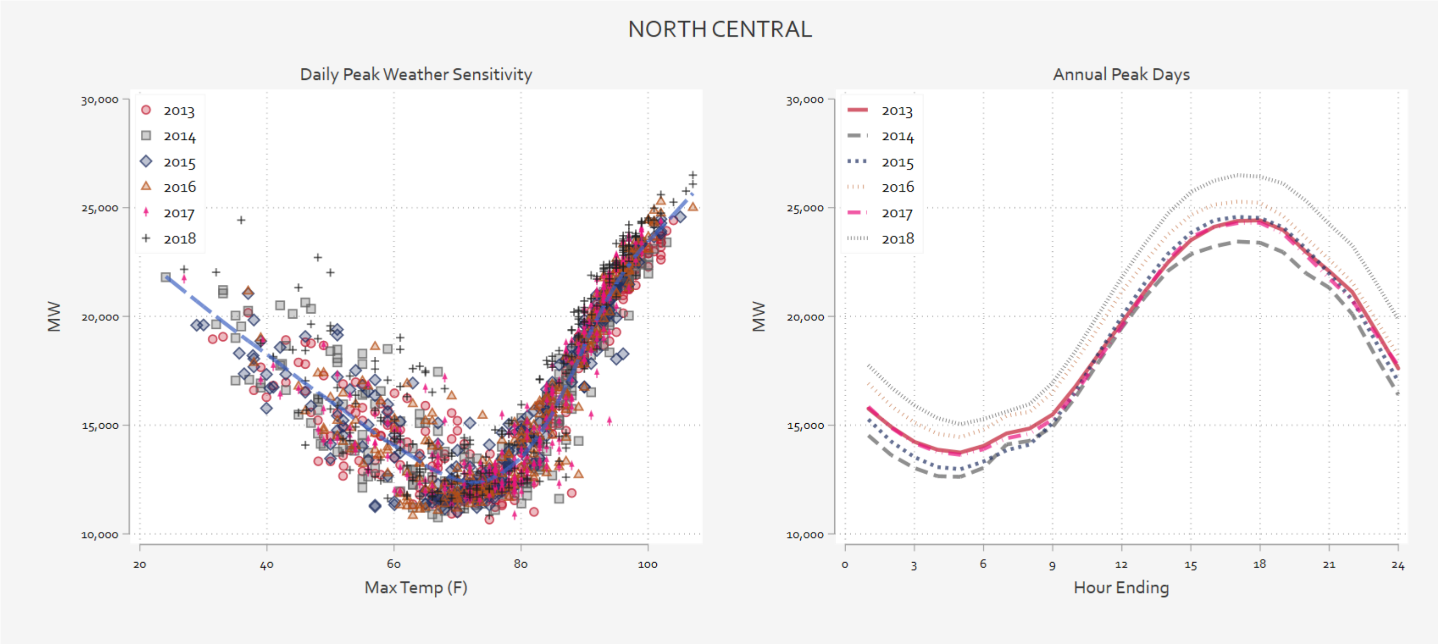




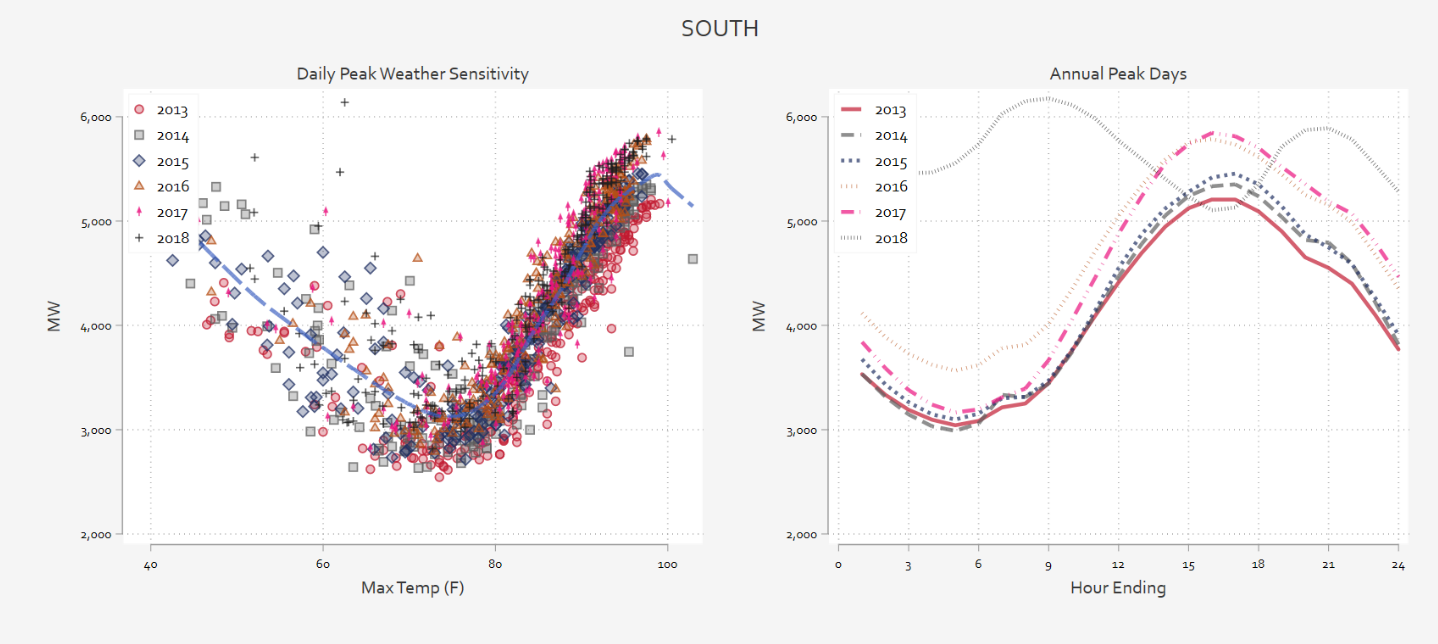
NORTH





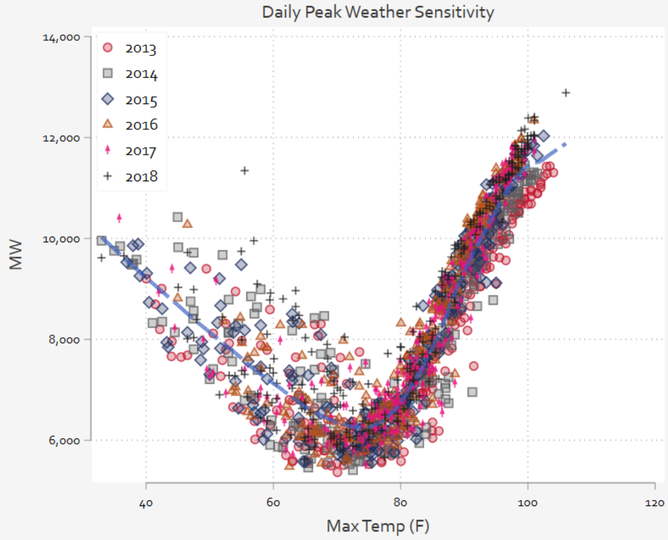


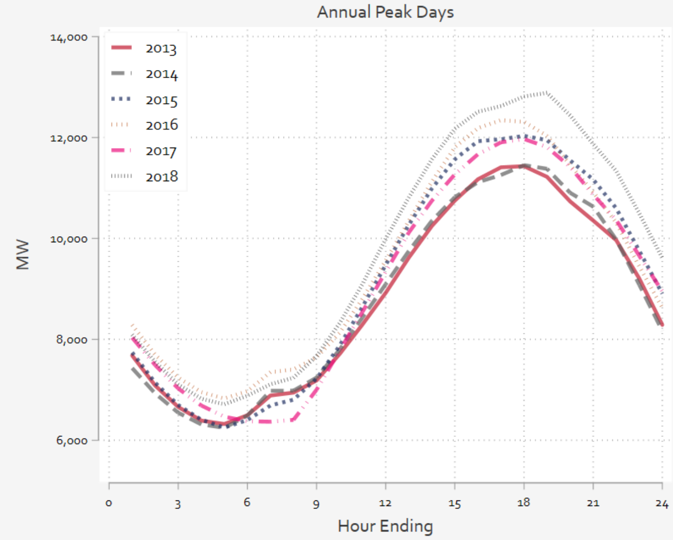
NORTH CENTRAL
Daily Peak Weather Sensitivity
Annual Peak Days
2013
2014
2015
2016
2017
2018
MW
30,000
25,000
20,000
15,000
10,000
20
40
60
80
100
Max Temp (F)
0
3
6
9
12
15
18
21
24
Hour Ending



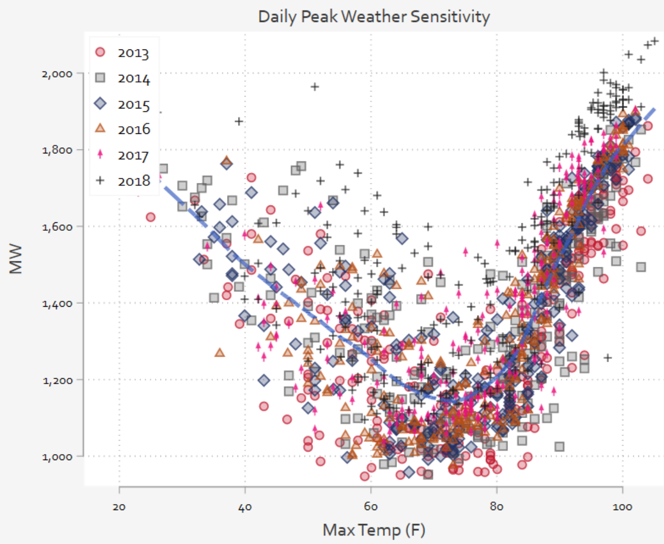
SOUTH
Daily Peak Weather Sensitivity
Annual Peak Days
2013
2014
2015
2016
2017
2018
MW
6,000
5,000
4,000
3,000
2,000
40
60
80
100
Max Temp (F)
0
3
6
9
12
15
18
21
24
Hour Ending

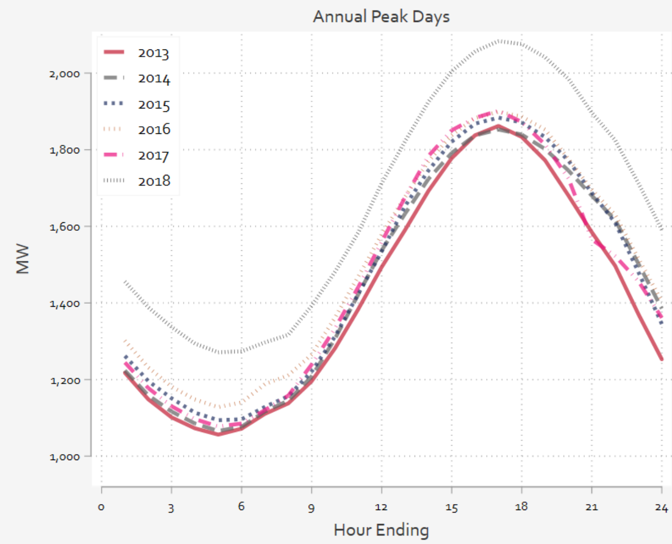
SOUTH CENTRAL





WEST





APPENDIX D: GRANULAR POPULATION GROWTH RATES

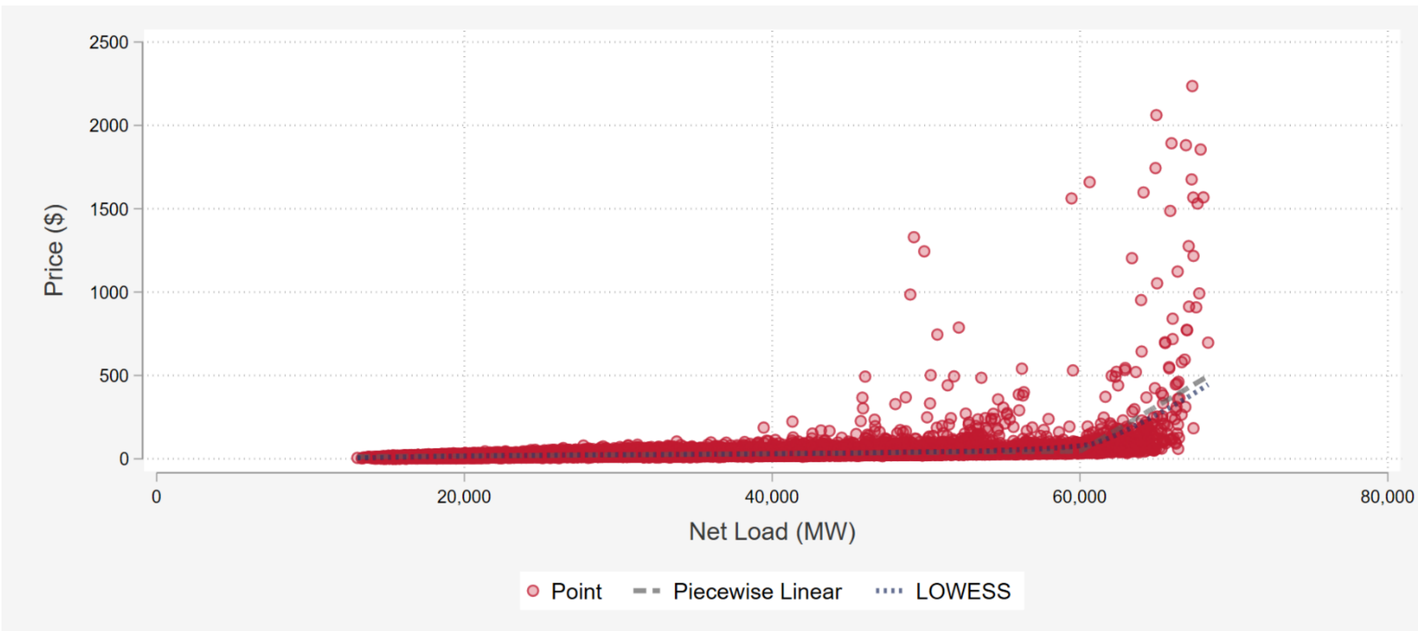
Type	Area	Population								Annual Growth Rate (%)
		2010	2011	2012	2013	2014	2015	2016	2017	
Metro Area	Abilene	165,583	166,633	167,452	167,426	168,143	169,478	169,733	170,219	**0.40%**
	Amarillo	252,674	255,992	257,777	258,847	260,662	261,508	263,036	264,925	**0.68%**
	Austin-Round Rock	1,727,495	1,780,610	1,834,566	1,883,528	1,942,255	2,000,784	2,060,558	2,115,827	**2.94%**
	Beaumont-Port Arthur	403,697	405,356	403,895	405,471	405,754	408,744	410,909	412,437	**0.31%**
	Brownsville-Harlingen	407,590	412,917	415,370	417,095	418,838	419,579	421,766	423,725	**0.56%**
	College Station-Bryan	229,449	231,451	234,126	237,820	242,533	250,138	254,230	258,044	**1.69%**
	Corpus Christi	427,872	430,908	436,575	442,812	447,671	452,355	454,066	454,008	**0.85%**
	Dallas-Fort Worth-Arlington	6,451,833	6,571,537	6,706,020	6,817,243	6,950,715	7,101,031	7,253,424	7,399,662	**1.98%**
	Dallas-Plano-Irving	4,246,983	4,333,377	4,429,673	4,507,349	4,602,351	4,705,624	4,809,999	4,911,124	**2.10%**
	Fort Worth-Arlington	2,204,850	2,238,160	2,276,347	2,309,894	2,348,364	2,395,407	2,443,425	2,488,538	**1.74%**
	El Paso	806,983	822,747	834,478	833,522	836,753	836,326	841,220	844,818	**0.66%**
	Houston-The Woodlands-Sugar Land	5,947,419	6,057,947	6,183,726	6,329,553	6,496,862	6,664,187	6,798,010	6,892,427	**2.13%**
	Killeen-Temple	408,277	412,376	423,529	424,069	426,600	432,741	436,803	443,773	**1.20%**
	Laredo	251,327	255,598	259,964	263,962	267,168	269,795	272,401	274,794	**1.28%**
	Longview	214,731	216,016	216,693	216,265	216,445	217,162	217,314	217,481	**0.18%**
	Lubbock	292,226	295,315	297,902	301,258	306,233	310,125	314,013	316,983	**1.17%**
	McAllen-Edinburg-Mission	779,015	794,639	806,725	817,526	829,210	840,113	850,187	860,661	**1.43%**
	Midland	141,788	145,061	152,251	157,593	162,036	167,688	169,161	170,675	**2.68%**
	Odessa	137,079	139,611	144,455	149,651	154,566	159,835	157,580	157,087	**1.97%**
	San Angelo	112,284	113,345	114,891	116,333	117,975	119,141	119,362	119,535	**0.90%**
	San Antonio-New Braunfels	2,152,961	2,193,620	2,236,395	2,279,878	2,328,419	2,379,054	2,426,211	2,473,974	**2.01%**
	Sherman-Denison	121,034	121,372	121,750	122,295	123,540	125,549	128,206	131,140	**1.15%**
	Texarkana	149,324	149,602	149,684	149,653	149,519	149,739	150,185	150,355	**0.10%**
	Tyler	210,398	212,653	214,707	216,426	219,517	222,410	225,305	227,727	**1.14%**
	Victoria	94,102	94,738	96,399	97,509	98,492	99,592	99,900	99,646	**0.82%**
	Waco	253,804	255,676	256,853	258,646	260,298	262,598	264,809	268,696	**0.82%**
	Wichita Falls	151,643	150,276	150,982	151,380	151,782	149,979	150,326	151,230	**-0.04%**
Micro Area	Alice	40,887	41,206	41,628	41,664	41,472	41,469	41,115	40,871	**-0.01%**
	Andrews	14,847	15,386	16,106	16,788	17,448	18,092	17,837	17,722	**2.56%**
	Athens	78,623	78,792	78,938	78,628	79,262	79,447	80,034	81,064	**0.44%**
	Bay City	36,705	36,681	36,543	36,506	36,494	36,762	37,117	36,840	**0.05%**
	Beeville	31,863	32,312	32,474	32,803	32,837	32,609	32,835	32,563	**0.31%**
	Big Spring	36,214	36,226	36,755	37,424	37,818	38,503	37,968	37,388	**0.46%**
	Bonham	33,917	33,872	33,576	33,541	33,615	33,476	33,855	34,446	**0.22%**
	Borger	22,210	22,013	22,004	21,894	21,898	21,781	21,570	21,375	**-0.55%**
	Brenham	33,708	33,957	33,911	34,191	34,411	34,869	34,821	35,043	**0.56%**
	Brownwood	38,079	37,981	37,755	37,610	37,500	37,709	38,065	38,053	**-0.01%**
	Corsicana	47,869	48,053	48,138	48,029	47,918	48,170	48,375	48,701	**0.25%**
	Del Rio	48,977	48,950	48,923	49,010	48,808	48,906	48,953	49,205	**0.07%**

Type	Area	Population								Annual Growth Rate (%)
		2010	2011	2012	2013	2014	2015	2016	2017	
	Dumas	22,010	22,090	22,437	22,145	22,021	21,880	21,935	22,097	**0.06%**
	Eagle Pass	54,447	55,224	55,658	56,462	57,031	57,658	57,989	58,216	**0.96%**
	El Campo	41,278	41,260	41,064	41,095	41,073	41,379	41,634	41,968	**0.24%**
	Fredericksburg	24,885	25,038	25,152	25,320	25,465	25,959	26,305	26,646	**0.98%**
	Gainesville	38,463	38,384	38,675	38,429	38,691	39,063	39,244	39,895	**0.52%**
	Hereford	19,458	19,490	19,327	19,148	19,099	18,802	18,850	18,836	**-0.46%**
	Huntsville	82,970	83,095	82,966	83,867	84,277	85,225	86,214	86,912	**0.67%**
	Jacksonville	50,939	51,076	51,261	51,088	51,174	51,573	51,896	52,240	**0.36%**
	Kerrville	49,619	49,607	49,686	49,760	50,275	50,753	51,296	51,720	**0.59%**
	Kingsville	32,450	32,462	32,536	32,451	32,281	31,831	31,775	31,505	**-0.42%**
	Lamesa	13,827	13,744	13,601	13,202	13,434	12,984	13,042	12,813	**-1.08%**
	Levelland	22,851	22,927	23,063	23,400	23,461	23,315	23,103	23,088	**0.15%**
	Lufkin	86,903	87,282	87,496	87,365	87,601	87,901	87,830	87,805	**0.15%**
	Marshall	65,752	66,324	66,242	66,254	66,626	66,760	66,730	66,661	**0.20%**
	Mineral Wells	28,082	28,052	27,856	27,872	28,016	27,956	28,132	28,570	**0.25%**
	Mount Pleasant	32,414	32,423	32,634	32,623	32,460	32,720	32,615	32,904	**0.21%**
	Nacogdoches	64,683	65,639	65,821	65,163	65,187	65,464	65,662	65,580	**0.20%**
	Palestine	58,495	58,379	58,036	57,960	57,837	57,641	57,558	57,741	**-0.19%**
	Pampa	22,467	22,651	22,908	22,986	23,437	23,245	22,738	22,404	**-0.04%**
	Paris	49,816	49,863	49,684	49,093	49,393	49,367	49,565	49,587	**-0.07%**
	Pecos	13,831	13,799	13,959	14,189	14,509	14,906	15,069	15,281	**1.43%**
	Plainview	36,291	36,398	36,269	35,703	34,490	34,099	34,209	34,134	**-0.87%**
	Port Lavaca	21,311	21,356	21,575	21,735	21,805	21,881	21,942	21,744	**0.29%**
	Raymondville	22,225	22,166	22,198	22,027	21,943	21,882	21,760	21,584	**-0.42%**
	Rio Grande City	61,145	61,582	61,823	62,290	62,914	63,512	63,931	64,454	**0.76%**
	Snyder	16,932	16,876	17,102	17,265	17,399	17,588	17,430	17,050	**0.10%**
	Stephenville	37,912	38,925	39,414	39,903	40,543	41,221	41,443	41,969	**1.46%**
	Sulphur Springs	35,204	35,253	35,313	35,302	35,683	35,959	36,203	36,496	**0.52%**
	Sweetwater	15,249	15,129	14,892	15,055	15,114	15,041	14,968	14,770	**-0.45%**
	Uvalde	26,438	26,565	26,715	26,848	27,062	26,925	27,106	27,132	**0.37%**
	Vernon	13,508	13,440	13,272	13,185	12,970	13,049	12,894	12,764	**-0.81%**
	Zapata	14,087	14,223	14,269	14,393	14,396	14,516	14,449	14,322	**0.24%**

APPENDIX E: PIECEWISE REGRESSION MODEL ESTIMATION

As discussed in Section 3.3 estimating the savings associated with DER market participation depends on developing a relationship between price and load. Five years of historical price and load data (2014-2018) provided the basis of our model. For system loads less than 60,000 MW, the relationship between price and load can be expressed well with a linear function that has a small upward slope but appears largely flat. In other words, large increases in load are necessary to cause a significant increase in price. Beyond 60,000 MW there is a visually evident change in slope. As load continues to rise the slope increases even more dramatically.

Figure 16: ERCOT Day Ahead Price vs Net Load (2014-2018)



In fitting a model to this data, the goal was to capture the dramatic change in slope that occurs at high loads while preventing any sections of the model with negative slopes. This might occur when fitting a polynomial function to the data, but would violate economic principles since a supply curve is always upward sloping. Visually the best fit is obtained using a locally weighted scatterplot smoothing (LOWESS) function which performs a weighted least squares estimation at each point in the dataset. The resulting curve fits the data well, but this methodology does not generate a functional form. This precludes estimating the price at a value of load not in the dataset.

We investigated a number of other methods including polynomials, fractional polynomicals, and restricted cubic splines but settled on a piecewise linear regression of price on net load to model the supply curve. The piecewise model fits separate linear regressions for different ranges of load. The function is continuous but not differentiable around the knot points which dictate the change in slope. By including a number of knots in the high load range we were able to mimic the shape of curve. The number cutpoints and location of the knots was allowed to differ by season to reflect the different resource availability across periods. Thus, the supply curve is really composed of three individual curves for each season. Visual evidence informs the lower bound at which we began introducing knots, and we used a threshold model to determine the location of the knots. By creating a set of linear splines from the net load data we can find the slope in each region using a single regression.

The result is a set of equations each defined for a specific range of the net load values. To simulate the impact of a DER addition we simply perform a shift of the piecewise function. This essentially changes the range over which each slope applies.

APPENDIX F: ANCILLARY SERVICE MARKETS

As described in Section 3.4, the ancillary service market prices are highly correlated with the day ahead market energy prices. As shown in Table 11, when loads are above 60,000 the Energy, Regulation Up, and Responsive Reserve markets are almost perfectly correlated. Because these markets track so closely, the estimates of savings from DER participation in markets are based solely on energy markets.

Table 11: Correlation Between Energy and Ancillary Service Market Products (Net Load< 60,000 MW)

	Energy	Regulation down	Regulation up	Responsive reserve service	Non-spinning reserves
Energy	1.0000				
Regulation down	0.6531	1.0000			
Regulation up	0.9996	0.6528	1.0000		
Responsive reserve service	0.9992	0.6512	0.9996	1.0000	
Non-spinnning reserve	0.5583	0.1913	0.5622	0.5667	1.0000

[1] http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_8.20.19.pdf

[2] https://nyrevconnect.com/non-wires-alternatives/

[3]https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/

[4] The amount amortized typically includes a revenue requirement adjustment, between 20-30%, to account for taxes, depreciation, and other carrying costs.

[5] Investor owned utilities must submit detailed tables “Form-1” each year to the Federal Energy Regulatory Commission (FERC). The requirement includes data about annual capital investment additions by granular expenditure categories. Investments summarized in the figure exclude costs tied to individual service connections and metering. Expenditures for

public utilities were estimated by applying a scaling factor based on annual sales (MWh, from EIA form 861) to the IOU expenditures. Additional detail can be found in the appendix.

[6] Real GDP for Texas (in indexed dollars), as reported by the US Bureau for Economic Analysis (https://apps.bea.gov/iTable/index.cfm)]

[7] US Census Bureau State Intercensal Tables https://www.census.gov/data/tables/time-series/demo/popest/2010s-state-total.html and https://www.census.gov/data/tables/time-series/demo/popest/intercensal-2000-2010-state.html

[8] To gather this data, secondary web searches were conducted. Search terms included "Capital forecasts", "Capital plan", "Expansion", "New business", "Growth", etc. Searches were done for utilities in general, as well as focused on utilities with operations in and outside of Texas or neighboring Texas. IOUs in California and New York were also specifically investigated given the expanded regulatory filing requirements. All data points found were included.

[9] Deferral Period = $\frac{\ln(1+\text{DER percent})}{\ln(1+\text{annual growth rate})}$

[10] T&D equipment have thermal ratings for normal and extreme conditions, which describe how the load the equipment can support. In practice, T&D equipment may be sized to allow re-routing of power (transfers), hence the use of a more generic term: "operating limit."

[11] https://www.infrastructurereportcard.org/wp-content/uploads/2017/01/Energy-Final.pdf

[12] https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf

[13]http://www.ercot.com/mktrules/issues/NPRR815#summary
[14] For additional detail see ERCOT's *2018 Annual Report of Demand Response* report. Available at: http://mis.ercot.com/misdownload/servlets/mirDownload?mimic_duns=&doclookupId=654416540

[15] ERCOT created a Distributed Resource Energy and Ancillaries Market Task Force which produced a number of of white papers and reports on DER growth and impacts: http://www.ercot.com/committee/dreamtf

They have also highlighted some pending changes to price signals for DERs and the need for enhanced visibility in recent legislative emerging issues breifings: http://www.ercot.com/content/wcm/lists/144928/LegislativeandPUCTBriefing-EmergingGridIssues-FINAL.pdf

[16] https://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf
[17] FERC Form-1 data for TNMP was not found for 2007-2016. To fill the gap, factors derived from years with data were applied to the years which were missing data. TNMP accounted for about 3% of total expenditures.
[18] FERC Form-1 is filed by utility entity. In cases of entities with operations in multiple states, a share was allocated to Texas based on the share of total electric sales in Texas. Share of electric sales in each year for each utility was derived using Total Sales (MWh) in EIA form 861.
[19] Because FERC Form-1 filing are not required for publicly owned utilities, expenditures for these entities were estimated by applying a scaling factor to IOU expenditures based on the ratio of public annual sales (from EIA form 861) to annual Texas sales for the IOUs. In practice transmission expenditures may be lower and distribution expenditures may be higher for public entities than for IOUs, but in total the difference may not meaningful or merit a more complex approach for estimating public expenditures.