# THE POTENTIAL OF DISTRIBUTED ENERGY RESOURCES IN ERCOT, AND THE IMPORTANCE OF GETTING IT RIGHT

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## A. Introduction and overview

### *1. The ever-changing electricity landscape*

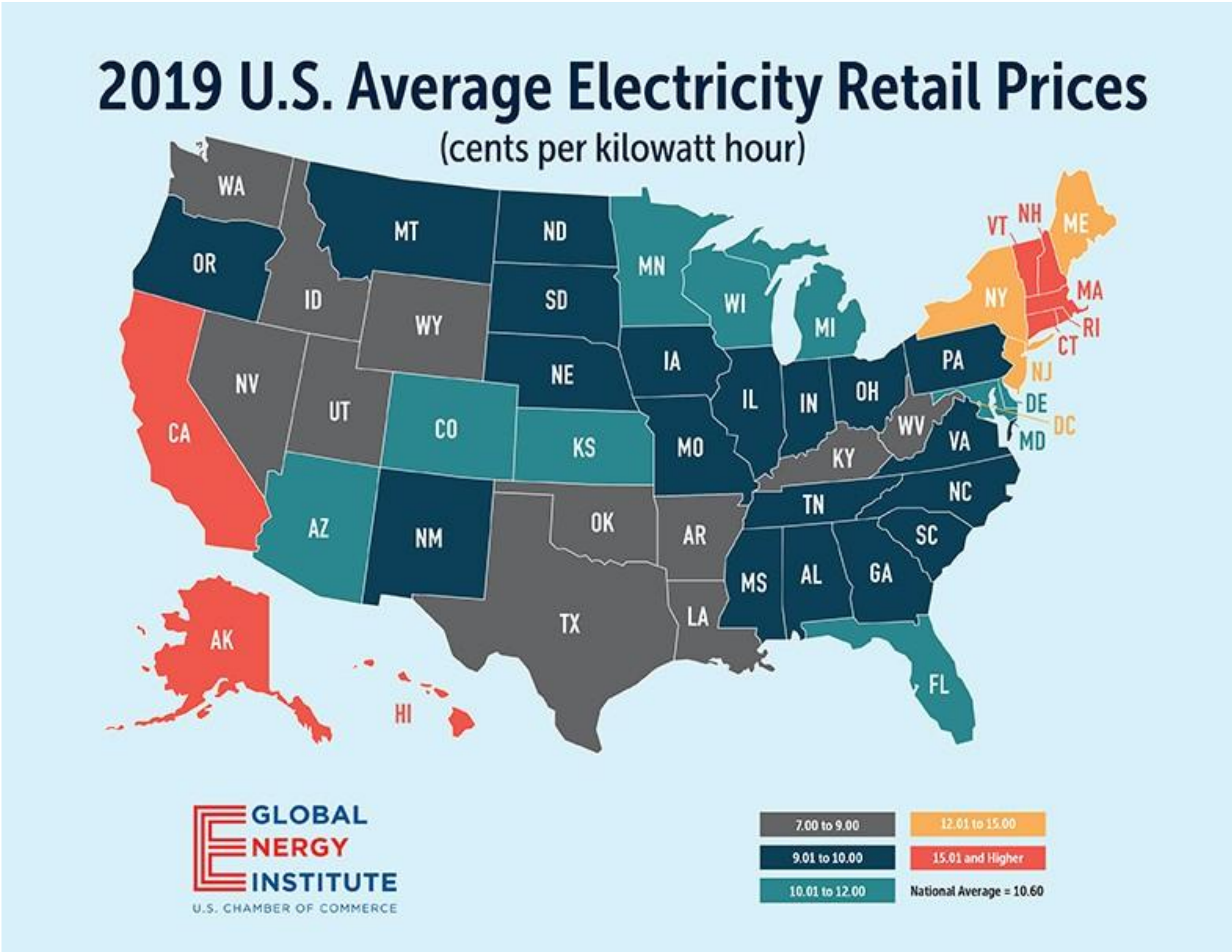
Twenty-five years ago, the power landscape was fairly straightforward. Electricity was generally delivered to customers by public utilities regulated by state authorities. These companies owned all of the assets required to generate, transmit, and distribute power to households and businesses, and they were guaranteed a fixed rate-of-return on their capital investments that was reflected in the rates charged customers.

Today, 20 states have totally or partially restructured their electricity markets, allowing independent power generators to compete in wholesale markets and retail electric providers to compete for end-use customers. Texas went further than most in embracing restructuring more than 20 years ago, with the result that its legacy power companies like Oncor, CenterPoint, AEP and TNMP have become regulated common carriers solely dedicated to the task of transmitting and distributing electricity—the so-called "poles and wires" business.

Another significant change on the Texas power landscape has been the evolution of renewable generation sources, in particular wind power. Currently, more than 29 gigawatts (GW) of wind energy are hooked up to the Texas power grid, representing almost a quarter of total installed capacity of 122 GW from all power types. Today, the state has almost as much wind in its generation mix as the next four states combined and nearly five-times as much as California. Industrial scale solar power has also grown rapidly in Texas, now supplying the grid with about 4.5 GW on sunny days.

On balance, the restructured Texas electricity market has been a boon for consumers. Competition in retail and wholesale markets has resulted in some of the lowest electricity prices in the nation. At the same time, a robust transmission and distribution network has kept electricity available for Texans whenever they need it. The average kilowatt hour cost in Texas last year was 8.5 cents compared with a national average of 10.5 cents. By contrast, Californians paid 16.8 cents per kWh while New Yorkers paid 14.8 cents. In fact, Texas currently boasts the lowest electricity rates of the 10 largest states, and relocating companies often cite competitive power rates as one of the justifications for moving to the state.

Figure 1:




Texas' competitive market plays a key role in spurning innovation and ensuring reliability. For example, entities that are not Transmission and Distribution Utilities (TDUs) are free to market their products of energy efficiency, load shedding, microgrids, and storage in the competitive market without limit. In ERCOT, there are currently numerous deployments of pure storage, storage coupled with solar, storage coupled with wind, etc. These entities are incentivized to participate in the market for a variety of reasons, including arbitrage, reliability, and responding to demand fluctuation. Furthermore, the products can be marketed straight to large Commercial and Industrial (C&I) customers. In addition, the entities can become vendors for TDUs if, for example, the TDUs wish to deploy certain technologies for certain applications at favorable prices.

Under the purview of the Public Utility Commission of Texas (PUC), TDUs have been adept at advancing appropriate and innovative technologies onto their transmission and distribution grids to cost-effectively serve customers. Examples of such technologies include smart meters, synchrophasors, and self-healing technologies that automatically detect problems and shorten recovery times. What is more, TDUs have provided highways for the proliferation of renewable technology. Perhaps the most salient example of is the Competitive Renewable Energy Zones (CREZ) project, which has delivered an abundance of wind power to the overall market and the Permian Basin in particular.

A much more recent proposal to change the Texas power landscape has been the adoption of distributed (or distribution-connected) energy resources (DERs) as a modification to the delivery process. Currently, transmission and distribution utilities operate almost entirely as "one-way" delivery services bringing electrons from the power grid into homes and businesses. DERs—in particular rooftop solar arrays and battery storage—are being proposed as cost-effective alternatives to traditional distribution services and even to transmission services and real-time operational issues. But their adoption also raises questions of safety, reliability, and cost assignment, as well as technical integration problems (see discussion below).

### 2. *Brief description of Texas power grid*

The Electric Reliability Council of Texas, Inc. (ERCOT) independently manages the flow of electric power to more than 25 million electric customers in Texas, representing about 90 percent of the state's electric load. The ERCOT grid consists of more than 46,500 miles of transmission lines and it connects more than 600 generation units.

ERCOT is a unique grid system operator in that it has extremely limited interconnects with other states and Mexico. This means Texas mostly generates its own electricity and is not reliant on trading large amounts of power with other states to balance supply and demand. Further, because ERCOT does not have major connections to other states, decisions on the direction of the market are almost exclusively regulated by the Texas Legislature and the Public Utility Commission of Texas (PUCT), not federal authorities. Among the contiguous 48 states, Texas is the only one with a stand-alone electricity grid, and the only one removed from the comprehensive jurisdiction of the Federal Energy Regulatory Commission (FERC).

Because the state's economy and population are projected to continue growing much faster than the nation as a whole in the foreseeable future, the Texas power grid and its transmission and distribution utilities will face challenges in the years ahead. ERCOT estimates Texas will need more than 16 gigawatts of new power over the next 10 years just to keep up with expected peak demand.

Figure 2:


3. *The current utility planning process for transmission and distribution*

Transmission planning is the process of identifying areas of the current transmission grid that are in need of expansion to maintain reliability and to accommodate new generation and/or growing load.

In Texas, an ERCOT-led regional planning group (RPG) evaluates future demand and reliability issues and considers new projects on an ongoing basis. This is one of the main advantages of having a transmission grid dedicated to serving the needs of just one state. Transmission improvement projects estimated to cost more than $25 million, or requiring a Certificate of Convenience and Necessity from the Texas Public Utility Commission (PUCT), are reviewed by the RPG prior to implementation. For the largest projects, RPG consideration is followed by an evaluation and endorsement by the ERCOT Board of Directors. The RPG is a non-voting forum comprising all interested parties—typically, this includes ERCOT, PUCT Staff, transmission service providers, various market participants, and any other interested stakeholders.

Texas utilities assess the need for new transmission lines by first conducting technical and economic studies. Subsequently, an application is submitted to the PUCT that includes an analysis of the need for the new line, cost estimates, and a proposed route. The PUCT then holds hearings to determine the need for the line, determine its exact route, and address landowner and community concerns. Once a permit is issued, and any eminent domain issues are resolved, the utility then builds and operates the new lines.

To deliver power to retail customers, the vast majority of distribution grids have a radial design that delivers electric service to end users from central substations, where energy voltage is stepped down to serve end-use customers. Typically, transformers are installed to convert high voltage transmission to low voltages, such as 120 volts for households and 480 volts for most industrial users. Large transformers are housed in substations where sections of a transmission and distribution system operating at different voltages are joined. Large substations sometimes have manned control rooms while smaller substations typically operate automatically. In addition to transformers, important substation equipment includes switchgear, circuit breakers, relays, and other protective equipment. Advocates of DER technologies, as noted above, argue they have the potential to reduce the need for new generation and transmission, lower power costs, avoid line losses, and improve grid reliability. They further claim that microgrids, using advanced smart grid technologies and distributed energy resources like batteries and rooftop solar, can operate autonomously during emergencies like extreme weather events.

Without question, the interplay between transmission, microgrids, and distributed generation will be an important economic and policy issue facing Texas regulators and public utilities in the years ahead; however, as discussed below, the situation is far more complex than DER proponents portray.

## B. <u>Distributed energy resources: DERs</u>

### *1. What is a DER?*

The characteristics of DERs are constantly changing, and no uniform definition exists. In the past, DERs referred mainly to small, geographically dispersed generation resources, such as solar or combined heat and power (CHP) systems, located on the distribution system. At a local scale, usually of a single customer, these energy generation systems could partially or completely meet electricity demands and, at times, feed surplus energy back into the distribution or even the transmission systems.

However, as technology has evolved in recent years, so too has the definition of a DER. Now, DERs include not only generation resources but also energy storage, energy efficiency, and demand response resources. Distributed generation resources, the traditional DERs, are often co-located with demand response and/or battery storage technologies, creating a bundled net demand that can be difficult for a utility to measure or predict.

Some entities, such as the California Public Utility Commission (CPUC), include only renewable resources in their definitions of a DER. Other entities, such as ERCOT, allow for the inclusion of fossil fuel resources including diesel-fired backup generators and natural gas microgrids. However, the National Association of Regulatory Utility Commissioners (NARUC) provides one of the most comprehensive definitions of a DER:

> A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER[s] include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).[1]

NARUC goes on to identify three distinguishing characteristics of a DER:

> (1) the resource is connected to the distribution grid and not the bulk transmission system;
>
> (2) the resource is relatively small, certainly under 10MW but generally much smaller; and
>
> (3) the resource is generally not individually scheduled by a regional transmission organization (RTO) or an independent system operator (ISO), nor is it necessary to report a DER individually to an RTO/ISO, since, if a DER is procured or dispatched at all, it would be on an aggregated manner by a third party or the utility itself.

A recent report released by the Environmental Defense Fund (EDF) asserts that Texas' power market could meet much of future demand growth, while sustaining grid resilience, by leveraging DERs along with energy efficiency measures.[2] Proponents further argue that DERs can respond to prices as well as to grid management signals. In the face of rapid demand growth and uncertain supply, these assets promise to de-risk the electric system by limiting peak load and ancillary service needs, thereby reducing the burden and cost of assuring adequate supply, flexibility, and grid integrity.

### 2. *Where do DERs fit into power grids?*

#### a. *What is the current inventory of DERs in Texas and elsewhere?*

In just the last five years, DERs have been expanding rapidly, albeit from a small base, in Texas and elsewhere. DERs in ERCOT grew 62% between 2015 and 2017 (see Figure 1). By the end of 2018, there were an estimated 1,300 MW of DERs in ERCOT, primarily diesel generators and

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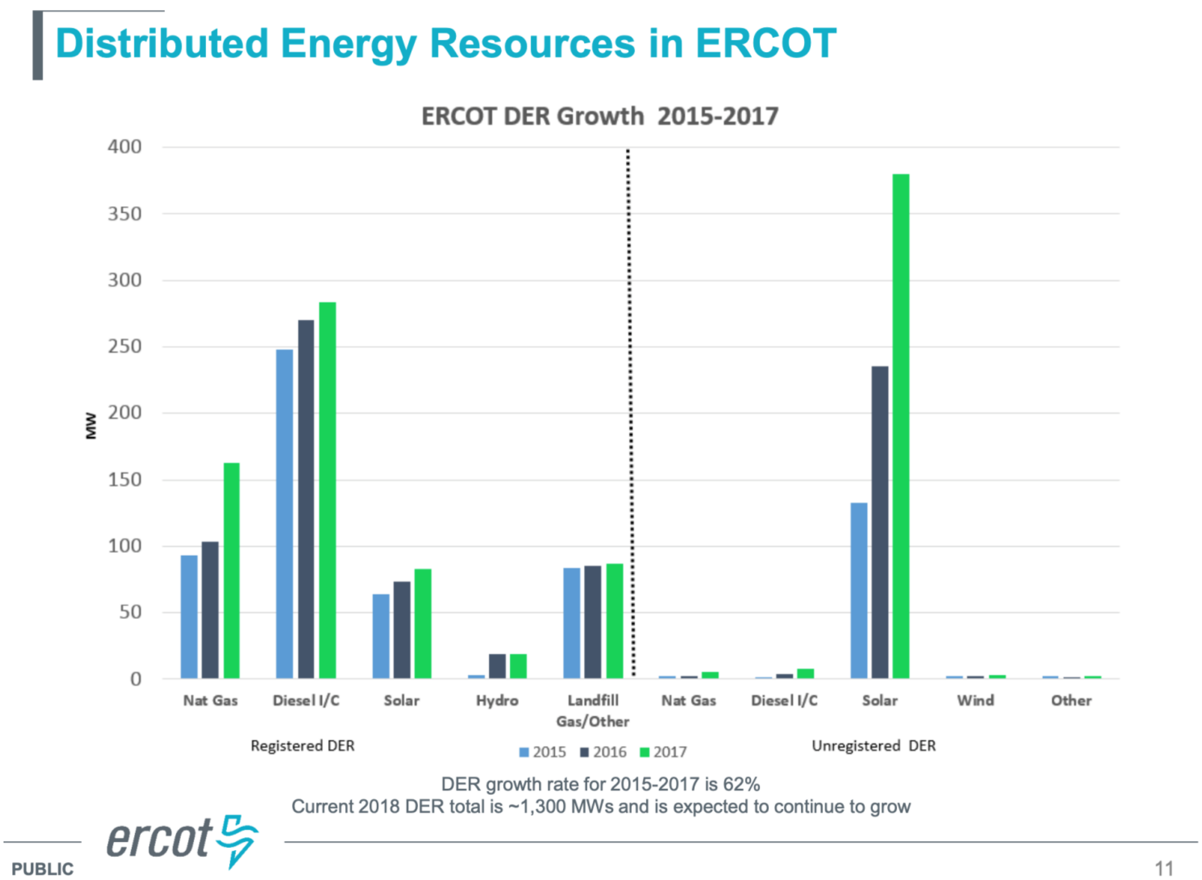
[1] "Distributed Energy Resources Rate Design and Compensation," *The National Association of Regulatory Utility Commissioners (NARUC)*, 2016, https://pubs.naruc.org/pub.cfm?id=19fdf48b-aa57-5160-dba1-be2e9c2f7ea0, 44.

[2] Alison Silverstein, "Resource Adequacy Challenges in Texas: Unleashing Demand-Side Resources in the ERCOT Competitive Market," *Environmental Defense Fund*, May 1, 2020, https://www.edf.org/sites/default/files/documents/EDF-ERCOT-Report.pdf.

rooftop solar arrays.[3] To put that in perspective, ERCOT expects to have a little over 82,000 MW of available power capacity during summer 2020.[4]

Figure 3[5]:




DER growth is expected to continue, especially as the costs of solar and battery storage continue to decrease. DERs between 1 MW and 10 MW that export power to the ERCOT grid are required to be registered with ERCOT, while DERs under 1 MW do not have to register.

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[3] Ira Shavel, Ahmad Faruqui, and Yingxia Yang, "Valuing and Compensating Distributed Energy Resources in ERCOT," *Texas Clean Energy Commission* (The Brattle Group, March 28, 2019), https://3vq5kdns38e1qxlmvvqmrzsi-wpengine.netdna-ssl.com/wp-content/uploads/2019/03/TCEC-Brattle-study-DER-in-ERCOT-28-March-2019-FINAL.pdf, 8.

[4] Sonal Patel, "Despite COVID-19, ERCOT Expects Record Summer Demand; Retired Coal Plant May Resume Service," POWER Magazine, May 14, 2020, https://www.powermag.com/despite-covid-19-ercot-expects-record-summer-demand-retired-coal-plant-may-resume-service/.

[5] "Emerging Grid Issues Briefing" (ERCOT, November 8, 2018), http://www.ercot.com/content/wcm/lists/144928/LegislativeandPUCTBriefing-EmergingGridIssues-FINAL.pdf, 11.

DERs are connected to distribution systems – and ERCOT historically has limited interaction with or visibility into the distribution side of the grid. ERCOT is beginning work to map all registered DERs to transmission load, with the goal of being able to accurately anticipate "net load" in the future.[6] It is also working to provide locational price signals to registered DERs to support reliability and efficiency. However, ERCOT recognizes that improved reporting will be necessary to properly capture the capabilities of DERs in system planning processes.[7]

Most of the recent growth in small, unregistered DERs in Texas has come from rooftop solar installations and some small natural gas-powered microgrids. Currently, only 89 MW of battery storage resources are registered with ERCOT, but nearly 1900 MW of battery storage capacity is being studied in the ERCOT resource interconnection queue.[8]

### b. *How can DERs participate in wholesale markets?*

As DER deployment continues to grow, so too will questions about how to fairly compensate the capabilities of these resources. For many residential and commercial customers, the primary reason for installing DERs is to reduce demand charges and bolster resilience to supply shocks. That being said, many DERs, including solar arrays, batteries, and natural-gas microgrids, have the ability to generate an excess supply of electricity at certain times. Models for how this excess supply can be sold to the grid with proper compensation are being explored across the country. Many systems in the U.S., particularly those along the east and west coasts, have introduced net metering, in which customers' total DER generation is netted against their total electricity demand over some period of time. This may be an unsupportable policy as DER penetration continues, because the full "net meter" price that a retail customer pays will include payments for the poles-and-wires delivery service; to include that portion in the payments *to* a retail customer for the DER power they put back onto the grid means a growing and unjustified transfer of costs from DER entities to the remainder of the market.[9] In California, net metering exceeds 12 percent of the state's peak load.[10]

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[6] Ira Shavel, Ahmad Faruqui, and Yingxia Yang, "Valuing and Compensating Distributed Energy Resources in ERCOT," *Texas Clean Energy Commission* (The Brattle Group, March 28, 2019), https://3vq5kdns38e1qxlmvvqmrzsi-wpengine.netdna-ssl.com/wp-content/uploads/2019/03/TCEC-Brattle-study-DER-in-ERCOT-28-March-2019-FINAL.pdf, 34.

[7] "Emerging Grid Issues Briefing" (ERCOT, November 8, 2018), http://www.ercot.com/content/wcm/lists/144928/LegislativeandPUCTBriefing-EmergingGridIssues-FINAL.pdf, 12.

[8] Ibid, 17.

[9] For a discussion of net metering and how it can unjustifiably transfer costs, see: Daniel Cohan, "Net Metering for Solar Power Sounds Simple, but Is It Fair?," The Hill, June 13, 2016, https://thehill.com/blogs/pundits-blog/energy-environment/283222-net-metering-for-solar-power-sounds-simple-but-is-it.

[10] "Distributed Energy Resources: Technical Considerations for the Bulk Power System," February 2018, https://www.ferc.gov/CalendarFiles/20180215112833-der-report.pdf, 36.

The California Independent System Operator has developed an extensive, cumbersome structure for aggregated DERs to sell power. Because of costly barriers associated with the current system, most California operators have found it advantageous to bid into the wholesale market only during times of load curtailment.[11] Consolidated Edison (Con Edison) and the New York Independent System Operator also offer retail and wholesale programs, respectively, that allow DERs to participate in the market. As in California, sellers of distributed generation in New York have received compensation mainly during times of peak demand in the form of either direct payments or demand-reduction credits. One notable exception is Co-op City in the Bronx, a residential development with a microgrid serving 50,000 residents using a combined heat and power (CHP) facility. Co-op City sells its excess power back to Con Edison and is compensated similar to an independent power producer. However, the microgrid must still pay standby charges typical for any consumer, eroding the financial benefits of its bi-directional grid connection.

Power providers and regulators are also beginning to explore how single-family residential DERs can be integrated into wholesale markets. Starting in 2022, aggregated rooftop solar and battery systems from approximately 5,000 New England homes will supply 20 MW of energy capacity to ISO New England, the New England grid operator. This represents the first use of residential solar and storage for forward capacity in a U.S. wholesale market.[12]

In Texas, where utility restructuring has separated the electric-delivery business from the retail business—and the electric-delivery utilities are not allowed to hold title to or to re-sell power—creating functional DER structures is more complicated; only a few retail providers, such as MP2 Energy and Green Mountain Energy, compensate exports to the grid from small DERs. Most retail electric providers do not have programs to compensate excess generation of solar power. In anticipation of growing DER deployment, ERCOT is considering a shift to locational pricing which would give DERs the ability to respond more accurately to real-time market price signals.[13] Because ERCOT does not have a capacity market, the economics of selling DER power into the wholesale market are less favorable in Texas than in other states.

DER participation in U.S. wholesale markets is still in its infancy. RTOs/ISOs and municipalities vary in their approaches to allowing DERs to sell power directly into wholesale markets. Stakeholders across the industry recognize that wholesale and retail market structures need to be updated in order to properly include DERs. In particular, the question of how to compensate the sale of power from aggregated DERs has not been answered by many grid operators, including ERCOT. This topic is significantly more complicated in ERCOT than it is elsewhere in the

[11] "Putting Distributed Energy Resources To Work in Wholesale Electricity Markets: Case Studies of Emerging Applications and Their Benefits for Customers and the Grid," *Advanced Energy Economy*, September 2019, https://info.aee.net/hubfs/Putting%20Distributed%20Energy%20Resources%20to%20Work%20in%20Wholesale%20Electricity%20Markets.pdf, 4-5.

[12] Chris Rauscher, "Let's Reduce Wholesale Market Costs by Tapping the Full Potential of DERs," Utility Dive, August 27, 2019, https://www.utilitydive.com/news/lets-reduce-wholesale-market-costs-by-tapping-the-full-potential-of-ders/561708/.

[13] Ibid, 36.

country, due to the separation of the electric delivery utilities from a restructured and competitive retail market. Further, the question of what costs DERs create, and who should pay those costs, is even less resolved.[14]

### c. DERs as non-wires alternatives (NWAs)

Much of the debate about DERs centers on payment for participation in retail and wholesale power markets. However, some DER proponents are beginning to advocate the deployment of DERs to supplant the poles, wires, substations, and transformers that underpin traditional transmission and distribution (T&D) networks. Furthermore, they argue that DERs should be compensated for deferring or replacing T&D investment – all while creating net savings for customers.[15] When evaluated as alternatives to conventional T&D investments, DERs fall under the umbrella of "non-wires alternatives." Navigant Research (now Guidehouse) has defined non-wires alternatives (NWAs) as follows:

> Non-wires alternatives is defined as "an electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as distributed generation (DG), energy storage, energy efficiency (EE), demand response (DR), and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level.[16]

Previous studies have suggested that strategic use of battery storage could defer some T&D investments in the ERCOT service area.[17] However, as discussed throughout the rest of this paper, the concept that DERs could reliably and economically replace large-scale T&D upgrades in ERCOT remains conjectural and unproven. Where it makes sense, ERCOT and Texas utilities are already embracing and leveraging the technology that underlies DERs as part of planning processes. For example, utilities have been utilizing load shedding, energy efficiency programs, and smart grid technologies to save consumers money and make sure the power stays on in Texas during natural disasters and times of peak demand, such as the hottest summer days. In

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[14] The EEI Transmission Policy Task Force recently asked members whether they are starting to see tariff charges for transforming DER power upward in voltage as yet. ERCOT pays all transmission costs on a load postage-stamp-rate basis, but the fact remains that DERs going onto the grid will create significant new costs.

[15] Demand Side Analytics, "The Value of Integrating Distributed Energy Resources in Texas," *Texas Advanced Energy Business Alliance*, November 2019, https://www.texasadvancedenergy.org/hubfs/TAEBA%20(2019)/Valuing%20DERs%20in%20ERCOT%20final.11.13.19.pdf.

[16] Brenda Chew et al., "Non-Wires Alternatives: Case Studies From Leading U.S. Projects," *E4TheFuture*, November 2018, https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf, 11.

[17] Judy Chang et al., "The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," *The Brattle Group* (ONCOR, March 2015), http://files.brattle.com/files/5977_the_value_of_distributed_electricity_storage_in_texas_-_proposed_policy_for_enabling_grid-integrated_storage_investments_full_technical_report.pdf, 28-35.

fact, the PUCT mandates that TDUs employ the most cost-effective solutions for consumers, thereby incentivizing the adoption of NWAs when they are economical. The PUCT, TDUs, and the Texas legislature are also evaluating the potential for energy storage to provide added reliability and even offset the construction of new transmission lines in situations where it is cost-effective.

Navigant expects global spending on NWAs to increase from $63 million in 2017 to $580 million in 2026.[18] Across the U.S., there are over 100 NWA projects in planning stages today, many the result of state-level regulatory mandates and public-private partnerships.[19] So far, only a few of these NWA projects have reached completion. Therefore, it is highly uncertain whether the touted benefits of non-utility NWA projects will be achieved.

One of the most cited examples of an operational NWA is New York's Brooklyn-Queens Demand Management (BQDM) program. Spurred by state initiatives to incentivize the deployment of DERs, Con Edison has invested $200 million since 2014 to create 52 MW of diverse DERs, including energy efficiency, demand response, fuel cells, and a solar-plus-storage microgrid. By using the DERs to reduce demand and generate electricity, Con Edison claims to have deferred the construction of a $1.2 billion substation for at least an estimated ten years.[20] Six years in, BQDM has achieved its load reduction goals, and the program has been extended to delay the substation build out past ten years – or even permanently. However, BDQM's success is not necessarily replicable in Texas. The area covered by BQDM is geographically small, dense, and already built-out; these facts are reflected in the avoided cost of the New York City substation. However, $1.2 billion would buy dozens of substations in Texas, even in the densest metro areas.

Another example of a completed NWA comes from North Carolina, where Duke Energy used solar and batteries to remove power lines atop Mt. Sterling's challenging terrain in Great Smoky Mountains National Park. Without any sunlight, the microgrid's fully charged battery can supply 11 days of power to its only load – communications equipment in a retired fire lookout.[21] The project may be a harbinger of the technological future, but given its extremely small scale and other unique characteristics, it is hardly relevant to the large and fast-growing state of Texas.

Similar to the compensation issues on the generation side, there are challenges to designing the right mechanism to reward but not unfairly subsidize non-wires alternatives. Some have suggested that ERCOT should implement a "Value of DER" tariff to compensate DERs not just

[18] Lisa Cohn, "What Are Non-Wires Alternatives?," Microgrid Knowledge, June 21, 2019, https://microgridknowledge.com/non-wires-alternatives-are/.
[19] Brenda Chew et al., "Non-Wires Alternatives: Case Studies From Leading U.S. Projects," *E4TheFuture*, November 2018, https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf, 7.
[20] Ibid, 21-22.
[21] Jessica Wells, "Lineman's Idea Leads to Microgrid in Great Smoky Mountains National Park," Duke Energy, December 11, 2019, https://illumination.duke-energy.com/articles/linemans-idea-leads-to-microgrid-in-great-smoky-mountains-national-park.

for the energy they produce but also for the T&D upgrades they defer or replace.[22] While such a tariff may seem straightforward in theory, it would be difficult and expensive to execute. Energy production from DERs such as solar arrays varies with the weather. As customers within a region choose their own unique DER solutions, it is likely that customers will experience peak demands from the grid at different times. By extension, it will become harder for utilities and grid operators to accurately forecast peak loads for regions within their grids. What is more, demands can grow quickly in regions for reasons beyond the control of utilities. All of this means that the DER promise to avoid or defer poles-and-wires investment can fail, and customers end up paying for DERs plus the infrastructure that is truly necessary to maintain reliability. In fact, some states that permit NWAs require utilities to build out "fail-safe" backups to ensure reliability, thus eliminating any savings and forcing higher costs on consumers.

Even with accurate modeling of supply from DERs, faster-than-expected population or industrial growth in a region could necessitate rapid deployment of new poles, wires, and substations. With reliability the number one concern for consumers and operators alike, caution should be employed in compensating a DER as a non-wire alternative absent a high degree of certainty that no new T&D investment will be required.

## C. Issues related to the integration and operation of DERs in the power distribution system

Given the huge number of potential "connection" points for DERs, the integration process is much more complex than is the case with selling wholesale power, whether from large-scale generators or DERs, into the power grid. Whereas wholesale transactions are a "one-way street," some potential DERs will be buying power from the grid at times and selling power to the grid at other times. Simply put, the sheer number of DERs that may want to interconnect to the distribution system—combined with their varied and complex operating characteristics—could place a significant burden on utility planning as well as operational reliability.

Integrating distribution-connected energy resources will pose a number of challenges for system operators including planning, revenue modeling and implementation, interconnection, and regulation. In the following discussion we break these challenges into two categories. The first is economic: How will the various participants be paid and/or charged for services provided? Will a new regulatory regime be required for DERs? The second set of challenges is technical and operational, in particular dealing with voltage changes, electron flow, and stability—ensuring the distribution system and the grid are neither overloaded nor undersupplied.

### *1. Economic and regulatory issues*

#### a. *Demand response*

[22] Ira Shavel, Ahmad Faruqui, and Yingxia Yang, "Valuing and Compensating Distributed Energy Resources in ERCOT," *Texas Clean Energy Commission* (The Brattle Group, March 28, 2019), https://3vq5kdns38e1qxlmvvqmrzsi-wpengine.netdna-ssl.com/wp-content/uploads/2019/03/TCEC-Brattle-study-DER-in-ERCOT-28-March-2019-FINAL.pdf, 28-30.

Reducing power demand is often cited as a "non-wires" alternative to adding either new generation to the grid or DERs like batteries and rooftop solar. Certain types of demand suppression have been used effectively in Texas in recent years. For example, in anticipation of higher prices, both business and residential customers cut consumption during peak hours of the summer heat waves in 2018 and 2019. According to ERCOT, in response to voluntary or compensated demand response programs, power use fell between 1,600 and 3,100 megawatts (MW) on extremely hot days over the past two years. These demand reductions allowed the most efficient generators to maximize output, helping to avoid brownouts, blackouts, or other load-shedding events.

In addition to voluntary and compensated demand reduction, ERCOT uses price signals to influence demand by accurately reflecting scarcity. Several years ago Texas regulators created a $9,000/MWh offer cap and implemented an energy price adder called the "Operating Reserve Demand Curve (ORDC)" that kicks in under scarcity conditions when there is a shortage of available supply and demand relief resources. The assumption behind the $9,000 price cap is that if there were a power outage, ERCOT customers would value the first MWh of electricity that would be lost at $9,000 per MWh. Though the average real-time energy price was $38 last year, ERCOT hit the $9000 cap twice during the summer of 2019. It is important to ensure that DER incentives do not undercut or cannibalize these programs.

### b. <u>*Cost recovery for DERs and utilities*</u>

In a recent policy brief, the American Public Power Association states that "…it is important that all customers pay their fair share of the costs of keeping the grid operating safely and reliably. Thus, rate structures should be designed to reflect costs and assure that those who benefit from the grid are sharing the costs associated with building a maintaining it."[23] The record to date is mixed.

Some electric utilities pay DERs through net-metering. Customers are credited with on-site generation for sales to the grid and charged when power consumption exceeds their generation. But if customers are both charged and credited at the full retail rate, they may be over-compensated with a value of generation that is higher than the utility's avoided cost. In Texas, net metering is not available to most consumers. However, three of the state's retail electric providers credit customers at the full retail rate. The problem is that this full retail rate includes compensation for transmission and distribution that the DERs do not provide or offset. Therefore, the retail provider's other customers are effectively subsidizing the DERs through higher rates. In a more equitable system, DERs would only be compensated for the energy they provide, unless they can effectively defer or replace transmission and distribution infrastructure. In some states, schemes have been developed to fully value the costs associated with DER integration. Cost recovery mechanisms include increased customer charges for fixed costs, time-

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[23] "Distributed Energy Resources Issue Brief," *American Public Power Association*, January 2020, https://www.publicpower.org/system/files/documents/Distributed%20Energy%20Resources%20-%20January%202020.pdf.

based pricing, and higher rates for peak power usage. But other states have not implemented such compensation schemes, creating uncertainties and economic burdens for both utilities and power customers.

### *c. Do DERs need a DSO?*

If more DERs are connected to distribution networks, the utility's function as a one-way kWh delivery mechanism will need to be modified. As energy users become suppliers, circuit flows will frequently change direction, with DER owners seeking to participate in wholesale power markets.

Recent years have witnessed huge advances in the technologies of high DER planning and operations such as distributed energy management systems (DERMS), hosting capacity analyses, and microgrid controllers. This has led many industry leaders to talk about modifying the roles and responsibilities of distribution utilities to become "distribution system operators," or DSOs.

Advocates of DSOs argue they can optimize the use of distribution networks while reducing the need for future grid investments. But the increasing penetration of DERs may lead to a less predictable and reverse flow of power in the system, which can affect the traditional planning and operation of distribution and transmission networks. Further, greater deployment of DERs can cause congestion in the distribution network and necessitate the need for an active distribution system operator.

In theory, DSOs can be structured along a continuum. At one extreme, the DSO could actually be owned and operated by the T&D utility. Indeed, that is already the case with municipal power companies ("munis") and co-ops. In addition to being distribution operators, these entities own the wires and all other assets in their systems.

At the other extreme, the DSO could be completely independent, a so-called IDSO that would simply be an aggregator, buying from and selling power to end users. The IDSO might or might not own any distribution assets and could conceivably be a non-profit entity. As with current T&D, it would be inefficient to have more than one operator serving a set of customers with duplicate wires, transformers, batteries, etc. So the DSO would likely be deemed a "natural monopoly" requiring regulatory oversight.

At the transmission level, some have suggested that ERCOT should allow NWAs to competitively bid against regulated utilities in infrastructure planning processes. Given that the utilities are ultimately responsible for the reliability and security of their network, a DSO would likely need to oversee the bidding and provide a vital coordination mechanism as more and more players enter the transmission and distribution grid.

Despite much discussion about the pros and cons of DSOs, and the regulatory changes that would be required to implement them, so far there have only been a handful of demonstration projects across the county.

### *2. Technical and operational issues with DERs*

Distribution relies on highly branched patterns, often in close proximity to communities, roadways, trees, and other potential interfering objects. Thus, the physical environment and exposure to the elements where distribution resides may cause occasional unplanned outages, due to, for example, cars hitting poles, failed equipment, animal activity, and unforeseen weather events. Under favorable conditions, often referred to as a "blue sky day," a T&D utility may still face outages affecting thousands of customers; during more significant incidents, such as storms, the number of outages increases significantly.

A unique attribute of the **distribution grid** is that it is reconfigured more frequently than the transmission system. For instance, switching distribution circuits changes the system's design to minimize customer impacts during routine maintenance outages or unplanned outages due to faults. Switching is required to isolate and clear affected locations on a distribution circuit to maintain service to customers on either side. Temporary configurations to isolate sections of distribution circuits are referred to as "abnormal" circuit conditions. Though this abnormal circuit configuration is usually temporary, abnormal configurations—following, say, damage from a hurricane—can remain in place for days or months if major work is required to restore the system to its normal and most reliable configuration.

Outages and abnormal circuit configurations can create capacity constraint conditions on a distribution grid, which in turn would affect a DER's ability to participate in wholesale energy markets. Depending on distribution grid loading or voltage conditions, DERs may need to be ramped up or curtailed if thermal or voltage violations occur, or reconfigurations between circuits may need to be initiated. Similarly, a lack of coordination between small generating facilities and the bulk power system can cause grid instability. These types of problems could be exacerbated due to a lack of **"situational awareness"** by the utility or ERCOT.[24]

For example, small changes in voltage from a DER or DSO can ripple through the electricity grid, again highlighting the need for situational awareness. Safety and reliability problems could result if DER operators are unaware of circuit reconfigurations that affect their various components, in particular PVs and storage batteries.

Another challenge is that DERs in Texas "self-dispatch" as load modifiers, making load forecasting difficult. As they grow, both the T&D utility and ERCOT will need accurate short-term forecasts to operate their systems reliably. This will require more metering and telemetry equipment from DERs, imposing costs that will have to be internalized by the individual DERs or the DSO.

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[24] NERC defines situational awareness as "ensuring that accurate information on current system conditions is continuously available to operators." See *Real-Time tools Survey Analysis and Recommendations*, NERC, March 2008, https://eta-publications.lbl.gov/sites/default/files/nerc-realtime-tool-survey-final-rpt.pdf, 3.

As mentioned earlier, DERs currently contribute relatively little power to ERCOT. But if they become more prolific in Texas, detailed and accurate modeling of the behavior of DERs will be needed to ensure grid stability and reliability.

In addition, DER outages/failures could compromise the reliability of the grid. Currently, the grid operator is responsible for repairing or replacing all assets on its system. However, it is less clear who would repair or replace an NWA when it is damaged, for example, by a tornado or hurricane. Would the grid operator bear the immediate responsibility for finding an alternative source of power? Or would the DER manufacturer/operator be first in line to repair or replace the DER? In a transmission system that relies heavily on NWAs, liability for outages will be more diffuse, which could slow restoration efforts and lead to blackouts or brownouts on the grid.

In sum, if Texas should develop a "high-DER" grid, with a large number of independent distribution networks, operators of the transmission and distribution systems will need to communicate and coordinate constantly to maintain the reliability of their respective systems and the grid as a whole. Even in a world where this communication produces a reliable grid, the additional transmission and distribution system management oversight will produce an added cost to be borne by consumers.

### D. Will consumers in Texas realize cost savings from NWAs?

A number of states are looking into requiring utilities to consider NWAs in their resource planning. But only a handful of projects have gone from identification to implementation.[25] What is more, few analyses have been conducted on the potential cost savings for consumers from incorporating more DERs into the distribution network.[26]

As discussed above, at present DERs play a limited role as supply resources in the ERCOT market. However, some proponents of distributed energy believe power consumers in Texas could reap sizeable savings if more NWAs were incorporated into the utility T&D planning and development process.

A recent report prepared by Demand Side Analytics on behalf of the Texas Advanced Energy Business Alliance (TAEBA) attempts to quantity the potential savings in Texas from integrating more NWAs into the power grid.[27] The study estimates the value of T&D deferral to be $344 million per year, or $2.45 billion over 10 years ($2019 present value). Put another way, deferring

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[25] Cristin Lyons, "Non-Wires Alternatives: Non-Traditional Solutions to Grid Needs," T&D World, June 6, 2019, https://www.tdworld.com/overhead-distribution/article/20972703/nonwires-alternatives-nontraditional-solutions-to-grid-needs.

[26] See earlier discussion of alleged T&D deferral of substation construction by Consolidated Edison in BQMD project.

[27] Demand Side Analytics, "The Value of Integrating Distributed Energy Resources in Texas," *Texas Advanced Energy Business Alliance*, November 2019, https://www.texasadvancedenergy.org/hubfs/TAEBA%20(2019)/Valuing%20DERs%20in%20ERCOT%20final.11.13.19.pdf.

T&D expansion by using DERs potentially could yield savings of $220 per Texas household over 10 years.

Yet, the TAEBA report provides few details to support its claims, and it ignores other likely costs. For example, the report does not explain how it accounts for the cost of installing and compensating DERs. After subsidies are considered, it may be the case that ratepayers would not realize any savings from NWAs. Further, the authors concede that most deferred T&D infrastructure will eventually need to be built. However, their sensitivity analysis does not consider whether the costs to build the infrastructure will be significantly higher in the future. If labor, equipment, and/or right-of-way acquisition become more expensive ten years down the line, the net present value of investment deferral will be significantly eroded. In other words, it could be more economical to simply build the T&D infrastructure now instead of deferring it.

Most importantly, the TAEBA report overlooks the reliability concerns associated with DERs. Locations in need of new T&D tend to be fast-growing and low on spare power capacity. After all, that is why they need investment in the first place. As mentioned above, DERs such as solar are intermittent, meaning they need to be paired with reliable backups, usually fossil fuel generation. Therefore, it is unlikely that DERs will defer traditional T&D with an acceptable level of reliability. In a more realistic scenario, DERs will be deployed to offset statewide peak demand and even reduce carbon emissions. However, DERs will still need to be supported by the T&D infrastructure that connects to the grid, especially in areas with large populations and a mix of consumer types. With reliability a top priority, it is hard to envision a scenario in which DERs can defer significant amounts of T&D investment, especially in a fast-growing state like Texas.

In fact, Texas consumers could face **higher** power costs if T&D infrastructure is deferred with NWAs. During times of high demand, such as the hottest summer days, electricity prices in Texas' energy-only market must rise in order to entice idle generation to come online. At these times, intermittency or technological failure from NWAs would be disastrous and costly for homes and businesses that need to keep the lights on and the air cool. In addition to reliability concerns, customers would likely have to pay even higher prices for scarce power in the absence of a robust connection to the state grid.

Even as DER penetration grows in Texas, it will be essential to build and maintain traditional T&D infrastructure to ensure that Texans have a robust, diverse, and affordable power supply when they need it the most.

## E. Summary and conclusion

Due to their novelty and limited track record, integrating DERs or NWAs into the utility planning process for transmission and distribution presents a host of technical, regulatory, and economic challenges. While a DER provider is looking to maintain a revenue stream, the distribution utility is primarily focused on reliability and system performance that could be compromised by a third-party solution. New and complicated organizational coordination may be required to deal with operations, supply chain, and capital planning. In addition, if many

DERs want to compete for delivery, a new regulatory authority, known as a distribution system operator (DSO), may be required.

Cost recovery remains another challenge. Under the purview of the PUCT, Texas TDUs already employ DER technology in cases where it will increase reliability or decrease costs for consumers – and TDUs will continue to do so by mandate. However, if ERCOT is to allow more DERs to enter the distribution market, rate structures must be designed that incorporate the full value of the costs associated with DER integration.

Though there may be some modest, short-run cost savings for consumers from greater use of NWAs, to the extent new utility investment is deferred, these savings may be offset by diminished network resiliency and reliability. If traditional infrastructure must ultimately be constructed to ensure fail-safe reliability, consumers may actually bear higher costs from non-economic utilization of NWAs. Thus, it is unclear and unproven that NWAs can reliably and economically defer large swaths of new T&D infrastructure investment in Texas.

Finally, there is no evidence to suggest the current ERCOT design with regards to planning and development of T&D by the state's electric utilities needs revision. Texas continues to lead the nation in population growth, housing starts, and job creation. Texas also attracts more business relocations than any other state.[28] The delivery of affordable and reliable power to new and existing households and businesses has not been a problem for the state's utilities.

[28] This was certainly the case before the Covid-19 pandemic, and these trends should resume once the national economy revives.