Distributed Resource Energy and Ancillaries Market Task Force (DREAM TF)
TAC Report - February 2016

Introduction

As directed by TAC, the DREAM Task Force reviewed the current regulatory and market framework for distributed resource participation in ERCOT, as well as proposed enhancements to the existing distributed resource market participation. The Task Force reviewed current and potential:

(1)   Abilities for a distributed resource to become associated with a Resource Node or logical Resource Node, to include registration and qualification requirements;

(2)   Inclusion of distributed Resource Nodes or logical Resource Nodes in Congestion Revenue Rights (CRR) markets;

(3)   Allowances for a distributed resource associated with a Resource Node or logical Resource Node to take an economic outage;

(4)   Allowances for aggregations on a zonal and system-wide basis;

(5)   Improvements to the existing Settlement meter data submittal process and ERCOT registration requirements for distributed resources (ex: AMI meters instead of EPS per an NPRR under review);

(6)   Opportunities for enhancements to distributed resource visibility and/or ERCOT dispatch and control;

(7)   Compliance metrics appropriate for distributed resources; and

(8)   Allowances for distributed resources associated with a Resource Node or logical Resource Node to return to a zonal pricing regime.

The Task Force also considered perceived impediments presented by a Market Participant who owns and operates distributed resources.

The DREAM Task Force did not evaluate or gain consensus on the items listed above, but rather attempted to understand and capture varying perspectives.

Review of current statutes, rules, protocols, and guides related to Distributed Energy Resources

Definitions

Currently, Protocols define Distributed Generation (DG) as "An electrical generating facility located at a Customer's point of delivery (point of common coupling) ten megawatts (MW) or less and connected at a voltage less than or equal to 60 kilovolts (kV) which may be connected in parallel operation to the utility system." The current definition is not inclusive of resources greater than ten megawatts and connected to the distribution system (less than or equal to 60kV) and does not differentiate DG that exceeds its native Load.

Interconnection

Distribution Service Providers (DSPs) adhere to P.U.C. SUBST. R. 25.211, Interconnection of On-Site Distributed Generation (DG), AND 25.212, Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation, but interconnection processes and

procedures may vary by DSP. P.U.C. SUBST. R. 25.211 and 25.212 are only applicable to facilities 10MW or less *and* connected to the distribution system. Distribution service providers may, currently, require supplemental terms and conditions to PUCT rule and DSPs operating in non-opt-in territories are not subject to these PUCT rules. ERCOT Protocols do not specifically govern or influence the DSP interconnection process.

Modeling and Registration

In accordance with Protocol Section 16.5, Registration of a Resource Entity, and Planning Guide Section 6.8.2, Resource Registration Process, DG connected to the ERCOT System and larger than 1 MW must register with ERCOT and provide resource registration data as required by the Planning Guide. ERCOT Protocols also require that all resources at a single point of interconnect be controlled by a single Resource Entity.

ERCOT market participation by distributed resources may require supplemental terms and conditions (ex: between a Resource Entity and DSP for outage scheduling related to Distribution System issues) not otherwise covered by the standard DG interconnection agreement.

Further, Section 5.1.1 of the ERCOT Planning Guide, relating to Generation Resource Interconnection, specifically states that the requirements in Section 5 are applicable to "Any Entity proposing a new All-Inclusive Generation Resource, including a storage device, with an aggregate power output (gross Generation Resource output minus auxiliary Load directly related to the Generation Resource) of ten MW or greater, planning to interconnect to transmission in the ERCOT System" and that the "[i]nterconnection requirements for on-site Distributed Generation (DG) are not subject to this Section 5." This leaves resources smaller than ten MW and/or those interconnecting at 60kV (or below) without clear requirements for registering as a Generation Resource.

Load Resources (LRs) connected to the Distribution System are modeled at the transmission substation as part the Common Information Model (CIM) Load with which they are associated. This is accomplished via a collaborative process at the time of LR registration involving ERCOT and the relevant TSP/DSP. As such, the LR does not have an assigned Resource Node (because it is not dispatched or settled for energy[1]), but rather exists in the CIM as an object. Distributed Generation could presumably be modeled or mapped in a similar fashion, but current business practices do not have explicit methods to do so. ERCOT, in its August 2015 DER concept document, proposed that a DER should be *mapped* to its appropriate CIM Load, rather than *modeling* the actual distribution system elements between the DER and the transmission grid. The mapping approach would alleviate the need to insert multiple distribution system elements into the CIM (which is otherwise limited to transmission elements greater than 60kV), a cumbersome process that would also require potentially significant changes to core system applications such as the State Estimator.

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[1] This applies to LRs participating in the Responsive Reserve market, but would not apply to a Controllable Load Resource participating in SCED.

Metering and Settlements

The task force reviewed the current regulatory framework for various distributed resource metering configurations. The requirements are as follows:

PURA § 39.916(f) states that "a [Distribution Service Provider] … shall make available to a [distributed renewable generator of 2,000 kw or less co-located with a retail customer] … metering required for services provided under this section, including separate meters that measure the load and generator output or a single meter capable of measuring in-flow and out-flow at the point of common coupling meter point.

P.U.C. SUBST. R. 25.213, Metering for Distributed Renewable Generation and Certain Qualifying Facilities, (b)(1) stipulates that:"…an electric utility shall provide metering at the point of common coupling using one or two meters that separately measure both the customer's electricity consumption from the distribution network and the out-flow that is delivered from the customer's side of the meter to the distribution network.

P.U.C. SUBST. R. 25.212(j) states that "…the utility may supply, own, and maintain all necessary meters and associated equipment to record energy purchases by the customer and energy exports to the utility system…"

Currently, registered DG must have an EPS to be settled on a timeline comparable to that of traditional resources. There is also an option to utilize TDSP metering that has a longer settlement period. In some instances, an Interval Data Recorder (IDR) meter may satisfy the timelines for ERCOT's initial Settlement, though the polling practices of IDR meters are not necessarily aligned with initial Settlement timelines. At least one Market Participant noted that EPS meters may be cost prohibitive, particularly for an aggregated distributed resource consisting of a large number of small sites. A Market Participant noted that they had received quotes for an EPS meter ranging from $5,000 to $200,000 per site. As per Protocol Section 10.2.2, TSP and DSP Metered Entities, the distributed generation resource owner must work with the host Transmission and/or Distribution Service Provider (TDSP) to ensure that an EPS Metering Design Proposal is submitted to ERCOT.

ERCOT is sponsoring a Nodal Protocol Revision Request (NPRR) that will allow DG with an Advanced Metering System (AMS) meter on-site to be settled more expeditiously. DG without an EPS meter is typically settled at final Settlement (55 days).

DER Reporting

Pursuant to P.U.C. SUBST. R. 25.211(n), all electric utilities as defined in PURA § 31.002 that own and operate a distribution system in Texas shall:

"By March 30 of each year, every electric utility shall file with the commission a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report shall list the new distributed generation facilities interconnected with the system since the previous year' report, any change in ownership or the cessation of operations of any distributed generation that has been reported to the electric utility and not included in the previous report, the capacity of each facility and whether it is a renewable energy resource, and the feeder or other point on the company's utility system where the facility is connected. The annual report shall also identify all applications for interconnection received during the previous one-year period, and the disposition of such application."

Historically, these reports are provided exclusively in PDF format, with varying degrees of individual organization, but satisfy PUCT requirements. Protocols currently support quarterly reporting of DG by ERCOT.

In addition, pursuant to Nodal Protocol 10.2.2(2)(e), each TSP, DSP, and NOIE DSP is responsible for "providing ERCOT with any data required by ERCOT for reporting purposes on unregistered DG as specified in Commercial Operations Market Guide Section 10.3, Unregistered Distributed Generation Reports." The Commercial Operations Market Guide Section 10.3, Unregistered Distributed Generation Reports, and Load Profiling Guide Appendix D, Profile Decision Tree "DG" tab, outline the specific DG reporting requirements by ERCOT.

Moreover, in an effort to expand the transparency and reporting for DG, NPRR719, Removal of Trigger and Requirement to Reduce the Distributed Generation (DG) Registration Threshold and COPMGRR040, Alignment with NPRR719, Removal of Trigger and Requirement to Reduce the Distributed Generation (DG) Registration Threshold, modifies the ERCOT DG report to include all unregistered DG sites in competitive territories by MW capacity by Load Zone and by the following primary fuel types:

- Solar
- Wind
- Other renewable; and
- Other non-renewable.

Applying the same unregistered DG reporting requirements to NOIE territories should be investigated.

Market Participation Options

Type	Qualifications	Energy	Ancillaries	Aggregations
Distributed Generation	Less than or equal to 10 MW, connected at less than 60 kV	Load Zone payment for injection	N/A	No
Distributed Renewable Generation	Less than or equal to 2 MW, renewable, installed on customer's side of a meter	Load Zone payment for injection	N/A	No
Non-Registered DG	< = 1 MW	Load Zone payment for injection	N/A	No
Distributed Renewable Generation (DRG) below registration threshold	Addressed in Protocol Section 11.4.4.2, Load Reduction for excess Photovoltaic and Wind Distributed Renewable Generation	Load Zone payment for injection	N/A	No
Non-DRG below registration threshold	Addressed in Protocol Section 11.4.4.3, Load Reduction for excess from Other Distributed Generation	Load Zone payment for injection	N/A	No
Emergency Response Service (ERS)	An emergency service consistent with P.U.C. Subst. R. 25.507, Electric Reliability Council of Texas (ERCOT),	Capacity Payment for contracted hours	N/A	Yes

	Emergency Response Service (ERS), used during an Energy Emergency Alert (EEA) to assist in maintaining or restoring ERCOT system frequency. ERS is not an Ancillary Service.			
Emergency Response Service Generator	Either (1) an individual generator contracted to provide ERS which is *not a Generation Resource* or a source of intermittent renewable generation and which provides ERS by injecting energy to the ERCOT system, or (2) an aggregation of such generators	Capacity Payment for contracted hours	N/A	Yes
DG within a Non-Opt In Entity (NOIE) area	If the DG is within a NOIE's boundary, the DG Resource owner will need to coordinate with the NOIE regarding possible data requirements to properly report the impact of the DG generation on the NOIE's exchange onto the ERCOT system.	Negotiated with NOIE	N/A	No
Aggregated Load Resource	Distributed resources within a load zone may aggregate to provide energy and/or ancillary services.	Ancillary Service Payments, bid-to-buy / avoided cost for deployment in response to price	Yes	Yes
DG acting as a Resource	Less than or equal to 10 MW, connected at less than 60 kV. LRS is capped at zero	Load Zone payment for injection	N/A	No

Recommendations and potential opportunities for further investigation or development

1.   **Current Business Practices for developing a Resource Node**

ERCOT maintains a Business Practice "Procedure for Identifying Resource Nodes" (Last updated 7/23/2008.) The existing Business Practice does not consider the potential physical and electrical distance between Resource Nodes and Connectivity Nodes that may be unique to distributed resources. Specifically, distributed resources may have miles of distribution line (not currently modeled by ERCOT) between its physical interconnection at distribution voltage and a transmission level representation of that resource at a Resource Node. ERCOT Protocols also lack guidance on how to represent a distributed resource at a transmission level Resource Node. DREAM generally agreed that if TAC were to support an allowance for distributed resources to be associated with a Resource Node, then stakeholders would develop practices to map distributed resources. The distributed resources would be mapped at a transmission bus (associated with a CIM

Load) and metered at the distributed resource's point of interconnection with the distribution system. A logical adjustment to the CIM Load to avoid double counting associated with distribution load served by the distributed resources would be required. Consideration would need to be given to the impact of distribution field switching on this mapping. This is consistent with the current practice of mapping distributed load resources that currently aggregate to offer ancillary services.

A Resource Node allowance enables distributed resources to participate in all ERCOT market activities, including Day-Ahead Market (DAM) Three-Part Supply Offers, Ancillary Service Offers, DAM offers/bids, CRR offers/bids, and/or Qualified Scheduling Entity (QSE) to QSE transactions. Such an allowance would allow distributed resources to:

(a)   Participate in price formation (rather than passive reversal) in a meaningful way;

(b)   Represent their willingness to sell in an organized market;

(c)   Be visible to ERCOT in forward and/or Real-Time reserve metrics;

(d)   Obtain the locational value their resource provides to the ERCOT transmission system[2];

(e)   Operate under comparable compliance/performance standards currently applicable to traditional resources; and;

(f)   Support nodal market design by using price as an incentive for DG developers to locate resources where pricing is more attractive (i.e. where congestion persists).

Currently, distributed resources injecting to the grid are paid the Load Zone price. This arrangement allows distributed resources to deliver energy in Real-Time, with no comparable compliance metrics or ERCOT knowledge of their intent to deploy. Distributed resources are compensated by Load Zone pricing regardless of their location within that Load Zone or impact to congested elements (positive or negative). Conversely, a traditional resource relies upon a CRR hedge to Load Zone procured in competitive auctions to receive comparable treatment. Said another way, distributed resources do not face the same risk or opportunity as traditional resources for delivery to the Load Zone.

2.   Inclusion of distributed resources in CRR markets

As mentioned above, development of a Resource Node for distributed resources would enhance the ability for distributed resources to participate in the ERCOT market. Market Participants questioned the appropriateness of an allowance for distributed resource Settlement Points to be associated with CRR markets.

Market Participants were concerned with the relative mobility of a single distributed energy resource or the logical resource node of an aggregation of distributed systems compared to that of a traditional resource, and corresponding opportunity to game the

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[2] Creating a Resource Node for a distributed resource would not provide visibility into the reliability impact of the resource on the distribution system.

CRR market. The opportunity to game would require that distributed resources maintain multiple interconnection points, a mobile resource, and a CRR position that would benefit from a long/short position while moving the resource to a different node.

3. **Allowance for economic outages of distributed resources**

Market Participants suggested that distributed resources that are formally associated with a Resource Node have an allowance to reduce the availability of those distributed resources to the marketplace by way of a Current Operating Plan (COP) update or other mechanism. The COP outage would not necessarily correspond to resource unavailability. Rather, the distributed resource owner could self-service a portion of their Load, rather than settle the output on a nodal basis. This would increase optionality and value for the distributed resource, allowing the resource owner (or QSE representing a resource owner) to optimize the injection of their resource and withdrawal for Load based upon nodal and Load Zone pricing. The load / resource combination could effectively choose between Load Zone and nodal pricing by virtue of a COP update or other mechanism. Certain Market Participants warned that introducing two price signals at an electrically equivalent location could be problematic. This is not consistent with treatment for other resources. Additionally, distributed resources are not subject to Reliability-Unit Commitment when needed to support system reliability.

4. **Provisions for Aggregations**

Numerous Market Participants expressed support for allowances for aggregated distributed resources. Currently, Aggregated Load Resources (ALRs) must all be located within the same Load Zone. Once qualified, ALRs can participate in energy and Ancillary Service markets. Energy market participants are currently limited to a Load Zone Dispatch with a bid-to-buy (rather than an offer to sell) represented in Security-Constrained Economic Dispatch (SCED). Ancillary Service awards are assigned on a system-wide basis, rather than on a Load Zone or more granular basis. Accordingly, ALRs may participate in Ancillary Service offerings.

Proponents of allowances for aggregated distributed resources have suggested the following options:

(1) Create aggregated distributed resources with a Load Zone-level identity.

(2) Create aggregated distributed resources with similarly situated electrical locations.

(3) Create aggregated distributed resources with nodal identity at a resource level and a corresponding portfolio with weighted shift factors.

(4) Create aggregated distributed resources without shift factor limitations, as standard SCED operations would place curtailment risk on the aggregated DER should it contain systems with shift factors requiring curtailment (i.e. a lowest common denominator for reliability risk is applied to the entire aggregation). Thus Market Participants would be encouraged to design aggregations with nodal topography that makes the most economic sense for the participants in the aggregation.

Each aggregation offers a nuanced approach to allow distributed resources to participate in Energy and Ancillary Services markets. Option 1 is comparable to the existing treatment for ALRs, where aggregated distributed resources would be dispatched on a Load-Zone portfolio basis. Option 1 may also preserve the existing Load Zone Settlement for distributed resources responding to energy prices, if the Load Zone-bounded aggregation is settled zonally instead of nodally but enable compliance guidelines for Dispatch and participation in Ancillary Service markets. Options 2 and 3 provide aggregated distributed resources a nodal Dispatch, which accurately assesses the marginal benefit of energy delivered to the Resource Node associated with the portfolios of distributed resources. Option 2 would impose an additional limitation on aggregations, that is, each resource participating within the aggregation must have an electrically similar Shift Factor relative to system constraints. (Option 1 could be chosen by itself or in combination with mutually exclusive Options 2, 3, or 4).

5. **Improvements to the Settlement meter data submittal process for distributed resources**

    Distributed resources that inject to the grid are settled based on data availability in ERCOT systems. For registered DG with IDR Meters, this is typically at final Settlement (55 days). Comparatively, resources with EPS meters are settled within 5 business days. ERCOT currently receives injection data from sites with advanced meter infrastructure (AMI/smart meter.) ERCOT has authored an NPRR and Retail Market Guide Revision Request (RMGRR) to leverage AMI to improve the Settlement meter data submittal process for distributed resources. ERCOT has authored an NPRR and Retail Market Guide Revision Request (RMGRR) to leverage AMI to improve the Settlement meter data submittal process for distributed resources.

    Currently, transmission connected resources and generation in excess of 10MW are required to have EPS meters. The cost of these meters is allocated across the rate base, rather than directly assigned to the individual resource. Distributed resources are required to absorb the cost of EPS meters, which is a barrier to entry that traditional resources do not face.

6. **Improving visibility and contribution to price formation from distributed resources**

    Currently, distributed resources are resources are not subject to participate in SCED and, with the exception of registered Distributed Generation, are not considered in the Report on Capacity, Demand and Reserves in the ERCOT Region (CDR), and are not required to register. Additionally, the location, fuel, availability, and size of unregistered distributed resources are not consistently reported to ERCOT.

    With respect to portfolio dispatch, DG that responds to SCED price, but not by SCED instruction, reduces apparent load and correspondingly reduces the system price. This current arrangement also does not allow ERCOT to estimate real-time resource availability

7. **Compliance Requirements**

The DREAM TF reviewed existing compliance metrics for traditional resources, which contribute to price formation and are managed for grid reliability. Registered and unregistered DG do not have currently comparable compliance metrics, including physical performance standards. DREAM considered the following existing compliance programs for traditional resources and their applicability to distributed resources:

- Basepoint deviation and GREDP/CLREDP
- No compliance metrics (status quo)
- ERS performance criteria
- Voltage support and Governor response
- Response to high and low voltage and frequencies
- Ancillary Service performance criteria (if applicable)

Currently DG is self-dispatched or intermittent, and appropriately lacks the above control. If DG plans to participate actively in price formation, then compliance metrics have heightened importance. DREAM TF suggests further discussion on compliance metrics for distributed resources should consider coordination with TDSPs, including but not limited to, UFLS, UVLS, T&D resource outages, and firm load shed.

8.   Switching between Load Zone and Nodal pricing

If we enable distributed resources to be registered with a Resource Node, then should that election be permanent? Distributed resources have expressed interest in switching between Load Zone and Nodal pricing.

Other Market Options:

DREAM TF seeks TAC direction on the following policy cuts:

1: To enable and define distributed resources eligible to participate in the DAM with a Three-Part Supply Offer, Ancillary Service Offer, DAM offers/bids, CRR offers/bids, and/or QSE to QSE transactions, TAC directs DREAM to develop revisions to existing Protocols to achieve these ends, given existing PUCT rules. Revisions should include detailed requirements for registration, modeling, metering, pricing options, and compliance metrics associated with distributed resources participation.

2: Direct CMWG to review eligibility for Resource Nodes created for distributed resources to participate in CRR markets and report back to DREAM/TAC, including a review of the necessary revisions to Load Serving Entity (LSE) Settlement calculations for customers with nodal distributed resources.

3: Direct QMWG/DREAM to propose Protocol revisions, consistent with PUCT rules, to allow distributed resources registered with a Resource Node to allow for economic outages,

including but not limited to, those outages initiated to allow a Load co-located with the DG to consume its output, and report back to TAC.

4: Direct QMWG and DSWG to update the ALR Other Binding Document and associated Protocols to reflect Option #(s) ___, detailed above in the Provisions for Aggregations section of this document.

5: Consider who should bear the cost of EPS meters deployed to support distributed resources, or put this matter on hold as we wait for the NPRR on use of AMI meters instead of EPS to work its way through the approval process.

6: Direct WMS / QMWG /DWSG to review the market impact of the status quo treatment for price responsive distributed resources. Passive distributed resources (e.g. solar, wind, or other non-price-responsive resources receiving negative Load Zone pricing when injecting) should be excluded from this assessment. WMS may consider and/or propose alternative arrangements that improve visibility and/or ERCOT control of price responsive resources.

7: Enable a distributed resource above a specified size to participate in energy and Ancillary Service markets on equal footing with a traditional resource by absorbing the cost of an EPS meter (in the rate base) per point of interconnect with the distribution system in the rate base, or put this matter on hold as we wait for the NPRR on use of AMI meters instead of EPS to work its way through the approval process.

8: Enable distributed resources to change their registration on a nodal basis (e.g. for the periodic inclusion and removal systems within an aggregation) and to allow a single registered distributed resource or an aggregation to participate in a Load Zone portfolio dispatch. The quickest frequency of either or both types of registration change should be X month(s).