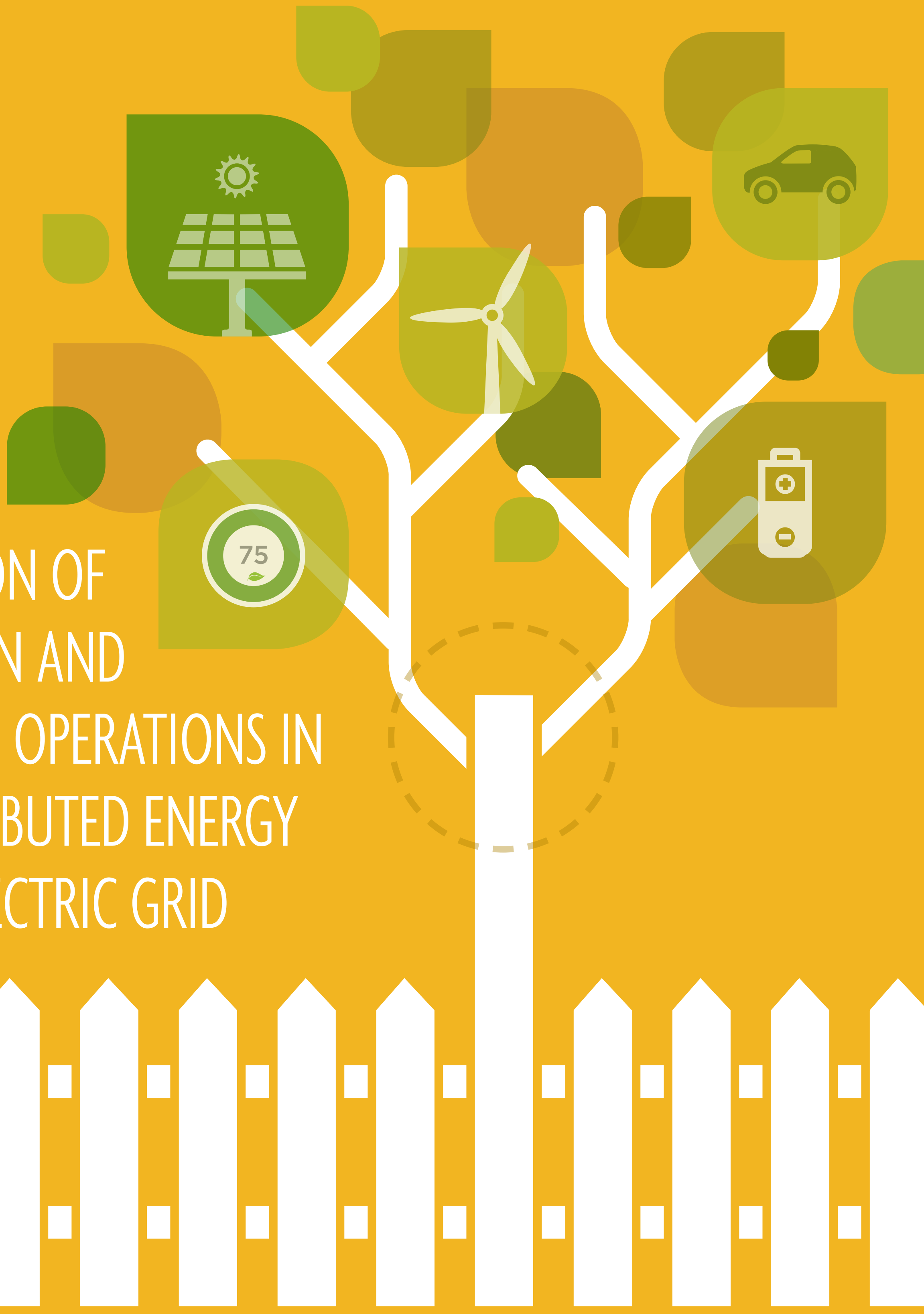

COORDINATION OF TRANSMISSION AND DISTRIBUTION OPERATIONS IN A HIGH DISTRIBUTED ENERGY RESOURCE ELECTRIC GRID

MORE THAN SMART

California ISO

Pacific Gas and Electric Company

Southern California Edison
An Edison International Company

SDG&E
A Sempra Energy utility

More than Smart is a 501(c)(3) nonprofit organization whose mission is to support policy-makers and stakeholders pursuing cleaner, more reliable, and more affordable electricity service through the integration of distributed energy resources into electricity grids.

MTS brings industry, advocacy and government experts together to develop solutions for integrating more distributed generation resources gradually into state electricity distribution grids. A key focus is in providing assistance to states to follow the MTS Walk/Jog/Run® Framework for modernizing distribution grids through an engineering-based framework that acknowledges the unique energy policies of each state.

MORE THAN SMART

More Than Smart acknowledges the generous support of the Energy Foundation whose support has made this effort possible.

MORE THAN SMART

COORDINATION OF TRANSMISSION AND DISTRIBUTION OPERATIONS IN A HIGH DISTRIBUTED ENERGY RESOURCE ELECTRIC GRID

JUNE 2017 | PREPARED BY STAFF OF CAISO, PG&E, SCE, SDG&E WITH SUPPORT FROM MORE THAN SMART

1 | EXECUTIVE SUMMARY

The electricity industry is going through a systemic transformation resulting from two major shifts. One is the shift away from traditional fossil-fuel generating resources to renewable resources, particular solar and wind generation. The other is the shift from a highly centralized system powered mainly by large remote generating plants to a more decentralized system, where technological advances and customer adoption are creating a vibrant "grid edge" of diverse distribution-connected or "distributed" energy resources ("DERs"[1]). The second shift is the focus of this paper.

The electricity supply system consists of generating facilities that produce electricity plus transmission and distribution facilities that move it from where it is produced to the energy users who need it. Although the transmission and distribution grids are interconnected they are distinct systems, with inherently different structures, characteristics, functions and operating principles. The primary function of the transmission grid is to deliver bulk electric power from utility-scale generating facilities to transmission-distribution (T-D) substations via interconnected high-voltage power lines organized as a meshed network. High voltage electric substations at numerous locations on the transmission network connect to distribution systems that deliver power to end-use customers via lower-voltage electric distribution lines. The T-D "interfaces" are those substations where the transmission and distribution grids interconnect.

In areas with organized wholesale power markets, the Independent System Operator (ISO) or Regional Transmission Organization (RTO), as the wholesale market and transmission

1 "DER" is not a consistently defined term across the industry. This paper uses the term DER to include all resources and facilities connected to the electric system at the distribution level, which means interconnected directly to a system controlled and operated by an electric distribution utility or operating behind the end-use customer meter. The term DER used here does not imply any specific resource types or sizes; it includes energy efficiency and demand response resources as well as rooftop and larger scale solar PV, energy storage, electric vehicles and charging facilities, building automation and microgrid systems, etc. The key feature for purposes of this paper is that DERs are connected to the distribution side of the transmission-distribution interface, rather than on the ISO controlled transmission side.

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system operator, dispatches resources to balance supply and demand and manage constraints on the transmission system. The ISO typically has little to no visibility into the current status of the distribution system, and with most generating resources connected to the distribution grid such visibility has not been needed. With DERs participating in the wholesale market, however, this lack of visibility may result in the ISO issuing dispatch instruction to DERs that the DERs are unable to comply with due to distribution system constraints, and may even contribute to operational problems on distribution. In a high-DER world, where DERs may seek to participate in wholesale markets and/or provide services to the distribution system, increased coordination and communication at the T-D interface becomes even more important.

One implication of a possible "high-DER" grid – a power grid containing large numbers of diverse DERs– is that the operators of the transmission and distribution systems will need to coordinate and communicate with each other in new ways to maintain reliable operation of their respective systems and, ultimately, of the electric system as a whole. Such coordination will take place in relation to the T-D interfaces, the substations that make up the boundary between the transmission network operated by the ISO and the distribution systems operated by the distribution utilities or distribution operators[2] ("DOs"). Hence the title of this paper.

During 2016 the authors of this paper were part of a working group[3] on "T-D Interface Coordination" that was organized and supported by More Than Smart[4] to bring together diverse industry participants and stakeholders to identify needs and develop recommendations toward developing a high-DER T-D coordination framework. This paper summarizes the findings and interim recommendations of the working group and identifies some of the operational considerations for accommodating growth of DER on the electric system and enabling DER participation in markets. The recommendations herein are necessarily interim because the growth of DER on the electric system is a dynamic process that will evolve over the coming years, revealing new use cases, business models, and technologies that create new challenges and coordination needs.

The working group will continue to meet into the future to track DER growth and further advance the T-D coordination framework through use case analysis. The objective of this analysis would be to better understand current and future electric distribution grid limitations, distribution grid availabilities for DER market participation, distribution operator coordination, and implications for sequencing required investments. The results of this analysis would help form hypotheses to pilot and test, before implementing system-wide changes. In addition, the results of this pilot and test work may have implications for distribution system upgrades. However, proposals for upgrades are outside the scope of the analysis and this paper.

There is no single generally accepted definition of DER in the industry today. For purposes of the working group, the most useful definition is simply to define DER in terms of their point of interconnection relative to the T-D interface. Under this definition DER are located on the distribution side of the T-D interface, either on the end-use customer side of the meter or on the utility side of the meter. With this as the primary criterion, there is no need to limit DER to any particular size or technology type. DER can include distributed generation, energy storage, electric vehicle charging, micro-grids, as well as more traditional energy efficiency and demand response resources.

Considering the possible DER growth as a force of change in the electric industry, it makes sense also to include new communication and control technologies that enable aggregation of smaller DERs into larger "virtual resources" to participate in wholesale energy markets and provide grid

ACRONYMS

CCA	Community Choice Aggregator
CPUC	California Public Utilities Commission
DA	Day Ahead
DR	Demand Response
DER	Distributed Energy Resource
DERA	Distributed Energy Resource Aggregation
DERP	Distributed Energy Resource Provider
DO	Utility Distribution Owner/Operator
DSO	Distribution System Operator
ESP	Energy Service Provider
FERC	Federal Energy Regulatory Commission
LSE	Load Serving Entity
ISO	Independent System Operator
M/LTE	Medium- /Long-Term Enhancement
MUA	Multi-Use Applications
NERC	North American Electric Reliability Corporation
NTE	Near-Term Enhancement
PV	Photovoltaic
RT	Real Time
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquistion
T-D	Transmission-Distribution
TO	Utility Transmission Owner
WDAT	Wholesale Distribution Access Tariff

2 Industry discussions of DER use the terms distribution utility, distribution operator, utility distribution company and, more recently and with a future-oriented focus, distribution system operator ("DSO") and distribution system platform ("DSP") provider, to represent potentially different specifications of the entity that operates an electric distribution system and may or may not assume additional roles and responsibilities with regard to DER. Because operation of the electric system is our primary focus, this article uses the term distribution operator or DO generically to refer to the entity that operates the distribution system, without getting into any distinctions the variety of terms may suggest. Toward the end we briefly consider potential future DSO or DSP models and how they might affect the design of an effective T-D interface coordination framework.

3 Advanced Microgrid Solutions, California Independent System Operator, California Energy Commission, Energy Innovation, Engie, Enphase Energy, Green Charge Networks, ICF, More Than Smart, Newport Consulting Group, NRG Energy, OhmConnect, Pacific Gas & Electric, Pathion, San Diego Gas & Electric, Southern California Edison, Sacramento Municipal Utility District, Silicon Valley Power, Tesla, and Stem.

4 See www.morethansmart.org for information on this organization.

services.[5] Currently, the DO does not have the same level of visibility, control and situational awareness of DERs on its system as the ISO does with transmission connected generators. This leads to one further distinction helpful for this effort. Some DERs will participate in wholesale markets operated by the ISO or provide other grid services at transmission level, whereas other DERs will operate entirely on the distribution side to provide services to end-use customers or to the DO. This distinction becomes important as we consider different DER use cases and the coordination or communication needs they raise.

To provide a manageable structure for its effort, the working group considered two future timeframes and three DER scenarios. The two timeframes are:

- Near-term (2017-18) with relatively low volumes of DERs but with some new DER aggregations participating in the ISO wholesale market, and
- Mid-term (at least 3-5 years into the future and possibly beyond) with much higher volumes and diversity of DERs and DER aggregations.

The paper examines three DER scenarios, where DERs:

1. Participate exclusively in the ISO market;
2. Provide services to the DO or to end-use customers, but do not participate in the ISO market; and
3. Engage in "multiple-use applications" ("MUA") by offering services from the same facility to the ISO, the DO and end-use customers; i.e., the combination of scenarios 1 and 2.

The paper recommends coordination steps for 2017 implementation that the ISO and DO should initiate, pilot and test, with support from DER providers. These steps should inform integration of new DER aggregations into the ISO market, without adverse impacts on system operation. For the near term, with small numbers of new DER aggregations expected, these operational measures will probably be manual procedures, in order to minimize implementation costs while organizations conduct pilots and "learn by doing".

- DOs should pilot processes to communicate advisory information on current system conditions to DER providers, so that the providers can modify their ISO market bids accordingly and if necessary submit outage or derate notifications to the ISO;
- The ISO should initiate processes that provide day-ahead DER schedules to the DO, for the DO to pilot performing a feasibility assessment or review to identify schedules that may create significant distribution system reliability or performance problems. In the longer term, if this procedure seems viable and useful, the ISO could also make available real-time dispatch instructions to the DO for feasibility assessment in conjunction with new DO technical capabilities such as DER Management Systems;
- The distributed energy resource provider should communicate constraints on its resources' performance to the ISO. This could be in the form of updated market bids for market intervals where bid submission is still open, or outage notifications for intervals where dispatch instructions have already been issued and there is no subsequent bidding opportunity;
- The DOs should pursue a pro forma DER Provider (DERP) "integration agreement" with the DER provider with regard to DER aggregations. The DO will typically have an interconnection agreement with an individual DER on its system, but when multiple DERs are aggregated into a virtual resource for ISO market participation, today there is no comparable agreement between the DO and the DER provider. The agreement could specify, for example, the responsibilities of the parties to support reliability of the system and enable the DER provider to realize the full value of the DER aggregation through provision of the various services its performance characteristics allow.

The final section then suggests some medium-term coordination possibilities in anticipation of a high-DER future, and briefly describes the need for further effort to explore how coordination arrangements might be shaped by different DSO models being explored in the industry. The section ends by indicating some of the tasks for ongoing working group activity in order to inform the development of a robust operational coordination framework for a high-DER future. Specifically, these other tasks for 2017 will analyze aggregated DER participation in wholesale energy markets under current and high DER penetrations using the following lenses:

- IMPACT ANALYSIS
  Conduct additional operational use case analyses to better understand existing and future electric distribution grid safety and reliability impacts.
- PROPOSED ENHANCEMENTS & MITIGATIONS
  Identify system protection and control enhancements and mitigations, to ensure distribution grid safety and reliability.
- OPERATIONAL FORECASTING
  Develop and pilot methods for short-term operational forecasting of DER activity and impacts at the T-D interfaces. This effort would emphasize the activities of DER that are serving customer needs or providing services to the DO, and may or may not be participating in the ISO market.[6]

5 The term "virtual resource" denotes the fact that from the perspective of the ISO and the wholesale market the aggregation is modeled as a single resource at a specific location on the transmission grid, even though physically the aggregation can be across multiple circuits and even p-nodes.

6 For more information, see the discussion of scenario 2 at the beginning of section 5.

2 | DER GROWTH IN CALIFORNIA

California's electric power resource mix is transforming, relying less on traditional, utility-scale fossil-fueled generation and more on renewable resources and distributed energy resources. The current trajectory in the growth, diversity, and energy contribution of DERs connected to the electric distribution system is expected to continue. Driving this growth are state policies and incentives encouraging DER development, the availability of cost-effective distributed technologies, and evolving customer preferences. Current levels of installed DER amount to approximately 10% of peak demand and are already affecting transmission and distribution system operations, with over 5,300 MW of rooftop solar installed on a system that has a peak demand under 50,000 MW.[7] Another growing DER type is plug-in electric vehicles. California is home to more than 250,000 plug-in electric vehicles.[8] To meet aggressive carbon reduction goals, "fuel switching" in the transportation sector will dramatically increase this number. Some forecasts predict DER capacity will double in California over the next decade. The increasing proportion of customer load served by DERs is making DERs an increasingly important part of California's electric supply mix.

The potential increased adoption and growth of all types of DERs is resulting in the electric grid becoming more decentralized. DER growth, especially from storage and electric vehicles, means owners of these devices can draw energy from, and inject energy into the grid at different times, amounts, and in the case of electric vehicles, locations. To defer costs and maximize return and revenue opportunities, DER owners and investors are interested in gaining access to wholesale markets and providing multiple services to multiple entities, e.g. the ISO, the distribution operator, and the end-use customer.

In response to the growing interest in DERs, efforts are underway in California to lower barriers to DER participation and enhance DER access to new energy service opportunities. These efforts include various California Public Utilities Commission (CPUC) proceedings aimed at exploring distribution services provided by non-wires solutions and clarifying the rules on multiple-use applications for DERs.[9] At the wholesale level, the California ISO (ISO) worked with stakeholders to develop a platform for DERs to participate in the wholesale electricity market. In March 2016, the ISO filed tariff revisions with the Federal Energy Regulatory Commission (FERC) to enable resources connected to distribution systems within the ISO's balancing area authority to form aggregations of 0.5 MW or greater to participate in ISO energy and ancillary services markets.[10] FERC approved the ISO's new DER aggregation platform in June 2016.

7 http://www.californiadgstats.ca.gov/

8 http://www.pevcollaborative.org/

9 CPUC proceedings particularly relevant to this working group effort are the Distribution Resources Plan ("DRP") proceeding (R.14-08-013) and the Integration of Distributed Energy Resources ("IDER") proceeding (R.14-10-003). Track 2 of the CPUC's Energy Storage proceeding (R.15-03-011) is addressing "multiple-use applications," situations where a DER provides services to and receives compensation from more than one entity, particularly the distribution utility and the ISO market. It should be emphasized, however, that the scope of the present working group and its focus on operations have been carefully specified to avoid overlapping issues with any CPUC existing proceedings and to focus on issues that CPUC proceedings are not addressing.

The growing contribution from DERs and their evolving role in response to new market opportunities are creating new operational challenges for the ISO and DOs. For instance, today 1) the ISO dispatches DERs without knowing the impact those dispatches have on the distribution system or if those dispatches are feasible and supported by the distribution system, 2) no adequate method exists to forecast how DER participation affects the net load and other important electrical characteristics, such as voltage, at the T-D interface, and 3) the DO does not have the same level of visibility, control and situational awareness of DERs as the ISO does with transmission connected generators. These challenges will only increase with increasing numbers of DERs; therefore, it is necessary and timely to identify the issues and consider how the ISO and DOs must enhance their operational coordination at the T-D interface to ensure the reliable operation of the grid in a high-DER future.

3 | OPERATIONAL CHALLENGES OF HIGH DER

DERs use both the transmission and distribution system when they participate in the ISO wholesale market, operate autonomously, or make sales and/or provide distribution services to the host DO. Although the two systems are interconnected and form the overall electric grid, the transmission and distribution grids are distinct, with inherently different structures, characteristics, functions and operating principles.

The primary function of the ISO controlled transmission grid is to provide bulk electric power delivery from utility-scale generation facilities to transmission-distribution substations via interconnected high voltage power lines organized as a meshed network. High voltage electric substations at numerous locations on the transmission network connect to distribution systems that deliver power to end-use customers via electric distribution lines.

The transmission-distribution (T-D) "interfaces" are those substations where the transmission and distribution grids interconnect. Historically, electric power at the T-D interfaces flowed only in one direction—from transmission to distribution. DERs can now inject electric power onto the distribution grid and, in certain circumstances, cause power to flow in reverse from the distribution system into the transmission system. At current DER penetration levels, utilities have already experienced reverse flows on certain distribution circuits.

3.1 | DISTRIBUTION SYSTEMS' LARGE AND COMPLEX TOPOLOGY

The different functions and operating paradigms of the transmission and distribution grids drive significant

10 Individual sub-resources in a DER aggregation cannot exceed 1MW in size.

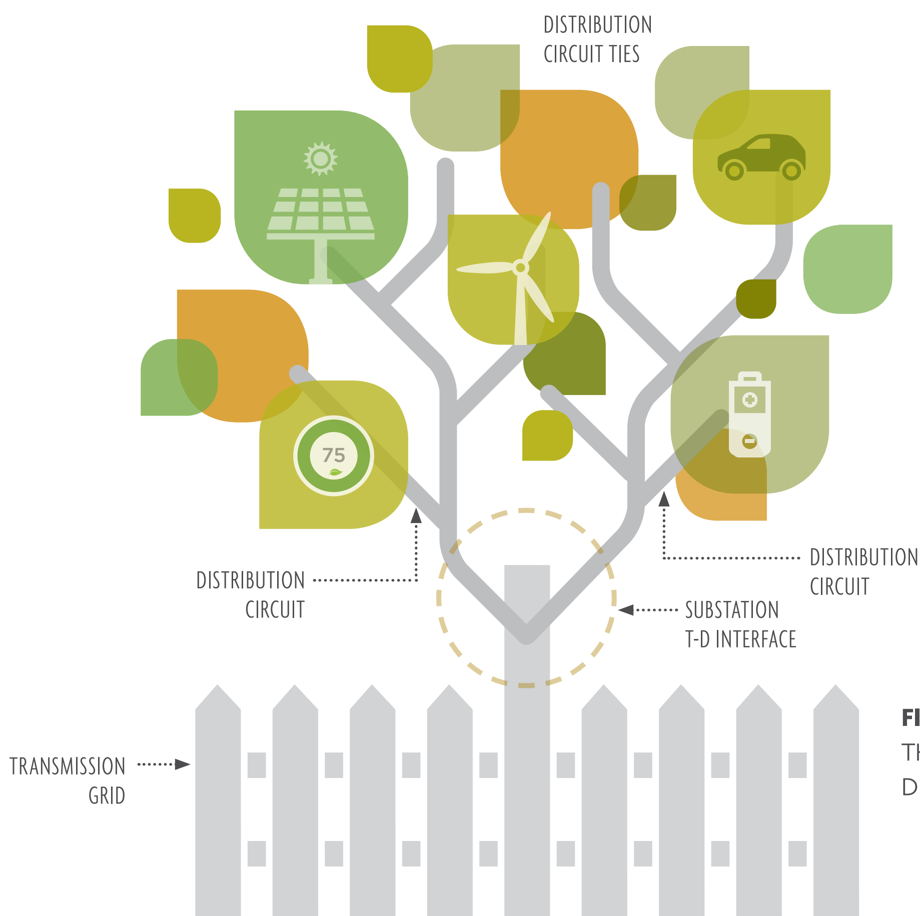

FIGURE 1. STRUCTURE OF THE TRANSMISSION AND DISTRIBUTION SYSTEMS

differences in their design. To deliver power to retail customers, the vast majority of distribution grids have a radial design that extends electric service to end users from a central substation, where energy flows down a circuit to serve end-use customers. In contrast, the transmission system[11] is largely a "meshed" (rather than a radial) network designed to facilitate the injection and withdraw of energy at multiple points on the network. The transmission grid is designed with redundancy to minimize bulk power outage impacts and to meet mandatory reliability standard requirements established by the North American Electric Reliability Corporation (NERC).

The simple diagram above illustrates how radial distribution circuits that make up the distribution grid offshoot from the networked transmission grid at the T-D interface.

The distribution system, represented by the tree in the illustration above, is much larger than the transmission system when measured by miles of lines. For instance, the ISO-controlled transmission grid is comprised of 26,000 miles of lines, while the three investor-owned utility distribution grids have over 255,000 miles of lines, in aggregate.[12] Although the larger size of the distribution grid creates more potential DER interconnection points, the grid cannot necessarily accommodate unlimited quantities of DER energy injections without further study and, in some instances, distribution grid enhancements. The sheer number of DERs that may want to interconnect to the distribution system could place a significant burden on distribution planning staff that must evaluate these interconnections, and will add complexity to the design and operation of the distribution system, while introducing new operational challenges at the T-D interfaces.

3.2 | FREQUENCY OF DISTRIBUTION OUTAGES AND USE OF SWITCHING CONFIGURATIONS

Distribution relies on highly branched topology, 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 causes a significant number of unplanned outages, due to, for example, cars hitting poles, failed equipment, animal activity, weather, etc. Under favorable conditions, often referred to as a "blue sky day", a DO may face multiple outages impacting 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.

11 The ISO manages the flow of electricity across the high-voltage, long-distance power lines that make up 80 percent of California's and a small part of Nevada's transmission grid.

12 PG&E has over 141,000 miles of distribution lines, SDG&E has almost 24,000 miles of distribution and SCE has 90,401 miles of distribution.

For instance, switching distribution circuits changes the system's topology 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. This abnormal circuit configuration is typically temporary, however, abnormal configurations can remain for multiple days to a few months if 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 affect a DER's ability to participate in wholesale energy markets on the transmission system without additional constraints. Depending on distribution grid loading or voltage conditions, DER's may need to be ramped up or curtailed if thermal or voltage violations occur, or reconfigurations between circuits may need to be initiated. This problem is exacerbated due to the lack of visibility into the operation of individual DERs and the power flowing on distribution circuits, given current distribution system automation and Supervisory Control and Data Acquisition (SCADA) capabilities. Thus, safety and reliability problems could result if DER operators are unaware of circuit reconfigurations that affect their DERs. Enhanced communication in advance of, and during outages, as well as greater visibility of DER performance by the DO is needed to ensure transparent, consistent, and feasible dispatch instructions are conveyed to DER operators at all times in response to system conditions. Currently, the DO does not have the same level of visibility, control, and situational awareness on DERs as the ISO does with transmission connected generators.

3.3 | FORECASTING THE SHORT-TERM EFFECTS OF DERS ON GROSS AND NET LOAD

Increased DERs present challenges for gross and net load short-term forecasting, for purposes of operating the transmission and distribution systems. The ISO and the DO need accurate short-term forecasts to operate their systems reliably and to run real-time wholesale markets. For example, the ISO needs to forecast real-time conditions accurately so that sufficient capacity can be committed at least cost to ensure the safe and reliable operation of the transmission system.

The challenge today is most DERs do not participate in the ISO market as supply resources, but "self-dispatch" as load modifiers, altering the overall load shape and making load forecasting difficult. Without accurate load forecasts, the ISO and DOs have less certainty about whether sufficient resources are available and committed to serve load and maintain system stability. This uncertainty can lead to inefficient over-commitment of supply resources to ensure against insufficient supply during real-time operation.

3.4 | LACK OF VISIBILITY, SITUATIONAL AWARENESS, AND CONTROL

Currently, the DO and the ISO do not have visibility and situational awareness about the location, status, and output of DERs, and their overall impact to power flows along each distribution circuit, sufficient to accurately predict the impact DERs have on the grid. Similarly, a DER operator does not have visibility into the distribution system's capabilities to ensure their exported energy is feasible and deliverable, creating risk regarding their ability to deliver on energy or ancillary services they may have sold in the market.

Distribution operators need better visibility into their own distribution systems, including tools to predict DER behavior, view real-time DER response, and forecast DERs' impacts on the grid. The ISO has very similar information and forecasting needs to reliably manage the transmission system. DOs may also need to modify a DER's behavior via instructions or controls to maintain the safe and reliable operation of the distribution grid. Similarly, DER operators need information about the state of the grid where they are interconnected so they can minimize deliverability risks and maximize market participation opportunities. In the future, the DO will require new tools, such as software control capabilities, to ensure the safe, reliable and efficient operation of the distribution grid.

3.5 | DER EFFECTS ON DISTRIBUTION SYSTEM PHASE BALANCING AND VOLTAGE REGULATION

Because most small DERs connect to one of three phases, balancing loads between the three phases[13] of the distribution system becomes more challenging with higher penetrations of DERs since DERs can alter power flow on the distribution system and create phase imbalances and voltage regulation problems. Historically, distribution engineers have generally allocated customer loads equally on the three phases based on peak loading scenarios, with load imbalances on each phase expected to be within a five percent tolerance. With higher levels of DERs on the distribution system, distribution engineers must also consider the effects DERs' output, location and characteristics have on the distribution system to determine how to mitigate phase imbalance and voltage regulation problems. Additionally, as more and more DERs interconnect to the distribution system, more sophisticated interconnection processes, planning processes, and construction methods will be required to maximize the efficient use of the distribution system, and to inform where investments are most needed.

13 Electric power is generated, transmitted and distributed using a three-phase system. A three-phase system is more economical than a single-phase system. In a three-phase system three wires each carry an alternating current of the same frequency and voltage but with a phase difference of 120 degrees between individual phases. Three-phase power may serve a neighborhood, but the individual household loads are connected only as single phase. In a perfectly balanced case all three wires share equivalent loads.

4 | TRANSMISSION-DISTRIBUTION COORDINATION TODAY

This section describes the current state of communication and coordination among key entities – the ISO, the DO and the DER providers – to provide a reference and starting place for identifying new and enhanced communication channels and procedures to support a high-DER future.

The diagram below illustrates the key functional entities involved with DER participation in the ISO market and the existing communication and coordination links between these entities. The diagram is based on how demand response (DR) works today; the DR processes and procedures are generally understood and relatively similar for all IOUs.

Note that the diagram identifies four key functional activities within the utility. The functional departments of the IOU are:

1. Utility transmission owner (TO)
2. Utility distribution operator (DO)
3. Utility demand response program manager (utility DR)
4. Load-serving entity (LSE)

These four departments are distinct entities because each has their own roles and responsibilities. The communication and coordination practices between them are typically well-defined and formalized, and these groups comprise an essential element of the working group's inquiry. For example, the Utility DR function may be called "Customer Programs" or "Customer Care" within an IOU organization, but the function is consistent across the IOUs. Another example is the utility LSE included in the same box with other types of LSEs, i.e., direct access electric service provider (ESP), community choice aggregator (CCA), and municipality (muni). This reinforces the point that the LSE role, like the other three distinct IOU roles, represents a distinct functional area considered by the working group.

The three entities directly involved in DER participation in wholesale markets are the ISO, the DO, and the DERP.[14] These entities are color-coded to distinguish them from the other entities in the diagram. One important observation is that today there is no direct connection between the ISO and the DO. This means, for example, that today the ISO communicates directly with the Utility TO regarding the dispatch of the non-market utility DR, and the Utility TO manages the dispatch of these resources. In a high-DER future, coordination between the ISO and the TO will necessarily remain, but ISO-DO coordination on operational matters will require direct communication between the ISO and the DO, rather than working through the TO as an intermediary.

Another important observation about this diagram is the one-way communication link between the Utility DO and the DER providers. This will be an important

14 There are two types of DER provider shown in the diagram for completeness, but for purposes of this article the differences between them are not relevant. A "WDAT DER" is a resource that interconnects to the distribution system under the FERC-jurisdictional "wholesale distribution access tariff" ("WDAT" or "WDT") explicitly for the purpose of participating in the wholesale market. The "non-utility DR/DER provider" involves resources that interconnect under a state-jurisdictional interconnection rule, such as the California PUC's Rule 21. Resources in this latter category typically connect behind the end-use customer meter.

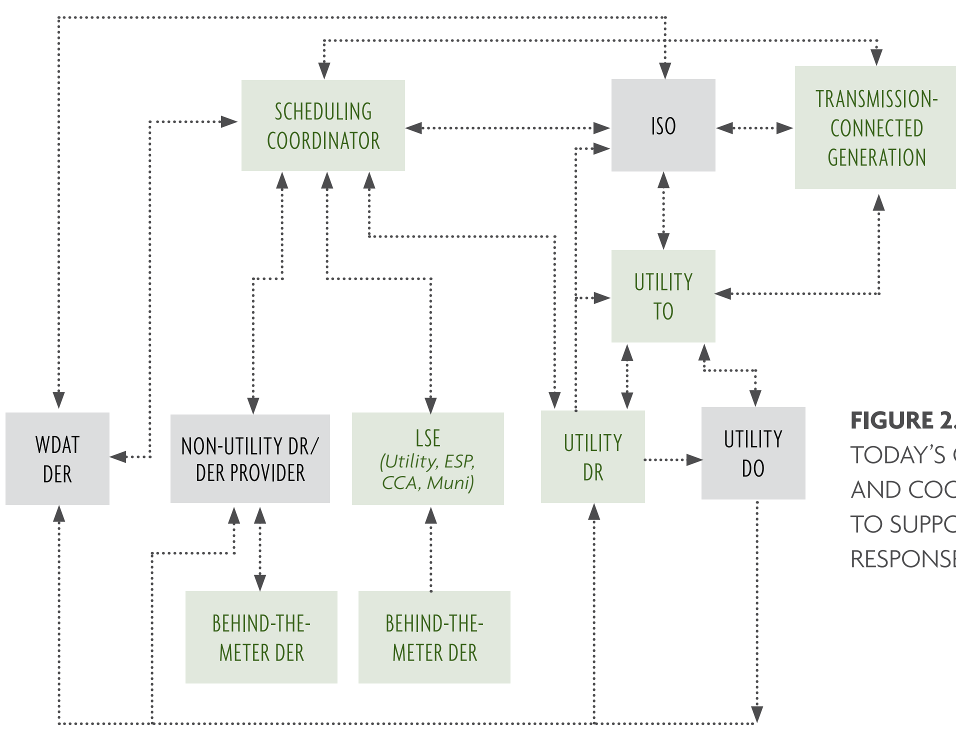

FIGURE 2. TODAY'S COMMUNICATION AND COORDINATION LINKS TO SUPPORT DEMAND RESPONSE (DR)

area for enhancement, as we discuss in the next section. For example, absent any enhanced coordination or new information sharing, a DER provider participating in the ISO market may lack information necessary for that entity to meet its respective responsibilities and objectives. In other words, based upon the information flows that exist today, each entity lacks sufficient and complete information to fully inform decisions in a high-DER future.

5 | THE HIGH-DER FUTURE

Taking Figure 2 as a starting point, we now consider how to enhance the communication and coordination flows to ensure reliable system operation as more numerous and more diverse DERs connect to the system. Some DER will participate actively in the ISO market, others will provide services to the DO or to end-use customers, and some will engage in multiple-use applications involving services to the ISO, the DO, and end-use customers from the same resource. All of these scenarios will have operational impacts on the distribution system and at the T-D interfaces.

This inquiry is structured in a number of steps, based on two future timeframes and three DER scenarios, to focus the discussion more effectively. The two timeframes are:

- Near-term (2017-2018) with relatively low volume of DER but some new DER aggregations entering the ISO market under the DERP model, and
- Mid-term (3-5 years into the future and possibly beyond) with higher volumes and diversity of DER and DER aggregations.

The three DER scenarios – which this paper discusses in sequence – are:

1. A DER participates in the ISO market only, and while it may be located behind the meter and provide services to end-use customers, it does not provide services to the DO. For example, this DER could be a 2 MW solar PV plus storage facility connected directly to the DO's distribution system, or it could be a commercial "smart building" that looks like a single resource/customer at a single point of interconnection, but has rooftop PV, workplace charging for employee vehicles, internal thermal storage for cooling, and an electronic control system for maintaining building services and responding to ISO dispatch signals. The relative simplicity of this scenario is due to the fact that the resource is not providing explicit services to the DO.
2. A DER provides services to the DO to support reliable operation or defer a distribution infrastructure upgrade, and may provide end-use customer services from behind the customer meter to reduce the customer's demand charges. For simplicity, the scenario assumes the resource is not participating in the ISO market. Thus, the concern at the T-D interface is more a problem of forecasting the net load at the T-D interface based on the anticipated behavior of the DER in the local area.
3. Scenario 3 moves fully into the multiple-use arena and allows DERs to operate simultaneously, providing multiple services under both scenarios 1 and 2. Scenario 3 raises operational concerns not present in the first two scenarios, such as the potential for conflicting needs and dispatch instructions from the DO and the ISO to the same DER at the same or overlapping times.

For the near-term horizon, the working group focused on scenario 1, with the expectation that some DER aggregations will participate in the ISO market under the ISO's DERP tariff provisions in 2017. For the mid-term, the working group considered all three scenarios.

5.1 | ROLES AND OBJECTIVES OF THE ISO, DO AND DER PROVIDER

For DERs or DER aggregations that participate in the ISO market, the following statements reflect certain ISO, DO, and DER/DERP roles and objectives relevant to this paper that are derived from the core operational responsibilities of the ISO and the utility distribution company, and which incorporate basic DER provider business objectives. They do not represent all of the ISO's or DO's responsibilities and objectives. For example, a core ISO responsibility is to operate a wholesale electricity market, but because this paper is focused on operational concerns, wholesale market details are not examined.

These objectives help guide the development of an enhanced operational coordination framework for the ISO, DO and DERP, and provide criteria for evaluating potential solutions to the various challenges identified earlier in Section 3. As with any set of potential approaches or solutions to address specific needs or problems, there are tradeoffs. In addition, the appropriateness and feasibility of particular approaches depend on how the functional roles and responsibilities of the DO evolve in the future (see section 5.4).

- OBJECTIVE
  Providing the ISO predictability of DER responses to dispatch instructions at the T-D interface.[15]

  The ISO needs confidence that resources will fully respond when it sends a dispatch instruction. This applies to distribution connected DER as well as transmission-connected resources. The ISO recognizes there is always uncertainty as to whether a resource will fully respond in a timely manner. The ISO market design addresses this concern by providing incentives for resources to comply with dispatch instructions. One important difference between DERs and conventional generators is

15 The T-D Interface is represented in the ISO market system as a p-node. The term "p-node" stands for pricing node, a point on the ISO controlled grid where the ISO market software calculates a nodal energy price. In general, a p-node is either a T-D substation where the ISO grid connects to a utility distribution system, or a generator point of interconnection, or an intertie between the ISO and a neighboring balancing authority area.

a DER's response to a dispatch instruction can be affected by current distribution system conditions, yet the ISO has no information about the state of the distribution system when issuing dispatch instructions. Moreover, the DER's response to an ISO dispatch, depending on DER penetration and participation levels, may have negative impacts on the distribution system that impact the resource's ability to fully respond to an ISO dispatch instruction. From the ISO's perspective, what is most important is having confidence that the expected energy from an ISO dispatch instruction is delivered at the T-D substation, which is consistent with the ISO's DERP tariff provisions. Enhanced coordination with the DO will support this objective.

Another ISO concern is DERs that do not participate in the ISO market, but whose behavior affects net demand or other operational parameters at the T-D interface. For instance, a DER providing services behind an end-use customer's meter, or providing services to the DO, or both, unbeknownst to the ISO. In a high-DER future, accurately forecasting autonomous DER behavior at the T-D interface will be crucial for transmission and distribution operations in support of safety and reliability. Therefore, a key element of operational coordination will be to specify the roles and responsibilities of the ISO, DO, and DER/DERP in ensuring timely and accurate information is available to produce accurate short-term forecasts.

- OBJECTIVE
  Ensuring a DO understands the current and predicted behavior of the DERs on its system to maintain reliability and safety.

  The information the DO requires depends upon more locationally granular short-term forecasting than the ISO needs. In addition the DO may need the ability to modify DERs' behavior via instructions or controls to maintain reliable operation. In scenario 2 the DO may attain the ability by procuring distribution grid services from a subset of appropriately-located DERs/DERA with the required performance capabilities. But under scenario 1, prior to establishing specific services that the DO can procure from DERs, the DO still needs some kind of operational control if required in real time to prevent an ISO dispatch instruction creating a problem on the distribution system.

- OBJECTIVE
  Allowing a DERP to participate in all markets for which it has the required performance and measurement capabilities, and to reasonably manage risks of potential curtailment.

  A DER/DERP must be able to participate in markets in a non-discriminatory manner, optimize its choice of market opportunities, and have the information and ability to manage risks and consequences of potential curtailment.

5.2 | A (RELATIVELY) SIMPLE INITIAL SCENARIO

As a starting point, scenario 1 is where a DER bids into the ISO wholesale market and receives an ISO dispatch instruction. Other more complicated scenarios will be considered, but focusing initially on this simple scenario reveals basic needs for an operational coordination framework.

Currently, the ISO's systems see a participating DER as if it is electrically connected at the T-D substation, not at its actual location in the distribution system. The DO knows the installed capacity and other characteristics of each DER from its interconnection process. However, existing processes and procedures do not inform the DO of a DER's bids or ISO dispatches, nor are there procedures to inform the ISO or the DER of current distribution system conditions that could inhibit the DER from fully responding to an ISO dispatch instruction. Thus none of the key parties – the ISO, the DO or the DER operator or its scheduling coordinator – has sufficient information to assess potential impacts DER bids and dispatches have on the distribution system, or how current conditions on the distribution system may render an ISO dispatch infeasible. This information and coordination gap, if not addressed, could create operational challenges that affect the reliability of the distribution and transmission systems.

5.3 | COORDINATION ENHANCEMENTS FOR 2017-2018

For 2017, the working group has focused on the basic scenario 1 described at the beginning of section 5, where the DER or DER aggregation is participating in the ISO market under the ISO's DERP tariff provisions. The table shows in cells without the numbered dots the types of information possessed today by the ISO, utility TO, utility DO and DER provider, and then adds with the numbered dots recommended near-term enhancements ("NTE" in the table) and medium-long term enhancements ("M/LTE" in the table).

One salient observation related to the preceding discussion is that until new information exchanges are implemented, the rows for day-ahead and real-time forecasts of DER impacts at the T-D interface (rows 6 and 7) and distribution feasibility of schedules (row 11) reflect gaps based on current communications infrastructure; that is, these functions do not exist today. None of these entities has knowledge of whether day-ahead schedules or real-time dispatch instructions by the ISO are feasible with respect to the distribution system. The DO does not know because it is not informed of, and has no procedures to act on, DER schedules and dispatches; the other entities do not know because they are not informed about current distribution system conditions.

The enhancements marked by the numbered dots in the table and discussed here reflect the working group's initial recommendations for dealing with information gaps that exist today but must be addressed as the volume of DERs grows. Keep in mind that the focus of this paper is the flow of operational communications, so there is no consideration

FIGURE 3. NUMBERED DOTS INDICATE POSSIBLE COORDINATION ENHANCEMENTS FOR 2017 (NTE) AND FOR THE MEDIUM-LONG TERM (M/LTE) TO SUPPORT RELIABLE OPERATION WITH HIGH DER

INFORMATION TYPE	ISO	UTILITY TO	UTILITY DO	DERP
1 | DER/DERA bids into ISO market	✔		NTE 2	✔
2 | Installed capacity of each DER and DERA			✔	✔
3 | Total installed DER capacity per T-D substation			✔	
4 | Transmission topology and conditions	✔	✔		✔
5 | Distribution topology and conditions			✔	NTE 1
6 | DA forecasts of DER impacts	M/LTE 9	M/LTE 10	M/LTE 7	
7 | RT forecasts of DER impacts	M/LTE 9	M/LTE 10	M/LTE 8	
8 | DA schedules (results of ISO market)	✔	M/LTE 11	NTE 3	✔
9 | RT dispatches (results of ISO market)	✔	M/LTE 11	NTE 3	✔
10 | Transmission feasibility of schedules	Ensured by ISO market optimization			Ensured by ISO market optimization
11 | Distribution feasibility of schedules	NTE 6		NTE 4	NTE 5
12 | DER/DERA revenue meter data	(for participating DER/DERA)			✔
13 | Generation Telemetry (for real-time observation)	(>= 10 MW or providing AS)		(>= 1 MW)	✔
14 | T and D System Telemetry (for real-time observation)	T system (consistent across the system)	T system (consistent across the system)	D system (inconsistent)	

of infrastructure planning and investment in this discussion.

For **near-term enhancements**, Figure 3 identifies the following:

- **Items 1 and 2 :** address "ex ante" coordination, i.e., prior to the DER submitting bids to the ISO.
- **Items 3 - 6 :** address "ex post" coordination, i.e., after the ISO has issued day-ahead schedules or real-time dispatch instructions to the DER.

Item 1 : The ability of a DER/DERP to utilize its full capacity in the ISO market will depend on current distribution system conditions. The DO's distribution system will have a specified "normal" configuration for all its circuits, which reflects the state of the system typically used for interconnection studies[16]. In practice, there will be some number of "abnormal" configurations in some areas of the distribution system almost all the time. This high degree of topology variability is a crucial feature that distinguishes distribution from transmission. This suggests that the DO could make available current system condition information[17] to the DER/DERP, ideally in advance of its submission of bids to the ISO (i.e., before 10 am for the day-ahead market, and hourly before the T-75 minute market for the real-time market).

One approach for 2017 could be for the DO to provide a circuit-level signal to the DER/DERP based on whether conditions relevant to DER performance capability render the dispatch infeasible as determined by the DO; the signals are relative to the original conditions evaluated for each DER's interconnection. A future approach may be to evaluate real-time violations via an automated distribution management system, whether due to changes in forecasts or circuit reconfigurations, and to notify affected aggregators accordingly. Regardless of the approach, the DO will require additional grid visibility.

A question to consider is whether the DO should also provide the same information to the ISO. The sense of the working group is that it would be preferable for the DO to provide this "conditions" signal to the DER/DERP who would then inform the ISO, as necessary and appropriate. This approach would likely involve some new requirement by the ISO for the DERP, to inform the ISO of limitations that are not due to the resource's ability to perform, but instead

16 Normal is defined at the point of the interconnection study and may permanently change in future circumstances.

17 Current system condition information could include planned maintenance, forced outages, system limitations, etc.

result from current distribution system constraints.[18]

Item 2 : A related question is whether the DO should receive the DER bid quantities prior to submission to the ISO to assess and then inform the DER/DERP whether the full bid amount is feasible given current and planned conditions. One variant is for the DO to assess whether there are circuit(s) constraints that may prohibit DERs from operating at full installed capacity (as reflected in the DER's interconnection agreement) and/or based on current distribution system conditions and provide this information to the DER/DERP without seeing the bid quantities, rather than assessing the feasibility of DER bid quantities. One consideration in favor of the DO seeing bid quantities is if multiple DER/DERA within a local area cannot all be feasibly dispatched at their full capacity due to a constraint, it may be possible to accommodate their full bid quantities if some of the DERs/DERAs bid less than their full capacity. This could avoid the need for the DO to apportion a curtailment among different DERs/DERPs, which is a function not likely feasible in 2017. However, this situation – where bid DER quantities are feasible while full DER capacities are not – may not be a common scenario, so there will eventually need to be transparent and non-discriminatory procedures for the DO to reliably and fairly apportion distribution system constraints across multiple DER/DERPs.

Items 3 - 5 : Once the ISO issues Day Ahead (DA) schedules and Real Time (RT) dispatches, the DO is in the best position to assess whether these are feasible dispatches given current distribution system conditions (item 4), for which the DO needs to be informed of the dispatches and schedules (item 3). For the near-term, distribution grid facilities must be in normal operating conditions with no planned or unplanned outages to support DERA market participation. While a manual process may work for a limited number of impacted circuits, once DER penetration increases, the question of how the DO coordinates reliable dispatch among multiple DER/DERPs will need to be addressed. Unless automated, DOs may not be able to accomplish the notifications. In any event, the DOs must have the ability to address violations that occur during real-time based on changing loads or reconfigurations.

Item 6 : An open question is whether the DO should also provide DER dispatch feasibility information to the ISO. As noted above with regard to ex ante constraint information, it may be most efficient to require the DER/DERP to provide this information to the ISO, which may entail creating new provisions requiring that the DER/DERP perform this function.

In addition to these measures involving information exchanges, another approach discussed in the working group is for the distribution utilities to develop a pro forma "integration agreement" between the DO and the DERP for a DERA. The DO would already have an interconnection agreement with each individual DER on its system that would have provisions to address curtailments for real-time operational needs. However, there is currently no such agreement between the DO and a DERP for a virtual resource that is an aggregation of individual DER sub-resources participating in the ISO market. The integration agreement would specify the DER aggregations' obligation to the DO as a condition of participation and, conversely, the DO's obligations to the DER aggregation.

RECOMMENDED 2017 ENHANCEMENTS

In conclusion, the working group offers the following recommendations for 2017 enhancement pilots to enable DERP participation, assuming low volumes of DER participation and reliance on manual processes.

1. **DOs should pilot processes that communicate advisory information on system conditions**

   To the extent known distribution system conditions will impact or prevent DER participation, the DOs should communicate advisory information on system conditions (if and when such information exists) that constrain DER performance on an "ex ante" basis so that the DER may modify their ISO market bids accordingly.

2. **The ISO should initiate processes that provide day-ahead DER schedules to the DO**

   The ISO should provide day-ahead DER schedules to the DO so that the DO can identify any infeasibilities in those schedules due to current distribution system conditions and notify the DER/DERP (e.g., an "unavailable" notification). In 2017, assuming small numbers of DER participating in the wholesale market, this would largely be a manual process. For the longer-term the working group will consider extending this feasibility assessment to include ISO real-time dispatches.

3. **The DERP should communicate constraints on DER performance to the ISO**

   The DERP should communicate to the ISO, through the ISO's outage management system, any distribution system constraints on DER performance that could limit the DER's availability or cause the DER to deviate from an ISO schedule or dispatch (i.e., the information provided by the DO to the DERP under items 1 and 2.

4. **The distribution utilities should assess a pro forma "integration agreement" with the DERP**

   The distribution utilities should assess the concept of a pro forma "integration agreement" between a DO and a DERP that is aggregating multiple DERs to form a virtual resource for ISO market participation. The agreement would specify the DERP's obligations to support the safety and reliability of the system to the DO as a condition for

18 The ISO PGA requires a generator to notify the ISO immediately of any derate in its capacity. For a transmission-based limitation, the ISO market optimization receives current grid conditions and uses that information to establish a feasible generator schedule or dispatch through the market. The ISO market optimization does not see derates on the distribution system, however, so if the UDC has to constrain the DER in some way, the rules need to clarify who has responsibility to inform the ISO. In such case the DER facility itself is not derated so the existing PGA rule would not apply.

participation and the DO's obligations to the DERP based on the various services its performance characteristics allow.

5.4 | POSSIBLE MID-TERM TO LONG-TERM COORDINATION ENHANCEMENTS

In the discussion in section 5.3 of enhancements for 2017, the working group focused only on scenario 1, the case where a DER/DERA participates only in the wholesale market. In this section, the working group expanded its focus to include scenarios 2 and 3, which was DERs serving end-use customers, providing services to the DO, and participating in the wholesale market. In terms of the DO models, the working group focused first on scenario 1 as the current trajectory model. The entries labeled "M/LTE" in the above table identify medium-/longer-term enhancements.

The first thing to notice is the entries in rows 6 and 7 for DA and RT forecasts of DER impacts. Items 7 and 8 indicate that the DO may be the entity best situated to create these forecasts. At the same time, with the great variety of DER coming onto the system, many of which will be controllable devices such as storage and will be providing multiple services to different parties, there will need to be considerable effort invested in developing short-term forecasting methods.

Items 9 and 10 indicate that the ISO and the Utility TO need to receive the forecasts. From the ISO perspective, this would entail forecasts at each T-D interface from the impacts of "autonomous" DER behavior (i.e., behavior other than DER responses to ISO schedules or dispatches), including DER services to end-use customers and services provided to the DO. The ISO needs forecasts in both DA and RT of the gross load and production at each T-D interface, not just the net load. The needs of the Utility TO would be essentially the same level of granularity, to support reliable operation of the transmission system.

The DO's needs would be more locationally granular, however, as the DO must manage DER activity on each circuit in its system. Since the DO has both the need for the most granular information and is best situated to obtain that information, the DO will likely have a major role in developing and providing the required forecasts.

Item 11 is the provision of DA schedules and RT dispatches to the Utility TO. This will be more important for operational reasons as the volume of DER in the wholesale market increases.

Scenario 3 under a high-DER future raises the question of multiple-use applications, specifically situations where DERs are providing services to the DO and participating in the ISO market. In this scenario, there is a potential for conflicting needs or instructions. As noted earlier, the subject of multiple-use applications is being considered in Track 2 of the CPUC's energy storage proceeding. The outcomes of that proceeding will likely have implications for further enhancement to ISO-DO-DER coordination.

In summary, the working group's primary recommendation in anticipation of a high-DER future is to explore ways to advance operational short-term forecasting of DER activity at sufficient temporal and geographic granularity to meet the operational needs of both distribution and transmission operations.

6 | TOPICS FOR CONTINUING WORKING GROUP EFFORT

The efforts described in this white paper represent a start on developing a high-DER coordination framework for the distribution utilities, the DER providers, and the ISO. The working group's efforts are continuing in 2017 to consider longer-term coordination needs and solutions, to learn from the experience of new DERs/DERAs coming into the market in 2017, and to keep pace with DER-related developments in California and the industry as a whole.

For 2017-18, the working group has identified the following topics:

- Develop and pilot methods for short-term operational forecasting of DER activity and impacts at the T-D interface. This effort would emphasize the activities of DER that are serving customer needs or providing services to the DO, and may or may not be participating in the ISO market (see the discussion of scenario 2 at the beginning of section 5).
- Perform additional operational use case analyses to better understand existing and future electric distribution grid safety and reliability impacts due to aggregated DER participation in wholesale energy markets under current and high DER penetration conditions.
- Identify options for feasibility assessment by the DO of ISO day-ahead schedules and real-time dispatches, to identify instances of infeasible schedules and dispatches and communicate the results to the DER and, at least for real-time dispatches, to the ISO.
- Develop proposed enhancements and mitigations around system protection and controls needed to ensure distribution grid safety and reliability due to aggregated DERs participation in wholesale energy markets under current and high DER penetrations
- Better define real-time coordination processes and procedures to address potential conflicts between DO operational needs and ISO dispatches. This concern is particularly relevant in the context of "multiple-use applications" where a DER provides services to the DO while participating in the ISO market. It is also relevant more generally, however, for instances where the DO needs to manage real-time operating conditions that may constrain a DER's ability to comply with its ISO schedule or dispatch instruction.
- Refine approaches for operational curtailments by the

DO to DERs affected by distribution constraints (e.g., precision beyond an "available/unavailable" order). In addition to the basic coordination between the DO and a DER provider regarding distribution system constraints, in a high-DER future there will likely be multiple DERs/DERAs with different owners/operators that are affected by a given distribution system constraint. In such cases the DO will need ways to allocate limited distribution capacity among the different DERs affected by the constraint.

- Refine communication descriptions, including timing and high-level requirements for the data exchange needed to implement the elements of the coordination framework.
- Explore how different "distribution system operator" ("DSO") constructs being explored in the industry would affect the structure of DSO-DER-ISO coordination. Although the different possible DSO models are beyond the scope of this paper, the working group has recognized that there is a range of possible ways to structure DSOs in the future, each with its own specification of roles and responsibilities between the DSO and the ISO with respect to T-D interface operation. Not surprisingly, the design of an optimal T-D coordination framework will depend on how the functions, roles and responsibilities of the future DSO are specified. Moreover, it is quite possible that different DSO models will be implemented in different jurisdictions and perhaps even in different geographic areas within a large utility service territory, depending on the extent of DER growth in the area. More Than Smart is considering a subsequent white paper on this topic.