2024 White Paper

Utility Strategies for Implementing Distributed Energy Resource Management Systems (DERMS)

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INTRODUCTION

Distributed energy resource management systems (DERMS) are the monitoring and control systems used to integrate distributed energy resources (DER)—such as solar photovoltaics (PV), battery storage, electric vehicles (EVs) and manageable loads—with the grid. With DERMS, it is envisioned that these resources can be active parts of the power system, having configurable behaviors and the ability to respond to commands to provide services to both distribution and bulk systems.

Global efforts over the past decade have set the stage for DERMS, with interconnection requirements and grid codes such as IEEE 1547-2018[1] that require DER to have a wide range of grid-supportive functionalities and open, standards-based communication interfaces that make mass integration possible. Further support has come from goals and policies at utility, state, and federal levels that target high percentages of energy production from renewables and zero or low carbon in the energy sector. Studies performed by EPRI[2] recognize that active, communication-based control of DER can substantially increase the quantity of resources that can be hosted on distribution systems and enhance DER value through services.

While the term DERMS has become common in the utility industry, at the present time the majority of DER operate without management by the utility, and in many cases without direct monitoring. To move from the present state to a future where DER are connected and actively managed is complex. There are many technical questions, risks, and architectures to be considered. Grid reliability, safety, and power quality cannot be compromised at any point, so any transition from the present to a connected-DER state is likely to be taken in measured steps, a gradual evolution.

This paper recognizes the need for gradual processes and lays out a number of DERMS adoption pathways that may be considered. In addition, it recognizes that the starting point and time will differ for each utility based on its situation, including DER adoption rates, regulatory policy, and distribution system capabilities.

1 "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," in IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003), vol., no., pp.1–138, 6 April 2018. https://ieeexplore.ieee.org/document/8332112.

2 DER Contributions Toward 100% Renewable Energy. EPRI. Palo Alto, CA: 2020. 3002023120.

STEP ONE – WHAT IS A DERMS AND WHEN IS IT NEEDED?

The first step in any consideration for DERMS adoption is to determine if and when to begin. DER have been interconnected on distribution systems for many years, and in some locations in substantial quantities, without systems for active monitoring or management. So, it is appropriate to ask why a DERMS is being considered. What has changed, and what are the fundamental drivers? When DER need to be managed, there are many possible architectures and components as illustrated in Figure 1, only some of which may be needed initially. For example, is the immediate connection to individual DER something the utility should do, or is it better to let third parties handle it? If third party aggregators are involved, then what system does the utility need in order to manage and integrate with them? Are centralized control and communications needed, or could local DER gateways satisfy the initial needs while deferring cost and reducing risk?

Commonly cited drivers for DERMS include increasing hosting capacity, enabling distribution and/or bulk system services, and improving operational flexibility and resiliency. Some look further ahead and conclude that management of distributed generation, storage, and load will be a necessity given fewer bulk generation plants. In all cases, the baseline for determining the value of DERMS is the best-possible outcome without it, such as fixed (set-and-forget) settings. Business cases for DERMS can be complex and may include stacking of multiple benefit streams. Recognizing that each utility's situation is unique and factors that are central to one may be irrelevant to another, EPRI is developing a DERMS cost-benefit analysis tool to support assessments.

Figure 2 is from a recent report[3] that studied many feeders to determine the limits of solar DER contribution toward high renewables goals. The chart represents the average of all feeders studied, and the Y-axis gives the percentage of annual energy consumption on a typical feeder that could be met by solar generation on the same feeder. The colored sections identify technologies typically needed to reach those levels.

3 DER Contributions Toward 100% Renewable Energy. EPRI. Palo Alto, CA: 2020. 3002023120.

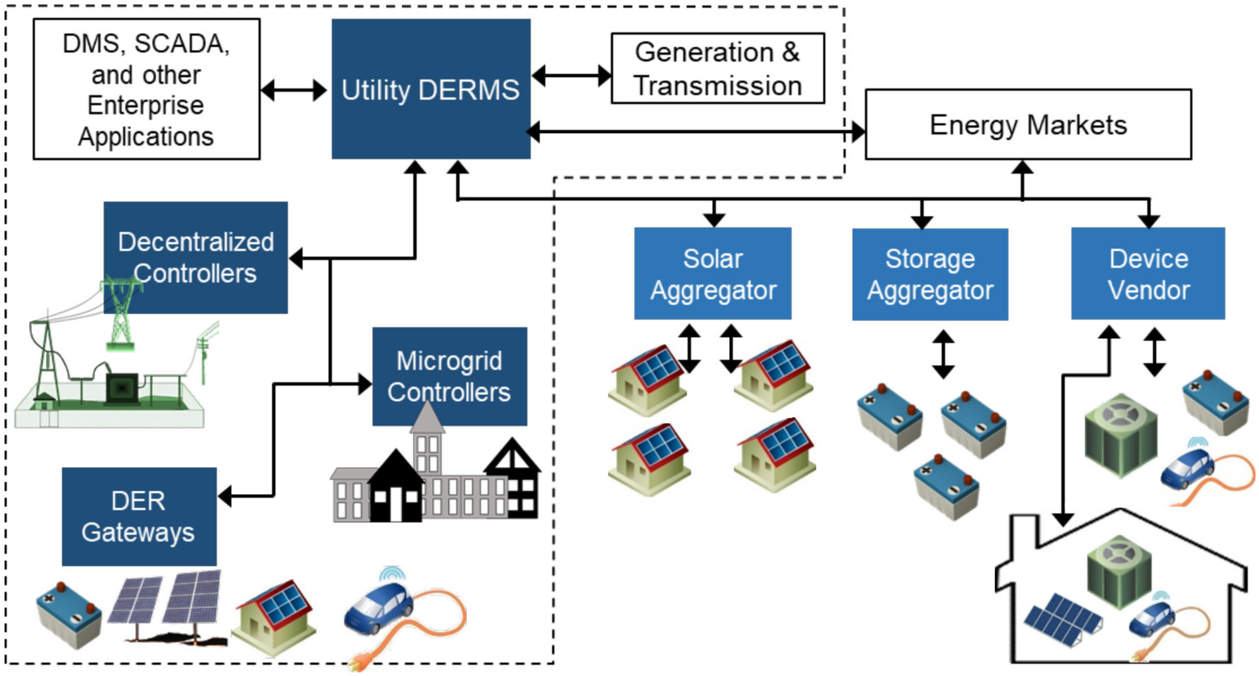

Figure 1. *DER management system (DERMS) components*

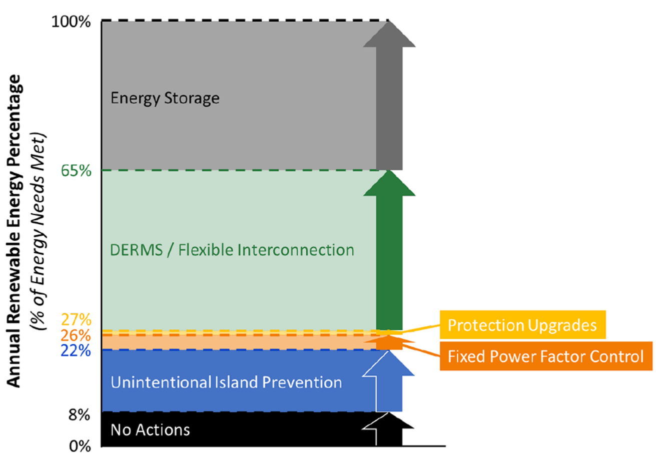

Figure 2. *DERMS use in increasing energy from distribution-connected solar*

Based on this data set, DERMS could increase what is achievable from 27% to 65%. While this is substantial, it is also notable that 27% could be achieved, on average, without it. For reference, in 2021, California produced 17.3%[4] of its energy needs from solar. If roughly 70% of this was distribution-connected, California would be at approximately 12% on the chart of Figure 2.

Since most regions have less solar PV and less DER overall than California, it is likely that aggregate, systemwide hosting capacity is not the first driver for DERMS. Individual circuits, on the other hand, may become constrained long before systemwide averages reach limits. The motivation for DERMS may begin when the first feeders become constrained, depending on regional policies and strategy. As discussed in the following sections, some DERMS adoption pathways may be useful to limit cost and risk when a few feeders are constrained but the systemwide average is low.

In some cases, the initial motivation for DERMS may be services—enabling DER to participate in non-wires alternatives (NWA) or through aggregation to participate in bulk-system markets. Providing this opportunity could add value to DERs and may be encouraged through policies and rulemaking such as the recent Federal Energy Regulatory Commission (FERC) Order 2222[5] in the United States. For this case, a key question is whether the utility or third-party aggregators will be directly managing the DERs, and the answer may depend on when the quantity of services provided by DER aggregations becomes mission critical—reliability related rather than just an economic optimizer. For situations where third parties are expected to perform aggregation initially, the utility's DERMS requirement may be a manager of aggregators rather than a manager of DERs directly.

4 https://ww2.energy.ca.gov/almanac/renewables_data/solar/index_cms.php.

5 https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.

CONSIDERING CONVENTIONAL APPROACHES

Existing distribution systems were, generally speaking, designed to deliver power in one direction and to do this in the most economical way given distances and load levels. So, it's no surprise that the integration of DER on these systems creates challenges. On the other hand, if distribution systems were completely redesigned with the requirement to support high levels of DER, then the solutions may be very different, such as shorter distances, higher voltage, and including more regulators and other utility control devices. It is likely that new designs would also include communication-based controls and edge intelligence, but these might play an optimizing role rather than being a critical dependence because of the inherent reliability and resilience of simple passive solutions.

The analysis behind Figure 2, and much of the industry effort in recent years, is about integrating DER on the systems that presently exist, the implication being that rebuilding the grid to accommodate high levels of DER will take time and more immediate solutions are required. But some conventional approaches may be possible without extensive redesign, including reconfiguring existing control devices, adding new ones, and selective reconductoring. The lower the projected adoption rates for solar and other DER, the longer before DERMS control may be needed, resulting in more time for a utility to make improvements that better position the system to accommodate DER.

Conventional approaches to increasing hosting capacity, sometimes called wires-based solutions, are robust in that they increase the fundamental capabilities of the grid, often passively, without depending on controllers, communication pathways, or other software. Once upgraded, the increased capacity is available 24/7 and long-life. However, while conventional grid improvements can improve hosting capacity, they typically don't address DERMS drivers such as enabling grid services and DER participation in microgrids. DERMS adoption roadmaps should take into account conventional upgrade plans and timelines.

PATHWAYS FOR GRADUAL DERMS ADOPTION

For some, the envisioned DERMS is a highly complex system with a large number of managed end devices, decentralized field hardware, many users, and interfaces with several other utility applications. It may include large databases and high computational speed responding to real-time data. For others, the plan may be simpler; but, in all cases, the newness of the application and uncertainties may lead to a desire to implement gradually. The following sections identify several ways this might be accomplished.

- Progressing from few to many connected DER
- Progressing from autonomous local controllers to connected central control
- Progressing from load control to other DER types
- Progressing from simple to complex capabilities
- Progressing from infrequent to frequent DER settings changes
- Progressing from human-operated to integrated/automated DERMS
- Progressing from unsupervised DERMS to manned distributed generation (DG) operations
- Progressing from third-party systems to utility systems
- Enterprise integration of DERMS

Progressing from Few to Many Connected DER

The complexity and cost that come with deploying a DERMS naturally increase with the quantity of DER that are connected. There may be certain fixed costs (those not scaling with quantity) such as procuring, installing, and integrating DERMS software in the control center, but also variable costs such as:

- Cost of onsite equipment required to get each DER communication connected
- Staff time to deploy and maintain the communication systems
- Ongoing data charges
- Data entry and setup of each managed DER or DER aggregator in the DERMS
- Establishing unique control algorithms to be applied to specific feeders or DERs

- Day-to-day staff time and attention to actively attend to individual DERs or DER aggregators
- Asset management/review to assess the health and security of connected DERs and communications

In addition to costs, there may be reliability and security considerations. Transitioning from simple, passive distribution operation to active management that includes control of DERs is new. Utilities may not have a long history with the software or communication systems involved and so may not have much data on which to base estimates of downtime.

A strategy for DERMS deployment that begins with a limited number of DERs and then increases the quantity over time is a straightforward way to manage these costs and complexities. Decisions to manage more DER can be based on a schedule (for example 10% per year), on an as-needed basis, or other rationale.

Selective Integration Based on Circuit Constraints

The decision to include a given DER in a management system may be based on necessity. If the location or feeder is constrained and cannot host a given DER's full unmanaged behavior, then the DER might be actively managed to avoid the violation. With this approach, the same size and type DER being deployed at a different location may not be managed by the DERMS because there is no need to do so. In either case, as conditions change over time, DERs could be added or removed from DERMS control.

Selective Integration Based on DER Scale

Another approach to limit the quantity of DER involved in a DERMS is to include only those above a certain scale. For example, a utility may require that PV systems greater than 500 kW be DERMS-connected while smaller ones are not. Because smaller systems tend to be more numerous, this may be an effective way to keep the quantity of DERMS-connected DERs low. DER scale alone, however, is an imperfect approach because (a) the aggregate effect of many smaller DERs is similar to the effect of one larger DER, and (b) regardless of what cutoff is used (for example 500 kW), there can always be locations that need DERMS to accommodate DERs smaller than the cutoff.

Selective Integration Based on DER Type or Usage

Some DER may require monitoring or management to achieve their intended purpose while others do not. Going forward, all inverter-based DER will likely be capable of providing autonomous grid-supportive services. For some, monitoring may be needed to quantify or verify services rendered even though remote management is not required. For example, certain DER that were conditionally interconnected (for example, must provide volt-var control) or are part of a paid autonomous program could require monitoring for verification or settlement. While standard advanced metering infrastructure (AMI) systems may be sufficient for some services, others that involve reactive power or voltage responses may require a DERMS.

For example, PV systems have a natural default behavior (peak power tracking) while battery storage systems may not. For this reason, in early DERMS deployments, battery DERs were found to be more likely to be integrated.[6] Another example is that of DER that are deployed with the purpose of providing bulk system services by participating in energy markets. These DERs require communication-connectivity so that they can receive dispatches and provide telemetry data.

To the extent that a distribution utility is involved in managing DERs with these types and uses, connectivity with the utility's DERMS may be limited accordingly.

Selective Integration by Region

In some cases, it may be advantageous to deploy DERMS one community or region at a time. In this way, the most pressing needs may be met while limiting risk, cost, and complexity. The areas deployed first serve as a learning opportunity for those that come later. A possible limitation of this approach is that the central DERMS software and associated training, operation (staff), and integration with other applications may be as complex as if all regions were covered. But there may also be upsides, for example:

- For many DERMS products studied by EPRI, licensing costs are a function of the number of DER managed, the total megawatts managed, or the number of circuits involved.

6 *Distributed Energy Resource Management System Case Studies.* EPRI, Palo Alto, CA: 2014. 3002003284.

- If the communication networks needed for DERMS do not already exist and are part of the DERMS rollout, then they could be built out incrementally. For example, fiber could be extended to one substation at a time, or radio access points could be stood up in one community at a time. As noted, this provides an opportunity to test these technologies and gain confidence in their performance before continuing to the next area.
- Particular areas within the service territory that have higher DER adoption rates could be addressed first. For example, based on economic factors, one community may have a higher adoption rate for electric vehicles or other advanced technologies.
- If utility staff or contractors are spending time at each DER site making connections, installing gateways, or conducting other activities, it is more efficient to move from home to home in the same area. Smart meter deployments are typically handled in this way, with communications and meter swap-outs happening according to a geographical schedule with the highest benefits or lowest risks first. In the case of DERMS, where there may be more uncertainty, there could be more time between steps to allow for observation and experience.

Progressing from Autonomous Local Controllers to Connected Central Control

The term "DERMS" or "Utility DERMS" most often refers to large-scale software applications that reside in operations centers and manage many DER. An overall DER communication hierarchy, however, may involve many parts including both centralized and decentralized controllers and communication networks as illustrated in Figure 1. For some utilities, there may be a need to have control logic at the DER site before there is a need for network connectivity to remotely update this control logic. For example, a utility may place a controller at a given DER site as part of a flexible interconnection arrangement that limits the production of the site according to a fixed limit or daily or seasonal schedule. In these cases, it is possible to initially deploy local DER controllers that operate autonomously, then later to deploy communication networks and central software when there is a need to modify the controller settings more often.

EPRI recently worked with utilities to develop applications and functional requirements[7] for a "DER Gateway"—a device that resides at the DER site and acts as an interface and controller. While some of the identified functions of a gateway necessitate connectivity to a central DERMS, many do not and could operate locally once configured.

Starting with local controllers may be appealing for several reasons. First, the cyber risk associated with communication-connected systems is a primary concern for DER because the potential impact of many DERs being simultaneously manipulated is high. By avoiding communication connections, this risk may be mitigated. Another factor is cost. Together, communication systems and large central software make up a large portion of the overall cost of a DERMS, and if a local controller can satisfy the needs, then some costs may be deferred.

The downside of local controllers that are not remotely manageable lies in the risk that the functionality needs to be changed or changed more frequently than expected. For example, it may be determined after a period of time that a local export-limit schedule needs to be shifted to account for changing load shapes. With DER quantities rising and smart inverter capabilities advancing, some utilities, and countries such as Germany, have found it difficult to select settings for DER sites that can remain in place long term.[8] However, if the number of sites and frequency of onsite changes is manageable, and if the equipment is designed with future connectivity in mind, then beginning with local controllers may be a good option.

Progressing from Load Control to Other DER Types

While the IEEE 1547-20181 and other interconnection standards may relate only to generating devices, the broader definition of DER includes manageable load. This broad view is used, for example in FERC Order 22223, when describing the types of end devices that might be aggregated to provide bulk system services. EPRI's DER Integration program is defined the same way, with manageable load being considered a "resource" because the utility can affect

7 *Applications of the Local Distributed Energy Resource (DER) Gateway: Low Cost, Secure DER Network Gateways for Integration of Smart Inverters.* EPRI, Palo Alto, CA: 2021. 3002018673.

8 *Rolling Out Smart Inverters: Assessing Utility Strategies and Approaches.* EPRI, Palo Alto, CA: 2021. 3002007047.

its behavior. Utilities indicate that a cohesive approach to managing all types of DERs is needed and that ultimately DERMS must accommodate a diversity of devices and even combinations of devices at each site.

It is interesting, however, to note that load management (demand response) systems have been around for 50 years. Some utilities have dynamically curtailed load through manual and/or automated systems since long before standard smart inverters existed. As a result, load control algorithms are better defined and the technologies, system impacts, side effects, and failure modes are better understood. Given this maturity, it may be beneficial to begin DERMS implementation with load management then add other DER types incrementally.

Smart charging of electric vehicles is one aspect of load control that may be of interest as a starting point. For some utilities, particularly in northern climates, adoption rates of solar are lower and EV charging is expected to become an issue first. With deferred or shifted load rather than generation, the risks may be easier to quantify, and as long as distribution upgrades were not deferred, control system malfunctions may be easier to accommodate than for generating types of DER. Also, there may be a natural evolutionary path forward with EV DERMS because as vehicle-to-grid (V2G) services are considered, industry stakeholders in the United States have shown intent to apply the IEEE 1547-20181 requirements. In other words, an electric vehicle that is discharging to the grid would be required to have the same manageable grid-support capabilities as a stationary battery. With this, there is a logical pathway from EV (as load) to V2G, to storage, and to solar.

Progressing from Simple to Complex Capabilities

Depending on the core driver for deploying DERMS, a utility (or an aggregator acting in response to utility signals) may be able to begin with just some early use cases for DERMS. This is illustrated by the crawl-walk-jog-run framework for DER management as illustrated in Figure 3. During the crawl phase, utilities can start with using a DERMS for situational awareness of DER in the distribution grid. In the walk phase, they may use the DERMS to effectively participate in grid operations by incentivizing customer DER. This can take the shape of creating load shaping or demand flexibility programs where DER provide flexible services when the grid is constrained. During the jog phase, the utility can enable more advanced use cases like grid services from DER. In the final run phase, multiple value streams could be enabled by using DERMS to stack grid services from DER.

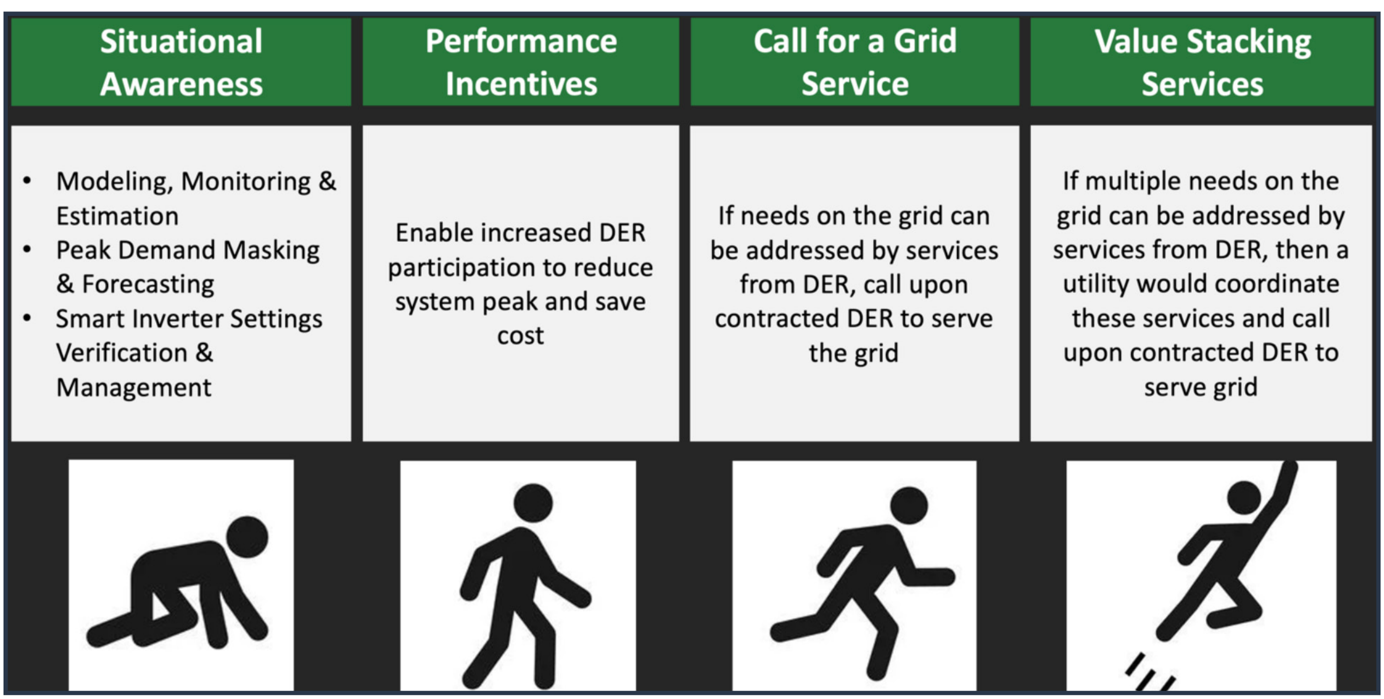

Figure 3. *Progressing from simple to advanced DERMS capabilities*

Progressing from Infrequent to Frequent DER Settings Changes

The functions of smart inverters are designed with autonomy and stand-alone operation in mind. Throughout standardization processes in the International Electrotechnical Commission (IEC) and IEEE, utility stakeholders recognized cases where it is necessary to limit dependency on communication networks and emphasized reliability and fail-safe operation. For this reason, many of the standardized functions are self-adjusting, such volt-var and volt-watt curve functions that change the DER's real or reactive output power based on the local voltage and configuration settings that define a piecewise linear "curve." Utilities have put significant effort into selecting smart inverter settings with the goal of leaving a given configuration in place for a significant period of time (that is, "set-and-forget" settings). This self-adjusting capability can help reduce the frequency with which DER settings need to be changed. Some use cases, however, such as the dispatch of DER to provide services to bulk markets or distribution systems, require settings changes. Some services, such as voltage or thermal support, may require updates every few minutes while others, such as regulation, may require updates every few seconds as discussed in prior EPRI reports.[9]

The required frequency of settings changes directly affects the selection of communication technology and the extent of enterprise application integration. Faster networks can typically perform all the functions of slower networks plus additional use cases with more data throughput or lower latency requirements.

9 *Communications Architecture Requirements for Near-Term Smart Inverter Use Cases – Second Edition: Study of the Communications Requirements for Utilities to Realize the Benefits from Grid-Ready Smart Inverters.* EPRI, Palo Alto, CA: 2020. 3002019357.

Table 1. *Influence of the frequency of DER settings*

REQUIRED FREQUENCY OF DER SETTINGS CHANGES	COMMUNICATION TECHNOLOGIES	DERMS / ENTERPRISE INTEGRATION
Never	No fixed communication network needed.	No DERMS needed in terms of control. Planning tools with smart inverter support required to determine fixed settings needed.
Years	No fixed communication network required for limited numbers of DER (e.g. large DER) as they may be reasonably reprogrammed onsite using portable handheld tools. Minimal/slow communication networks are needed for larger numbers of DER. Impact on throughput is insignificant.	Similar to above, except tools used to determine DER settings during interconnection are used thereafter as settings are updated.
Seasonal	Minimal/slow communication networks are needed. Impact on throughput is insignificant.	DERMS may serve this need as a stand-alone, human-operated application. No hard requirement for automated interfaces with other applications.
Daily or Day-Ahead	Medium-speed networks needed. Common mesh radio-frequency (RF) AMI systems and radio supervisory control and data acquisition (SCADA) will likely work, slower power-line-carrier (PLC) systems may not.	With daily frequency, DERMS are likely to be integrated with the systems that are producing the requests, such as energy management systems (EMS) for peak load management or energy markets for bulk system services. The value of having DERMS integrated with geospatial information systems (GIS)/systems of record rises.
Minutes to Hourly	Fast communication systems needed. High-performance AMI systems may work, particularly if group broadcasting is supported. Faster field area networks such as private LTE may be needed.	Distribution grid services and certain bulk-system services are likely drivers for these dispatch rates.
Seconds	Very fast communication required.	These speeds typically needed for telemetry and regulation services in bulk-system markets or microgrid management of primary grid-forming devices.

Progressing from Human-Operated to Integrated/Automated DERMS

Field experience in Germany and other locations has taught that DER function settings may need to be changed, even if initially intended to be set permanently. Some utilities have concluded upfront that they will need to modify settings over time and describe their initial DERMS as simply a "DER configuration updater." This means that their needs are generally met by the DER's internal functions on a day-to-day basis, but that as DER levels rise and load changes over long periods of time (for example, years), they expect that updating DER settings will be necessary.

A DERMS to meet this need does not need to be extensively integrated with other applications in the operations center. Instead, it may be human operated, and used, at least from a control perspective, relatively infrequently. For example, a user may be able to select DERs one at a time or sort and select multiple DERs by geographical area, size, type, or other characteristics, to update settings. Because it is an infrequent activity, fewer staff need to know how to perform the operation, and the process doesn't have to be completed quickly.

While this kind of system still carries the cost of a communication network, the data and performance requirements of the network are low. Perhaps more significantly, the cost of integration with other applications, such as an advanced distribution management system (ADMS), is deferred until needed. Software integration costs can be substantial as observed with some AMI deployments where the cost of application integration exceeded the cost of the actual meters and communication networks.

When it no longer meets business and operational needs, a human-operated DERMS could be replaced with a more automated system. With planning and specifications upfront, it may be possible to transition the same software to a more automated mode of operation by integrating it with energy markets and other systems.

Progressing from Unsupervised DERMS to Manned DG Operations Centers

In contrast to the previous section, it is also possible that an automated DERMS without live supervision may initially be acceptable when the quantity of managed DER is too low to cause a major issue. Later, when the quantity of managed DER rises, a utility may build out a DER operations center that is continuously staffed or manage from an existing manned distribution operations center. The automation may or may not require DERMS integration with other applications but could reduce upfront costs and reduce the time required to get the initial system operational through savings in training staff and standing up an operations center.

Progressing from Third-Party Systems to Utility Systems

In some circumstances, third parties may perform some or all DERMS functions, including responsibility for communication connectivity and control of groups of DER to produce standard grid services[10,11] from organized groups of DER. This may have several benefits, including:

- Deference of capital required to deploy utility systems
- Avoiding the staff time and training required to operate and maintain an internal DERMS
- Leveraging preexisting connectivity to DER, and the maintenance of this connectivity, that is handled by DER manufacturers for customer relationship and product maintenance purposes (typically internet)
- Staying removed from potential negative customer experience and comfort issues that could result from control actions taken by the aggregator

Using third-party DERMS is similar to progressing from few-to-many DERs in that aggregation is performed and a utility has to manage only one interface to affect the behavior of many DERs in a group. In addition, a utility may consider beginning with just one aggregator (if permitted to do so) and progressing to others over time.

There are two primary limitations when utilizing third-party aggregators to perform DER management. First, it is important to be aware of the high architectural significance of the utility-to-aggregator interface, shown in red in Figure 4. The interactions on this interface must represent the actual grid services needed by the utility9 and the internal designs of the utility DERMS, and other utility systems depend directly on these service definitions. In addition, utility process such as long- and short-term planning as well as interconnection processing, billing, and others require understanding and modeling of these services.

10 *Common Functions for DER Group Management, Third Edition.* EPRI, Palo Alto, CA: 2016. 3002008215.

11 *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2021. 3002022405.

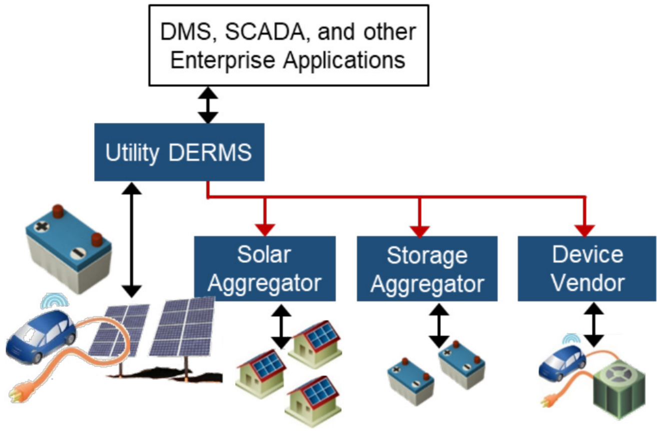

Figure 4. *Significance of the utility-aggregator interface*

For this reason, the utility should design and specify the grid service definitions, the supporting group-level functions, and the communication protocols to be used on this interface. There have been cases where vendor-aggregators of various DER such as thermostats, battery-storage, and EVs suggest that they will define the service (for example, the visibility, notification, actions provided, durations, accuracy, ramp up/down times, reliability) and the communication protocols to be used to dispatch, verify, and settle for these services. A third-party defined interface may be used for demonstration purposes, but it is not extensible or manageable once additional aggregators become involved. Additionally, it should be anticipated that there will be a utility DERMS to manage aggregators, and as shown in Figure 4, the design of this DERMS must be operable with many third-party aggregators so that from operations and planning perspectives all can be considered together and uniformly.

The second primary limitation of third-party DER aggregation has to do with the total quantity of service provided, the degree of grid dependence on these services, and the frameworks that ensure security of the grid and future availability of the services. EPRI uses four levels to describe the role that DER play in the grid:

- **Level 1: The DER-Agnostic Grid:** Quantities of DER are low and have a negligible impact on the grid. Utilities may reasonably ignore the DER in planning and operations.
- **Level 2: The DER-Aware Grid:** DER are common enough that they have impact in planning and noticeable effect on grid operations. Utilities consider them in both planning and operations. Improved DER visibility may be required, but control is not necessary.
- **Level 3: The DER-Leveraging Grid:** DER quantities are high enough that there is benefit to DER owners and utilities to use the DER for bulk market or distribution support and services. The grid, however, is not dependent on these services and would continue to operate safely and reliably without them, although perhaps suboptimally. Even if the DER were intentionally manipulated in a synchronized fashion by an attacker, it would not cause harm to the grid or disrupt service.
- **Level 4: The DER-Dependent Grid:** DER have been integrated into the grid to the degree that they have become mission-critical assets required for safe and reliable grid operations. Utilities rely on DER to manage voltage and thermal constraints and/or to balance generation and load.

As long as the total quantity of services provided by third-party aggregators remains at a level that is not mission critical, it may be reasonable to utilize them. However, it should be recognized that as DER quantities continue to rise it will become necessary that the utility take on certain DERMS and DER management roles so that it can ensure the safe and reliable operation of the grid. In this regard, a DER management strategy could begin with only third-party systems and progress to include utility systems over time.

Enterprise Integration of DERMS

The enterprise integration of a utility DERMS with other utility software applications is one of the most complex and expensive aspects of DER management and monitoring. As noted previously, many lessons can be learned from prior utility deployments of AMI. Metering and DER management are similar in several regards: involve a large number of end devices, have geographical distribution that spans the utility service territory, require low-cost but highly reliable communication systems, include a large-scale head-end software, and result in data that is needed or useful for many utility applications. With AMI deployment, some utilities included extensive data integration with the initial project (for example, those for which the business case depended on such integration) while others started with basic billing and gradually added other integrations over time. Similar options exist for DERMS.

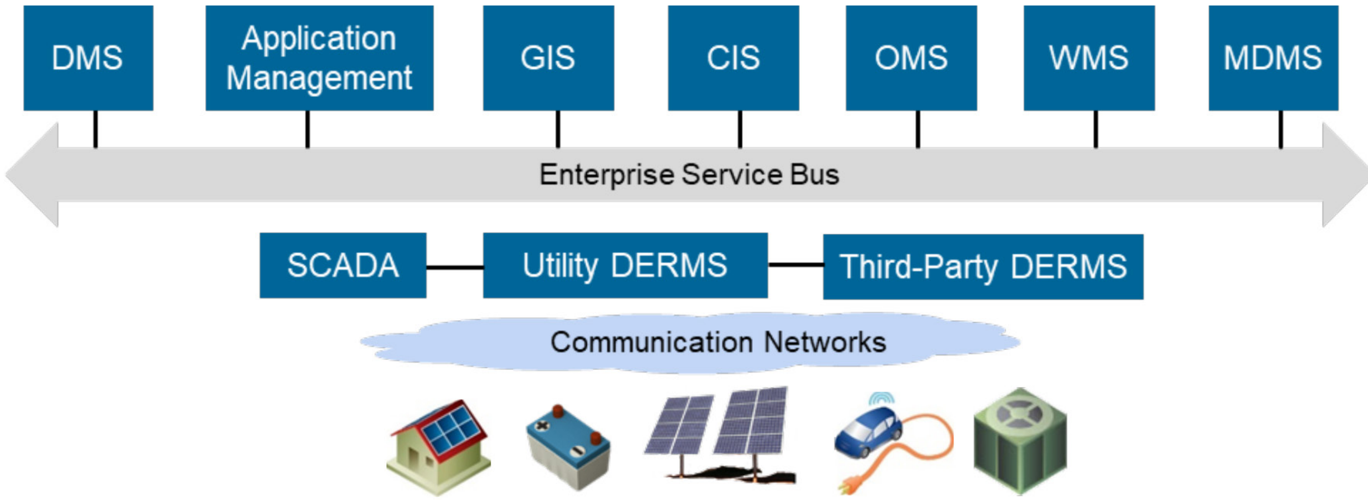

Figure 5. *Enterprise integration of DERMS*

As illustrated in Figure 5 and discussed in the following sections, there are several utility departments and software applications that may benefit from integration with DERMS. Rather than a large number of custom application-to-application interfaces, the preferred architecture for integration is a standardized enterprise service bus.[12] An enterprise service bus defines a set of standard services for the exchange of data between applications and ideally is based on a standard information model such as the IEC Common Information Model (CIM)[13] or the NRECA MultiSpeak.[14] Integrated in this way, N-applications require N-interfaces to maintain rather than N^2.

Planning for phased enterprise integration is a good strategy for controlling the complexity of DERMS adoption. Standard information models for the enterprise integration of DERMS have been in process for several years and continue to expand and evolve.[15] For example, the IEC 61968-5[16] identifies CIM models for the information to define, maintain, monitor and manage DER groups and group-level services. Early integrations are likely to require a significant amount of custom extensions to the information standards, adding cost and time.

12 *Utility Enterprise Architecture Guidebook, 7th Edition.* EPRI, Palo Alto, CA: 2022. 3002024183.
13 https://webstore.iec.ch/en/publication/62698.
14 https://www.multispeak.org/.
15 *DER Protocol Reference Guidebook – 5th Edition.* EPRI, Palo Alto, CA: 2021. 3002021352.
16 https://webstore.iec.ch/en/publication/60069.

Network Interfaces

DERMS must have access to networks to communicate with DERs and/or third-party DER aggregators. While it is possible that a DERMS product has built-in network access and handling capability, it is common that they gain network access through another application such as SCADA, AMI, or field-area network (FAN) headends. In these cases, integration with these applications is unavoidable for DERMS to function and should be taken into account as a part of the beginning step in DERMS adoption.

DER Application Management

Many utilities have developed or purchased software to help facilitate the DER interconnection process. These applications may include customer-facing elements that handle initial applications, maintain queues, and track the progress of screening, engineering studies, and commissioning testing.

Some application management systems may serve as a database of connected DER or may be integrated with a separate system-of-record as described in the following section. Regardless of how or where DER data is stored, the initial interconnection/application process is a primary source of many types of information about DER. The migration of DER information from application management to other systems may be handled manually if the quantity of DER is low and a time lag is acceptable. However, as the rate of DER interconnection requests rises, DERMS and application management systems will likely need to exchange information in an automated fashion.

DER Systems of Record (for example Geospatial Information Systems)

A utility's "DER System of Record" is the database that contains a comprehensive set of attributes regarding the DER on its system. The content of such a database may include:

- DER type, scale, and locations
- Present settings and configuration
- Capabilities and range of adjustability of functions
- Interconnection agreements, contracts, and program participations
- Lifecycle information: commissioning, testing, maintenance, and end-of-life forecast

The DER System of Record could be a standalone application, part of a broader database such as a GIS, or embedded in some other application such as an ADMS. There are advantages to having all DER-related information in one database (that is, a single source of truth) from which other systems are updated, but this also requires extensive enterprise integration. If only one department or application needs to know about DER, such as planning, then a simpler starting strategy may be to house the DER data natively in the planning model database and defer integration with other departments and applications until needed.

Meter Data Management System Integration

A meter data management system (MDMS) or AMI headend stores historical interval metering data used for billing and settlement and providing load data to other applications.

Data from DERMS to MDMS: While the metering data is typically the only information needed for billing purposes, there are emerging cases where information from DERMS may also be useful, such as:

- DERMS providing estimation of lost PV production due to volt-watt, frequency-watt, or power-limit functions, if regulations require compensation
- DERMS providing quantified information regarding services provided by the DER, such as reactive power support, curtailment, energy, or regulation

Data from MDMS to DERMS: A DERMS may benefit from having access to historical load data. For example, a DERMS performing EV charge management to optimize a customer's bill may be informed by prior load shapes at a given customer site.

Advanced Distribution Management System Integration

DERMS-to-ADMS integration becomes increasingly important in every utility DERMS deployment. DERMS-to-ADMS integration has many potential purposes and may be considered in stages. For example:

- One-way data flow from DERMS to ADMS can be used for improved state estimation. With direct connection to DER, DERMS may be able to provide visibility that is more real time than AMI systems can support and able to represent actual generation that is masked in net metering arrangements.
- ADMS to DERMS integration can be straightforward when both the platforms are from the same vendor. Communication protocols to support sharing the network model from ADMS to DERMS are still at its infancy and may need further updates. The network model in DERMS can run the optimal power flow algorithm to effectively dispatch DER when there is a voltage and thermal constraint in the grid.

Outage Management Integration

DERMS integration with outage management systems (OMS) is generally optional. It is typically not needed for detecting outages because outage reporting has become so common in AMI and SCADA metering systems. There are, however, some use cases that require information exchange between these systems. One example is informing DERMS of what DER are offline so that DERMS can modify its group-management algorithms to compensate for devices that are unavailable. Another use case is a DERMS detecting that a DER is tripped or otherwise offline when power to the site remains on and reporting this to DMS for awareness that the resource is lost or to OMS for operator visibility and customer support. Another more forward-looking example is DERMS informing OMS of which customers have local backup power so that the prioritization of restoration work is better informed.

Work Management Systems

Work management systems (WMS) are used to inform, coordinate, and optimize utility crews in the field for a wide range of activities. Utility WMS may also interface with other entities such as local fire and emergency services to support public-safety activities. Some field work may be specific to DER, such as commissioning/recommissioning or maintenance of utility-operated assets. Other activities may be focused on wires, transformers, and other assets but benefit from information about DER in the area. DER information that may support WMS includes:

- **Presence of DER:** Indication of whether there is DER, and if so what types and quantities, at a given site
- **DER operational status:** Real-time indication of whether or not a DER is operating
- **DER layout, commissioning, and maintenance records:** Online availability, potentially including photos, instructions, and more, to support onsite work, for example speeding the process of locating DC and AC disconnects and other safety equipment
- **DER alarms and logs:** Supporting revenue protection and tamper detection

Sequencing DERMS Enterprise Integration

Depending on the utility's DERMS business case and needs, each may develop a timeline for enterprise integration with the systems identified above and others. Establishing such a timeline may be of benefit to simplify initial DERMS deployment, to limit initial project risk and cost, and to await advancements in standards that simplify enterprise integration.

Table 2 provides an example of a DERMS integration timeline. In practice, the specific interfaces that are established, the sequence, and the timelines will depend on the individual utility's needs and system architecture. The point here is simply that it can be done in steps, and the order can be linked to the business needs. Some interfaces, including those in this example, may never be needed.

DERMS BUSINESS CASE: IMPACT ON ADOPTION PATHWAYS

This document identifies possible ways that DERMS adoption could be gradual and more manageable. But for a given utility, the core benefits of DERMS that underpin its business case may limit the options. For example, if the primary value is driven by real-time distribution services, then delaying integration of DERMS with third-party aggregators may not be an option.

Table 3 provides a sample set of utility business cases/drivers for DERMS and identifies what adoption pathways may be of more or less interest. These are just examples, and depending on a given utility's unique circumstances, the interesting paths may differ.

Table 2. *Example time sequence of DERMS enterprise integration*

MONTH	INTERFACE	CAPABILITY
0	DERMS to SCADA or AMI headend	Integration for communication network access. DERMS is human operated, data loaded manually.
6	DER System of Record to AMS	The application management system is integrated with the DER system of record (e.g. GIS) such that new DER appear as they are commissioned, including electrical Point of Common Coupling (PCC ,) communication addresses, owner/operator info, DER capabilities, settings, and program participation.
12	DERMS to application management system	As new DER are added to the system (or removed, modified, etc.), they automatically become part of the appropriate managed groups in DERMS according to their location, capabilities, agreements, etc.
24	DERMS to ADMS	ADMS optimization algorithms (e.g. integrated volt/var optimization) begin to make use of the services of DER groups as provided via DERMS, adjusting settings to improve efficiency, reliability, and/or power quality. This integration may be gradual by-feeder, focusing on high-penetration areas first.
36	DERMS to ISO/TSO	The DERMS is integrated with bulk system operators and energy markets to coordinate regarding distribution-connected resources providing bulk-system services. The DERMS may support review of new DER aggregation enrollment in market services and review of planned dispatches to inform of constraints.
42	DERMS to WMS	Present DER operational information and static DER descriptive data are made available within tools and applications used by field crews and dispatchers.
48	DERMS to OMS	DERMS is interfaced with OMS to enhance outage awareness and to optimize DERMS functions.

Table 3. Example adoption pathway selections

EXAMPLE DERMS DRIVERS AND BUSINESS CASE	ADOPTION PATHWAYS OF LESS INTEREST	ADOPTION PATHWAYS OF GREATER INTEREST
Rapid and widespread adoption of behind-the-meter/rooftop PV, hosting capacity limits occurring	• Selective DERMS integration based on DER scale • Selective integration based on DER type • Beginning with load control	• Beginning with local controllers (e.g. DER gateway with scheduled export limiting) • Enterprise integration with application management • Starting with third-party aggregators
Gradual and clustered adoption of various DER sizes and types: PV, PV+storage, EVs. Eventually reaching system limits	• Selective integration by type	• Progressing from infrequent to more frequent controls • Selective integration by circuit/feeder • Selective integration by region • Starting with little/no enterprise integration
Rapid arrival of large DERs >1MW	• Starting with third-party aggregators • Starting with local controllers	• Selective DERMS integration based on DER scale (only addressing these large plants) • Enterprise integration with ADMS
Real-time distribution system or bulk system services	• Beginning with a human-operated DERMS • Beginning with infrequent control actions • Delaying DERMS-to-ADMS integration	• Enterprise integration with ADMS or EMS/markets • Beginning with storage DER and progressing to other types • Beginning with load control and progressing to other DER types
Seasonal export limiting for flexible interconnection, increasing hosting capacity	• Beginning with storage DER and progressing to PV • Enterprise integration with ADMS	• Beginning with local controllers • Beginning with only the export limit function • Beginning with large DER and progressing to smaller DER

EPRI SUPPORT FOR UTILITY DERMS ROADMAPPING AND ADOPTION PLANNING

EPRI's DER Integration program provides member support services.[17] This dedicated team is available and interested to work with utilities to identify roadmaps for DERMS that fit their individual needs. These engagements are important to EPRI's public-service mission, helping to align ongoing DERMS research with real-world scenarios and practical technologies.

17 See "Individual Member Support Projects" section, Page 10 in: *DER Integration: Program 174 Overview.* EPRI, Palo Alto, CA: 2021. 3002023211.

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe. Together…shaping the future of energy.

EPRI CONTACT

AJIT ANBIAH RENJIT, *Senior Principal Team Lead*
614.620.3154, arenjit@epri.com

For more information, contact:

EPRI Customer Assistance Center
800.313.3774 • askepri@epri.com

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EPRI
3420 Hillview Avenue, Palo Alto, California 94304-1338 USA • 650.855.2121 • www.epri.com