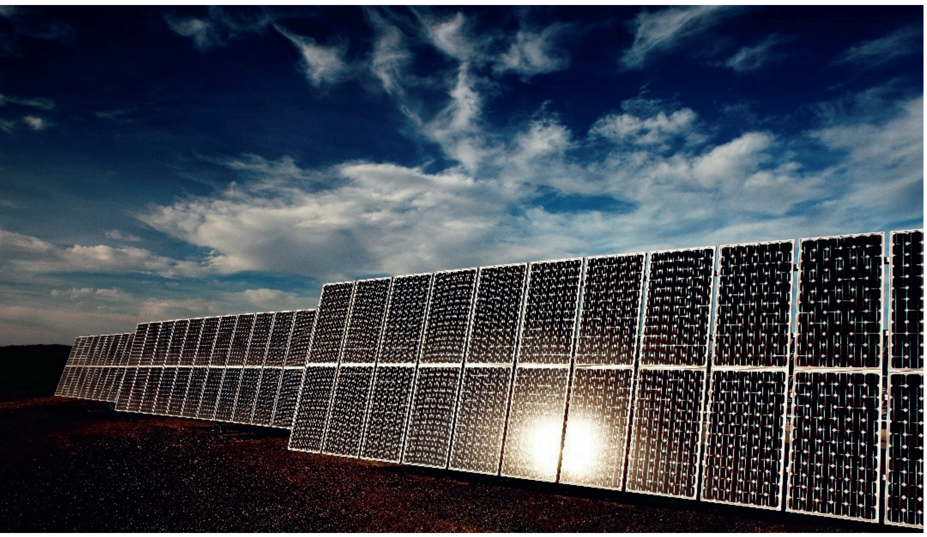
WHITE PAPER

Distributed energy resources:
What's next for distribution grid management?



The power industry is undergoing its greatest transformation since its inception, and much of the change is being driven by distributed energy resources (DERs). These are generation and storage resources (e.g., solar, batteries) connected to the grid at the distribution level "downstream" from the utility substation.

While DER deployments still account for only a tiny fraction of installed generation capacity, they are growing rapidly and their potential—for better and worse—is undeniable.

On the plus side, the potential benefits abound. Reduced environmental impact, deferred capacity upgrades, optimized distribution operations, expanded demand response capabilities and improved power system resiliency are all on the menu, according to EPRI. You can add customer choice as well since in some cases DERs are located behind the meter (e.g., rooftop solar).

DERs represent a vexing challenge for utilities, though, namely keeping their promise to provide safe, reliable and affordable power despite the introduction of thousands of new supply resources, bi-directional power flows and greater intermittency. DERs are also driving a tectonic shift in the industry's very structure, which we will address later.

In the case of renewables, the Electric Power Research Institute (EPRI) identifies four potential problems with widespread DER adoption:

- Grid-edge connections producing local over-voltage or loading issues
- Increased risk of significant loss of generation (intermittency)
- System planning disruptions due to variability
- The lack of inertia from large plants to stabilize the network

These challenges mean "utilities must operate the grid in a much more agile manner," as a recent IDC report observes. In particular, "utilities need to learn how to integrate externally originated asset, market, and grid data." And that's really the core of the issue. Industry observers, whether they applaud the widespread adoption of DERs or decry it, agree that much more is coming.

The success of broad DER adoption is predicated on utilities' ability to monitor and control the assets, link them with SCADA/DMS and other enterprise systems, and interact with market operators. Doing so will allow DERs to realize their potential, maximizing returns for asset owners and optimizing operations for utilities.

The DERMS solution

In its 2014 report entitled "The Integrated Grid," EPRI notes that "in nearly all settings, the full value of DER requires grid connection to provide reliability... and access to upstream markets." For this reason, says EPRI, DER and the grid should not be seen as competitors but rather as complementary, but we are not there yet.

As the EPRI report notes, “[s]o far, rapidly expanding deployments of DER are connected to the grid but not integrated into grid operations, which is a pattern that is unlikely to be sustainable.”

Solving the integration problem requires a DER management system (DERMS), which Navigant Research defines as “a control system that enables optimized control of the grid and DER, including capabilities such as Volt/VAR optimization (VVO), power quality management and the coordination of DER dispatch to support operational needs.”

“There are two main use cases for DERMS,” explains ABB’s Rick Nicholson, head of global product management for the company’s Enterprise Software business. The first is operational, he says, simply managing a variety of generation resources, especially renewables and energy storage, that are located at the grid edge. Balancing EV charging with variable generation like wind is one example.

The other DERMS use case is economic, perhaps best illustrated by the concept of a virtual power plant (VPP) where a variety of different resources—including storage—can be aggregated via DERMS and presented to the grid operator as a single, dispatchable resource.

In a 2017 paper, Navigant Consulting expresses the optimistic view that “if designed intelligently… a VPP can help foster a system whereby a full portfolio of grid services (regulation service, voltage management, fast DR, contingency reserve, peak demand management, and renewable firming) can be provided by the same DER components that were once feared to be the primary contributors to grid imbalances.”

Who’s in control here?

While DERs hold tremendous potential for utilities, consumers and third parties, the question at the heart of every application is: Who controls the assets? The answer is that depends on the particulars of the use case.

Most assets behind the meter require approval from the asset owner to allow the utility to control them. Permission might hinge on the nature of contractual agreements between the utility and asset owner and why the utility needs control (e.g., for reliability purposes or capacity needs). The utility might offer an incentive, for example, in exchange for the ability to control a solar-plus-storage installation at an industrial site.

In cases involving an aggregator such as demand response programs or VPPs, the aggregator would likely retain control over the assets in order to ensure they optimize returns.

In any case, control over DER assets comes down to two main functions: “doing the math” in real time to make the system work (i.e., DER monitoring and control) and communications, whether with an aggregator via an automated gateway or directly with the asset owner. This is an area where the DER ecosystem is still evolving as the industry seeks to standardize DER communications around a common set of protocols (e.g., IEEE2030.5) to replace proprietary ones.

The state of DERMS

The evolution of DERMS and the assets they control is happening rapidly. Presently, the industry stands at an early crossroads, with a substantial majority of utilities indicating plans to implement DERMS in the near future, but with less clarity around how those systems will be integrated with existing distribution management systems.

DERMS developer and ABB technology partner Enbala conducted a survey of attendees at DistributTECH 2017 and found that while less than a fifth had a DERMS in place, more than three quarters (77%) said they planned to deploy one within the next three years. Interestingly, half of survey respondents indicated “meeting grid reliability concerns” as the top reason for DERMS investment.

A broader Newton-Evans survey published in NEMA’s Electroindustry magazine in November 2017 showed that 64% of investor-owned utilities surveyed indicated they had “activities underway or planned for [distribution management] systems to include some level of deployment of DER management tools.” Of those with ADMS either planned or already in place, 82% said they either had DERMS functionality already or would include it in the future.

However, despite the industry’s apparent willingness to move forward with DER integration, utilities still face a disconnect on the technology side. As IDC Research Director John Villali noted in a DERMS webinar last year, 60% of utilities buy DERMS as a completely separate procurement process from their DMS/ADMS while only 10% of DMS/ADMS purchases include DERMS capabilities out of the box.

These findings demonstrate that DERMS has yet to be integrated with the other (formerly stand-alone) applications that now live behind the single user interface of ADMS. That is likely to change as the industry coalesces around a set of must-have capabilities for DER management.

So, standards and capabilities are evolving, but what should utilities do today when looking to implement DERMS?

Shopping for DERMS: What to look for

There are a few broad characteristics that utilities should insist on when it comes to implementing DERMS. These include:

- **High performance and scalability.** Distributed computing architecture delivers the compute power required to manage thousands of assets on a distribution network in real time.
- **Fast network response.** DERMS provide real-time control and optimization of assets, so the communications system must be able to keep up.
- **Asset agnostic.** DERMS manage various categories of DER (e.g., batteries, smart solar inverters, capacitors, controllable loads), so they should accommodate the operating characteristics of each on a level playing field.

There are also a few specific functions that any DERMS should perform, such as registration of assets, forecasting their output and monitoring/control at the grid edge. The ability to support demand management and voltage optimization schemes (e.g., VVO, CVR) is also foundational.

Integration – the key to value

Perhaps the most consequential capability for any given DERMS implementation is the system's ability to interface with distribution management systems and other existing utility platforms, whether in operations technology (OT) or information technology (IT). Approaching the issue from the perspective of ADMS, a recent IDC report notes that "a significant component of successful digital transformation is having an ADMS that can integrate with a DERMS that includes a packaged set of capabilities to support DER needs."

In particular, DERMS should share the same as-operated network model used by ADMS applications. Similarly, the DERMS-ADMS interface should make distribution SCADA telemetry data equally available to each side, and should synchronize state changes and the results of power flow calculations.

Done properly, the integration of DERMS with DMS/ADMS yields benefits that by now are familiar within the realm of integration projects. Grid operators, for example, will now have a single view of DER assets and events that allows them to respond quickly to changes in operating conditions.

From an IT perspective, marrying DERMS with ADMS eliminates the need to maintain data in two separate systems. It also reduces cost and implementation time thanks to a pre-integrated, productized solution that comes ready to plug and play.

Future of DERMS

In the long term, ABB's Rick Nicholson says the adoption of DERMS "hinges on the development of distribution-level markets for DER. These markets may be structured centrally in a similar fashion to existing wholesale markets, could be structured in a more decentralized mode, or might even include peer-to-peer energy trading enabled by blockchain technology." In the meantime, centralized wholesale markets will continue to set prices for DER-provided services.

It's true that the regulatory and market structures under which DERMS will operate are still evolving. However, it's also clear that while the underlying technologies are here, more work needs to be done, particularly with regard to integration. For DER to realize its potential, DERMS will have to evolve further to deliver resource optimization, market participation and commercial settlement functionality in addition to managing voltage, active power and power quality on the distribution network.

For now, though, these systems already provide utilities, their customers and third-party players the means to derive value from distributed assets in a number of different use cases. As the technology (and regulatory framework) advances, DERs will be able to deliver even more.