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Harnessing Virtual Power Plants Reliably

Enabling tools for increased observability, controllability, operation, and aggregation of distributed energy resources.

THE INTEGRATION OF DISTRIBUTED ENERGY resources (DERs) into utility electricity grids is a major component in the global *energy transition*, in which the energy sector makes the concerted shift from fossil-based energy production to renewable and sustainable options. This universal phenomenon, occurring at an unprecedented scale, presents both challenges and opportunities for utilities. This integration is facilitated by standard and reliable tools that assist in the design and planning of these additions at both utility-scale and behind the meter (BTM). However, the effective management of DERs requires the development of operational tools.

According to a U.S. Department of Energy (DOE) report, utilities are exploring different technologies and methodologies to aggregate DERs—i.e., virtual power plants (VPPs)—to reconcile the impending retirements in large fossil-based centralized generation plants and the projected growth in system peak demand. VPPs hold the promise of resource adequacy at low cost, extending system resilience, reducing emissions, alleviating network congestion, and providing energy justice to communities. According to a Wood Mackenzie report referenced in the U.S. DOE report, there is at least one, and as many as 10, third-party VPP projects procured by utilities in more than half of the states in the United States, each with a unique set of goals and a mix of technologies. However, the challenges commonly faced by utilities include getting enough customers to sign up for real-world pilots and demonstrating the coordinated operation of multiple technologies.

From a European context, aggregating DERs in a VPP aligns with the concept of the distribution system operator (DSO)—an entity responsible for operating, maintaining, and developing a specific location's distribution system—through its Distribution Network Development Plans for a sustainable energy future.

In the United States, the U.S. Federal Energy Regulatory Commission (FERC) Order 2222 is a landmark legislation that levels the playing field for DERs to participate with other resources through DER aggregations. However, there are many challenges that require resolution for integrating and aggregating DERs into utility grids over the longer term.

Effective management of BTM DERs is paramount in stable and reliable distribution grid operations. A primary obstacle in this management process is the absence of

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observability, leading to uncertainty in utilizing this resource as a VPP for reliable operations. A recent project completed by a team of coauthors for the U.S. DOE Solar Energy Technologies Office focused on the development of technologies to address this issue.

The aim of this article is to introduce three enabling technologies that can accelerate the evolution of DERs into VPPs. These technologies focus on enhancing the observability and controllability of BTM DERs, broadening the functionality of a widely used distribution planning tool with DER operational capability, and converting traditional uninterruptible power supplies (UPSs) into a fundamental component for VPPs.

DERs and VPPs

A U.S. DOE report outlines the evolution of U.S. electric distribution systems, facilitating DERs to operate as VPPs, and presents a representative technology S-curve, shown in Figure 1. Despite the absence of specific data and details for this S-curve, the plot indicates the onset of a "rapid progress" phase sometime near 2025, transitioning to a slowing or stagnation phase by the mid-2030s, characterized by a significant aggregation of DERs into VPPs.

The chronological phases prior to the "rapid progress" neck of any technology S-curve are the "incubation" and the "takeoff" periods, which occur prior to 2015 and 2025, respectively, for DER integration and utilization (according to Figure 1). To measure these phases with supporting data and to identify some appropriate enablers, we present the following approach. We will specifically address a composite figure of merit (FOM_C) for this technology development by considering the product of two metrics: the total number of customers in all sectors that are net-metered (N) and the actual peak demand savings in megawatts (D) per annum. N and D represent the commercial aspect of DERs from the end-user and the utility sides (benefits), respectively. This information is collected by the U.S. Energy Information Administration (EIA) via Form EIA-861. Note that these data are current up to 2021 at the time of drafting of this article. Table 1 and Figure 2 show the relative improvements in the FOM_C from 2013 to 2021.

Observation and Inference

From Table 1, we see that, while N has increased nearly sevenfold over nine years, D has barely changed. This is due to energy-efficiency measures by utilities, such as free or low-cost energy audits, discounted light bulbs, and rebates for ENERGY STAR-certified appliances. In 2017, U.S. utilities spent about US$6 billion on energy-efficiency programs, saving approximately 30 million MWh and 6,000 MW annually. By contrast, US$1.3 billion spent on demand response (DR) programs saved about 2 million MWh and 12,250 MW. According to a FERC report from 2023, despite high potential DR capacity, actual peak usage is limited by rate design, lack of dynamic pricing, and market structures favoring supply-side resources.

From Figure 2, we can observe the following: the year on year (YoY) improvement has not dropped below unity, indicating a steady increase in DER integration in utility grids, as measured by net-metered customers. Further, the improvement of the FOM_C of each year relative to 2013 indicates a trend that resembles the "takeoff" period in the technology S-curve for DER integration in utility grids shown in Figure 1. If the technology adheres to this S-curve for some time in the future, we may conjecture, with caution, that the trajectory for the DER integration, utilization, and therefore, aggregation for use as VPPs is realistic. This is aligned with the tailwinds from federal incentives, like the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022, that are expected to accelerate DER installations across all sectors in the U.S. electric grid. Addressing the limitations of inadequate control, observability, and DER management is essential. Without effective control mechanisms, the grid's stability and reliability are at risk. Additionally, limited observability hinders our ability to monitor and optimize the performance of DERs, resulting in inefficiencies, which may slow down or limit the penetration of DERs.

The proliferation of DERs will require enabling technologies like energy management systems (EMSs), software, and platforms like DER management systems (DERMSs), without which DER penetration may stagnate because of limited investor opportunities. Currently, the industry experiences a deficiency in enabling tools that transcend the design and planning stages for DERs. Unified solutions are particularly limited in enhancing the observability of BTM DERs, managing DER operations, and leveraging DER flexibility. This article discusses a technology addressing each of these areas.

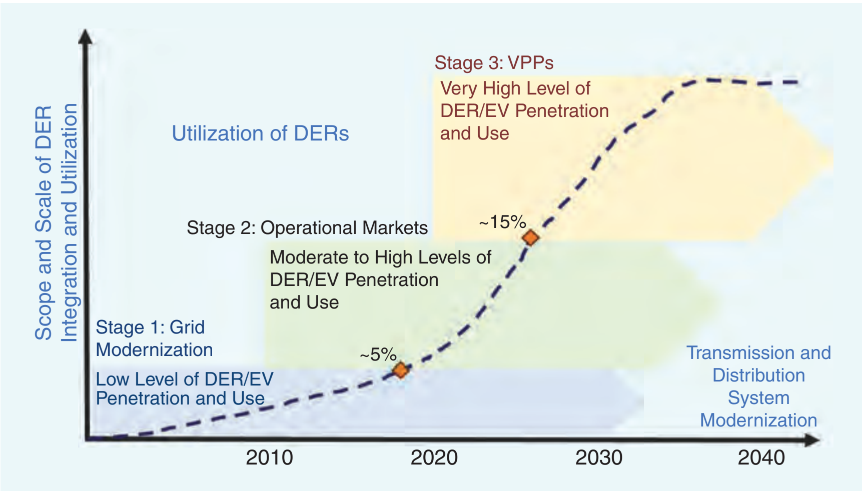

Figure 1. Classic technology S-curve of DER integration and utilization. EV: electric vehicle. (Recreated directly from P. De Martini et al. in "See Further Reading" section.)

Enhancing Observability and Controllability of BTM DERs

The VPP value propositions addressed by enhancing observability and controllability of BTM DERs include *resource adequacy* and *alleviating network congestion*. These can be unlocked via access to reliable measurements and well-coordinated control strategies. A hierarchical control architecture, extending from the service provider to the end user, may achieve these goals. In this section, we will describe the benefits derived from the creation, execution, and field testing of such an approach. The formulation of the control approach leverages existing advanced metering infrastructure (AMI), communication standards, and industry-compliant application programming interfaces (APIs). This technology was derisked via comprehensive hardware-in-the-loop (HIL) testing, followed by data gathering from field testing and subsequent analytical insights drawn from simulation studies using those data.

Managing the operations of BTM resources in conjunction with other household appliances, such as heating, ventilation, and air-conditioning (HVAC) systems and electric water heaters (EWHs), for grid services presents a unique set of challenges for service providers. These include the necessity for enhanced observability within the premises to harness flexibility and guarantee a level of control. Another challenge is the coordination of BTM assets via a premises EMS that needs to be scalable and capable of secure data exchange. These challenges underscore the complexity of integrating BTM resources into residential sectors and power grids.

TABLE 1. A composite FOM_C-based technology S-curve for DER integration in utility grids.

Year	N (number)	D (MW)	FOM_C ($10^9 \times N \times D$) (MW)	FOM_C Improvement	
				Relative to Year 1	YoY
2013	487,817	11,883	5.79	1	1
2014	697,021	12,683	8.84	1.53	1.53
2015	1,022,420	13,036	13.3	2.3	1.51
2016	1,410,982	11,841	16.7	2.88	1.25
2017	1,727,698	12,248	21.2	3.65	1.27
2018	2,029,588	12,522	25.4	4.38	1.2
2019	2,413,666	11,334	27.4	4.72	1.08
2020	2,801,727	10,387	29.1	5.02	1.06
2021	3,318,795	12,211	40.5	6.99	1.39

In the state-of-the-art solution, DR requests are directed toward individual assets that may cause user discomfort—imagine losing the HVAC to cycling for 15 min during the peak of summer in a hot location like Phoenix, Arizona, where the average summer temperature regularly exceeds 100 °F. In the proposed solution with the technology that increases the BTM DER observability, DR requests are sent to the premises EMS, which coordinates the BTM assets to reduce demand while ensuring customer comfort, as shown in Figure 3.

The architecture of this hierarchical control system, shown in Figure 4, for managing residential energy resources comprises a controller embedded in a premises device, such as a meter, which balances user comfort and utility requests. This controller, with access to real-time weather and utility data, operates in two modes: idle and grid event. In the idle mode, the objective is to optimize electricity consumption by forecasting uncontrolled assets like lighting and scheduling controlled resources like DERs, EWHs, and HVAC systems. During a grid event, such as an emergency DR, the controller limits the net peak load within the premises to a predefined threshold. The DR management system (DRMS) or central controller, at the top of the hierarchy located at the utility head end, manages both predictable and unforeseen grid events, analyzing factors like DER flexibility, weather forecasts, feeder models, and real-time load data. Premises controllers receive messages from the DRMS and control individual appliances and DERs via dedicated load control switches and the IEEE 2030.5 protocol. This establishes an end-to-end hierarchical architecture for DR, enabling DERs and other controllable loads beyond traditional ones like HVAC and EWHs.

An end-to-end control HIL setup including the premises controller prototype and the central controller was set up at a specialized testing facility located in a U.S. DOE National Renewable Energy Laboratory that included calibrated home appliances like HVAC, EWHs, solar photovoltaic (PV) emulators, and uncontrolled loads, and using real load data (see Figure 5). The controller's performance was verified through 24-h tests under various scenarios, including baseline, idle, and grid event conditions. Results showed a nearly 20% energy savings and 22% cost savings during grid events, with a 30% peak power reduction by shifting appliances outside grid event windows (see Figure 6). Indoor temperatures were maintained within preset bounds, with minor deviations due to virtual indoor temperature estimation. This technology

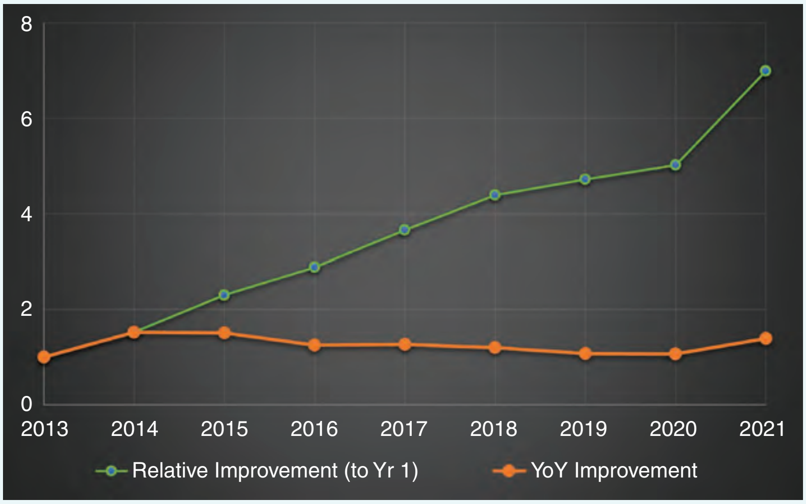

Figure 2. Relative improvements in FOM_C for DER integration in utility grids between 2013 and 2021 based on data from U.S. EIA.

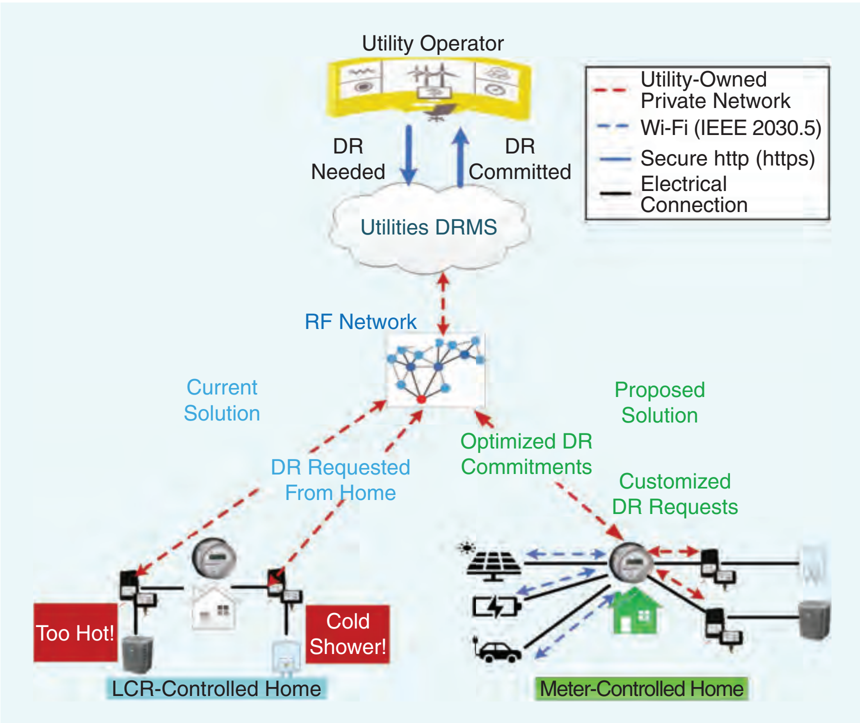

Figure 3. Current and proposed solution for residential DR.

was field tested in nearly 20 volunteer residential premises in the service area of an electric cooperative utility located in the eastern United States (Figure 7), and data were collected from the trial, which lasted over the summer of 2023. The collected data include various residences with different BTM preferences and performance settings, accounting for nonperformance. This data were utilized in simulation studies to estimate the potential peak reduction for the utility provider during coincidental peak (CP) events during the trial period, which is shown in Figure 8.

The aggregated potential of the BTM DERs, enhanced with technology for improved observability and controllability, is simulated for CP days in the network in response to emergency demand response signals during the trial period. On six such CP days, the performance of the BTM DERs varied, depending on factors such as weather, user comfort settings, the BTM assets, and other uncontrollable

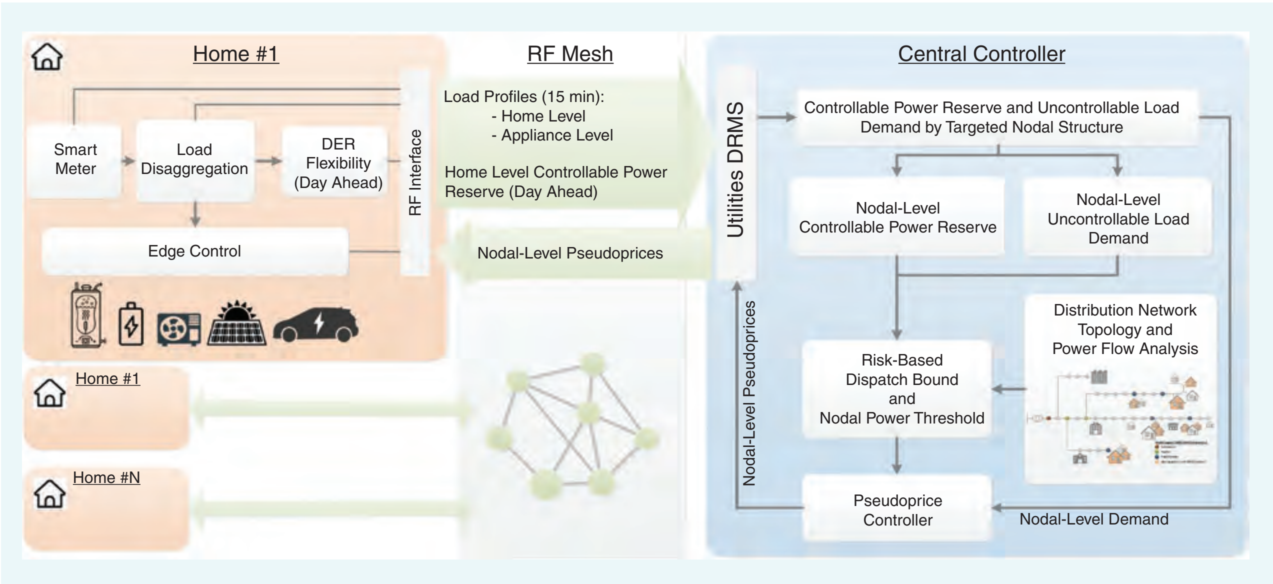

Figure 4. Hierarchical control architecture to enable scalable integration of residential assets to a utility DRMS.

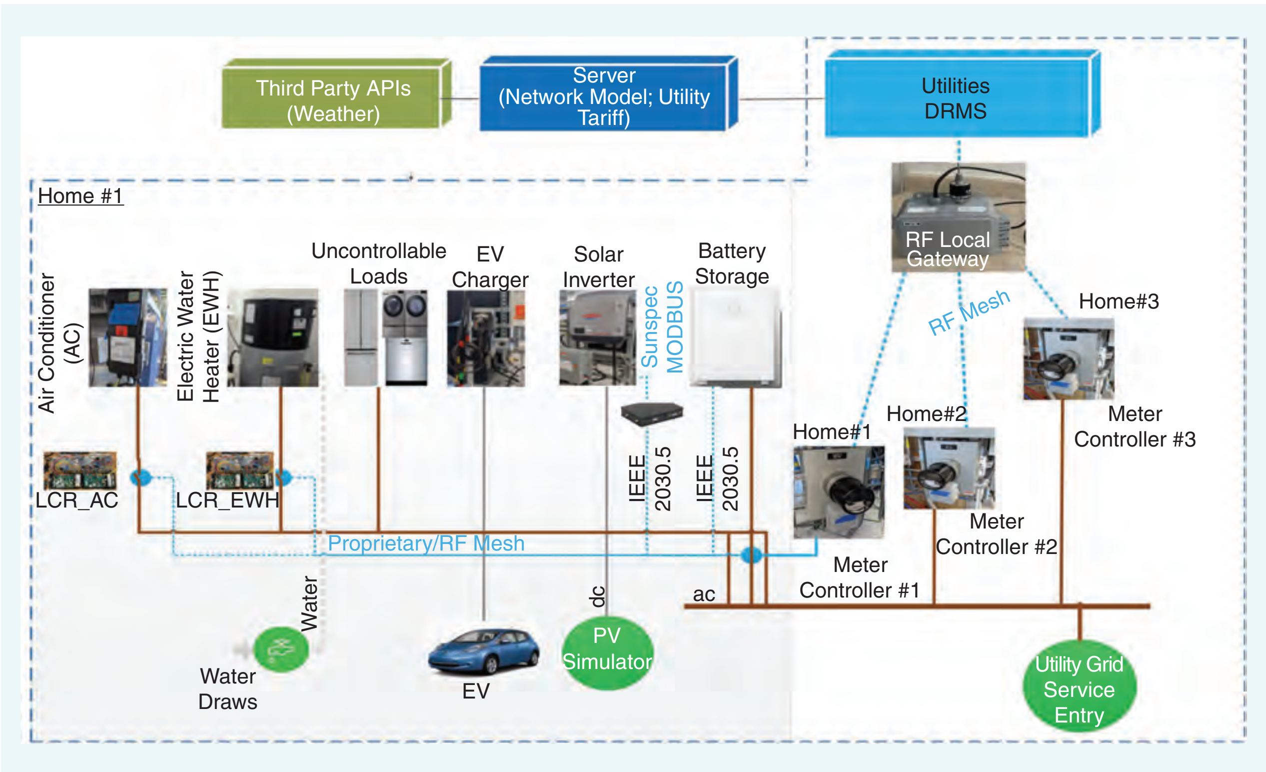

Figure 5. Derisking the solution with real devices in a specialized lab.

loads. It was observed that, on four of these days, the BTM DERs were able to successfully provide grid services as an aggregated resource (see Figure 8).

To integrate this solution into a utility's system, residential meters were upgraded to a meter-as-controller system with RF communication capabilities. Note that the meter serves as a gateway to BTM devices; alternatively, a load center at the premises can be used. While this field validation exercise used existing communication infrastructure, a broader implementation will require additional infrastructure to handle increased data flow. This architecture's flexibility enhances consumer acceptance by balancing user comfort with utility needs. Consequently, this technology improves the visibility of BTM DERs for utilities, enhances resource adequacy, and provides relief during network congestion through aggregation, thus enabling VPPs.

Operation and Management of DERs

To fully benefit from large-scale VPP integration in distribution grids, without adversely affecting system reliability, it is vital to enhance situational awareness. The rapid growth of electric vehicles (EVs) and the accompanying multimegawatt-scale EV charging infrastructure will soon push the electricity network to operate at its limit, setting up situations for blackouts and brownouts. While the aggregation of these distributed resources, facilitated by FERC Order 2222, can provide grid services, it is necessary for the operation of the distribution grid to evolve concurrently to manage potential congestion and power quality issues. As mentioned earlier, FERC Order 2222 allows DERs to participate in both wholesale markets and retail programs, which can decrease their predictability and intensify operational challenges for the grid.

Addressing these challenges by upgrading the physical grid infrastructure to ensure an adequate operational security margin is both costly and unrealistic. A more practical solution for distribution utilities is to enhance real-time situational awareness by integrating existing planning tools with DERMSs, which primarily consist of three functionalities: resource registration and grouping, monitoring, and control. In the following discussion, we will explore an emerging issue in the distribution grid and demonstrate how it can be resolved by integrating DERMSs with a widely used advanced planning tool in the industry.

Figure 9 depicts a reference architecture for the implementation of a DERMS at a distribution utility's control center, highlighting that the VPPs are external to the utility's environment. The two key components of DERMS, supervisory control and data acquisition (SCADA) and optimal power flow (OPF), are responsible for the system's monitoring and control functionalities.

An advanced OPF routine periodically solves an optimization problem, typically every 15 min. The goal is to determine the optimal operating set points for controllable resources to minimize the grid's operational cost,

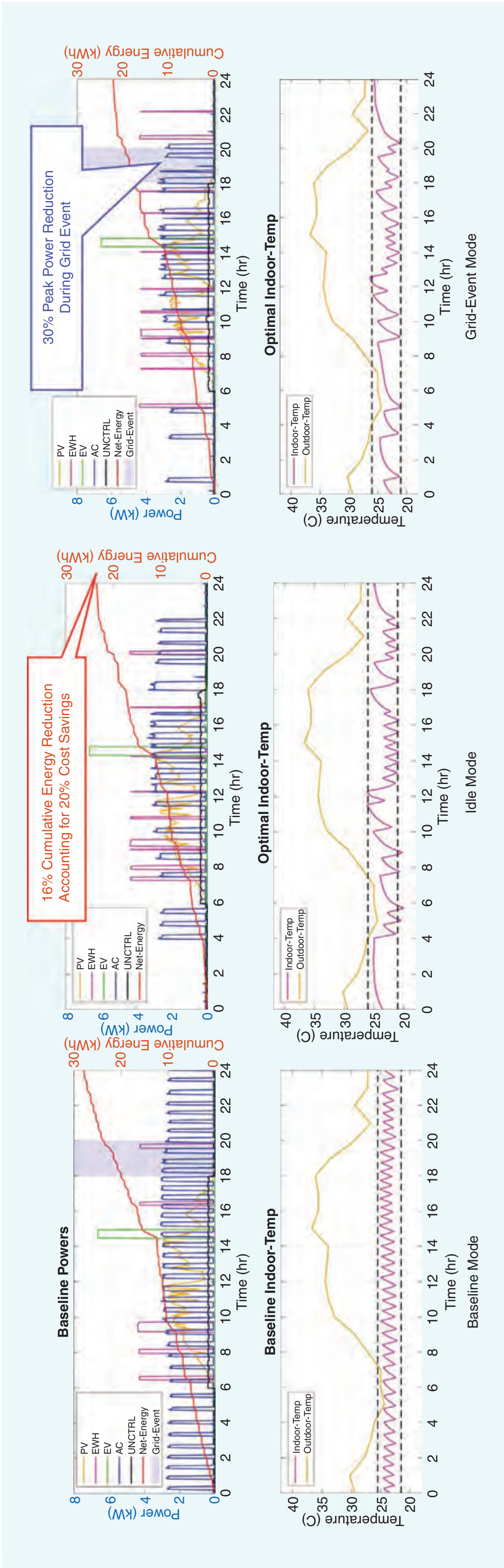

Figure 6. Results from 24-h long controller HIL tests.

subject to network constraints. These constraints are often linearized to ensure the solution's computational tractability. However, when operating near the future grid's limits, the assumption of linearity for network constraints may introduce significant errors, making the computed set points unreliable. The grid service capabilities of the DER also present predictability challenges. These issues highlight the importance of verifying the robustness of the computed set points against resource uncertainty before dispatching them.

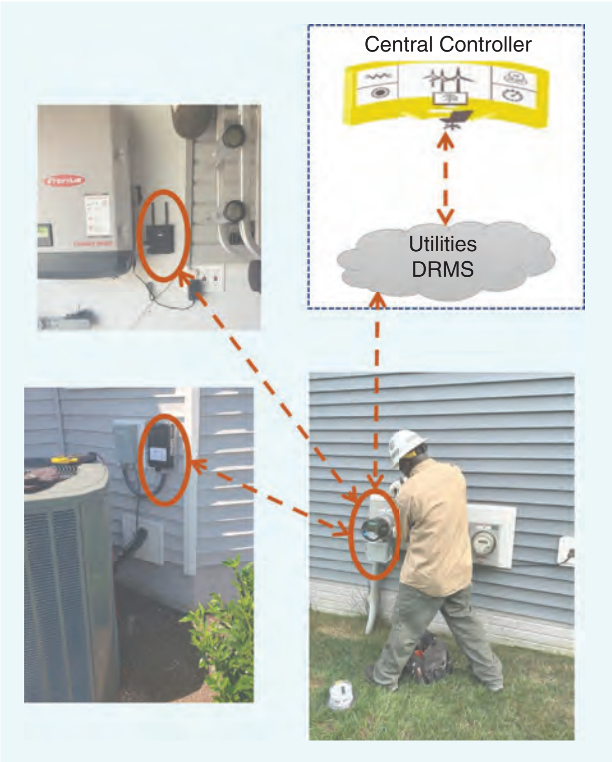

Figure 7. Technology deployment at volunteer homes on a partner utility's network.

Consider an industry-standard software that is a sophisticated distribution planning tool extensively utilized by utilities for various functions, such as maintaining a grid model and executing unbalanced load flow, scenario, and DER hosting capacity analyses. While it is primarily used for offline studies, the server capabilities of this software make it highly suitable for enterprise-level usage in utility control centers. Here, it can be integrated with SCADA systems to maintain a near-real-time grid model, considering variations in demand and network topology (see Figure 10 for a schematic illustration). BTM observability can be improved by integrating the day-ahead AMI data into the grid model, while data redundancy can be managed using the software's built-in state estimation engine.

The near-real-time grid model in the industry-standard software can be employed to validate the integrity of the optimal set points computed by the DERMS through an unbalanced nonlinear power flow-based scenario analysis. These scenarios can be identified by utilities based on short-term forecasts and an estimate of resource uncertainty. A successful scenario analysis affirms the reliability of dispatching the resource set points, which are computed using the DERMS algorithm under the assumption of linearity in the grid network model. Conversely, if any scenario analysis fails, the set points need to be adjusted before dispatch. This adjustment could be rule based or computed by reoptimizing the set point, subject to additional constraints derived from the nature of the failure encountered in the scenario analysis.

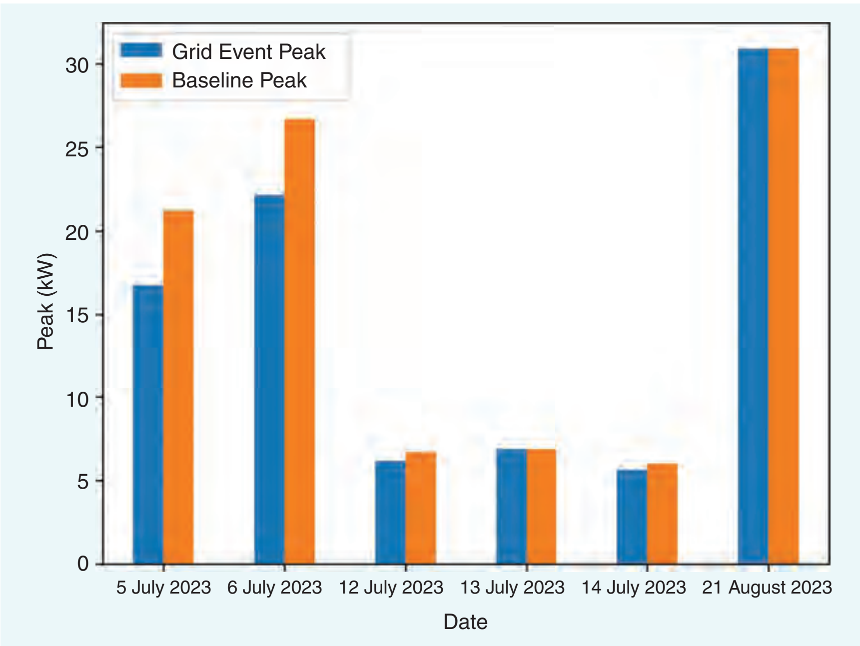

Figure 8. Potential peak reduction for utility provider during CP events in July–September 2023.

The proposed integration of an industry-standard distribution planning tool with DERMS capabilities facilitates informed decision making for optimal asset operation amid grid nonlinearity and resource uncertainty. This enhances grid reliability without necessitating substantial infrastructure upgrades. To benefit from this framework, distribution utilities must improve the visibility of secondary distribution networks for accurate integration of AMI data and BTM DERs into systemwide models. As current technologies are still maturing, this remains an active research area. Additionally, a robust and secure data flow involving independent system operator (ISOs)/regional transmission organizations (RTOs), distribution utilities, VPPs, and DER owners is essential. As of 2024, stakeholders are working actively on this for their compliance toward FERC Order 2222.

Transformation of Conventional Elements

UPSs are backup power systems traditionally used to ensure the continuity of a power supply to critical systems during short-term power outages. With the increasing need for systemwide reliability, resilience, and a shift toward sustainable energy solutions, these conventional UPS systems hold the promise of supporting grid services, thereby transforming them into building blocks for VPPs. This not only improves the use of existing infrastructure but also enhances the overall efficiency and resilience of the power grid.

Efforts are underway to develop a cost-effective, grid-interactive UPS that can serve as a battery energy storage system (BESS) for buildings. One of the proposed solutions, shown in Figure 11, involves retrofitting or upgrading a traditional UPS, which could reduce the cost of a BESS by 75%. This also has the potential to quickly unlock the significant battery capacity within existing UPS systems and provide grid services in a synchronized manner with networked UPSs and other DERs.

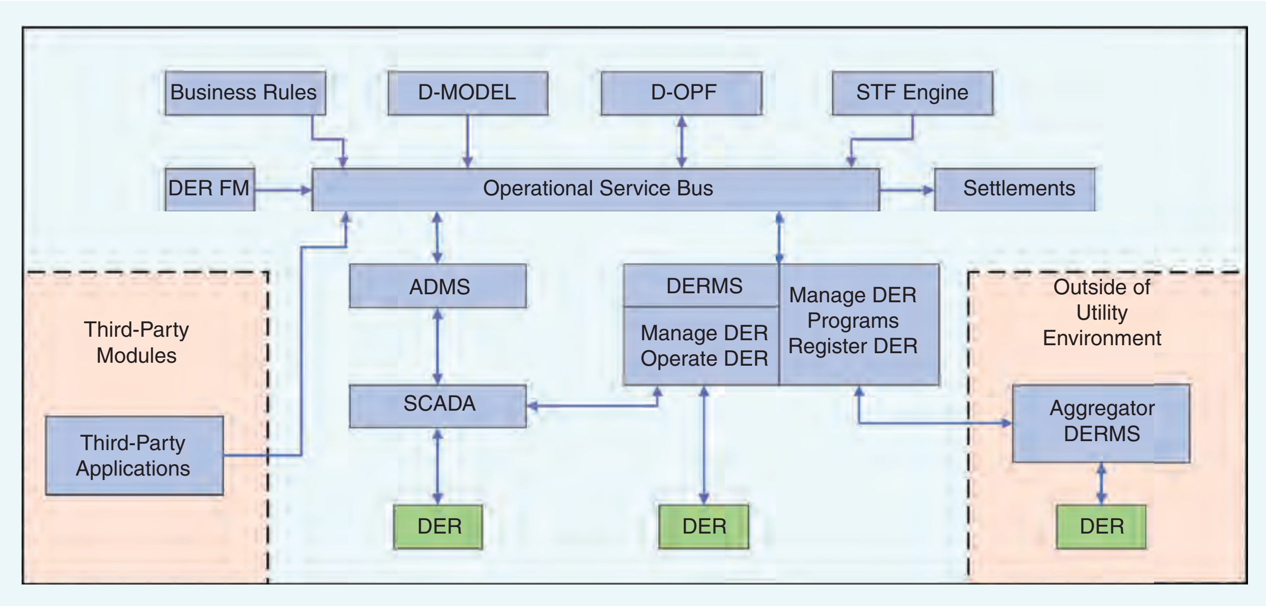

Figure 9. DERMS deployment and operation in a distribution utility's control center. ADMS: advanced distribution management system; D-Model: distribution model; D-OPF: distribution optimal power flow; FM: fleet management; STF: short-term forecast.

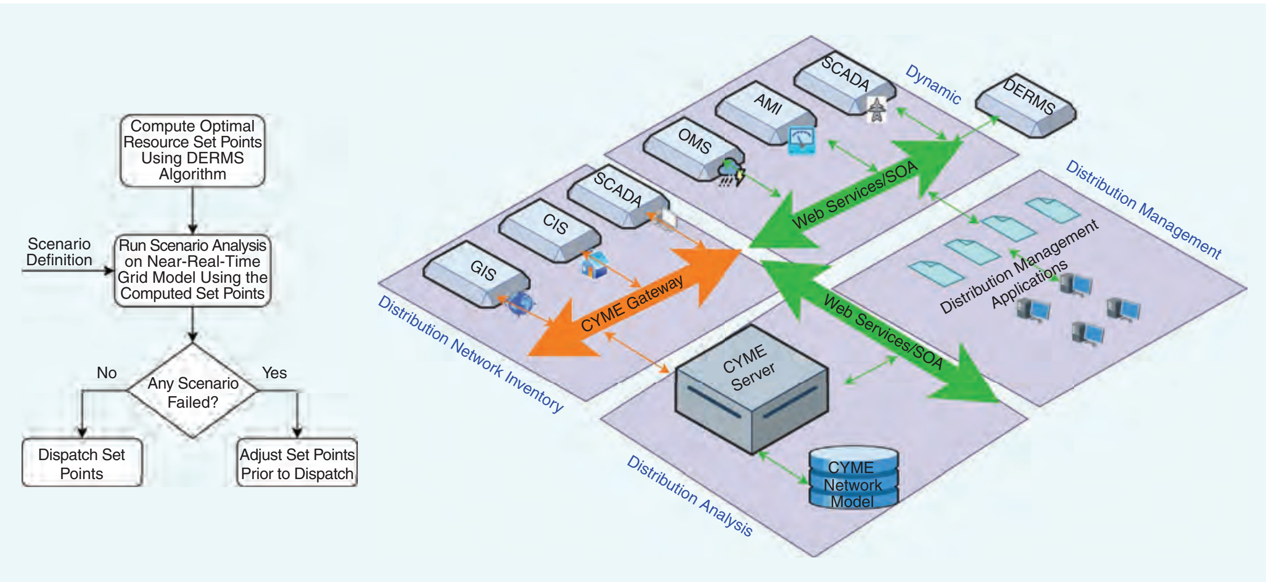

Figure 10. Schematic illustration of a DERMS integrated with industry-grade distribution planning tool. CIS: customer information system; GIS: geographic information system; OMS: outage management system; SOA: service-oriented architecture.

The development of this solution involves the following key technologies:

- *Upgrading UPS systems for grid services*: Traditional UPS systems are designed for off-grid operation, supplying power directly to the connected load. To support grid services, the UPS needs to be equipped with a grid-tied inverter, allowing it to synchronize with the system frequency and voltage and either absorb or inject power as needed. This upgrade requires advanced power electronics capable of managing the direction and magnitude of power flow based on grid conditions.

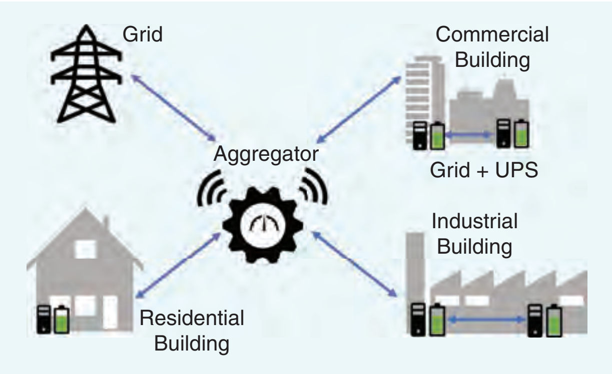

Figure 11. A grid-interactive UPS concept.

- *Novel battery and management system (BMS) enhancement*: The battery storage within a UPS is a fundamental component for grid services. Newly emerged battery technologies offer advantages over traditional batteries, such as lower material costs, high-power capabilities with rapid charge and discharge rates, and safer integration into UPS systems. An enhanced BMS that optimizes battery performance, manages state of charge (SOC), and ensures longevity while participating in grid services like frequency regulation, load shifting, and DR is an imperative.
- *Grid-aware UPS controller enabling control and communication with grid aggregator*: A new UPS controller is essential for monitoring and controlling the UPS system in real time, allowing users to optimize their energy consumption and improve efficiency. This controller should be able to track energy usage for individual components of the UPS system, including the battery, rectifier, and inverter. This feature will identify inefficiencies in energy consumption and enable necessary adjustments. The controller also needs to include advanced power management features that can help reduce energy consumption and save money. Ideally, the

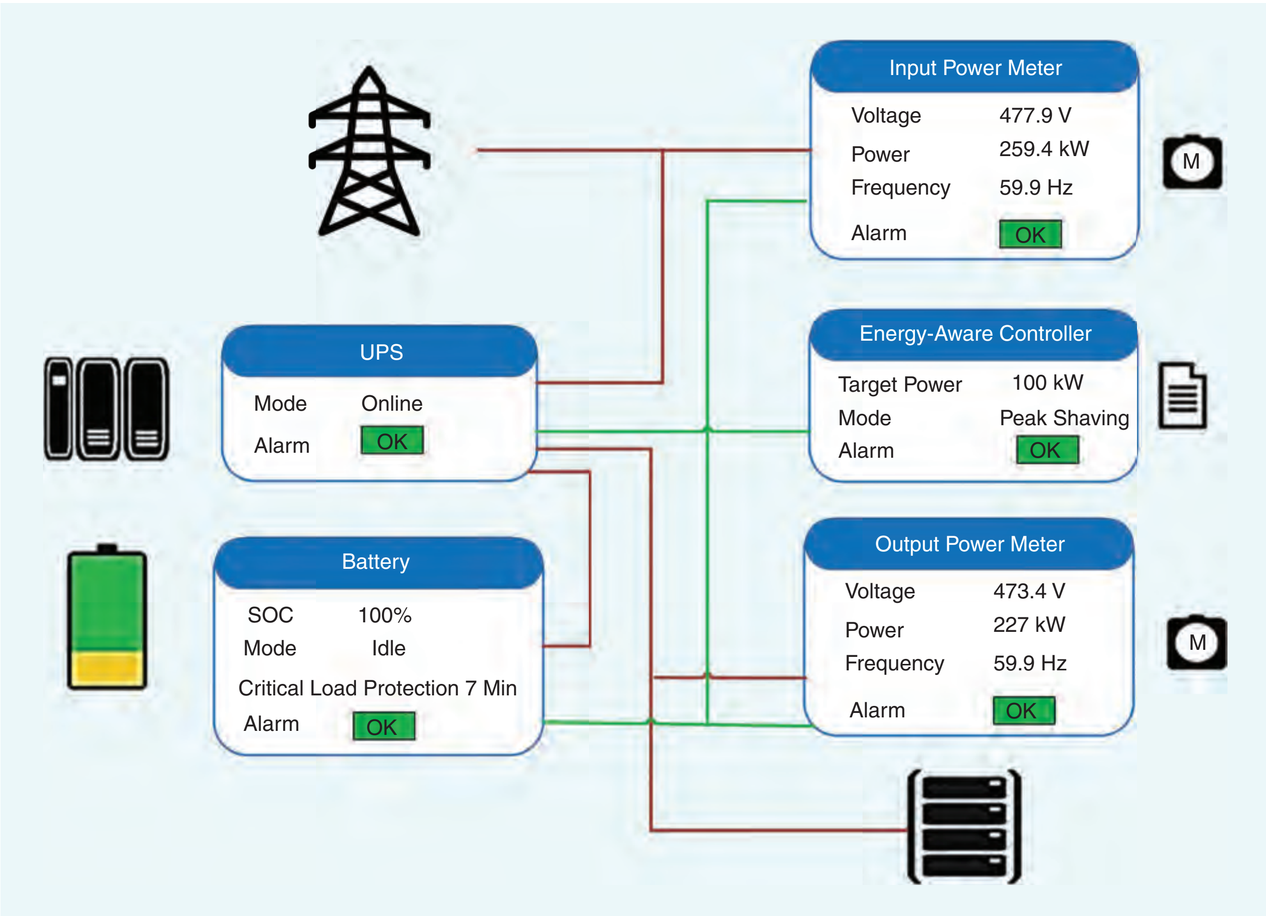

Figure 12. Conceptual visualization of an EMS dashboard for the grid-aware UPS.

controller will automatically adjust the operating parameters of the UPS system based on real-time data, such as demand and input voltage, to ensure maximum efficiency and reliability, as shown in Figure 12. Another important feature of such a controller is the ability to integrate with other EMSs. The controller should support a range of protocols, allowing it to communicate with other EMSs and share data for analysis and optimization. There must be a gateway to the grid via a dedicated site controller to perform more grid services when needed.

UPS systems show limitations when addressing longer duration grid needs, especially during sustained overloads lasting several hours. As electrification demand grows, these systems, designed for short-term backup, face significant challenges, like limited capacity and battery degradation over extended use. They struggle to maintain consistent performance over long periods, necessitating further evaluation and potential upgrades. Solutions are needed to bridge the gap between short-term backup and long-term energy storage for critical infrastructure.

The transformation of conventional UPS systems into building blocks for VPPs represents a significant step toward a more resilient and sustainable energy future. This enabling technology will be integrated as a DER, connected to the grid through a site controller capable of providing grid services, such as DR, peak shaving, and frequency regulation, via grid aggregation aided by favorable regulations, such as FERC Order 2222. By upgrading existing UPS installations in commercial and industrial buildings, the solution will be able to increase the energy storage capacity and significantly improve the payback economics for building owners.

Conclusions and Future Directions

The integration of DERs into utility grids is a critical step in the global energy transition. The aggregation of DERs into VPPs, which provide grid services, defer capital investment costs, and increase reliability and resilience, is essential for utility grids to manage this transition. The introduction of three key technologies that enhance the observability and controllability of BTM DERs, expand the functionality of a standard distribution planning tool, and transform traditional UPS into a VPP component are advancements that could potentially facilitate the growth of VPPs.

Moving forward, additional research, development, and demonstration projects are necessary to address the challenges associated with integrating DERs into utility grids and aggregating them into functioning VPPs. This includes finding effective strategies to encourage customer participation in real-world pilots and demonstrating the coordinated operation of multiple technologies necessary for the successful evolution of VPPs. In the future, the concept of the DSO, as seen in the European context, could become more prevalent in North America. The industry should be prepared for a shift toward price-responsive DERs and VPPs, which could further enhance the efficiency and effectiveness of energy distribution. The technologies presented in this article are some of the enablers for this envisioned future.

Acknowledgment and Disclaimer

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The views expressed herein do not necessarily represent the view of the U.S. DOE or the U.S. Government.

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