Distribution Grid Orchestration

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Disclaimer

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Introduction

Utilities are increasingly seeking to use distributed energy resources (DERs) and DER aggregations to meet distribution grid needs associated with rising load growth and the expanded penetration of distributed renewable energy. For example, DERs, individually or in aggregations, can be used to reduce and shift load on the distribution system and provide resiliency services.[1] This paradigm involves controllable DERs, such as smart inverters, battery energy storage, electric vehicles, smart thermostats, and water heaters.[2]

However, under large penetrations of DERs, the behavior of energy injection-capable distributed resources will need to be carefully managed to avoid the inadvertent creation of grid constraints (such as thermal and voltage violations). With a greater prevalence of DERs on the distribution system, it is possible that the frequency of multidirectional power flows will grow. These power flows may result in system constraints that occur at different times depending on the location and characteristics of distributed resources. Based on where the resources are sited, constraints may occur at all levels of the distribution system – on secondary circuits fed from a service transformer, feeder lateral branches, and on mainline circuits. Figure 1 provides a high-level overview of a future distribution system with a diversity in the types and locations of distributed resources. The black arrows represent the direction of power flows from DERs that do not result in grid constraints. The red arrows represent power flows that may result in grid constraints, with the red bubbles representing the locations of these constraints and violations.

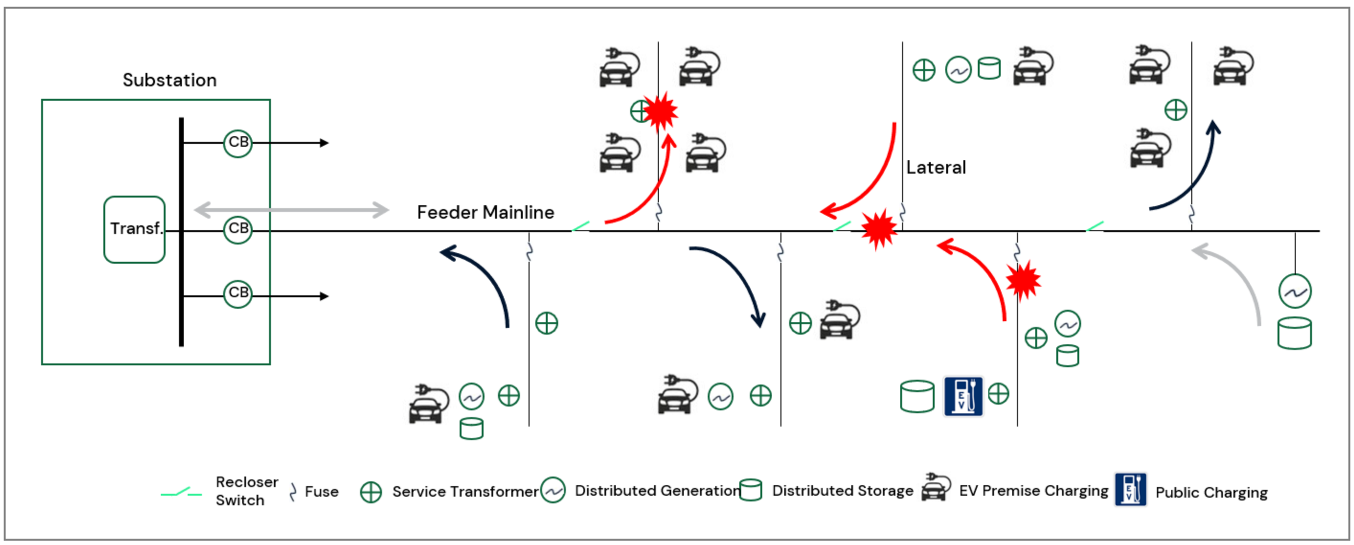

Figure 1. Distribution Feeder Constraints with High DER Penetration and Electrification

Furthermore, studies show that distribution system upgrades required to accommodate load growth from

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[1] US DOE, Bulk Power, Distribution, and Grid Edge Services Definitions, November 2023. Available online: https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf

[2] Solar photovoltaics (solar PV) can also be controlled to the extent that their inverters are capable of receiving setpoints (for example, active power or Volt-Watt/ Volt-VAr setpoints). However, this functionality is very nascent and not widespread.

the electrification of buildings and transportation systems, and new data centers could be very costly.[3, 4, 5]

The capability and flexibility offered by DERs and DER aggregations can play a role in offsetting some of these costs, as well as preventing grid constraints and violations on the distribution system. For example, EVs could be managed and orchestrated to stagger their charging times such that their cumulative power draw does not stress grid equipment, in turn avoiding the need for an equipment upgrade. Similarly, smart thermostats could incorporate settings that pre-cool dwellings before their occupants arrive, which would reduce the simultaneous power draw from several air conditioning units, and in turn offset a utility's need for incremental peaking capacity. Flexible load management and DER programs could also be designed in a way such that these resources are managed in a manner that benefits both customers and the grid operator. Without orchestration, the system is constrained to a single counterparty for each grid limitation, significantly limiting opportunities for non-wires alternatives (NWA). Non-contracted DERs remain underutilized (in terms of helping to meet grid needs) and do not contribute effectively due to high barriers to entry into bilateral contracts and procurement processes. Moreover, the participation of DERs in local grid services is minimal, as there are no incentives for customers or aggregators to act in the best interest of the grid. Nonetheless, in future, when considering the use of DERs to meet distribution grid needs, careful selection of the appropriate orchestration mechanism, as well as the interplay between various orchestration mechanisms is required.

Without orchestration, the system is constrained to a single counterparty for each grid limitation, significantly limiting opportunities for non-wires alternatives (nwa). Non-contracted DERs remain underutilized and do not contribute effectively due to high barriers to entry in bilateral contracts and procurement processes. Moreover, participation of DERs in local grid services is minimal, as there are no incentives for customers or aggregators to act in the best interest of the grid.

This paper discusses current and emerging techniques for DER orchestration on the electric distribution system. The paper describes the various mechanisms through which the output and characteristics of DERs can be managed. It also discusses the underlying technologies that enable the various orchestration mechanisms including their operational maturity in relation to use on the distribution system. The paper also provides examples of various orchestration mechanisms employed in pilots and programs.

The DER Orchestration Model

To illustrate the various mechanisms for managing DER, this paper introduces a DER orchestration model. The model presents a framework to organize and classify DER orchestration techniques. The model is shown below in Figure 2. Orchestration mechanisms are classified broadly into three categories – dispatch signal-based, autonomous, and behavioral.

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[3] Kevala, Electrification Impacts Study Part I: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates, May 9, 2023. Available online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF

[4] California Public Advocates Office, Distribution Grid Electrification Model Study and Report, August 2023. Available online: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf

[5] US DOE, Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles, March 2024. Available online: https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

Dispatch signal-based orchestration mechanisms can be further classified into centralized and decentralized approaches. In both approaches, DERs could be managed using prices or control signals that are transmitted to a DER or group of DERs to influence their behavior. Autonomous orchestration mechanisms consist of fixed and dynamic parametric approaches. Fixed parametric approaches consist of pre-set standards based and pre-set engineering-based methods. In these approaches, DER output is responsive to the parameters dictated by industry and engineering/ design standards. Dynamic parametric approaches include periodic engineering updates and dynamic responses to grid conditions. In these techniques, DER output changes based on frequently changing setpoints or control instructions. Behavioral orchestration mechanisms include responsive demand and energy conservation techniques.

The orchestration model also considers varying types of interfaces between DER operators and distributed resources. A direct interface connection entails communication links between distributed resources and a utility control center. A one level indirect interface entails the utility dispatch of distributed resources via an intermediary such as an aggregator or device manufacturer. A two-level indirect interface entails utility dispatch of distributed resources through an aggregator and device manufacturer.

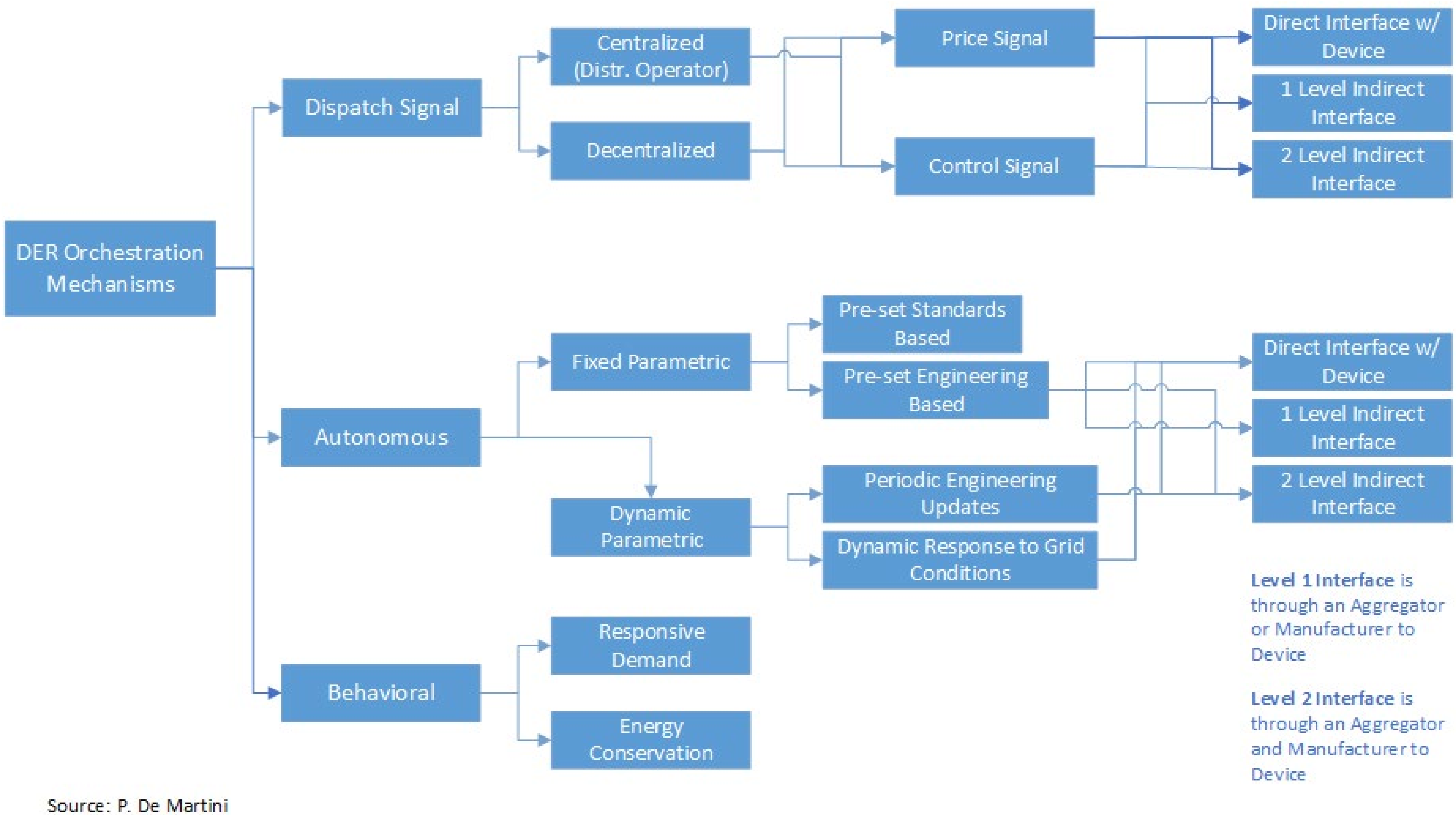

Figure 2. Conceptual DER Orchestration Model

The various modes of DER orchestration are further explained in Table 1 and Table 2 below.

Table 1. Dispatch Signal-Based DER Orchestration Mechanisms

DER Orchestration Mechanism	Orchestration Mechanism Type	Orchestration Mechanism Sub-Type	Related DER Program Examples
Dispatch Signal-Based Orchestration The dispatch signal-based orchestration method entails the communication of control and dispatch signals to DERs and DER aggregations.	**Centralized Orchestration** In the centralized approach, control and command signals are sent to individual or multiple DERs or DER aggregations through a control center, operated by an ISO/ RTO, utility, DER aggregator, or device manufacturer.	**Price Signals** DER/ DER aggregation behavior reacts to a price signal/ monetary incentive from a centralized system that indicates to the DER/ DER aggregation operator whether it should increase or reduce the output of a DER/ DER aggregation.	MIDAS, CalFUSE
		Control Signals DER/ DER aggregation behavior is controlled in response to a dispatch instruction from a centralized system that indicates whether the DER/ DER aggregation should increase or reduce its output.	Direct Load Control (DLC); Automated Demand Response (ADR); Grid-Interactive Water Heaters; Utility-Owned Storage Projects; Virtual Power Plant (VPP) programs; Utility-Controlled Inverter program
	Decentralized Orchestration In the decentralized approach, control signals are sent to DERs and field devices in smaller geographic areas, such as single feeders or feeder laterals, from the control center via a "lead field device". Decentralized control mechanisms can	**Price Signals** DER/ DER aggregation behavior responds to a distributed decision-making approach (Transactive Energy) that coordinates the operation of energy-consuming and producing devices based on real-time price signals. These price signals reflect the value	Transactive Energy Programs

DER Orchestration Mechanism	Orchestration Mechanism Type	Orchestration Mechanism Sub-Type	Related DER Program Examples
	include 2-way communication paths between DERs, field devices, and the lead field device, such that the lead field device adjusts and reissues dispatch instructions to DERs and aggregations based on evolving field conditions.	of electricity at a specific time and location, allowing DERs and end-use devices to adjust and aggregate their behavior accordingly.	
		Control Signals DER/ DER aggregation behavior is controlled in response to a dispatch instruction that indicates whether the DER/ DER aggregation should increase or reduce its output. Participants manage their DERs independently, often with incentives for behaviors that support grid stability. Control is local, with participants making operational decisions.	Community Microgrid. Peer to Peer Energy Trading; Distributed Load Control

Table 2. Autonomous DER Orchestration Mechanisms

DER Orchestration Mechanism	Orchestration Mechanism Type	Orchestration Mechanism Sub-Type	Related DER Program Examples
Autonomous Orchestration Autonomous orchestration techniques involve DERs modifying their behavior independently without external signaling and inputs. The autonomous mode of DER orchestration can be further classified into fixed parametric and dynamic parametric	**Fixed Parametric** In a fixed parametric orchestration approach, DERs and DER aggregations operate autonomously to attain and/or remain within the limits of pre-set power system parameters determined by standards or engineering guidelines. These pre-set parameter values remain static and typically do not change with time or	**Pre-Set Standards Based Control** Pre-set standards-based control ensures power system parameters remain within tolerances defined by standards in the presence of DERs (such as maintaining voltage within the limits specified by ANSI C84.1).	Smart inverter autonomous functions in compliance with IEEE 1547-2018.
		Pre-Set Engineering Based Control Pre-set engineering-	SCE Localized Autonomous LCMS pilot.

DER Orchestration Mechanism	Orchestration Mechanism Type	Orchestration Mechanism Sub-Type	Related DER Program Examples
approaches.	change very infrequently.	based orchestration approaches ensure that DER/ DER aggregation behaviors do not trigger violations of engineering standards (for example, the power output of a DER does not exceed conductor thermal limits).	
	Dynamic Parametric Dynamic parametric orchestration approaches include the autonomous behavior of DERs and aggregations to adjust to real-time grid conditions and attain power system parameters that vary with time.	**Periodic Engineering Updates** This approach entails periodic engineering updates to control DER behavior, such as via seasonal adjustments to inverter settings.	Seasonal remote updates to smart inverter settings
		Real Time Engineering Updates DERs adapt their output and response to changing grid dynamics, and/or parameters that are communicated to them on a frequent basis.	SCE Communication Based LCMS pilot

Table 3. Behavioral DER Orchestration Mechanisms

DER Orchestration Mechanism	Orchestration Mechanism Type	Related DER Program Examples
Behavioral Techniques Behavioral techniques involve the use of presentation of information that influences energy consumption patterns.	**Responsive Demand** This approach includes methods such as time of use (TOU) and real time pricing (RTP) rates and programs that can influence a customer' energy usage as well as control of DERs.	TOU rates; Critical Peak Pricing (CPP), RTP programs
	Energy Conservation This approach includes	Behavioral energy efficiency incentives and rebates

DER Orchestration Mechanism	Orchestration Mechanism Type	Related DER Program Examples
	behavioral nudges that prompt customers to minimize or reduce energy use during the operation of an electric load, system or machine or when producing a good or service.	

Figure 3 below illustrates the current maturity of the various DER orchestration mechanisms, ranging from stages such as research and development (R&D) to mature deployment and coordinated orchestration. The orchestration adoption cycle X-axis, "Current Adoption," identifies the stage of adoption for a specific orchestration mechanism and the Y-axis, "Technology Performance and Customer Benefits" is meant to indicate value to utilities and customers as an orchestration mechanism matures.

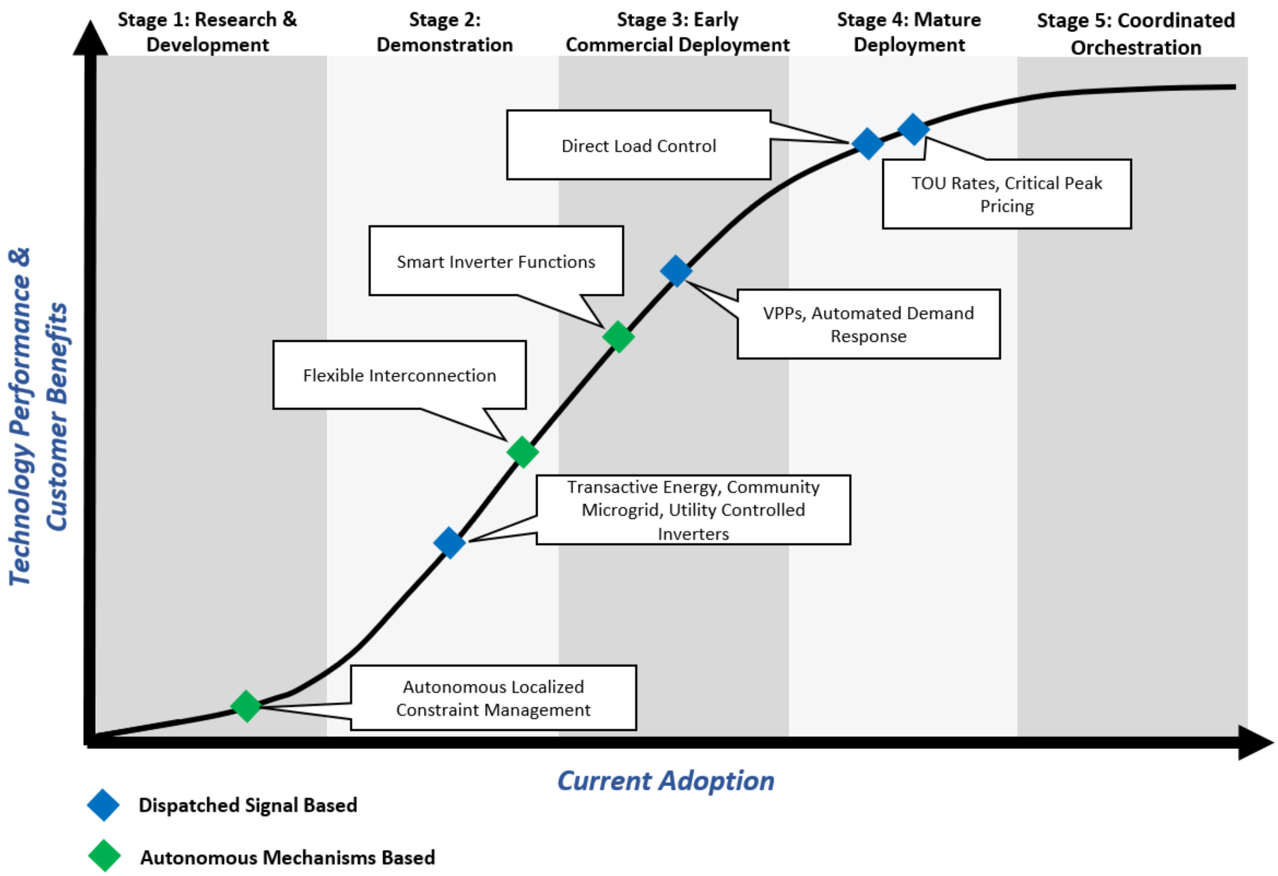

Figure 3. DER Orchestration Adoption Cycle

DER Orchestration Mechanisms

Dispatch Signal Based Mechanisms – Centralized

Centralized dispatch signal-based orchestration involves a control center, operated by an distribution utility, aggregator, or device manufacturer, sending control or command signals to individual or multiple

DERs or DER aggregations. These signals guide the DERs in responding to grid needs by either adjusting their output or consumption based on real-time grid conditions. The primary types of centralized dispatch signals include.

- Price signals: DERs respond to market-based pricing for distribution services.
- Control signals: DERs respond to dispatch instructions from control systems (i.e., utility direct control and/or through intermediaries).

Price Signal Based Orchestration

Price signal-based orchestration involves DERs responding to monetary incentives that indicate whether they should increase or decrease their output. This type of orchestration aims to align DER behavior with grid needs through economic signals. For example, in a price signal mechanism, a grid operator might offer higher payments during peak demand periods to encourage DERs to provide additional power or reduce consumption. Relevant standards and technologies include OpenADR 2.0, which automates the process of sending price signals to DERs, and IEEE 2030.5, which facilitates low-cost telemetry and emergency control for grid-edge DERs.

An advanced model for price signal-based orchestration is the CalFUSE framework[6] that integrates multiple pricing models to generate unified flexible grid signals to achieve demand flexibility. Unlike special-purpose utility rates, CalFUSE focuses on real-time pricing signals for both energy and capacity, providing more accurate reflections of grid conditions. Additional options such as bidirectional pricing, subscription plans, and transactive features provide customers with more flexibility in how they participate and respond to grid signals.

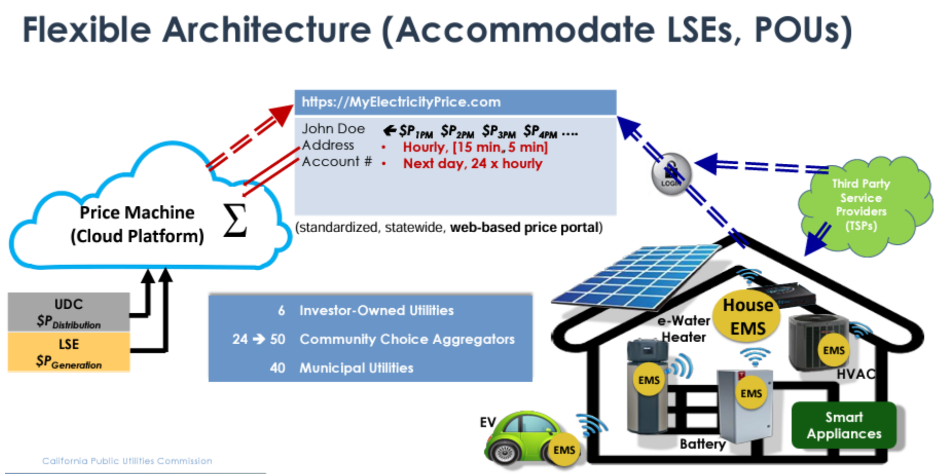

Figure 4. CalFUSE: Standardized Access to Electricity Price

Price signal-based centralized orchestration is in an early demonstration phase, where real-time pricing directed to customer devices is being tested but is not yet mature. Utilities have substantial experience with structured rates like Critical Peak Pricing (CPP) and Time-of-Use (TOU) schemes, which influence grid demand predictably, but real-time, device-specific price signals for orchestrating DERs are still largely experimental. Programs like CalFUSE lay the groundwork for these dynamic signals by centralizing rate, emissions, and alert data. However, significant challenges around security, coordination, and real-time

[6] California Public Utilities Commission (CPUC), Workshop: CalFUSE Whitepaper and Staff Proposal, July 21, 2022. Available online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/workshop-pdfs/slides-calfuse-workshop-21july2022f-publish-pdf.pdf

responsiveness indicate that broad deployment of device-oriented price signals remains in development.

Control Signal Based Orchestration

Control signal-based orchestration involves DERs responding to direct dispatch instructions indicating whether to increase or decrease their output. This method focuses on real-time operational needs and immediate adjustments to DER behavior. Control signals are essential for managing grid stability and reliability, especially during unexpected grid events. Programs under this category include direct load control (DLC)[7], automated demand response (ADR)[8], utility scale battery energy storage systems (BESS), and virtual power plant (VPP) programs. Standards and protocols relevant to control signal orchestration include OpenADR 2.0, which enables automated demand response, and IEEE 1547, which provides guidelines for the execution of control signals.

An illustrative example of centralized control signal-based orchestration is Duke Energy's Dynamic Voltage and VAR Control program.[9] This program employs advanced inverters and a Distribution Management System (DMS) to regulate voltage and reactive power across the distribution network. By coordinating local inverter control with integrated volt/VAR control, the program ensures that voltage levels are maintained within desired ranges, enhancing power quality and grid stability. The challenges associated with this program include the latency of system response, as the Integrated Volt/VAR Control (IVVC) algorithm solves issues every ten minutes, which may not be fast enough to fully compensate for large PV ramping events. Additionally, the program requires coordinated control considerations with other grid devices, such as Load Tap Changers (LTC) and capacitor banks, to balance local control modes with centralized strategies effectively.

Centralized control signal-based orchestration is a mature and well-established approach that has been applied both at a system level and in large-scale deployments, primarily driven by specific grid needs. Programs like Florida Power and Light's On Call Program[10] and large-scale initiatives like California's Emergency Load Reduction Program (ELRP)[11] demonstrate how control signal-based orchestration has been utilized as part of system operations and in large-scale deployments. These programs are specifically designed to meet grid reliability needs, such as reducing load during critical periods, and have been successfully implemented either in localized areas or across broader grid segments. For example, the ELRP incentivizes industrial and commercial users to reduce load during grid emergencies by directly responding to control signals from the grid operator.

Dispatch Signal-Based Mechanisms – Decentralized

Decentralized orchestration prioritizes local dispatch, where decisions are made closer to the point of generation or consumption, allowing for a rapid response to changing grid conditions without the need for centralized control. This approach involves decentralized grid controllers that can either facilitate local price formation or dispatch instructions to local area DER based on local grid conditions. This approach may utilize communication between field devices, grid devices, and DERs to enable localized decision-making to

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[7] In Direct Load Control programs, specific loads such as air conditioners, water heaters, or industrial equipment can be turned off or adjusted remotely to reduce demand during peak periods or grid emergencies.

[8] Automated Demand Response programs enable grid operators to curtail or shift demand in response to grid conditions, leveraging pre-arranged agreements with consumers or aggregators.

[9] NREL, Feeder Voltage Regulation with High-Penetration PV Using Advanced Inverters and Distribution Management System – A Duke Energy Case Study, November 2016. Available online: https://www.nrel.gov/docs/fy17osti/65551.pdf

[10] Florida Power & Light. Available online: https://www.fpl.com/save/pdf/oncall.pdf

[11] CPUC, Emergency Load Reduction Program. Available online: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program

changing grid conditions. The primary types of decentralized dispatch signals include price signals and control signals.

Price Signal Based Orchestration

In decentralized price signal-based orchestration methods, DERs respond to localized economic incentives that reflect local grid conditions. Decentralized price signal-based orchestration begins with the generation of price signals within a local grid segment. These signals are derived from real-time conditions such as the availability of DERs, current demand levels, and any grid constraints. Once generated, these signals are communicated to DERs either directly through a decentralized communication network or through intermediaries like aggregators. In some cases, decentralized communication networks or peer-to-peer systems are used to facilitate real-time communication between grid devices and DERs, ensuring relevant price signals are promptly received. Alternatively, the local price may be provided to aggregators, who then relay the information to individual devices via the internet or other communication channels. Upon receiving these signals, DERs decide whether to produce, consume, store, or trade energy based on the current price. They then execute their decisions by adjusting their output or consumption in real-time.

An example of a decentralized price signal-based program is the RATES (Retail Automated Transactive Energy System) Pilot, implemented by SCE. This pilot used a transactive energy platform that dynamically adjusts energy consumption and generation based on real-time pricing signals. These signals were generated through forward tenders—offers with specified prices and quantities of energy—sent to participants at predetermined intervals. These pricing signals were related to real-time market conditions and grid needs (these signals were generated by incorporating locational marginal prices (LMPs) from the CAISO along with distribution and generation scarcity-based price adders. These adders increased during periods of high grid usage and decreased when demand was low), allowing participants to adjust their energy usage or generation to optimize their benefits. The system was designed to automatically respond to hourly, 15-minute, and 5-minute tender prices, optimizing energy use according to both grid needs and customer preferences.

By interfacing with the SCE load-serving entity, the distribution operator, and the California Independent System Operator (CAISO), the RATES platform allowed participants to balance their net energy use efficiently while participating in a dynamic market environment. Some project-level challenges included the need for reliable data interfaces to ensure timely and accurate meter data collection from customer premises. Ensuring consistent and reliable connectivity within customer homes, especially with devices using Z-Wave (a narrowband wireless link)[12] and Wi-Fi, proved difficult and required additional efforts to maintain stable communication. Moreover, cybersecurity concerns arose regarding the secure transmission of tenders and transactions.

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[12] In the context of home automation, Z-Wave is often used for controlling smart thermostats, lighting systems, and other energy-efficient devices. See https://z-wavealliance.org/

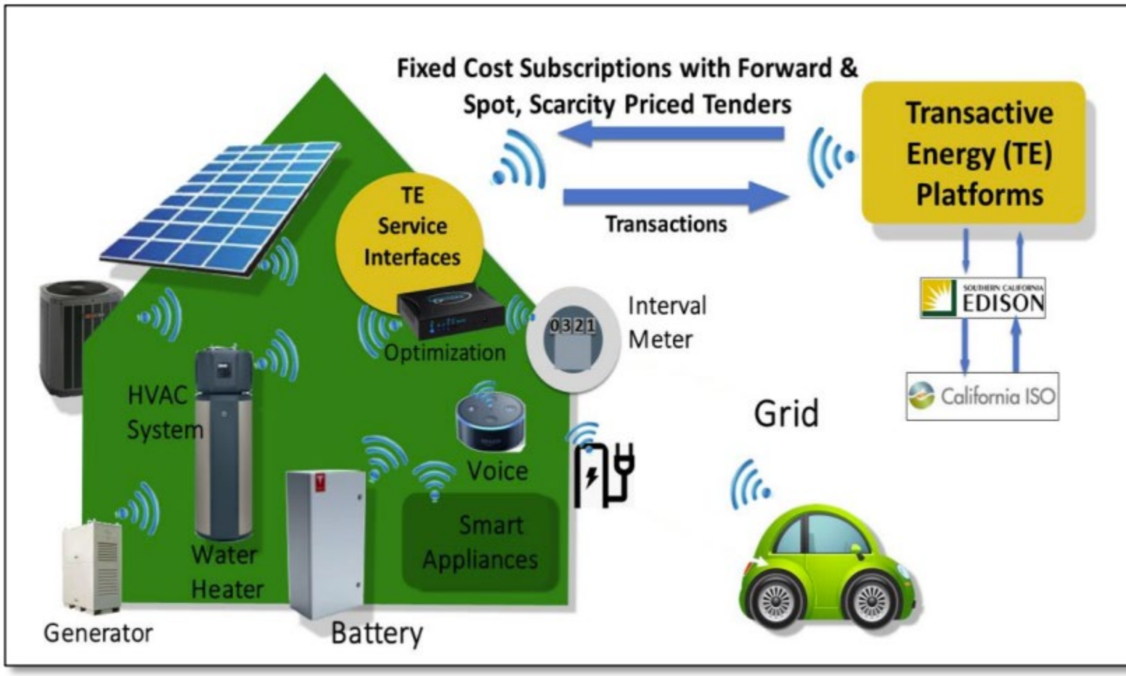

Figure 5. CPUC Transactive Energy[13]

The maturity level of decentralized price signal orchestration mechanisms is in the pilot and demonstration phase. However, further development and scalability of these systems is still in progress. For example, pilots like this have shown that transactive systems struggled with certain aspects of accurately representing system-wide energy dispatch and monetizing energy resources. The detailed modeling of grid conditions and more accurate predictions of load responses are necessary for decentralized price signal systems, especially for distribution constraints, to perform effectively at scale. Improvements in control architecture, prediction algorithms, incentive structures, and system interoperability will be crucial for decentralized orchestration to become more widely adopted and reliable at scale.

Control Signal Based Orchestration

In decentralized control signal-based orchestration mechanisms, DERs respond to locally generated control signals to adjust their behavior in real-time. These signals are typically generated by localized grid control systems that incorporate federated analytics and controls to coordinate the actions of multiple DERs within a specific area. Local distribution grid control systems generate control signals based on real-time local grid conditions, including factors like voltage levels and power flow.

An example of decentralized control signal-based orchestration is Duke Energy's Open Field Message Bus (OpenFMB) program.[14] This initiative uses an open-source framework to facilitate peer-to-peer communication among grid devices and DERs at the grid's edge. By enabling real-time data exchange and decentralized decision-making, OpenFMB allows DERs, such as smart inverters and battery storage systems, to respond dynamically to local grid conditions without the need for central coordination. For instance, if a voltage anomaly is detected on a feeder, OpenFMB-equipped devices can adjust their operations to stabilize the grid, thereby enhancing overall grid reliability and responsiveness. This decentralized approach reduces latency in control actions and improves the grid's ability to integrate a

[13] California Energy Commission (CEC), Complete and Low-Cost Retail Automated Transactive Energy System (RATES), June 2020. Available online: https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-038.pdf

[14] Duke Energy's Open FMB. Available Online: Smart Grid – Coalition – Duke Energy

growing number of DERs efficiently.

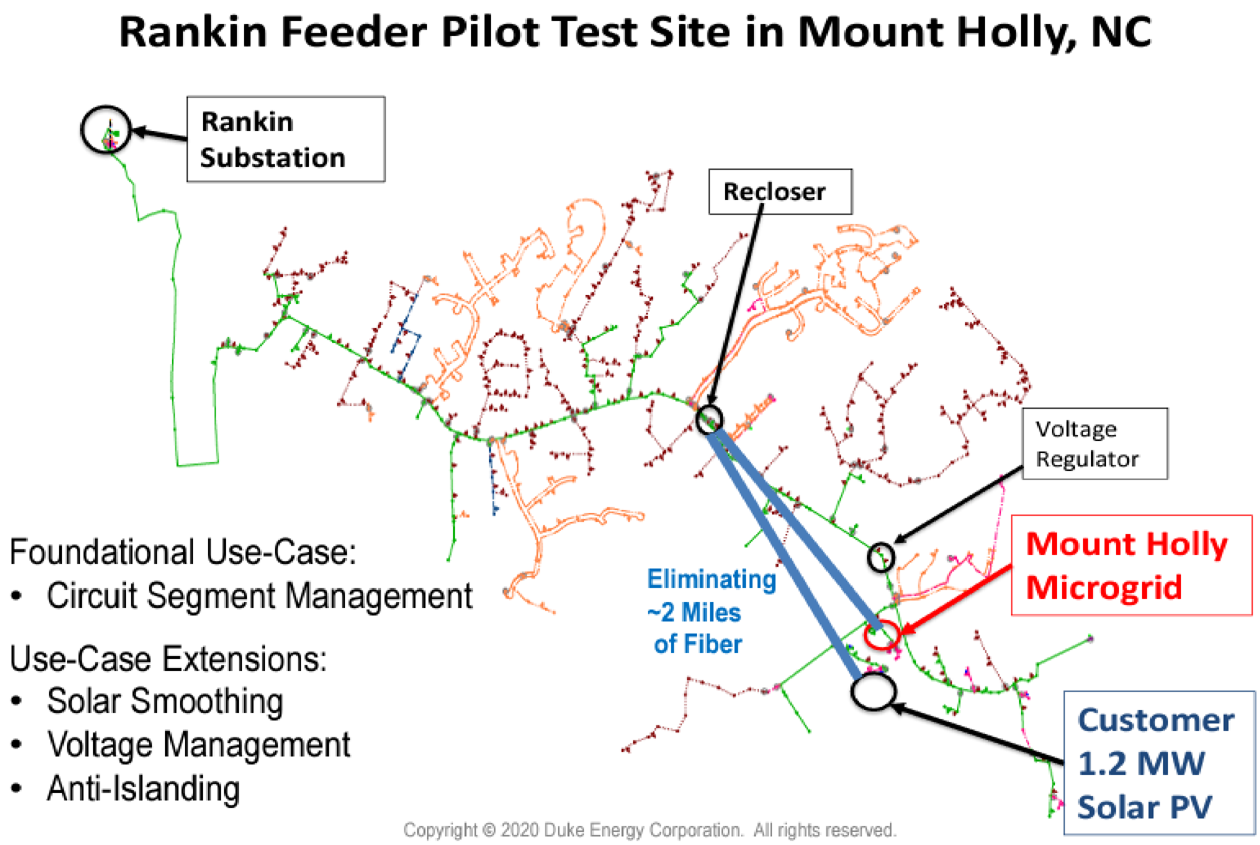

Figure 6. OpenFMB Pilot, Mount Holly, NC (Duke Energy)[15]

Autonomous Mechanisms – Fixed Parametric

The fixed parametric mode of autonomous DER orchestration entails the ability of DERs to adjust their behavior in response to setpoints or control instructions that are changed infrequently (for example, on an annual basis). DERs autonomously adjust their output or consumption based on system conditions and in keeping with the setpoints to ensure that the grid parameter(s) remain constant or within an acceptable range. The intelligence and control systems required for fixed parametric orchestration are typically co-located or housed with the DER. Fixed parametric mechanisms for DER control and orchestration include pre-set standards based and pre-set engineering-based mechanisms.

Pre-Set Standards Based

In this context, autonomous DER orchestration mechanisms ensure that distributed resources adjust their output or consumption such that power system parameters adhere to the settings dictated by industry standards. For example, DERs that are equipped with inverters that are compliant with IEEE 1547-2018 might be programmed with Volt – Watt, Volt – VAr or Frequency – Watt curves that can dynamically adjust the DER's output based on voltage and frequency readings at the inverter terminals. Using voltage as an example, this dynamic adjustment ensures that when voltages deviate from normal values and fall out of

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[15] Duke Energy Emerging Technology Office, Enabling Grid-Edge Interoperability to Accelerate DER Adoption and Integration, 2020. Available online: https://arpa-e.energy.gov/sites/default/files/EMC2%20Workshop%20Day%202%20-%20SLaval.pdf

bounds defined by ANSI C84.1, the inverter-based resource can react autonomously to increase or reduce the amount of power sent to the grid.[16] One example where such methods have been put into practice is in California. Distribution utilities in California require all inverter-based resources to activate the Volt-Watt function.[17] Another example is Minnesota, where inverter-based resources are required to enable both the Volt-VAr and Volt-Watt functions by default.[18] Additionally, Hawaiian Electric is using a technology known as secondary var controllers (SVCs) to regulate voltages.[19, 20] These controllers can be installed on the secondary side of a service transformer, and inject reactive power when voltage drops below a setpoint, and absorb reactive power when voltage rises. As a result, voltages are maintained within ANSI C84.1 and utility standards.

The current maturity of pre-set standards-based orchestration mechanisms can be classified in the early commercial deployment phase.

Pre-Set Engineering Based

Pre-set engineering based autonomous orchestration mechanisms refer to the control schemes that adjust DER behavior such that engineering standards (as defined by engineering calculations or by distribution utility design standards) are not violated. For example, DERs could be controlled through such schemes so that their output does not adversely affect conductor thermal or voltage limits. In such schemes, system limitations are communicated to a controller/ control system on an infrequent basis (annually, biannually, seasonally etc.), typically by an electric utility. The control system is then responsible for adjusting DER output such that the system limits (as set by engineering standards) are not violated. The communicated system limits do not change on a dynamic basis.

An example of the implementation of such an orchestration mechanism is Southern California Edison's (SCE) Localized Autonomous Load Control Management System (LCMS) pilot for EV charging. The pilot is designed to allow customers to receive an electrical service connection based on the currently available grid capacity, avoiding delays in the customer's EV charging interconnection until required grid upgrades are completed to support charging at full capacity. SCE will develop annual, seasonal, or time of day specific charging profiles, and the customer is responsible for programming these into the LCMS.[21] The customer's LCMS can reduce charging levels, disconnect specific devices, or stop charging at specific chargers to remain within distribution grid operating limits. Customers are responsible for purchasing and installing the LCMS, which operates independently without real-time external communication, using pre-

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[16] In the US, the ANSI C84.1 standard establishes the nominal and operating voltage ratings for equipment operating at 60 Hz and between 100 V and 1200 kV.

[17] Pacific Gas and Electric Company, Electric Rule No. 21 Generating Facility Interconnections (see section Hh). Available online: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf

[18] State of Minnesota Technical Interconnection and Interoperability Requirements. Available online: https://mn.gov/puc/assets/MN%20TIIR_TSG_020623_Final%20Draft_Clean%204.11.23_tcm14-595663.pdf

[19] M. Asano, F. Wong, R. Ueda, R. Moghe, H. Chun and D. Tholomier, "Secondary VAr Controllers: A New Approach to Increase Solar Hosting Capacity in Distribution Grids," *2019 IEEE Power & Energy Society General Meeting (PESGM)*, Atlanta, GA, USA, 2019, pp. 1-5, doi: 10.1109/PESGM40551.2019.8973690.

[20] In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. HAWAI'I ELECTRIC LIGHT COMPANY, INC. MAUI ELECTRIC COMPANY, LIMITED dba HAWAIIAN ELECTRIC, SUPPLEMENT TO AND UPDATE OF APPLICATION OF HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC. AND MAUI ELECTRIC COMPANY, LIMITED VERIFICATION EXHIBITS "A"–"L" AND CERTIFICATE OF SERVICE, Docket No. 2019-0327. Available online: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/2019_0327_20210331_heco_grid_mod_phase_2_supplement.pdf

[21] US DOE, Flexible DER and EV Connections, July 2024. Available online: https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf

programmed limits to manage power usage.

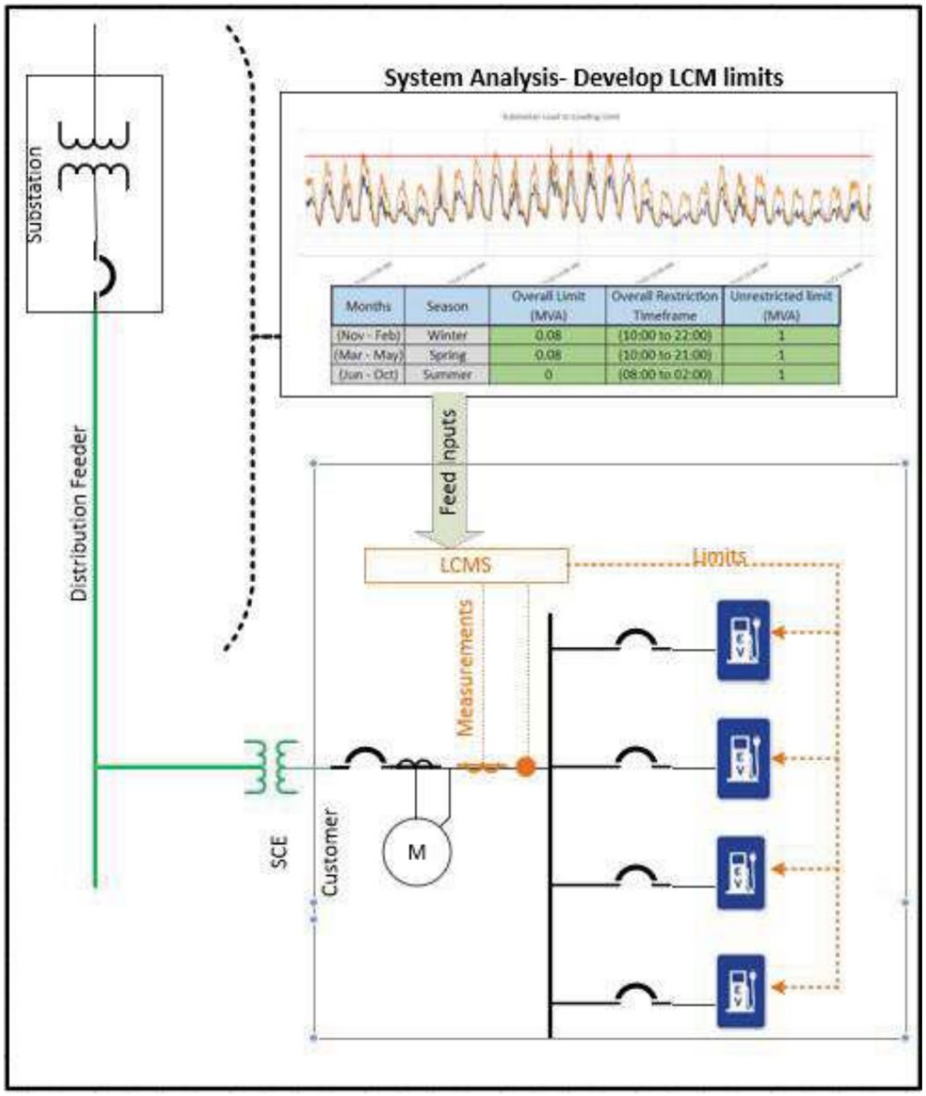

Figure 7. SCE Localized Autonomous LCMS Pilot Details[22]

Another example of this orchestration mechanism is the use of limited generation profiles (LGPs) in California.[23] The LGPs define the maximum amount of electric generation a DER can export to the grid at different times of the year, while remaining cognizant of grid conditions. These LGPs are programmed into a power control system (PCS), which communicates power limit commands to DERs, and measures DER output. Three types of LGP configurations are available:

- 24-hour configuration: In this configuration, an LGP export limit is created for each hour of the day for 12 months (24 hourly values per month for each month), resulting in a maximum of 288 LGP

[22] CPUC Rulemaking 23-12-008, VEHICLE-GRID INTEGRATION FORUM WORKSHOP REPORT FILED BY SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), May 21, 2024. Available online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K262/532262533.PDF

[23] CPUC, Resolution E-5296, March 2024. Available online: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M526/K988/526988970.PDF

values in a year.

- Block configuration: This configuration aggregates the 24-hour values into several blocks, each block representing a period during which the export limit remains constant. For example, the day might be divided into six 4-hour blocks, each with its export limit.
- 18-23 fixed configuration: The 18-23-fixed configuration (i.e., two hourly blocks 6 PM-midnight and midnight-6 PM for each of 12 months) provides a hybrid approach, where the hourly values are fixed, and the remaining hours are aggregated into blocks or assigned different export limits.

The current maturity of pre-set engineering-based autonomous orchestration mechanisms can be classified into the operational demonstration category. A very limited number of projects utilizing this orchestration mechanism have been implemented in practice. Similar to the considerations described previously for the pre-set standards-based mechanism, local control systems should have a proven capability to respond to and maintain adherence to pre-programmed setpoints. An additional impediment is the current lack of standards that can certify the behavior of local control systems such as PCS. However, efforts are underway in the industry to define the requirements for such systems – the development of the UL 3141 standard is one such example.

Autonomous Mechanisms – Dynamic Parametric

The dynamic parametric mode of autonomous DER orchestration entails the ability of DERs to autonomously adjust their behavior in response to setpoints or control instructions that change frequently or on a pre-determined basis. DERs autonomously adjust their output or consumption based on system conditions and in keeping with the setpoints to ensure that the grid parameter(s) remain constant or within an acceptable range. Similar to fixed parametric mechanisms, the intelligence and control systems required for dynamic parametric orchestration are typically co-located or housed with the DER. Dynamic parametric mechanisms for DER control and orchestration include periodic engineering updates and real-time engineering updates.

Periodic Engineering Updates

In this context, autonomous DER orchestration mechanisms ensure that distributed resources adjust their output or consumption based on settings that are communicated to the resource on a periodic basis. An example of where this mechanism has been put into practice is an EPRI effort with Salt River Project (SRP) in Arizona. In this effort, settings were communicated seasonally from the utility distribution management system (DMS) over a cellular network to 250 smart inverters in SRP's service territory.[24] Additionally, an example of a tool that can facilitate periodic updates in inverter settings is NREL's PRECISE.[25] The tool is currently used by utility distribution engineers at Sacramento Municipal Utility District (SMUD) during the DER interconnection process to establish optimized inverter settings for individual DERs based on grid topology and data. In future, the tool could be used on a more frequent basis to establish updates for inverter settings, as grid topology and customer loads change.

The maturity of this orchestration mechanism can be considered to be in the demonstration phase. Several factors are key to the success of this mechanism. These include the necessity for a robust and low latency communications network that can send parameters to DER sites. Additionally, the parameters that are sent may need to be site specific, and ideally not communicated in a serial fashion (that is, sent to all DERs at once, rather than one DER after the other). Depending on the number of DERs to which the setpoints need to be sent, serial communication can be a lengthy process. Additionally, determining the settings that

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[24] *SRP Advanced Inverter Project: Research Findings.* EPRI, Palo Alto, CA: 2019. 3002016625.
[25] Available online: https://www.nrel.gov/grid/precise-tool.html

result in the optimal operation of the distribution system with high DER penetrations will require sophisticated control and computational capabilities.

Dynamic Response to Grid Conditions (Real Time Engineering Updates)

In this orchestration mechanism, engineering setpoints or limits are communicated on a frequent basis to customer DERs or control equipment. These DERs or control equipment subsequently autonomously adjust the power output or import capability of resources to adhere to the communicated setpoints, thus preserving grid safety and reliability, and preventing equipment violations.

An example of a project using such an orchestration scheme is SCE's Communication-Based LCMS technology (note that this mechanism is different and distinct from the Localized Autonomous LCMS described previously).[26] The goal of this implementation is to provide electricity to new load customers (mainly EV fleets and public EV chargers) who are requesting service in a constrained area of the distribution system. This is accomplished by adjusting the customer's power draw to those times of the day when there is sufficient capacity on the distribution system. In this scheme, SCE's Advanced Distribution Management System (ADMS) determines load limits based on current and forecasted grid conditions and a system assessment. SCE's Distributed Energy Resource Management System (DERMS) sends these limits to the customer facility's communications interface over the IEEE 2030.5 communications protocol. The interface subsequently transmits the limits to the LCMS for execution. SCE may adjust and transmit the limits at different timescales, such as day-ahead, real-time, or other intervals. The LCMS communicates site performance back to SCE, and SCE can verify LCMS/ customer behavior via data from customer meters.

A schematic of the Communications Based LCMS is below.

[26] US DOE, Flexible DER and EV Connections, July 2024. Available online: https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf

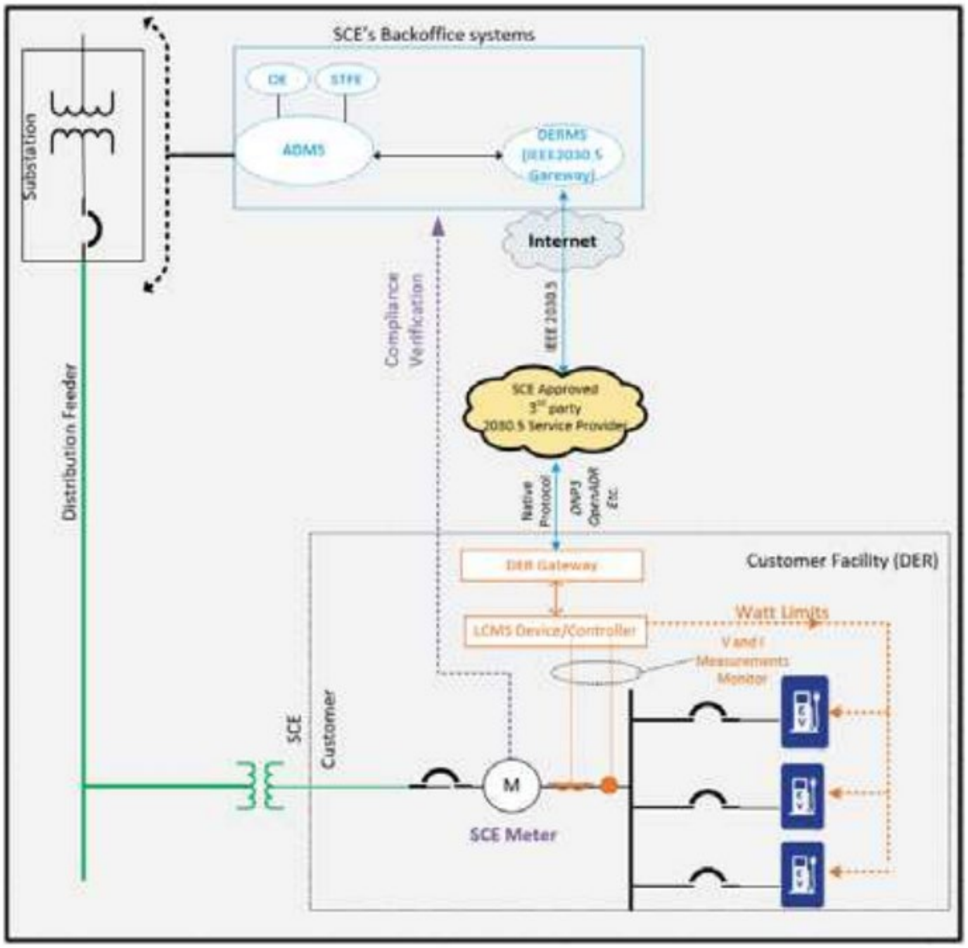

Figure 8. SCE Communications Based LCMS Schematic[27]

Another example of a project using an autonomous orchestration scheme is NREL's work with Holy Cross Energy, a community-owned cooperative utility, at the Basalt Vista Affordable Housing Project in Basalt, Colorado. In the project, four homes have been equipped with distributed resources, including solar PV, batteries, an EV charger, a smart water heater, and a heat pump. The resources are controlled by device-specific distributed controllers located in each home, which in turn are connected to a central coordinator. The utility monitors power flows on the feeder to which the homes are connected, which enables its ADMS to provide voltage and system power limits to the home controllers via the coordinator. The utility-owned home controllers subsequently operate the resources in each home to remain within the constraints communicated by the utility.[28]

[27] CPUC Rulemaking 23-12-008, VEHICLE-GRID INTEGRATION FORUM WORKSHOP REPORT FILED BY SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), May 21, 2024. Available online: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K262/532262533.PDF

[28] Holy Cross Energy, Real-Time Optimization and Control of New Generation Distribution Infrastructure – HCE and NREL Demonstration, January 16, 2020. Available online: https://www.nrel.gov/grid/assets/pdfs/rto-bilby.pdf

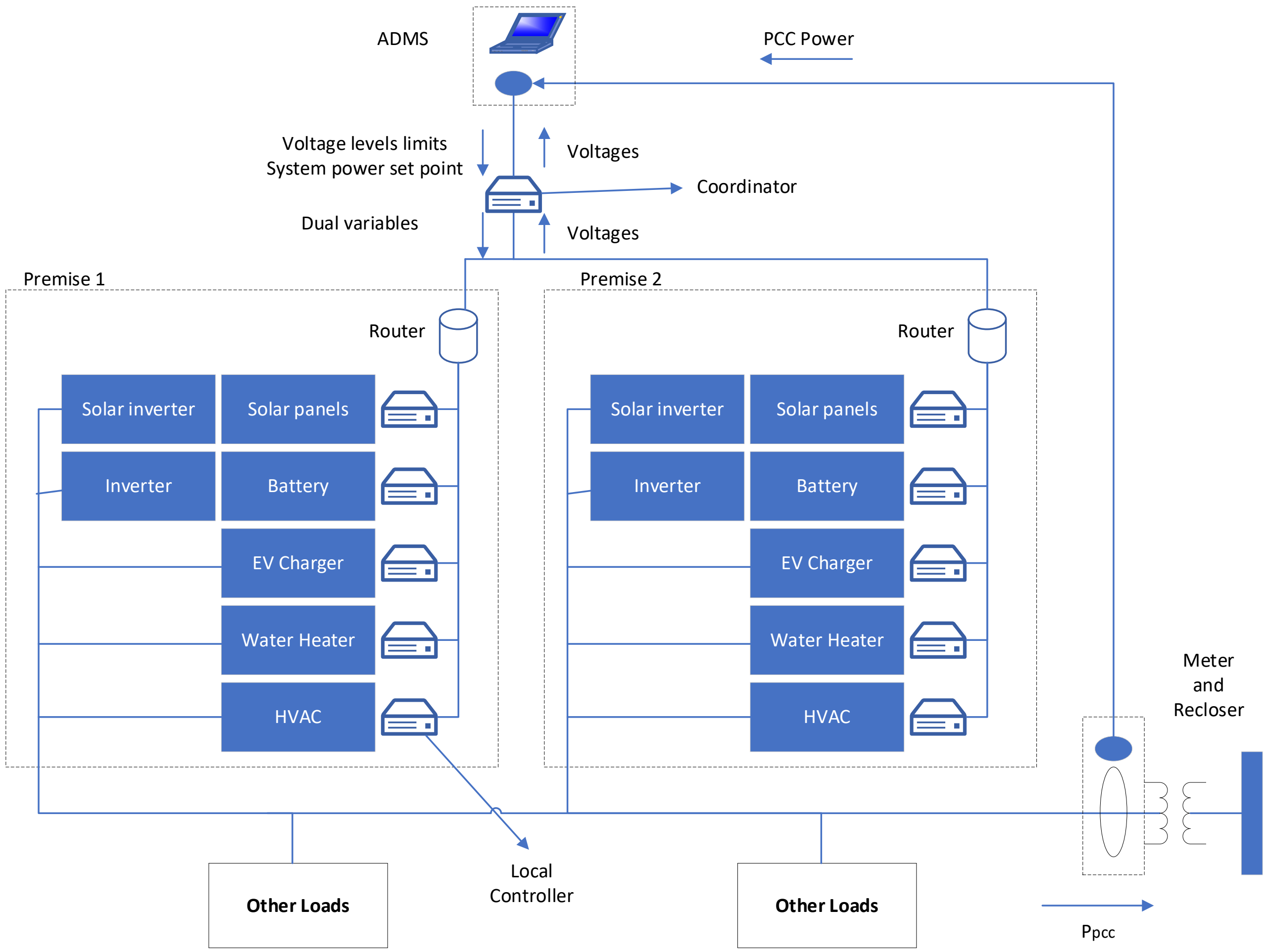

Figure 9. Basalt Vista System Architecture[29]

This orchestration mechanism can be considered to be in the research and development phase. Several barriers and development areas discussed previously within the context of the "periodic engineering updates" category, such as reliable communication networks and powerful computational systems are required. Other considerations to developing and deploying this mechanism at scale and at high levels of DER penetration include the necessity to develop accurate feeder models and incorporate dynamic updates to system parameters and circuit configurations. For example, distribution systems are dynamic in nature and may be frequently reconfigured. Additionally, each distribution feeder is unique in terms of the number and types of customers, types of interconnected DERs, feeder length etc. To accurately run power flow calculations and convey setpoints to DERs, precise circuit models will be required, along with advanced computational tools such as a utility ADMS.

Behavioral Mechanisms

Behavioral mechanisms include techniques that incentivize customers to adjust or minimize their energy consumption. This category consists of time-varying rates and energy efficiency programs. For example, with residential EV TOU rates, the price difference between the on- and off-peak rates is meant to shift

[29] Adapted from - Holy Cross Energy, Real-Time Optimization and Control of New Generation Distribution Infrastructure – HCE and NREL Demonstration, January 16, 2020. Available online: https://www.nrel.gov/grid/assets/pdfs/rto-bilby.pdf.

charging times away from early morning and late evening peak periods. Hence, such rates act as an indicator for customers to consciously adjust or shift their energy usage. Additionally, energy conservation programs that incentivize consumers to adjust or reduce their energy use through more efficient appliances or home insulation, for example, are also included in this category.

Responsive Demand

Time varying rates indicate to customers when they should increase or decrease DER energy import or export (e.g., generation and batteries). This type of orchestration aims to align customer behavior with grid needs through the economic signal conveyed by the retail rate. For example, a utility might impose higher costs during peak demand periods to encourage DERs to provide additional power, or to incentivize customers to reduce consumption. This approach is exemplified by approaches such as TOU rates, Critical Peak Pricing (CPP), RTP tariffs, and utility-specific tariffs for DERs such as EVs.

An example of a recent implementation of time varying rate is Pacific Gas and Electric's (PG&E) Hourly Flex Pricing pilot, designed for agricultural, business, and residential customers.[30] Running from November 1, 2024, to December 31, 2027, the pilot provides hourly pricing information where prices fluctuate based on grid conditions, incentivizing customers to adjust their energy usage accordingly. The prices are forecast seven days in advance and set one day in advance. Customers can view the prices on PG&E's website, or they can work with automation service providers who can send price signals directly to devices. Using the pricing information, customers can shift their energy usage (such as EV charging, air conditioning, manufacturing operations etc.) to a lower priced period.

Time varying rates are considered to be in mature deployment. Time-varying rates have been used for many decades and more recently being applied to DER and EV charging as their uptake continues to rise through various programs and pilots.

Energy Conservation

Energy conservation involves both incentivizing customers to use less electricity as well as the adoption of more efficient consumer devices and increases in the efficiency of the built environment, such as buildings. Both approaches involve customer decision-making to effect the desired reduction in energy use.

An example of a customer-focused energy efficiency program is Southern Maryland Electric Cooperative's (SMECO) program to analyze customer AMI data, thus pinpointing customers with appliances that used excessive energy. SMECO then provided these customers with individualized offers and rebates on energy efficient equipment such as water heaters and heat pumps as well as smart thermostats. The utility also provided customers with information on how to conserve energy. The initiative resulted in a doubling of the pace of thermostat adoption and a five-fold participation increase in SMECO's home energy improvement program.[31] These types of initiatives are beginning to be deployed to address specific distribution grid needs through geo-targeting customers in constrained areas of the distribution grid.

Energy efficiency and conservation initiatives that are geo-targeted to address specific distribution needs are in the stage of early commercial deployment. Some prominent examples of projects that used such geo-targeted mechanisms include Con Edison's Brooklyn Queens Demand Management (BQDM) project

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[30] Pacific Gas and Electric, Hourly Flex Pricing. Available online: https://www.pge.com/en/account/rate-plans/find-your-best-rate-plan/hourly-flex-pricing.html#

[31] Oracle, SMECO Boosts Energy Efficiency and Reliability with Oracle Utilities. Available online: https://www.oracle.com/customers/smeco/

and Consumers Energy's Swartz Creek project.[32]

Orchestration Implementation Considerations and Conclusion

This paper describes a DER orchestration framework and various control mechanisms, offering a structured lens through which to view the various ways that DER are being managed to address distribution grid needs. As the penetration of DERs on the distribution system grows and interest rises in using distributed resources to serve as solutions to meet distribution system needs, careful selection of the most suitable orchestration mechanism, as well consideration of the interplay and interaction between the DERs and orchestration mechanisms is required. For example, today, a utility may use different orchestration mechanisms to manage different types of DERs on its system – with one management mechanism for solar PV, another for EVs, and another for smart thermostats. Selecting the most appropriate control mechanism for each DER, as well as considering how these approaches interact with each other would be beneficial, especially when sourcing DERs to serve location-specific grid needs.

Additionally, from the examples described above, several considerations for the widespread enablement and adoption of DER orchestration mechanisms for serving distribution grid needs can be synthesized. These are summarized below.

1. **Accurate and Actionable Data is Required –** Utilities need accurate, timely, and verifiable grid and DER data to plan and operate their systems. Examples of grid data points include voltage and power demand, while DER data points include DER output power, availability status (on/off), and location on the distribution system. Such data collection is enabled by field devices and communication paths that can transmit the data between the devices and utility systems. Data is also required to inform circuit models and DER management decisions.
2. **Systems Interoperability is Paramount -** The challenge of interoperability between DER assets and platform solutions is significant. Manufacturers, product developers, and vendors often use varied protocols and communication techniques, which makes the creation and adoption of standardized communication approaches between utilities and these vendors difficult. The lack of standardized approaches necessitates the development of bespoke solutions for individual projects, which hinders the widespread use of DER to meet distribution grid needs.
3. **Technology and Standards are Still Maturing –** The deployment of utility and aggregator control and information technology (IT)/ operational technology (OT) systems such as Grid and Edge DERMS[33] that can control DERs is maturing. Specifically, the capability of these systems to manage DERs to meet localized distribution grid needs at various levels of the distribution system (single circuit, single transformer bank, substation etc.) is still evolving. Additionally, technical standards that govern advanced DER orchestration functionality are nascent and in development (for example, UL 3141).[34]
4. **Robust Communications Technology is Required for Dispatchable Resources –** The complexity of

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[32] SEPA, Non-Wires Alternatives: Case Studies from Leading US Projects, November 2018. Available online: https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf

[33] The term Grid DERMS refers to a system that typically manages assets located in front of the customer meter. Whereas, an Edge DERMS typically manages resources deployed behind the customer meter.

[34] For example, an assessment of communications protocols can be found in: EPRI, DER Protocol – 6th Edition: Assessment of Information and Protocol Standards for Distributed Energy Resources (DER), Electric Vehicles, and Demand Response Technologies, December 21, 2022. Available online: https://www.epri.com/research/products/000000003002024179

managing tens of thousands to hundreds of thousands of DERs, both behind and in front of the meter, requires robust, scalable, and flexible communication frameworks. These systems must facilitate the rapid transfer of signals between DERs, utility control centers, and aggregators to ensure timely and coordinated responses to grid conditions. This consideration applies to communications paths between utilities and DERs, as well as paths between aggregators and DERs. These linked communication systems are only as reliable as the weakest link in the chain, which places a high burden and importance of maintaining system uptime.