Pacific Northwest
NATIONAL LABORATORY

ARCHITECTING THE GRID EDGE

ENSURING RELIABILITY AND RESILIENCE

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Summary

Changes in technology, customer expectations, and business and regulatory environments are rapidly evolving causing fundamental changes in the nation's electrical infrastructure. Nowhere is this more apparent that at the "grid edge", where there is an increasing number of new devices and systems, as well as complex new interactions between them. This is leading to the traditional relationship between the end-use customers and their utilities being expanded by an increasing number of stakeholders, each with their own operational and financial objectives, governed by regulatory policy. While there are concerns about the rapidly increasing complexity negatively impacting reliable and resilience of the electrical infrastructure, these changes are also bringing new resources and opportunities that hold great potential if they can be properly coordinated.

This white paper outlines the considerations for the coordination of multi-stakeholder objectives with electric utility requirements using the concept of grid services. Describing a framework that enables new stakeholders to achieve their local technical and economic objectives, while simultaneously delivering operational benefits to the electrical infrastructure. The concepts of grid architecture are presented as a tool to evaluate how stakeholders might participate in, and benefit from, services, and how utilities can make decision on the reliance on services to ensure reliability and resilience, translating abstract concepts into actionable information for utilities and grid edge stakeholders.

The end result of proper coordination, informed by grid architecture, will be a range of new devices and systems, operated by new stakeholders, achieving their local objectives while also increasing the reliability, resilience, security, and affordability of the nation's critical electrical infrastructure.

1.0 | Introduction

The nations electrical infrastructure has been continually evolving since Thomas Edison placed his first commercial central power plant in operation in 1882 [1]. Changes in technology, customer needs, and regulatory policy drove the transition from small isolated systems, through regional consolidation, to the continent spanning interconnected system that is operated today [2]. The same forces that resulted in the current electrical infrastructure continue to drive change today. This change is readily apparent at the "grid edge" where once passive actors who simply consumed electricity are actively engaging with multiple stakeholders and in some cases producing electricity locally.

The grid edge is a concept, and not a single piece or portion of the nation's electric infrastructure. While it is often associated with behind the meter technologies, it is much more than that. In addition to the systems and capabilities that a utility may deploy at the feeder and/or substation level, the grid edge also includes all of the systems and relationships that interconnect the individual devices, for all stakeholders.

While customers are typically only supplied by a single electrical utility, their relationship with the electric power system is becoming much more complicated. The changing relationship is due to a complex interaction of technologies, customer expectations, and changes in the regulatory and policy environment.

1.1 | CHANGING TECHNOLOGIES

The first electric power systems were direct current and primarily supplied electric lighting to customers within a mile of the central generating facility, typically located in a city [1]. Over time, the size of generating units increased, the types of generators expanded, and the system expanded as an AC network that spanned the continent [2]. During this time, the range of appliances available to end-use customers increased, providing a range of benefits such as refrigeration, heating and cooling, as well as entertainment. While the range of amenities available to end-use customers expanded into the 1980's, their relationship with the electric power system was essentially unchanged; they consumed electricity in predictable patterns and interacted only with their local utility. At this point, the grid edge was still effectively passive with only a single bilateral relationship between the utility and the customer; there were no other stakeholders, other than regulatory entities. Additionally, distribution utilities typically had little to no visibility or control beyond the substation [3]. And even then, substation control was primarily achieved through utility personal located at a substation full time or dispatched from a local facility.

As the cost of computing power, communications systems, and power electronics has decreased, the possibility of what can be done at the grid edge has drastically changed. This is true for both end-use customers, but also for what utilities can deploy.

Solid-state and microprocessor-based systems have enabled the potential for computing and control at any points in the electrical power system, including at the substation, on the distribution circuit, and behind the end-use meter. This has enabled increased level of substation automation, distribution automation, as well as control at the end-use load level [4].

A combination of fiber optics, radio frequency (RF), and cellular communications has allowed for the potential to communicate with every device connected to the system. It is now possible for customers to connect major systems such as heat pumps and Electric Vehicles (EVs) via the internet. While communications capabilities vary across the 2900+ electric utilities in the country, it is not uncommon for a utility have fiber optic communications to major, or all, substations with RF and/or cellular to devices on the distribution circuits; with end-use meters connected to automated meter infrastructure (AMI) systems.

Advancements in power electronics have allowed for inverters to be developed that can interface distributed energy resources (DERs) with electric distribution systems. DERs can supply loads locally and export power back into the distribution system. It is the power electronics that allow for the interconnection of DC equipment such as solar photovoltaic (PV) and batteries.

1.2 | INCREASING CUSTOMERS EXPECTATIONS

In the early days of electric distribution systems, it was not uncommon for electric utilities to give away residential appliances in an attempt to increase the amount of load on the system [5]. Over time people have become more reliant on electricity and today, end-users are installing their own devices which are now driving the needs of distribution systems. Additionally, new stakeholder and loads are beginning to be deployed, to meet other stakeholder needs.

At the residential level, customers are installing new devices and becoming more dependent on reliable and resilient electricity. This ranges from relatively small loads such as computers and home network routers, to larger loads such as heat pumps and electric vehicles.

At the commercial level, the electrification of buildings and fleet electric vehicles represent new loads that can represent a 2-3X increase in peak load for an individual customer [6]. This has implications for not just the distribution systems, but also transmission systems.

1.3 | EVOLVING POLICY & REGULATORY ENVIRONMENT

Historically, residential, and commercial end-use consumers purchased electricity from a single electrical distribution company and were billed for the energy through a combination of base services charges and energy charges. For residential customers, a daily base service charge was applied for any active meter, with the energy charge based on the kWh consumed, using either a flat rate, a season rate, and/or tiered rates. For commercial and industrial customers, there could also be a “capacity” charge to reflect high power users. Regardless of the specific implementation, the customers consumed electricity and were billed at the end of the billing cycle. It was the responsibility of the electric utility to estimate end-use loads and to ensure reliable service through continue system upgrades, which was relatively straight forward given the loads were passive and typically consumed electricity following predictable patterns.

While the changes in technologies, customer expectations, and regulatory & policy present challenges to the way electric power systems were historically operated, they also present a range of new opportunities. As such, to fully capture the potential befits of the new technologies and interactions that are emerging, it is necessary to fully understand the grid edge from the perspective of multiple stakeholders.

The purpose of this white paper is to examine the changes that are occurring at the grid edge, and to present methods and approaches that can be used to ensure that the reliability and resiliency of the nation’s electrical infrastructure is maintained or increased. Specifically, examining how the operational and planning needs of the nation’s electrical infrastructure can be orchestrated with the changing needs of the end-users, using the concept of grid services as a tool. And then using grid architecture concepts to determine how to best acquire services in a way that improves the level of reliability and resiliency.

This white paper is organized as follows. Section 2.0 examines the individual elements of the grid edge. These represent the “things” that are physically being deployed and the relationships between them. Section 3.0 will discuss the fundamental capabilities that utility systems operators need to meet the technical requirements of maintain a reliable and resiliency electric infrastructure. Section 4.0 introduces the concept of grid services as a mechanism to map between the new devices and systems on the grid edge, and what utilities technically require to improve resiliency and reliability. Section 5.0 contains the concluding comments and Section 6.0 contains the references. Appendix A includes an expanded discussion on the changing characteristics of the grid edge and Appendix B provides additional details on grid services.

2.0 | New Grid Edge Elements and the Relationships

Historically, the grid edge was not engaged because it was not technically practical, and as a result there were no customer expectations to do so, or regulations to enable it. Today, technological advancements provide the technical potential to engage the grid edge [4]. Because of this technical potential, customer expectations are changing, as is the policy and regulatory environment. Appendix A provides a more comprehensive discussion on these changes, but the following sections summarize them.

2.1 | ENABLING TECHNOLOGIES

There are a wide range of technologies that are enabling the engagement of the grid edge, with three classes of technologies that are having the largest impact. Power electronics, modern computing capabilities, and communications infrastructures.

2.1.1 | Power Electronics

Prior to power electronics, generation sources required a rotating machine to interconnect to the system. While there are still many rotating machines in operation, power electronics allow for the interconnection of equipment at all power levels [7]. These range from high vorlage direct current (HVDC) at the transmission level to utility scale DERs that are typically connected at the medium voltage distribution level, which can range from 4.0 kV-34.5 kV, with residential and commercial scale DER connected behind the meter as 240V or 480V respectively. In addition to the ability to convert between AC and DC, and vice versa, power electronics can implement a range of control functions [8]. While the controls in a variable frequency drive for a residential heat pump will only adjust the power consumption to optimization HVAC performance, an inverter can inject power into the distribution system. Additionally, the injection of power, both active and reactive, can be controlled in multiple ways. For traditional "grid following" inverters, a utility provided voltage source is necessary to maintain a stable frequency and voltage [8]. Inverters can also implement "grid forming" control which allow them to independently maintain a stable frequency and voltage, supporting stand-alone islanded operations. Control capabilities can range from adherence to IEEE-1547 [9] to being integrated into a larger control scheme. Regardless of the specific controls implemented, modern power electronics make it possible to interconnect a range of devices to the electric infrastructure.

2.1.2 | Modern Computing Capabilities

With currently available commercial products, it is possible to have computing capabilities at any nearly point in an electric power system. Behind the meter, residential homes are full of personally owned computers and devices with significant computing capabilities. At the interface between the end-use customer and the distribution utility is a revenue grade meter, which is able to do far more than just calculate energy consumption. Currently available meters can integrate into larger meter data management system (MDMS) and advanced metering infrastructure (AMI), as well as having the ability to locally support computational functions. For some models, these functions include the ability to locally run applications. Modern micro-processor-based relays can be deployed at the substation level, or on a distribution circuit, and can be equipped with multiple processors [10]. In addition to the relays and computing capabilities directly deployed on a utilities industrial control system (ICS), larger central resources can be accessed from a number of locations. These computing resources can range from near real-time local calculations to cloud-based services such as Microgrid's Azure [11] and Amazon Web Services (AWS) [12]. Additionally, large centralized super computing capabilities can be used for off-line analysis [13].

2.1.3 | Communications Infrastructure

The ability to locally processes data provides technical potential, but the ability to move it to other locations, enabling the combination of information, provides significantly more potential. Behind the meter, many end-use customers (residential, commercial, and industrial) have their own networks. For the 2,900+ electric utilities in the country, it is not uncommon for a utility to have fiber optic communications to major, or all, substations with RF and/or cellular to devices on the distribution circuits; with revenue meters connected to AMI systems [4].

2.2 | MULTI-STAKEHOLDER DEVICES AND SYSTEMS

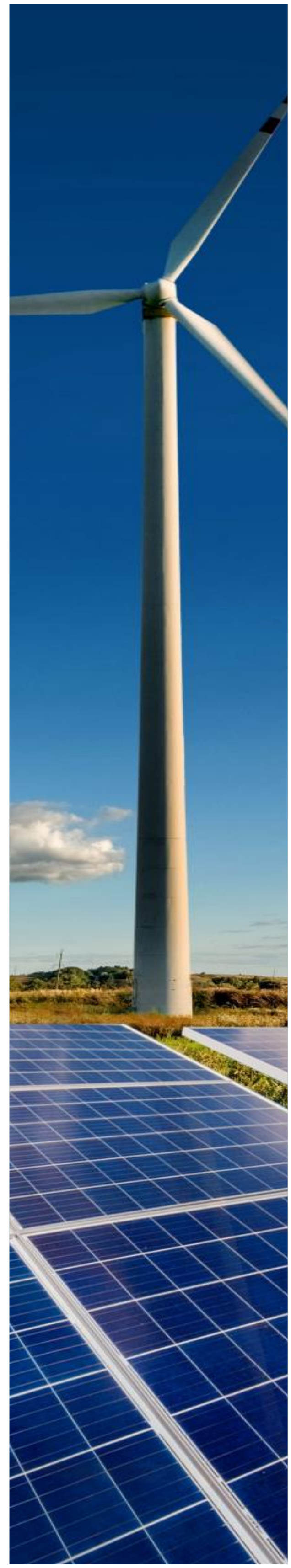
Enabled by the technologies discussed in Section 2.1, new devices and systems are being deployed by traditional end-use customers, a range of new and emerging stakeholders, and electric utilities. Additionally, the traditional bilateral relationship between the utility and customer is changing into an environment where there are numerous stakeholders interacting with the customers, utilities, and each other, in ways that are still evolving.

2.2.1 | New End-use Loads (Building Electrification and Electric Vehicles)

Modern society is becoming increasingly dependent on reliable and resilient electricity, and this can be seen in the number and types of end-use loads that customers are installing and electrifying. At the residential level, customers are electrifying a range of functions that were once supplied by other energy sources, with the two largest being heat pumps and electric vehicles.

While the heat pump is a high efficiency unit, a common value of peak electrical load in heat pump mode is approximately 3.5 kW, and 15+ kW when the resistive heating elements are all energized. As a result, during continual operation the unit represents a moderate load with a high duty cycle, running 90% of the time in cold/hot weather, but can be a very large load if the backup heating strips are energized.

Residential level II EV charging can be up to an 8 kW load that remains constant for 8-10 hours. At this power level, an EV can easily be one of the largest loads in a house. While the vast majority of EV chargers only provide power to the EV, referred to as V1G, there are numerous plans to engage EVs with bidirectional flows so that they can feed power back into the grid, V2G. These schemes could include direct load control as well as incentive-based schemes. Regardless, of the specific control mechanism, because of the size of batteries used in EVs, and the large numbers of EVs, they represent a large technical potential to provide services that a range of stakeholders are evaluating.



2.2.2 | End-use Generation (Solar Photovoltaic)

In addition to changes in the load profile of the end-use customers, there are stakeholders that actively inject power at the distribution level. At the grid edge, the most common form of distribute generation (DG) is PV. While it is possible to connect wind turbine generators (WTGs) at the grid edge, it is far less common than PV because of siting and permitting issues. Similarly, diesel generators are commonly interconnected at the grid edge, but typically they are only used in backup power applications due to the constraints of emission permits. This type of generation is commonly used to meet backup requirements at hospitals [14]. While backup diesel generators have been used for some market functions [15], they are not typically deployed solely for that purpose because of siting, permitting, and emission issues.

Solar PV can be deployed at the residential level, at the kW scale, or at the commercial level, MW scale. The injection of active power from newer solar PV inverters is typically in accordance with IEEE std 1547 [9], but many units have the potential to also inject reactive power. While the inverters currently being deployed have substantial technical potential to support system operations, they currently do not do so outside of IEEE std 1547. Similar to EVs, distributed solar PV represents a significant technical potential to offer grid services to the grid, in addition to the energy provided, but is typically not engaged.

2.2.3 | End-use Battery Energy Storage Systems

In addition to connecting generation sources, inverters, both grid-following and grid-forming, can interconnect battery energy storage systems (BESS) at the grid edge. Units commercially available are modular in size allowing for a set power level and a range of storage capacities. Currently, the most common battery chemistry is lithium-ion because of its energy density [16], but a range of other chemistries are being explored by researchers and industry. Similar to solar PV, residential units are kW scale and commercial units tend to be at the MW scale. BESS systems are sometimes paired with solar PV so that the two can be used to shape the combined profile, mitigating some of the variability issues of solar PV.

When coupled with a grid forming inverter and appropriate switching equipment, a residential BESS can provide resiliency benefits by supplying power when there is a disruption in the local electric distribution system. Similar to electric vehicles, residential BESS are a resource that represents a large technical potential for the system. While an individual unit may only be a few kW and tens of kWh, collections of multiple units operated in coordination with other units, can form a resource that can affect system level operations.

2.3 | NEW UTILITY DEVICES AND SYSTEMS

Similar to the end-users, the technologies discussed in Section 2.1 have enabled distribution utilities to deploy a range of new devices and systems at the grid edge.

2.3.1 | Advanced Sensors and Communications

One of the earliest “smart grid” technologies deployed by distribution utilities were the smart meters associated with AMI systems. One of the primary reasons for this was because of the lack of observability at the grid edge. While AMI typically does not give complete real-time visibility of the grid edge due to communications bandwidth limitations, it can provide time-delayed complete data sets, as well as real-time select measurements. The complete data sets are used for revenue purposes and have the potential to provide off-line analytics. Operational systems, such as outage managements systems (OMS) and volt-var voltage optimization (VVO) applications can make use of individual meter reads that can be obtained in real-time.

Modern AMI systems, and the associated smart meters, are enabled by a combination of advanced computing capabilities and communications infrastructures. The first generation of smart meters had the ability to measure active power, reactive power, and voltage magnitude. The current generation has the ability to run independent applications on the meter, leveraging local measurements as well as data from other meters.

Currently, communications infrastructures limit the frequency at which data can be collected. Typically, a complete read of all system meters is done once or twice a day, with a limited ability to pole a small subset of meters for real-time values.

2.3.2 | Distribution Automation and Controls

Distribution automation (DA) is a broadly used term that can refer to a range of technologies, including, but not limited to, remote breaker/switch operation, capacitor and regulator automation, coordinated reclosers and sectionalizers, and automated systems such as fault location, isolation, and services restoration (FLISR) [4]. The key characteristics of these technologies often include local sensing, computing capabilities, and communications systems. DA systems can be automated stand-alone devices and/or collected of integrated devices. Integration can be at the device-to-device level, and/or with larger centralized control systems such as a distribution management system (DMS).

2.3.3 | Utility Scale Battery Energy Storage Systems

The previously discussed BESS units are deployed behind the customer meter, 120/240V, and are typically kWh or tens of kWh in size. Utility BESS is connected at the primary distribution level voltages, 4.0-35.5 kV, and rated in the MWh size. Despite the differences in power, energy, and interconnection voltage, both can be considered as part of the grid edge. While customer units are typically deployed for local benefits, utility scale units are deployed to support distribution circuit level and possible transmission considerations. For very large installations that primarily support transmission system operations, they may or may not be considered part of the grid edge.

2.3.4 | Advances Distribution Managements Systems and Distributed Energy Managements Systems

Because early electric distribution systems were manually intensive operations, the deployment of early sensors and DA systems required stand-alone control systems. Specifically, because distribution operations were manual processes that centered around physical “mimic boards” and operators talking with crews in the field, there were no central systems to coordinate the new systems with. Distribution Managements Systems (DMS), and later Advanced Distribution Managements Systems (ADMS) coupled with Distributed Energy Resource Managements Systems (DERMS) began to address this. The orignal EMS systems were centered around utility systems and utilize supervisory control and data acquisition (SCADA) systems to bring data from remote sensing to a control center, and to allow operators at the control center a level of control of field devices. DERMS systems were designed to specifically integrate distributed resources such as solar PV and BESS. Later, ADMS was developed as a way to integrate DMS, DERMS, OMS, AMI, and other systems into a single control system. While the exact names of systems, and their capabilities, varies between vendors, these systems represented the first generation of command and control for the industrial control systems at the grid edge.

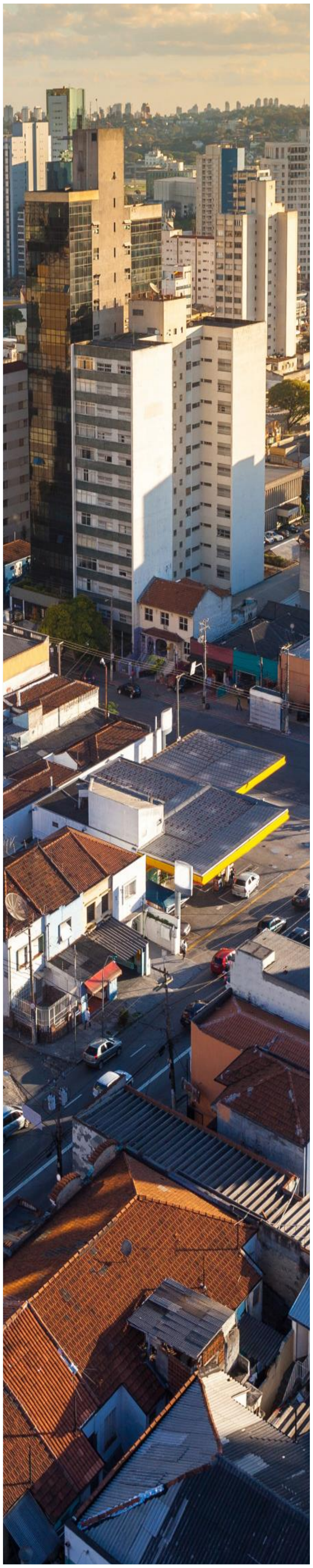
2.4 | THE CHANGING RELATIONSHIPS BETWEEN DEVICES AND SYSTEMS ON THE GRID EDGE

As important, if not more important, than the devices and systems being deployed by utilities and other stakeholders at the grid edge, is the relationships between them, including the actors involved This includes not just the communications and control relationships, but also the business and regulatory relationships.

Historically, the relationship between the grid edge and the utility has been bilateral. The utility provided the electricity at a regulated rate and the end-use customers purchased directly from them, typically at a flat rate independent of time of day. This type of bilateral approached worked well when the only actors were the utility supplying the electricity and the customers who consumed the electricity. In fact, the recognition that electric distribution systems are a “natural monopoly” is exactly why this relationship replaced the early systems where there could be multiple distribution infrastructures in a single area. This type of competition led to duplicative infrastructure, which was expensive to build and maintain, and was not in the best interest of the end-use customers.

While it would be conceptually possible to extend the centralized bilateral approach to the range of new devices and systems, this approach would face significant scalability and complexity challenges because of the large number of devices and the mixed-ownership environment. In particular, it would not be practical, or even feasible, for every new customer EV and BESS to be integrated into the utility ADMS and/or DERMS.

Instead of a purely centralized control approach, effective engagement of the grid edge will require a departure from the exclusive bilateral relationship between the utility and the edge. Because the new technologies discussed in Section 2.0 will be owned by an array of stakeholders, new relationships will need to be established. And while it is expected that the utility will retain responsibility for the reliability and resiliency of the grid, the new stakeholders, and their grid edge devices, will need to be cooridated. If the new stakeholders can be effectively coordinated with the utility, then they will become a resource to support reliability and resiliency. If they are not effectively coordinated, then reliability and resiliency could degrade. To better understand what the new relationships might look like, it is necessary to examine what some of the new stakeholder entities look like.



2.4.1 | Microgrids

A modern microgrid is a collection of generation assets, end-use loads, interconnecting distribution lines, and the control and communications systems that enable safe and reliable operations [17]. Typically, they are 10 MW or less in size and operate at medium voltage levels, 4.0-34.5 kV, but these are not a strict requirement. Microgrids can be interconnected to a bulk power system or can operate in a stand-alone mode, such as when they are the primary power source for a remote Alaskan village or island community. When grid connected, a microgrid can serve as a point of aggregation and control for a large number of renewable resources, controlled locally or connected to an ADMS and/or DERMS systems. When islanded, a microgrid operates as a self-contained power system with local controls that allow for operation during outages of the bulk power system [18]. In addition to grid connected and islanded, there is ongoing research around the concepts of networked microgrids [19]. In networked microgrids the idea is that groups of microgrids coordinate their operations, even when there is mixed ownership between microgrids, to achieve common global objectives. When grid connected the common objective can be to support the bulk power system during extreme events. If there is a loss of the bulk power system, the microgrids can coordinate their operations and self-assemble to support critical end-use loads. Networked microgrids are still an area of active research and are not comply deployed [20].

Microgrids can be owned and operated by a utility, a community, university, private company, or the military. Because microgrids may not be owned by a traditional customer, they represent a different relationship between the edge and the utility. Instead of a unidirectional flow of power and a monthly billing cycle, the microgrid represents a dynamic actor that can produce or consume energy, impacts the utility voltage control and protection systems, and has the technical potential to support key system operating requirements.

2.4.2 | Third-Party Aggregators

While a microgrid has the potential to coordinate the operate a number of DERs locally, the concept of a third-party aggregator is to control a large number of devices that can be over a broad area. The central idea being that any single device may not be a significant resource, but if hundreds or thousands can be aggregated, they represent a large resource. For example, a third-party aggregator might enroll customers in a program to control residential heating thermostats; each of which communes 3-5 kW when in operation. In exchange for some level of compensation, each residential customer would allow the aggregator to adjust their thermostat setting within an agreed upon range. The aggregator can then work with the system operator to offer the service of controlling the aggregated load in a desirable manner. For example, during a heat wave the third-party aggregator can adjust the settings on thousands of thermostats to provide a reduction for a period of time. Aggregation schemes can also be implemented for electric hot water heaters, EVs, DERRs, storage, and a range of other equipment.

2.4.3 | Virtual Power Plants

A virtual power plant (VPP) is similar to a third-party aggregator, except that it explicitly attempts to reproduce the performance of a generating unit using a number of smaller resources. For example, a collection of solar PV and batteries might be coordinated so that in aggregate they can provide the same level of dispatchable output as a single gas turbine unit. In addition to DERs, it is possible for a VPP to engage end-use loads and other behind the meter resources.

3.0 | Services as a Structure to Obtain Operational lexibility from the GridEdge

While there are challenges and uncertainties with the devices and systems being deployed at the grid edge, and the associate stakeholder relationships, they represent a technical potential that can transform the nation's power system. Currently, there are mechanisms for grid edge devices to engage with the system, but these interactions are based on the historic bilateral relationship between the utilities and the edge. In particular, the construct that utilities are obligated to serve all customers in their service territory. Maintain reliability and resiliency, and that electricity would be billed on a kWh basis, typically regardless of the time of day.

The engagement of the grid edge can be traced back to the Public Utility Regulatory Policy Act (PURPA) Act of 1978 [21], which among other things, enabled non-utility power producers. Net metering policies further enabled more active participation with the Energy Policy Act of 2005 requiring all utilities to consider adopting net metering policies [22]. While these policies enabled the potential for the grid edge to participate, they were still based on the concepts of using kWh as the basic unit of interaction. In effect, treating a service as a commodity, which introduced a range of unintended and undesired consequences.

To unlock the technical potential of the grid edge, the concept of grid services can be used [23]. For this white paper, grid services are defined the basic functions that an electrical power system must have to ensure reliability and resiliency. These services are fundamental to a power system and are applicable regardless of size or era of the power system. In particular, these services are required for a modern power system, the system of a hundred years ago, and the systems of the future. The primary difference is in the way the services are provided.

The work of [23] identified the six key services shown in Figure 3.1.

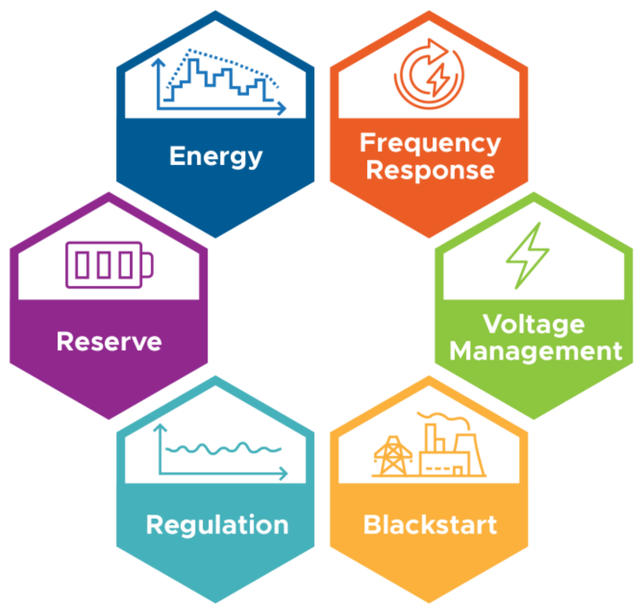


Figure 3.1: Critical services for reliable and resilient power system operations.

The six grid services shown in Figure 3.1 and described in detail in [23] and Appendix B, have detailed descriptions of the electrical attributed, the timing attributes, and the performance determinations. Before describing each of the grid services, it is necessary to examine the basic functions that a power system requires, in order to understand the role of each of the six services.

3.1 | BASIC OPERATIONAL FUNCTIONS THAT ARE NEEDED

In order for an electric power system to operated reliably and resiliently, there are basic technical functions that need to be executed. At a basic level, it is necessary to be able to observe, to some degree, what is occurring in the system, and it is necessary to be able to exert a level of control over the system [24]. Without either of these abilities it is difficult, if not impossible, to effectively run a system within the desirable operating parameters. For an electric power system, this means a system that provides frequency and voltage within the mandated range, is able to restore power after an outage in a timely manner and minimize the number and duration of outages to an acceptable level, as measured by IEEE std. 1366 [25].

3.1.1 | Observability

Figure 3.2: Sub-transmission line with voltage measurement on a single phase.

For electric power systems, observability can be sub-divided into system states, such as voltage at a node or position of a breaker, that are visible through direct measurement and states that can be estimated through mathematical means. The degree to which a system is observable varies significantly between the transmission and distribution level. From the utility perspective, observability is primarily achieved via utility owned and operated SCADA systems, with phasor measurements units (PMUs) used to varying degrees at the transmission level.

The nation's bulk transmission system has a significant number of sensors, connected via SCADA systems, that allows direct visibility of most major sections. Additionally, because of the large number of direct measurements, which is greater than the number of observed states, it is possible to use state estimators to account for measurement error and data loss [24]. As a result, for all major transmission lines, the voltage magnitude at each end is known, as well as the current flowing through the lines. At the sub-transmission level voltages, approximately 69-115 kV, direct visibility decreases because of reduced number of measurements, but these systems are still visible to varying degrees through state estimation systems.

Figure 3.3: Primary distribution line with three phase voltage measurement.

In contrast to the bulk power system, individual electric distribution circuits often lack real-time observability beyond the substation. While many utilities may have SCADA measurements at the substation level, enabling visibility at the beginning of a circuit, it is not uncommon for distribution circuits to have limited or no additional real-time measurements. While there are utilities that have additional measurements via reclosers or other DA devices, and the number of these is increasing, the majority of distribution circuits in the nation lack this visibility. Additionally, because of the large number of states and lack of measurements, there are significant challenges with distribution level state estimation providing full observability. However, there are some systems that use reduced order model, internal calculations, and time-delayed AMI measurements to execute a distribution level state estimation. Typically, this is not of the same level of accuracy as the transmission level counterparts.

With the engagement of the grid edge, the number and types of measurements is rapidly increasing. This includes traditional utility SCADA measurements, as well as a range of new data sources and types from grid edge stakeholders. As such, the technical potential for observability is expected to increase significantly in the future. For example, a distribution circuit that has a full AMI system, DA systems, and DERs, has enough measurements to technically achieve full observability. The challenge with this is that the data is owned by multiple stakeholders, and the information is typically on different communications systems, and is not accessible to any one control system. This is especially true of customer data and data that is measurement and collected by third parties.

Despite the lack of real-time observability, distribution systems have still been able to be operated. This is because the circuits were designed based on predicable behavior of the end-use loads and measured peak loads. Specifically, utilities have estimates for the peak and annual energy consumption for various types of end-use loads, and based on this they design the individual circuits. By knowing the peak load of the of the system, line, cables, and transformers are selected so that the voltage will stay within the accepted range. This approach is less effective as the grid edge becomes more engaged.

3.1.2 | Controllability

Figure 3.4: Recloser on the primary distribution level with remote control capabilities.

Controllability refers to the ability to affect change on the system states [24]. For an electric power system this can include operations such as changing the output on a generator, operating a breaker to change the system topology, or switching in a shunt capacitor for voltage support. In early electric power systems operations were typically manually, with system operators dispatching field crews. While field crews still manually conduct many operations, the increased deployment of communications infrastructure has enabled an increased array of remote controllability.

Direct controllability refers to the ability to take direct action that produces the desired result. For example, the distribution operator uses the ADMS interface to the SCADA system to issue a command that results in a recloser changing its position. Indirect controllability refers to the process by which a series of indirect actions leads to the desired results. For example, a utility issues a request to a third-party aggregator to reduce load during a high demand period. The aggregator then issues its control signal to the participants in its program, such as thermostats or EVs, which results in the desired reduction in load.

While system operators have historically relied on direct control, the devices at the grid edge offer a new level of technical capability. However, because many of these devices will be owned by the type of stakeholders discussed in Section 2.4, it will be necessary to determine the relationships between the various stakeholders and develop processes and procedure by which they can interact with one another.

3.2 | GRID SERVICES AS A BRIDGE BETWEEN THE GRID EDGE AND THE UTILITY

For a system with observability and controllability, it is necessary to define the necessary grid services. The grid services are explained in detail in Appendix B, but they include energy, regulation, frequency response, voltage management, reserves, and blackstart. These six services are the basic services needed to operate an electrical power system. But beyond that, they also provide the framework by which devices and systems on the grid edge can interact and/or support the electrical infrastructure. Specifically, by providing well defined electrical, timing, and performance requirements, the grid services approach provides for a formal structure to engage the grid edge, bridging the gap between the needs of the systems and the capabilities of the grid edge devices and systems.

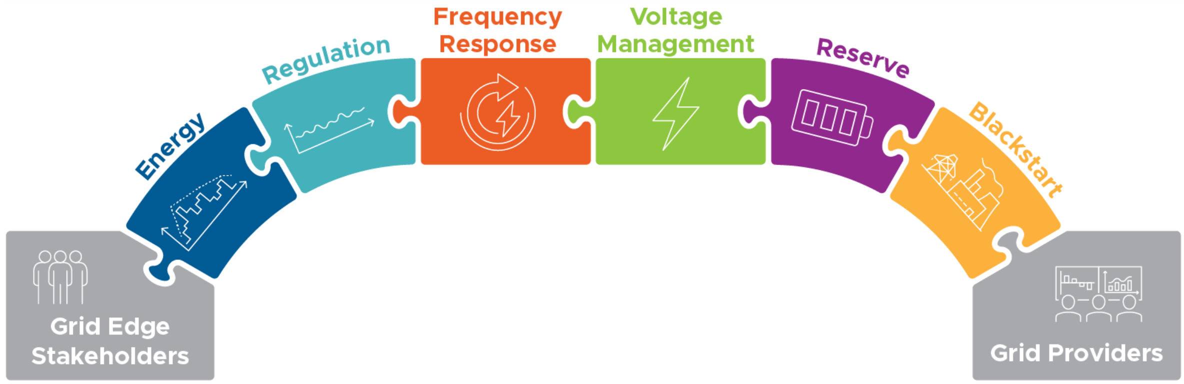


Figure 3.5: Grid services forming a bridge between the grid edge stakeholders and the grid providers.

3.3 | RELATIONSHIPS FOR EACH OF THE GRID SERVICES

The grid services of the previous section described the services at a requirements level, without discussions for how a specific implementation might be achieved. Specifically, there in no requirements as to how the services are obtained. For example, a system operator might decide to internally provide all six services, or they might contract with another provider for some portion of one or more of the services. When there is an engagement with another provider for a service, the relationship with the grid edge must be considered. In Section 2.4 it was discussed how the relationship between the utility and the various stakeholder would be different than the previous bilateral relationship between utility and customers. In fact, for each of the six relationships there could be a different set of relationships.

For both the system operators and the grid edge stakeholders, evaluating the options for how obtain or and plan for grid services, or how to participate as a service, can be a complex task. To deal with this level of complexity grid architecture has shown to be an effective tool.

4.0 | Architecture as a Tool to Obtain Services for Reliability and Resiliency

In a power system with an actively engaged grid edge there are a number of decisions that stake holders need to make. System operators, meaning the utilities, need to determine if they will obtain the necessary grid services internally, or if they engage the grid edge for some portion of them. For the grid edge stakeholder, they need to determine if participating in one or more grid services is possible with their devices and/or systems capabilities, and if it is well aligned with their business and operational goals. It is the grid services that serves as the bridge between the system operator and the grid edge stakeholders.

These decisions need to be made on both the operational and planning time frames. For a utility it means that they have to have an operational plan in the near-term for obtaining the services necessary for anticipated conditions. In the planning timeframe, the utility must make mid and long-term determination if they will invest in the capital projects necessary to provide all of the anticipated services they will need, or if they will only secure a portion and plan on engaging grid edge stakeholders for the rest.

Grid architecture is a tool that can be used to help manage complexity and risk [26], [27]. A first step in the use of grid architecture is to examine how reliability and resiliency are evaluate when services are obtained through a combination of direct and indirect methods.

4.1 | DIRECT VS. INDIRECT RESOURCES

With respect to reliability and resiliency, a system operator needs to determine if they will obtain the necessary services internally through direct resources and capabilities, or indirectly through grid edge resources. Using the energy grid service as an example, Figure 4.1 shows a conceptual example of a predicted peak load over a 24-hour period, the uncertainty of the load estimated, and the direct and indirect energy resources available.

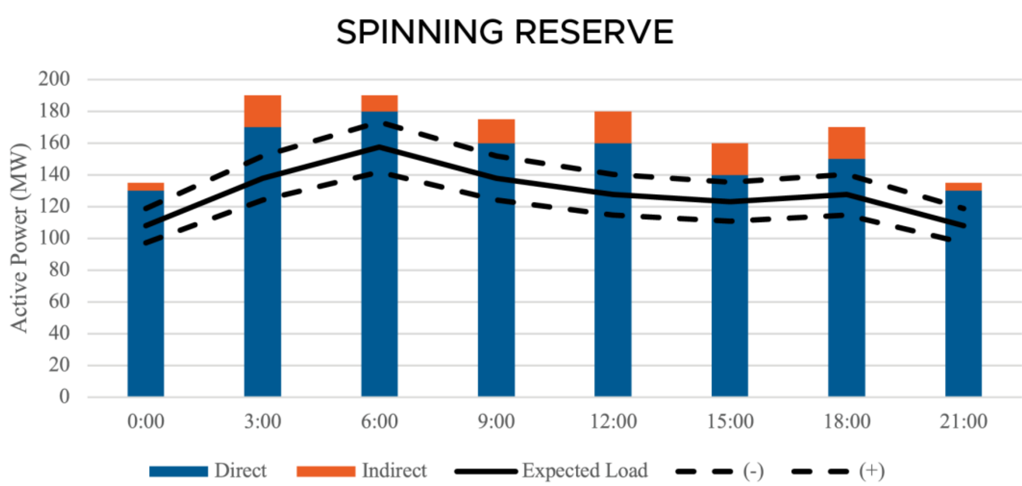


Figure 4.1: Spinning reserve, with uncertainty lines, along with available direct and indirect resources. In this case, the required spinning reserve, including maximum uncertainty, can be met with direct resources.

For the conceptual values shown in Figure 4.1, direct and indirect values are stacked for each time period to show how the available resources compare to the expected peak load as well as a band for estimate uncertainty. In this case, it is possible for the utility to meet the expected peak load exclusively with direct internal resources even in the extreme error estimates, and reflects historical operating approaches,

In contrast to Figure 4.1, Figure 4.2, show the same level of expected reserves needed, and while there are sufficient direct resources to meet the load if the estimate has no error, the upper end of the estimate error cannot be meet exclusively with internal resources. In this case, the system operator needs to evaluate the confidence in the peak load prediction error and determine if indirect services should be secured.

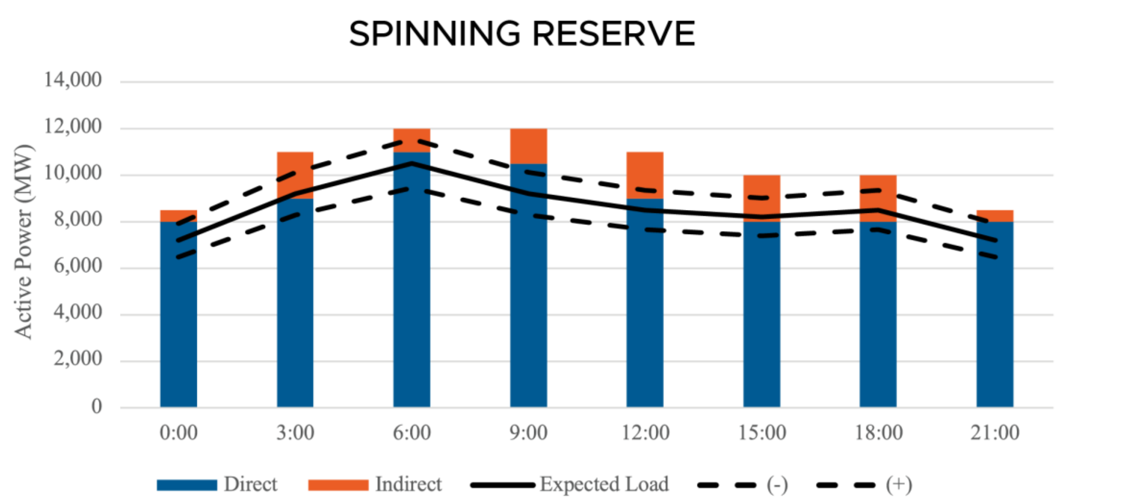


Figure 4.2: Conceptual expected peak system load, with uncertainty lines, along with available direct and indirect resources.

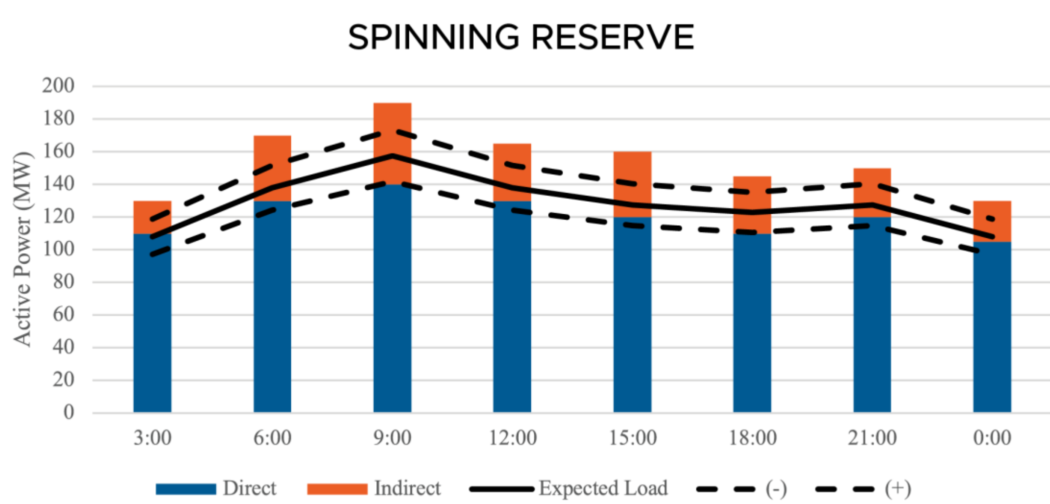


Figure 4.3: Spinning reserve, with uncertainty lines, along with available direct and indirect resources. In this case, the required spinning reserve, including maximum uncertainty, can be met with some level of indirect resources.

While the case in Figure 4.1 has sufficient reserves and Figure 4.3 does not, both cases could potentially engage indirect resources if the utility chose to do so. The selection between direct and indirect resources allocation is a selection that the system operator needs to make based on available resources, costs, and willingness to engage outside resources. For the data shown in Figure 4.3, it is almost certain that the system operator would need to rely on indirect services.

4.2 | QUALIFICATION OF INDIRECT RESOURCES

With respect to reliability and resiliency, an indirect resource must be “qualified” before it can be used. The exact definition what constitutes qualification will vary, but there must be a verifiable capability to meet power and/or energy requirements, over a defined timeframe, with acceptable ranges of uncertainty. For example, if a third-party aggregator is going to use a population of residential BESS units to provide a spinning reserve service, there must be a verification of the power level that can be output, how long the output can be maintained, and an assurance that the resources will be available when called on. If any of these cannot be verified, then the service cannot be relied on for a service that is essential to reliability and resiliency.

4.3 | EXAMPLES OF DIRECT AND INDIRECT RESOURCES MIXES DURING DIFFERENT ERAS

There has always been a need for the technical capabilities represented by the services introduced in Section 3.2, and discussed in detail in Appendix B, to ensure that electric power systems operate reliably. While the name and method of obtaining these services have changed at different points in time, their need has never changed.

4.3.1 | 1882-1900: Small Local Systems

The earliest electric power systems were small isolated microgrids [1], initially direct current and then eventually alternating current. Because of the relatively low voltages (≈120-480 V), these systems were small, with multiple systems required for a single city. Similar to modern systems, they were capital intensive businesses, but they were not able to take advance of economies of scale that make modern systems so effective.

In this era, energy services were typically provided by local small local steam units (≈10-100 kW), fueled by wood or coal, suppling loads that were within a radius of a few miles at the maximum. In some remote areas, hydroelectric was an option, but typically not in urban environments. Reserves were typically supplied by a single company, meaning that they would need to have extra units running in case of a generator failure. Regulation was provided by the small number of units, controlled by a manual human operator. Frequency response was controlled by automatic mechanical steam governing devices on the units. Voltage management was achieved by manual operator actions at the generating units. Blackstart services were manual operations where the power plant operator would place a unit back in operation, and crews would manually operate switches in the system as necessary to restore power after a fault.

4.3.2 | 1900-1930: Regional Systems

With advances in technology, the individual systems were interconnected via increasingly high AC voltage lines (≈30,000 V) [2]. The higher voltage AC lines allowed for the interconnection of larger generating units and remote areas, such as Niagara Falls, and for populations centers to share resources.

In this era, energy services were provided by local and remote larger steam units (≈250-10,000 kW), fueled by wood or coal, suppling loads at the regional level. In some remote areas where hydroelectric was an option, the units were interconnected with higher voltage AC lines to regional systems. Reserves were typically supplied by multiple companies, sharing resources across the region. Regulation was provided by a small number of units, through a combination of early mechanical automation and a human operator controlling the designated regulation unit(s). Frequency response was controlled by automatic mechanical steam governing devices on the units implanting droop type controls [28], typically using early flywheel type mechanisms. Voltage management was achieved by manual operator actions at the generating units. Blackstart services were manual operations, coordinated via telephone, where the power plant operators would place units back in operation, and crews would manually operate switches in the system as necessary to restore power after a fault.

4.3.3 | 1930-1980: Interconnected Bulk Power System

With continued advances in technology, the individual systems were interconnected via increasingly high AC voltage lines (≈230-765 kV). The higher voltage AC lines allowed for the interconnection of the entire continental United States into three synchronous areas, with high voltage direct current (HVDC) ties.

In this era, energy services were provided by larger central generating facilities (≈250-1,500 MW), fueled by oil, natural gas, coal, nuclear, and hydroelectric. While utility scale wind and solar were not commercially available at this time, they were in the research and development stage. Reserves were typically supplied by multiple companies, sharing resources at the interconnection scale. Regulation was provided by a small number of units, through the use of coordination signals such as automatic generation control (AGC) [28]. Which did not require a single unit to be designed as the regulation unit. Frequency response was provided by electromechanical governors implementing droop characteristics. Voltage management was achieved by automatic control on generating units, manual and remote control of shunt capacitors and inductors at the transmission level, and manual and automatic control of shunt capacitors and volage regulators at the distribution level. Blackstart services were still manual operations, coordinated via telephone, where system operators at the balancing authority (BA) level would coordinate operations BAs, in coordination with large generating units.

4.3.4 | 1980-2020: The Smart Grid

In this recent era, the voltage level of transmission systems leveled off as did the size of central generating units. Advances in materials and power electronics enabled the increased deployment of DG, primarily in the form of wind turbine generators and solar PV. Additionally, advances in computing, controls, and power electronics enabled increased levels of automation and the widescale deployment of solid state and microprocessor-based technologies [29].

In this era, energy services were still primarily provided by large central generating units, but in some regions DERs were a significant portion of the generation mix at times. Reserves were supplied by multiple companies, sharing resources across the region. DERs were not active participants in providing reserve services. Regulation was provided by a small number of large central units, through the use of coordination signals such as automatic generation control (AGC). Frequency response was controlled by automatic mechanical governing devices on the units, but DERs began to have frequency response requirements as part of approved standards [9]. Voltage management was achieved by automatic control on generating units, manual and remote control of shunt capacitors and inductors at the transmission level, and manual and automatic control of shunt capacitors and volage regulators at the distribution level; because of the increased communications infrastructure automation and coordination of voltage regulation devices was significantly increased from previous eras. Blackstart services were still manual operations, coordinated via telephone and computers, where system operators at the BA level would coordinate operations Bas, in coordination with large generating units.

4.3.5 | 2020-2050: The Engaged Grid Edge

While concepts are still evolving, this era will likely be characterized by a transition away from a system that relies only on large central generating units, with utility entities being the sole provider of grid services. A primary difference from the previous eras is an active grid edge where new devices and systems, along with new stakeholders, have fundamentally changed the way power is produced, moved, and consumed. This system makes extensive use of continually evolving computing capabilities, power electronics, and communications systems,

In this era, it is expected that up to 30% of the energy services will be provided from the grid edge, with legacy centralized systems still being critical for reliable and resilient operations. Reserves will be provided by legacy central units as well as from devices and systems at the edge. A primary difference will be that reserves provide by the edge will often be from providers other than the utilities, requiring new relationships between the stakeholders to properly manage role and responsibilities. Similar to reserves, regulation could be provided by a mix of centralized units and devices and systems from the edge. The system operator will still have to coordinate with a system such as AGC, but the edge could be an active participant. Frequency response will continue to be required from all units that provide energy services, centralized and grid edge devices and systems, but there may also be requirements for the response of power electronic connected loads as well as other power electronic devices on the system. Voltage management will still continue to include traditional devices and systems, but it will also include edge resources. This could include microgrids, VPPs, third party aggregators, and new stakeholders such as fleet EV charging stations. Blackstart services will evolve to supplement the traditional “top-down approach” with a coordinated “bottoms-up approach”. This will entail the centralized restoration of the bulk power system in coordination with the restoration and recovery from the edge using DERs and microgrid technologies.

4.4 | EXAMPLE ARCHITECTURAL USE-CASE

The previous sections discussed how the fundamental grid services been obtained in past eras, as well as how they might be obtained from the grid edge in the future, From the perspective of a system operator, they must determine what is the best way to obtain services for their system to ensure that it is reliable and resilient, while managing costs. Because future systems will include not just a range of new devices and systems, but also new stakeholders who can potentially provide services, there will be a wide range of options available.

Because of the complexity of these options, grid architecture is a tool that can be used to support decisions about obtaining the necessary services. This section will examine a relatively simple case where grid architecture concepts can be used to evaluate the potential options to secure the required services. For this example, the work of the DOE funded Citadels project will be used [20], which examined approached for the deployment of networked microgrid to support normal and abnormal operations.

4.4.1 | Use-case Background

The Citadels project addressed the increasingly common challenge of coordinating large numbers of DERs to support the operations of the electric power system. While systems such as DERMS can centrally dispatch DERs, there are practical limits to the number of DERs that can be integrated: the central approach limits operational flexibility in a mixed ownership environment and the DERMS represents a single point of failure. While microgrids have been shown to be an effective way to aggregate the operation of multiple DERs, independently or in coordination with resiliency functions, centralized coordination still limits their full capability. These challenges can be seen in utilities such as the Electric Power Board of Chattanooga (EPB) where microgrids are being deployed to coordinate the operation of DERs and for resiliency purposes. The specific challenge for EPB is to develop methods and approaches to coordinate the operation of numerous mixed-ownership microgrids to support normal and abnormal system-level operations.

The approach developed, deployed, evaluated, and validated in the Citadels project utilized Open Field Message Bus (OpenFMB) to implement a layered control system that increased operational flexibility by facilitating a level of control at the system “edge”. At the edge, consensus algorithms were deployed as containerized applications to allow groups of microgrid controllers to communicate, exchange information, determine operational goals, and execute operational actions to achieve global objectives. Figure 4.4 shows an architectural diagram of the Citadels concept, which focuses on the operation of microgrids, both utility and non-utility owned.

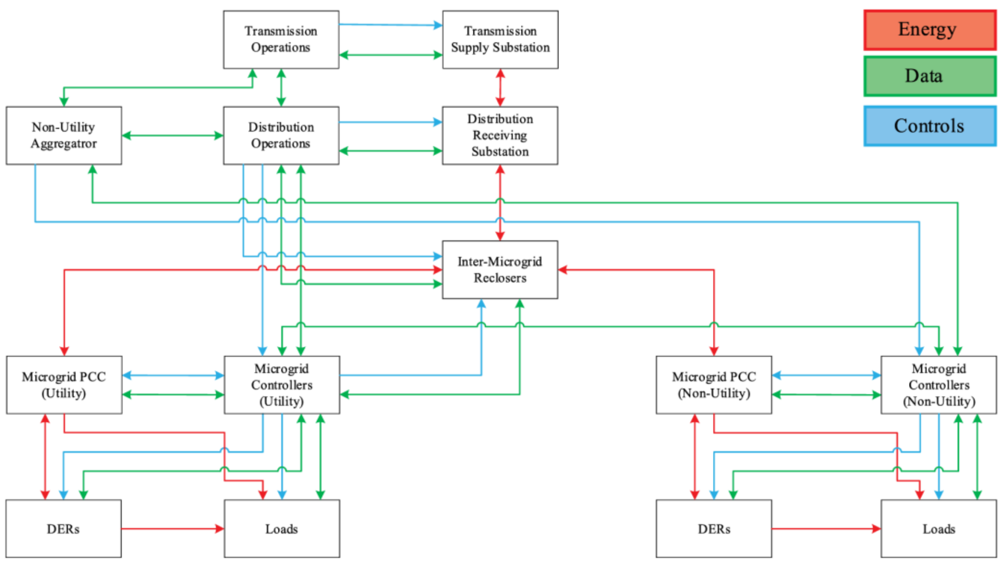


Figure 4.4: Example architecture from the Citadels project.

In the architectural diagram of Figure 4.4, the individual elements are connected by three types of lines, each indicating a different type of interaction. First, the red lines indicate the flow of electricity between entities or devices. Second, the blue lines indicate data/information flow between entities and/or devices. And third, the green lines indicate control signals. While the Citadels project examined the operation of networked microgrids, the architectural figure can also be used to examine options for obtaining grid services. In particular, evaluating the options for how services could be obtained, directly or indirectly.

4.4.2 | Use-case Example to Determine Direct vs. Indirect Resources

In Figure 4.4, the stakeholders represented are the transmission utility, distribution utility, and non-utility aggregators. Additionally, utility and non-utility microgrids were included because the Citadels project examined the use of networked microgrids to support normal and abnormal operations. For this use-case, the architecture shown in Figure 4.4 is used to evaluate between two options of obtaining grid services. The first option is to obtain the desired service, voltage in this case, directly from the microgrids, with the second option being to obtain it indirectly.

From Figure 4.4, it can be seen that the distribution utility has data and control connections, green and blue respectively, to the utility microgrid controllers, but not to the non-utility microgrid controllers. As such, there is the technical potential to obtain voltage services directly from the utility owned microgrids, but not the non-utility owned microgrids. It would be possible to deploy new data and control connections, but ownership issues would likely prevent the utility from directly controlling an assert they do not own. Another option would be to use a combination of the utility owned microgrids, and to leverage the existing data connection to the non-utility aggregator to indirectly engage their microgrids to obtain the needed voltage service.

With this information obtained from the architectural diagram of Figure 4.4 the utility would need to evaluate the business case considerations for the three possible options to supply the needed voltage services. Direct control of the microgrids they own and operate, installation of new devices and systems to directly control microgrids they do not own, and leveraging the existing connection with the third-party aggregate to indirectly obtain the services.

The following sections contain the concluding comments for this white paper and areas for suggested next steps to advance the use of grid services and grid architecture to ensure reliable and resilient engagement of the grid edge.

5.0 | Concluding Comments

This white paper has outlined how grid services and grid architecture can be used as tools to ensure that reliability and resiliency are maintained as the grid edge continue to evolve. This includes addressing not only the range of new devices and systems that are being deployed, but also the relations and interactions between them. While this white paper has outlined the basic concepts and approach, significant work is still needed to mature this into tools and capabilities that can be used by the range of stakeholders involved with the grid edge.

5.1 | Suggestion Action Areas

In order to mature the structure and use of grid services and grid architecture, work in the following areas in needed.

- Categorize the new stakeholders/actors that are interact with the grid edge, including individual types and classes.
- Define grid services and their specifications. This includes an evaluation if the current list is sufficient and how to address uncertainty in service procurement.
- Identify locational elements of various grid services, such as voltage and black start.
- Identify how grid edge concepts can be integrated into regional level planning and operations.
- Define how to qualify resources as a grid service, and how to quantify value. Similar to an IEEE or other industry body standard.
- Define how to contract for grid services. Both from the utility and grid edge stake holder perspectives.
- Develop a framework for how to map various devices and systems to individual grid services they could support. This might be a subset of previous bullet.
- Make grid architecture easier to use for evaluating direct and indirect evaluation options. Extend the work being done on grid services and contracts and include use-cases that directly address understandable utility challenges.

Appendix A | Detailed Description of the Changing Characteristics of the Grid Edge

As previously discussed, the grid edge has historically been a passive portion of the nation's electrical infrastructure, with the relationship between the electric utility and the customer being bilateral. The importance of the grid edge is increasing as move devices and systems are deployed at this level, and the relationships between an increasing number of stakeholders becomes more complex. The following sections examine changes in supporting technologies, the new devices and systems being deployed by both customers and utilities, and the complex relationships between the various stakeholders.

A.1 | ENABLING TECHNOLOGIES

Changes in technology drive change in society at all levels, including the electrical infrastructure. Three areas of advancement that are enabling significant change at the grid edge are power electronics, improved computing capabilities, and communications infrastructures [29]. These advancements are accessible to all stakeholders, provide new capabilities and options to end-use customer, utilities, and others.

A.1.1 | Power Electronics

Prior to power electronics, generation sources required a rotating machine to interconnect to the system. The first large scale power electronics to be deployed on electric utilities were thyristor-controlled devices at the high voltage direct current (HVDC) station at the Eel River Convert Station in New Brunswick Canada, in 1972 [30]. This was the first deployment of a fully solid-state facility, moving away from th previously generation of mercury arc valves. Since 1972, multiple large-scale power electric based HVDC stations have been either converted or commissioned in the United States. Figure A.1 shows an example of an operational HVDC gate stack.

Figure A.1: Operational high voltage direct current gate stack.

In addition to HVDC applications, power electronics have been introduced throughout the nation's electric infrastructure. This includes, but is not limited to, flexible alternating current transmission systems (FACTS) devices, variable frequency motor drives, electric vehicle charging stations, and inverters for DERs. Utility scale DERs are typically connected at the medium voltage distribution level, which typically ranges from 4.0 kV-34.5 kV, with residential and commercial scale DER connected behind the meter at 240V or 480V respectively.

In addition to the ability to convert between AC and DC, and vice versa, power electronics can implement a range of control functions. While the controls in a variable frequency drive for a residential heat pump will only adjust the power consumption to optimize performance, an inverter can inject power into the distribution system. Additionally, the injection of power, both active and reactive, can be controlled in multiple ways. For traditional "grid following" inverters, a utility provided voltage source is necessary to maintain a stable frequency and voltage [8]. Inverters can also implement "grid forming" control which allow them to independently maintain a stable frequency and voltage, supporting stand-alone islanded operations. Control capabilities can range from adherence to IEEE-1547 [9] to being integrated into a larger control scheme. Regardless of the specific controls implemented, modern power electronics make it possible to interconnect a range of devices to the electric infrastructure.

A.1.2 | Computing Capabilities

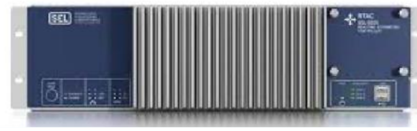


Figure A.2: Example microprocessor relay with multiple computing cores.

With currently available commercial products, it is possible to have computing capabilities at almost any point in an electric power system. Behind the meter, residential homes are full of personally owned computers and devices with significant computing capabilities. At the interface between the end-use customer and the distribution utility is a revenue grade meter, which is able to do far more than just calculate energy consumption. Currently available meters can integrate into larger MDMS and AMI, as well as having the ability to locally support computational functions. For some models, these functions include the ability to locally run applications.

Modern micro-processor-based relays can be deployed at the substation level, or on a distribution circuit, and can be equipped with multiple processors. The relay shown in Figure A.2 is the Schweitzer Engineering Laboratories (SEL) Real-Time Automation Control (RTAC), but there are numerous other vendors with similar products.

Figure A.3: Frontier supercomputer at Oak Ridge National Laboratory.

In addition to the relays and computing capabilities directly deployed on a utilities ICS, larger central resources can be accessed from a number of locations. These computing resources can range from local resources to near real-time cloud-based services such as Microgrid's Azure and Amazon's (AWS). Additionally, large centralized super computing capabilities can be used for off-line analysis. Currently, the world fastest supercomputer, Frontier [13], is located at the Oak Ridge National Laboratory (ORNL) and has been used to conduct power system analysis. An image of the Frontier supercomputer at ORNL can be seen in Figure A.3.

While the development and engagement of the grid edge is not uniform across the nation, where it is advancing is due in part to the leveraging of computing capabilities.

A.1.3 | Communications Infrastructure

The ability to locally processes data provides technical potential, but the ability to move data to other locations, enabling the combination of information, provides significantly more potential. Behind the meter, many end-use customers (residential, commercial, and industrial) have their own networks. For the 2900+ electric utilities in the country, it is not uncommon for a utility to have fiber optic communications to major, or all, substations with RF and/or cellular to devices on the distribution circuits; with revenue meters connected to an AMI system.

A.2 | MULTI-STAKEHOLDER DEVICES AND SYSTEMS

Enabled by the technologies discussed in Section 2.1, new devices and systems are being deployed by traditional end-use customers, a range of new and emerging stakeholders, and electric utilities. Additionally, the traditional bilateral relationship between the utility and customer is changing into an environment where there are numerous stakeholders interacting with the customers, utilities, and each other, in ways that are still evolving.

A.2.1 | New End-use Loads (Building Electrification and Electric Vehicles)

Modern society is becoming increasingly dependent on electricity, and this can be seen in the amount and types of end-use loads that customers are installing. As the residential level, customers are electrifying a range of functions that were once supplied by other energy sources. The two primary examples of this are heat pumps and electric vehicles. Figure A.4 shows a picture of a modern 3-ton heat pump, with emergency resistive heating strips as a retrofit installation. While the heat pump is a high efficiency unit, the peak electrical load in heat pump mode is approximately 3.5 kW, and 15+ kW when the resistive heating elements are all energized. As a result, during continual operation the unit represents a moderate load with a high duty cycle, running 90% of the time in cold weather, but can be a very large load if the backup heating strips are energized.

Figure A.4: 3.0 ton residential heat pump retrofit on a 100+ year old house.

Residential level II EV charging can be up to an 8 kW load that remains constant for 8-10 hours. Figure A.5 shows an example of level II charging. At this power level, an EV can easily be one of the largest loads in a house. While residential charging typically occurs at night when system load is typically lower, commercial charging can be during the day and/or at nighttime. At the distribution level, this represents a fundamental change in the load profile and has the potential to even change the peak load from a daytime peak to nighttime peak. Additionally, since EVs do not typically need to be charged every day, the load profile will change depending on a range of factors that are not easily estimated. While it is possible to generate estimates for populations of EVs, for any specific vehicle it will be more challenging. For commercial charging, the change in load profile will depend on the type of facility. For an office building, the charging will likely occur during the day while people are working. But for a facility such as a fleet charging depot, there could be heavy charging during the evening, and possibly even during the day. In either case, the charging patterns could change based on the commercial business needs, which may not always be information that the system operator has access to.

Figure A.5: Level 2 charging of an electric vehicle.

While the vast majority of EV chargers only provide power to the EV, referred to as V1G, there are numerous plans to engage EVs with bidirectional flows so that they can feed power back into the grid, V2G. These schemes could include direct load control as well as incentive-based schemes. Regardless, of the specific control mechanism, because of the size of batteries used in EVs, and the large numbers of EVs, they represent a technical potential to the system that a range of stakeholders are evaluating.

A.2.2 | End-use Generation (Solar Photovoltaics)

In addition to changes in the load profile of the end-use customers, there are stakeholders that actively inject power into the power system. At the grid edge, the most common form of DG is PV. While it is possible to connect WTGs at the grid edge, it is rarely done because of siting and permitting issues. Similarly, diesel generators are commonly interconnected at the grid edge, but typically they are only used in backup power applications. This type of generation is commonly used to meet backup requirements at hospitals [14]. While backup diesel generators have been used for some market functions [15], they are not typically deployed solely for that purpose because of siting, permitting, and emission issues.

Figure A.6: Commercial solar PV facility.

Solar PV can be deployed at the residential level, at the kW scale, or at the commercial level, MW scale. Figure A.6 shows an example of a commercial solar PV deployment in the Northeast United States,

The injection of active power from newer solar PV inverters is typically in accordance with IEEE std 1547 [9], but many units have the potential to also inject reactive power. While the inverters currently being deployed have substantial technical potential to support system operations, they currently do not do so outside of IEEE std 1547. Similar to EVs, distributed solar PV represents a significant technical potential to offer grid services to the grid, in addition to the energy provided, but is typically not engaged.

A.2.3 | End-use Battery Energy Storage Systems

Figure A.7: Commercial residential battery storage.

In addition to connecting generation sources, inverters, both grid-following and grid-forming, can interconnect battery energy storage systems (BESS) at the grid edge. Units commercially available are modular in size allowing for a set power level and a range of storage capacities. Currently, the most common battery chemistry is lithium-ion because of its energy density [16], but a range of other chemistries are being explored by researchers and industry. Similar to solar PV, residential units are kW scale and commercial units tend to be at the MW scale. BESS systems are sometimes paired with solar PV so that the two can be used to shape the combined profile, mitigating some of the variability issues of solar PV.

When couple with a grid forming inverter, a residential BESS can provide resiliency benefits by supplying power when there is a disruption in the local electric distribution system.

Similar to electric vehicles, residential BESS are a resource that represents a large technical potential for the system. While an individual unit may only be a few kW and tens of kWh, collections of multiple units operated in coordination with other units, can form a resource that can affect system operations. This will be discussed additionally in Section 2.4

Figure A.7 shows and example of a 5 kW, 15.5 kWh, unit. This particular example is the Tesla Power Wall 2 [31].

A.3 | NEW UTILITY DEVICES AND SYSTEMS

Similar to the end-users, the technologies discussed in Section 2.1 have enabled distribution utilities to deploy a range of new devices and systems at the grid edge.

Figure A.8: Single-phase residential meter.

A.3.1 | Advanced Sensors and Communications

One of the earliest "smart grid" technologies deployed by distribution utilities were the smart meters associated with AMI systems. One of the primary reasons for this was because of the lack of observability at the grid edge. While AMI typically does not give complete real-time visibility of the grid edge, it can provide time-delayed complete data sets, as well as real-time select measurements. The complete data sets are used for revenue purposes and have the potential to provide off-line analytics. Operational systems, such as OMS and VVO applications can make use of individual meter reads that can be obtained in real-time.

Modern AMI systems, and the associated smart meters, are enabled by a combination of advanced computing capabilities and communications infrastructures. The first generation of smart meters had the ability to measure active power, reactive power, and voltage magnitude. The current generation has the ability to run independent applications on the meter, leveraging local measurements as well as data from other meters.

Currently, communications infrastructures limit the frequency at which data can be collected. Typically, a complete read of all system meters is done once or twice a day, with a limited ability to pole a small subset of meters for real-time values.

A.3.2 | Distribution Automation and Control

Distribution automation is a broadly used term that can refer to a range of technologies, including, but not limited to, remote breaker/switch operation, capacitor and regulator automation, coordinated reclosers and sectionalizers, as automated systems such as FLISR. The key characteristics of these technologies often include local sensing, computing capabilities, and communications systems.

Figure A.9: Three-phase recloser on primary distribution system.

DA systems can be automated stand-alone devices and/or collected of integrated devices. Integration can be at the device-to-device level, and/or with larger centralized control systems such as a DMS.

A.3.3 | Utility Scale Battery Energy Storage Systems

The BESS units previously discussed are deployed behind the customer meter, 120/240V, and are typically kW/kWh or tens of kW/kWh in size. Utility BESS is connected at the primary distribution level voltages, 4.0-34.5 kV, and rated in the MW/MWh size. Despite the differences in power, energy, and interconnection voltage, both are part of the grid edge. While customer units are typically deployed for local benefits, utility scale units are deployed to support distribution circuit level considerations.

Figure A.10: Utility scale BESS.

The unit shown in Figure A.10 is a 2 MW, 4.4 MWh Li-ion battery that is deployed adjacent to the distribution substation. The unit was deployed in 2015 to provide backup power to a remote city, and to provide peak load reduction and balancing services during normal operations [32]. Because of the unit's ability to operate independently it can also be considered a stand-alone microgrid.

A.3.4 | Advanced Distribution Management Systems and Distribution Energy Management Systems

Because early electric distribution systems were manually intensive operations, the deployment of early sensors and DA systems required stand-alone control systems. Specifically, because distribution operations were manual processes that centered around physical "mimic boards" and operators talking with crews in the field, there were no central systems to coordinate the new systems with. DMS and later with ADMS coupled with DERMS began to address this. The orignal EMS systems were centered around utility systems and utilize SCADA systems to bring data from remote sensing to a control center, and to allow operators at the control center a level of control of field devices. DERMS systems were designed to specifically integrate distributed resources such as solar PV and BESS. Later, ADMS was developed as a way to integrate DMS, DERMS, OMS, AMI, and other systems into a single control system. While the exact names of systems, and their capabilities, varies between vendors, these systems represented the first generation of command and control for ICS at the grid edge.

A.4 | THE CHANGING RELATIONSHIP BETWEEN DEVICES AND SYSTEMS ON THE GRID EDGE

As important, if not more important, than the devices and systems being deployed by utilities and other stakeholders at the grid edge, is the relationships between them, including the actors involved This includes not just the communications and control relationships, but also the business and regulatory relationships.

Historically, the relationship between the grid edge and the utility has been bilateral. As shown conceptually in Figure A.11, the utility representing the centralized grid system, and the end-use customers at the grid edge interacted with the system exclusively though the utility. The utility provided the electricity at a regulated rate and the end-use customers purchased directly from them, typically at a flat rate independent of time of day. This

Figure A.11: Traditional bilateral relationship between the distribution utility and the end-use customers.

type of bilateral approached worked well when the only actors were the utility supplying the electricity and the customers who consumed the electricity. In fact, the recognition that electric distribution systems are a "natural monopoly" is exactly why this relationship replaced the early systems where there could be multiple distribution systems in a single area. This type of competition led to duplicative infrastructure, which was expensive to build and maintain, and was not in the best interest of the end-users.

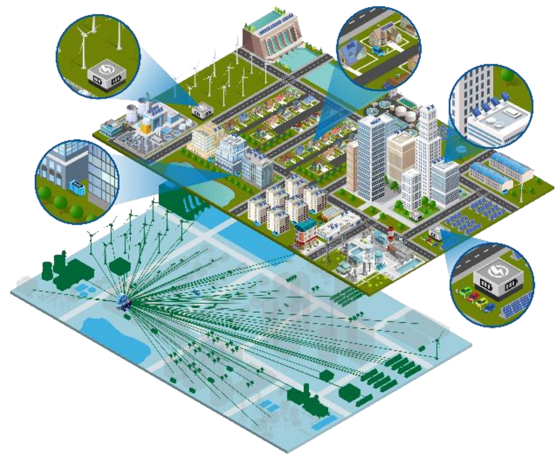


Figure A.12: Traditional bilateral relationship extended to the range of new services and system at the grid edge.

While it would be conceptually possible to extend the centralized bilateral approach to the range of new devices and systems discussed in Section 2.0, and as conceptually shown in Figure A.12, this approach would face significant scalability and complexity challenges because of the large number of devices and the mixed-ownership environment. In particular, it would not be practical, or even feasible, for every new customer EV and BESS to be integrated into the utility ADMS and/or DERMS.

Figure A.13: New relationships needed for the range of new devices and systems at the grid edge.

Instead of the centralized approach shown conceptually in Figure A.12, effective engagement of the grid edge will require a departure from the historic bilateral relationship between the utility and the edge. Because the new technologies discussed in Section 2.0 will be owned by an array of stakeholders, new relationships will need to be established. And while it is expected that the utility will retain responsibility for the reliability and resiliency of the grid, there new stakeholders, and their grid edge devices, will need to be integrated.

If the new stakeholders can be effectively coordinated with the utility, then they will become a resource to support reliability and resiliency. If they are not effectively coordinated, then reliability and resiliency could degrade. To better understand what the new relationships might look like, it is necessary to examine what some of the new stakeholder entities look like.

A.4.1 Microgrids

A modern microgrid is a collection of generation assets, end-use loads, interconnecting distribution lines, and the control and communications systems that enable safe and reliable operations. Typically, they are 10 MW or less in size and operate at medium voltage levels, 4.0-34.5 kV, but these are not a strict requirement [17]. Microgrids can be interconnected to a bulk power system or can operate in a stand-alone mode, such as when they are the primary power source for a remote Alaskan village or island community. When grid connected, a microgrid can serve as a point of aggregation and control for a large number of renewable resources, controlled locally or connected to an ADMS and/or DERMS systems. When islanded, a microgrid operates as a self-contained power system with local controls that allow for operation during outages of the bulk power system. In addition to grid connected and islanded, there is ongoing research around the concepts of networked microgrids [19]. In networked microgrids the idea is that groups of microgrids coordinate their operations, even when there is mixed ownership between microgrids, to achieve common global objectives. When grid connected the common objective can be to support the bulk power system during extreme events. If there is a loss of the bulk power system, the microgrids can coordinate their operations and self-assemble to support critical end-use loads. Networked microgrids are still an area of active research and are not widely deployed [20].

Figure A.14: Example image of a microgrid control interface.

Microgrids can be owned and operated by a utility, a community, university, private company, or the military. Because microgrids may not be owned by a traditional customer, they represent a different relationship between the edge and the utility. Instead of a unidirectional flow of power and a monthly billing cycle, the microgrid represents a dynamic actor that can produce or consume energy, impacts the utility voltage control and protection systems, and has the technical potential to support key system operating requirements.

A.4.2 Third Party Aggregators

While a microgrid has the potential to coordinate the operate a number of DERs locally, the concept of a third-party aggregator is to control a large number of devices that can be over a larger area. The central idea being that any single device may not be a significant resource, but if hundreds or thousands can be aggregated, they represent a large resource. For example, a third-party aggregator might enroll customers in a program to control residential heating thermostats; each of which communes 3-5 kW when in operation. In exchange for some level of compensation, each residential customer would allow the aggregator to adjust their thermostat setting within an agreed upon range. The aggregator can then work with the system operator to offer the service of controlling the aggregated load in a desirable manner. For example, during a heat wave the third-party aggregator can adjust the settings on thousands of thermostats to provide a reduction for a period of time. Aggregation schemes can also be implemented for electric hot water heaters, EVs, DERRs, storage, and a range of other equipment.

A.4.3 Virtual Power Plants

A VPP is similar to a third-party aggregator, except that it explicitly attempts to reproduce the performance of a generating unit using a number of smaller resources. For example, a collection of solar PV and batteries might be coordinated so that in aggregate they can provide the same level of dispatchable output as a single gas turbine unit. In addition to DERs, it is possible for a VPP to engage end-use loads and other behind the meter resources.

Appendix B | Detailed Description of Grid Services

This appendix contains summarized information from [23], which outlines the details for grid services.

B.1 | ENERGY SERVICES

The energy service is the basic mechanism for balancing the planned production and consumption of energy in the system to set up a reliable flow of power in the electric system. Scheduling the production and consumption of energy over time allows the system operator to balance energy use with generation to manage delivery limitations caused by power flow constraints as well as stressed periods of operation, such as system peak load management.

Wholesale markets arrange for scheduled blocks of energy to match anticipated loads. These blocks of energy are scheduled in many forms, including bilateral agreements between energy suppliers and energy users. They are also done in centrally managed markets, such as those run by independent market operators. In the wholesale situation, the price and quantity of energy delivery over the performance period is negotiated ahead of time with information provided to an independent system operator to ensure reliable system operation. The agreements also stipulate the penalties or fees for non-performance (over or under production and consumption).

Most independent system operators have real-time (5-minute to one hour) and day-ahead (next operating day) energy markets at the wholesale level. They also have real-time and day-ahead demand response energy scheduling programs for retail customers to be able to respond to wholesale electricity prices. Participants are compensated based on the amount of reduction made during the delivery schedule interval.

Description: A scheduled production or consumption of energy at an electrical location over a committed period.
Example service requestor operational objectives: System peak load management, balance energy use with production, and manage delivery limitations caused by power flow constraints.

B.2 | RESERVE SERVICES

System operators use spinning (fast responding) and non-spinning (slower responding) reserves to maintain a reliable balance of production and consumption of energy in the system. Bulk energy systems schedule blocks of energy reserves to support this need. Independent System Operators (ISOs) and Regional Transmission Operators operate wholesale markets to establish reserve resources. In the wholesale market situation, the price and quantity of power and energy available over the commitment period will be negotiated ahead of time with information provided to an independent system operator to ensure reliable system operation. Besides establishing a fee for being available (on reserve), the governing documents also stipulate penalties or fees for non-performance. They also establish the way a service provider will be compensated if the reserve is called upon. Reserve markets typically settle the amount of energy produced or consumed from a reserve service at the real-time market price.

While wholesale markets set prices for operating the resources, the owners agree to follow control instructions for their resources from the system operator during the operating period. In vertically integrated utility situations, generation reserve requirements are established, and generators are scheduled to be on-call to provide the service.

Demand-side resources also participate in many wholesale markets and are used like contingency reserves. That is, aggregated demand response providers may be called upon for various operating situations. They usually have longer contract intervals and notification periods. They may have stipulations on the maximum number of times they are called in a year or season. Their process for determining performance and settlement can be different than that of traditional generation reserve resources. The objective of defining a reserve service is to be agnostic to whether the service is provided by producers or consumers, as long as they meet the performance expectation.

Description: Reserves a specified capacity to produce or consume energy at an electrical location when called upon over a committed period.
Example service requestor operational objectives: System operations use the concept of reserves to address unplanned situations that regularly occur. These include contingency responses from line or generation equipment outages or derations that cause deviations from planned operations. Environmental events may also deviate from planned production from solar or wind-generator resources. These deviations may require fast-acting reserves (such as from synchronized generators) or slow response reserves (such as from non-synchronized generators that need several minutes to become available).

Depending on the operational situation, reserves may need to be available at different rates. For example, a weather forecast event may have one or more hours for reserves.

B.3 | REGULATION SERVICES

Historically, regulation service has been provided by large generator units. Generators often provide regulation services in conjunction with energy scheduling services. However, single, large-load, storage, and aggregated demand-side resources were also allowed to participate in the regulation service in some markets (e.g., at PJM and CAISO) in the recent decade or so (Pratt et al. 2021).

The resources providing regulation service must be able to respond to regulation signals sent by the system operator periodically, typically within one to several seconds (Zhou et al. 2016). Generators adjust their output up or down following the regulation signal; demand resources increase or decrease consumption based on a predetermined basepoint (Pratt et al. 2021). In some electricity markets in the U.S., separate products are offered for upward versus downward regulation services, for example at CAISO.

In PJM's market, the Regulation D signal is a fast, dynamic signal for quick responding resources, whereas Regulation A is a slower signal intended to help recover large, long fluctuations.

The term power mileage is used to describe the summation of power level movements up and down that a regulation service provider takes over the course of the delivery schedule. Mileage is a multiplier in the compensation calculation in some electricity markets. In addition, the mileage contained in service request signals can affect a resource's performance score in these markets.

Description: Continuously provides an increase or decrease in real power from an electrical location over a specified scheduled period against a predefined real-power basepoint following a service requestor's signal. The signal interval is typically one to several seconds, and the associated performance period is significantly shorter duration than the typical energy service performance period.

Example service requestor operational objectives: The regulation service is used to balance small fluctuations in supply and demand in real time (Zhou et al. 2016). In the frequency control continuum (NERC 2011), regulation service falls under the secondary control category; for example, once frequency drop has been arrested by primary control (in seconds), regulation service corrects the deviation (1–10 minutes) to the target value.

B.4 | FREQUENCY RESPONSE SERVICES

Frequency response service is used to stabilize frequency immediately following the sudden change in generation or load. It is a critical component to the reliable operation of an electric power system, particularly during disturbances and restoration.

Frequency response service is referred to by NERC as primary control or primary frequency response, which includes inertial response. This is a reliability service for the bulk electric system and has operational guidelines for the balancing authorities, generator operators and owners, and transmission operators and owners. Since frequency response is a bulk electric service traditionally provided by spinning generators with governors, it includes attributes such as deadband and percent droop settings that are measured at the resource level. Balancing authorities are responsible for dispatch and management of their area control error (ACE) and are expected to have available a reserve capacity that exceeds the largest expected loss with margin.

The reliable provision of the frequency response service must be so quick as to require the active response of resources based on locally measured or sensed changes in frequency, i.e., autonomous response. Traditionally, spinning generator governors are applied proportionally to alter operation immediately, based on droop curves for frequency excursions outside of deadband limits. More recently, inverter-based resources have demonstrated their ability to provide frequency response in accordance with the common droop rule.

Description: Responds to a change in system frequency nearly instantaneously by consuming or producing power over a committed period.

Example service requestor operational objectives: Stabilize system frequency from large energy impulse events (e.g., loss of a major generating unit or highly loaded line in the transmission system). In an islanded microgrid situation, relatively smaller events can cause frequency fluctuations, requiring a similarly stable response.

B.5 | VOLTAGE MANAGEMENT SERVICES

In the bulk power system, due to the highly inductive nature of transmission lines, the frequency and voltage control can be roughly decoupled such that the voltage is associated with the reactive power and the frequency can be controlled by the real power. Voltage management is typically provided by adjusting exciters on rotating generators, changing inverter settings on power electronic controlled devices, and changing transformer tap settings or manipulating capacitor banks in substations.

Due to the dynamic nature of maintaining proper operating voltage, voltage management is traditionally provided through system operation studies, resource assignments, and voltage level settings provided by these engineering studies and based on codes for reliable system operations set forth in governing documents.

In the distribution system, voltage management is done by changing transformer tap settings or manipulating capacitor banks. Inverter equipment power factors can be managed with fixed settings or dynamically

Description: Provides voltage support (raise or lower) within a specified upper and lower voltage range at an electrical location over a committed period.

Example service requestor operational objectives: Maintain voltage within a reliable operating range for running equipment and maintaining system stability. In the transmission system, equipment is rated to operate efficiently and effectively within a voltage range.

In the distribution system, voltage management maintains a voltage profile along a distribution circuit to manage voltage sags and swells. These issues may come from high-voltage situations caused by neighborhood roof-top solar, low-voltage situations caused by excessive electric vehicle charging, or high or low voltage profiles from circuit sectionalizing. In addition, the voltage is sometimes managed to the lower part of the operating range as an energy efficiency measure, especially for resistive loads.

B.6 | BLACKSTART SERVICES

This service category covers the coordination of resources in dire operating scenarios. Blackstart service is the capability of a generation resource to start and provide power before being connected to the electric grid or to remain available even if the electric grid goes down. More generally, the blackstart service includes procedures that are used as part of a restoration plan following a blackout (NERC 2023).

Planned demand curtailment services, such as New York Independent System Operator's (NYISO's) emergency demand response program, are used to put the system in a more reliable operating posture; however, the service follows the reserve service paradigm. In islanded operating scenarios that may occur after system collapse or as part of system restoration, generation and load balance is achieved with blackstart facilities and managed load pickup by switching in combinations of distribution circuits and controlled loads as generation allows.

System operating organizations recognize that emergency situations require extraordinary actions to preserve and restore the health and integrity of the electric system. Emergency operating procedures are spelled out by each operating organization and comprise emergency alerts or notifications as well as emergency operating procedures. The responsibilities of system operators and other participants are identified in these procedures.

The categorization of common grid services recognizes that the coordination of resources under emergency conditions requires agreements on operating policy. However, from a grid service perspective, the coordination falls into one or more of the common grid service definitions already described. The fact that the service is called upon in an emergency situation explains the operational objective of the service.

Description: Energize or remain available without grid electrical supply to energize part of the electric system over a committed period.

Example service requestor operational objectives: Examples of blackstart service include re-energization after a blackout or balancing supply and demand in an islanding emergency.

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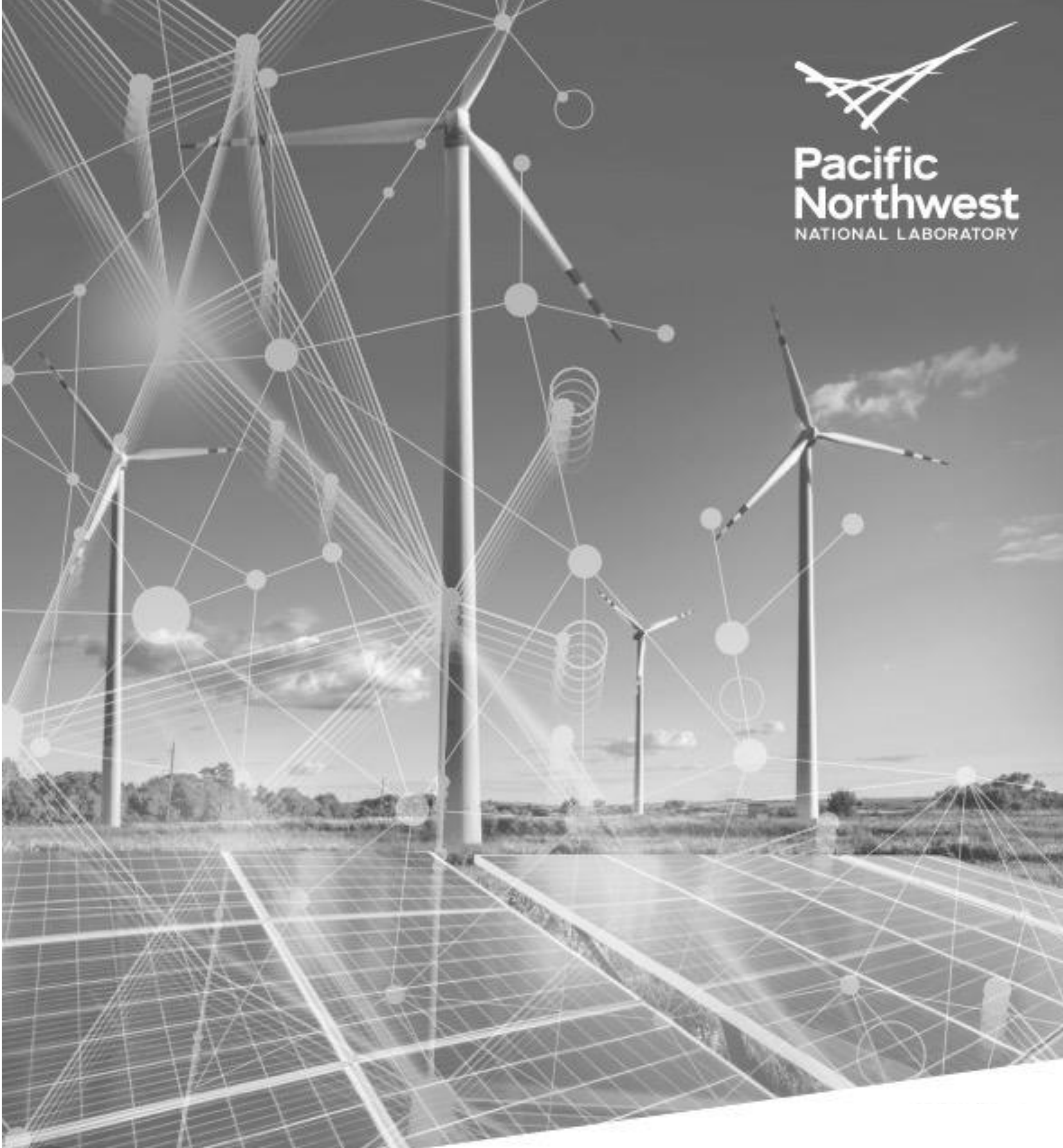
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