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Evolving Architectures and Considerations to address Distributed Energy Resources and Non-Wired Alternatives

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1.1 Executive Summary

The electric grid is in the beginning stage of a transformation, arguably the most significant in its history. This transformation is driven by a combination of shutdowns of coal-fired plants, commissioning of new natural-gas plants, and tremendous growth in energy supply from renewables, wind, and solar, based on location. Regardless of this transformation, customer expectations for reliability, power quality, and resiliency have only increased – customers want improved reliability and better power quality, supplied by sustainable (green) energy sources through a resilient grid at the lowest possible cost. Even as these expectations increase, grid reliability is threatened by increasingly erratic and severe weather events and changing customer behavior of adding renewables and non-wires alternatives both on the grid and behind-the-meter. As utilities navigate this transformation, their progress is supported by advances in Operational Technologies (OT), and Informational Technologies (IT), such as automation, smart inverters, cloud computing, mobile computing, machine learning, big data analytics, and others, which have the potential to enable advanced capabilities more efficiently and at a lower cost. Finally, the industry is experiencing new business entities like aggregators, community choice aggregation (CCA), microgrids, and others that will interact with the grid in novel ways. There is another dimension to be considered here. In addition to advanced solutions, the industry is at another tipping point where new technological architectures are essential to managing grid complexity.

These changes will significantly affect transmission and distribution operations. Expected changes will include (1) different system operators controlling segments of the system; (2) different sources of active/reactive power supply ranging from transmission-located to rooftop solar-based, some of which will be from renewable sources and could vary depending on solar/wind availability; (3) the ability to dispatch sources of power supply versus 'must take' when available; (4) new cost models for this power whether tariff-based or market-based; (5) adjusting how ancillary services are procured to ensure the grid will still work reliably providing quality power to all. Continuing support for legacy technology investments is required to enable this new future scenario. Along with cybersecurity and equity issues, the future will require new architectural approaches for electric grid operations to tackle the rapidly evolving requirements of the future electric grid.

This white paper focuses on the architectural considerations that will allow the industry to handle this transition in a planned manner. It introduces and formalizes two architectural constructs –the data bus and the control bus. The data bus is responsible for carrying all non-operational models and information necessary to drive utility decisions. In contrast, the control bus is responsible for carrying all operational data and control actions taken at the local level, centralized level, or other levels in-between, should they exist. This separation was necessary to isolate data and actions that control the electric grid from getting interspersed with other types of information exchange. These may already exist in today's architectures at a conceptual level, but not as formal components. Both constructs are necessary to ensure that the most efficient processing of information and control occurs at the proper location. The two buses also need to work through a broad range of communications mechanisms and protocols and support all the systems (e.g., centralized, decentralized, distributed, and non-utility).

The two buses are isolated by one or more security mechanisms, ensuring information transported by either of them or their actions are not compromised. These buses are also supported by a combination of (1) standards-based data structures, (2) standardized interfaces (i.e., Application Program Interfaces (APIs)), (3) a standardized set of available services in the architecture, (4) standardized as-built and as-operated models, all leading to (5) self-registration and provisioning of devices, applications, and systems on the network. These support components apply to the buses, applications and devices on the power grid.

The future of reliable electricity supply relies on an information-rich environment where an increasing amount of data will come from sensors on the electrical system and beyond (grid-edge and Behind-The-Meter [BTM]). The data is often accompanied by its implicit patterns and behaviors, providing insights into electric grid behavior. The overall architectures and systems implemented must evolve with these changes. This white paper reviews those architectural considerations and provides a detailed perspective on their requirements and how they will evolve.

This paper intends to provide a context for vendors, utilities, and their service providers to review and understand the changes that are coming in the future and get ready for them. Each vendor and utility may approach the journey in their own ways to stay competitive and ahead of the others. Still, we hope they approach these changes using the constructs presented in this paper allowing for more seamless interactions between the various stakeholders in the evolving marketplace and also to avoid their assets from being stranded. .

1.2 Acknowledgments

This paper would not have been possible without the input and support from the following:Industry

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This work was done under the auspices of the GridAPPS-D™ project, a Department of Energy-sponsored open-source software platform being developed for data integration and application development. As a part of this project, the analysis of architectural considerations was needed to ensure that today's architectures could transition to handle tomorrow's planning / operational problems and situations.

1.3 About the GridAPPS-D™ project

This work was funded under the GridAPPS-D™ project. The United States (U.S.) Department of Energy (DOE) Office of Electricity (OE), Advanced Grid Research sponsors the GridAPPS-D™ project, which focuses on reducing time and cost to integrate advanced functionality into distribution operations and create a more reliable and resilient grid. Under Pacific Northwest National Laboratory (PNNL) leadership, the GridAPPS-D™ program has developed a reference open architecture environment (platform) to support that objective.

What GridAPPS-D™ does

GridAPPS-D™ standardizes the data exchange interfaces between field devices, distributed applications, and applications in the control room. With this standardization, information can flow between systems that have historically been siloed. This creates "data fusion," where an Advanced Distribution Management System (ADMS) can access all data through a common bus (interface) across multiple applications and execute command functions, all using a common and consistent power system model.

The GridAPPS-D™ platform uses a standards-based data model, logical data abstractions, and an exchange mechanism to enable the development of portable applications easily deployable within any operational environment that supports the GridAPPS-D™ programming model regardless of the utility or vendor system.

The GridAPPS-D™ approach is based on the premise that the best approach to providing cost-effective integration and enabling advanced control and coordination applications for a future decarbonized distribution system is to move to a standards-based approach that uses open Application Programming Interfaces (API's) and architectures.

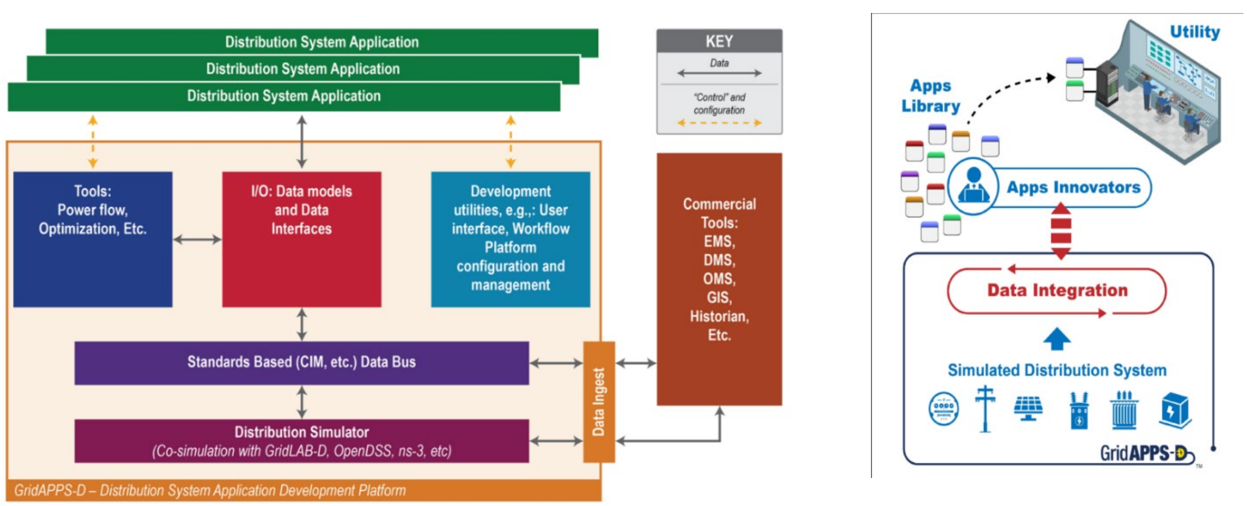

Figure 1: GridAPPS-D™ Architecture

The connection between GridAPPS-D™ and this white paper

GridAPPS-D™ is an open-source, standardized architecture and implementation approach for power system applications targeted at a utility's planning and operations functions. Application innovators and vendors can use it when developing their advanced applications for distribution management to reduce cost and complexity while decreasing time to market. Still, reaching a successful outcome requires assessing the architectural needs of distribution operations and how those needs evolve in the future in concert with ensuring legacy applications are still supported. This white paper creates a bridge between the past (legacy architectures) and a future supporting a broad range of operational needs.

1.4 Acronyms and Abbreviations

AC – Alternating Current

ADMS – Advanced Distribution Management System

AGC – Automatic General Control

AI/ML – Artificial Intelligence/Machine Leaning

AMI – Advanced Metering Infrastructure

AMR – Automatic Meter Reading

API – Application Programming Interface

ARRA - American Recovery and Reinvestment Act of 2009

BESS – Battery Energy Storage System

BMS – Building Management System

BTM – Behind The Metering

BYOD – Bring Your Own Device

C&I – Commercial and Industrial (Load)

CAN – Controller Area Network (Bus)

CCA – Customer Choice Aggregate

CIM – Common Information Model

CIP – Critical Infrastructure Protection

CIS – Customer Information System

D - Distribution

DaaS – Desktop as a Service

DC – Direct Current

DCaaS – Data Center as a Service

DER – Distributed Energy Resources

DERMS – Distributed Energy Resource Management System

DNP3 – Distributed Network Protocol

DOE – Department of Energy

DR – Demand Response

DSO -Distribution System Operator

EMS – Energy Management System

ERCOT – Electricity Reliability Council of Texas

IoT – Internet of Things

IOU – Investor-Owned Utility

ISO – Independent System Operator

IT – Information Technology

ITMaaS – Information Technology Management as a Service

KVAR – Kilo-Volt Ampere Reactive

KW - Kilowatt

MaaS – Managed software as a Service

MBaaS – Mobile Backend as a Service

MW - Megawatt

MWAR – Megawatt Amperes Reactive

MWFM – Mobile Work Force Management

NAESB - North American Energy Standards Board

NERC – North American Electric Reliability Council

NWA – Non-Wires Alternatives

OMS – Outage Management System

OpenADR – Open Automated Demand Response

OpenFMB – Open Field Message Bus

OT – Operations Technology

PaaS - Platform as a Service

PCC – Point of Common Coupling

PNNL – Pacific Northwest National Laboratory

PV – Photo-Voltaic

PUC – Public Utilities Commission

REBA – Renewable Energy Buyers Alliance

REC – Renewable Energy Credits

REP – Retail Energy Provider

REST - REpresentational State Transfer

RTO – Regional Transmission Organization

SaaS – Software as a Service

ERP – Enterprise Resource Planning

ESB - Enterprise Services Bus

EV – Electric Vehicle

FERC – Federal Energy Regulatory Commission

FLISR – Fault Location Isolation and Service Restoration

GIS – Geospatial Information System

GPS – Global Positioning System

HVAC – Heating Ventilation and Air Condition

IaaS - Infrastructure as a Service

ICCP – Inter-Control Center Communications Protocol

IEEE – Institute of Electrical and Electronic Engineers

SAP – System Application and Product in Processing

SCADA – Supervisory Control and Data Acquisition

SGIP - Smart Grid Interoperability Panel

SMB – Small and Medium Businesses

SO – System Operator

T – Transmission

TAC - Technology Application Center at the University of Illinois

TOU – Time of Use

UID – Universal Identifier

VVO – Volt-VAR Optimization

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1.7 Abstract

GridAPPS-D™ is a Department of Energy (DOE) Office of Electricity- (OE) sponsored and PNNL-led open-source software platform for data integration and application development. One of its key focus areas is developing a platform to support distribution planning and operations built on open standards, enabling the industry to develop, integrate, and test software applications more easily more efficiently. As the platform continues to evolve, application innovators and vendors will be provided code sets and capabilities to develop their advanced tools for distribution management to reduce cost and complexity. The primary role of GridAPPS-D™ is not to compete with vendors but to provide the foundational tools enabling them to market a new generation of capabilities quickly. Additionally, GridAPPS-D™ is designed to support the development of applications for a range of industry stakeholders, including utilities of all sizes and types including third-party application developers. For this effort to be successful, it is essential to assess the architectural needs of distribution operations, potential interactions with transmission operations, and future evolution while ensuring the legacy applications are still supported. The work needs to support a transition from

- The needs of a centralized business environment which primarily consist of utilities, some large generation companies, and a few wholesale and fewer retail markets,

to

- A centralized/decentralized/distributed environment supporting an evolving business framework, one in which the individual customer also may elect to play an active role, potentially leading to more efficient use of resources than the current regulatory construct can produce. In this environment, generation may come from sources spread across transmission and distribution, contributing to grid reliability and resiliency and providing tremendous flexibility.

This white paper bridges the past, legacy architectures with the future needs that support a broad range of operational, business model, and configurational needs. Utility architectures move slowly, very often due to conservative regulatory thinking and the investment scale/delivery durations of existing implementations. Similarly, the timescales of power system operations/equipment also take time to change from previous generations of technology to taking advantage of the latest technological advances. Any deviation can incur significant costs. Finally, the regulated utility model of investment is subject to utility commission oversight and requires thoughtful and justifiable investment. The architecture of the future needs to consider these requirements as it evolves.

1. Introduction and setting the context

As systems utilized by distribution operations continue to migrate from siloed solutions to integrated Advanced Distribution Management System (ADMS) platforms, the resulting reduction in integration costs and elimination of system-to-system integration has had a positive effect. However, the tradeoff has often led to single-vendor solutions, limiting the utility to applications available from an ADMS vendor or incurring additional complexity and costs to integrate functionality from other vendors. These moves also limit the utility's ability to take advantage of advances in third-party systems, especially in the cloud-based services that have the potential to enhance and accelerate the digital transformation of the entire grid. Given the diverse range of application domains in distribution grid management, this tradeoff constrains the utility's ability to select the optimal application for a particular domain.

The industry recognizes that addressing the introduction of key technologies such as Distributed Energy Resources (DERs), Electric Vehicles (EVs), microgrids, and others requires an architecture that is a combination of centralized, distributed (hierarchical), and decentralized. It also recognizes the need to create "digital twins" [1] for the systems deployed in the field. This helps asset management, asset tracking, operational intelligence and analysis of performance (expected vs. actual). Expecting a single vendor to have all necessary future solutions may be unrealistic because most vendors concentrate on solving specific classes of problems along the value chain. There is a likelihood that distribution operations in the future will include market operations as well as reliability operations. It is almost certain that a single vendor will not provide complete solutions for both. Not relying on a single vendor platform is especially important as more functionality moves to the edge of the grid and beyond, encompassing an increased range of devices, control systems, and stakeholders.

The alternative is that utilities could rapidly integrate solutions from different providers who focus on solving a specific problem much more closely aligned to their specific requirements than perhaps their utility's ADMS platform supplier. This also provides utilities the freedom to select solutions and tools that may not be available from their vendor, be more cost-effective, or be better suited to their operations. For this to be viable, future distribution operations platforms require a standards-based architectural approach that allows a utility, if it chooses, to easily integrate applications/systems from various vendors and other sources to solve the complexities that it may face without compromising functionality, security, availability, or reliability.

While the underlying need or priority comes from integrating distribution applications supporting operations and planning, this paper is not focusing separately on transmission or distribution operations. It is possible that in the future, the line separating operations between transmission and distribution could become much fuzzier, requiring architectures to consider tighter integration between the two. Instead, this paper focuses on architectural considerations for IT[1] and OT[2] systems (across transmission and distribution) required to support the changing dynamics of operating the grid as it moves from today's primarily centralized generation-based model to a future where an increasing amount of generation will come from distributed sources. This white paper's focus is on the utility of the future. It is important to note that this topic applies to all stakeholders that will have a role in this changing marketplace.

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[1] Information Technology (IT) is the use of computers to store, retrieve, transmit, and manipulate data, or information, often in the context of a business or other enterprise. An IT system is generally an information system, a communications system or, more specifically speaking, a computer system – including all hardware, software, and peripheral equipment – operated by a group of users. https://en.wikipedia.org/wiki/Information_technology

[2] Operational technology (OT) is hardware and software that detects or causes a change, through the direct monitoring and/or control of industrial equipment, assets, processes, and events. https://www.gartner.com/en/information-technology/glossary/operational-technology-ot

Because of the complexity of this issue, the first sections of this white paper focus on setting the context for the evolving changes that are occurring now and others that are expected to emerge in the utility industry. This change is visualized through several dimensions.

- Section 1 reviews the changes in the electric grid business that are transformative. This dimension is included to help the reader understand the potential needs of the new and transforming future.
- Section 2 analyzes existing and new stakeholders in the utility industry transformation and their system operations' impact at both the transmission and distribution levels. This dimension is included to help the reader understand the impact of these new players and their objectives on system operations. The emerging architecture must also enable these stakeholders.
- Section 3 reviews the state of operational architectures today. This specific analysis is included to underscore that any movement to a new architecture must take the legacy systems and their architectures into consideration so that the two (old and new) can coexist and not introduce uncertainty or confusion to operations. Section 3 also focuses on the existing and upcoming electric grid technologies and innovations. The paper introduces several emerging solutions and the legacy components that must be considered in the future grid.
- Section 4 sets the context which is very important because it sets the stage for discussing the architectural constructs and concepts. This section starts with a high-level diagram that introduces the key components of the architecture at a conceptual level. This section introduces the Data/IT bus and the Control/OT bus and their importance to the mechanisms required in future architecture.
- Section is the last section of this white paper. It presents a roadmap defining the future grid architecture requirements. This roadmap identifies signposts that help the utility architect evaluate their current situation and maturity of specific technologies and systems against industry needs and desire for particular outcomes.

1.1. Utility structural constructs

In general, words such as grid, power system, and others are used interchangeably in this white paper to mean any transmission, sub-transmission, or distribution systems unless a part of the description is intended to focus on one of the segments specifically. This is done to make the paper easier to read when the explanation is intended to encompass all the areas described below.

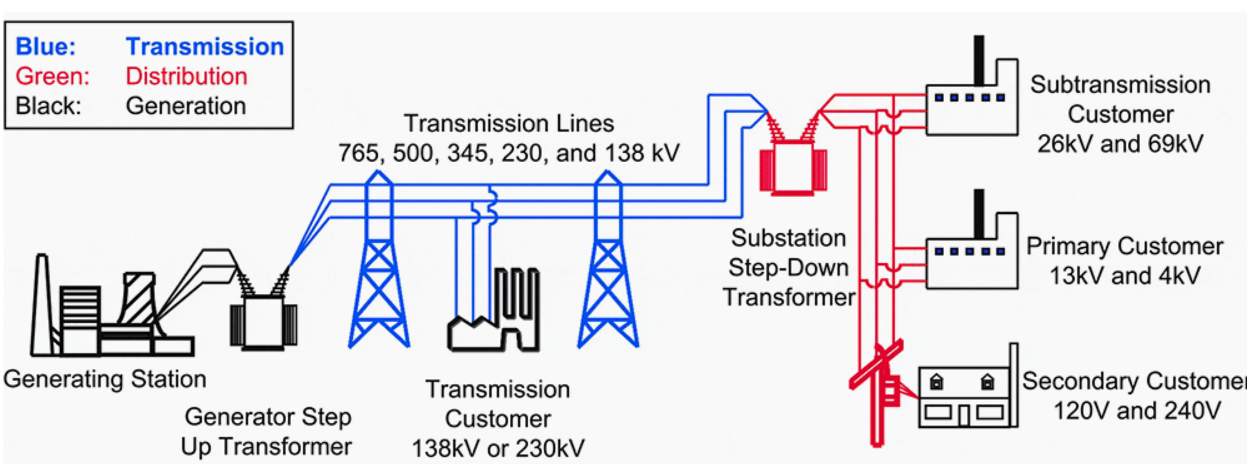

Figure 2: A typical legacy utility energy delivery process

Figure 2 [2] presents a structural view of a traditional electric power system where power flows from the generator to the customer. While electricity supply changes from large, centralized generators to a mix with a greater percentage of distributed generation, the core delivery mechanism consisting of transmission, sub-transmission, distribution, and customers remain the same.

- **Transmission.** Transmission covers the transportation of bulk quantities of electric energy via electric conductors, from generation sources to an electric distribution system, load center, or tie-line with a neighboring utility. Transmission involves the high-voltage flow of electricity from the points of generation to locations of groups of electricity users, industrial parks, and commercial centers. Transmission is almost always designed to be a grid – multiple paths to get power to a single location.
- **Sub-transmission.** Sub-transmission is part of an electric power transmission system that runs at relatively lower voltages. It is uneconomical to connect all distribution substations to transmission voltages because the equipment required is larger and more expensive. Typically, only larger substations connect with this high voltage. It is stepped down and sent to smaller substations in communities and neighborhoods. Sub-transmission circuits are usually arranged in loops or networks, preventing a single line failure that cuts off service to many customers for more than a short time.
- **Distribution.** A distribution system carries electricity coming through the transmission or sub-transmission grid and delivers it to consumers. Typically, the network would include medium-voltage, less than 50 kV power lines, substations, and pole-mounted transformers, low-voltage, less than 0.5 kV, distribution wiring, and meters. An electric distribution system delivers electric energy to consumers. Distribution systems are primarily radial. Increasingly distribution systems are designed as redundant radial or looped radial where customers could be fed from two possible paths. Downtown distribution systems in some cities are also networked (meshed). As more generation in the future is connected at the distribution level, utilities may consider designing more portions of the distribution network to be more truly networked, similar to transmission system design.
- **Customer.** Customers are the consumers of electricity. They are grouped into specific categories depending on their quantity of use or where they are connected to the electric utility grid. Typical categories are residential, commercial, agricultural, industrial, and transportation.

1.2. Utility transformation

For the past two decades, the electric grid has undergone a significant transformation, and this transformation is expected to accelerate. The major changes are due in large part to:

- **Changing themes on regulatory mandates and legislative policy**

  Electric utilities are wrestling with the push and the pull of more renewables coming online through changing regulatory policy with the overarching need to deliver reliable power to their customers at an affordable cost.

- **Increased options for solving the same problem**

  Distributed Energy Resources (DER) and Non-Wires Alternatives (NWA3) provide new options for generation, transmission, distribution, and consumption of power. Examples include:

[3] Non-wires alternatives (NWAs) are electric utility system investments and operating practices that can defer or replace the need for specific transmission and/or distribution projects, at lower total resource cost, by reliably reducing transmission congestion or distribution system constraints at times of maximum demand in specific grid areas. Examples include demand response, distributed generation (DG), energy efficiency, electricity and thermal storage, load management, and rate design. The most common usage of NWA is energy storage.

  - Energy storage vs. demand response where either of these can can help achieve load reduction.
  - Energy storage vs. peak-supply generators where a storage device charging during low demand can supply power to fulfill on-peak demand
  - Energy storage vs. grid expansion where a storage device can delay or eliminate the need for an expansion of a feeder or substation's capabilities
  - Distributed wind/solar farms and other NWAs that can provide localized sources of real and reactive power when needed.

  The number, size, and impact of DERs and NWAs in the grid are increasing. Their presence is greater in some markets and less in others, but there is an unmistakable global trend in that their number and size are growing. While not all of them are renewable, it is important to note that the most significant growth area is renewable DERs. These resources bring challenges of intermittency, variability of output, and location that impact the reliable and resilient operation of the grid. As energy storage technology costs drop, growth in this form of DER will increase dramatically.

- **Increased focus on security**

  There is now a well-documented and increasing cyber threat from malicious actors seeking to disrupt the electricity system that everyone relies on to power homes and businesses [3]. The safety and security of a nation's critical infrastructure depend on its resilience to incidents such as cyber-attacks.

- **More affordable and up-to-date Operations Technologies (OT)**

  Sensors and controls exploiting cheaper access to ubiquitous communications allow the utility operator to control the flow of power at lower costs. These technologies also allow ease of deployment and integration of additional sensors (e.g., Automated Meter Reading [AMI] data) and access to data from existing third-party sensors (e.g., solar irradiance data) into the operational environment. A potential game-changer that is being considered by many utilities for grid operations (reliability and market) is wireless communication, notably private LTE.

- **Computer Science and Information Technology (IT) advances**

  Cloud computing, mobile computing, machine learning, big data analytics, and artificial intelligence can enable companies to implement advanced solutions more efficiently and at a lower cost allowing smaller utilities access to capabilities that they would never have been able to deploy. Additionally, newer architecture concepts allow the building of loosely coupled and more distributed systems that allow components to be added/removed in a plug-and-play manner without disrupting the entire system. Noteworthy among these is the movement of computing and artificial intelligence at the edge.

- **Growing customer expectations**

  The mobile-internet-device enabled electric utility customer now expects their utility to provide quick feedback on the status of outages, more choice on power use, and the ability to interact via apps. Customers also expect electricity service that can adapt to changing societal priorities and expectations.

- **Customer grid interactions beyond energy consumption**

  Customers are also introducing other changes. They are installing wind turbines and rooftop solar, buying electric cars that can also be used for energy storage. At the residential level, this is seen in the BYOD (Bring Your Own Device) model, where customers bring devices such as storage, electric vehicles, rooftop solar, and others connecting them behind the meter (BTM). In the more than 100-year history of the utility industry, this is the first transformation heavily influenced by customers. Most of the previous transformations, such as wholesale and retail deregulation, have always been driven by legislation and regulation. Legislation and regulation are predictable. Customer behavior is unpredictable. These changes impact the transmission and distribution levels, changing the delivery landscape and the traditional utility/customer relationship.

- **Business Model Changes**

  Experiences from retail markets in ERCOT and several states with retail choice (e.g., Pennsylvania, Illinois, California, Massachusetts) have led to new business entities like aggregators. In addition to providing retail energy services, these entities may also provide other value-added services to the customer, thereby creating the possibility of relegating the traditional utility to merely a wires-and-pipes entity. They are also forcing the utility to change their offerings to customers, such as the shift to a subscription model (fixed bill + clean energy + thermostat), Time-of-Use (TOU) rates, sub-metered TOU for EVs, and others. A similar situation arises with the emergence of community choice aggregators in states such as California and New York [4].

While much, if not most, of these changes happen at the sub-transmission and distribution system level, the aggregated effects (e.g., FERC Order 2222 – See Section 4.2) are significant enough to impact the transmission systems of the future. These changes and others can significantly alter the future structure and role of the traditional transmission system requiring the need for integrated grid (transmission and distribution) planning and operations.

2. Participants and their impact on system operations

The industry is changing – new stakeholders are performing functions previously provided by established utility industry incumbents. Figure 3 presents a conceptual view of the various stakeholders and how they are connected to each other across the energy value chain.

This section is mainly focusing on the stakeholders who are new, emerging, or transforming. As this narrative gets into the following subsections, two key terms need to be defined.

- System Operators (SO) is the general term for the entity responsible for managing the transmission and distribution grids, and in vertically integrated utilities, for also dispatching the generation. On the business side, SO performs contract management and reconciles physical energy consumption supporting financial settlements. Further, SO also coordinates energy schedules and manages network congestion. [5]
- Distribution System Operator (DSO) is a new and still-evolving term that, at its core, performs today's function of managing and operating the distribution system. However, as it evolves, some future projections of this function could include operations planning and distribution/retail market operations (somewhat like the RTO/ISO but at the distribution/retail level).

2.1. Vertically integrated utility

While the traditional utility will still endure for some time, it is unknown what form of transformation will take in each jurisdiction. It is generally accepted that in each jurisdiction in the U.S. and worldwide, some level of disaggregation and even consolidation will occur. Some changes are happening due to regulatory mandates, while others result from economics and the need to stay competitive in this time of rapid change. For example,

- Consolidation: There is significant merger and acquisition activity taking place in the Investor-Owned Utility (IOU) space leading to the formation of holding companies such as Exelon Utilities, Duke Energy, Berkshire Hathaway Energy, and others having several utilities within their portfolio. [6,7]
- Disaggregation: Some utilities are seeing a push toward municipalization. Examples of these are Boulder's failed attempt at seceding from Xcel Energy and more recent attempts to break up PG&E in California.
- Erosion of the value chain: With the growth of DERs, vertically integrated utilities see a combination of coal-fired and nuclear plant retirements, new natural-gas plants coming online, and tremendous growth in energy supply from renewables, wind, or solar, based on location. Many solar-powered and wind-powered locations are also supported by localized storage installations providing a greater degree of dispatchability. Given their regional and locational diversity, these installations can provide increased flexibility for system operators to dispatch energy and ancillary services. The journey to maturation of storage technology will drive the industry towards the full transition to renewable for two reasons: dispatchability and localized stability.

These changes affect the traditional utility through erosion of monopoly protection from competition, resulting in the need to make the utility a beneficiary versus victim of electrification and justify/extend the value of providing grid services differently.

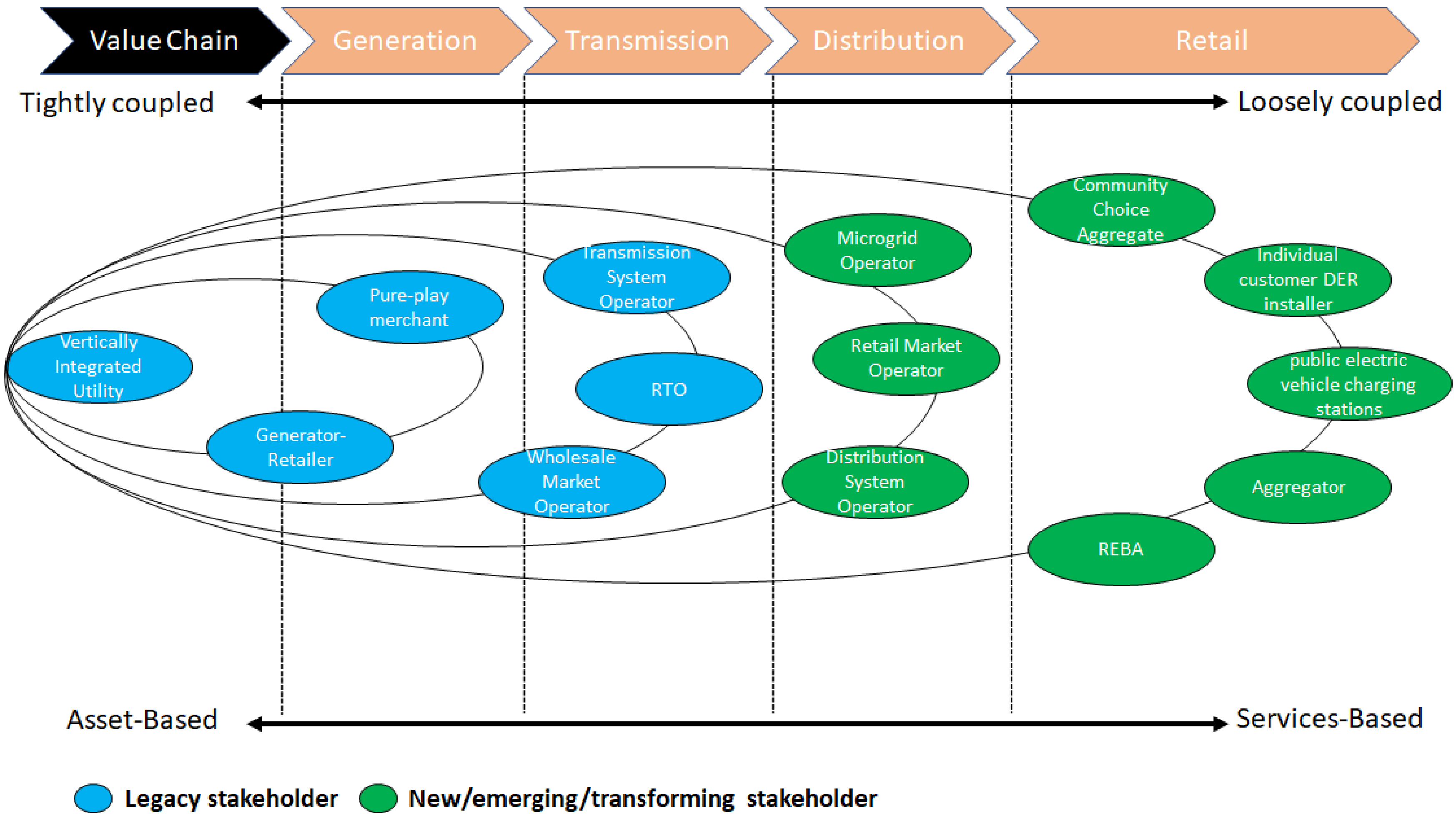

Figure 3: Impact of changes along the energy value chain

REBA – Renewable Energy Buyers Alliance

System Operations Impacts: Operations at traditional utilities will be impacted by distributed energy resources, large, centralized renewables, and microgrids, all of which could be either utility, customer-owned or third-party owned. All the stakeholders identified in this section could also exist within a utility's jurisdiction. Utility system operational functions must support their own needs and those of the various stakeholders. One of the biggest challenges that system operators face in the near and mid-term future will be to dispatch these newer and more intermittent sources of generation to provide continued reliability and resiliency to the network. In some cases, system operations will not have control or dispatch authority of DERs and will need to manage the grid in a manner that flexes with the economic signals these sources will respond to.

2.2. Regional Transmission Organizations, Independent System Operator (RTO/ISO)

An RTO in the United States is an electric power transmission system operator that coordinates, controls, and monitors an electric grid across multiple states. An independent system operator (ISO) is similarly an organization that also coordinates, controls, and monitors the electric grid, but usually within a single U.S. state, although can cover multiple states. RTOs typically cover a larger geographic area. The creation of RTOs was initiated by FERC Order No. 2000, issued on December 20, 1999 [8]. The potential for significant impact to the RTO comes from the more recent FERC Order 2222 [9]. This rule enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations; opening U.S. organized wholesale markets to new energy and grid services sources. This rule allows several sources of distributed electricity to aggregate to satisfy minimum size and performance requirements that each may not meet individually.

System Operations Impact: RTOs have been in existence for several years, and their interactions with most participants are quite mature. However, the impact of the recently introduced FERC order 2222 is not yet fully known. This is mainly because most of these resources are connected to the distribution system traditionally under the DSO's control, whose role in the electric value chain is still evolving. In addition, it is unknown how distribution-level resources will provide services in the wholesale market.

2.3. Community Choice Aggregation (CCA)

CCAs, also known as municipal aggregation, are programs that allow local governments to procure power on behalf of their communities (residents, businesses, and municipal accounts) from alternative suppliers while still receiving transmission and distribution services from their existing utility provider. CCAs are an attractive option for communities that want more local control over their electricity sources, for example, more green power options than those offered by the local distribution utility, lower electricity prices, and a source of additional community revenue. By aggregating demand, communities gain leverage to negotiate better rates with competitive suppliers and choose greener power sources [10]. In 2021, CCAs delivered about 52 GWHs of green power to about 4.3 million customers [11] across 190+ cities and counties (e.g., Napa, Sonoma, and Marin) in California alone [12]. Also, several other states are exploring CCAs.

System Operations Impact: The main impact of CCAs is in separating power procurement from power delivery at the distribution level. This separation creates a potential for lack of transparency to the system operator of the CCA actions, resulting in operational challenges due to the decoupling of system control and responsibility for operations. This impact is like that of the wholesale market, where the generation procurement is external to the System Operator. Wholesale markets have multiple generation suppliers, whereas, in this case, the CCA is the only supplier. This concept is still new, and its long-term success and viability still need to be observed. Few, if any, CCAs thus far have faced a complete life cycle of resource procurement with contingencies.

The location of the sources where CCAs are procuring power adds an extra layer of complexity. In some cases, CCAs either build or procure significant long-term power contracts from large solar farms and individual residential customers with DER. However, suppose a significant percentage of the power procured is from individual residential customers who send their surplus power back into the grid. In that case, the system operator requires increased visibility into the amount and location of energy injected into the distribution grid. In addition, key functions such as load/resource forecasting (including DERs), scheduling/dispatch, and others need to be quite sophisticated to manage power flows from these sources.

2.4. Aggregators

Aggregators are a relatively recent business entity in the utility landscape. Some aggregators appeared following the creation of the ERCOT marketplace [13] in 1996, and many more came into existence over the last few years. Aggregators in the market structure provide value by capturing customer groups and providing services a utility fails to or is not allowed to perform. These are private enterprises that could be entirely independent of the incumbent utility or unregulated utility subsidiary. They could also be the utility acting as an aggregator under some specific circumstances [14]. Examples of aggregator services provided are listed below.

- Procure energy from wholesale suppliers and provide it to their customers. The energy source could be from traditional energy sources, such as fossil or hydro. Others are also providing renewable energy by contracting with entities such as solar and wind farms.
- Procure energy from a large group of suppliers and supply them to the wholesale markets. This energy could be from a broad range of sources: traditional, renewable, residential, commercial, or others. The energy source could also be Demand Response (DR) services or a virtual power plant operator. These are the disruptors in the marketplace who can take services offered to a large and diverse group of customers and trade them in the broader wholesale market. The reduction in load from DR is offered either as a generation or ancillary service.

  The aggregator may also pay someone to procure (e.g., DR) services in a service territory. In this case, the DR aggregator is, in effect, a technology vendor that provides integrations saving time for utility software development. Additional add-ons may be marketing, customer care, and event scheduling.
- Bundling energy, home security, telecom, and other such services by providing a single billing and customer service mechanism. For example, the Retail Electric Providers (REP) in the ERCOT marketplace are quite successful with these offerings [15].

The implementation of FERC Order 2222 [16] brings greater complexity by ordering wholesale markets to engage aggregators. Under FERC 2222, aggregators have access to customers from around 125 utilities. That number would be higher if it were not for the four million megawatt-hour minimum in annual volume rule prohibiting system operators from accepting aggregator bids for smaller utility customers. This order may force larger utilities into an aggregator role to remain competitive. The initial impact will be on those utilities under RTO/ISOs, but non-RTO/ISO members may eventually be subject to FERC 2222 if they are FERC-regulated.

System Operations Impact: The aggregator can have some of the most complex impacts on the System Operator. The aggregator's services are not precisely defined or limited to a concise set of services. However, at a minimum, an aggregator (1) has an agreement to procure power for their customers, (2) possibly modify their customers' consumption (DR), and (3) may deliver power procured from multiple sources to and represent load in a wholesale market.

It remains the utility's responsibility to ensure customers get power reliably. To work effectively, there needs to be close interaction between the transmission (wholesale) operator, DSO, and the aggregator to ensure that the aggregator's actions are fully visible to both sets of operators and included in both real-time operations and forecasts.

2.5. Renewable Energy Buyers Alliance (REBA)

Energy buyers are combining forces to procure renewable energy. REBA [17] is one such membership association for large-scale energy buyers seeking to procure renewable energy across the U.S. It includes stakeholders from across the commercial and industrial sector, non-profit organizations, as well as energy providers and service providers. Its objective is to create a single marketplace for all nonresidential energy buyers to transition to a cleaner, zero-carbon energy future.

Since 2014, the REBA community has grown to over 200 large energy buyers and over 150 clean energy developers and service providers. Participants in the REBA community have been a part of 95 percent of all large-scale U.S. corporate renewable energy deals thus far.

REBA aims to catalyze 60 gigawatts (GW) of new renewable energy by 2025 and expand the number of organizations buying clean power from dozens today to tens of thousands.

System Operations Impact: In essence, REBA is a type of aggregator where the generation procurement is external to the system operations function. However, just like CCAs, there is additional complexity. Since, as the name implies, much of this procured power is based on renewables, the transmission operator and DSO will need to have full visibility into the amount and location of energy coming into the grid. As a result, load forecasting will need to be quite sophisticated and possibly down to the feeder level and perhaps to even lower levels of the grid.

2.6. Microgrid operator

According to the U.S. DOE Microgrid Exchange Group (MEG) [18], a microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity for the grid. A microgrid can connect and disconnect from the grid to operate in either grid-connected or island mode.

System Operations Impact: Microgrids bring several levels of challenges and opportunities to the grid's operation.

1. **Operation of the microgrid**. At the Point of Common Coupling (PCC), the microgrid may appear either as a load or a source. The System Operator focuses on managing load and electrical supply to the area surrounding the microgrid, while the microgrid could be consuming, suppling, or islanded. The microgrid's flexibility of actions complicates the system operator's ability to balance load and supply. Depending on who controls the microgrid, the complexity increases because microgrids often contain one or more DERs, impacting real-time dispatch and management of the electricity supply.
2. **Operation of the distribution grid connected to multiple microgrids**. These can be utility-owned and or third-party owned. The DSO's actions must provide a reliable electricity supply and be viewed as commercially fair to the third-party microgrid owners.
3. **Load forecast**. The system operator will need to forecast its load (power delivery) obligations to consider whether the microgrid is functioning in a grid-connected or grid-disconnected mode.

2.7. Customers installing renewables and non-wired alternative solutions on the grid

Large numbers of individual customers (residential, commercial, and industrial) install DERs and connect them to the grid across the country. Examples of installations include photovoltaic (PV), storage, and PV plus storage.

System Operations Impact: Depending on the installation's size and interconnection location, the DER or NWA will need to be visible and controllable by the System Operator. If visible or controllable, then information on the installation will also need to be provided to the System Operator so that the installation is considered in all aspects of operations – power system model, outage management, restoration, and others.

2.8. Public and commercial electric vehicle charging stations

While many EV owners charge at home, there is a need for more widespread electric vehicle charging stations as the market share and range of EVs increases. Currently, a small but growing number of retail, corporate, and government entities offer EV charging. As gasoline and diesel engines are displaced with EVs, the fueling station we commonly use today will shift to offer both traditional fossil fuels and electrons. Fast charging technology is advancing rapidly, and it will be practical for EV owners to "fill up" at a conventional fueling station. The existing network of gas station locations is ideally suited to offer a range of fuel types. Building out the EV charging infrastructure will be a value-added product and an incremental cost to their current brick-and-mortar facilities.

System Operations Impact: Depending on location, there will be a high concentration of EV charging loads that the System Operator (specifically, the DSO) will need to manage. The peak of the load curve may shift if increasing number of EV owners start charging at night.. Overall system load will increase with EVs and system upgrades will be required to support the new load profile on affected feeders.

2.9. Summary

The key to the breakdown of the industry's stakeholders is that they do not exist in isolation. Initially, one or all of them will exist simultaneously within current constructs, requiring the next generation of architectures to consider them as they evolve. The system operations impact depends on how tightly (Figure 3) the grid control systems must be coupled with these new stakeholder assets to enable reliable operations. In addition, no single view exists of what should be done for System Operations in response to each of these participants. The needs of the System Operator depend on the specifics of the actions taken by the participants. A means of establishing an interface that respects technical and ownership boundaries are required at a minimum. These behaviors will drive the next generation of architectures and interactions for services that need to be provided across the various business and technical entities.

3. State of operational architectures and systems

Figure 2 showed the power delivery mechanism of the past, which was unidirectional from the generators through transmission and distribution to the customer from the beginning of modern electricity systems. This is now changing. Figure 4 shows a conceptual view of a future power delivery mechanism. However, today's operational systems are designed with a diverse set of architectures, some centralized (e.g., EMS / ADMS defined later in this section), some distributed (e.g.,intelligent relays), and some decentralized (e.g., distributed Fault Location Identification and Service Restoration, or in short, FLISR – see later in this section) without any specific pre-defined interaction with each other. For the most part, systems are defined, designed, and implemented independently of each other. Most of the integration is either applied after the fact or implemented initially through purpose-built custom interfaces. Within a given utility and the utility industry overall, the systems are somewhat vertically integrated. Therefore, systems are integrated based on their intended use. Key examples include transmission systems, distribution systems, market systems, customer systems, asset management systems, geospatial systems, and other corporate systems such as human resources and finance[4].

Key operational systems at most electric utilities tend to last for at least ten years, with many of them under maintenance and support agreements with their vendors for multiple decades. These systems are expensive and procured, very often, with customer-funded money. Replacing them or upgrading them tends to be a tedious process requiring approvals from utility executives and regulators. This complexity also means that any move towards a future architecture will need to consider interactions with legacy systems to ensure both acceptance and continuity. Moving to a new architecture will require compatibility with the legacy systems to ensure migration can be done incrementally and with zero disruption to 24x7 system operations. Any utility would consider it impractical to start from scratch on anything this important, especially in their operational systems.

In 2014, the Pacific Northwest National Laboratory (PNNL) introduced the concept of Grid Architecture to the U.S. DOE as a discipline that could address the grid as a whole and provide the means to manage the inherent complexity of grid modernization (adapted from [19]). In this case, Grid Architecture was combined with elements from network engineering, software engineering, and control theory. The PNNL concept also included various forms of mathematics, including optimization methods and graph theory, as applied to electric grids. More information on Grid Architectures is available in other white papers [20, 21, 22].

The grid's complexity arises from its many already complex sub-structures. These sub-structures are interconnected and interact in complicated ways. Such systems have characteristics that pose special challenges, including:

- Inherently conflicting diverse requirements
- Decentralized data, control, and development
- Continuous (or at least longtime scales) evolution and deployment
- Heterogeneous, inconsistent, and changing elements
- Operation involving diverse time scales
- Operation involving large geographic scales
- Normal and expected failures (Failures are common and frequent, not exceptional events.)

[4] In some utilities, enterprise systems like System Applications and Products (SAP) become the glue that brings many of these systems together. However, it is important to understand that this glue is externally superimposed rather than designed to perform in a native manner. They are also designed to support other corporate functions instead of the real-time needs of these operational system. As a result, the interfaces are still enforced through the needs to interface with SAP instead of externally designed to handle change over time.

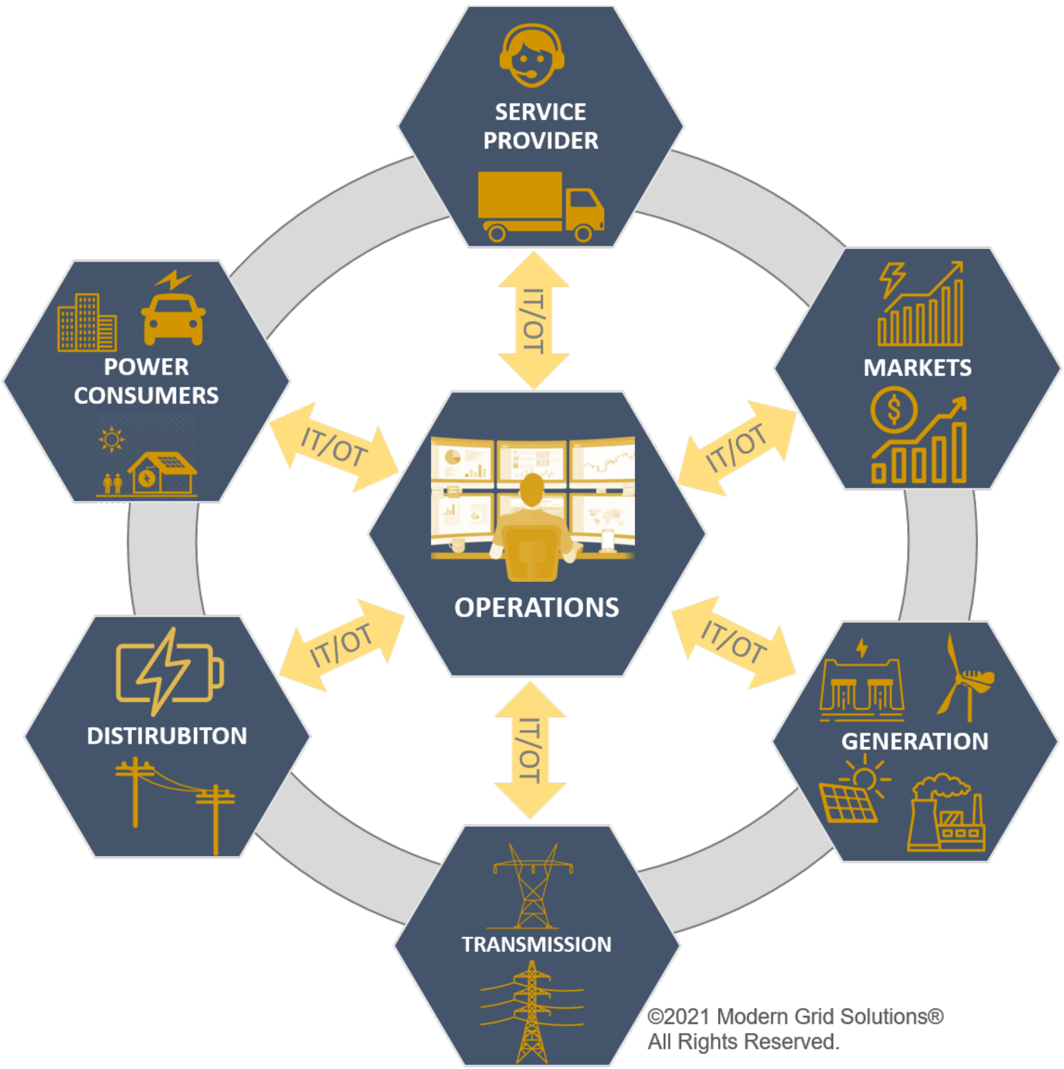

Figure 4: A conceptual view of the power delivery mechanism

It is not uncommon for utilities to implement local, one-off solutions to problems that other utilities have faced and solved. Sometimes even within a specific utility, multiple system solutions exist to solve the same problem. As DER installations increase, these one-off approaches are not sustainable nor scalable. In addition, integration of these disparate solutions can become complex and the costs significant.

This white paper does not intend to replicate the findings detailed in the comprehensive works previously discussed. Instead, this white paper highlights the practical and realistic considerations necessary to evolve the existing utility architectures for those facing an uncertain future, one where potentially disruptive technological innovations can completely change the current situation. Regardless, the work done at PNNL is the bedrock on which much of this white paper is based.

3.1. Core systems

The future grid architecture will have several components that need to be considered. Many are legacy systems, which means that any future architectural changes will need to consider them.

Systems such as Energy Management System (EMS), ADMS, Geospatial Information System (GIS), Distributed Energy Resource Management System (DERMS), and a few others exist in a centralized location. Data comes into them from multiple sources, systems, and locations. This data is used to analyze the power system state. Depending on the operational state, when devices in the field need to be controlled remotely, commands are sent from one or more of these systems, to manipulate the status of one or more devices in the field. Key characteristics of these installations, which cover both transmission and distribution operations, include:

- The systems generally exist in one or more control center-like environments to support operations performed by system operators.
- They provide a broad, system-wide, integrated assessment of utility grid operations.
- They tend to support more complex algorithms and multiple applications.
- They are data intensive. All the relevant data needs to be gathered from the field for execution.
- Sometimes, there is also a need for engineering or corporate data not from the field.
- They are communications intensive. Extensive communications need to be in place to get all the data to one location and for the controls to be sent from that location to field devices.
- Because these systems provide system operators with grid visibility and the ability to manipulate network configuration, they must be exceptionally reliable and redundant.
- They implement procedural (e.g., switching orders) as well as analytic solutions.

Two key functions stand out as the most commonly deployed ADMS applications supporting distribution operations, provided here as an example. They are FLISR[5] and VVO (Voltage-VAR

FLISR EXAMPLE

Decentralized: Utilities install devices in the field which monitor fault currents on specific feeders. When a fault is detected, it acts by opening and closing certain switches based on the settings built into the scheme. These are OT devices installed in the field and function independently of other devices in the field. These devices are generally installed to take quick action to solve a specific local problem. Key characteristics of these installations include:

a. They are much quicker to install given that their sphere of responsibility is localized and limited.
b. They deliver autonomous action by intelligent agents at local component/node level.
c. They are more suitable for distribution networks due to radial nature of networks and localized impacts of changes.
d. They make rapid and localized decisions in a dynamic environment.
e. Their actions are reported to the centralized system in the control center where the overall connectivity and state of the network is maintained.

They are, however, unaware of the current connectivity state of the system they are monitoring. They are configured for the normal state of connectivity and turn themselves off once they act and the connectivity of the system has changed because of their action. Similarly, they are configured based on a static load model not well suited to the fast-changing load behavior with the presence of DERs. The presence of reverse power flow may impact settings used to respond to local faults. To implement configuration changes or to turn them backon after field action requires a trip to the actual location increasing operational costs of the system.

Centralized: Utilities are moving toward centralizing functions such as FLISR and VVO. For this mechanism to work, fault locators and their sensing status needs to be available in a centralized location. Two types exist here:

a. Rules-based: There is a rules-based engine which takes the fault information and applies a series of rules and identifies switches that need to be opened or closed to achieve the new end-state. The control commands are routed through SCADA. This approach provides for greater flexibility to the utility supporting a few off-nominal scenarios.
b. Model-based: It is considered the most flexible and sustainable because it allows the FLISR process to continue operation under different switching configurations. Fault information is fed into a Power Flow application which identifies the location of the fault and then opens and closes the appropriate switches to restore as many of the customers as possible.

[5] FLISR technologies and systems involve automated feeder switches and reclosers, line monitors, communication networks and other technologies. These technologies work in tandem to automate power restoration, reducing both

Optimization). These names apply to functions that could either be centralized, distributed, or decentralized. For the sake of clarity, we have divided them into three main types using FLISR as an illustrative example (see inset). The same characteristics apply to VVO.

3.1.1. Geospatial Information System

A Geospatial Information System (GIS) is designed to capture, store, manipulate, analyze, manage, and present all types of geographically referenced data. Utilities use GISs to store and correlate their assets, attributes, characteristics, and location, Global Positioning System (GPS) coordinates, along with the as-built connectivity model and geospatial rendering.

Utilities need a GIS to collect, organize, maintain, and manage geospatial data about system assets. The GIS is foundational for utilities because it helps them visualize information and points of interest, manage spatial data, and present it. This system can be considered grid visualization technology to have a global vision of consumers, generators, power line locations, and so forth.

GISs have been widely used by utilities for years providing automated mapping and facilities management, back-office records management, asset management, transmission line siting, and more recently, for design and construction, energy conservation, vegetation management, mobile workforce management (MWFM), and as the source of the as-built network model for the Outage Management System (OMS).

Now, utilities integrate GISs with AMI and Supervisory Control and Data Acquisition (SCADA) systems. Using intelligent design techniques has enabled the cross-over from utilities' offices to the field, enabled by GIS capabilities. Geospatial-related analytics, spatial analytics, is a critical aspect of electric utility operations in the smart grid era. Looking for patterns and correlations between different land, weather, terrain, assets, and other geodata types will be increasingly important for utilities. Power-related analytics with geospatial components include network fault tracing, load flow analysis, Volt/VAR analysis, real-time disaster situational awareness, condition-based maintenance, and vegetation management.

These newly identified needs and solutions require an accurate GIS model so that their solutions reflect the system configuration in the field and not outdated by days, weeks, or months. GIS data quality is one of the biggest issues utilities face, especially given the number of changes that impact this model daily. Keeping the GIS current, accurately reflecting what is in the field and how it is connected, has become a corporate and strategically significant initiative at most utilities. Its importance is exacerbated by the need to make real-time automated decisions.

3.1.2. Supervisory Control and Data Acquisition

SCADA is the eyes, ears, and arms of EMS [23]. Most external data from field sensors come in through SCADA, and similarly, most controls sent to operate devices in the field go through SCADA. An example of SCADA tasks is provided below:

- **Data Acquisition:** SCADA gets data from utility field devices. It converts the data from the raw format to its corresponding engineering units, such as voltage, megawatts (MWs), or mega VARs (MVARs) reading. It also performs error checking of incoming data and if limits get violated, alarms are issued.
- **Supervisory control:** All utility controls to field devices go through SCADA. These actions include controls manually sent by the operator and those sent automatically by other programs;

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the impact and length of power interruptions. FLISR can reduce the number of customers impacted by a fault by automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits.

for example, generator set point and pulse controls generated by the Automatic Generation Control (AGC) application.

- **Historical data recording:** SCADA captures and stores historical data on key devices and operator actions to allow personnel to go back in time and understand a specific event and learn all that happened–either from a training perspective or to identify the core problem and fix it.

SCADA is implemented in many places (transmission, distribution, generation, and industrial processes). Terminology such as Transmission-SCADA (T-SCADA – integrated within an EMS) and Distribution-SCADA (D-SCADA – integrated within an ADMS) are also used. SCADA is also implemented in DER locations, microgrids, and other areas.

3.1.3. Outage Management System

An OMS is much more prevalent in distribution control centers than in transmission control centers. This is mainly because most customers (residential, commercial, and industrial) are connected to the distribution system. There are a few exceptions to this where certain large (generally industrial) customers are directly connected to the transmission system. Also, the main objective of the OMS, a system that evolved from the trouble-call management system, is focused on tracking outages at the customer level.

An OMS is primarily used to track outages. All outages are tracked in an OMS and the information from this system directs field crews to fix the problems and restore customers' power . Outage information can come in through direct customer calls or signals from smart meters in the field. Core to the functions of an OMS is:

- Taking in outage calls and information coming in from customers and smart meters
- Managing and maintaining the as-operated state of the network
- Tracking work performed by field crew and updating
- Reporting on outage performance

The OMS is an integral part of the DMS in newer systems, resulting in the name ADMS.

3.1.4. Advanced Distribution Management System

An ADMS is a system of computer-aided tools used by DSOs to monitor, control, and optimize the distribution system's performance [23]. Following some of the earlier sub-sections, the ADMS is a combination of SCADA (called D-SCADA for distribution), OMS, and advanced applications such as FLISR and VVO. Among other things, it allows the Operator to:

- Proactively manage the distribution system
- Increase the reliability and resiliency of the system
- Process real-time data quickly
- Make energy savings via applications that manage the voltage profile of the feeders in specific and the system in general
- Improve decision making
- Minimize outage duration
- Reduce crew patrol and drive times
- Improve utility disaster response

In addition to these benefits, an ADMS also provides the operator with enhanced situational grid awareness, a real-time operational source of the truth.

3.1.5. Energy Management System

An EMS is an integrated system of computer hardware, software, and firmware designed to allow a System Operator in the control room to monitor, control, and optimize the near real-time electric power flow in a transmission system using advanced algorithms, intelligent techniques, and situational awareness-based visualization mechanisms. Simply put, the EMS is the transmission equivalent of the (ADMS) system which is used to monitor and control the distribution system.

3.1.6. DER/Renewables Management and Optimization

The commonly used term for this system is DERMS. This relatively new software-based product promises to solve the challenges of integrating more distributed solar, energy storage, demand response, battery storage, and other energy resources on the grid. It can also use these DERs to improve grid operations.

This system is still evolving and its core capabilities are in flux. While many vendors have systems that fulfill bits and pieces of functionality, and some are farther ahead than others, all of them still have significant gaps. The next generation ADMS (the distribution system operations platform) and EMS (the transmission system operations platform) will need to encompass traditional operational problems in the context of high DER deployment, eliminating the need for a separate system. It would need to integrate with both the transmission and distribution operator and their systems seamlessly. It would also need to interface and work with third-party systems to support customer DER assets which will only share data with the ADMS specific to their operational and financial objectives.

3.1.7. Advanced Metering Infrastructure

AMI is defined as a system that collects, measures, and analyzes energy usage data via a two-way communications network connecting advanced meters (smart meters), and utility back-office systems. AMI systems evolved from legacy AMR (Automated Meter Reading) systems to support one-way communications from the meter to the utility and not the other way around.

The smart meter measures, collects, and stores end-user energy consumption data, commonly at 5- or 15-minute intervals. Smart meters provide greater granularity of usage data enabling more accurate billing and other services. AMI enables remote meter reading for billing, remote connect/disconnect capabilities, voltage measurements, outage detection and management, tamper, and theft detection – all of which lead to a more reliable, lower cost, and smarter grid. Using the smart meter as a communication hub, internal customer systems also have the potential for two-way communication with the utility. This includes home area networks, building management systems, and other customer-side-of-the-meter equipment enabling smart grid functions in residential, commercial, and industrial facilities. [24]

AMI technologies are evolving to the next generation. Now smart meters can perform many more actions, sense more data types in the field, and deliver data more frequently. Smart meters and related technologies are rapidly moving forward with advanced sensors and other sophisticated electronic components such as microprocessor control and support different wireless communications technologies. They also include mechanisms capable of sensing energy, frequency, power quality, and other quantities, transmitting this data on demand. In addition, many utilities are connecting their distribution automation devices to their AMI network, delivering a lower cost, high-reliability communications platform. Others are also considering connecting outdoor lighting and DR into the same network [25]. One of the next steps in AMI is the potential for incorporating real-time AMI data into grid operations supporting ADMS functions such as state estimation, contingency analysis, outage planning, and others.

3.1.8. Customer Information System

The Customer Information System (CIS) is a utility's primary interface to its customer. From an operational perspective, key sets of information from the CIS include customer information and connectivity to the grid, all of which are needed to support the proper functioning of the OMS.

3.2. Non-core systems

In addition to the systems mentioned in section 3.1, there are several others that utilities need to interact with and therefore require integration. These systems could either be utility- or non-utility-owned. However, all of them play an essential role in the management and operation of the utility infrastructure. Grid architectures of the future need to interact with systems with architectures at different levels of sophistication.

3.2.1. Microgrid operations

Stand-alone microgrids with basic functionalities are well understood, but the newer generation of a highly integrated system is still emerging. Modern microgrids are still relatively new technically and commercially. Outside of stand-alone microgrids in isolated regions such as Alaskan villages, most pilot installations are still used as proof-of-technology demonstrations. Operationally they could be owned by the utility or by independent third parties. Regardless, microgrids require separate control system software, which is usually centralized to the entity operating the microgrid. These control systems must accomplish the same operational functions as the bulk power system, just within the boundary of the microgrid.

Even utility-owned microgrids tend to install independent systems loosely integrated with operational systems, such as ADMS. Fundamental components such as the power system model are not commonly shared with the ADMS. The integration is generally one-off and custom to a specific microgrid and generally restricted to the PCC.

The independent nature of microgrids results in a significant limitation because integration is focused on basic control - keeping the microgrid connected or not - instead of dispatching to co-optimize the combined grid. Access to real-time data helps both with the microgrid's operational management and in the distribution, monitoring, and most importantly, predicting how best to respond based on patterns from last day, week, month, etc., and considering weather, seasonality, and other factors. These additions also allow advanced Artificial Intelligence (AI) and Machine Learning (ML) algorithms to be embedded to better support operations. The data will need to be collected, cleansed, normalized, and structured to feed into the ML/AI models/algorithms.

Extending integration to co-optimize and coordinate the microgrid's capabilities and the macro-grid[6] to solve local problems is a missed opportunity. DOE is currently researching networked microgrids operations to support both critical end-use loads and the bulk power system. This is just an example of how microgrids have the potential to be a fundamental building block of future power system architectures [26].

3.2.2. Grid edge systems

These are systems that connect (for example) solar PV installations to the grid. Like traditional inverters, smart inverters convert the direct current (DC) output of solar panels into the alternating current (AC) that consumers can use in their homes and businesses. "Smart inverters" is a general term that applies to a range of inverter capabilities. This can include grid-forming inverters that can actively regulate voltage and frequency and grid-following inverters that can implement voltage response curves and ride-through capabilities [27].

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[6] Macro-grid is a term loosely used in this context to refer to utility grid external to the microgrid.

Most smart inverters [28] are not integrated with the other operational systems, either local or centralized. Suppose the solar site's capabilities are larger than some specific amount, which varies by jurisdiction. In that case, smart inverters may have some level of SCADA or AMI connection. This connectivity starts with AMI and then moves up to SCADA as the capacity of the resource increases.

Like microgrid integration, the key characteristic of inverter integration is primarily focused on controlling at the PCC, keeping the solar PV installation connected or not, instead of dispatching to co-optimize the combined grid.

Extending integration to co-optimize and coordinate the capabilities of grid edge devices, allowing them to participate in the solution of local or system-wide problems, is a current gap. This option also requires coordination across multiple smart inverters to avoid competition based on differing objectives.

3.2.3. In-home and in-building systems

With the advent of capabilities provided by Amazon, Google, and others, the Smart Home is becoming real [29]. Sometimes these devices are also called behind the meter (BTM) devices. Homes and buildings become self-sufficient with significant load and generation components such as EVs, solar PV, local energy storage, and remote controllable equipment such as lights, Heating Ventilation and Air Conditioning (HVAC), wi-fi thermostats, and others. Today, these loads are managed locally from within the house or remotely by the homeowner or business owner/operator.

Except for some utility programs that involve direct control of home thermostats, most in-home systems are not controlled or even visible to the utility operator but could be made responsive to an incentive or coordination signal. Even for commercial buildings, today, there is little to no integration with the utility.

Smart buildings and the smart grid have many mutual advantages for improving their direct interaction through greater interoperability. Buildings and their subsystems are becoming more intelligent, more network-aware, and better able to adapt in real-time using Building Management Systems (BMS). These systems are creating new opportunities to provide substantial benefits to system operators. They provide great potential to help the system operator balance generation with load, optimize generation and defer infrastructure investment through peak load shaving. [30].

In addition, opportunities exist for deep decarbonization by accessing buildings' flexibility to offset the variability from increased DER penetration and its intermittency.

3.2.4. Demand Response

Historically utility DR programs have been used to curtail energy consumption during peak demand periods. Customer programs are built around economic incentives to reduce load to offset the need to run high-cost generation. A combination of utilities and aggregators provides DR services by management of residential and commercial building energy consumption. Typically, each entity, either the utility or aggregator, performs DR independent of others, and there is little to no integration with other systems. Even within a utility, DR is often managed by the customer service department, and these systems or actions are not integrated with the operational systems.

The situation concerning DR is slowly changing at the utility. System operators are beginning to coordinate the control of DR by having direct access to the DR program itself. To work seamlessly, access to many systems is typically required as the DR spans Commercial and Industrial (C&I) loads, Small and Medium Businesses (SMB), and residential customers. An excellent example of this move is Rocky Mountain Power’s DR program used for frequency response [31], necessitating control by the transmission control center.

As the DR signals are sent and load is reduced in response, it is mainly tracked from a revenue and billing perspective.

Moving forward, there will be significant benefits by considering both DR and DERs as complementary portfolios focused on managing and controlling net load. For example, pairing DER production and DR together allows DR to become the first option to smooth out the voltage variations from DER. DR can completely handle minor variations in DER production without any need to dispatch other generation.

3.2.5. Electric Vehicles

While EVs have not yet appeared on a large enough scale to be of widespread impact to utilities, the percentage of EVs will continue to increase over the next decade. Most projections indicate EVs will comprise more than 50% of all light-duty vehicles by 2040 [32].

Another key EV segment to watch is vehicle fleets. Fleets [33] are expected to convert to EVs at a much faster pace than privately-owned vehicles. The 2019 Amazon-Rivian order of 100,000 electric delivery vans [34] and UPS-Arrival order of 10,000 electric delivery vans [35], and equally important orders from commuter and school buses will transform the landscape well before a similar amount of change can be seen in the privately-owned vehicle space.

Equally important is that these vehicles have a much more defined use pattern and duty-cycle, presenting an excellent option for Vehicle to Grid (V2G) integration and potential for net load control. For example, school buses are used in the morning and the afternoon, not traveling many miles during these times. They provide an excellent opportunity for utilizing their batteries to provide either energy or ancillary services into the grid at specific locations in between trips. Providing for fleet charging can significantly impact the utility's ability to meet the load, and so, its location on the distribution network becomes an important consideration. For these aspects to work effectively, it is important to consider the communications and control requirements from the System Operator.

However, until that happens, EV charging is something that utilities are actively piloting now, and it is expected to take on a more prominent role in the next 5-10 years.

3.2.6. Internet of Things

The Internet-of-Things (IoT) is essentially a culmination of advances in the connectivity of hardware and data networks that SCADA provides, as well as cloud computing and bit-data processing. In short, IoT begins where SCADA ends. So, while the IoT market is still in early production, it can coexist with SCADA [36]. IoT[7] devices are being deployed inside homes and buildings and some outdoor settings. For a utility, IoT technology is most synonymous with products pertaining to the concept of the "smart home," such as lighting fixtures, thermostats, home security systems, cameras, and other home appliances that support one or more common ecosystems and can be controlled via different digital assistants [37]. Very often, BTM systems implemented in homes and buildings are also implemented using IoT-based architectures.

IoT devices and their management systems are slowly making their presence felt in utilities – for now in non-critical areas. However, as they make their impact felt both from an effectiveness and cost and performance perspective, they are slowly moving toward operational areas.

Figure 5 presents a view of representative IoT devices in a house and the potential for controlling them either for entertainment, security, or energy management. Hospitals, commercial office buildings,

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[7] IoT is a system of interrelated computing devices, mechanical and digital machines, objects, that are provided with Unique Identifiers (UIDs) and the ability to transfer data over a network without requiring human-to-human or human-to-computer interaction. The definition of the IoT has evolved due to the convergence of multiple technologies, real-time analytics, machine learning, commodity sensors, and embedded systems. Traditional fields of embedded systems, wireless sensor networks, control systems, automation (including home and building automation), and others all contribute to enabling IoT.

industrial and manufacturing facilities, and educational campuses are the first entities to use IoT-based sensors and networks with intelligence based in the cloud.

In the utility operational realm, it is expected that one of the first areas of penetration of IoT devices will be in the microgrid space.

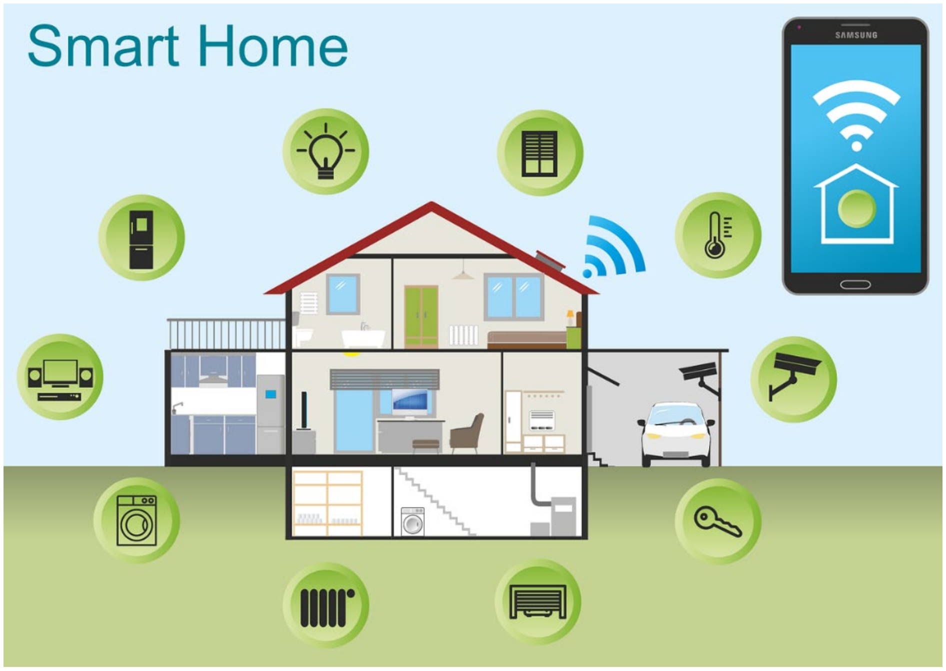

Figure 5: Devices at the grid-edge and beyond. An Opportunity for IoT.
https://pixabay.com/vectors/smart-home-house-technology-2005993/

3.2.7. Battery Energy Storage Systems

Stationary Battery Energy Storage Systems (BESSs) development continues to advance at residential, commercial, and utility-scale. Energy storage has long been considered a game-changing technology that can reduce the need for generation at peak times. Charging batteries during excess generation periods and discharging during high use periods reduces the peak demand and can potentially reduce the ramp rates by smoothening out the daily demand curve.

In the future, providing the System Operator with visibility into the cycling patterns of charging and which sources of energy are being used, such as DERs, will allow for improved grid operations. BESS charge/discharge scheduling and control are potential tools that will develop as this technology matures.

3.3. In Summary, a Need for Integration

Sections 3.1 and 3.2 depict a set of systems, some legacy and still evolving, and others still new and on their way to maturity. All of these systems are different architecturally and functionally. Still, they need to work together as seamlessly as possible so that the utility still functions as a combined entity delivering reliable power to its customers. Figure 6, an adaptation of figure 10.2 from reference [23] presents a conceptual depiction of these integration points from an operational perspective.

Key highlights to take away from this picture include:

- **EMS – ADMS:** These are two real-time systems that monitor and control different portions of the same electric grid at different voltage levels. As a result, actions taken in one portion of the system impact the other. Consequently, the systems need to be integrated, and actions need to be coordinated for maximum benefit.

- **EMS/ADMS – DER/Renewables Management and Optimization:** Renewables, large and small, may be connected to transmission or distribution networks. All renewables will need to be managed and optimized at the transmission/wholesale level for balancing authority functions even though the control may be through the appropriate system (EMS/SCADA or ADMS / SCADA).
- **EMS/ADMS – SCADA:** Some utilities implement a single SCADA system to route all interactions with the field. In such cases, both the EMS and ADMS will need tight integration with SCADA.

In addition to integrating the systems, it is also essential to look at the business imperatives behind some integrations. It's expected that stakeholders will need to be convinced to allow other parties to control the electricity and devices withint their homes, buildings, etc. This will require some kind of outreach or incentives for that kind of integration to successfully occur.

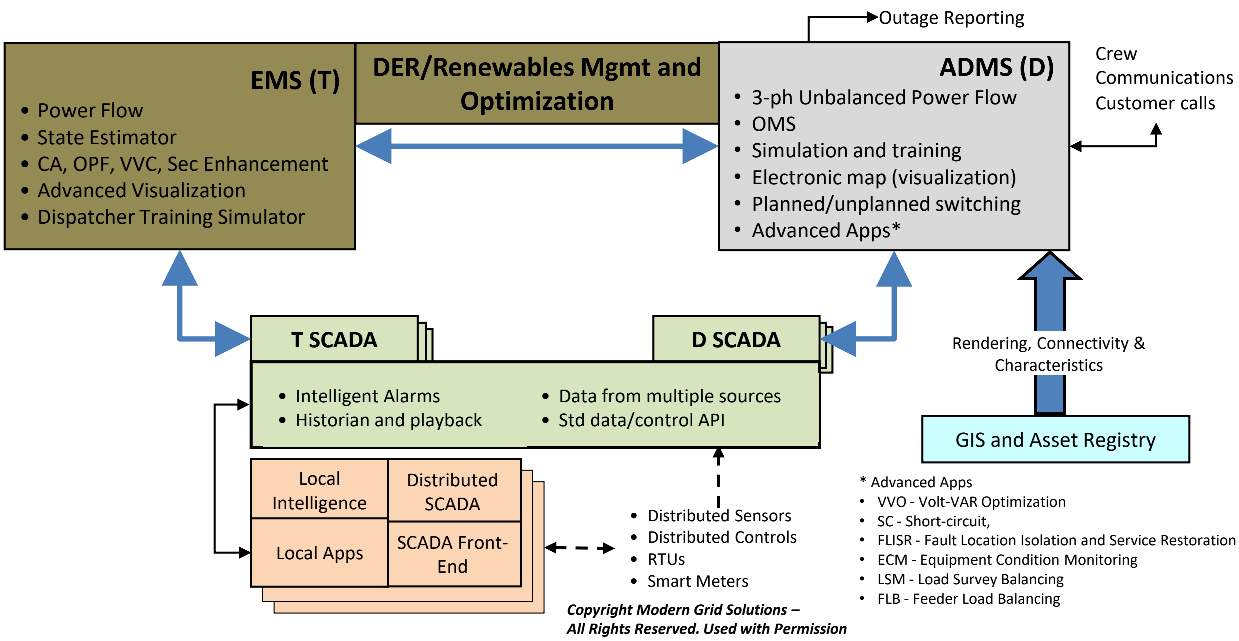

Figure 6: Demonstrating the need for integration of all systems

A common thread, from centralized systems to grid edge to emerging technology, is that they all have the potential to provide data that is essential to the operation of the grid. For example, as more supply resources move from centralized locations towards the edge, the grid will behave much more dynamically. This happens because of the change from one way flow of energy (from large generators to the consumer) to two-way flows due to the placement of DERs. In support of this change, and as the architecture evolves and expands, the need for timely, high-quality data and information will be fundamental to system operations' understanding of how the grid is behaving and its ability to control it to ensure reliable operation.

Data is beginning to become recognized as a critical utility asset whose governance needs to become a corporate priority. Data governance must control its characteristics, ownership, level of detail, confidentiality, accuracy, transformation over time, and the location of its single-source-of-the-truth. Further, its usage - who can use it, under what circumstances, when, and how often – must be addressed. An example: AMI data needs to be anonymized and aggregated before it can be shared with parties external to the utility, which may introduce latency, errors, and lower confidence in its use for real-time operational actions.

4. Key characteristics of the operational architecture of the future

The future operational architecture has several components, which are described in more detail in the following sub-sections. These components are that:

- It supports the existence of centralized legacy systems such as SCADA, EMS, OMS, and others while still expanding to incorporate the newer and emerging systems that could be either centralized, decentralized, or distributed. The next generation ADMS will also need to be forward and backward compatible with these systems as they mature.
- It has a complete, up-to-date, and accurate as-built state[8] and as-operated state[9] of the network that is resident centrally where it is managed and maintained. All decentralized and distributed systems and applications derive the models (state) from this centralized location depending on their needs independent of others.
- Its remote systems, decentralized or distributed, can be situated across the utility grid at different locations. Of course, the same concept applies to centralized systems as well.
    - They are connected to the centralized systems through various data/control bus mechanisms and secured via multiple methods to ensure the overall integrity of the information and cybersecurity posture of the system. This connection is important to ensure a central location where full situational awareness on the as-operated state of the system is maintained.
    - All or most intelligence required to make decisions is available at the remote location in a computer or an embedded system. Enough information is available locally to ensure the localized intelligence can make the appropriate decisions.

  The remote systems can operate individually or as a collection of systems and connect with one or a group of devices, each of which can be either utility-owned or third-party owned. With the increase of more third-party owned systems and decentralized applications the observability of utilities have been decreasing and a well designed architecture will help make sure operators have all the necessary information and applications at their disposal so that they can make optimal decisions.
- Services supported by this architecture could include (note, this is not intended to be an exhaustive list):
    - Dispatch of energy (MWs/KWs) and/or reactive power (MVARs/KVARs)
    - Monitoring of DERs and bringing related local data such as irradiance data to where it is needed
    - Deliver market or transactive economic signals to support both wholesale and retail markets
    - Perform microgrid monitoring, management, and control
    - Provide local and centralized support for field personnel to perform their work safely
    - Share data and models with the operators of all the systems, utility, and third party(ies)
    - Share with others as needed now or in the future

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[8] The As-built model is the model that is maintained in a GIS or equivalent repository. This model contains all the device characteristics and in addition, the device status in case of the normal operating position.

[9] The As-operated model is the one that superimposes the existing device status from the field on top of the as-built model. This model now includes switch positions which may be different from the As-built (designed normal operating state) which in turn will change the flow of power and the voltages at the various buses.

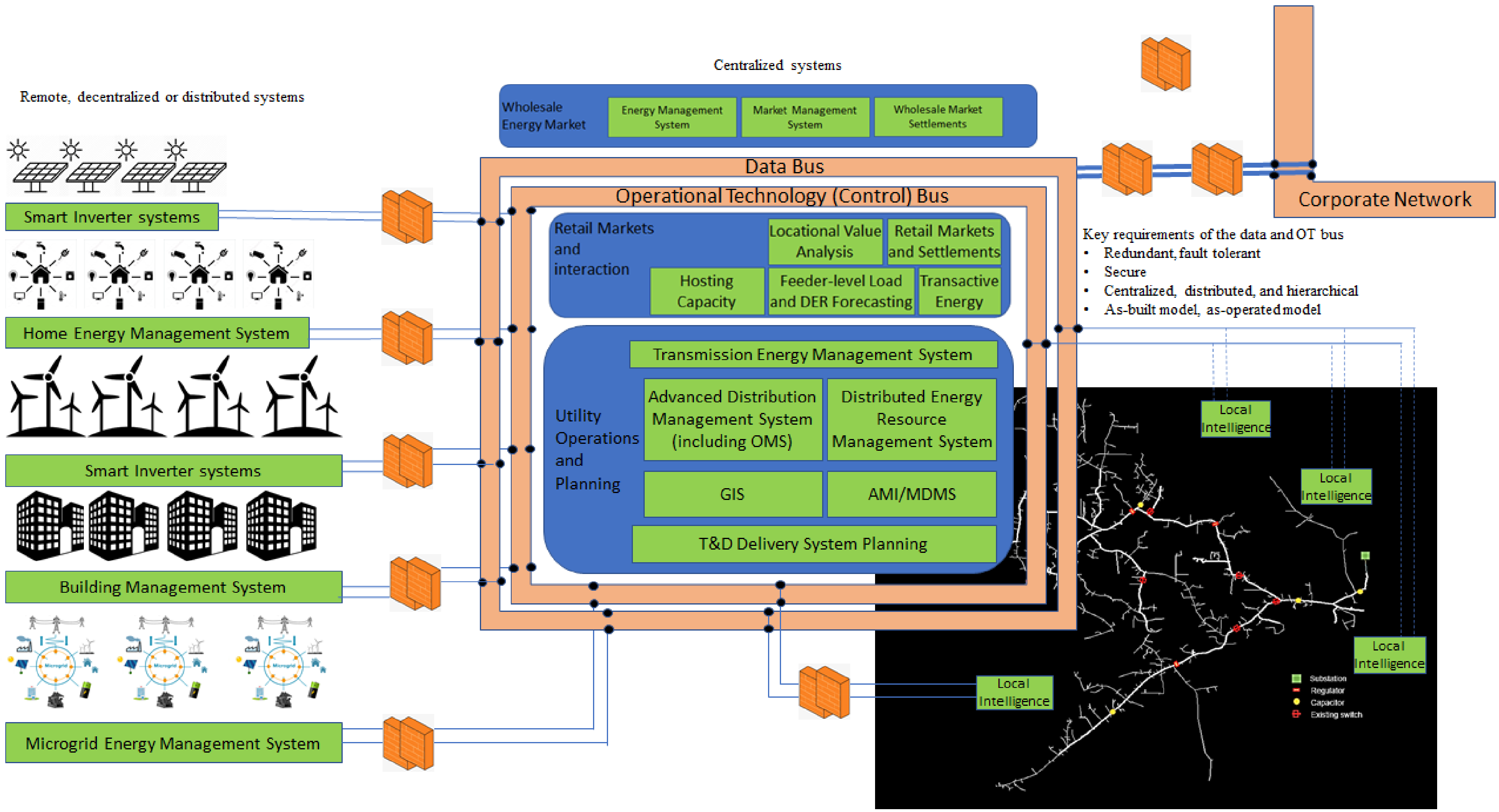

Figure 7: A Logical Architectural Construct of the Future Grid

- The move of operational control from a predominantly centralized location to one that could be either centralized, decentralized, or distributed increases the exposure to threats that could be either physical or cyber. As a result, there is a need to separate non-operational interactions between these systems from operational interactions. An approach presented in this paper is to achieve this through the creation of two separate communications mechanisms – the IT/Data bus and the OT/Control bus. The data bus is responsible for carrying all the non-operational models and information necessary to drive key grid network decisions. In contrast, the control bus is responsible for carrying all the operational data and control actions taken at the local level, centralized level, or at other levels in-between, should they exist.

  Some of this change is also considering that a Critical Infrastructure Protection (CIP) like requirement may come to include distribution systems in the near future. Creating the two buses will allow the NERC CIP constraints to be applied to the OT/Control bus and not possibly apply to the IT/Data bus.

Figure 7 presents a high-level view of the proposed grid architecture to support future transmission and distribution planning/operations scenarios. The following sections expand on some of the core characteristics of the grid architecture of the future.

4.1. Two new types of buses

A bus or a data highway is a critical part of a computer network used to move data between components within a computer or between computers or between devices in the field and computers. The term "bus" generally covers the hardware, software, and communications protocols that manage and control this data transportation. Over time, the bus has been transformed into an Enterprise Services Bus (ESB). Applications and software can communicate with each other through a common set of connectors that allow application components to pass information to the bus. In addition, the ESB comes with middleware software that manages the flow of information through its network, making sure that (among other things) the information reliably flows from the originator to the destination in a secure manner.

In this paper, we introduce the two conceptual10 architectural components necessary to support the requirements of the devices and systems. The two buses will enable the most efficient processing of information and control to occur at the optimum location. In addition, this separation was thought to be necessary to isolate data and actions that control the electric grid from getting interspersed with other types of information exchange. Both the IT/Data and OT/Control buses need to work across a broad range of communications mechanisms supporting protocols and systems (e.g., centralized, decentralized, distributed, non-utility, external).

As a point of clarification, this paper is not comparing the two conceptual buses proposed here with their physical counterparts in computer networks. Instead, the constructs presented here demonstrate the need to separate the kinds of information to function securely and reliably.

1. Data bus

The data bus should fulfill the following requirements to support the next-generation systems:

- **Incorporate both as-built and as-operated models:** It should be capable of the following grid network model changes
    - delivering either of the models based on the needs of each component,
    - delivering either the whole model or portions thereof based on the need of the specific component, and
    - keeping track of changes, with change source and time stamp, in either model and updating those specific components based on their exact needs while only sending the changes required.

[10] Important to note that portions of both the OT/control bus and IT/data bus do exist in several vendor solutions. Our expectation is that the next generation architecture will have these components as a standard part of the component list.

- **Manage non-operational data:** In addition to the mostly operational and power system data that has been discussed, the data bus also needs to be capable of handling non-operational data such as:
    - Registration information: Particularly important, especially with the advent of DERs expected to increase in numbers and scale. Their presence on the grid along with information such as physical location (address, GPS coordinates, etc.), topological location (where they are connected on the electric grid), their capability (e.g., nameplate ratings), and information on their control and sensing capabilities.
    - Contractual information: DERs connected to the grid can be either utility-owned (regulated asset), third-party asset, or utility-owned (unregulated). Many of these will also come with contractual constraints that may limit the actions taken on them during operations.
- **Accept slow-changing and static data:** It should manage data that does not change as often, such as:
    - Load characteristics
    - Load forecast (system-wide, end-user, and DERs)

    And, in addition,
- **Be fully redundant and fault-tolerant:** It should always be available and resilient under a broad set of failure modes.
- **Be highly secure:** It should be capable of handling evolving cyber threats and can isolate attacks to minimize their impact on the grid's broader operation.
- **Ensure data and personal privacy requirements are met:** It should be designed to provide only the necessary data to each component and system based on its needs and permissions, even though it may have access to a broader range of data.
- **Integrate with centralized, hierarchical, or fully distributed systems:** It should work equally well with multivariate solutions and various architectural models as needed to perform its functions.

2. <u>Control bus</u>

The Operational Technology Bus (OT bus or the control bus) is a newer concept for utilities and one in which all control actions are taken in real-time or near-real-time. The OT bus must fulfill the following main requirements of next-generation systems.

- **Control Signals:** It must communicate control signals from the appropriate function (centralized or decentralized) to the correct field device. The control signals can be one of many, such as:
    - Turn devices on/off
    - Set or change setpoints for devices in the field
    - Set operational schedules (time) for changing settings
    - Send either MW or MVAR setpoints for devices in the field
    - Send market (pricing) signals to specific devices or groups of devices in the field
    - Send specific instructions to technical (microgrid) or business aggregators in the field to take specific actions
    - Log and track all control actions and their results
    - Log and track all operator or human actions and their results
- **Alarms:** Present and communicate alarms on specific devices based on when the device functions outside of specific pre-defined operating parameters, remains in an abnormal state for a designated time, or trends to an unacceptable value for a specific period (e.g., rate of change).
- **Substation actions:** It must support hierarchical and distributed actions such as the substation and process bus, which perform activities local to a substation.

- **Process data in real-time:** It should maintain all the data and changes in real-time, including:
    - SCADA data – analogs, statuses, and control actions
    - High fidelity time-synchronized data like synchrophasors at both the T&D levels, including advancements using continuous point-on-wave measurements for detecting transients
    - Alarms and alerts
    - AMI/meter data
    - Data from the grid-edge device
    - Data from all other systems centralized and remote
    - Others as identified
- **Be fully redundant and fault-tolerant:** It should always be fully available under a broad set of different failure modes.
- **Be highly secure:** It should be capable of handling all cyber threats, containing attacks to minimize their impact on the grid's broader operation.
- **Support privacy:** It should be designed to provide only the necessary data and controls to each component and system based on its needs and permissions while providing access to a comprehensive model.
- **Centralized, hierarchical, or fully distributed:** It should work under different architectural modes as needed to perform its functions.
- **System-wide data:** It should also keep a complete copy of all the system-wide data both for real-time centralized operations and also to support (1) fault-tolerant actions as well as (2) other non-real-time analyses. In addition, it should also store all relevant data and models in an archival system.

4.2. Standardized and open interfaces

As previously described, there is significant growth in the number and complexity of components to consider in the future operational architecture. The best approach to providing cost-effective integration and enabling advanced control and coordination of these components and related applications is to move to a standards-based approach, using open APIs and architectures. A standards-based approach uses industry-recognized protocols, open APIs, and modular architectures. With this approach, the industry can separate data integration, a problem that grows in complexity with increased deployment of distribution system DERs and load electrification, from the issue of delivering the functionality required to manage, operate, and control the different parts of the distribution system. Standardizing the integration between systems, and modules in a system, allows them to evolve much faster and meet the changing needs of the system operators. Implementing it using a standards-driven approach allows the entire suite of solutions to become more flexible, more nimble, and capable of changing faster while keeping up with the industry's changing needs.

Standardized interfaces can support offerings from multiple vendors with clearly defined market segments. Additionally, through this approach, utilities can select functionality appropriate to operational environments, which better match their operating environment. The benefits of this approach include:

- Scalability in features, up or down, for utilities of different sizes
- Scales with growth in system complexity that accompany EVs and DER penetration driven by decarbonization
- Applications portable from one system to another with reduced system integration needs
- Vendors independent from platform suppliers can deploy applications due to API standardization
- Provides architectural flexibility where applications and services can be distributed independently across a utility or even mixed hybrid cloud environments

Standardization is not a new or novel approach. Other industries have encountered similar challenges and have met them with great success. Examples abound in 1) Online banking, 2) Cloud computing Hypertext Transfer

Protocol Secure + Representational state transfer (HTTPS + REST[11]), 3) Transportation Control Area Network bus (CAN bus), 4) Industrial electronics (Modbus), (5) Building controls Building Automation and Controls Network (BACnet, and Modbus). Added to all of this is the ubiquitous Universal Serial Bus (USB) standard that has become so pervasive that almost every person is aware of it as they interact with their PCs, smartphones, and other electric devices.

The utility industry is already familiar with the concept and leverages multiple standards. A few key examples are:

- Common Information Model (CIM), which is heavily used by almost all utilities when exchanging transmission system models
- Inter Control-Center Communications Protocol (ICCP), which is used to exchange real-time data between control centers
- Distributed Network Protocol 3 (DNP3), a set of communications protocols used in real-time operations and control
- International Electrotechnical Commission (IEC) 61850, international standard defining communication protocols for intelligent electronic devices at electrical substations
- Institute of Electrical and Electronics Engineers (IEEE) 2030.5 an application layer protocol that supports integration with DERs, Pricing, Metering, etc.

The result is that the design of applications is standardized and modularized. This outcome results when the component design is focused more on functionality instead of integration at a system level. This also allows each function to be more universally available to all components and used in multiple contexts.

4.3. Standardized tools and APIs

The distribution system component designer (application developer, solution architect, product owner, and so on) benefits from common and standardized tools and APIs to support their applications and integration. Commonly used ones are listed below. Other tools may need to be added, such as:

- Alarms
- Display builders
- Ability to perform controls, e.g., open/close switches, change transformer/regulator taps, deliver setpoint to a solar farm inverter, and so on
- Optimizers
- Distribution power flow
- Permissions
- A full range of advanced applications
- Self-registering of devices and components
- Security
- Model management – as-built model and as-operated model
- Historical Data Recording

A standardized process for integrating new application, function or system is needed, which will address how a particular tool or API is invoked, how all data and (in particular, the power system model) are transferred into it, how data is extracted from it, and how the utility is managed and configured. GridAPPS-D™ [38] offers a standardized toolset to access such tools and APIs.

These standardized utilities/tools/functions are the crux to making the next generation of architecture work. Not only do these need to be developed, but they need to be adopted and utilized going forward to begin to enable this massive data exchange.

[11] Representational state transfer (REST) is a software architectural style which uses a subset of HTTP.[1] It is commonly used to create interactive applications that use Web services.

4.4. **Standards-based and standardized models**

Establishing and utilizing a standard allows for modeling the various components to be done in a structured manner using a common approach. The most significant benefit of using these standards is that it normalizes exchanging data and model information using common and accepted structures. The data elements stored in all the systems and subsystems would need to follow a standard such as CIM[12], Multispeak[13], Smart Inverter[14], Open Field Message Bus (OpenFMB)[15], IEEE 2030.5, and others such as Open Automated Demand Response (OpenADR[16]) to achieve this simplification. However, it would also be vital for all of them to support the ability to prepare the data for exchange with each other using standards-based models.

It is also vital that the systems and subsystems (centralized, decentralized, or distributed) function based on the same as-built and as-operated power system model. Depending on the component requirements, the following capabilities will need to be supported:

- The ability to share the as-built model in its entirety or in piece-parts (as needed) with all applications, whether centralized, decentralized or distributed
- The ability to share the as-operated model to be reflected within the ADMS or any control system so that the applications have an opportunity to solve for the "best" solution. Telemetry alone will not achieve it since every device may not be reporting back to an ADMS/the control system.
- The ability to share the as-operated model or enough data to recreate it in a different location or instance

4.5. **Self-registration of devices, applications, and systems**

One of the key requirements of the future grid architecture is the need to connect many devices, applications, and systems to the electric grid in the coming decades. Depending on the time-of-the-day, day-of-the-week, seasonal, or other business reasons, these devices, applications, and systems may either be connected to the grid or not (e.g., a microgrid could be either be connected to the grid or not). The electric grid is similar to a computer network in that computer, automation, and power system devices and components are continuously added and removed from the grid's network. Today, these changes are manually managed and maintained. It is

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[12] In electric power transmission and distribution, the Common Information Model (CIM), a standard developed by the electric power industry that has been officially adopted by the International Electrotechnical Commission (IEC), to allow application software to exchange information about an electrical network. It defines a common vocabulary and basic ontology for aspects of the electric power industry. The model describes the basic components used to transport electricity. The standard that defines the core packages of the CIM is IEC 61970-301, with a focus on the needs of electricity transmission, where related applications include energy management system, SCADA, planning and optimization. The IEC 61968 series of standards extend the CIM to meet the needs of electrical distribution, where related applications include distribution management system, outage management system, planning, metering, work management, geographic information system, asset management, customer information systems and enterprise resource planning.

[13] The MultiSpeak Specification is a key industry-wide standard for realizing the potential of enterprise application interoperability. The MultiSpeak Specification is a standard in North America pertaining to distribution utilities and all portions of vertically integrated utilities except generation and power marketing. The current Specification covers over 40 functional endpoints including meter reading, connect/disconnect, meter data management, outage detection, load management, SCADA, demand response, and distribution automation control.

[14] Smart inverters are an emerging technology that can enable more efficient integration of DERs. Like traditional inverters, smart inverters convert the direct current output of solar panels into the alternating current that can be used by consumers in their homes and businesses. Examples of these standards include IEEE 1547-2018, IEEE 2030.5.

[15] OpenFMB is a reference architecture and framework for allowing distributed intelligent nodes to interact with each other. These nodes manage distributed resources that communicate via common semantics and federate data locally for control and reporting. It was formally adopted by two task forces within the Smart Grid Interoperability Panel (SGIP) and the North America Energy Standards Board (NAESB)

[16] The OpenADR Alliance was created to standardize, automate, and simplify DR and DER to enable utilities and aggregators to cost-effectively manage growing energy demand & decentralized energy production, and customers to control their energy future. OpenADR is an open, highly secure, and two-way information exchange model and Smart Grid standard. https://www.openadr.org/

expected that the number of distributed devices will increase dramatically [39], making the manual maintenance of these devices very time-consuming and not sustainable in the long run. The architecture should support tools and APIs that detect new/modified components, classify them, and incorporate them into the system as appropriate. The ability of these devices to "self-register" and advertise their existence and associated connection points on the grid is essential.

Some of the main benefits of self-registration are to ensure that:

- Devices, applications, or systems that interconnect, and the centralized systems need to be authenticated and provisioned through the centralized mechanism, so current capabilities are known and are authorized to act on the system
- When they pass information, it is treated as coming from a trusted source
- Every component knows what is currently connected to the system, its state (grid-connected, grid-disconnected, or other), and its capabilities (what it can do, and so on)
- Remote components can then communicate with each other through a trust-based process

For devices and systems to self-register, there needs to be a proper and standard protocol, and all devices must "adhere" and "support" those protocols and standards. Sometimes, a better mechanism is to approach it through discovery, data collection, and classification of such devices, which tends to be much more reliable.

4.6. Raising awareness and understanding evolving grid operational needs

Sections 1, 2, and 3 set the stage by focusing on the context for the changes beginning to impact the utility industry. The change was visualized through several dimensions such as (1) changes in the electric grid that were transformative, (2) existing and new stakeholders in this transforming utility industry and their impact on system operations, (3) the state of the operational architectures today, and (4) existing and upcoming electric grid technologies and systems. The architectural characteristics presented in Section 4 focused on delivering on those needs. In particular, they highlighted:

1. **Transformative events are changing how we interact with the utility**. The architecture is designed to support different kinds of operational interactions with the utility, whether within the jurisdiction or external.
2. **Identifying new and existing stakeholders who are actively interacting with the grid and their resulting impact on system operations**. As figure 7 shows, the architecture is designed to interact with different stakeholders operationally. The two conceptual buses (IT/Data and OT/Control) provide an advanced level of flexibility and scalability while still maintaining a focus on cybersecurity by bringing special constructs and mechanisms to combat the various forms of attacks of today and tomorrow.
3. **The ability to support today's operational architectures**. The conceptual architecture has also identified mechanisms to interact with a host of systems operationally, whether designed to function in a centralized, decentralized, or distributed manner.
4. **The ability to support existing and emerging electric grid technologies and systems**. Lastly, the proposed conceptual architecture is also designed to interact with existing and known systems prevalent in the operational realm of an electric utility.

4.7. Architecture in summary

The electric utility industry has the opportunity to learn from other industries and environments and move towards an architecture where the application or subsystem is separate from the data. We are moving towards a data-rich environment where a tremendous amount of data comes from sensors in the grid and beyond (grid-edge and BTM). The systems and the architectures they are built on need to evolve with the changes. This means that we need to be aware of the following important considerations:

- Applications, people, and devices that self-register into the environment and have the permissions they are allowed. Among other aspects, permissions would determine:
    - What data they can have access to, and when
    - What functions they can perform and
    - What data they can share, and to whom
- Based on their permissions, the applications, people, or devices will:
    - Ask for and get the portions of the as-built and/or as-operated model that they require.
    - Ask for and get the data they need to perform their actions.
    - Perform their functionality and provide their output to all other components that require it and have the permissions to get it.
    - All permissions are secure, private, and trust/need-based.
- Other key considerations:
    - As the grid evolves, there are several tradeoffs to consider in terms of communication and data needs. For example, how will communication and control infrastructure (IT and OT bus) evolve with the centralized/distributed/decentralized architectures? How will the cost Vs. benefit tradeoff be assessed as the architecture evolves?
    - Emerging challenges to cybersecurity need to be considered and managed as the architecture evolves. For example, cybersecurity will only become more critical as the OT infrastructure moves from today's mostly centralized, utility-controlled model to one in which the utility is dependent on third-party suppliers of energy and other grid services.
    - The tradeoff between privacy and visibility will become more critical as an increased number of private stakeholders emerge, and the utility will need to engage and interact with them operationally. Specific code of conduct standards may need to be developed to ensure that the data is handled only to the extent required to operate the system.
    - The commercial considerations may constrain and drive the operational and technical flexibility requiring notification or limiting available control and optimization based on contractual commitments.
    - As customers become more active and diverse, several non-technical considerations need to be incorporated into the modeling of loads and consumers. These are considerations that will overlay on top of technical considerations. Some non-technical considerations will focus on countering negative behaviors such as greed, gaming, participants falsifying information, etc. They will need to be considered with regard to DR for grid services. A newer technique to identify either technical issues in DR is to overlay AMI (disaggregated) and DR event data to pinpoint customer sites to investigate.
    - The Human-in-the-Loop takes humans who are involved in the operation of the grid. Examples of humans being considered include operators, planners, and customers. It also provides end loads with smart devices and aspects of human-machine teaming. The architecture of the future also needs to consider the human element and how the decision-making tools present data to the decision-makers because of its vital importance to the successful operation of our future grid.
    - The utility industry should accelerate the adoption of new environments such as cloud and SaaS[17] alternatives. These solutions could be implemented either on a public cloud, private

[17] Software as a Service (SaaS) is a software licensing and delivery model in which software is licensed on a subscription basis and is centrally hosted. It is also sometimes referred to as "on-demand software" or Web-based/Web-hosted software. SaaS is considered to be part of cloud computing, along with infrastructure as a service (IaaS), platform as a service (PaaS), desktop as a service (DaaS),[6] managed software as a service (MSaaS), mobile backend as a service (MBaaS), datacenter as a service (DCaaS), and information technology management as a service (ITMaaS). SaaS apps are typically accessed by

cloud, or the same solution implemented as an on-premise solution. With appropriate security, Cloud and SaaS provide greater flexibility in the solutions, tools and utilities that make it easier for rapid development and implementation at a lower cost profile.

- Lastly, another key area that requires some self-assessment is the regulatory arena. Much of the transmission considered to be supporting interstate commerce is regulated mainly by FERC, whereas much of the distribution system is regulated by state Public Utility Commissions (PUCs). As the line between transmission and distribution becomes increasingly blurred, the regulatory mandate also needs to be flexible to adapt to these changes.

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users using a thin client, e.g., via a web browser. SaaS has become a common delivery model for many business applications, including office software, payroll processing / accounting / invoicing, customer relationship management (CRM), and enterprise resource planning (ERP).

5. A roadmap to defining grid architecture requirements of the future

The architecture described in this white paper cannot be implemented immediately. Moving from today's mostly centralized systems approach to one that supports a combination of centralized, distributed, and decentralized systems will take time and effort. The architectures, along with the systems and the sophistication of their capabilities, will evolve. This is a continuously developing journey whose trajectory will be influenced by assumptions about several factors such as business and customer need, technology maturity, changes in regulatory environments, and utility industry focus which may change over time.

Figure 8 represents a roadmap that drives the foundation of how these architectures will change. Driven by conditions in the industry, the roadmap defines the requirements of the future architecture. The roadmap is intended to be a living construct that will evolve as needs, signposts and technology maturity change, which in turn also influences their impacts on the evolution of utility operational architectures.

5.1. Description of the roadmap

There are several components to how the technical architecture for distribution planning and operations will evolve in the future:

- **Guiding Principles**: These define the approach and identify the essential aspects of the decisions made as this roadmap evolves into the future.
- **Timeframes**: The following timeframes have been identified and are based on how technology moves from concept to production.
    - **Introductory (Now)**: The technology and its components are in production and working now.
    - **Foundational (1-3 years):** The technology and its components are in pilot mode and are getting ready for production.
    - **Evolutionary (4-7 years):** The technology and its components are in research mode and will need to move first to pilot mode before going into the production environment.
    - **Revolutionary (7+ years):** These technologies and their components are on the horizon but not nearly ready for any actual implementation in a utility. However, there needs to be a close watch on them to review periodically for consideration if they should be brought forward.
    - **Disruptive (variable):** These are technologies that may be at a conceptual stage monitored closely. These can come up at any time. Most will be long-term, but some may not. For example, a breakthrough in energy storage could occur with a 3-year time frame. When they become available, they will change the game completely.

5.2. Key assumptions for building the roadmap

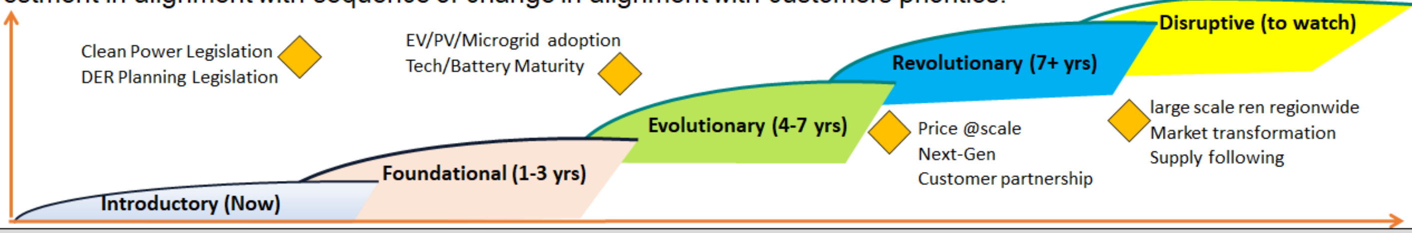
There are several assumptions to consider in building a roadmap for the grid architecture of the future:

- **Signposts utilities should watch for:** Signposts are indicators that utilities and technology providers should watch before deciding to change from meeting the technology needs of one timeframe to the next.
- **How industry and customer needs evolve**: Utility roadmaps start with industry and customer needs. This evolution drives the needs of the technologies that then get implemented to respond to the needs.
- **How technology matures**: Technology (IT and OT) maturation in utilities generally shows up somewhat behind other industries, mainly because of the more conservative nature of the utility industry. They are generally more hesitant to try new technologies because of the critical nature of electrical infrastructure.

A roadmap defines investment in alignment with sequence of change in alignment with customers priorities.

Guiding Principles

1. *Align pace with customers' aspirations, and affordability.*
2. *Track/influence policy & regulatory changes – state and federal.*
3. *Spend prudently – spending customer's money*
4. *Watching technology trends and signposts to determine when / if need to act.*
5. *Keep an eye on the distance for disruptive technologies that might come to bear.*
6. *Learn from (pilots, Living lab, customer insights, etc.) – even if from other utilities experiences.*
7. *Assumptions informing immediate tactical tangible action plans in the short term.*
   - *Visibility insights and control*
   - *Reliability, resiliency and grid optimization.*
   - *Distributed energy, resources integration.*
   - *Customer empowerment and stakeholder engagement.*



As Industry Factors and Customer Needs Evolve (assumptions)				
Per utility • DER/DR/NWAs % penetration: Low • EV Penetration: Low, rising • Microgrids coming of age • Storage maturing	Per utility • DERs: 20 ckts, 100 MW rooftop PV • DR/NWA still opportunistic in use • EV Penetration. 75K – 100K • 3-5 microgrids • Targeted Storage implementations	Per utility • Planning: More NWA (+storage) • DR: increased use as an alternative • Transactive DR under consideration • DERs: 50 ckts, 500 MW rooftop PV • EV Penetration> 200K. • Micrograds in 10-15% utility territory	Per utility • DR: more prevalent as an alternative • Transactive DR getting common • NWA becoming more common • 20-25% micrograds in utility • EV/HV/ST 35-45% transport • DERs: 200 ckts and growing • Storage/NWA – commonplace	Per utility • DER/DR/NWA commonplace • Vehicle-to-Grid (V2G), >50% EVs • CCAs commonplace • 100% renewable; Cold fusion • Full rate unbundling
and Technology Matures (Assumptions)				
• AMI Mature, Comm still slow • 1st gen PV mature / inexpensive • 1st gen storage emerging • 1st gen EV gaining acceptance • 1st gen Microgrid – pilot mode • 5G communication emerging	• ADMS/AMI – Mature. DA/Grid-Edge automation emerging • 1st gen PV continuing price/perf imp • 1st gen storage maturing • 1st gen EV gaining critical mass • 1st gen microgrid evolving • 5G communication prevalent	• DA/Grid-Edge automation increasing • Solid-state PS components emerging • 2nd gen PV (+ storage) emerging • 2nd gen storage emerging • 1st gen EV (>20% penetration). Bigger impact in fleet. • Microgrid capability maturing. Commercially justifiable • Comm bandwidth and latency imp	• Real-time AMI introduction. • DA/Grid-Edge automation mature – intelligence embedded. • Solid state PS components evolving • Early 2nd gen PV (+ storage) • 2nd gen Storage – enhanced capacity / duration • 2nd gen EV emerging (V2G) • Microgrids at scale • Comm bandwidth and latency imp	• AMI//DA/Grid-Edge tech evolution • Solid state PS components common – complete w/remote intelligence • Ubiquitous Solar PV • Storage/DERs/ NWAs Pricing signals • Carbon sequestration • D grid conglomeration of microgrids • Nuclear fusion(?) • Comm bandwidth and latency imp
And utilities continue their focus on improvements in reliability, resiliency, safety, risks and new customer options (assumptions)				

• Initial Grid-Edge visibility for safety
• Beginnings of
  • Reliability at a lower cost
  • Operational flexibility
  • Early DER int for imp cust choice
	• Complete grid edge visibility
	• Targeted peak load shifting
	• Reliability at lower cost - Initial CBM
	• Alt cust DER partnership opportunities
	• Imp power quality in specific feeders
		• Early edge of grid control and dispatch
		• Expanded load shifting during peak
		• CBM for all high-risk equipment
		• Integrated Grid Planning is prevalent
		• Customer collaboration solidified
			• Edge of grid control/dispatch at scale
			• Carbon impact at 70% reduction
			• Consumer prosumers: customer as energy operations partners
				• Significant transmission investments
				• Retail markets transformation and CCA
				• Carbon neutrality – 100%

Driving a need for updates to utility architectures – Technology architecture evolution (Projection based on assumptions)				
• Cloud installations - awareness • Primary decision-making central • Limited to no intelligence at edge – basically independent devices • Data and OT bus just a concept • As-Operated state knowledge central • AI/ML in operations – awareness • Microgrid integration – manual • Open source S/W – awareness	• Cloud considered by small utilities • Primary decision-making central • Grid-edge intelligence emerging – still basically independent devices • Data and OT bus still a concept • As-Operated state knowledge central • AI/ML in operations – investigating / advisory • Microgrid integration – still manual • Open Source S/W – Still awareness	• More cloud apps – Small utilities (some large) • Primary decision-making still central • But grid-edge intelligence evolving – some coordination among devices • Data and OT bus emerging • As-Operated state knowledge central – but some knowledge at edge • AI/ML in operations – advisory / pilots. Aug reality introduced in field • Microgrid integration – increased awareness • Open source S/W – inc acceptance	• Cloud apps norm • Decision-making divided between centralized and grid-edge. • Grid-Edge intelligence mature –full PS state knowledge + coordination • Data and OT bus evolving • As-Operated state knowledge central – but full knowledge at edge • AI/ML in operations – evolving. Aug reality norm in field • Microgrid – Full integration • Open source S/W – Inc acceptance	• Next-gen app dev env emerging • More decision-making moving from centralized to grid-edge. • Grid-Edge intelligence normal –full PS state knowledge + coordination • Data and OT bus standard • As-Operated state knowledge central – but full knowledge at edge • AI/ML in operations – commonplace and in closed-loop operation. • Microgrid – internal to D Operations • Open source S/W – Inc acceptance

Figure 8: Grid Operations Architecture Roadmap

However, lately, utilities are keener on working with research laboratories, universities, and other similar entities to try new technologies. In addition, since the 2008 American Recovery and Reinvestment Act (ARRA) grants, utilities are also more interested in piloting new technologies at their locations to solve specific problems. Some examples include:

  - Duke Energy and Avista working on OpenFMB [40]
  - Southern California Edison [41] working on augmented reality for its field staff
  - Ameren partnering with the University of Illinois on the Technology Application Center (TAC). The TAC houses a microgrid to prove various microgrid technologies but is connected to Ameren's grid and serves Ameren retail customers [42,43].
  - Argonne National Laboratory and Exelon [44] having a cooperative research and development agreement focused on identifying new technology and systems to help develop the next-generation energy grid

- **How utilities continue their focus on improvements in reliability, resiliency, safety, risks, and new customer options**: The industry/customer needs to be supported by new IT and OT technologies to drive new solutions required to solve new problems or develop better solutions for existing problems.
- **How the technology architectures evolves**: The definition of architecture changes is based on known information from today's situation covering both the utility industry and others. In the past, the utility industry could change on its own and at its own pace. This option may no longer be sustainable. Instead, the utility industry will need to follow the evolution of technologies and architectures in line with the broader mainstream enterprises.

Roadmaps are created based on assumptions and observations. These assumptions will need to be reviewed periodically to ensure that the roadmap is always up to date.

5.3. Key challenges as the roadmap is traversed

The path taken by utilities and vendors as they traverse the roadmap will not be easy or known ahead of time. Several challenges will need to be faced, some technical, some business, and some legal. A few of those challenges are listed below:

- Industries that drive to standards rapidly allow the standards to be either driven by the private sector or one in which the private sector has a major say. Excellent examples of this are in computers, telecom, and gas. This means that a combination of utilities and vendors may need to drive the discussion on standards to get them accepted and adopted.
- Although not directly considered in this white paper, cost is a driving factor for utility/consumer behaviors (i.e., premium pay for green energy, renewable Energy Credits (RECs), etc.).
- Establishing "trusted" components is expensive, and the same concepts of trust will need to be adopted by all participants. This becomes an important aspect when utility-owned and third-party-owned components all exist in a grid and jointly contribute to its reliability and resilience. Without that, componentization of functionality - either through software or hardware - will be exceedingly difficult and the ease of their integration nearly impossible.
- Challenges from vendors on exposing what they believe are their technical or competitive advantages. Any vendor movement on the roadmap will only happen if they perceive a business benefit to themselves (e.g., they will sell more systems, more applications, or more something), or the utility is mandating.
- Cybersecurity challenges, which are only increasing in numbers and their impacts, will seriously affect the potential use of open-source software for mission-critical applications in the utility operations space. The fallout of the Solar-Winds hack [45] was that the breach was not only one

of the largest in recent memory, but also came as a wake-up call for federal cybersecurity efforts. In addition, the recent ransomware attack on Colonial Pipeline [46], which forced the company to halt all pipeline operations to contain the attack and make a payment of nearly $5 Million, has brought an increased focus on the impact of cyber threats on the critical grid infrastructure. The belief is that non-vendor implemented or controlled implementations may not pass the next CIPs release audits.

5.4. Key takeaways from the roadmap

The roadmap outcomes focused on technology architecture evolution over an approximate set of timeframes have been defined in Section 5.1. These outcomes are incorporated based on utility architectures and not based on those more often found at academic or research institutions.

Introductory (Now): Year 2021

Key aspects of the technical architecture of today include:

- Primary decision-making is still central.
- Knowledge of the as-operated state is still only available centrally.
- There is limited to no intelligence at the grid edge. Fundamentally, most grid-edge devices function independently of each other.
- Integration of utility operations with microgrid operations (utility-owned and 3rd party-owned) is primarily manual.
- Data and OT buses are still mainly implemented by vendors and utilities generally at a conceptual level.
- Technologies and architectural constructs are still at an awareness stage but not in active use within system operations.
    - Cloud/Software as a Service (SaaS) installations
    - AI/ML in operations
    - Open-source S/W

Foundational (1-3 yrs.): Years 2022 – 2024

Key aspects of the technical architecture in the 1-3 years' timeframe include:

- Primary decision-making is still central.
- Knowledge of the as-operated state is still only available centrally.
- Application of intelligence at the grid edge is emerging. However, fundamentally, most grid-edge devices still function primarily independently of each other.
- Integration of utility operations with microgrid operations (utility-owned and third-party-owned) is still mostly manual.
- Data and OT buses are still implemented mainly by vendors and utilities mainly at a conceptual level.
- Many utilities are implementing cloud/SaaS solutions for HR, finance, and customer systems. However, while smaller utilities are considering implementing some functions in the operational space, their larger counterparts have not yet made any major plans.
- Some utilities are investigating incorporating AI/ML solutions into operations. However, for the most part, they are still in advisory mode.
- The use of open-source software is still at an awareness stage but not in active use within system operations.

Evolutionary (4-7 yrs.): Years 2025 – 2027

Key aspects of the technical architecture in the 4-7 years' timeframe include:

- Primary decision-making is still central.
- Knowledge of the as-operated state is mostly available centrally, but some knowledge of the overall state is at the grid edge.
- The application of intelligence at the grid edge continues to evolve. Some level of coordination among grid-edge devices is beginning to emerge.
- There is an increased awareness of integrating utility operations with microgrid operations (utility-owned and third-party-owned). This is due to the increased number of microgrids requiring some level of automation in their interactions.
- Formal constructs for Data and OT buses are emerging in vendors and utility operational architectures.
- More utilities are beginning to implement some of their operational solutions as cloud/SaaS services.
- AI/ML solutions are emerging into the operational realm, still mostly in an advisory mode. In addition, augmented reality is being introduced in the field.
- Increased acceptance of open-source software for use in operations.

Revolutionary (7+ yrs.): After year 2027

Key aspects of the technical architecture in the 7 years' timeframe include:

- Operational implementations allow decision-making to be divided between centralized and at the grid edge.
- Knowledge of the as-operated state is still located centrally, but there is full knowledge of this information at the grid edge also.
- The application of intelligence at the grid edge continues to evolve. Full power system state knowledge and coordination among grid-edge devices are in place.
- Utility and microgrid (utility-owned and third-party-owned) operations are fully integrated and automated.
- Formal constructs for Data and OT buses are emerging and evolving in vendors and utility operational architectures.
- Cloud/SaaS services are now fully available in operational environments.
- AI/ML solutions are fully established and implemented in utility operations. In addition, augmented reality is the norm in the field.
- Increased acceptance of open-source software for use in operations.

Disruptive (to watch):

Key aspects of the technical architecture in the years well beyond 2027 – 2030 include:

- More decision-making moving to the grid edge with the centralized infrastructure mainly providing a coordinating role.
- Knowledge of the as-operated state is still located centrally, but there is full knowledge of the overall state at the grid edge.
- Application of intelligence at edge mature. Full power system state knowledge and coordination among grid-edge devices are in place.
- Utility and microgrid (utility-owned and third-party-owned) operations are fully integrated and automated.
- Formal constructs for Data and OT bus are in place and mature at all vendors and utility operational architectures.
- AI/ML solutions are fully established and implemented in utility operations. In addition, augmented reality is the norm in the field.

- Increased acceptance of open-source software for use in operations. The increased acceptance comes from greater adherence to standards-based approaches.
- Next-generation application development environments emerge for consideration for utility operations.

6. Conclusions and next steps

As stated in the executive summary, the electric grid is changing, and the impact of this change is significant and occurring quickly. Utilities are navigating a "perfect storm" of factors including the shutdown of coal-fired plants accompanied by growth in renewable energy sources, the emergence of new stakeholders interacting with the utility, the increase of severe weather events, and the changing needs of visibility and control at the grid edge. These issues are compounded by the need to function with legacy systems and architectures while evolving to the next generation grid.

6.1. Conclusions

A key question in the minds of utility planners and operators is, "How should the transmission and distribution grid and their IT/OT architectures be redesigned to make it ready for the various new drivers?" Other fundamental questions include:

- Is the grid DR-ready, PV-ready, and EV-ready? How does the system operator need to change to get there?
- How can the barriers be removed to make it easier for customers and other third-party providers to participate and assist in providing resources to the grid operator? Can they receive full value of all the programs and technologies that are available to them?
- How does the potential scaling up of third-party providers - both in numbers/capacity and the associated rapid increase in non-utility-owned sensors and controls – impact the focus on cyber and physical grid security.

Grid ecosystems and architectures must also evolve to lower the needed capital deployments as utilities deliver the "green" value to customers and stakeholders. The future holds integration and reliance on customer-owned behind-the-meter assets, furthering the need for a robust and secure grid architecture.

Finally, external transparency into the process has become more important than ever as these complex decisions are made in forecasting, designing, and operating the grid.

The paper is not providing a specific architectural solution to the utility industry. Instead, it offers a set of characteristics that need to be considered during the period of significant change so that utility operations can continue to provide the best levels of reliability and resilience at the lowest cost. This paper:

- Introduces and formalizes two architectural constructs – Data (IT) and the Control (OT) Bus, which already exist in today's architectures at a conceptual level, but not as distinguished, formal components. These two components are necessary to ensure that the most efficient processing of information and control is happening at the proper location.
- Focuses on a combination of (1) standards-based data representation, (2) standardized interfaces, (3) standardized set of utilities available to all the components in the architecture, (4) standardized as-built and as-operated model, all leading to (5) self-registration of devices, applications, and systems in the network.

The utility industry is moving toward a data-rich environment with a tremendous amount of information coming from sensors in the grid and beyond (grid-edge and BTM). The paper has attempted to define an architecture where application/functionality is separate from data. Furthermore, where the systems and the architectures are designed and built to be more flexible to adapt to changes.

The utility industry cannot (and should not) change suddenly to move to these new architectural constructs. Given the cost, timeframe, and change management considerations, these changes need to evolve. The paper also presents a roadmap to define when these changes need to happen and the signposts that everyone will need to watch to make the right changes at the right time and justify them. In line with this approach, every utility should develop its own roadmap that will guide its approach and application of investments to a successful future.

This paper intends to provide a context for vendors, utilities, and their service providers to review and understand the changes that are coming in the future and get ready for them. Of course, each vendor and utility may approach the journey in their own ways to stay competitive and ahead of the others. Still, we hope they approach these changes using the constructs presented in this paper allowing for more seamless interactions between the various stakeholders in the evolving marketplace.

6.2. Next Steps

From this white paper, it is evident that the change for the future requires an analysis very unlike what past distribution planners and operators have seen in the last 100 years. It also needs to take both planning and operations into consideration, mainly because one feeds the other. For example, suggestions of wired and non-wired alternatives must be automatically generated to deploy capital effectively. In addition, insights into the systems' capability must be interwoven within the analysis. While the actual future state is somewhat unknown, the trajectory is somewhat known. More importantly, it is clear that disruptive technologies on the horizon could completely change the landscape as we move forward.

The recommendation of this white paper is for DOE to take the lead for this effort but with participation by a broad range of utilities (RTOs, investor-owned utilities, municipal utilities, and cooperatives), vendors, and regulators. It cannot be a theoretical exercise but needs to be practical and consider the realities of utility-funding constraints, utilities' pace and cost of such changes, the pace of regulatory processes for transmission and distribution, and other issues. It also cannot be one-offs with every different stakeholder. Key considerations of this roadmap include:

- **Business constructs:** With every new entrant, the system operator will need to evolve their systems and business processes to interact with the third-party's systems and processes.
- **Overall technological considerations:** The two buses introduced in this paper will need to be standardized and formalized over time. Interactions with these buses will need to be defined and documented.

  In addition, as an example, cybersecurity will become highly critical with the entrance of third-party (non-utility) players who will bring their systems into the utility operational equation. While this is already happening and managed by utilities as one-offs, today's approach is not sustainable when their numbers and capability scale up. Therefore, the concept of trust as a specific attribute will become more important to define the kinds of interactions between components in the field with specific systems responsible for maintaining the reliable operations of the grid.
- **OT technologies:** OT technologies can be divided into several classes of components and include evolution of sensors and controls mechanisms, and power system components such as solid state transformers, circuit breakers, and so on. Equally important, they also need to consider the evolution of existing sources of generation and the introduction of new and innovative sources.
- **IT technologies:** IT technologies are evolving at a tremendous pace. However, given the criticality of the nation's power system, they cannot be introduced into system operations architectures right away. They need to be assessed carefully and introduced when ready. This includes items such as computer systems and the advent of the cloud in system operations, communications, and new analytical mechanisms such as AI/ML.
- **Timing of these changes:** Determining which of these technologies is expected to come to fruition for utility use (either pilot or production) and when.

The outcome of these would be a roadmap that would be built in detail once and then updated every year to ensure that the results of key activities such as technology trend-spotting and their impacts can be incorporated into the roadmap document. In addition, for this roadmap to be truly useful for each utility, it must be defined so that every utility can use this roadmap as a starting point to develop one specific to their functional and timing needs and circumstances and be justifiable within their regulatory landscape.

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