PNNL-24643

Pacific Northwest
NATIONAL LABORATORY

Proudly Operated by Battelle Since 1965

The Emerging Interdependence of the Electric Power Grid & Information and Communication Technology

Final
August 2015

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

The Emerging Interdependence of the Electric Power Grid & Information and Communication Technology

Final
August 2015

Executive Summary

This paper examines the implications of emerging interdependencies between the electric power grid and Information and Communication Technology (ICT). Over the past two decades, electricity and ICT infrastructure have become increasingly interdependent, driven by a combination of factors including advances in sensor, network and software technologies and progress in their deployment, the need to provide increasing levels of wide-area situational awareness regarding grid conditions, and the promise of enhanced operational efficiencies. Grid operators' ability to utilize new and closer-to-real-time data generated by sensors throughout the system is providing early returns, particularly with respect to management of the transmission system for purposes of reliability, coordination, congestion management, and integration of variable electricity resources such as wind generation.

In addition, many utilities throughout the country have begun investing in the build-out of sensor systems and networks at the distribution level, particularly Advanced Metering Infrastructure (AMI), consisting of smart meters, communication networks and information management systems. It's estimated that some 65 million smart meters will be installed nationwide by 2015, accounting for more than a third of all U.S. electricity customers.[1] Initially, many of these deployments have supported functions such as more frequent and efficient meter-reading, as well as demand-response programs at pilot scale. But in addition, a number of emerging trends suggest even richer new data streams relevant to distribution system operations will become available in coming years, given a proliferation of grid-connected intelligent devices and sensors throughout the system—further enhancing the interdependence of electric power and ICT infrastructure.

It must be acknowledged that this coupling creates potential vulnerabilities in the area of cyber security, and should continue to remain a focus of both federal research and development and information-sharing efforts with industry. Nevertheless, the convergence of electricity and ICT networks also holds promise as a key element of a platform for energy innovation, leading to potential new value streams and enhanced system resilience. The pace at which this convergence occurs and new services and operational methods emerge will depend on a number of factors, including regulatory structures that set the framework within which utilities and grid operators prioritize infrastructure investment decisions.

This paper seeks to describe the challenges and opportunities presented by the enhanced interdependence of grid and ICT infrastructure, provide options for mitigating any associated vulnerabilities and characterize opportunities to leverage this emerging network convergence. In particular, this paper will highlight:

- The need for a ***reference architecture for control systems***-- extensible across electric and ICT networks--as a key first step in enabling the kinds of innovations that will enhance grid observability and controllability in coming decades. A reference architecture is a technology neutral framework applicable to complex systems such as the grid, which takes a disciplined approach to illustrating system components, structures and attributes. Such an architecture helps identify potential gaps in technology and operations, assists in defining key system and component interfaces and provides context for interoperability and standards-setting activities.

[1] U.S. Department of Energy, 2014 Smart Grid System Report to Congress (Draft; April 2014).

- Considerations relevant to ***ensuring ICT network investments are sufficient*** to enable enhanced grid management functions at the distribution level. For example, while wireless mesh networks built to support AMI deployments are more affordable than optical fiber or other advanced wireless technologies, certain characteristics may render them insufficient for system restoration and resilience functions in an outage or emergency scenario. In addition, early indications suggest meter communication networks have often been designed only to support consumers' usage reporting and thus lack the bandwidth and latency capabilities needed to support operation as a grid sensor network. Networks are increasingly integral to modern power grid operations, yet most power grid simulation and design tools today lack means to include communications-related elements. Measures to accelerate integration efforts and move them into use by utility planners and design engineers may help better inform grid operators' investment decisions. Moreover, certain regulatory reforms and/or tax incentives to encourage appropriately scaled investments may warrant consideration.
- And finally, the importance of ***accelerating ongoing federal research and development efforts to develop new grid management tools***, linking Department of Energy capabilities in high-performance computing and advanced power systems engineering with software developers and utility/grid operators. While it's reasonable to expect the commercial marketplace to ***eventually*** solve issues associated with emerging software needs of the utility industry, it is unclear this will take place in time to keep pace with the changing operational landscape of the grid, particularly at the distribution level. That's because software developers face a classic "chicken and egg" scenario. The market in the U.S. for these solutions is relatively thin, which leads to conservatism in investing in new products for control systems that, in essence, might also replace existing product lines. Utilities, in turn, may agree with an assessment of their changing needs—but don't commit to buying new solutions until they have been well tested and demonstrated, ands existing system shave been accounted for via the regulatory process. Within this context, DOE can play a key ongoing role in bringing together the ecosystem of stakeholders required to accelerate the path for new products from the laboratory to control rooms, in a way that unlocks new value streams and bolsters system attributes such as enhanced reliability and resilience.

Acknowledgements

This paper was prepared for the U.S. Department of Energy's Energy Policy and Systems Analysis (EPSA) Office. The authors wish to acknowledge the guidance and direction of Dr. Lara Pierpoint (EPSA), as well as the contributions of Sandra Jenkins, Carol Battershell, and Karen Wayland. In addition, special thanks are afforded to Rick Geiger of Cisco Systems and Wade Malcolm of Omnetric for their review efforts.

Table of Contents

1.0 Purpose and Scope

This paper examines the implications of emerging interdependencies between the electric power grid and Information and Communication Technology (ICT). Over the past two decades, electricity and ICT infrastructure have become more interdependent, driven by a combination of factors including initial advances in sensor, network and software technologies, the need to provide higher levels of wide-area situational awareness regarding grid conditions, and the promise of enhanced operational efficiencies. Grid operators' ability to utilize new and closer-to-real-time data generated by sensors throughout the system is providing early returns, particularly with respect to management of the transmission system for purposes of reliability, coordination, congestion management and integration of variable electricity resources such as wind generation.

In addition, many utilities throughout the country have begun investing in the build-out of sensor systems and networks at the distribution level, particularly Advanced Metering Infrastructure (AMI), consisting of smart meters, communication networks and information management systems. It's estimated that some 65 million smart meters will be installed nationwide by 2015, accounting for more than a third of U.S. electricity customers.[2] Many of these deployments initially have supported functions such as more frequent and efficient meter-reading, as well as demand-response programs at pilot scale. But in addition, a number of emerging trends suggest even richer new data streams relevant to distribution system operations will become available in coming decades, given a proliferation of grid-connected intelligent devices and sensors throughout the system—further enhancing the interdependence of electric power and ICT infrastructure. Despite the increasing interdependency, ICT is typically viewed as not adding value in itself, but rather acting as an enabler. While this is reasonable, treating ICT in this manner makes it difficult to build business cases for communication infrastructure upgrades separately from other specific projects.

It must be acknowledged that this coupling creates vulnerabilities in the area of cyber security, and should continue to remain a focus of both federal research and development and information-sharing efforts with industry. Nevertheless, the convergence of electricity and ICT networks also holds promise as a platform for energy innovation, leading to potential new value streams and enhanced system resilience. The pace at which this convergence occurs and new services and operational methods emerge will turn on a number of factors, including regulatory structures that set the framework within which utilities and grid operators prioritize infrastructure investment decisions.

This paper seeks to describe the challenges and opportunities presented by the enhanced interdependence of grid and ICT infrastructure, provide options for mitigating any associated vulnerabilities and characterize opportunities to leverage this emerging network convergence.

In particular, it focuses on the operational aspects of the entire power delivery chain, from the transmission interconnection level all the way to the distribution level. It recognizes the transactive nature of emerging "prosumer" (producer-consumer) interactions with grid infrastructure, as well as interactions between utilities and third-party Energy Services Organizations (ESO's).[3]

---

[2] ibid.

[3] In depth discussion of particular trends associated with the utility/prosumer and utility/ESO demarcation points is beyond the immediate scope of this paper. However, many similar themes emerge in a discussion of such topics. An

Within this context, it is instructive to consider interdependencies of the grid and both communications (data, voice, video, etc.) and computing resources, including both computing platforms and applications that run on them. While this paper will focus more on computing platforms and their interconnection with communications and the grid than on functionality of specific applications, Section 7 does give an overview of key applications at various levels in the grid hierarchy. Appendix 1 provides a depiction of this hierarchy, illustrating that—in practice-- US/North American utility grids have several forms of organization, depending on geographic location, as well as industry segment (Investor Owned Vertically-Integrated Utility, Investor Owned Disaggregated Utility, Public Power, Rural Cooperative, and Municipal Utility). In addition, there are a variety of related organizations providing various kinds of coordination, oversight and grid-related services.

It is quite likely that the particular node an organization occupies within this hierarchy— and the regulatory structure(s) shaping its investment decisions and rate structure —will have a material impact on its approach to managing the opportunities and potential challenges associated with emerging interdependence of grid and ICT infrastructure. Within this context, the Department of Energy may be well positioned to play a leadership role in:

- Working with industry to devise a technology-neutral reference architecture to inform innovation and deployment of control systems required to keep pace with evolution of the grid, and likewise provide the context within which interoperability standards may take root
- Providing the assessment tools and methods to specify ICT requirements necessary to support advanced grid functions, including integration of variable energy resources and enhanced system resilience while ensuring system security, as well as basic functions like forecasting, dispatch, and balance in the emerging grid environment
- Advancing research and development initiatives that might accelerate the path to market for new grid management tools required to keep pace with the evolving operational landscape

---

introductory treatment of ICT implications for buildings/grid integration can be found at: http://energy.gov/sites/prod/files/2014/03/f14/B2G_Tech_Opps--Info_Comm_Tech_Perspective.pdf

2.0 Convergence of Networking, Computing, and the Electric Grid

In order to understand the interdependencies discussed in this paper, it is helpful to have an appreciation for the concept of network convergence as it applies to electric utilities. Convergence[4] of networks is a powerful transformative force that has strong implications for both business and technology. The concept is widely known in the telecommunications industry, which has undergone several convergences over the past few decades. In that industry, convergence is often thought of in terms of bit streams, but in fact the concept also applies to energy streams, and hence to electric power systems. Convergence is a concept that applies to whole industry segments--not just individual companies or customers--and results in significant changes in how products or service are delivered, and how economic value is created.

> Convergence is the transformation of two or more networks or systems to share resources and interact synergistically via a common and seamless architecture, thus enabling new value streams.

Convergence is an industry macro-process that comes about as a result of some imperative, which may be social, economic, or regulatory–or a combination thereof. In fact, regulation is one of the larger drivers (or inhibitors) of convergence.

Indications suggest the electric power system in the US has been experiencing a complex, multi-network convergence for some time now. There are four classes of networks involved, as shown in Figure 2.1 below.

[4] Paul De Martini and Jeffrey D. Taft, "Value Creation Through Integrated Network and Convergence," February, 2015, available online: http://smart.caltech.edu/papers/ElectricNetworksConvergence_final_022315.pdf

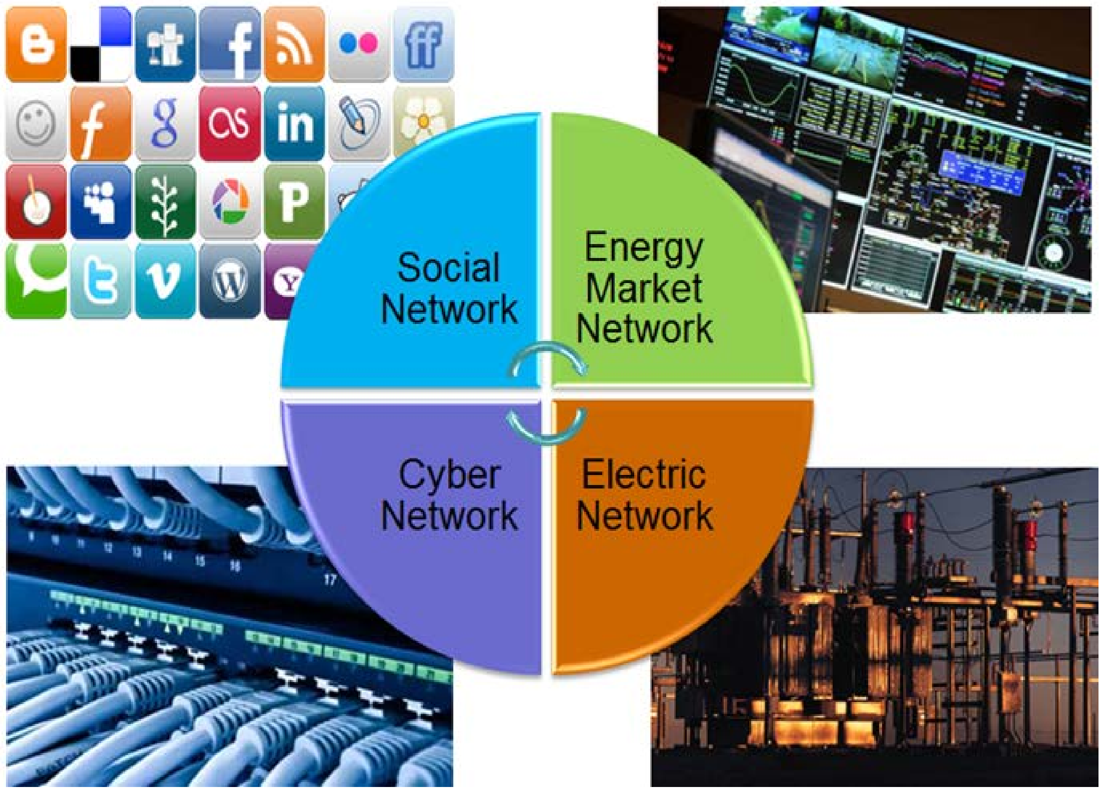

Figure 2.1. Four Class Convergence for Electric Grids (Source: P De Martini, Newport Consulting)

2.1 Grid/ICT (Cyber) Convergence

The convergence of the grid with information and communication networks has been underway for quite some time, and received a boost during the "smart grid" phase of grid evolution in the last decade. It continues with the focus on grid modernization and not only brings its own value streams, but also comprises a part of the platform that will enable the convergences discussed below.

2.2 Grid/Financial Network Convergence

The creation of power and energy wholesale markets that began with industry restructuring efforts in the 1990s has continued--albeit in fits and starts--with markets and market-like mechanisms either implemented or proposed for ever deeper penetration into the grid in certain regions. While not all parts of the US have access to organized, wholesale bulk energy markets, there have been recent expansions of existing markets to include various ancillary services. Considerable work is being done on how to monetize a variety of potential grid services, such as those provided by energy storage. These organized markets have been historically tethered to transactions at the wholesale/bulk transmission level, and as the financial instruments traded within them have reached enhanced levels of complexity, occasional jurisdictional concerns have been raised about the appropriate regulatory structure(s) governing their oversight.

That is to say, policymakers, industry and consumer advocates alike have noted the potential lack of clarity around where the Federal Power Act's (and by extension, the Federal Energy Regulatory

Commission's [FERC's]) economic regulation of bulk power markets might end, and where the Commodity Exchange Act and the Commodity Futures Trading Commission's (CFTC's) oversight of relevant financial instruments traded within these markets might rightly begin. In fact, in the wake of the 2010 enactment of the Dodd-Frank Wall Street Reform and Consumer Protection Act,[5] certain grid market operators sought clarification as to whether the CFTC intended to regulate certain electricity-related transactions (historically under the purview of FERC) pursuant to new rules governing "swaps" passed in response to the financial market collapse of 2008. The CFTC in 2013 issued a rule[6] suggesting it would conditionally exempt certain classes of bulk power market transactions (Financial Transmission Rights, Energy Transactions, Forward Capacity Transactions and Reserve or Regulation Transactions) but stopped short of granting a blanket exemption for electricity-related financial products.

Meantime, in places like California and New York there is emerging consideration of how markets may be organized to better coordinate generation and demand response in the distribution system, where organized markets do not yet exist.[7] In this context, markets are viewed as mechanisms to enable prosumers to offer services to grids, as a means to price those services, and as a part of a distributed control mechanism to coordinate large numbers of resources that can supply the same services. An example of such a service would be the use of prosumer-owned roof-top solar PV with DC-AC inverters to supply voltage and reactive power regulation services on a distribution feeder. As discussed more fully in Section 3, this trend is being driven in part by policies and incentives—such as net metering initiatives and tax benefits—encouraging the proliferation of distributed generation as well as the market participation of third-party service providers, including demand response aggregators and/or solar leasing entities. Nevertheless, thinking about the structure of markets at the distribution level remains very new, and it is not yet obvious what kinds of entities may emerge that would operate such markets and own the networks necessary to support them. However, it is certain that sufficient ICT infrastructure would be a key consideration for purposes of ensuring the integrity of such markets and orderly settlement of relevant financial transactions. Market settlement – the reconciliation of interlocking transactions and transfer of funds and purchased items (whether they are stocks, commodities or whatever) is a key challenge of today' power markets. In disaggregated markets, reconciliation of retailer purchase contracts on bulk generation, with the delivery to transmission operators, and subsequent delivery to distribution operators and ultimate consumers is done at monthly intervals or longer and in the case of residential consumers by estimates of their real time consumption using profiles rather than actual data.

Implementation of these existing and expanding market mechanisms will require the use of ICT. Depending on the structures involved, this can raise issues of scalability as larger numbers of smaller players are admitted to the markets; markets therefore have to scale software and communications capabilities to provide access and to maintain market technical performance.

2.3 Grid/Social Network Convergence

Capitalizing on networking and the Web, social networks have become ubiquitous. As such, it is not surprising that utilities would turn to them to provide new ways to interact with their customers. Some

[5] P.L. 111-203

[6] 78 FR 19880, April 2, 2013

[7] CalTech Resnick Institute/Greentech Leadership Group, "More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient"; (August 2014). Available at: http://greentechleadership.org/wp-content/uploads/2014/08/More-Than-Smart-Report-by-GTLG-and-Caltech.pdf

utilities have encouraged customers to interact with each other via social media to support and reinforce energy conservation practices. Social networks can also represent threats to electric power grids, as discussed more fully in Section 5.

2.4 Natural Gas/Electric Generation Convergence

Recently much attention has been focused on the interaction of the natural gas industry with the electric industry, due largely to the shale gas boom. Since the gas industry has historically viewed electric generation as a downstream use of its product--not essentially different from fertilizer manufacture, for example--characteristics of a network convergence did not arise until recently. However, developments in the past few years have suggested industry participants are modifying their infrastructure investment strategies on account of economic and environmental incentives, resulting in a tighter coupling of natural gas and electric generation. Likewise, the potential implications associated with differing contractual mechanisms and financial settlement practices across electric and gas markets have merited the attention of industry and policymakers.

In the winter of 2013-2014, persistent cold weather occurred coincident with congested natural gas transmission in the Midwest and Northeast, spurred by demand for gas for both heating and generation. These circumstances required multiple emergency actions on the part of the Federal Energy Regulatory Commission (FERC), including orders allowing additional non-public information-sharing between electric and natural gas stakeholders in the PJM market,[8] as well as temporary waiver of PJM's $1000/MWh price cap for bids into the generation capacity market due to "unprecedented spikes in fuel costs caused by recurring extreme cold weather events.[9] FERC has since initiated a Notice of Proposed Rulemaking on proposals to revise natural gas scheduling practices on interstate pipelines, as well as proceedings under both the Federal Power Act and Natural Gas Act to enhance coordination between market practices.[10]

Recently, the industry has seen the rise of mid-stream electric generation, where small (less than 20 MW) electric generators are located close to mid-stream shale gas processing plants. These started out as a means for smaller gas producers to get to markets where gas transmission pipeline congestion had been blocking them. Subsequently, it has turned out that in addition to relieving gas transmission line congestion, this also aids in relieving electric transmission line congestion. In order for electric system operators to make use of this and to deal with gas sourcing for bulk generators, it is necessary for the system operator to not only handle the wholesale electric markets, but also to participate in the gas real time markets and pipeline services markets. Given these issues, it seems clear that a convergence is occurring across multiple aspects of control systems and markets.

Note that it is only very recently that the relationship between gas and electricity took on the characteristic of a convergence. Formerly, this was an interdependence of electricity upon natural gas as a fuel, but there were no forces driving these two systems to a common architecture or a meshing of operations. Electric transportation is in roughly the same position regarding electricity as electric generation was to gas suppliers. Transportation is seen primarily as a load by utilities, and one that could offset reductions in traditional loads in response to efficiency initiatives and trends toward distributed

[8] 146 FERC ¶ 61,033, Docket ER14-951-000 (January 17, 2014);
[9] 146 FERC ¶ 61,078, Docket ER14-1145-000 (February 11, 2014);
[10] http://www.ferc.gov/media/news-releases/2014/2014-1/03-20-14-M-1.asp#.U-f4QE0U_IU

generation. Nevertheless, interesting new concepts are being explored in places including California and elsewhere, which would leverage electric vehicle recharging infrastructure for purposes of providing ancillary services to the grid. A number of financial, regulatory and technical considerations will determine whether such concepts begin to take hold—in which case, signs of convergence may begin to emerge.[11]

It is worth reinforcing that many of these developments hinge in part on future regulatory developments. In any event, where electric and natural gas infrastructure is concerned, it is clear that a strong interdependence has developed with implications in both directions. Consequently, the emergence of a common architecture and platform discussed more fully below involving natural gas and electric generation seems likely. This convergence will strongly involve ICT and the resulting tighter coupling will increase the natural gas/electric generation interdependence.

2.5 Convergence and Platforms

When convergence occurs, common architectural and design elements eventually merge to create a platform upon which a variety of functions execute. Such platforms may emerge only to be recognized after the fact, or may be planned. In either case, the use of a platform has two effects:

1. It enables synergistic developments and innovations leading to new value streams, especially if the platform is open in terms of access and interoperability; and
2. It causes a tighter coupling of the various elements and networks being converged, meaning the platform becomes a point of interdependence.

Generally speaking, "platform" is taken to mean computing platform, but in the electric power case, the convergence of networks concept implies that platforms are really composed of computing, communications networking, and the electric grid itself, *especially the distribution grid*. This realization points up the need for a proper framework for the grid and other convergent networks, which in turn leads to a proper context for definitions of interoperability.

> The convergence of ICT with electric distribution grids should be viewed not only as a point of interdependence, but also as the source of an emergent platform for energy innovation leading to new value streams, some of which may not even be known yet.

It's worth noting that a second level of convergence is possible: convergence of the grid cyber-physical network with the commercial ICT network (internet, Cloud, Software as a Service [SaaS] etc.). There is a degree of tension related to this concept, as there are both cyber-security and financial issues associated with the use of the internet/Cloud infrastructure and services by electric utilities. At the same time, third party energy services organizations such as demand response aggregators have already used the internet as a channel to residential and commercial customers—essentially bypassing utility communication networks.

[11] California ISO, "Advancing and Maximizing the Value of Energy Storage Technology, available online: https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf

Some utilities, especially smaller co-ops and municipals, have initially been more open to using SaaS, since they do not have the same financial issues as large IOU’s and typically do not have extensive IT departments. SaaS is a concept that often leverages cloud computing infrastructure, such that many common business applications (such as messaging, invoicing and accounting software) are centrally hosted and offered as a subscription service, rather than as up-front purchase of a software license in perpetuity. In the grid context, IOU’s may be inclined to invest in assets rather than services—“Cap-ex versus Op-ex”—given the way regulators have historically viewed return on investment. If Cloud services become treatable as capital costs, that would likely accelerate SaaS adoption by the larger utilities. Developments with respect to Critical Infrastructure Protection (CIP) standards governed by ongoing proceedings of the North American Electric Reliability Corporation (NERC) add an additional source of uncertainty about the extent to which utilities may be able to leverage Cloud or SaaS resources.

Recently however, some larger IOU’s have begun exploring the concept of splitting applications into ”Core” and “Other,” with the idea that those in the” Other” category might in fact be moved to Cloud/SaaS. As of this writing, it is too early to determine if this will actually happen and whether there are efficiencies to be captured.

The remainder of this paper will focus on the implications of grid/ICT convergence and interdependence, but keep in mind that grid/financial network and grid/social network convergences are directly enabled by grid/ICT convergence.

3.0 Key Emerging Trends in the US Electric Utility industry

A number of inter-related trends in the US utility industry are beginning to reach scales at which they may impact grid operations and interact with one another—an indicator that the type of previously discussed convergence is underway.

3.1 Increasing Data Volumes from the Grid

While much of the public discussion around increasing volumes of grid data has focused on meter data, the really large volumes are in fact coming --and will continue to grow--from newer instrumentation on both transmission and distribution grids. Already the more than 1,000 Phasor Measurement Units (PMU's) on the US transmission grid produce vast volumes of data,[12] and the number of PMU's is expected to grow significantly in coming years (PNNL expects that US PMU data flow will eventually reach 50,000 PMU's and 1.5 Petabytes/year[13]). Early adopters are the reliability coordinators and system operators (ISO/RTO), with transmission system operators following. Early work on applications of PMU's at the distribution level is being done, but no significant penetration exists to date.

PMU's are devices that measure voltage and current at different points across the grid as often as 30 or 60 times per second now and some of these devices are made to produce data as fast as 240 times per second[14] although they are not used in this mode yet. These measurements are also time-stamped, or synchronized, by GPS technology, which means that by comparing the measurements at any given moment operators can get an unprecedented picture of system conditions in near real-time. A handful of utilities and federal power marketing entities pioneered the early deployment of PMU networks, for purposes of wide-area situational awareness on the transmission system, particularly in response to cascading outage events in the West in 1996 and again in 1999. The Bonneville Power Administration became the first utility to deploy such a network in 2000.[15] Public/private partnerships were key to accelerating deployment of these networks after the Northeast/Midwest blackout of 2003—the largest in US history--and a number of investments pursuant to the American Recovery and Reinvestment Act (ARRA) of 2009 successfully leveraged additional industry investment.[16]

The vast amounts of data now being generated from PMU's are due to that fact that these are streaming devices--much like video--in that, they produce streams of data that are used at multiple destinations. It's expected that similar technology is about to start penetrating distribution grids, which will have orders of magnitude more streaming sensors than the transmission system. As interest in asset monitoring continues to increase, vast new volumes of asset health and operational data will be generated, some to be used in real time, some to be stored and analyzed later. The newer protection and control

---

[12] North American Synchrophasor Initiative, "PMUs and Synchrophasor Data Flow in North America as of March 19, 2014;" available at: https://www.smartgrid.gov/sites/default/files/doc/files/naspi_pmu_data_flows_map_20140325.pdf

[13] A Petabyte is 1,000 Terabytes or 1 million Gigabytes or 10^{15} bytes.

[14] https://www.selinc.com/SEL-3373/

[15] Virden et al, "Next Steps in Grid Modernization: Early Returns on U.S. Investment, and New Innovations in Electric Infrastructure Policy & Technology"; (April 2012).

[16] For example, see: Vanzandt and Nokes, "A Western Partnership Succeeds In Enhancing Grid Reliability"; (August 2014); available at: http://smartgrid.ieee.org/august-2014/1131-a-western-partnership-succeeds-in-enhancing-grid-reliability

systems needed for advanced grid functionality, such as integration of distributed generation and responsive loads at increasing scale will generate enormous volumes of sensor data that must be transported, processed, and consumed in real time, and potentially stored for offline analysis. All told, the utility industry will experience an expansion of data collection, transport, storage, and analysis needs of several orders of magnitude by 2030. Part of this growth is due to the next item in this list.

3.2 Faster System Dynamics

The implementation of new grid capabilities has brought with it great increases in the speed with which grid events occur. This is especially true on distribution grids, although the trend exists for transmission as well. In the last century, aside from protection, distribution grid control processes operated on time scale stretching from about five minutes to much longer, and human-in-the-loop was (and still is) common. With the increasing presence of technologies such as solar PV, wind generation, and power electronics for inverters and flow controllers, active time scales are moving down to sub-seconds and even to milliseconds. The presence of significant levels or penetration of solar PV (where prosumers may inject power into the distribution system) or distribution-connected wind energy on a feeder has led to voltage stability problems, according to initial reports from San Diego Gas & Electric (SDG&E)[17,18]. Conventional feeder control has been too slow to compensate, so each utility has applied fast power electronics in the form of DSTATCOM devices to stabilize voltages. As this fast automatic control has become necessary, the need to obtain data on the same times scales on which control must operate has arisen. Consequently, there is a sort of double impact: there are many more new devices to control on the system--and much faster dynamics for each device--leading to vast new data streams and increasing dependence on ICT for data acquisition and transport, analysis, and automated decision-making.

3.3 Hidden Feedbacks and Cross-Coupling

As more advanced grid applications and systems are developed and deployed, more system interactions are emerging. These interactions are inevitable, although it seems that many applications have been developed to execute specific functions—without reference to broader system implications. These interactions occur and will continue to occur because the grid itself constitutes a hidden coupling layer for all grid systems. The coupling occurs due to the electrical physics of the grid, and in most cases this coupling propagates at nearly the speed of light. Such coupling can cause effects ranging from reduced effectiveness of smart grid functions, up to and including wide area blackout. Coupling exists because of electrical connectivity: for example, devices connected to the same feeder share voltages. In instances in which demand response (DR) is operated independently of voltage regulation, sudden changes in load change the conditions under which voltage regulation settings were created. This, in turn, leads to the settings becoming inappropriate on very short notice – too short for the relatively slow conventional voltage regulation methods to compensate effectively.

---

[17] SDG&E, "Enhanced Inverter Functions – Executive Summary," August 2013. Available online: https://www.sdge.com/sites/default/files/documents/1167748181/Inverter%20Executive%20Summary%20Aug%207%202013.pdf?nid=8441

[18] John MacDonald, "Solar Impacts: Power Electronics to the Rescue," IEEE Smart Grid, October 2013. Available online: http://smartgrid.ieee.org/october-2013/987-solar-impacts-power-electronics-to-the-rescue

This applies to both commercial DR and aggregated residential DR, although most commercial DR has been operated so slowly that in the past this was not much of a problem, until more fully automated DR became available. The net impacts of this particular interaction can include:[19]

- Reduction of the effectiveness of DR by as much as 15 percent;
- Voltage violations on the affected feeder; and
- Feeder level circuit breaker trips.

This situation is further complicated by the fact DR applications may be developed outside the context of utilities' distribution management systems; and that, in some cases, third-parties are bypassing utility systems altogether, to aggregate DR through direct interaction with customers.

Other interactions have the potential to create wide area blackouts if they should occur during times of low stability margin operation. As smart grid functions become more complex, it is to be expected that more interactions will become manifest. Generally, effects of such interactions will not be important at the scale of pilot projects and demonstrations, but will become significant as penetrations pass tipping points that are becoming apparent from experience at several utilities.[20,21] In such cases, the correlation and concentration of assets involved in these new grid applications—within and potentially outside utilities' control—will determine the operational consequences of such interactions.

3.4 RPS and VER Penetration

The trend of converting from traditional thermal generation to renewables such as solar and wind (known as Variable Energy Resources [VER]) has been driven by a combination of factors over the past decade, including Federal tax policy and state Renewable Portfolio Standards (RPS). Since VER is not dispatchable in the same way as traditional generation, operational challenges arise for a system originally designed around the concepts of power balance and load-following generation control. Solutions to these problems involve new types of grid components such as energy storage, but also greatly expanded measurement, data transport, analytics, and control.

3.5 Bifurcation of the Generation Model

Similarly, the VER/RPS trend is shifting the model of central station generation connected to transmission, to a mix of that and distributed generation connected to distribution grids. This shift changes grid operations drastically, introducing multi-way real power flows and other effects not included in original grid design assumptions. In addition, distributed generation may be able to offer services ***back*** to the grid operator, such as reactive power regulation—a shift in paradigm that can provide operational benefits if the appropriate incentives are put in place.

---

[19] Medina, et al, "Demand Response and Distribution Grid Operations: Opportunities and Challenges," IEEE Trans. On Smart Grid, September, 2010, pp 193-198
[20] Thomas Bialek, "Renewable Impact on Electric Planning," available online: http://www1.eere.energy.gov/solar/pdfs/highpenforum2013_1_3_sdge.pdf
[21] Martin Lamonica, "Why is Hawaii Scaling Back on Solar?" Greenbiz.com, Jan 28, 2014, available online: http://www.greenbiz.com/blog/2014/01/28/solar-hawaii-utilities-scaling-back

3.6 Responsive Loads

Demand Side Management, including Demand Response (DR) has been used by the utilities for decades, mostly in conjunction with commercial and industrial customers, and mostly in a non-automated fashion. More recently, efforts have been made to create automatically responsive loads at the commercial building level, at the residential level, and even at the individual appliance level. With the rise of advanced commercial building controls, behind-the-meter storage, wide area communications, bulk power markets, and evolving approaches to "transactive" load coordination and control, the concept of building-to-grid integration is moving to a bidirectional multi-services model. This suggests it is possible that a grid/buildings convergence is forming.[22] As discussed above, this will result in a platform formation, which is a point of interdependence for buildings and grids—rather than the traditional arrangement in which buildings are simply passive consumers of electricity. Ultimately, this convergence would result in an extension of the grid--involving yet another class of assets *not* owned by the utilities. In this scenario, the observability and controllability issues resident in the operation of today's distribution grids (discussed more thoroughly in Sections 4 and 5) will also extend to include grid-connected, responsive loads.

3.7 Changing Fuel Mix

The change from traditional thermal generation to renewable sources is one shift that's been underway for some time; but it is also the case that retirements of coal and potentially nuclear plants will manifest in new grid operating characteristics. In addition, this trend is surfacing in its effect on utility planning – for example, in some regions, gas pipeline planning and build-out has to a significant degree displaced transmission line planning and build-out. The industry tools required for ***joint*** electric and gas system planning need to be improved. Moreover, ICT platforms do not yet commonly exist within utilities to support interactions with both electric and natural gas markets.

3.8 Evolving Industry/Business Models and Structure

A number of key stakeholders believe that the penetration of new functions at the distribution level, along with responsive loads and distributed generation, is causing the original mode of distribution operations to become inadequate. Proceedings in Hawaii, New York, and California are all aimed at reconsidering the roles and responsibilities of distribution grid operators as is much thought leadership in the industry at large.[23,24,25]

---

[22] See Hagerman et al, "Buildings to Grid Technical Opportunities"; available at: http://energy.gov/sites/prod/files/2014/03/f14/B2G_Tech_Opps--Intro_and_Vision.pdf

[23] Lorenzo Kristov and Paul De Martini, "21st Century Electric Distribution System Operations," available online: http://smart.caltech.edu/papers/21stCElectricSystemOperations050714.pdf

[24] Hawaii PUC, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," available online: http://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

[25] NYS Department of Public Service staff, "Reforming the Energy Vision," available online: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf

3.9 Evolving Control System Structure

Utility controls systems have traditionally been centralized, with hub and spoke communication to remote subsystems and equipment, as needed. As the various trends cited above have emerged, the need for changes in control system structure has become apparent. Specifically, the view has emerged that control systems must change from being centralized to a hybrid of central and distributed control. Distributed control is distinguished from *decentralized* control in the following important way: decentralized control involves moving some control to remote locations; but the remote elements perform controls tasks in isolation, with perhaps some coordination from a centralized supervisory element. Distributed control includes those aspects, but also is distinguished by the following: the decentralized elements cooperate on solving a common problem. This aspect creates new requirements for communication, methods for coordinating the elements and converging on a common solution.

An implication common to the various trends emerging across the electric utility industry is that power grids need greatly increased ***observability*** and ***controllability*** – both capabilities that are very dependent on ICT. Moreover, control architecture must change from centralized to distributed form in order to accommodate new industry and grid structures and capabilities, as well as to increase resilience.

Opportunities for Federal Leadership:

- Efforts to convene industry for purposes of devising a reference architecture for control systems--extensible across potential network convergence(s)-- is a key first step in enabling the kinds of innovations that will enhance grid observability and controllability. A reference architecture is a technology neutral framework applicable to complex systems such as the grid, which takes a disciplined approach to illustrating ***system components, structures*** and ***attributes***. Such an architecture helps identify potential gaps in technology and operations, assists in defining key system and component interfaces and provides context for interoperability and standards-setting activities. An initial, Phase 1 Skeleton Architecture is underway pursuant to the QER.
- Additional R&D is needed with respect to understanding system interactions such as Volt/VAr demand response, effect of distributed generation on system security and stability at both distribution and transmission levels, and interactions between distribution and transmission, as well as pioneering interactions at the grid/buildings interface. All are topics that exist beyond the capabilities of any one industry segment or stakeholder group—yet are crucial to enabling new value streams associated with grid/ICT interdependence. DOE's Office of Electricity Delivery and Energy Reliability (OE) is pioneering work in this area, which will become increasingly important as penetration of new distribution-level technologies reach scale. Similarly, DOE EERE's Building Technologies Program has launched efforts to begin consideration of issues and R&D needs relevant to the grid/buildings interface.

4.0 An Overview of Data-Related Considerations

It has been conventional wisdom in the utility industry for years that grid modernization will produce a "tsunami" of data. Early on, this was thought of as a big problem for traditional grid operators, but more recently, is properly becoming viewed as an opportunity to improve performance through enhanced situational awareness. Increasing grid situational awareness has cross-cutting impacts on grid attributes, as shown in Figure 4.1.

While it is true that the data volumes that can and are being produced by grid modernization are large by utility standards, it is worth noting that they are *not necessarily* large by the standards of other sectors, such as the financial industry. While data volumes and data rates impact system design and operational costs, it is not data itself that inherently has value, but the information that can be extracted from the data.

It is difficult to assign value to information, even though a great deal of effort has gone into researching ways to do so. As a simple first order method for utilities, it has been suggested that information can be valued using the following simplification:

The value of information is precisely that of decisions being derived from it.[26]

The shift from raw data to extracted information introduces a new element and a dependency: the use of analytics to extract actionable information from raw data. Considering data that arises from the grid itself (not by any means the only data we must consider), then we have a logical progression from signals to data; from data to information; and from information to knowledge. The transformation from signals to data typically occurs at the edge device level. The transformation from data to information, when performed automatically, is the task of analytics. This leads to a key principle regarding power grids:

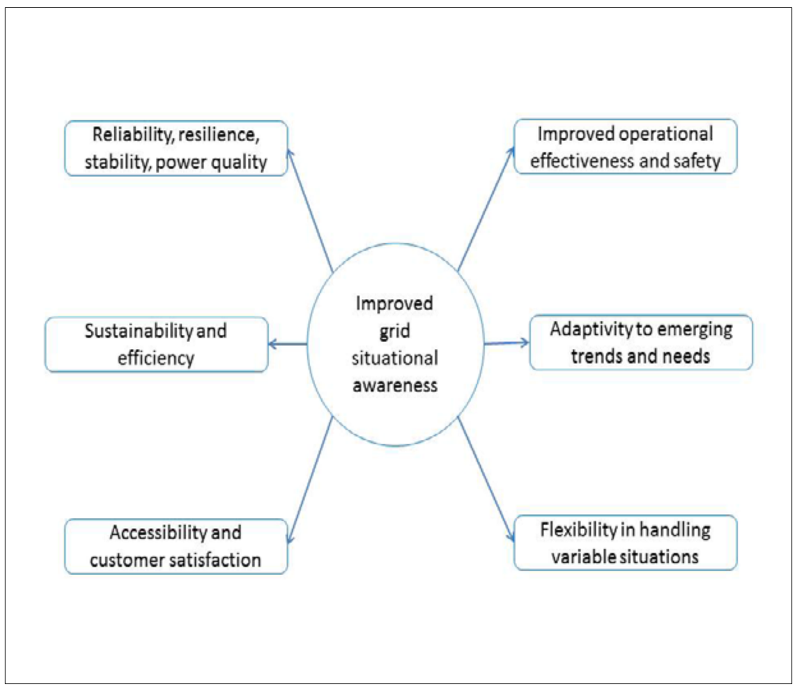

Figure 4.1. Wide Impact of Improved Situational Awareness

[26] John F. Hauer, et. al., "Integrated Dynamic Information for the Western Power System: WAMS Analysis in 2005," Power System Stability and Control, CRC Press, 2007, pp. 14-1 to 14-51.

Data is not useful in itself; extraction of information must occur via analytics, and connection of that information to decision and control processes is necessary in order to realize the value inherent in the information. Thus, there is a key interdependence involving data, analytics, and decision and control processes and systems. All of this occurs in a *context*, and that context is the physical power grid itself, along with its associated systems and devices.

It is important to appreciate that due to the grid context, grid data is spread over both wide geographic range and temporal range. Alexandra von Meier has captured both of these issues in the diagram of Figure 4.2. Few systems have the range of geographic and time values inherent in the grid, which poses significant challenges for control systems in particular, as most control methods apply to a limited range of time scales.

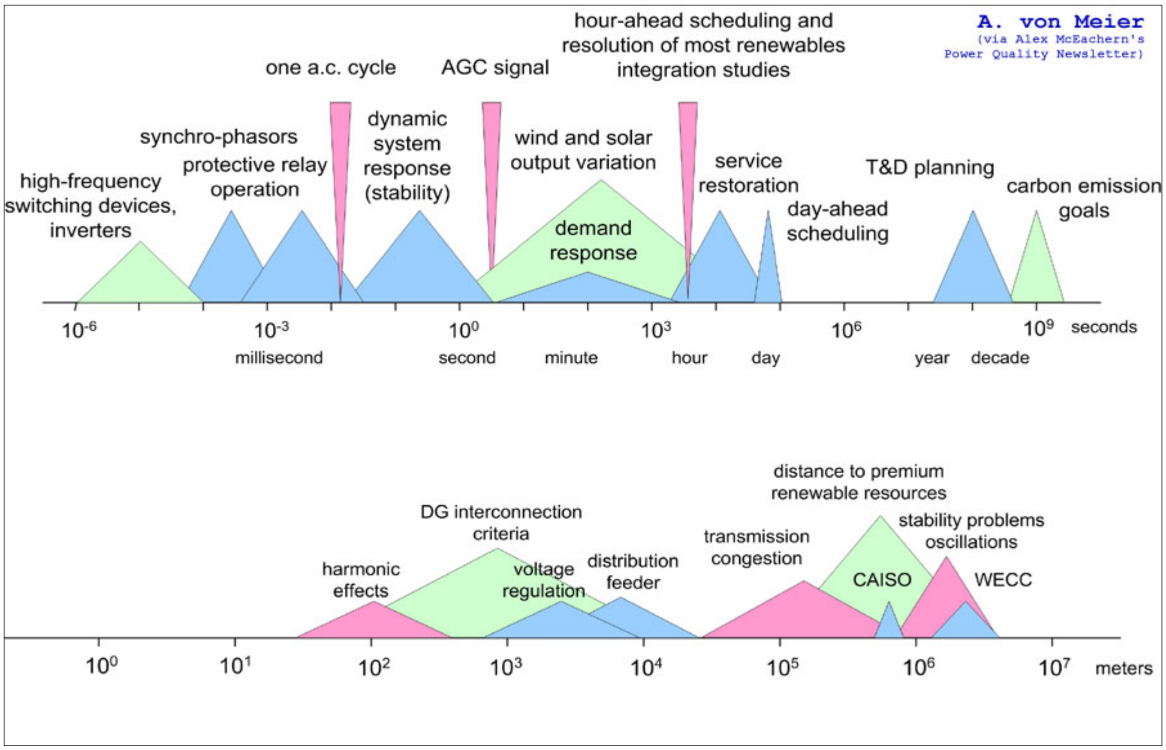

Figure 4.2. Power Grid Time and Spatial Scales

It is worthwhile to make a distinction between data *sets* and data *streams*. Data sets are maintained in conventional data stores and are managed using both conventional and new database technologies (e.g., Hadoop – see discussion below regarding data management). Data mining is a discipline that provides tools and methods for extracting information from large data sets. *Streaming data*, on the other hand—such as the data generated by PMU's--is about *data in motion*, a much more useful concept for grid operations on a real time basis than data mining. Here the data must be analyzed on the fly, so that the results can be used in a timely fashion, where "timely" is defined by the specific application using the data, and therefore by the underlying physical system.

4.1 Grid Data Classes

The current "Big Data" discussion often revolves around the concepts of Volume/Velocity/Variety--and more recently Veracity (see the discussion below regarding data quality). In the grid context, however, it is necessary to characterize data more specifically—in a manner that relates the several different types of data found in utility operations and their temporal attributes, to the electric grid system's requirements and interdependencies. It is important to distinguish the different types of data, including, among others, energy characteristics, operational state for energy production/storage/use, economic utility values, building/plant, process/device performance characteristics, market participant/customer data, geospatial information, electric network contextual information, and temporal/service attributes. To manage data effectively, it is essential to understand the differences related to each data class, their potential applications, and their respective latency considerations. Framing the data characteristics correctly allows proper treatment and identification of effective management solutions.

Data arising from smart grid devices and systems may be grouped into five classes. Each has its own key characteristics and business value. An understanding of these classes is important in the development of networking solutions for electric utilities. Table 4.1 below describes these five key data classes.

Table 4.1. Data Classes

Data Class	Description	Key Characteristics
Telemetry	Measurements made repetitively on power grid variables and equipment operating parameters; some of this data is used by SCADA systems	Constant volume flow rates when the data collection technique is polling; standard SCADA polling cycles are about 4 seconds, but the trend is to go faster; telemetry can involve a very large number of sensing points. Telemetry data usually comes in small packets (perhaps 1500 bytes or so). PMU data streams at anywhere from 30 to 120 samples per second per device.
Oscillography	Sample data from voltage and current waveforms	Typically available in bursts or as files stored in the grid device, captured due to a triggering event; transferred on demand for use in various kinds of analyses. For some kinds of sensing systems, waveform data is acquired continuously and is consumed at or near the sensing point to generate characterization values that may be used locally or reported out (e.g., converting waveform samples to RMS voltage or current values periodically); waveform sampling may be at very high rates from some devices such as power quality monitors.
Usage Data	Typically meter data, although metering can occur in many forms beside residential usage meters; typically captured by time-integrating demand measurements combined with voltage to calculate real power	May be acquired on time periods ranging from seconds to 30 days or more; residential metering may store data taken as often as 15 minutes, to be reported out of the meter one to three times per day

Asynchronous Event Messages	May be generated by any grid device that has embedded processing capability; typically event messages generated in response to some physical event; this category also includes commands generated by grid control systems and communicated to grid devices; may also be a response to an asynchronous business process, e.g., a meter ping or meter voltage read	For this class, burst behavior is a key factor; depending on the nature of the devices, the communication network may be required to handle peak bursts that are up to three orders of magnitude larger than base rates for the same devices; also, since many grid devices will typically react to the same physical event, bursting can easily become flooding .
Meta-data	Data that is necessary to interpret other grid data, or to manage grid devices and systems or grid data	Meta-data includes power grid connectivity, network and device management data, point lists, sensor calibration data, and a rather wide variety of special information, including element names, which may have high multiplicity

Note that the business value of each class is not necessarily equal to that of other classes. It is important that each utility understand this concept and define the business value of each data class, perhaps to the point of subdividing the classes as appropriate for the specific utility's drivers and constraints, so that proper data management solutions may be derived that reflect the utility's business requirements. Performance and security issues could and should be included. Also, data often is used by multiple departments within a utility that may have widely differing perspectives on the classifications above. It is critical that a holistic approach is utilized along with an effective governance process to reconcile any differences. The governance process used for enterprise business process management should be utilized, as the potential prioritization and ownership issues with data are part of this domain. While some utilities have done well with certain aspects of this issue, to date there is no single example of a comprehensive approach to utility data management in practical use.

4.2 Latency

Identifying the temporal aspects of the underlying business processes and control systems is a critical consideration to develop effective data management strategies and architectures. A lot of grid data has multiple uses; in fact, it's an element of synergy that has significant impact on smart grid economics and system design (networking, data architecture, and analytics) to ensure that data is used to support as many outcomes as possible.

Latency in this context can be defined as both the time interval between the time data is requested by the system and the time the data is provided by a source, and/or the time that elapses between an event and the response to it. This is why it is important to understand how data is consumed in a variety of ways and locations in power grids and utility operations.

While much industry focus has been directed at customer energy consumption data generated from smart metering systems, it is also important to understand the implications of the growth in grid sensor and control data streams throughout power systems. This is because much of this sensing and control data does not enter the data center, and some does not even enter the control/operations center, as it must be consumed while streaming in grid devices and systems in the field. Consequently it is important to classify data according to the latency requirements of the devices, systems, or applications that use it--and define its appropriate persistence (or in some cases, the lack thereof). Figure 4.3 illustrates the concept of latency hierarchy. Ultimately, this hierarchy is a result of the time scales across which the grid is operated; this has significant implications for grid system architecture, especially control and communications architecture.

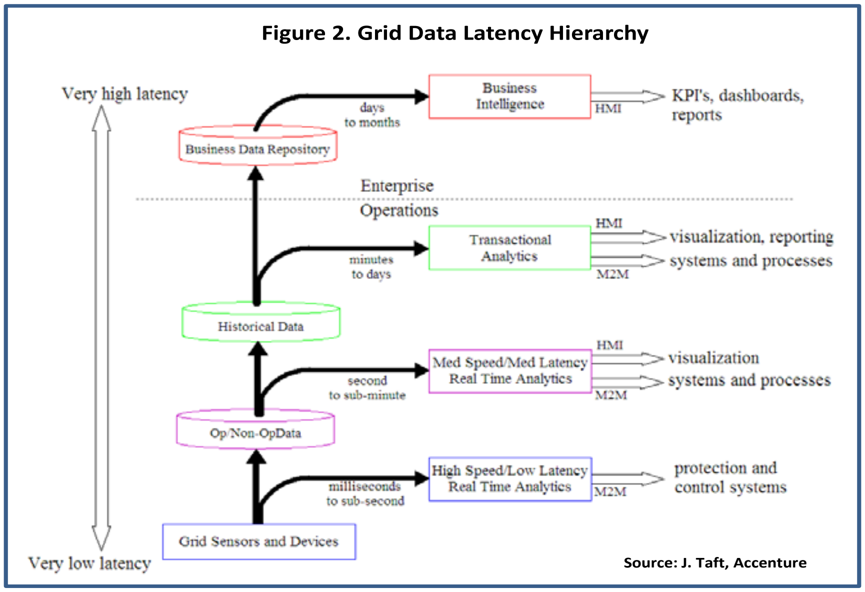

Figure 4.3. Grid Data Latency Hierarchy

Latency hierarchy is a key concept in the design of both data management and analytics applications for physical networks with control systems or other real time applications. What the latency hierarchy chart does not illustrate is that a given data element may, in fact, have multiple latency requirements and uses--meaning that any particular datum may have multiple destinations. Note that we treat latency requirements as aspects of the data (this point of view is helpful in network design); but in reality the latency requirements arise from the applications that use the data. Figure 4.4 illustrates how data from just a meter system may be used to support multiple operational process and analyses within a utility. Each use has unique performance and latency requirements.

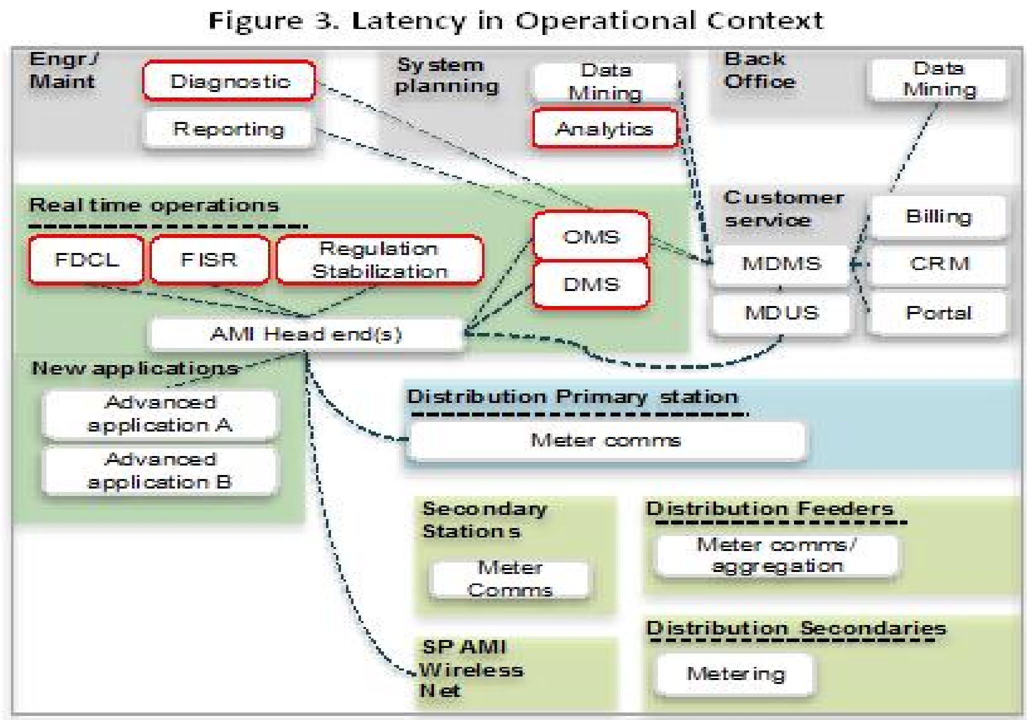

Figure 4.4. Example: Meter Data latency and Applications

This is why latency considerations must be included in the design of an energy platform. Otherwise, significant, and potentially fatal architectural issues will arise. These include inability for applications or data stores to scale, inability to access data on a timely basis to meet business and operational needs, and/or creation of choke points on underlying telecommunications and computing infrastructure.

Data latency is crucial in grid applications involving protection and control. Consequently, there is a strong interdependency between real time grid applications that use the data and the networks that transport the data--since network design and performance strongly influence latency.

The latency hierarchy issue is also directly connected to the issue of lifespan classes, meaning that depending on how the data is to be used, there are various classes of storage that may have to be applied. This typically results in hierarchical data storage architecture, with different types of storage being applied at different points in the grid corresponding to the data sources and sinks, coupled with latency requirements. Table 4.2 below lists some types of data lifespan classes that are relevant to smart grid devices and systems.[27]

[27] Figures and some of the discussion for this section is derived from “Utility Data Management & Intelligence,” by JD Taft, P De Martini and L von Prellwitz, available online at http://www.cisco.com/web/strategy/docs/energy/managing_utility_data_intelligence.pdf

Table 4.2. Data Lifespan Classes

Data Lifespan Class	Characteristics
Transit	Data exists for only the time necessary to travel from source to sink and be used; it persists only momentarily in the network and the data sink and is then discarded; examples are an event message used by protection relays, and sensor data used in closed loop controls; persistence time may be microseconds
Burst/Flow	Data that is produced in bursts or is processed in bursts may exist temporarily in FIFO queues or circular buffers until it is consumed or overwritten; examples include telemetry data and asynchronous event messages (assuming they are not logged) – often the storage for these data are incorporated directly into applications, e.g., CEP engine event buffers
Operational	Data that may be used from moment to moment but is continually updated with refreshed values so that old values are overwritten since only present (fresh) values are needed; example: grid (power) state data such as SCADA data that may be updated every few seconds
Transactional	Data that exists for an extended but not indefinite time; typically used in transaction processing and business intelligence applications; storage may be in databases incorporated into applications or in data warehouses, datamarts or business data repositories
Archival	Data that must be saved for very long (even indefinite) time periods; includes meter usage data (e.g. seven years), PMU data at ISO/RTO’s (several years); log files. Note that some data may be retained in multiple copies; for example, ISO’s must retain PMU data in quadruplicate.

4.3 Grid Data Sources

Power grid systems use a variety of sensors for measurement of electrical and non-electrical variables. In addition, many control devices have embedded sensing or data gathering capabilities. As the partial list below shows, there are a great variety of devices that produce grid data. Innovation as it relates to deployment of sensors and data gathering in distribution system equipment is expected to continue in coming years. This poses a problem familiar to the utilities: how to accommodate a time-varying mix of system changes and upgrades

Table 4.3. Example Grid Sensors and Measurement Devices

Device Type	Comment
Relay, through which various instruments such as Voltage Transformers (VT’s –used for AC voltage sensing) and Current Transformers (CT’s –used for AC current sensing) are read	advanced digital relays may provide as many as a thousand different data points for readout
Substation instrumentation (i.e. weather stations, substation battery monitors, fire sensors, etc.)	can supply data on substation device/subsystem state, health, and sensor telemetry
Meters (residential, C&I, feeder, substation)	Usage data and some grid state variables; C&I meters may also provide waveforms and power quality data
Recloser, sectionalizer, and inter-tie switch controllers; capacitor, voltage regulator, and line drop compensator controllers; tap changer controllers and monitors	Can supply data from internal sensing elements on grid state variables and device health and status
Line sensors and their Remote Terminal Units (RTU’s)	Line sensors have AC voltage and/or current sensing capability (through VT’s and CT’s attached to the power lines) plus local computation of derived quantities like real and reactive power

Device Type	Comment
Faulted circuit indicators (FCI's)	Indicate if a fault current has passed through the sensing point
Substation RTU's	Act as gateways for substation sensor data in older substation designs; can also have control capability
Fault recorders (waveform recorders, digital fault recorders)	Record power waveforms related to circuit faults in detail for later analysis
Serial event recorders	Record grid events for later analysis
Power quality monitors	Record power waveforms in detail for later analysis of waveform conformity to standards
Transformer dissolved gas analyzers (power substation)	Asset health sensing
Transformer partial discharge monitors (power substation)	Asset health sensing
Transformer top oil temperature monitors (power substation)	Asset health sensing
Line sag/sway/Aeolian vibration monitors	Located on transmission lines or at towers
Line ice/snow load monitors	Located on transmission lines or distribution feeder lines
Bushing capacitance monitors (transformer and breaker) and cable tan delta monitors	Asset health sensing
Phasor Measurement Units (PMU's) for both transmission and distribution	Streaming data sources being widely deployed on Transmission; will move to Distribution as well
Cable temperature monitors incl. fiber/Raman backscatter transmission line temp measurement systems	Asset health sensing
Fuse and distribution transformer monitors	Asset health sensing
Distributed Energy Resource (DER) controllers and gateways	Point of contact for aggregated DER data

In addition, most power grid subsystems have internal instrumentation that can also report out grid and device data of various kinds. In the case of the extended grid (including non-utility assets such as buildings) vast additional sources of data exist and may be made available for grid use in the future.[28] At present, the necessary communications and control infrastructure to do this at scale does not exist given the necessary performance, reliability, and security requirements.

4.4 Data Acquisition

Power grid devices and sensors operate in one or more of five data acquisition modes:

- Polling – a polling master queries the device, which responds with the most recent values of the specified data points; polling is usually on a regular schedule and data volume per query is modest.
- Report by exception – the device pushes a data message to the master when the data changes by a specified amount.
- Streaming – a sensor sends a continuous stream of data, once streaming is initiated and until streaming is terminated by command or abnormal exit condition.

[28] Again, see: http://energy.gov/sites/prod/files/2014/03/f14/B2G_Tech_Opps--Info_Comm_Tech_Perspective.pdf

- Interrogation of stored files – the device maintains a log or data file; upon query, it transmits the log or file to the master. This differs from polling in terms of data size per query and frequency/regularity of the query.
- Asynchronous event message – the device uses internal processing to detect a specific condition indicated by the data, and spontaneously sends an event message to the master or any subscribing system. The message may or may not contain actual sensor data relevant to the event; the internal event can be a clock signal or countdown, so that the messages are sent on a regular basis, but initiated by the sensor, not a central controller. This method can and does result in message bursts and floods, due to multiple grid devices reacting to the same physical event. These bursts and floods can easily overwhelm the communications network and the application that is handling the messages.

Polling is common in grid control systems, but report by exception is used in some systems to reduce data volumes and therefore communication line bandwidth. Streaming is common for advanced sensors such as PMU-based wide area measurement systems (WAMPACS). Interrogation of stored data files is common for meters, data loggers and grid devices that collect records on a power waveform-triggered basis. Asynchronous event messages are becoming more common in devices that contain significant local processing and are therefore able to detect and report events.

Acquisition of grid data can span state boundaries, and given the growth of cloud-based data services, could result in data acquisition being performed across national boundaries. Given the sensitive nature of much grid data, and given that in the future distribution operations will have increasing impact of bulk system operations, new clarification of NERC CIP rules and state level oversight of the data acquisition process may be needed.

4.5 Advanced Metering Infrastructure (AMI)

AMI deployment is becoming widespread in the U.S, spurred by mandates in many states requiring utilities to install automated meters for residential use, along with ARRA investments[29]. Among the key lessons emerging from Recovery Act smart grid projects is that communications infrastructure is a foundational element; and that building sufficient capacity to enable both near- and long-term applications is a crucial consideration—particularly for projects involving deployments at scale.[30] Automated meters for Commercial and Industrial (C&I) use have been common for many years. C&I meters typically have sophisticated measurement and reporting capabilities, although reporting of their data to a central location has been limited by low bandwidth communications (sometimes as simple as leased telephone lines). Meter data has multiple uses of course, but some utilities have reported that customers had unrealistic expectation about the usefulness of smart meters and others have reported that meter data may be of more interest to the utilities than the electricity customers.

With the deployment of residential smart meters, many utilities expected to benefit greatly from the existence of a fine-grained sensor network spread over its distribution grid. In practice, residential smart meter systems have not proven to be the all-encompassing sensor fabrics for power grids that many have

[29] In 2012, 533 U.S. electric utilities had 43,165,185 advanced ("smart") metering infrastructure (AMI) installations; about 89% were residential customer installations according to EIA data.
[30] Proceedings of the IEEE Power & Energy Society 2014 Innovative Smart Grid Technologies Conference, February 19-21, 2014; Summary available at: https://www.smartgrid.gov/sites/default/files/doc/files/IEEE-ISGT_conference_summary.pdf

desired them to be. This is largely due to the constant drive to keep meter and meter network costs low, resulting in design decisions that have left residential meter networks lacking. This has resulted in a variety of limitations:

- Residential smart meters often do not have advanced sensing capabilities. This means that they do not measure many of the useful quantities needed for grid state determination. In some cases, the existing measurements are not made in a manner useful for utility operations.
- Meter communication networks have often been designed only to support usage reporting and so do not have the bandwidth and latency capabilities to support operation as a grid sensor network. This means that the meters cannot provide sensor-type data fast enough to be useful for any but the slowest distribution automation control systems.
- Until recently, meter communication protocols did not support sensor-like operation, having been developed from a usage reporting point of view. Consequently, it is normally necessary for other operational systems to go through the meter data collection head-end to obtain any meter data, including voltage readings. Full Internet Protocol (IP) stacks in the meters could alleviate this, but few meter deployments have them.
- Meter installation databases generally relate geospatial and customer information to the meter, but there is often either incorrect or no documented relationship to power grid connectivity (as discussed more fully below). For operational purposes, power grid connectivity—how the various physical elements in the grid are connected to one another--is the context in which sensed data must be interpreted.
- Wireless mesh-based meter communications networks have arisen as the least-cost option for utilities. However, these networks can take very long time periods to re-establish meshing upon partial or complete power restoration. As such, the meters do not come online fast enough to report grid state information that would be useful for restoration operations or grid control during restoration.
- Wireless mesh-based meter communications networks are also “lossy”, meaning that they are unreliable in terms of message packet delivery. This is not a severe problem for usage reporting, but is a major problem for control system operation.
- Some residential meters do not have strong timing capabilities, so that time-synchronized measurements, important for control system operation, are not possible with these meters.

For meters to be useful for any but the simplest distribution automation functions, these issues must be remedied. This means reliable communications, efficient communication protocols and interfaces, IP support, support for time synchronization, synchronized sampling capability, and sensor-grade measurement functions for more than just usage. It is expected that utilities with existing AMI deployments may take a variety of approaches to remedying these issues, depending on a number of factors including regulatory variables. The communication network issues may be addressed by replacement, or by the addition of “canopy” multi-services networks that augment the AMI network. The shortcomings in the meters could be addressed by replacement of the meters, but given the cost sensitivity of this, it is more likely that utilities will develop observability strategies and sensor network designs to obtain the necessary grid data. No tools exist presently to assist the utilities in developing these sensing strategies.

4.6 Grid Data Representation and Interchange

At one time in the US utility industry, the SCADA (supervisory control and data acquisition) systems that represented the state of the art in grid monitoring used proprietary data representations and communications protocols were dozens in existence. Eventually, this utility “Tower of Babel” was addressed with the development of a SCADA protocol that, in its present form, is known as DNP3. It is now widely used in utility SCADA in the US but more recently, the International Electrotechnical Commission (IEC) has developed a body of standards for both data representation and exchange under the IEC 61850 family. This includes a representation schema known as the IEC Common Information Model (CIM). While vendor support for IEC 61850 in Europe is strong, uptake in the US utility industry has been slow at the device level. It is somewhat stronger at the system interchange level. At the same time, the National Rural Electric Co-op Association (NRECA) has fostered the development and proliferation of a protocol and representation schema known as MultiSpeak for its members. MultiSpeak is widely used among rural co-ops, but is rarely used in large IOU’s. The IEC has been working on harmonizing MultiSpeak with IEC 61850, a useful step since MultiSpeak has arguably better methods for exchanging power state information than IEC 61850 has.

Meantime, the makers of power inverters (which are crucial to interfacing of solar PV, wind, and storage to the grid) have used Modbus and some proprietary protocols for control interfaces, leading to new grid interoperability issues. Still separately, Lawrence Berkeley National Laboratory (LBNL) has established a standard for information interchange for energy management and Demand Response called OpenADR. [31] It exists in an environment that at the building level includes BACNet, LonMark, and Smart Energy Profile 2.0 (SEP2.0), which is Zigbee-based.

Consequently, while the data interchange situation is better than the “Tower of Babel” days, there is much to be done in this area. Among the key issues has been lack of a comprehensive control framework to act as context for standards development and specification.[32]

> Interoperability standards work, as good as it has been, has not achieved as much traction as necessary in the US utility industry. A major reason for this is the lack of a contextual framework for interfaces. Standards such as IEEE P2030 provide inventories of interfaces, but this does not resolve the basic issue of framing when and where interfaces should be used and what properties they should have. Consequently, existing interface standards have developed bottom-up. What is needed is a reference architecture that focuses on structure--especially grid control system structure--in the context of industry/business structure and regulatory overlays. Frameworks that are essentially enterprise IT exercises do not address the specific needs associated with the convergence of grid and ICT infrastructure.

4.7 Grid Data Management

Utility data management in the context of increasing interdependence between grid and ICT systems is a matter more complex than databases and analytics applications. There are significant issues of data governance, storage hierarchy, data quality assurance, and curation that involve not just technology, but also people and processes challenging utilities’ traditional ways of doing business. Nevertheless, this

[31] http://openadr.lbl.gov/
[32] J. Taft and AS Becker-Dippmann, Grid Architecture, PNNL-24044, Pacific Northwest National Laboratory, 2015

paper will focus on technical issues associated with grid data management, starting with the matter of data persistence. Due to the issue of latency hierarchy discussed earlier, data persistence is not just a simple matter of a storage area network at the utility enterprise data center. Many types of storage and database technologies are useful in the grid modernization context. Table 4.4 below summarizes principal data storage types. Some are specialized for specific purposes; others like standard Structured Query Logic (SQL) databases are used for more general utility applications.

Table 4.4. Data Store Types

Store Type	Comments
Operational Data Stores	Used to hold state data which is continually refreshed, such as power and device state data, real time grid topology.
Time Series Stores	Used to hold telemetry that will be processed in various ways over various time scales, but specifically including very long times.
FIFO Queues and Circular Buffers	Very short term storage for data being consumed quickly by applications; often implemented in the application itself as memory resident small volume buffers
Meter Usage Data Repositories	Large scale repositories for meter data; these often hold the data of record for billing; generally associated with meter data management systems, although some independent MUDR’s have been implemented.
Relational Databases	Widely used in a variety of operational and enterprise contexts; built using either standard relational database technologies or memory-resident versions for faster response, especially in business intelligence and decision support applications. Utilities may have many such databases that have grown organically over many years of operation.
Warehouses and Datamarts	Used for storage of very large data sets for business intelligence, data mining, and the like; generally relational, but newer approaches are emerging.
True Distributed Databases	Databases in which various data elements exist in non-duplicated form on various physical stores, non-duplication being key to scalability; useful for operational data/grid state in distributed intelligence environments.
Waveform Repositories	Used to hold waveform files (oscillography); the waveform files may be treated as BLOB’s; repositories can be special purpose or a general content management tool.
GIS as a Data Store	Geographic Information Systems are often the system of record for as-built physical network topology (occasionally it may be the Outage Management System that performs this function for Distribution); some smart grid applications need access to the as-built topology meta-data, so it can be necessary to use the GIS as a database, although most are not built for real time or near real time query support. Consequently, as-built topology may be staged to a datamart for near real time access, with periodic updates from the GIS to the datamart.
Federated Databases	This is not a database type so much as a middleware for databases; federation can tie together heterogeneous databases so that querying systems do not need the details of the multiple underlying databases; this technology, along with CIM-structured relational databases has been used to integrate multiple operational, transactional, and time-series databases in smart grid data management solutions

Store Type	Comments
No-SQL/NoReL databases	Developing in response to “big data” requirements, these databases avoid the use of relational structure (hence the names “No-SQL” and “NoRel”), these databases are intended to scale to petabytes and beyond. These are beginning to see some use for business intelligence applications but have not penetrated utilities much as yet.
Content Manager Stores	Databases designed specifically for content management, so that files of various kinds can be stored, access-controlled, version-controlled, etc. Useful for BLOB-like data, hence the mention above for waveform repositories, but also useful for engineering drawings, video, manuals, and grid device settings/configurations

As an example of why it is important to understand the relationships among the data classes, persistence models, and data store types, consider the present interest in the Hadoop “Big Data” storage model. Hadoop was originally designed to analyze very large data volumes with a mix of complex and structured data that don’t fit nicely into relational databases. As such, the Hadoop model can be very good for enterprise-level business data repositories. However, for utility operational data it has several drawbacks:[33]

- The centralized data store model cannot satisfy the needs of low latency multi-objective/multi-controller (MO/MC) systems, where analytics must often be consumed close to the point of data generation.
- The Hadoop Distributed File System (HDFS) coherency model does not work for dynamic operational state information and bursty event message data flows, which are huge components of the big data challenge associated with smart physical systems. “HDFS applications need a write-once-read-many access model for files. A file once created, written, and closed need not be changed.”
- The HDFS data access model is not suitable for highly interactive, real-time system operations: “HDFS is designed more for batch processing rather than interactive use by users. The emphasis is on high throughput of data access rather than low latency of data access.”
- The destination for much of the data in a smart grid/smart physical system environment is NOT an enterprise data center. Instead, it is consumed by many different systems across the grid infrastructure.

As another example of how data characteristics influence data and analytics architecture, consider the processing of data that is logically treated as a batch (such as meter usage data) as compared to data that is available as a stream, such as Phasor Measurement Unit (PMU) data. In the batch case, there is a data collection process that aggregates and accumulates data into a large store; then various data processing steps are applied to the entire set of data. In the meter case, this includes Validation, Editing, and Estimation (VEE), and the processing of billing determinants into actual billing statements. For PMU data on the other hand, the situation more nearly resembles live streaming video. In this case, it is grid power state measurement data that is streaming, but when the goal is to provide ongoing grid operator decision support, the real-time use of such data eliminates the possibility of accumulating it into a large store to be processed offline. In such a case, the data is processed live, so that real-time data stores such as First

[33] The discussion and quotations regarding the use of Hadoop are based on material from the Hadoop website: (http://hadoop.apache.org/)

In/First Out (FIFO) queues are the first destination of the data, which is then piped into streaming analytics. As a secondary issue, the data may then be sent to a time series repository, so that offline analyses can in fact also be performed later. ***Thus, multi-stage data management and analytics architecture is needed.*** Streaming data is increasingly common in smart grid implementations, as is bursty asynchronous event message data. This leads to the need for a newer model for processing such data types, namely Complex Event Processing, which has lately also become known by the name "streaming database"— essentially, methods for interpreting multiple sources of streaming data simultaneously (for further discussion, see Section 6 regarding Analytics & Visualization).

4.8 Data Quality Assurance

Another issue relevant to the increasing interdependence of grid and ICT infrastructure pertains to data quality assurance. Grid data can suffer from many sources of error and corruption. In the meter data case, a formal process (aforementioned VEE) is used to deal with this problem. More generally, all grid data must be subject to some form of data quality assurance. This is not only for simple data quality purposes, but also because data may be manipulated maliciously by bad actors and this can effectively compromise control system operations.

Most IT approaches assume the data is archived and can be operated on over relatively long periods of time. However, as discussed, much grid data is used on variable latency scales, including in very short timeframes that may preclude any possibility of central storage and classic data quality processing. Methods for assuring data quality for data in motion are not well established and thus are usually implemented in *ad hoc* rules embedded somewhere in a large system. Fairly recently, the concept of using Complex Event Processing and streaming database tools for data quality assurance on low latency data ("data cleansing") has been implemented for intelligent oil fields.[34] Additional R&D is required to apply these concepts to electric distribution grids, where these methods and tools would require distributed and embedded implementations that do not presently exist.

4.9 Meta-Data Management

Meta-data is data about data. In the utility context, this includes power grid connectivity, network and device management data, point lists, sensor calibration data, and a rather wide variety of special information, including element names, which may have high multiplicity. Meta-data, such as the contextual information provided by power grid connectivity, is necessary to interpret sensor and other grid data. Traditionally, meta-data has been hand-managed, but with the emergence of multiple applications using various data subsets in overlapping fashion, the issue of meta-data collection, dissemination, and update has become a crucial chokepoint for advanced grid functionality. This is especially true for distribution systems, where grid connectivity—utilities' actual knowledge of which elements in the field are connected and how--is poorly known. Some have estimated that distribution

[34] "Complex Event Processing for Intelligent Fields," Saudi Aramco Journal of Technology, Summer 2014. Available online: http://www.saudiaramco.com/content/dam/Publications/Journal%20of%20Technology/Summer2014/Complex_Event.pdf

utilities' connectivity databases are only 50 percent to 80 percent accurate,[35] as grid connectivity changes on both fast (circuit switching) and slow (field service and maintenance) time scales. It should be noted that this problem does not occur on transmission systems. But since circuit connectivity is the basic context in which all grid data and controls must be interpreted, lack of accurate connectivity information is a key challenge for advanced distribution grids.

> Meta-data management is a "hidden" vulnerability in distribution grid modernization. The distribution circuit connectivity issue is the most severe aspect and despite various approaches and even product releases, there is no good solution to automatically continuously refreshing grid connectivity databases. Between this issue and lack of sound means to re-synchronize all meta-data in a timely fashion, most advanced distribution applications are currently hampered in terms of providing strong benefits realization.

4.10 Distribution Grid Observability

For most operational purposes, systems make use of elements of grid state. Grid state is the set of values (in control engineering: state variables, in mathematics: canonical variables) that describe the instantaneous condition of a dynamic system. State variables may be continuous (physical systems), discrete (logical systems and processes), or stochastic (such as Markov model states). For many types of systems and for linear systems in particular, the mathematics of state are well defined in the context of differential equation solutions of system dynamics. State has the property that future state of a dynamic system is completely defined by the present state and system inputs only. Knowledge of past state trajectory is not necessary.

Grid state is most often thought of as power state – the set of electrical variables (voltages, currents, phase angles) that define power flow. A great deal of other information is necessary for grid operations, so the concept of extended grid state is useful. Extended grid state includes power state plus other state information, such as equipment operating states, thermal states, etc. Figure 4.5 illustrates a taxonomy of extended grid state elements. Note that a variety of other values that do not meet the definition of state variable are also needed; many of those are derived for state and raw measurements via estimators, modelers, forecasters, etc. A robust systems information model has been suggested as a crucial element for advancing grid analytics.

[35] "AMI: Smart Enough? Metering Potential and Limitations for Smart Grid Design," Accenture, 2010.Available online: http://www.accenture.com/Microsites/accenturesmartsolutions-meterdatamanagement/Documents/Accenture_POV_AMI_Smart_Enough.pdf

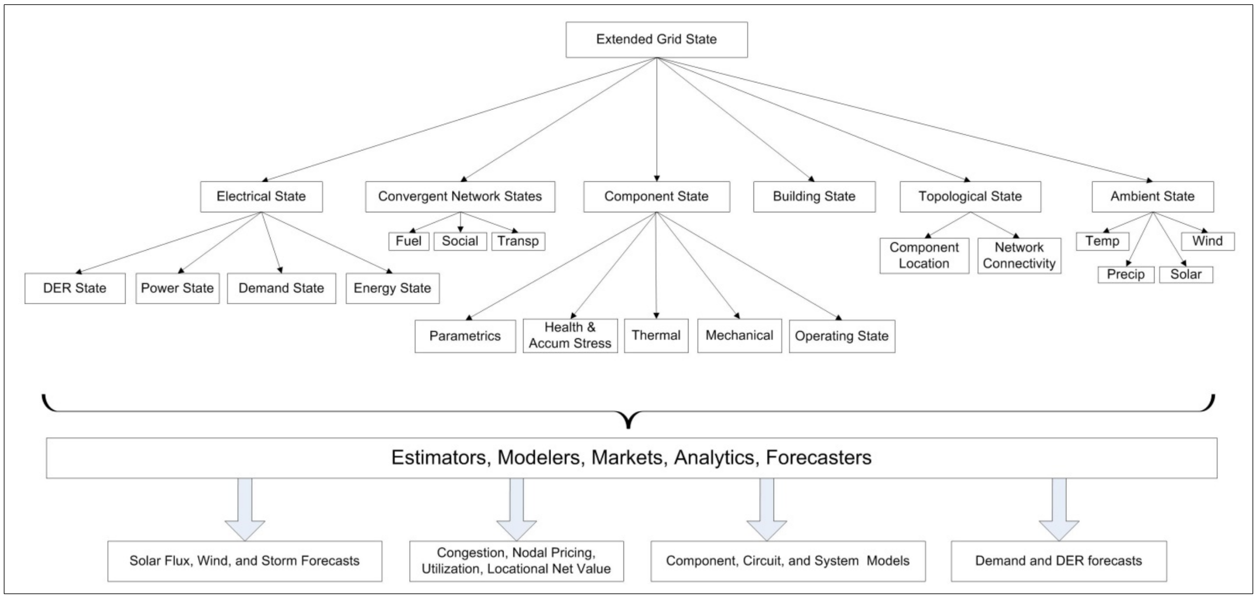

Figure 4.5. Taxonomy of Extended Grid State Elements

Clearly, a great deal of data must be acquired, managed, and processed to support grid operations. Typically, extended grid state is not assembled in one data structure, but is fragmented over many systems, causing difficulties when more than one system needs any specific state element values. An unstated presumption of the work done on interoperability standards is that systems will just exchange data as needed. The problem with this assumption is that in a low latency, distributed systems environment, moving data from system to system to system is not practical. Data architectures and tools to disseminate grid state elements appropriately across a variety of distributed systems and devices are not yet in use in utility systems.

System observability is the ability to determine system state from a set of measurements or data points taken from the system in question. Another view of observability is that it is temporal, geospatial, and topological awareness of all grid variables and assets, and may also be thought of as *grid visibility*. It is logical to extend this concept to include ICT situational awareness, which has operational and security implications.

Observability for distribution grids is fundamentally a more difficult issue than for transmission for all but the simplest radial systems. Complicating factors include feeder branches and laterals, unbalanced circuits, poorly documented circuits, large numbers of attached loads and devices and, in the case of feeders with inter-ties, time-varying circuit topology. In general, circuit topology and device electrical connectivity may be poorly (incompletely or inaccurately or both) known. These issues make state estimation more difficult than for transmission systems, so it is necessary to rely more upon state measurement and less on estimation.

It is not economical or even possible to measure all states directly; consequently states may be estimated analytically. In fact, it is quite common on transmission systems to use tools called state estimators that perform these extensive iterative calculations based on a system model and a sparse set of grid measurements to estimate complete transmission grid state. Such state estimation may not be as useful a tool for some distribution grids, for three reasons:

1. Unlike transmission systems, three phase distribution systems are generally unbalanced across phases, meaning that three times as much computation is needed to determine state as with transmission (to solve per phase)
2. Distribution grids are topologically more complex that transmission grid, making computations much more complicated than in transmission state estimation
3. Distribution grids with partial meshing are time varying in structure on both short and long time scales. Grid state calculations must be based on instantaneous as-operated structure, which can change quickly.

Distribution utilities do not have a formal and rigorous means to determine type and placement of sensors to establish grid observability. Significant tradeoffs exist in terms of types of sensors to be used, locations of sensors, and impact on communications systems design, but no tools or methods exist to aid in the creation of *distribution observability strategies,* and consequent sensor network designs. This is a gap that should be addressed in advance of the $675 Billion that The Brattle Group has estimated the industry will be investing in distribution the US by 2030.[36] At the transmission level, there are design guidelines for placement of PMU's based on the solutions to optimization problems[37] that constitute a form of observability strategy, but as noted, the problem there is somewhat simpler than for distribution grids. For distribution, note that the cost of installing a sensor on a feeder circuit outside of a substation is very high, such that installation cost is a significant factor in any approach to optimization of sensor network design (in the transmission case, the sensors are almost always located in the transmission substations). Many approaches to instrumentation for distribution systems have been based on sensors located in the distribution substations, but this is increasingly inadequate as distribution circuits become more complex due to the penetration of distributed generation and responsive loads.

The lack of observability on distribution systems is a major issue for grid modernization. The deployment of AMI has not materially improved the situation and utilities do not have tools or methods to guide them in the development of grid observability solutions. The lack of an automated means to continually update distribution grid electrical "as-operated" connectivity (which differs from "as-built" connectivity) is a basic limitation for advanced distribution automation.

4.11 Data Sharing and Repositories

Privacy and confidentiality issues place constraints on inter-utility data sharing, but lack of availability of real grid data also hampers efforts to develop advanced analytics, planning and control algorithms and tools. In the Western Interconnection, the North American SynchroPhasor Initiative (NASPI) has made progress on data sharing agreements and methods for PMU data; and groups in the Eastern Interconnection are now working on the same. There is value to sharing other data, especially distribution grid data, where models and methods are less well developed than for transmission, but there is very little in the way of data sharing or repositories at this level. This is not so much a matter of data representation as a matter of sharing processes and means for data curation.

[36] The Brattle Group. "Transforming America's Power Industry", 2008.
[37] F. Aminifar, et. al.,"Contingency-Constrained PMU Placement in Power Networks," IEEE Transactions on Power Systems, Vol. 25, No. 1, Feb 2010, pp 516-523.

Opportunities for Federal Leadership:

- Once again, reference architecture efforts will enable more robust adoption of interoperability standards—by setting the framework in which they might be most usefully applied.
- Given that utilities across the country differ greatly in the size and structure, as do the levels of investment in in-house ICT resources, a partnership with industry to devise assessment tools with respect to maturity of data management architecture and strategy—similar to efforts that led to DOE's Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) —may pay dividends.
- As noted, distribution utilities do not have a formal and rigorous means to determine type and placement of sensors to establish grid observability. Significant tradeoffs exist in terms of types of sensors to be used, locations of sensors, and impact on communications system design. But no tools or methods exist to aid in the creation of distribution observability strategies. Potential actions might include:
  - R&D efforts to address the need for technologies that might continually rediscover the connectivity of the "as operated" distribution grid, as well as efforts to develop cost-effective tools and methods for developing observability strategies.
  - Data sharing repositories for support of R&D efforts could leverage data from ARRA projects and data sets accumulating at utilities across the country. However, various non-technical barriers must be addressed to make this possible. The advantage of such sharing would be significant improvement in developing core technology for advanced grid analytics, planning, data quality assurance and grid control tools—especially at the distribution level.

5.0 Implications for Communications and Networking

Networking and digital communications are crucial to any modern enterprise, but especially so for those that involve geographically distributed infrastructure and operations. The data communications problem (moving data among various devices and systems at ever increasing volumes and speeds) for utilities is complicated by several factors:

- The speed with which electric energy moves – essentially, at the same speed as information about electricity can be moved
- With the advent of AMI and automatic Demand Response, utility networks have huge numbers of network endpoints in the public
- The tension between accessibility for energy innovation and the need to secure critical infrastructure

A number of models have been proposed to relate the value of a network to the number of users (n) , including Reed (2^n), Sarnoff (n), Metcalfe (n^2), and the Briscoe/Odlyzko/Tilly model (n log n).[38] Regardless of which model applies, the number of "users" (not just people, but devices and systems in an advanced grid) is huge and growing. If one considers the value of the networks to be related to the value of the information being transported, one arrives at the conclusion that these networks can have very high value, potentially much higher than the simple cost to implement.

Nevertheless, utilities have difficulties justifying expenditures for communication networks under traditional regulatory regimes (especially at the distribution level), given the emergent nature of technologies enabling advanced grid functions and the lack of a concrete set of tools for estimating costs and benefits. This has led to deployment of utility networks that are undersized and insufficiently scalable for new capabilities required to meet the challenges of integrating variable energy generation and improving system resilience. This has been especially true for AMI networks that were supposed to support advanced distribution automation but often only support basic meter reading functions.

As more devices are connected to power grids, the communication network becomes more valuable, and therefore network investment strategies should consider end state, not just initial usage. Sizing networks for this is not done well for both technical and financial/regulatory reasons, leading to stranded investments and blocked benefits realization.

5.1 Grid Communications Tier Model

The complexity of the US utility industry has led to complexity in the communications networks. Within a given power delivery chain there are multiple network types, owners, and requirements sets. Cisco Systems developed a reference model for communications in the utility industry that defines 11 tiers of networking based on such criteria.[39] The model, which has gotten good initial traction in the utility industry, is shown in Figure 5.1. Each of the "pipes" in the diagram represents a logical communication tier (not a physical network). Logical tiers are defined by organizational and system boundaries, performance requirements and typical network ownership. The definitions of the tiers in this model are given below, starting with the bottom tier and working upward.

---

[38] Bob Briscoe, et. al., "Metcalfe's Law is Wrong," IEEE Spectrum, July 2006, pp. 34-39.
[39] http://www.cisco.com/web/strategy/docs/energy/gridblocks_ref_model.pdf

Prosumer Tier – networks that are not part of the utility infrastructure but involve devices and systems that interact significantly with the utility, such as responsive loads in residences and commercial/industrial facilities, on-board electric vehicle networks , etc. (Prosumer is a compound of "producer" and "consumer," used here to include third party distributed generation that puts energy into the grid.)

Distribution Level 2 Tier – Networks at the distribution level and typically owned by the distribution utility between primary distribution substations and end users are broken into two sub- levels. The lower sub-level is composed of any number of purpose-built networks that operate at what is often viewed as the "last mile," or Neighborhood Area Network (NAN) level. These networks may service metering, distribution automation, and public infrastructure for electric vehicle charging, for example. In some cases, a telecommunications service provider network may be used on a leased basis by the utility.

Distribution Level 1 Tier – Networks at the distribution level upper sub-level, which is a multi-services tier that integrates the various Level 2 tier networks and provides backhaul connectivity in two ways: directly back to control centers via the system control tier (defined below); or directly to primary substations, to facilitate substation level distributed intelligence. It also provides peer-to-peer connectivity for distributed intelligence at the distribution level. Grid devices and subsystems may be connected at either of the two distribution tiers, depending on communication performance requirements. Again, this may be a service provide network, but this is rare. Mobile workforce communications, which need high reliability, operate through this tier as well.

Substation Tier – Networks inside substations of all types. These networks are owned by the substation owner and can have wide ranging requirements, from very simple for European secondary stations to very complex for primary substations involved in low latency critical functions such as teleprotection (circuit breakers operated remotely and automatically via very fast communication links to protect grid assets from damage in the event of a circuit fault). Internally to the substation, these networks may comprise from one to three buses (system bus, process bus, and multi-services bus).

System Control Tier – Networks that interconnect substations with each other and with control centers. These networks are wide-area networks and while a few are service provider networks, most are owned by the utilities that own the substations. The high-end performance requirements for these networks can be stringent in terms of latency and burst response. In addition, these networks require very flexible scalability; and due to geographic challenges, they can require mixed physical media and multiple aggregation topologies. System control tier networks provide networking for SCADA, SIPS, event messaging, and remote asset monitoring telemetry traffic, as well as peer-to-peer connectivity for teleprotection and substation-level distributed intelligence.

Intra-Control Center/Intra-Data Center Tier **–** Networks inside two different types of facilities in the utility: utility data centers and utility control centers. These are owned by the utilities that own the controls and data centers; and while the networks are at the same logical tier level, they are *not* the same networks, as control centers have very different requirements for connection to real time systems and for security, as compared to enterprise data centers, which do not connect to real time systems. Each type provides connectivity for systems inside the facility and connections to external networks, such as system control and utility tier networks.

Utility Tier – Enterprise or campus networks, as well as inter-control center networks. Since utilities typically have multiple control centers and multiple campuses that are widely separated geographically, this tier has to include more than metro networks. These networks may be owned by the utility or be leased from a service provider.

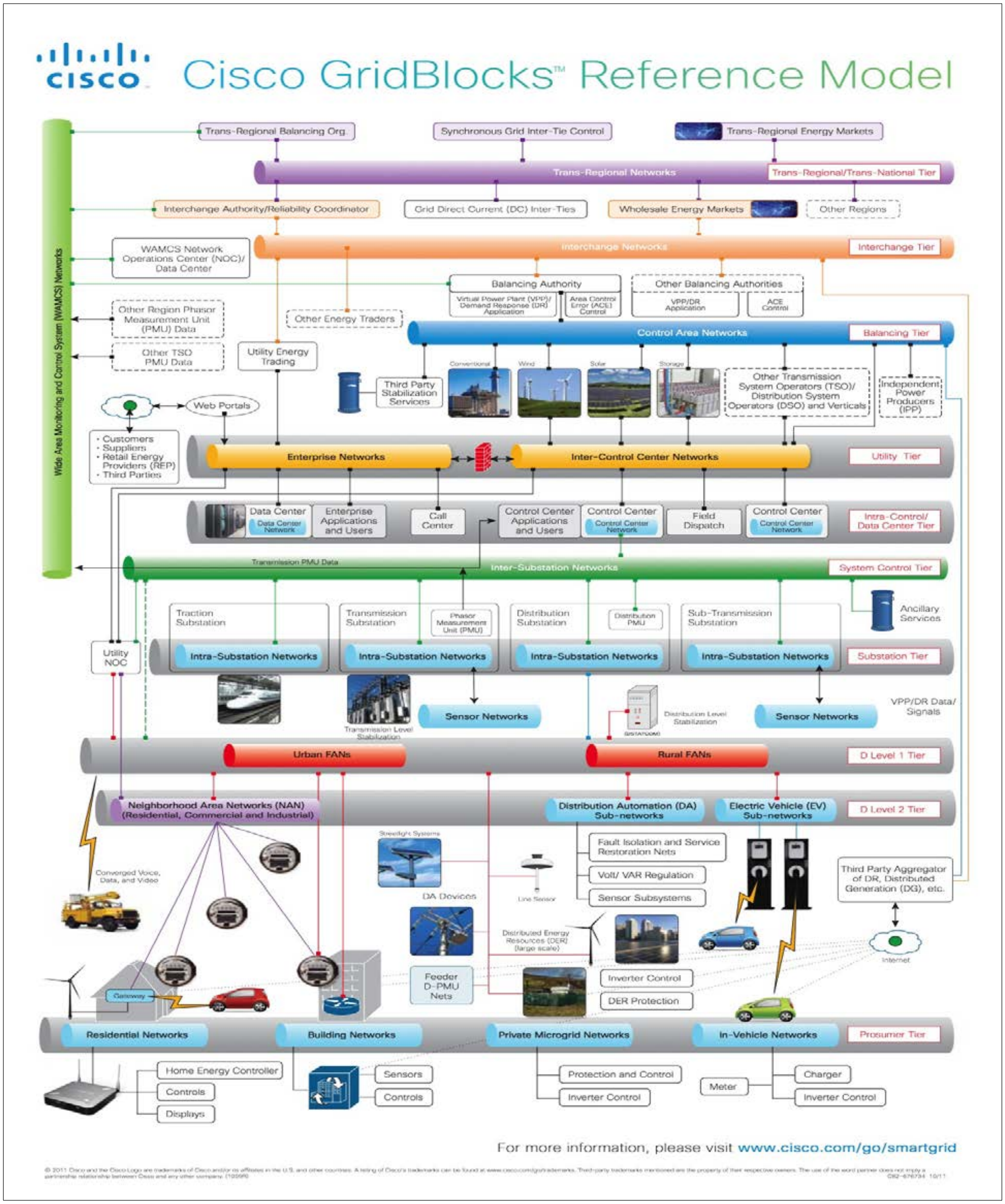

Figure 5.1. Utility Communications Reference Model. Courtesy of Cisco Systems

Balancing Tier – These networks interconnect generation operators and independent power producers with balancing authorities, and interconnect balancing authorities with each other. In some emerging cases, balancing authorities may also dispatch retail level distributed energy resources or responsive load. Communications is usually via the ICCP protocol and may be via dedicated or public carrier network. These networks are utility owned in the vertical utility case, or are owned by the members of an ISO, where such system operators exist.

Interchange Tier – Networks that interconnect regional reliability coordinators with entities such as transmission operators and power producers, as well as networks that connect wholesale electricity markets to market operators, providers, retailers, and traders. In some cases, the bulk power markets are being opened up to small prosumers, so that they have a retail-like aspect that impacts networking for involved entities. Communications is usually via the ICCP protocol and may be via dedicated or public carrier network.

Trans-Regional/Trans-National Tier – Networks that interconnect synchronous grids for power interchange, as well as emerging national or even continental scale networks for grid monitoring, inter-tie power flow management, and national or continental scale renewable energy markets.

WAMCS Tier – networks for Wide Area Measurement Systems (WAMS; basically PMU networks), although terms like Wide Area Measurement and Control System (WAMCS) and Wide Area Measurement, Protection, and Control System (WAMPACS) are also used. This tier is represented somewhat differently on the Reference Model than the others because it inherently must connect to entities at other tier levels--but will typically do so through special network arrangements. This is a wide-area, low latency network, where the owner/operator of the network may not be any of the member utilities who are sharing PMU data over it. These networks may be public or private and use IEEE 37.118 or IEC 61850-90-5 protocols. Networks of this type have been proliferating as a result of the penetration of PMU's at the bulk system level, so the users are reliability coordination, system operators, and transmission operators. Some have built networks for themselves, but many have used leased networks. For example, WECC uses a optical fiber network operated by Harris Corporation, which was originally built for handling national FAA air traffic control data.

5.2 Legacy Communications in Electric Utilities

Utilities have traditionally used multiple non-converged communication networks for telemetry, meter data, voice, digital field data, protection and control, inter-control center communication, video, and enterprise networking. Some utilities have had as many as nine separate communications networks, often owned and managed by different departments within a single utility. Some are as simple as twisted wire pair hub and spoke links from control centers to substations. Others make use of telephone leased lines; still others use fiber, various forms of wireless links, satellite links, and even power line communication (where the physical medium is the actual power line). In all, utilities have made use of more than two dozen classes of communication networks and have used both private networks that they built as well as public service provider networks, including telephone lines and MPLS networks provided by internet backbone companies. At least one has used the Harris Corporation private national fiber optic network developed for use by the FAA to carry PMU data.[40]

Since most utilities choose to carry critical data on their own private networks, investments in networks represent significant stranded asset risk. As a result, utility executives have historically been reluctant to upgrade or replace them until their useful lifetimes have been reached. This leads to legacy networks being somewhat of a bottleneck in terms of grid modernization. The cost implication for distribution automation has typically been that communications systems cost about 15 percent of the total automation system cost. More recent experience from the ARRA program suggests that for advanced grids, this may approach 25 percent.

5.3 Advanced Networking for Electric Grids: the Value of IP

IP here refers to the set of digital communication protocols known collectively as Internet Protocol. The IP suite is a widely supported open standard and is one of the key reasons for the success of the internet (another being the internet's core/edge architecture). It is important to distinguish between IP and the actual internet, however. IP can and is used extensively in private networks, including utility networks. The IP suite provides excellent interoperability and enormous flexibility and capability, not just in actual data transport, but also in management of communication networks. IP has consistently displaced older forms of networking. Its principal benefits include:

- Standards-based interoperability
- Built-in security measures and tools
- Flexibility for physical connectivity
- Practically unlimited scalability with IPv6
- High performance and congestion management
- Ability to prioritize traffic (Quality of Service, or QoS tagging)
- Proven migration path from multiple proprietary protocols to IP architecture

While IPv4 address depletion was much in the news a few years ago, various techniques such as Network Address Translation (NAT) have worked well as mitigation. The issue is real but the transition to IPv6 has nevertheless been slow, so that while it has compelling scalability, overall support within the communications and utility industries remains weak.

Understanding of the real power of IP is uneven in the utility industry. The situation with PMU networking is illustrative. Rather than adopt the standard IP methods used for streaming video multi-cast (PIM/SSM), the industry elected to superimpose a network of Phasor Data Concentrators (PDC's) onto the underlying IP network, thus destroying the core/edge architecture that makes the internet so powerful. Now the industry is beginning to see the problems caused by PDC stacking and is looking to undo and rework some of the networking, to fix the performance problems created by the PDC approach.

---

[40] Vicki Van Zandt, "Western Interconnection Synchrophasor Program," NASPI Workgroup Meeting, October 12-13, 2011. Available online: https://www.smartgrid.gov/sites/default/files/doc/files/NASPI%20Oct%202011%20master%20-%20WECC_1.pdf

Industry adoption of IP is uneven and lacks depth, so that capabilities inherent in the IP network are being duplicated (in less effective ways). The result is sub-optimal performance and additional costs. Utilities have not yet uniformly mastered the means to maximize benefits of their network investments and IPv6 proliferation is slow in general, limiting the advantages it could provide utilities and their customers.

5.4 Network Management

Communication networks include not just routers, switches, network cards, and physical media, but also tools to configure networks, monitor performance, and manage behavior. Present network management tools can handle up to about five million elements, although most presently deployed network management systems actually handle far less. With the growth of intelligent power grid endpoints that must be networked, it appears that within a decade there will be a need to manage utility networks of more than 20 million endpoints. At the same time, in addition to managing network devices, it is clearly desirable to use the same tools to manage intelligent power devices such as substation relays and grid device controllers, and to monitor and manage distributed databases and applications in the grid. These capabilities do not exist in present network management systems, and thus represent a fertile area for research and development with respect to management of emerging distributed grid control systems.

5.5 Communication Networks as Computing Platforms

Many network routers contain a range of computing capabilities—from modest to powerful. Recently, two manufacturers have begun to open up these devices to host third party applications software in secure computing environments within the routers made for field area use (deployment on utility poles, for example).[41] This has excellent potential for enabling distributed data acquisition, analytics and control capabilities for the modern grid, since the data flows pass through the routers anyway. However, the use of routers as application computing platforms creates new requirements for network management systems, and raises intra-router security issues (app to app security within the router programming platform) that do not exist presently.

5.6 Wireless Mesh Network Issues

Many AMI last mile networks (called Field Area Networks or FAN's) use wireless mesh technology. These networks have rather low effective bandwidth for two reasons. First, the raw bandwidth rate is not all that high to start (64-100 Kbits per second); and second, the mesh network protocols have so much internal overhead traffic just to maintain the mesh that surprisingly little is left over for actual application payload data. These networks also rely upon packet hopping from node to node to move data through the network to a collector, which in turn connects to a higher bandwidth backhaul network. Each hop adds latency, so these are also high latency networks. But perhaps more challenging is the behavior of wireless mesh networks in outage situations. Some mesh networks do not store mesh information in a nonvolatile manner at the nodes to keep internal traffic down, so when a major outage occurs and nodes lose power

[41] Jeff St. John, "Cisco Launches the Smart Grid Router as Apps Platform," greentechgrid, Jan 29, 2014. Available online: http://www.greentechmedia.com/articles/read/cisco-launches-the-smart-grid-router-as-apps-platform

(after battery backup is exhausted) the mesh state information is lost. When the nodes are powered back up, they must go through an extensive process to re-form the mesh, using beacon signals and other means. This process can take anywhere from *hours to days*, meaning that the mesh network is useless for assisting utility restoration operations. If the nodes maintained mesh state information via nonvolatile memory, then upon power up they could reform most of the mesh almost immediately. However, this would come at the cost of degraded performance under normal operating conditions, as well as cost for the nonvolatile memory hardware. All that being said, wireless mesh networks do provide a certain advantage: providing coverage in frequency bands where propagation conditions are constantly changing not only from movement of physical objects, but also construction and (with some frequencies) even seasonal foliage. Compare to cellular telephone networks where this problem is addressed by moving the endpoint – i.e., walking to where you can get a signal (as we all have done). This is something a stationary meter clearly cannot do. Given these issues, wireless mesh is often selected to provide better lower cost coverage than other technologies.

Last mile FANs, especially those that use wireless mesh networking, have not been a serious issue as long as their principal use is reading meter data. However, much investment has been made in such networks with the idea that they will support advanced distribution automation. The challenge is that these existing networks will not be adequate for advanced functions. Still, some utilities have already made significant investments in them. The utilities will be hampered both by financial realities and utility aversion to asset replacement/upgrade before the useful life of the asset has expired. This could result in significant delay in realization of benefits from advanced distribution automation.

5.7 Network Cyber-Security Issues

Before 1998 in the US, network security in the utility industry relied upon a combination of proprietary protocols, private networks (in many, but not all cases) and simple measures such as Select Before Operate (SBO, more for protection against line noise than anything else) and dial-back modems. Physical security was high at nuclear generating stations and transmission operations centers, less so at distribution operations centers, and fairly low at substations (mainly fences with padlocked gates and locked control house doors). European secondary distribution stations and US 4kV distribution stations had and still have minimal security.

In 1998, the US government began to focus on Critical Infrastructure Protection (CIP), including but not limited to electric power infrastructure. In the US, CIP regulation for electric utilities is driven by the Federal Energy regulatory Commission (FERC) via the North American Electric Reliability Corporation (NERC). NERC has promulgated CIP rules for the electric power industry, and continues to update these rules over time. This has driven the industry to invest considerable effort in developing policies and processes, and to invest in solutions for improving both cyber and physical security. Nevertheless, the industry continues to face significant challenges, especially in the network security area, for two reasons:

- Increasing numbers of communication devices being attached to power grids as a result of smart grid transitions and a number of trends discussed in Section 2
- Existence of legacy devices that do not support modern cyber security services

Utilities are not able to pursue a "shut down-rip and replace-restart" model; the process of rolling out new devices is slow and creates a variable hybrid environment during the process. Consequently, while they are very interested in applying the capabilities inherent in the IP protocol suite, utilities face transition issues, just as with the rest of ICT.

In recent years, utilities have been engaged in replacing simple residential electric meters with Advanced Meter Infrastructure (AMI). With AMI, the utility has up to millions of endpoints that provide two-way communications capability, usually through wireless networks or via Power Line Communication (PLC). The existence of these systems has raised both system security and data privacy and confidentiality concerns in some regions.

There has been some misleading discussion in the industry about whether certain kinds of protocols are vulnerable and this has been used as an argument against using Internet Protocols for utility communications. The correct view is that *any* connectivity introduces security vulnerabilities, as the Stuxnet incident has shown (a USB data storage device was the source of infection).[42]

Considerable effort has gone into developing security technology for networks, due to vast financial and other concerns. Approaches to network security may be encapsulated into four major categories:

1. Access control
2. Data protection
3. Device/system integrity
4. Threat detection and mitigation

Data protection is further broken down into data integrity, data confidentiality (limiting access to information), and data privacy (control of personally identifiable or otherwise sensitive information).

Despite extensive investment in technology, it is not possible to entirely guarantee network or general ICT security. Consequently, layered approaches with multiple classes of defenses plus extensive processes and training for people are considered best practices. Unfortunately, use of best practices is not uniform across the industry. Even the most basic principle (connectivity creates vulnerability) is in tension with the desire to use the internet for various utility communication needs. The use of the internet and telecommunication service provider networks for critical data traffic has generally been avoided by utilities, but arguably more for reasons of emergency access priority and capital equipment ownership than as a security measure.

Network and data system security is not a solved issue. Use of the internet exacerbates the problem because the internet was not designed for security; and yet, there is increasing pressure on utilities to make use of the internet for various purposes. ICT remains a source of vulnerability in power grids, where security requires a layered approach, multiple classes of defenses, and extensive processes and training.

[42] Alekander Matrasov, et. al., "Stuxnet Under the Microscope", ESET, available online: http://go.eset.com/us/resources/white-papers/Stuxnet_Under_the_Microscope.pdf

Other technology developments may also contribute to threats to grid operation, but exist entirely outside the utility itself. The rise of social networking, coupled with the "Internet of Things (IoT)" concept --making ordinary objects networkable and connected via the internet--has posed the possibility of mass manipulation of utility loads in a synchronized manner, either through social action (think flash crowd, but with household energy using devices instead of people) or via hacking.[43] There are no security requirements for these non-utility load controls and it may not be difficult to aggregate sufficient load to affect grid operations. Most "IoT" devices are configured for little or no security and their owners are not motivated to employ any security best practices. The "Internet of Things" is viewed by some as a massive security problem,[44] since the internet itself was built without strong security measures.

5.8 Utility Dedicated Spectrum

Large utilities mostly build and use private networks for utility operations. Some utilities have used network service provider (telco) networks, but generally this has not been the case. Essentially all US utilities use a combination of public and private networks, but in differing proportions. As a result, utilities active in stakeholder groups such as the Utilities Telecom Council (UTC) have advocated for dedicated spectrum for their wireless networks, with a uniform lack of success at both the Federal Communications Commission (FCC) and in the legislative arena.[45] Telcos are incentivized to fight the allocation of dedicated spectrum issue, insofar as it ensures utilities' use of telco networks. The utilities have said in the past that they have security requirements that may include NERC CIP rules, but NERC CIP now explicitly excludes telco networks from security requirements as long as the utilities use VPN, IPSEC, or other security measures for data in transit across those networks. Utilities have also suggested that telcos' wireless base stations do not have adequate battery backup for outage situations and therefore are insufficiently resilient for utility purposes; and moreover, that service provider networks cannot guarantee adequate bandwidth and sufficiently low latency for grid operations. This concern has been reinforced by actual experience of cell site overload during natural disasters followed by shutdown as the backup power was exhausted.

It has often been suggested that utilities share municipal wireless networks. The utilities have objected to this on the basis that they need "first responder" status. Police/fire/EMS groups have fought the utilities vigorously and successfully to keep utilities from getting "first responder" status on existing wireless networks. This issue and the base station resilience issue are likely resolvable via Service Level Agreements (SLAs), but anecdotally, utilities have been skeptical of telcos' negotiating tactics around such agreements.

Much of this may be resolved within one or two generations of technology development around software defined radio (SDR)—that is to say, potentially within the next five years. SDR technology with sufficient intelligence (known as cognitive radio) could actually eliminate the need for dedicated spectrum entirely through auto configuration of band, modulation technique and other means.[46] Some of

---

[43] Mike Rowand of Duke Energy, "The Integrated Grid and the Connected Customer," Role of the Electric Distribution System in an Integrated Grid, EPRI workshop July 10-11, 2014, Washington, D.C.
[44] Jeffrey Burt, "Internet of Things Presents a Host of Security Challenges," eWeek, May 7, 2014, available online: http://www.eweek.com/security/internet-of-things-present-host-of-security-challenges.html
[45] http://www.utc.org/advocacy_issue/talking-points-why-utilities-need-spectrum
[46] SDR Forum, "Considerations and Recommendations for Software Defined Radio Technologies for the 700 MHz Public/Private Partnership," December, 2007. Available online: http://groups.winnforum.org/d/do/1579

these solutions are currently being explored by the Department of Defense. SDR's in and of themselves don't necessarily make a robust and resilient architecture, but SDR has the potential be used to implement a robust and resilient architecture with the advantage of making notions of dedicated spectrum obsolete.

5.9 Need for Co-Simulation

Networks are integral to modern power grid operations and are becoming increasingly critical as grid dynamics speed up and as more controls become closed loop in form. However, most of today's tools for power grid simulation and design have no means to include the behavior of communication networks. Nevertheless, network performance and behavior affect the grid in substantial ways, as key elements of grid protection and control systems. As such, there is a need to integrate network behavior into grid simulations used by industry and the regulators that oversee it. Such capabilities are just in their early stages[47] and are not widely available to utility planners and design engineers. Feedback and control latencies and hysteresis are essential parts of control system design but the design of electric utility control and communication networks systems haven't adopted these well-known disciplines.

5.10 Timing Distribution via Networks

Many grid protection, control, and measurement operations require synchronization of applications that reside in geographically dispersed locations. Such applications include acquisition and processing of PMU data and grid protection control. For PMU's it is common to have local GPS timing data; however, in the long run, it would be more cost effective and flexible to use precise timing distributed over wide areas via the communications network. Such timing distribution is possible via the IEEE 1588/C37.238 standards. An issue is that while very precise timing (1 microsecond) can be sent through the network, the means to get the timing into applications without loss of precision or accuracy is lacking because the only available mechanism is Network Time Protocol (10-100 milliseconds). Some work is being done at the National Institute of Standards and Technology (NIST) on this issue,[48] and should be moved forward expeditiously such that product vendors and application designers can make use of it. This will allow reduced dependence on GPS and more flexibility is choosing clock sources. In addition, use of secure network mechanisms reduces potential security vulnerability of methods that rely on open "over-the-air" approaches that could be spoofed or jammed.

Timing issues have a strong impact on analytics, which are discussed in the next section. The basic issue is that with the many sources of data and their various update rate and latency characteristics, and the many methods by which data are time-stamped, it is difficult to merge data from such disparate sources if time is a crucial aspect of the value of the information being conveyed. Network timing distribution may help alleviate the issue but must resolve the precision distribution issue described above.

[47] J. C. Fuller, et.al., "Communication Simulations for Power System Applications," available online: http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6623314

[48] Chad Boutin, "Lack of Effective Timing Signals Could Hamper Internet of Things Development", NIST Tech Beat, March 19, 2015. Available online: http://www.nist.gov/pml/div688/timing-031915.cfm

Opportunities for Federal Leadership:

- Networks are increasingly integral to modern power grid operations, yet most power grid simulation and design tools today lack means to include communications-related elements. Measures to accelerate integration efforts and move them into use by utility planners and design engineers may help better inform grid operators' investment decisions.
- Anything more than anecdotal information regarding utilities' communications and network investment strategies appears to be extremely scarce. Survey or data collection efforts in this regard may assist in adding empirical grounding to potential efforts to provide additional incentives for right-sized investments.
- Regulatory reforms at the State level are one means of opening the aperture on enhanced investments in communications and networks to support advanced distribution system functions. However, little exists in the way of distribution level "use cases" casting the costs/benefits of these investments in terms "digestable" by State regulators. Such an exercise may help set the parameters for State action.
- While some utilities may choose a "rip and replace" approach to insufficient distribution level networking, others might pursue a "two-tiered" distribution network. Consideration of mechanisms such as accelerated depreciation or investment tax credits could prime utility consideration of new communications/networking investments, in recognition of the "accelerated obsolescence" of these assets in the face of the evolving landscape facing grid operators.
- Wireless mesh networks built to support AMI deployments are more affordable than optical fiber, but may not be sufficient for system restoration and resilience functions. Incentives to deploy mobile WiMAX (Worldwide Interoperability for Microwave Access) or other advanced wireless technology where critical infrastructure is concerned could help bolster resilience.
- To the extent utility access to spectrum remains a subject of controversy among various stakeholders—particularly during restoration-related incidents--adapting solutions such as Software Defined and Cognitive Radio to utility purposes may prove useful. This technology is currently being piloted in defense contexts, but may be ready for migration to more commercial markets within a few generations of technology development.

6.0 Analytics and Visualization

Analytics are tools, processes, or methods that extract useful information from masses of data and it is important to keep in mind the distinction between data (basically measurements, event records, etc.) and information (actionable intelligence derived from data). Generally, analytics are implemented in software to process digital data. Visualization is the depiction of complex data and information in a visual format, to aid human comprehension. Analytics are used in several modes:

- For human decision support, where they are often coupled with visualizations; here a great concern for utilities is what has been termed “shifting situational awareness”
- For use in automation decision and control systems, where visualization is less important, except to aid human supervision of the automated systems
- As support for the validation of system models used in system control, operations, and planning

The scope of analytics for electric utilities is very wide, encompassing system planning, real time operations, maintenance and upgrade, customer relations, and regulatory compliance, among other functions. The range of analytics and analytics tools is correspondingly large.

Analytics may be placed roughly into three time regimes:

1. Real time –examples: power state determination and asset utilization for automatic control
2. Near real time –example: transmission system loading and generation flexibility for ISO dispatchers
3. Non real time –examples: analysis of meter data for support of system expansion planning and asset accumulated stress component and loss of life for asset management.

Southern California Edison has developed a smart grid reference architecture in which it classified analytics in terms of logical relationships between data sources and uses. In the process, the utility categorized analytics into six categories, and end uses into eight categories, as shown in Figure 6.1 below.[49]

[49] SCE, IBM, and Cisco, ”Smart Grid Reference Architecture Volume 1,” available online: http://www.pointview.com/data/files/1/636/2181.pdf

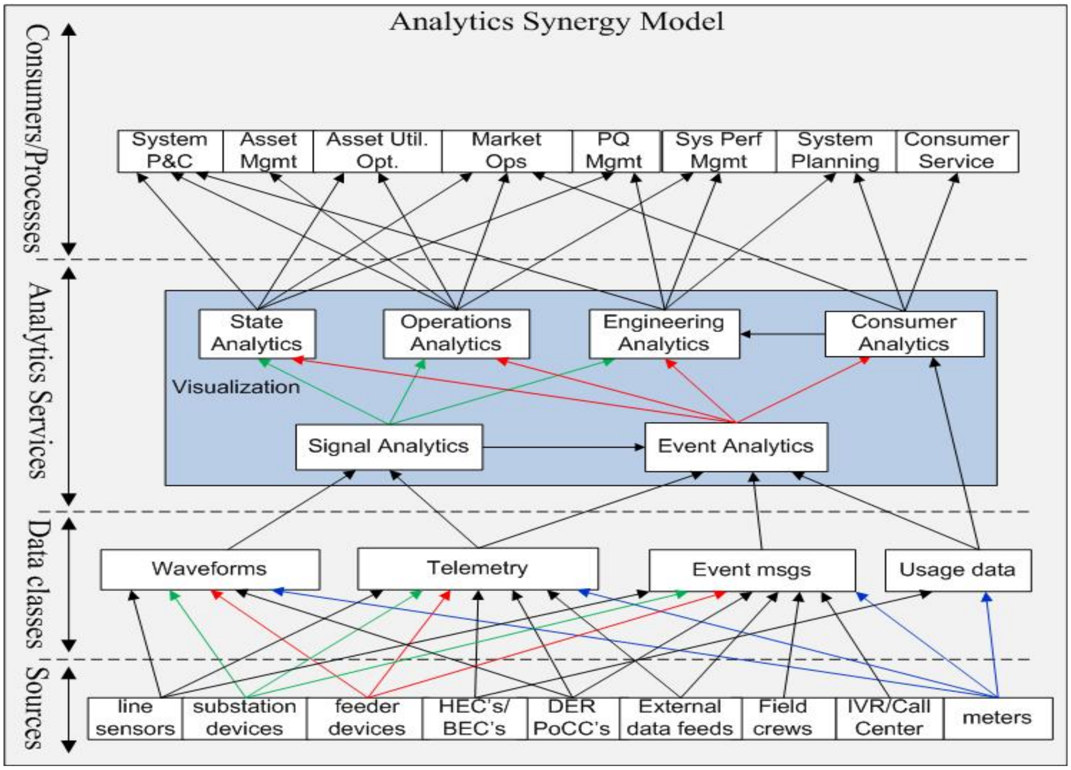

Figure 6.1. SCE Analytics Classification Schema

Regardless of how analytics are classified, the fact is that utility usage of grid data is highly dependent on analytics and visualization, and the dependency is growing as the volumes and types of data grow.

Signal and event analytics are low level or early processes that transform raw sensor data or device event messages into forms more useful for abstract analysis. Methods at this level use capabilities like digital signal processing for transducer data and Complex Event Processing (CEP) for event message filtering. Data validation and quality control are often performed at this level as well, especially for data in motion. Analytics at this level may be embedded or may be in standalone processing systems; either way, they are subject to the challenges associated with both meta-data management and extended network management.

The four higher level analytics classes are focused on specific problem domains for electric grid operations. It should be noted that there are other data sources that may also be required to support these analytics classes. These include weather and lightning strike databases, customer satisfaction surveys, network management systems, and eventually operational data from new subsystems such as Distributed Energy Resource Management Systems and intelligent building control interfaces. In addition, it would be logical to include security analytics and situational awareness to the set of analytics classes, with inputs from not just security sensing (e.g., video) but also from include Security Information and Event Management (SIEM) and other cyber-security tools.

Over the last five years, the utility industry has recognized the value of analytics and a small but growing ecosystem of researchers and product vendors has grown up around the issue. The adoption of analytics in the industry is case-dependent and there is no general approach to developing analytics standards, architectures or comprehensive solutions. Further, some power grid analytics requite massive number-crunching capabilities, and so are limited by the availability of High Performance Computing (HPC) at the utilities. This set of technologies, which are still developing and integrating into utilities, face the danger of becoming a massive set of new siloes by evolution, a situation the utility industry does not need. This suggests that some amount of effort to provide an architectural framework for analytics would be useful to avoid the siloing, and to ensure interoperability.

6.1 Real Time/Data-in-Motion Analytics

Data in motion automatically introduces the issue of analytics in motion, necessitated by the issue of latency hierarchy and the resultant move to distributed processing and control, as well as the need to handle data streams at centralized locations. New tools have evolved to help meet this need, including Complex Event Processing (CEP) and streaming databases. The existing tools are rather bulky in terms of software footprint and are not suitable to embedded application at the edge device level, or even at the level of routers that can host applications (as discussed in Section 5). It is reasonable to believe the private sector companies will address the footprint issue, but the proliferation of distributed analytics in motion will put new requirements upon communication networks that are already inadequate, and will add new functional requirements to network management systems. Finally, utilities will need methods and tools to help them develop analytics architectures and to deploy the resultant implementations.

Distributing computing of any kind requires new/improved methods of code distribution, code security and device authentication, configuration management and version control. And when dealing with thousands to millions of computational elements, no update or change of any kind mode over the network can be carried out without imposing significant load on the network and taking significant time. Consider for example, the task of updating the firmware in a million meters “over the air.”

Analytics for many purposes are being developed by commercial companies. There are technical gaps in selected areas: high end number crunching for advanced simulation, analytics for near real time interpretation of PMU data, and embedded streaming/event based analytics for real time control.

Opportunities for Federal Leadership:

- Marrying up the high-performance computing (HPC) assets resident within the research community with product vendors and the real-world concerns of grid operators can accelerate the development of useful analytics and visualization tools.
- Research and development with respect to analytics must keep pace with the evolution of the grid and its control systems to a more distributed model. Eventually, the focus on centralized analytics to support human decision-making should be augmented with work on distributed analytics to support the operation of devices in the field.

7.0 Software for Grid Operations

The use of traditional software for power grids is becoming problematic because the way the grid is evolving is moving away from the basic assumptions built into existing grid planning, management, and control tools. New tools are needed that:

- operate on much more finely-grained time scales
- employ both deterministic and stochastic methods
- merge planning tools with operations tools
- combine power grid, communications and control into integrated simulation and design
- move away from the centralized control paradigm to a hybrid of central and distributed control, where much intelligence will move out of the control centers and into substations and beyond.

Once again, these advances imply new and better network/application management strategies among utilities and grid operators, as well as advances in HPC, algorithms, and fundamental control system structure. At present, DOE-OE and its Clean Energy Transmission and Reliability (CETR) and Advanced Modeling Grid Research (AMGR) subprograms--leveraging additional capabilities from the Office of Science-are pioneering advances in these fields.

The following sections describe the kinds of software currently used by various utility entities for grid operations.

7.1 Reliability Coordinator Tools

Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions, typically on a 30-minutes time scale. Software tools include:

State estimator for the entire reliability region **-** calculation of voltages, currents, power flows and phase angles from sparse measurements made on the entire regional system;

Real time contingency analyzer **-** analysis of potential fault conditions and effects; monitoring and prediction for violations of System Operating Limits that may become violations of Interconnection Reliability Operating Limits; results are posted to ISOs and other organizations on a secure website and directions for mitigation re telephoned if single organizations are involved, or broadcast electronically if the entire reliability region is involved;

System modeler and simulator – simulation of reliability region system operation

PMU data analytics and display – tools to analyze PMU data to detect regional instability, inter-area oscillations, etc.

Message broadcast software **--**provides instant communication to all of the entities in the reliability region simultaneously. For example, in the PEAK reliability region I the western US, this is known as

WECCNet; WECCNet client programs run on computers and servers at the various organizations in the reliability region.

For state estimation, system simulation, and contingency analysis software, the reliability coordinator uses a system known as an ***Energy Management System (EMS)***. Such systems are common at the ISO and Transmission Operator levels, as well.

Reliability Coordinators may be required by NERC to have ***Outage Management Systems***; since outage systems for regional outages are not available, they may have to be custom built.[50]

7.2 Balancing Authority/ISO/RTO

The Balancing Authority or ISO/RTO has the responsibility to maintain generation/load balance and system reliability within a control area. Their primary functions typically operate on five-minute time cycles (for dispatch) and a four to six second time cycle (for load frequency control via Automatic Generator Control [AGC]).

Software for this level includes an ***Energy Management System*** with a software suite that includes tools for:

- ***State estimation*** – calculation of voltages, currents, power flows and phase angles from sparse measurements made on the entire regional system
- ***Forecasting and scheduling*** – load forecasting based on historical performance and environmental variables such as weather forecasts; forward scheduling of generation assets
- ***Optimal power flow solution*** – solutions for real and reactive power flow scheduling, net power interchanges, load shedding if necessary, LTC and control voltage settings
- ***Economic dispatch*** – optimal dispatch of generation from the available fleet
- ***Area balance and frequency control*** – calculation of area control error and unit control error, dispatch of generation and interchanges; incremental AGC for system frequency regulation (load frequency control)
- ***Contingency analysis*** – analysis of potential fault conditions and effects; short term planning for impact mitigation
- ***Simulation and planning*** – simulation of ISO service area system operation
- ***Bulk power market software*** – tools for market operations.

For those that use the Locational Marginal Pricing (LMP) method of transmission congestion management, there are also tools for calculating LMP values.

These organizations also use a variety of analytics and visualization tools to understand system operations in near real time. These include analytics and visualization for PMU data and system state, as well as generation flexibility and various performance metrics. Data historians and other data stores are employed for telemetry logging; in some cases, the organization must keep such data in quadruplicate.

[50] Information for the Reliability Coordinator software section supplied courtesy of Ali Miremadi at CA ISO.

These organizations also use OASIS node software. Existing EMS tools for system operator use are lacking in terms of speed and scope, and the ability to perform increasingly complex contingency analyses that are needed to maintain system reliability on a near real time basis. The ability to include distribution impacts on transmission is also lacking, but this is becoming important as penetration of DG increases and system inertia decreases, thus decreasing small signal stability.

7.3 Transmission

The bulk of the sensing and control devices for transmission systems are in the transmission substations, although there are a few sensors made for use on transmission lines outside of substations. Sensed data and control commands are transmitted between Transmission Operations Center (TOC) and substations via a SCADA system. The SCADA system consists of computing and communications hardware and a software suite that performs data collection, grid data management, command distribution, and user interface.

The primary software suite for Transmission is also known as an Energy Management System (EMS). It usually sits atop the SCADA system and provides a set of functions including state estimation, transmission grid model management, contingency analysis, flow control, FACTS device control, and circuit fault analysis. If the transmission system has PMUs, then most likely the utility will have Phasor Data Concentrator software as well, and may have PMU analytics tools. It will have a data historian for logging telemetry data and software for grid planning and simulation. If the transmission utility is a member of an ISO or RTO, then it will have software for communication with the ISO or RTO (ICCP and OASIS). Existing transmission level EMS tools are also lacking in terms of speed and scope, and the ability to perform increasingly complex contingency analyses. The ability to include distribution impacts on transmission is also lacking, as are tools for integrated transmission/distribution planning.

In a wires company (combined transmission and distribution), the EMS may also control the distribution substations. The combination of transmission and distribution substation control is known as System Control or Real Time Operations. This may also include control of load tap changers (voltage control) or capacitors (reactive power control) located inside the distribution substations.

7.4 Distribution

Distribution grid operators generally use distribution SCADA although there are some distribution grids that have no distribution SCADA and very little in the way of sensing and control. On the other hand, a number of utilities that participated in ARRA's Smart Grid Investment Grant (SGIG) program, administered by OE, have had the opportunity to build/deploy advanced systems. Some of the most advanced utilities in this regard are the ones driven by emerging trends: for example, Southern California Edison (SCE), due to penetration of VER/DER and storage within its service territory; and National Grid, driven by resilience issues and general distribution automation. Given the range of sophistication among utilities and the varying complexity of territories that they serve, there is a wide array of software solutions at work in distribution control rooms, including:

DMS – Distribution Management System, a suite of software that resides on top of SCADA and provides a collection of capabilities, including distribution flow control; feeder power balance; Volt/VAr regulation; and circuit fault detection, location, isolation, and power restoration. DMS has not widely penetrated the distribution utilities and it is becoming clear that the original approach to DMS may not be suitable for those places where high penetrations of DER/DG exist, since the fundamental control problems are changing. Also, the ability to perform state estimation on distribution at high speeds is lacking, as are tools for integrated transmission/distribution planning.

OMS – Outage Management System, a system that manages outages, including outage detection and extent mapping, root cause determination, field crew dispatch, restoration tracking, nested root cause determination, and restoration notification. There is a trend toward merging the DMS and OMS functions; the resultant system is known as integrated DMS or iDMS.

CIS – Customer Information System, a system that maintains customer data and may provide the bill scheduling, preparation and account tracking functions. CIS may be used in conjunction with OMS to assist with customer notifications related to outages.

GIS – Geographic Information System, a database and graphical display system containing locations of utility assets including circuits and devices, streets and boundaries, etc.

AMI –Advanced Metering Infrastructure, the meter reading system that communicates with meters, acquires the stored meter data, and provides the data to the Meter Data Management System (MDMS). It may also handle meter event messages or pass them off to another system.

MDMS – Meter Data Management System, a system that accumulates meter reading data from the AMI system, performs VEE, and provides billing determinant to the utility billing system. In many jurisdictions, meter data must be kept for up to seven years for potential dispute resolution.

IVR – Integrated Voice Response system **-** a system that handles customer telephone calls and may also provide outgoing messages via phone, text, or other media to alert customers about power outages and restorations.

DERMS – Distributed Energy Resources Management System, which provides communication and control for DER. This type of system is relatively new and is still evolving; not many exist in the field presently.

Asset Ratings Engine – a few utilities have commissioned the creation of custom software for calculating asset re-rating based on actual loading and environmental conditions such and temperature. It is logical to expect this functionality to fold into DMS eventually.

Historian – system for storing telemetry data.

Distribution operators also have software for circuit planning, as well as tools for processing weather data feeds and lightning strike data. Existing planning tools do not provide strong methods to account for the impact of advanced grid capabilities, such as highly penetrated DG, large numbers of responsive loads, and correlation with transmission planning.

While it's reasonable to expect the commercial marketplace to solve issues associated with emerging software needs of the utility industry, it is unclear this will take place ***in time*** to keep pace with the changing operational landscape of the grid, particularly at the distribution level. That's because software developers face a classic "chicken and egg" scenario. The market for these solutions is relatively thin (confined to the number of utilities in North America), which leads to conservatism in investing in new products for control systems that, in essence, might also replace existing product lines. Utilities, in turn, may agree with an assessment of their changing needs—but don't commit to buying new solutions until they have been well tested and demonstrated.

Opportunity for Federal Leadership:

- DOE is well positioned to break the logjam with its continuing efforts within the Office of Electricity and elsewhere, to fund new software tools development, in a way that elicits the early engagement of software developers, the research community and utilities/grid operators, which collectively can help accelerate the path for new products from laboratory to control rooms.

8.0 Conclusions

Interdependence of electric and ICT infrastructure has increased in recent decades, and recent trends in the utility industry suggest an even tighter coupling of these networks in coming years. While cyber vulnerability must remain a focus of federal research, development and information-sharing efforts with industry, the convergence of these networks also holds substantial promise as a platform for energy innovation, leading to potential new value streams and enhanced system resilience. The pace at which this convergence occurs and new services and operational methods emerge will turn on a number of factors, including regulatory structures that set the framework within which utilities and grid operators prioritize infrastructure investment decisions.

In assessing the challenges and opportunities presented by the enhanced interdependence of grid and ICT infrastructure, it is key to understand the ways in which utilities might use different classes of data, the characteristics (such as latency) that determine the operational and business value of that data, the implications for communications network investments, and required evolution in analytics, visualization and software tools that will help unlock new services and bolster desired system attributes such as resilience. Grounded in this understanding, a handful of key priorities emerge as potentially appropriate Federal initiatives designed to convene relevant stakeholders, provide tools and methods that help inform industry investment strategies, and accelerate the pace at which innovations are brought to market. In particular:

- Leadership in convening industry stakeholders for purposes of developing a ***reference architecture for power grids with emphasis on control and coordination frameworks*****--** extensible across electric and ICT networks--is a key first step in enabling the kinds of innovations that will enhance grid observability and controllability in coming decades. A reference architecture is a technology neutral framework applicable to complex systems such as the grid, which takes a disciplined approach to characterizing system components, structures and attributes. Such an architecture helps identify potential gaps in technology and operations, assists in defining key system and component interfaces and provides context for interoperability and standards-setting activities. In practice, given the diversity of the US utility industry and given the pace at which change is occurring, support for developing a grid architecture capability in the industry so that all the appropriate variations can be built as needed and changed as needed is an appropriate goal. Roadmaps then may be constructed as a series of architectures.
- Exploration of mechanisms and tools relevant to ***ensuring ICT network investments are sufficient*** to enable enhanced grid management functions at the distribution level. For example, while wireless mesh networks built to support AMI deployments are more affordable than optical fiber or other advanced wireless technologies, certain characteristics may render them insufficient for system restoration and resilience functions in an outage or emergency scenario. In addition, early indications suggest meter communication networks have often been designed only to support consumers' usage reporting and thus lack the bandwidth and latency capabilities needed to support operation as a grid sensor network. Networks are increasingly integral to modern power grid operations, yet most power grid simulation and design tools today lack means to include communications-related elements. Measures to accelerate integration efforts and move them into use by utility planners and design engineers may help better inform grid operators' investment decisions. Moreover, certain regulatory reforms and/or tax incentives to encourage appropriately scaled investments may warrant consideration.

- And finally, ***acceleration of ongoing federal research and development efforts to develop new grid management tools***, linking Department of Energy capabilities in high-performance computing and advanced power systems engineering with software developers and utility/grid operators. While it's reasonable to expect the commercial marketplace to ***eventually*** solve issues associated with emerging software needs of the utility industry, it is unclear this will take place in time to keep pace with the changing operational landscape of the grid, particularly at the distribution level. That's because software developers face a classic "chicken and egg" scenario. The market for these solutions is relatively thin (confined to the number of utilities in North America), which leads to conservatism in investing in new products for control systems that, in essence, might also replace existing product lines. Utilities, in turn, may agree with an assessment of their changing needs—but don't commit to buying new solutions until they have been well tested and demonstrated. Within this context, DOE can play a key, ongoing role in bringing together the ecosystem of stakeholders required to accelerate the path for new products from the laboratory to control rooms, in a way that unlocks new value streams and bolsters system attributes such as enhanced reliability and resilience.

Appendix A

Brief Background on US Electric Power System Structure

Appendix A

Brief Background on US Electric Power System Structure

The US utility industry is a complex construct of over 3,000 organizations, arranged in a semi-hierarchical structure that puts multiple overlays on the physical infrastructure, which in itself has a partially hierarchal structure. In addition, there are multiple regulatory jurisdictions, some of which overlay others. The types of organizations that comprise the utility industry include regional reliability coordinators, qualified scheduling entities (which include balancing authorities, Independent System Operators (ISO's), Regional Transmission Operators (RTO's), and Interchange Authorities), Transmission Operators, Distribution Operators, Retailers, and Energy Services Organizations (ESO's). Some organizations server multiple functions (balancing may be done by independent balancing authorities, ISO's and RTO's; interchange may be done by reliability coordinators or balancing authorities, for example). There is a rough geographic nesting of systems and their organizations, based largely on grid structure, but modified by business structure. This nesting is illustrated in Figure A.1 and the various components and organizations are briefly described and illustrated below.

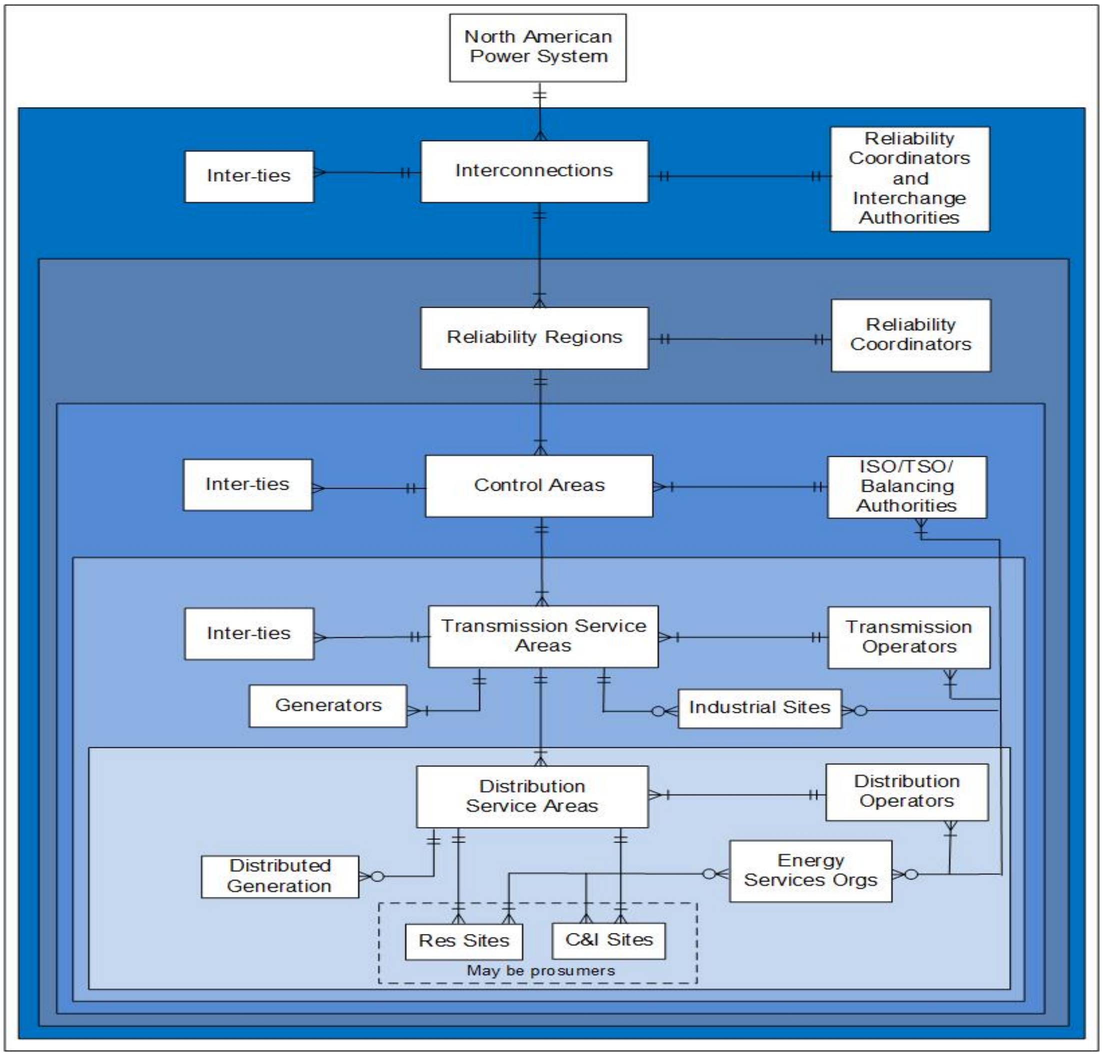

Figure A.1. US Utility Geographic Hierarchy

A.1 Interconnections

Power systems in the contiguous US are organized into three large Interconnections. Within each Interconnection, AC generators are synchronized, such that all these generators, the transmission and distribution infrastructure and AC loads constitute one machine. This is why the Eastern Interconnection has been described as the largest machine ever built by humanity. There are a number of pair-wise intertie points across which power can flow as needed and as scheduled by Interchange Authorities. There are also small interconnections in Alaska and Hawaii, and a larger one in Canada. One three-way interchange point is planned near Clovis, New Mexico (Tres Amigas), largely intended to facilitate a national market in wind energy.[51] Figure A.2 shows the geographic regions covered by the Interconnections in North America.

[51] Dan Mayfield, "Tres Amigas Signs Its First Customer," Albuquerque Business First, Feb. 4, 2014. Available online: http://www.bizjournals.com/albuquerque/news/2014/02/04/tres-amigas-signs-customer-broadview.html

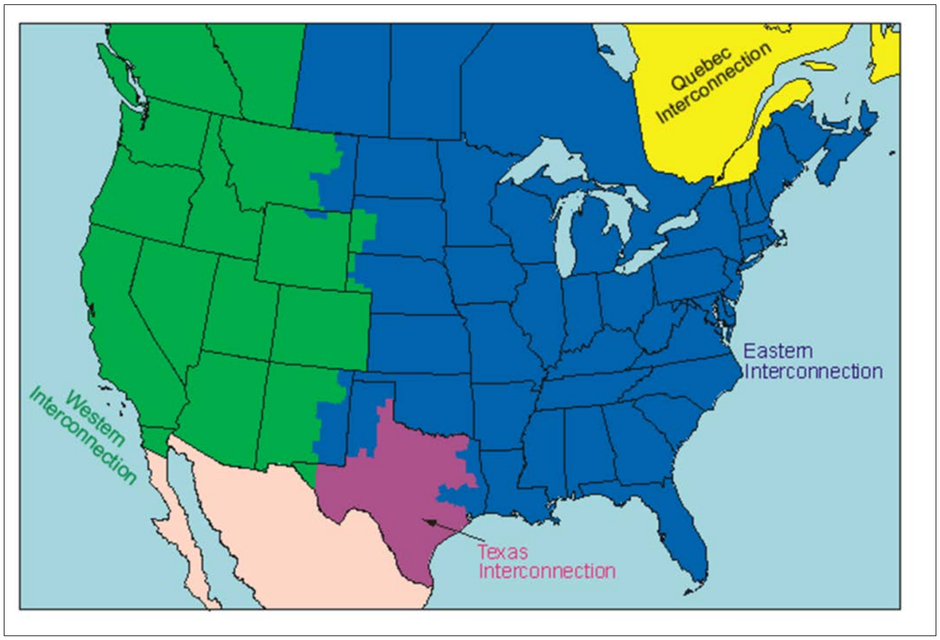

Figure A.2. Major North America Interconnections

A.2 Reliability Regions

The US is divided into geographic reliability regions, each overseen by a Reliability Coordinator. The boundaries of each reliability region coincide with the boundaries of one or more Balancing Authority Control Area (see below for more on Balancing Authorities). Reliability Regions and Coordinators are authorized by NERC with the definition (as per OpenEI):

> The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[52]

NERC's map of Reliability Regions is shown in Figure A.3.

[52] http://en.openei.org/wiki/Definition:Reliability_Coordinator

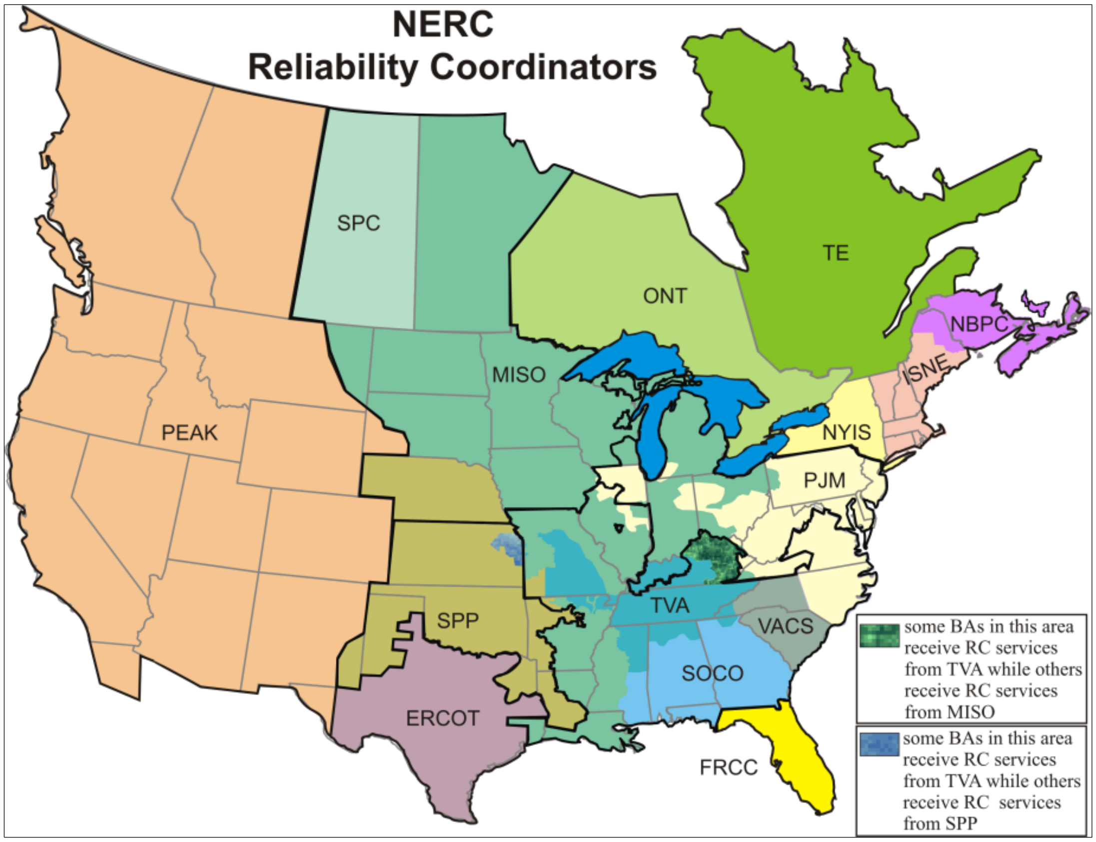

Figure A.3. NEC Reliability Regions

Dating back to 1996, FERC Orders 888[53] and 889 laid the groundwork for formalized restructuring of the industry and led to the creation of the network of Open Access Same-Time Information System (OASIS) nodes. OASIS is a set of internet-based nodes that enable services such as power interchanges. Access is web-based but public access is limited. Initial problems related to OASIS were resolved when NERC introduced NERC tags for end to end power transactions; NERC also took control of the Transmission System Information Networks database, which lists generation points, transmission facilities, delivery points, and transmission and generation priority definitions.

A.3 Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)

ISOs are organizations that coordinate bulk energy system operations, often within a single large state. RTOs have essentially the same function but usually operate over multiple states or parts of states,. ISOs are created at the recommendation or direction of FERC, but local utilities do not have to be members. RTOs are designated by FERC and have slightly more stringent short term reliability management responsibilities. The present list of ISOs includes: CAISO (California), NYISO (New York), ERCOT (Texas), AEISO (Alberta, Canada), ISO-NE (New England), Midwest Independent Transmission System Operator (MISO), and IESO (Ontario, Canada). The list of RTOs is shorter: PJM, MISO, Southwest Power Pool (SWPP), and ISO-NE. Both ISOs and RTOs can operate markets, but RTOs also

[53] http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

have FERC-mandated responsibility for short term grid reliability. As is often the case, there are various functional overlaps; several ISOs and RTOs are also reliability coordinators and Balancing Authorities. Figure A.4 shows the ISO/RTO geographic regions in the contiguous US. Note that one Canadian province is a member is a US RTO, and two others have Electric System Operators (ESOs) that are essentially equivalent to US ISOs. This illustrates the interdependence of the US and Canadian power systems; a great deal of hydro power from Canada flows to the US. In Texas, ERCOT does not fall under the authority of FERC, but operates separate reliability and market functions to comply with NERC rules.

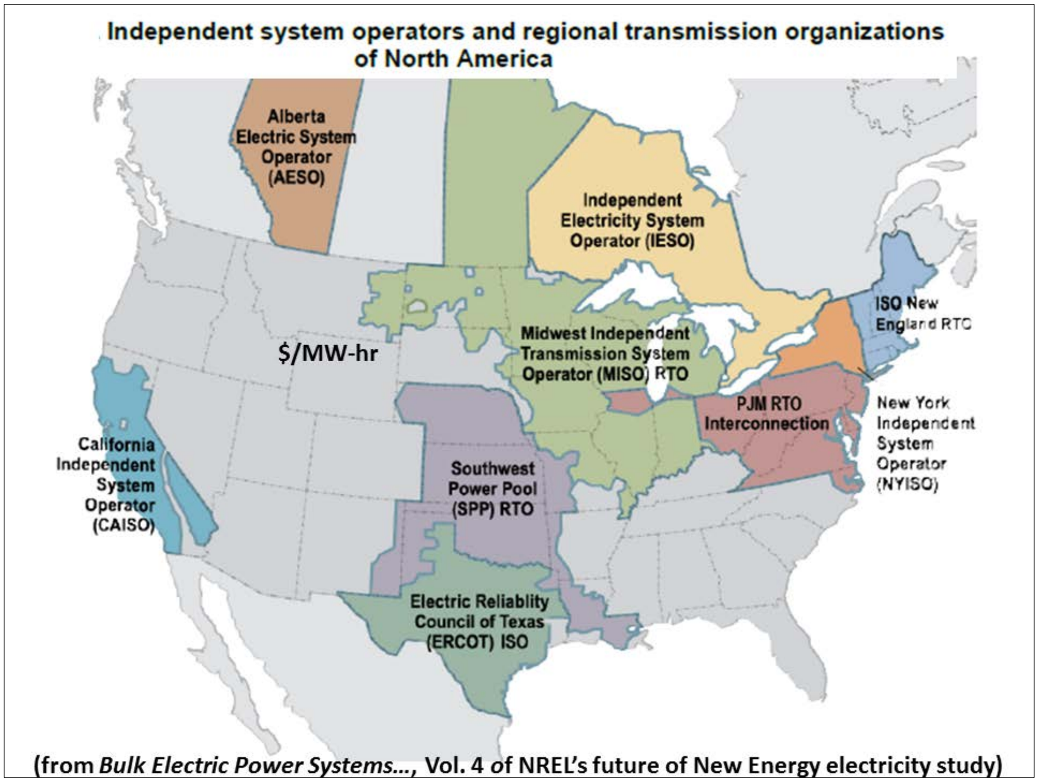

Figure A.4. ISO and RTO Geographic Regions

ISOs operate the bulk power markets in the US. Large portions of the Northwest, Southwest, and Southeast do not have ISOs, so power exchanges between utilities in these regions is mostly via bilateral contracts and power purchase agreements.

A.4 Balancing Authorities

The US is also divided into a set of Control Areas, each overseen by a Balancing Authority. The role of the Balancing Authority is to control generation to flow and balance load and to schedule power interchanges with neighboring Control Areas. The Balancing function is a crucial aspect of grid control. Given the lack of significant energy storage in the grid, it is necessary to balance generation closely against load. This is done via load forecasting combined with generator dispatch (for those generators that are dispatchable) on a five minute cycle, plus closed loop incremental update of generation settings every four seconds, using system frequency as the key state variable upon which the Automatic Generator Control (AGC) updates are based. The four second update on generation is known as support for interconnection frequency. The introduction of wind and solar power has complicated this entire process since neither is dispatchable, although the IEEE Power and Energy Society regards wind forecasting as advanced enough to rate large wind farms (not small distributed ones) as dispatchable to 20% of their rated capacity.

The number of Control Areas and Balancing Authorities is somewhat variable. There are dozens of Balancing Authorities and over 100 Control Areas in the US. A NERC map of Balancing Authorities is shown in Figure A.5. Over time, Control Areas have tended to grow in size (and reduce in number).

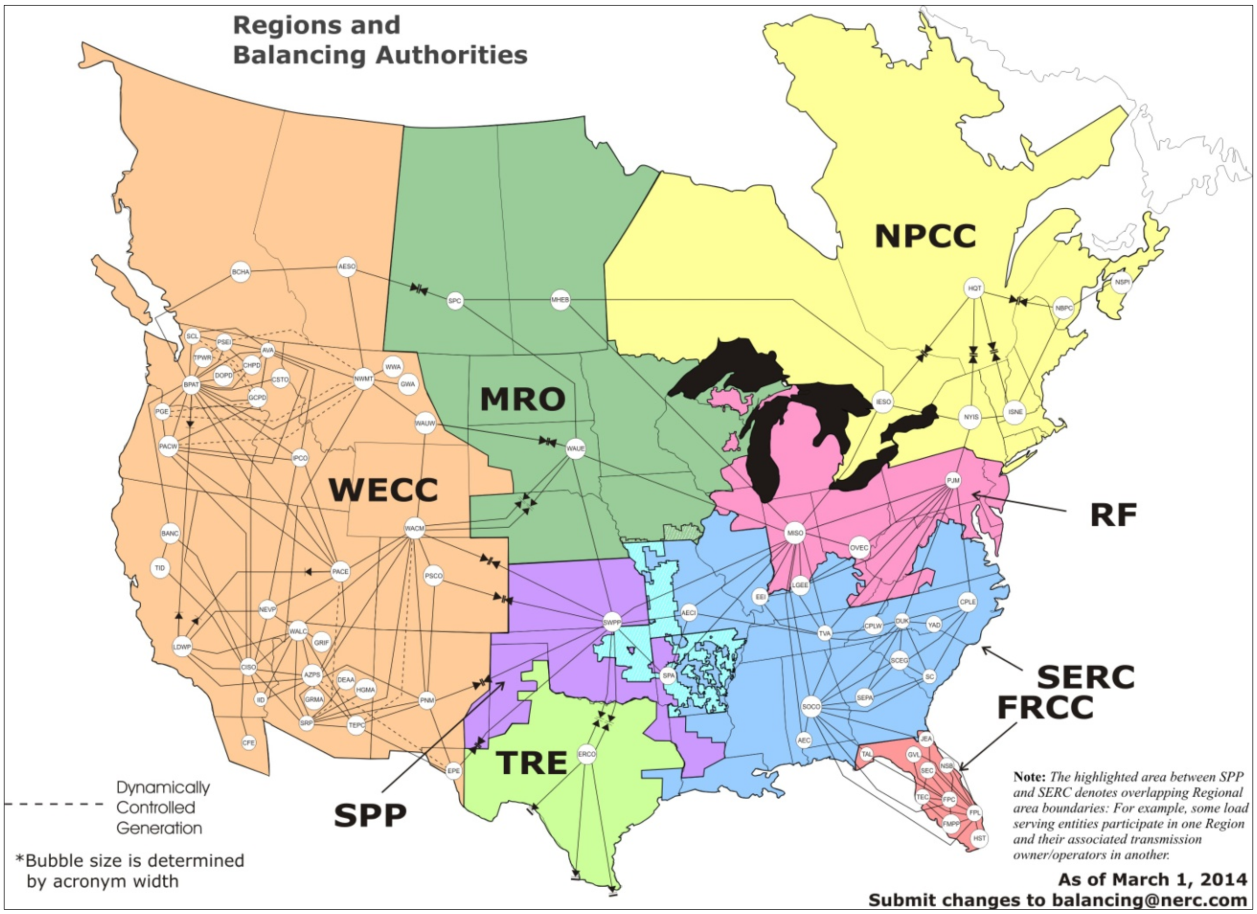

Figure A.5. US Balancing Authorities Map

A.5 Transmission and Bulk Power Systems

The US has an extensive set of transmission lines and systems, operated by various utilities and merchant Transmission Operators (TO's). Many of the transmission systems are interconnected, so that flexible bulk power flows can be accommodated. The physics of electricity is such that power from any given source flows along all of the parallel paths available to it via the meshed transmission grid, so that power flow control and transmission line congestion have become complex grid management problems. A low resolution map of US transmission lines is shown in Figure A.6. A higher resolution map would reveal even more transmission lines.

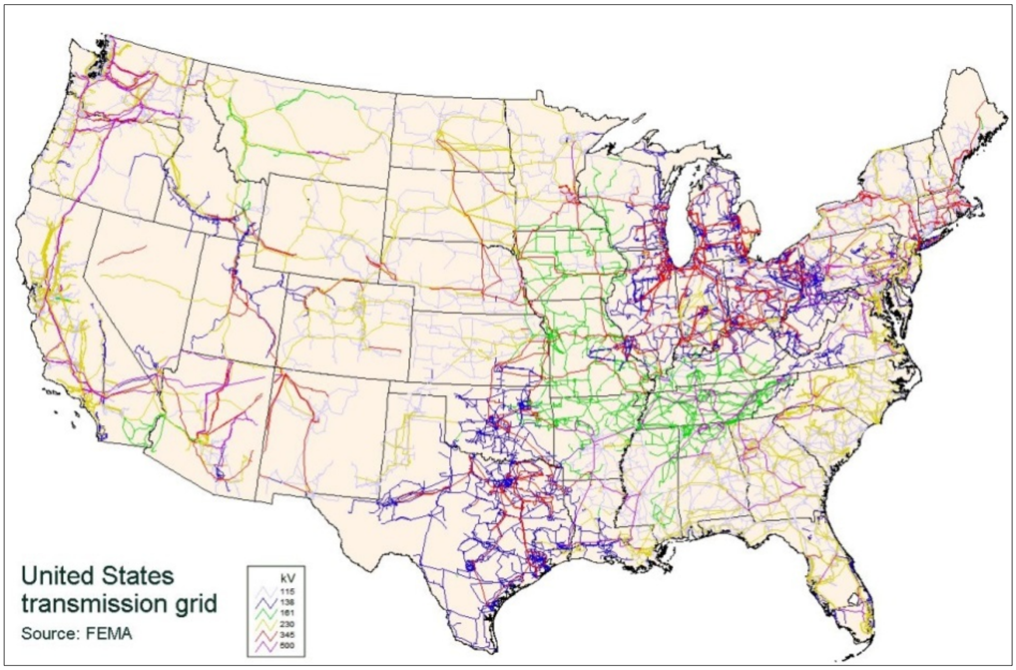

Figure A.6. Low Resolution US Transmission Line Map

Figure A.7 illustrates the meshing nature of most transmission grids.

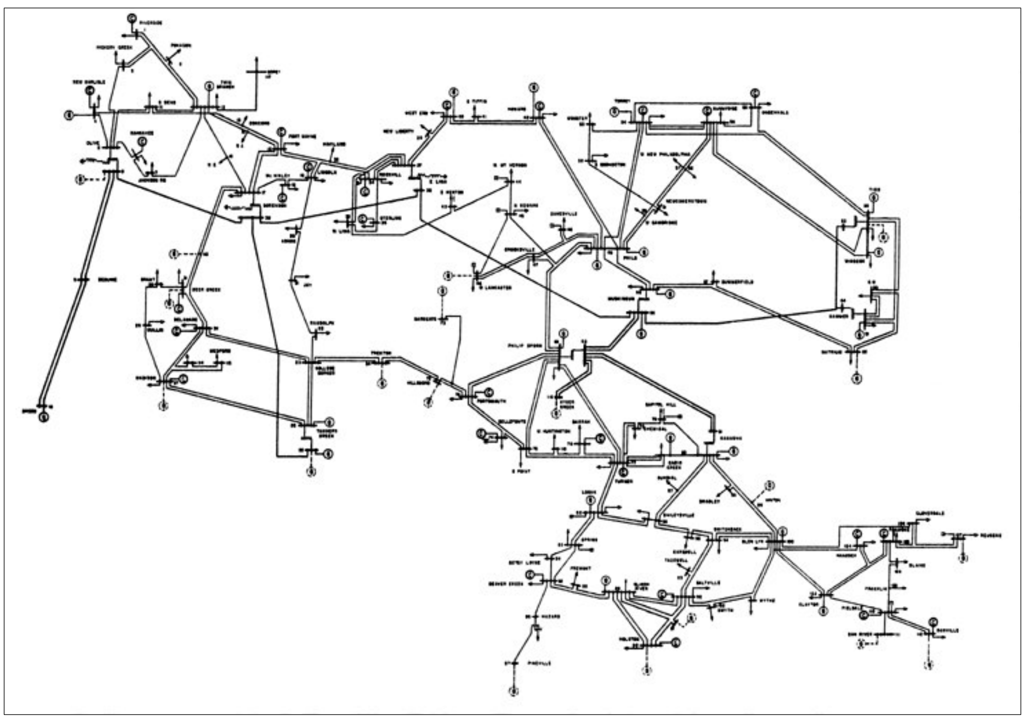

Figure A.7. Example of Transmission Grid Meshing

The structures and organizations described above are overlaid on this physical infrastructure. Combined with the centralized generator plants, this constitutes the bulk power system, which is under the jurisdiction of FERC. Many hundreds of generators are connected to this transmission grid (really multiple grids - see Interconnections above). Some generators are owned by vertically integrated utilities, public power authorities, or even rural co-ops and municipal utilities. Some generators are owned by merchant generator organizations or Independent Power Producers.

A.6 Electric Cooperatives and Other Utility Structures

Dating to policy efforts in the mid-1930s to promote rural electrification across the nation, much electric infrastructure is owned and operated still today by any of several hundred electric cooperatives. Figure A.8 shows a map of electric cooperative geographic extent in the US.

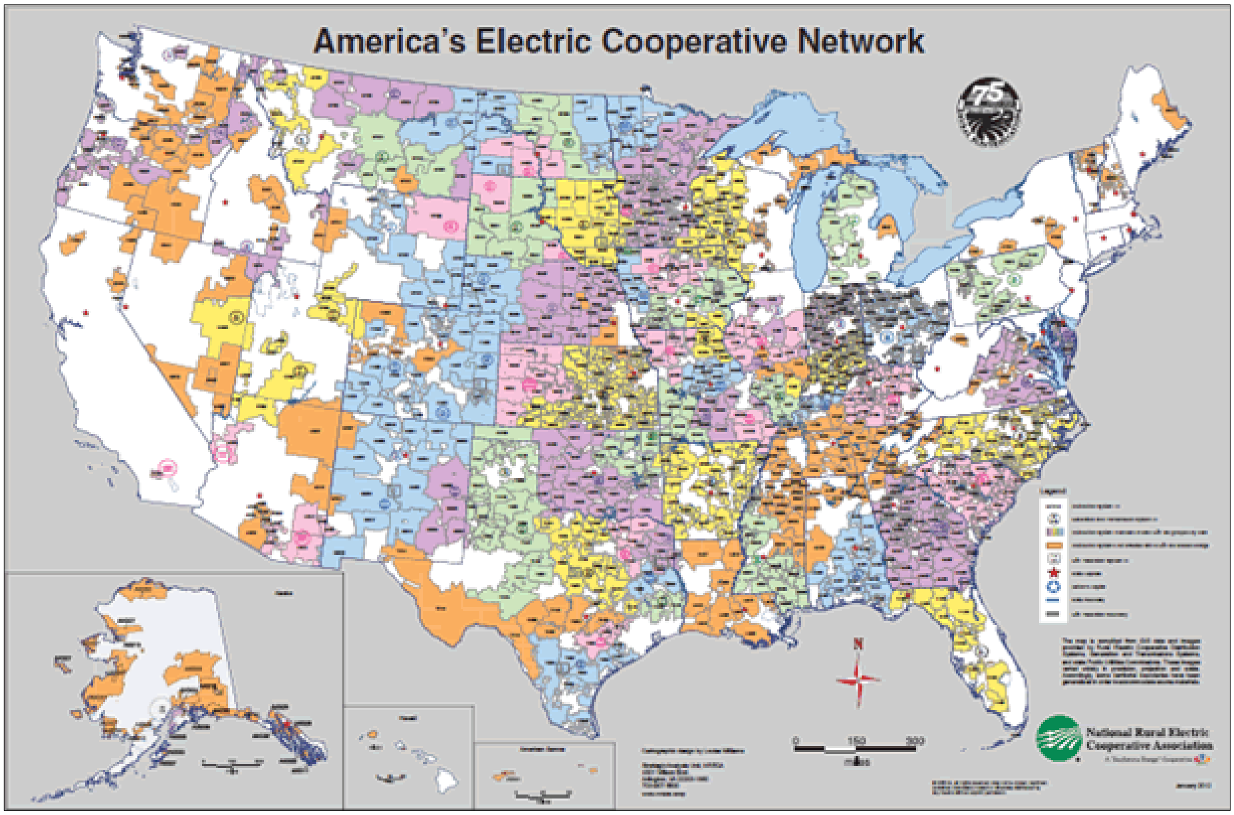

Figure A.8. US Electric Cooperatives

According to NRECA, there are 840 co-op distribution systems and 65 generation and transmission co-ops in the U.S., which include a small number of rural public power districts. The co-ops account for 42 percent of US distribution lines.[54] Private, consumer-owned non-profit entities, co-ops are eligible for financing benefits from the U.S. Department of Agriculture's Rural Utility Service.

In addition to co-ops, many investor-owned utilities operate a combination of transmission and distribution systems, as do municipal utilities and other public power entities (such as Public Utility Districts) authorized under the laws in many states. While FERC regulates wholesale markets and transmission in interstate commerce, State Public Utility Commissions (PUCs) regulate investor-owned utilities that serve retail customers at the distribution level, and determine the rate of return for utility

[54] http://www.nreca.coop/about-electric-cooperatives/co-op-facts-figures/

investment. Consumer- or publicly-owned utilities (rural co-ops, public utility districts and municipal utilities), by contrast, are overseen by elected boards, commissions and even city councils. State legislatures and Governors set the policy framework within which these retail-serving utilities operate[55].

A.7 The Physics of Distribution Systems

Distribution systems transport electricity from the bulk power system to end users via medium (1,440 to 34 kV) voltage and low (under 1 kV) voltage grids. Distribution systems consist primarily of distribution substations, medium feeder circuits that bring power to local neighborhoods, and secondary circuits that connect the primaries to customer facilities via distribution transformers. A wide variety of grid devices are used both in the substations and on the circuits themselves, and the number and types are increasing as distribution automation is rolled out. Many distribution circuits were simple radials, and mostly still are in rural areas; but increasingly, distribution circuits are partially meshed to increase reliability and functional flexibility. Figure A.9 illustrates the emerging complexity of modern distribution circuits.

[55] Grid Modernization Strategy and Program Plan Draft (6/9/2014); Hoffman et al;

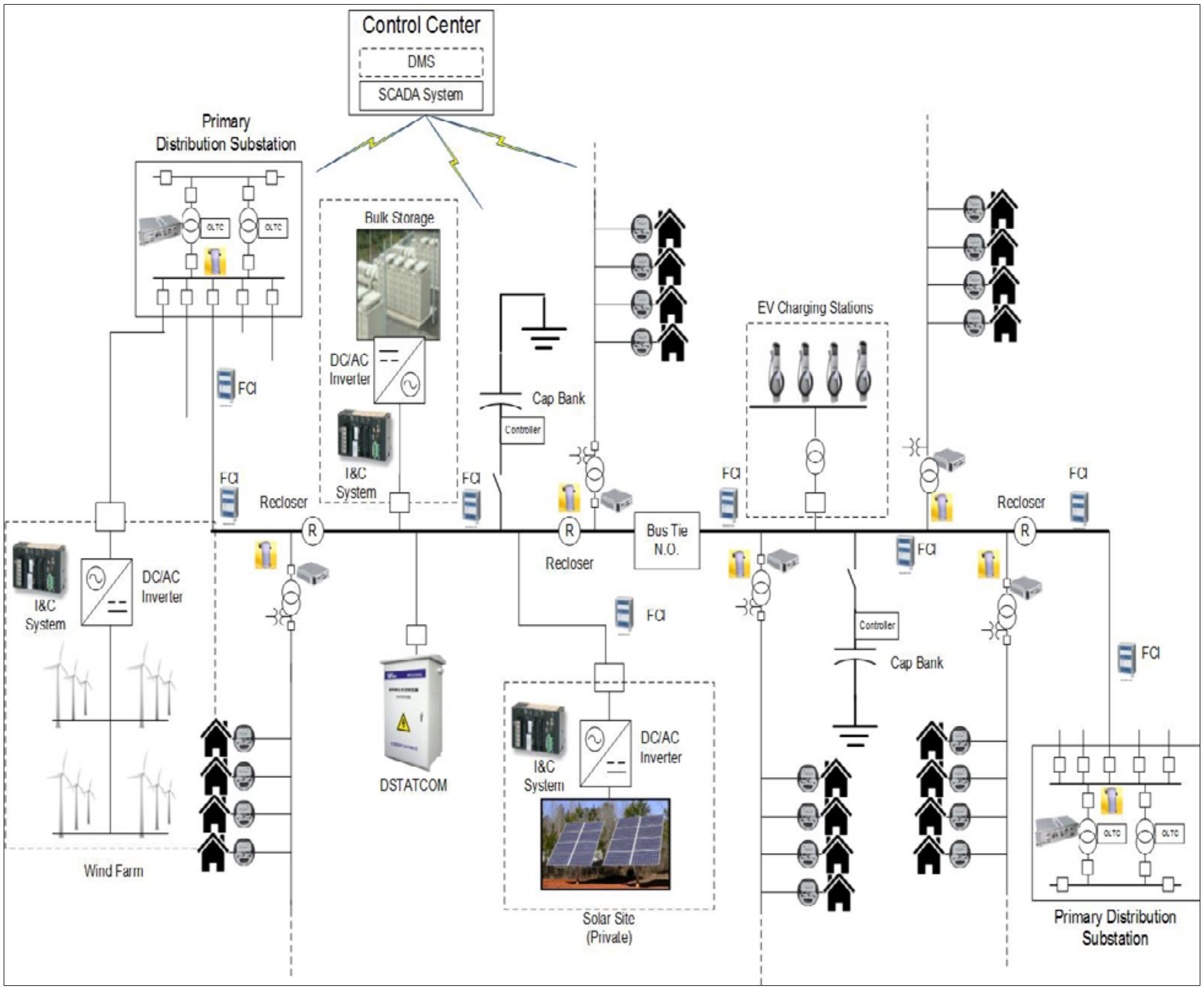

Figure A.9. Distribution Circuit Complexity Example

Simple radials and partially meshed circuits are not the only types in use. For dense urban areas, underground meshes are common, as illustrated in the left half of Figure A10. These are intended for high reliability and make use of components not found on ordinary distribution, namely network transformers and network protectors. Compare to the typical partially meshed above-ground feeder shown in the right half of Figure A.10.

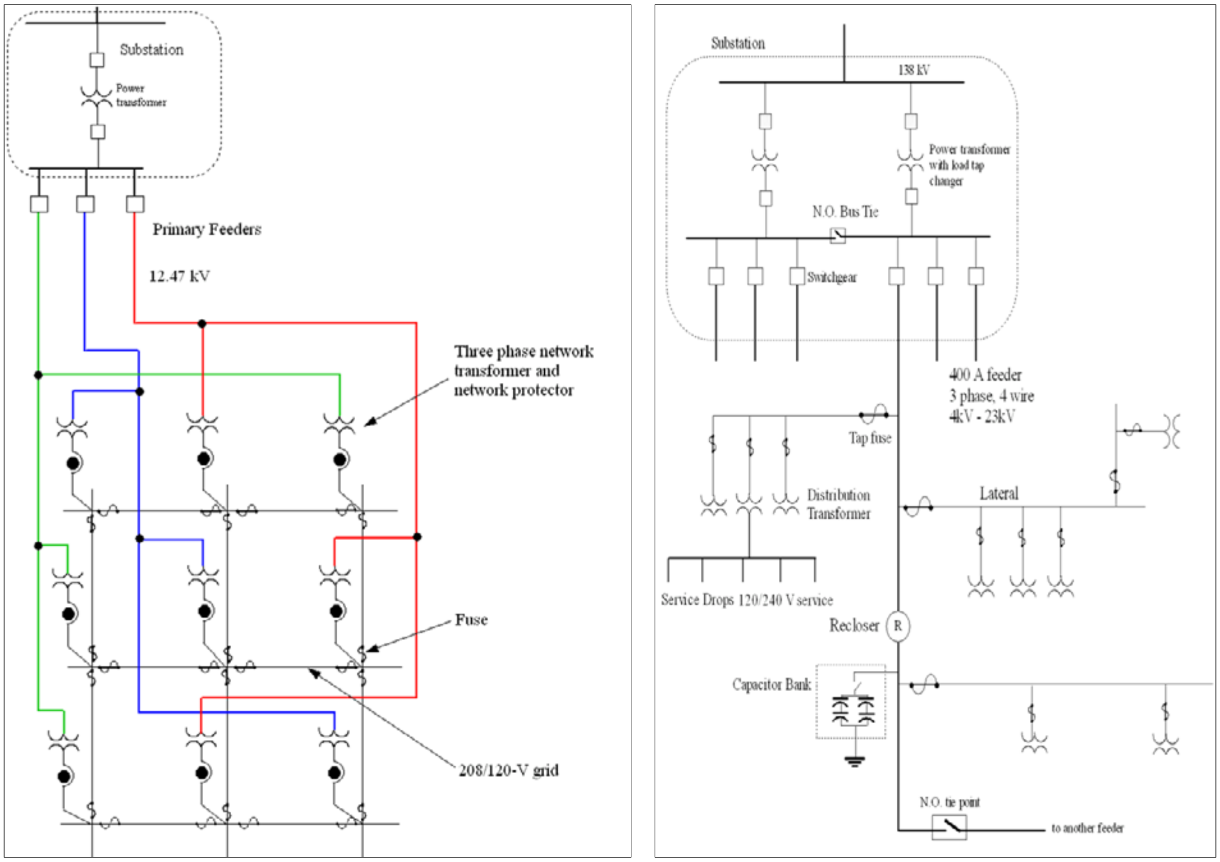

Figure A.10. Fully Meshed and Partially Meshed Distribution Circuits

Distribution company service areas are often complex and inter-penetrated. This leads to various issues in terms of control systems and their communication networks, as well as the need for a distribution company to deal with multiple state regulators (Xcel Energy for operates in eight states for example). Figure A.11 shows distribution service area inter-penetration in Texas.

Recently, the utility industry has begun to re-examine the roles and responsibilities of distribution companies and it is possible that a significant restructuring of distribution systems will result.

A.8 Retailer and Energy Services Organizations

Utilities have a retail function that is often organized as distinct business units that provide billing and other customer services to residential and C&I customers. In regions with restructured energy markets, Retail Energy Providers (REP's) can exist as independent entities and may represent multiple power providers in areas where such choices exist.

As additional energy services opportunities have arisen, ESO's have formed around the new value streams. Chief among them are Demand Response aggregators and merchant DER companies. The latter are primarily in the business of installing and managing solar installations on private premises, in exchange for electricity savings by the premise customer. As the power grid evolves to a more open energy innovation platform, more ESO concepts will be tried in the retail market.

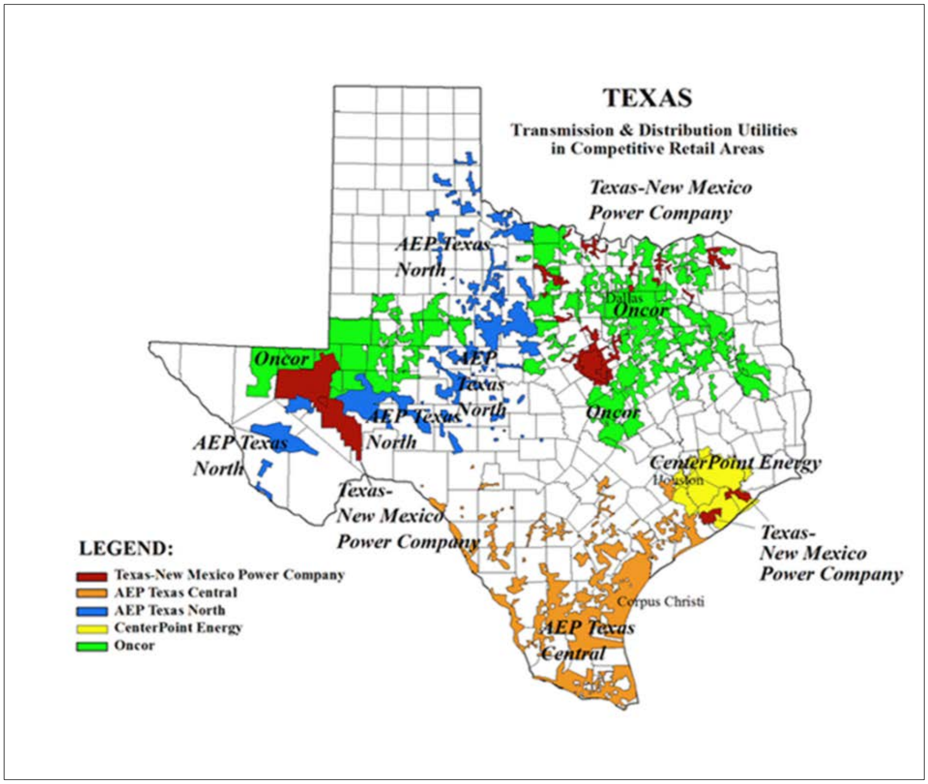

Figure A.11. Service Area Inter-penetration in Texas

A.9 Prosumers

With the rise of net metering and Renewable Portfolio Standards in certain states that provide incentives for distributed generation such as rooftop solar, premise owners can provide excess energy generated on site back into the grid, thus becoming producer/consumers, or prosumers. It is not clear whether the merchant DER model or the individual prosumer model will prevail, or whether this will be region-dependent.

A.10 Utility Business Structure

Utility structure has evolved in parts of the country while it has remained static in others. This has resulted in a variety of organization types, some of which have been covered above. The core view of generation, transmission, distribution and retail may have any of the following structures:

- Vertically integrated –contains generation, transmission, distribution, and retail functions;
- Transmission operator – owns and operates transmission assets only;
- Distribution operator – owns and operates distribution assets only;

- Retail Energy Provider – provides billing and other customer facing services as well as marketing to customers for utilities;
- Merchant Generator – owns and operated generation assets;
- Merchant DER –owns and operates Distributed Energy Resources; and
- Wires Company – owns and operates transmission and distribution assets.

As previously discussed, utilities may be investor owned, municipal, cooperative, public power authorities, or in some cases, such as ESO's, and merchant generation, transmission and DER, they may be privately owned.

Appendix B

Glossary

Appendix B

Glossary

AGC – Automatic Generator Control – automatic control of generator output so as to maintain balance between generated power and demand from loads; the load-following grid system has very little storage so generation must track load precisely so as to ensure sufficient power and not to waste fuel on over generation; this is done through system frequency regulation as a proxy for balance.

BLOB – Binary Large Object - an unstructured set of data stored as a single database object.

Bulk energy/power markets – ISO-operated wholesale markets for energy, power (ancillary services) and capacity.

CEP – Complex Event Processing – processing of multiple streams of event messages and data with a fixed query applied over a moving time window.

CRM – Customer Relationship Management – a software system that supports business functions related to account management and billing**.**

DER – Distributed Energy Resource(s) – small scale distributed generation and storage, usually connected to a distribution grid. Some definitions also include Demand Response (see responsive load below) in DER.

DSTATCOM –Distribution Static Compensator –power electronic device for use on distribution grids; it provides voltage and power stabilization functions at very high speed.

FDCL – Fault Detection, Characterization, and Localization - a set of functions that aid in fault management by processing sensor and meter event data.

FERC – ***Federal Energy Regulatory Commission***.

FISR – ***Fault Isolation and Service Restoration*** – a set of control capabilities that act upon the result of FDCL to isolate faults, reroute power flows, and restore electric service to as many users as possible in advance of repair of the fault. FDCL and FISR and are the essence of self-healing distribution circuits.

IP – Internet Protocol – a suite of open standard network communication protocols.

IPSEC – Internet Protocol Security – a set of protocols for securing IP communications.

MDMS – Meter Data Management System – head end system that manages AMI data, typically performing data cleansing and data storage, and may include calculation of billing determinants and may also provide applications for managing meter installation roll-outs.

MDUS – Meter Data, Unification, and Synchronization – a system that provides integration of multiple MDMS and AMI systems and provides a set of web services to make meter data available to enterprise applications.

MPLS – Multi-Protocol Label Switching – network protocol originally intended to use short data packet labels as part of the routing process but now mainly used to provide variable Quality of Service

Phasor – contraction of "phase angle vector" – this is a mathematical quantity that is used to describe AC voltage or current waveforms in a compact manner which can be manipulated mathematically; they are used extensively in power system design and analysis and actual time-synchronized phasors (known as synchrophasors) are measured on the grid using phasor measurement units (PMUs).

QoS – Quality of Service – data flow priority in IP networks.

Reactive power – power flow in AC electric networks caused by misalignment of voltage and current waveforms; this misalignment is usually due to the type of load on the circuit and causes a power flow that moves back and forth in a circuit but does not get consumed by the customer. Reactive power flow causes undesirable effects in the power grid but does not generate revenue for the utility.

Responsive load – customer load that can respond to signals from the utility to aid in grid operations; commercial building and residential Demand Response (DR) are two conspicuous examples.

SLA – Service Level Agreement – agreements used in the telecommunications industry to specify network performance guarantees.

SP – Service Provider - a telecommunications service provider, such as Verizon.

SQL – Structured Query Language – a standard format for database queries on structured databases.

UTC – Utilities Telecom Council – utility industry trade association focused on communication networks issues.

VAr – Volt-Amperes reactive – the units in which reactive power is measured (real power consumed by the utility customer is measured in Watts). Volts are the units for the pressure that causes electricity to flow in a circuit; Amperes are the units of current flow.

VPN – Virtual Private Network – tools for extending a private network across a public network in a secure manner using point to point logical connections, data encryption, and other techniques.

WAMPACS – Wide Area Measurement Protection and Control Systems – sensor based protection and control systems on bulk power grids; the primary sensors are phasor measurement units (PMU's).

Pacific Northwest
NATIONAL LABORATORY

U.S. DEPARTMENT OF
ENERGY

Proudly Operated by **Battelle** *Since 1965*

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99352
1-888-375-PNNL (7665)

www.pnnl.gov