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Electricity Distribution System Baseline Report

July 2016

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U.S. DEPARTMENT OF ENERGY

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

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This report is a DOE EPSA product and part of a series of "baseline" reports intended to inform the second installment of the Quadrennial Energy Review (QER 1.2). QER 1.2 will provide a comprehensive review of the nation's electricity system and covers the current state and key trends related to the electricity system, including generation, transmission, distribution, grid operations and planning, and end use. The baseline reports provide an overview of elements of the electricity system.

To help understand how the energy systems might develop into the future under Business as Usual (BAU) conditions QER 1.1 relied upon the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2014 Reference Case. EPSA could not rely completely upon AEO for QER 1.2 as AEO 2016 was not completed and AEO 2015 did not include the Clean Power Plan. So the EPSA Base Case was developed and it aligns as closely as possible with AEO 2016 given the timing issues.

The EPSA Base Case scenario was constructed using EPSA-NEMS[a]*, a version of the same integrated energy system model used by EIA. The EPSA Base Case input assumptions were based mainly on the final release of AEO 2015, with a few exceptions as noted below, and then updated to include the Clean Power Plan and tax extenders. As with the AEO, the ESPA Base Case provides one possible scenario of base case energy sector demand, generation, and emissions from present day to 2040, and it does not include future policies that might be passed or future technological progress.*

The EPSA Base Case input assumptions were based mainly on the final release of the AEO 2015, with a few updates that reflect current technology cost and performance estimates, policies, and measures. Assumptions from the EIA 2015 High Oil and Gas Resources Case were used; it has lower gas prices similar to those in AEO 2016. The EPSA Base Case achieves the broad emission reductions required by the Clean Power Plan. While states will ultimately decide how to comply with the Clean Power Plan, the EPSA Base Case assumes that states choose the mass-based state goal approach with new source complement and assumes national emission trading among the states, but does not model the Clean Energy Incentive Program because it is not yet finalized. The EPSA Base Case also includes the tax credit extensions for solar and wind passed in December 2015. In addition, the utility-scale solar and wind renewable cost and performance estimates have been updated to be consistent with EIA's AEO 2016. Carbon capture and storage (CCS) cost and performance estimates have also been updated to be consistent with the latest published information from the National Energy Technologies Laboratory. An EPSA Side Case was also completed, which has higher gas prices similar to those in the AEO 2015 Reference Case.

[a] The version of the National Energy Modeling System (NEMS) used for the QER base case has been run by OnLocation, Inc., with input assumptions by EPSA. It uses a version of NEMS that differs from the one used by the U.S. Energy Information Administration (EIA), the model is referred to as EPSA-NEMS.

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Executive Summary

This Electricity Distribution Baseline describes current practices, emerging trends, and national implications of an evolving electricity distribution sector in the United States. It is organized into two parts.

The first section, *The Legacy of the 20th Century Utility*, provides an overview of the history and current state of the distribution sector. Topics covered in this section include the following:

- The history of the regulatory compact
- An overview of utility types and their characteristics
- A summary of ratemaking and regulatory oversight
- Engineering descriptions of key components of the system
- A discussion of distribution system operations
- An overview of distribution system planning.

The second section, *Toward a 21st Century Utility*, discusses emerging issues related to advanced grid technologies, the integration of distributed energy resources, and the evolving expectations for utilities. Topics covered in this section include the following:

- An overview of advanced grid technologies
- Measures of advanced grid technology proliferation across utility types
- Microgrids
- Emerging regulatory practices
- Jurisdictional issues.

Below are key findings that emerge from this comprehensive overview of distribution systems grouped by theme.

Distributed Energy Resource (DER) System Integration

- DER[b] deployment is growing rapidly and is forecasted to increase over time. Traditional distribution system functions and physical architectures that enable passive one-way electricity delivery from central power plants to end-use customers are unlikely to be adequate for a high-DER future. Distribution utilities will need new approaches for system operation, grid planning, interconnection procedures, and coordination with transmission system and wholesale markets to handle forecasted increases in DER penetration.

[b] The U.S. Department of Energy defines distributed energy resources as, "… a range of smaller-scale and modular devices designed to provide electricity, and sometimes also thermal energy, in locations close to consumers. They include fossil and renewable energy technologies (e.g., photovoltaic arrays, wind turbines, microturbines, reciprocating engines, fuel cells, combustion turbines, and steam turbines); energy storage devices (e.g., batteries and flywheels); and combined heat and power systems." Source: http://energy.gov/oe/services/technology-development/smart-grid/distributed-energy.

- Proliferation of distributed generation (DG)[c] and home area networks (HANs) has been largely driven by customer choice, which is in turn influenced by state and local policies, utility rate design, and technology cost-effectiveness. Some consumer-focused DERs, like smart thermostats and Internet-connected electric vehicle-charging infrastructure that constitute HANs, allow a more hands-off approach to energy management and greater response to dynamic price signals than what was once available. The automated nature of these devices lowers barriers for sustained household participation in demand response programs and dynamic pricing structures.
- According to one study, rural cooperatives and municipal utilities, which together serve roughly 30 percent of the nation's customers, are less likely to have distribution management system (DMS) equipment in place, thereby increasing their incremental DER integration costs relative to investor-owned utilities (IOUs), which tend to be larger. Higher incremental costs threaten to inhibit adoption of advanced grid technologies thereby excluding some, largely rural, customers from full participation in advanced grid technologies, in turn raising potential ratepayer equity concerns.

Proliferation of Advanced Grid Technologies

- Utility adoption and use of advanced grid technologies—including physical components, grid-monitoring software, and grid-management tools—vary by utility type and size. IOUs reported investment in significantly more advanced grid technologies than municipal and cooperative utilities, which are usually much smaller than IOUs. Municipal utilities are more likely than cooperatives to have implemented advanced grid technologies. The lesser degree of investment by municipal and cooperative utilities suggests that there may be significant barriers to their adoption and/or that the net benefits of these new technologies are not [yet] applicable to municipal and cooperative utilities' system characteristics. No matter the cause, the lag in advanced grid technology implementation could cause persistent differences in customer access to DER and total system costs between IOUs, which are usually large and serve urban customers, and municipal and cooperative utilities, which are usually smaller and serve rural customers. There is still a need, however, for more analysis to understand barriers and implications for the lack of small utility adoption of advanced grid technologies.
- Utilities have installed various advanced grid management systems, though these systems are rarely integrated with one another, potentially limiting their full contribution of system benefits. One survey of utility professionals found that data management, analysis, application, and integration of both systems and data from disparate systems is their greatest challenge to utility management.
- A foundational technology to enable the grid of the future is Supervisory Control and Data Acquisition (SCADA). SCADA extends beyond the distribution substation to provide situational awareness of distribution system status, automation of critical distribution system management components, and a communications system that can interact with individual customers and their grid-connected end uses. When distribution-level SCADA pairs with a DMS, formerly manual operations can be conducted remotely, increasing the speed at which

[c] Distributed generation excludes distributed energy resources that apply to demand reduction but do not generate energy.

a utility can identify and locate faults on the distribution system and restore service as well as manage voltage and reactive power to reduce energy losses and integrate distributed generation and storage technologies. Maximizing the value of DER will likely require the integration of advanced grid software and hardware; utility challenges with integration may prove to be a barrier for efficient proliferation of DER.

Risk and Regulatory Approval of Advanced Grid Technologies

- Costs of advanced grid technologies, weighed against uncertain financial benefits for utilities and their customers, have stymied utility investment. The impasse stems from utilities' concern about the likelihood of obtaining regulatory approval of advanced grid technologies, costs, and regulators' concern that costs to consumers may not be commensurate with their benefits.
- Utility estimates suggest that initial DER integration costs will largely be for enabling infrastructure—such as two-way communication and control systems, metering, and safety equipment—which is unlikely to provide an immediate financial benefit to offset the initial costs.
- Use of uniform equipment and standard design criteria has lowered utility costs and enabled rapid restoration of service; they have also made it harder to implementing non-uniform parts and procedures in utility systems. Performance risk, or the risk that the product will not perform as expected, is greater for advanced grid components and systems than for comparable traditional assets.
- Stranded costs and risks associated with rapid obsolescence of advanced technology have presented barriers to utilities' and regulators' acceptance of new technologies. Several policy and regulatory options have come into existence to mitigate risk associated with rapid obsolescence of advanced grid technologies. Proliferation of these policy and regulatory measures could facilitate utility adoption of advanced grid technologies.

Distribution System Planning and Analysis

- Tools that utilities use for long-term resource planning, short-term power management, transmission planning and operations, distribution planning and monitoring, revenue forecasting, and rate setting are purpose-specific and generally not integrated with one another. This lack of integrated-analysis tools complicates the integration of advanced grid technologies. The complexity and costliness of integrated systems modeling tools may stymie utility-by-utility development; the industry may benefit from flexible and specifiable shared modeling resources.

Distribution System Efficiency

- While the U.S. electric transmission and distribution system is among the most efficient in the world, roughly 6 percent of total generated electricity is lost in the system.
- One of the largest sources of loss is distribution transformers, which contribute roughly a third of total losses, or 2 percent of all generated electricity in the United States. However

new federal efficiency standards are expected to reduce these losses significantly, saving 3.6 quads of energy over 30 years.

- Further efficiency improvements are possible with both upgrades to more efficient equipment as well as new technologies that allow for the more efficient management of power flows to reduce losses.
- No one has undertaken a comprehensive, national study of the economic potential for efficiency upgrades in the U.S. distribution system. Studies of loss-reduction potential for specific technologies have estimated what losses each technology could reduce; however, these studies predominantly focus on the technical potential of either full deployment of a technology or optimizing operations to minimize losses. These results are likely to overstate the potential for loss reduction when improvements must also be subject to cost-benefit tests or other network-specific operational constraints.
- Replacing existing infrastructure for loss-reduction purposes alone is typically not justifiable on economic grounds. However, there can be positive net benefits for incorporating loss-reduction considerations into the design or planning of new capacity or reliability investments being made for other reasons.
- Efforts to invest in cost-effective efficiency improvements are likely further constrained in part by regulatory policies that do not allow recovery of the cost of the full capture of efficiency benefits by the operators who would incur the costs. For example, most states that require utilities to meet energy efficiency resource standards allow only end-use efficiency to count toward the target, meaning that there is no incentive for transmission and distribution (T&D) investments, which could have the same impact of reducing the level of generation needed to meet demand.

Microgrids

- Although a number of microgrid systems are being demonstrated, it will be difficult to increase the utility industry's average reliability. Most IOUs claim 99.9 percent availability or better. Large utilities, like those serving urban areas, tend to have lower outage rates than smaller utilities. Despite the high reliability and relatively low cost of utility-provided power, in some cases, the added expense of a microgrid will justify the associated benefits of increased reliability.
- Motivations for building microgrids vary regionally and among entities with different goals. Among the Mid-Atlantic states, microgrids are seen as a bulwark against the widespread grid outages caused by events like Superstorm Sandy. In California, they are seen as a natural extension of the state's RPS, sustainability, and retail choice policies. The U.S. Department of Defense's motivation is its need for secure energy to sustain operations during grid outages at permanent bases as well as more efficient ways to provide power when operating outside of the United States.
- Microgrid operators coordinate load and generation within their own system and with the utility. This coordination can make it easier to integrate DER than it would be with an equivalent collection of dispersed resources.

Utility Business Models

- The conventional regulatory framework has been assumed to provide IOUs with an incentive to favor capital investments that add to the utility rate base, so as to increase stockholder earnings from the allowed rate of return and to promote increased energy sales. The profits from increased energy sales can be a disincentive for fair consideration of energy efficiency or other, more optimal strategies to serve customers. Decoupling revenues from energy sales allows utilities to meet revenue targets via rate true-up mechanisms even if energy sales are low. If designed and implemented correctly, decoupling should have the effect of stabilizing the revenue stream of the utility because its revenues are no longer dependent on variable sales. Sixteen states are now experimenting with decoupling. Incentive regulation is similar to decoupling in that the revenues utilities earn are at least partly decoupled from sales and tied to meeting performance goals. However, decoupling and incentive ratemaking alone do not directly address the issue of utilities potentially favoring their own financing of infrastructure over considering other, potentially less costly, options.
- The number of IOUs continues to decrease through mergers to form ever-larger utilities and utility holding companies spurred by the hope of benefits from economies of scope and scale, and ultimately motivated by the expectation of increased investor returns. If municipal and cooperative utilities cannot take advantage of economies of scope and scale, this may increase differences between IOUs and municipal and cooperative utilities in terms of relative system costs and the ability to adapt to changing requirements of an advanced grid future. More analysis is needed to understand if there are systematic barriers to grid modernization facing smaller utilities.
- Several states are considering how to redefine the roles, responsibilities, and incentives of regulated utilities. In some cases, as in Hawaii and New York, the redefinition, in part, explicitly addresses the challenges and opportunities of DER. Even utilities in the states that are not currently redefining the role of electric utilities will need to develop new business processes to harness opportunities presented by advanced grid technologies, especially those related to information technology systems.

Data and Analysis Needs

- Information on distribution infrastructure by utility type is difficult to collect due to inconsistencies in reporting. For example, the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA) provides summaries of data from the Annual Electric Power Industry Report Form EIA-861, including the number of distribution circuits for each responding utility. However, information on circuit voltage and length is not provided. Although Form EIA-861 data is the most comprehensive, statistical summaries drawn from it are sometimes at odds with surveys using better data collection protocols, clearer definitions and directions, fewer yes/no response categories, and follow-up clarifications. EIA also exempts utilities with fewer than 100,000 megawatt-hours (MWh) in annual sales from full reporting. The short version of Form EIA-861, which exempt utilities use, has very limited information and doesn't permit cross tabulation by utility type or customer class. This is a segment of the industry about which little is known and, from its responses, appears to have invested less in grid modernization than its peers. More and better data, through targeted surveys of utilities by type and size, would facilitate a better understanding of the unique challenges presented by the comparatively small size of municipal utilities and geographic scale of cooperative utilities.

Acknowledgements

This work was sponsored by the Office of Energy Policy and Systems Analysis (EPSA), U.S. Department of Energy (DOE). We would like to acknowledge the following people who provided constructive feedback and guidance in the development of this report: Melanie Kenderdine, Jonathan Pershing, Carol Battershell, Judy Greenwald, Kevin Lynn, Robert Anderson, Carla Frisch, Cynthia Wilson, Robert Horner, Alex Breckel, Liz Hartman, Courtney Grosvenor, David Rosner, Rima Oueid, and Michael Kintner-Meyer.

Acronyms and Abbreviations

AC	alternating current
AMI	advanced metering infrastructure
AMR	automated meter reading
ANSI	American National Standards Institute
APPA	American Public Power Association
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CCA	community choice aggregator
CHP	combined heat and power
COU	customer-owned utility
CVR	conservation voltage reduction
DC	direct current
DER	distributed energy resource
DG	distributed generation
DMS	distribution management system
DOE	U.S. Department of Energy
DR	demand response
DRMS	demand response management system
DRP	distribution resources plan
DS	distributed storage
D-SCADA	distribution system supervisory control and data acquisition system
DSM	demand-side management
DSO	distribution system operator
EE	energy efficiency
EEI	Edison Electric Institute
EIA	Energy Information Agency
ESP	energy service provider
FDIR	fault detection, isolation, and recovery
FERC	Federal Energy Regulatory Commission
FIT	feed-in tariff
G&A	general and administrative
GMI	Grid Modernization Index
GWh	gigawatt-hours
HAN	home area network
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility

IRP	integrated resource plan
IT	information technology
kV	kilovolts
MDMS	meter data management systems
MWh	megawatt-hour
NEG	net excess generation
NEM	net energy metering
NYPSC	New York Public Service Commission
O&M	operations and maintenance
OMS	outage management system
PMU	phasor measurement units
PUC	public utilities commission
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
QER	Quadrennial Energy Review
REC	Renewable Energy Certificate
ROR	rate of return
RPS	renewable portfolio standard
RTO	regional transmission operators
SAIDI	System Average Interruption Duration Index
SCADA	supervisory control and data acquisition
T&D	transmission and distribution
TOU	time-of-use
TSO	transmission system operator
VAR	volt-ampere reactive
VVO	volt/var optimization

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1.0 Introduction

Among the key findings regarding grid modernization in the first installment of the *Quadrennial Energy Review* (QER), published by the U.S. Department of Energy (DOE) in 2015, are these conclusions; "The transmission network can enable connection to high-quality renewables and other lower-carbon resources far from load centers," and "distributed energy resource can provide local low-carbon power and efficiency." The QER also found that "investments in energy efficiency, smart grid technologies, storage, and distribution generation can contribute to enhanced resiliency and reduced pollution, as well as provide operational flexibility for grid operators." A key enabler will be the "appropriate valuation of new services and technologies and energy efficiency… [to] provide options for the utility business model." Thus, the QER concluded that the 21st century power system will meet consumer needs relying on both central and distributed resources.

1.1 Purpose and Approach

According to the viewpoint above, the distribution system will begin to provide some of the historic functions of the bulk power system to local customers as well as to those customers located further away by feeding power up from retail customers to the bulk power system.[d] The first question this raises is: are there physical or operational reasons preventing modernization of the existing distribution system to fulfill the envisioned function? The U.S. electric utility industry is not homogenous; rather, the size, form of ownership/management, and regulation of utilities vary, which raises a second question. Are there differences across utilities or regulatory practices that may interfere with the required modernization? Are these differences evident in adoption of smart grid-enabling technologies or measures, such as advanced meters and time-varying rates? Finally, what do answers to these questions contribute to DOE's understanding of the current status of utility distribution systems and their transition to a contributing element of the 21st century utility industry?

This distribution baseline report will address these questions using readily available statistical data from the U.S. Energy Information Administration (EIA) and others as well as surveys conducted by third parties relevant to these subjects. Specifications for the design of the distribution system of the 21st century utility do not exist, although there is general agreement on the necessary functions as noted above. The division between distribution systems and transmission systems is also elusive. The Federal Energy Regulatory Commission (FERC) defines transmission as 100 kilovolts (kV) and above, but it reserves the right to set the bar lower on a case-by-case basis. Very few retail customers receive utility service from facilities above 34 kV, and those customers tend to be large industrial firms with specially negotiated rates and terms of service. Accordingly, the focus of this paper is distribution infrastructure at and below the level of 34 kV and the retail customers it may serve.

The questions posed do not lend themselves to engineering answers due to the diverse nature of retail distribution utilities and the unique features of utilities as economic institutions, specifically their monopoly status. Both the monopoly status and diversity of utilities are

[d] The Bulk Power System includes "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generation facilities needed to maintain the transmission reliability." 16 U.S.C. § 824o (2011).

consequences of the history of the industry. That history, especially the connection between utility finance and electric power rates, provides valuable context for the measurement of distribution system modernization progress and, therefore, is a subject for Chapter 2, along with an overview of the physical characteristics of distribution systems and a statistical survey of the U.S. utility industry. Chapter 3 reviews available statistics and other measures of utilities' progress toward a 21st century distribution system to the initial questions presented above. The final chapter is a response based on the materials in Chapters 2 and 3 to the initial questions presented above. Appendix A provides more detailed information about distribution system components.

2.0 Legacy of the 20th Century Utility

2.1 Industry Overview

Under different regulatory structures, electric utilities can provide three functions: generation, transmission, and distribution. This report provides a baseline for the distribution function; however, the role of distribution must first be placed in the context of utility operations as a whole, including system operations and utility business and regulatory practices. This chapter provides a brief history of the U.S. electric utility industry and important utility business and regulatory issues; an organizational survey of the industry and major institutions; and an overview of distribution system components and operations.

2.1.1 Brief History of the Origins of the U.S. Utility Industry

The U.S. electric utility industry is generally dated from Thomas Edison's first commercial power plant, the Pearl Street Station, in 1882. Edison developed the Pearl Street Station to provide electricity to the New York Financial District and to sell Edison light bulbs, which were invented in 1879. Then, as now, the power distribution system was a means to an end: the provision of electric power. Early utilities distributed power over low-voltage, direct current (DC) lines. The use of DC limited utility service to an area no more than one mile from the generator. Multiple generators and dedicated distribution lines were required to serve a larger area. The limited reach of distribution lines and lack of regulation over utilities resulted in the co-location of multiple independent utilities and competition for customers where lines overlapped. In 1896, alternating current (AC) generation emerged as a competitor to DC with the development of generators at Niagara Falls, New York, and the transmission of power 20 miles to Buffalo, New York. AC power generation allowed a single utility to serve an area greater than one mile from the generator, broadening the base of customers and sources of revenue, which created conflicts with utilities already established using DC technology—eventually leading to legislative intervention. This development history and associated conflict had a parallel in the railroad industry. In 1905, the state of Wisconsin established a regulatory body to rationalize railroad routes and rates after concluding railroads were natural monopolies and, therefore, that the regulation of competition and rates was in the public interest. Wisconsin extended this form of regulation to electric utilities in 1907. The State of New York regulated utilities the same year, and by 1914, 43 states regulated electric utilities.[1]

Electric utilities emerged during a period of rapid industrialization and associated wealth creation, which the press caricatured in the form of so-called robber barons. It was also a period of machine politics and associated patronage exemplified by Tammany Hall's influence in New York City. This is note-worthy simply because public perceptions of corporate and municipal corruption influenced the ownership and regulation of local utilities. The public favored municipal ownership in areas where there was distrust in corporations, but in areas where the public feared political corruption and cronyism, it trusted and preferred corporations. Those choices allowed both private and public utility business models to develop and persist to this day.

2.1.2 Types of Utilities

Investor-owned utilities (IOUs) are organized as for-profit corporations, and are subject to further regulation of electricity rates and service according to the laws of the states where they operate. Municipal utilities, rural electric cooperatives, and public utility districts are forms of customer-owned utilities (sometimes called COUs). Municipal and cooperative utilities are governed by the retail customers they serve through elected governing bodies, be they municipal governments, county governments, cooperative governing boards, or service district representatives.[2] Most states allow municipal and cooperative utilities to establish rates without state regulatory oversight.[3]

IOUs provide the majority of U.S. electricity customers with retail delivery service.[4] The continued presence of municipal and cooperative utilities provides an ongoing opportunity to compare and contrast the performance of IOU and municipal and cooperative utility operations and regulatory models as they affect retail power delivery.

2.2 Utility Characteristics

2.2.1 Types and Location of Utilities and Characteristics

Traditional vertically integrated electric utilities operate as distribution monopolies with the sole right to provide retail service to specified customers as well as an obligation to do so. Urban areas were the first to establish utility service areas. The density of potential customers made them attractive to investors who requested franchises. Municipal utilities formed where municipal governments chose to take on this responsibility.

By the 1930s, most urban areas were electrified; however, sparsely populated rural areas generally were not. The *Rural Electrification Act* of 1936 aimed to address this apparent failure of the regulated monopoly model by enabling a new corporate form of utility ownership that enjoyed financial support from the federal government (i.e., rural electric cooperatives). Increased federal investment in hydropower generation to serve these new consumers followed, and **b**y the 1960s, rural electrification was largely complete.

The retail power distribution industry today is made up of roughly 3,000 utilities organized under two primary management structures: IOU and COU. Within the COU category, there are utilities organized under municipalities, cooperatives organized under the *Rural Electrification Act*, and utilities formed as municipal corporations under state law that serve specific constituent groups, such as the public utility districts in Oregon and Washington and irrigation districts in California. Table 2.1 summarizes the number of distribution utilities by type and customers served as well as other statistics. Although other entities such as irrigation districts may be engaged in the sale of electricity to retail customers, the utilities noted in Table 2.1 provide virtually all distribution service to deliver retail electricity purchases.

Table 2.1. Statistical Comparison of Utilities by Type of Organization[5]

The table below compares the variance in size, revenue, distribution, customer makeup, and other factors among the different types of utility organizations. IOUs serve by far the most customers, though cooperative utilities in aggregate have a comparable fraction of distribution line miles. The median size of municipal utilities is very small. Despite these characteristic differences, the distribution plant per customer is roughly the same across utility types.

	Investor-Owned Utilities (IOU)	Municipal Utilities	Cooperative Utilities	Total
Total number of customers (millions)	104	21	18.5	144
Total revenue ($ billions)	273	53	40	366
Number of organizations (#)	200	2,000	912	3,112
Size (median number of customers)	400,000	2,000	13,000	
Revenues (percent of total)	75	14	11	
Customers (percent of total)	72	15	12	
KWh sales (percent of total)	73	16	11	
Sales (billion kWh)				
Residential	992	212	239	1,443
Commercial	1,057	210	84	1,351
Industrial	659	148	90	897
Total	2,708	570	413	3,691
Fraction of distribution line miles (percent)	50	7	43	100
Customers per mile of line (density)	34	48	7.4	
Revenue ($/per mile of line)	75,500	113,000	15,000	
Distribution plant per customer ($ per capita)	$2,798	$2,740[(a)]	$3,290	
Assets ($ billions)	870	260[(a)]	140	1,270[(a)]
Equity ($ billions)	280	76[(a)]	42	398[(a)]
Equity (percent)	32	32[(a)]	30	

(a) Estimate

Acronyms: KWh = kilowatt-hours.

Most of the electricity sold to retail customers in the United States is delivered by IOUs, most of which are members of the Edison Electric Institute (EEI) trade association. Figure 2.1 shows the service territories of IOUs that are members of EEI. Electric cooperatives are the most geographically dispersed retail distribution utilities, serving customers in 2,500 of the nation's 3,141 counties, as shown in Figure 2.2.

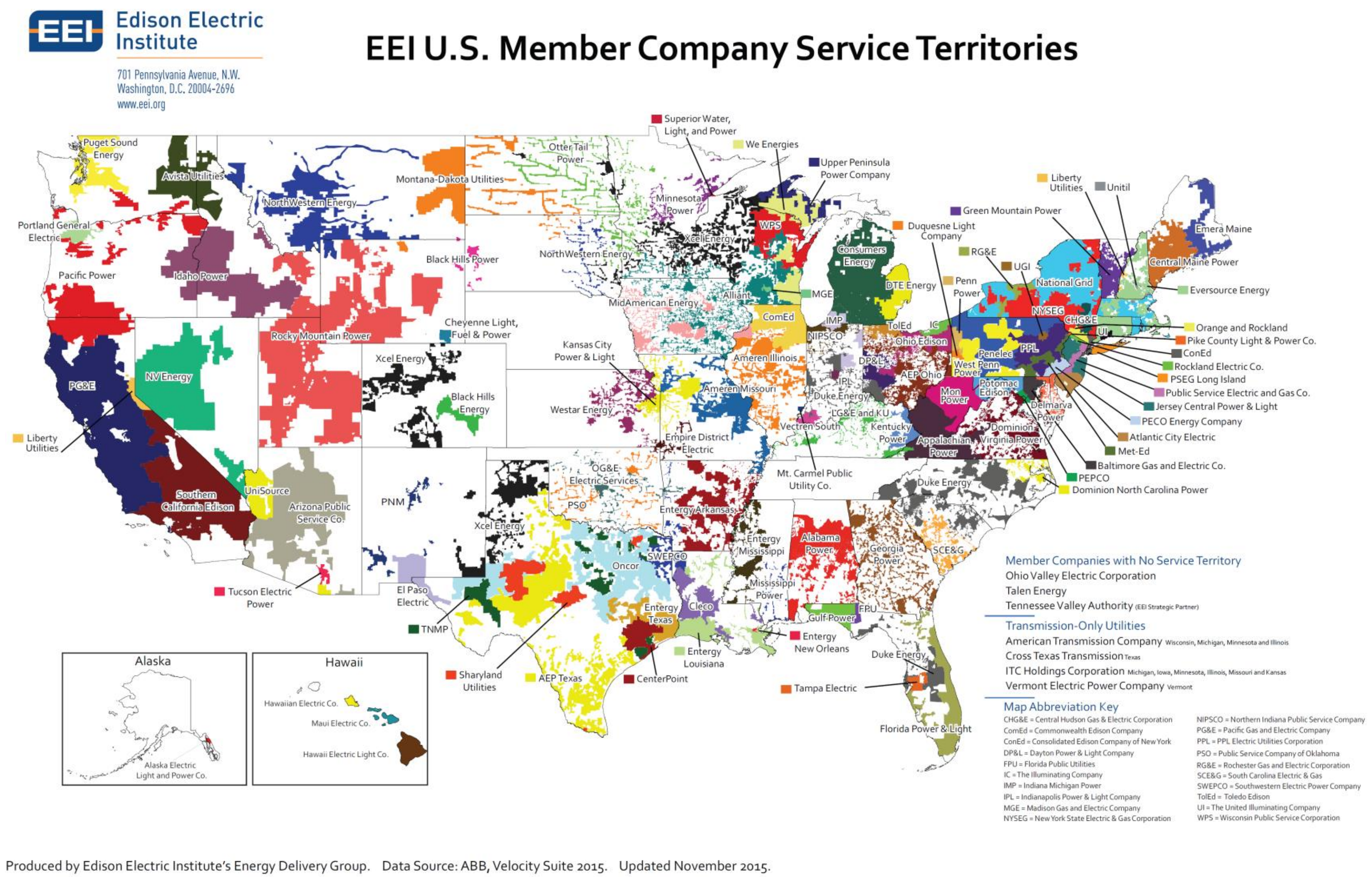


Figure 2.1. Location of EEI Member Investor-Owned Utilities in the United States[6]

This map denotes the geographic region operated by each investor-owned utility throughout the nation.

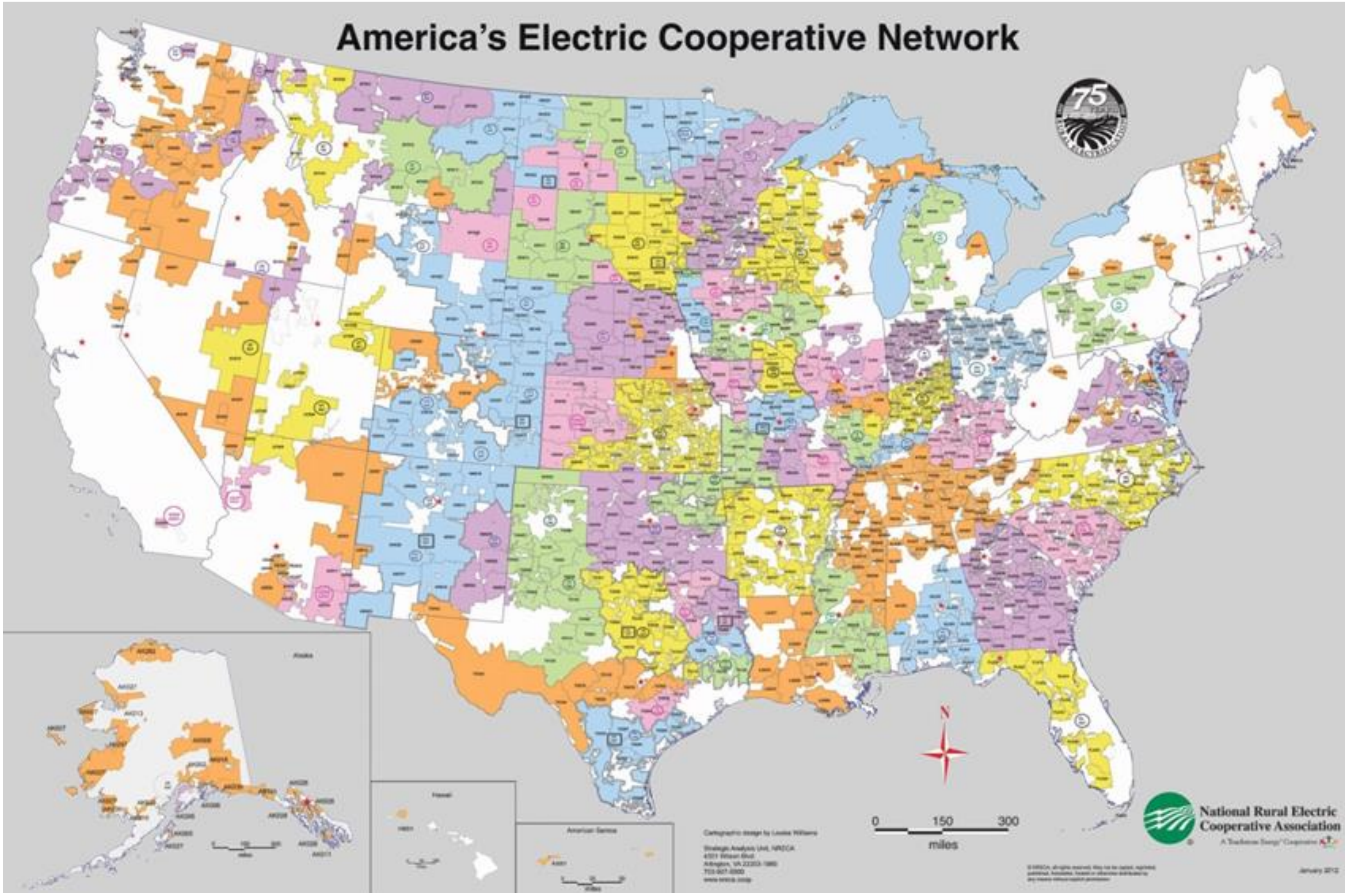


Figure 2.2. Location of Electric Cooperatives in the United States and Samoa[7]

As the most geographically dispersed retail distribution utilities, electric cooperatives serve customers in 2,500 of the nation's 3,141 counties.

The 2,000 municipal utilities are the most numerous retail electricity distribution entities, although they range in size from a handful of customers to the Los Angeles Department of Water and Power and its nearly 1.5 million customers, as shown in Figure 2.3.

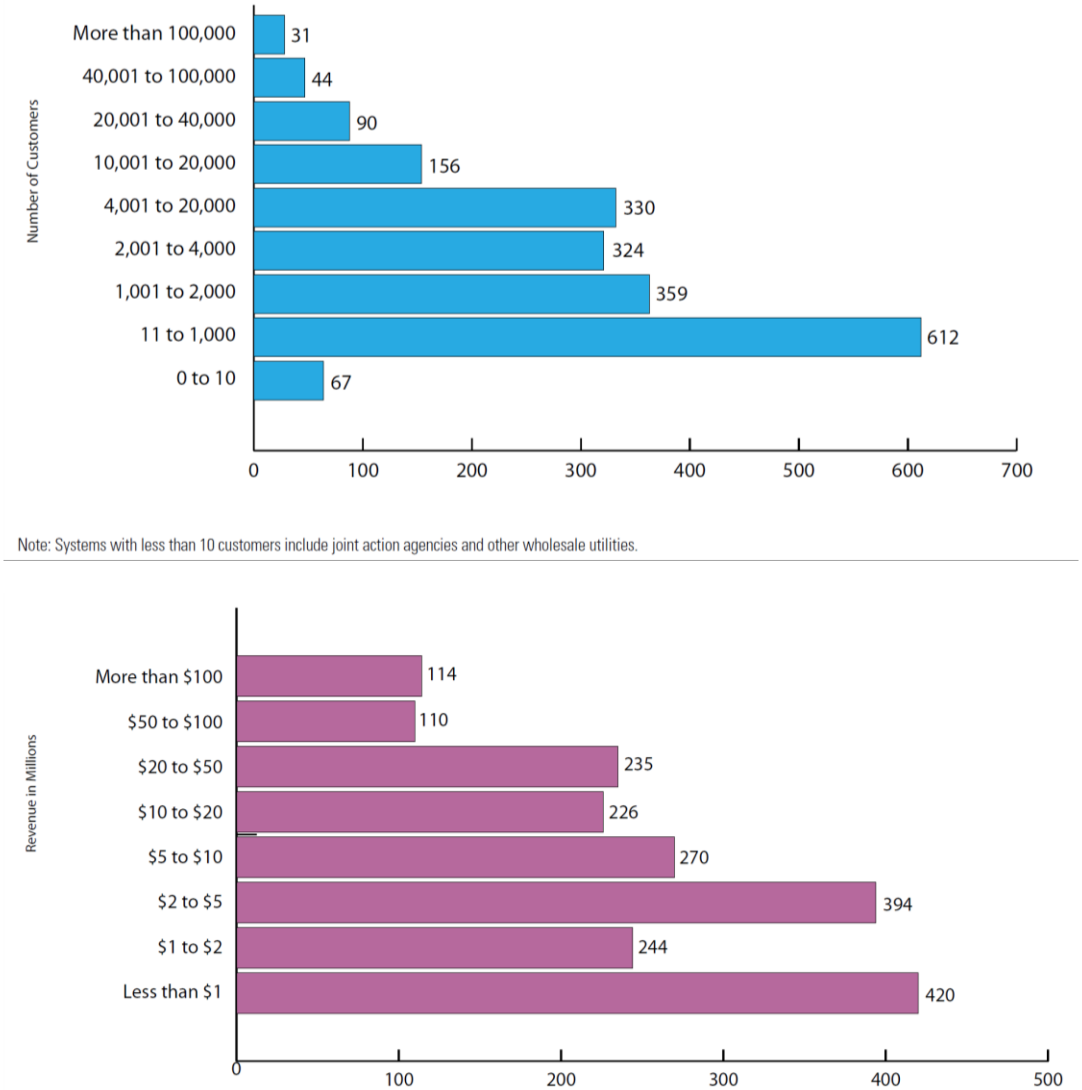


Figure 2.3. Two Views of Municipal Utilities; by Customer Count and Total Revenue[8]

The bar graphs above show the range in size of municipal utilities based on number of customers (top) and total revenue by year (bottom).

2.2.2 Deregulation and Resulting Alternative Retail Energy Suppliers

Although utilities are the only entities that can deliver power directly to retail customers using the distribution system, they are not the only option for retail energy supply. In 1998, the California Public Utility Commission (PUC) began a process to deregulate retail electricity sales for IOU customers by allowing what has since been called "customer choice." In customer choice areas, energy service providers (ESPs) compete to supply end-use customers with electricity services. A number of other states followed suit. After an electricity supply crisis in

2000, California suspended retail competition, as did several other states.[9] Figure 2.4 shows the current status.

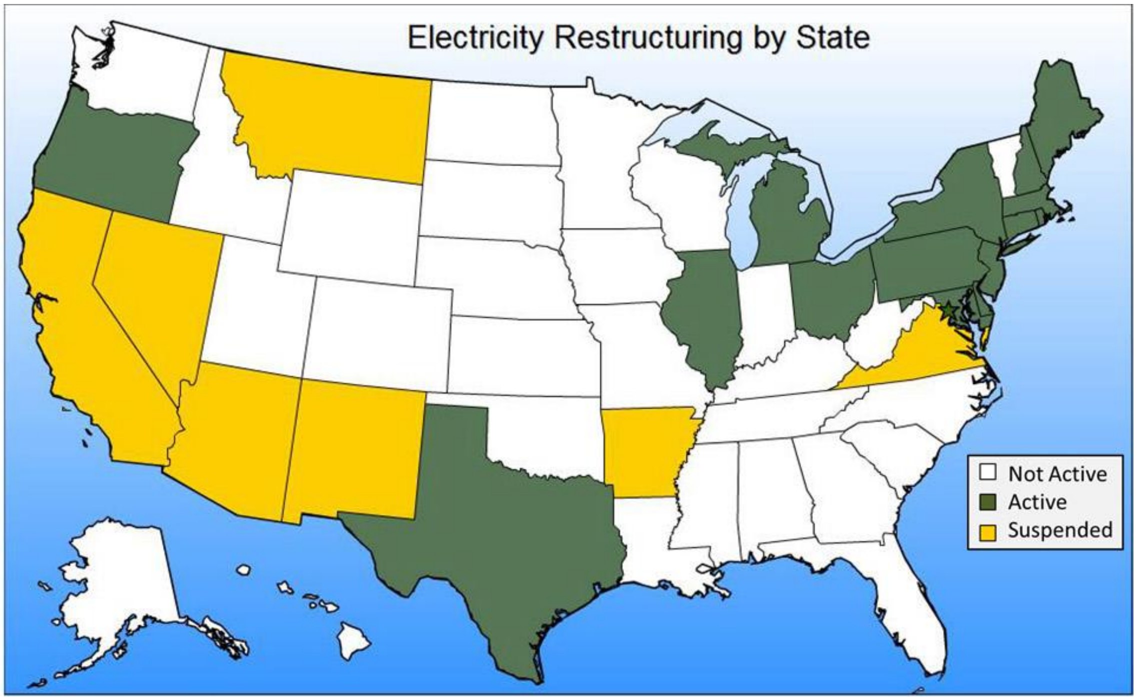


Figure 2.4. Status of Retail Electricity Customer Choice by State[10]

This map shows the status of customer choice programs in several states. While several states such as California, Arizona and Virginia have suspended activity, others like Texas, New York, and Illinois are still actively implementing it.

Because retail sales are regulated at the state level, retail deregulation rules vary from state to state. Typically, customer choice of energy supplier is only required for customers served by IOUs, although most states allow municipal and cooperative utilities to opt in under the same rules. Although retail customers can choose from among a variety of ESPs, they can only select a single ESP, and electricity is still delivered by the distribution utility. In other words, retail customers cannot purchase wind power from one marketer and the rest of their needs from another; however, an ESP can bundle generation sources on their behalf. This requirement exists so there is a single point of coordination between the local delivery utility and the ESP.

The ESP is contractually obligated to both fulfill its commitment to its retail customers and to provide the required power and related services to the utility through which energy is delivered to the retail customer. If an ESP fails to do so, the local distribution utility or its agent is responsible for procuring the necessary energy and related services on behalf of the retail customer in order to avoid curtailing service to them.

Most states that allow for retail competition permit the incumbent utility to continue to supply power to customers. However, IOUs in Texas are prohibited from providing retail supply services to retail customers.[11] As a result, incumbent IOUs in Texas are true “wires-only” utilities that only own and operate distribution systems that facilitate delivery of electricity supplied by other utilities to end-use customers.

2.2.2.1 Wires-Only Utilities and ESPs

A wires-only utility retains responsibility for elements of the regulatory compact concerning universal access to the grid (through the distribution system) and service quality and reliability for the power delivery system under its control. Most of the retail choice states belong to regional transmission operators (RTOs) that coordinate planning and management of the regional transmission grid, although incumbent utilities and new transmission-only utilities continue to own and maintain transmission infrastructure. All generation and power sale transactions are scheduled through the RTO along with transmission of power to points-of-delivery owned and operated by the local utility. At that point, the delivery to ultimate retail customers uses the local distribution system.

2.2.2.2 Virtual Utilities: Community Choice Aggregators and Community Solar

Another new power supplier option is the "aggregator." In California and several other states, municipalities within IOU service areas were allowed to form "community choice aggregators (CCAs)." A community could enroll its citizens in a CCA and secure power supplies on their behalf as if it were any other municipal or cooperative utility, although in this case, power would continue to be delivered by the incumbent IOU.[12]

A recent variation is the "community solar" aggregator. In this variation, consumers interested in owning solar systems but without the ability to host them individually can band together, or aggregate, to purchase either shares in an off-site solar system or contract for the output from such a system. The energy from the solar system could displace power purchases from the utility at the current tariff rate. If energy from the solar system is less expensive than alternative suppliers, participants save money. Regardless, they may benefit from tax and other incentives from owning a solar system and from having a long-term supply of energy at a fixed price.[13]

Both CCAs and community solar aggregations are a form of a "virtual" utility, where generation, transmission, and distribution are contractually, but not physically, integrated. In other words, energy continues to be supplied to retail customers by the incumbent distribution utility using existing infrastructure and rates; however, the charge for energy is based on the contract price negotiated by the CCA or with the community solar project.

2.2.3 Distribution Infrastructure by Utility Type

Information on distribution infrastructure by utility type is difficult to collect due to inconsistencies in reporting. For example, DOE's EIA provides summaries of data from its Annual Electric Power Industry Report (Form EIA-861), including number of distribution circuits for each responding utility. Distribution circuits are the main wires that connect substations, where power is delivered from the bulk power system, to end users. However, information on circuit voltage and length is not provided.

Table 2.2 provides a summary of the aggregate length of distribution and transmission lines by mile for each utility type.

Table 2.2. Distribution and Transmission Line Miles by Utility Type[14]

Though municipal utilities are the greatest in number, IOUS have the greatest amount of distribution and transmission line miles.

Utility Type	Number of Utilities	Line Miles of Distribution	Line Miles of Transmission
IOU	206	3,467,216	382,295
Cooperative	811	2,395,384	47,756
Municipal	1,865	320,953	27,585
Public Utility District	107	138,683	18,762
Total	2,989	6,322,236	476,398

2.2.4 Aging Distribution Infrastructure

Although utilities date from the turn of the 19th century, very little of that original infrastructure remains. Newer technology has mostly replaced it. As a result, the "age" of utility infrastructure is difficult to define. For example, distribution transformers are changed to accommodate increased demand along a feeder. Do the new transformers reduce the age of the feeder, or do they reduce the age of the stock of distribution transformers? Would either statistic be a meaningful measure of the distribution system's age? The constant repair and replacement of components of the distribution system makes "age" a rolling average.

What is more relevant is how utilities manage aging components. There are two basic strategies to address aging components: a replacement schedule based on the installed date/chronological age, and "asset management," which uses chronological age in a formula that also includes an estimate of the use of the asset (i.e., hard versus light) and the consequences if the component fails (how many customers will be affected, for how long, and at what cost?).[15] Using chronological age may recommend replacement of every distribution pole when it reaches 40 years of age, whereas asset management might recommend preventative maintenance or replacement at 20 years and 10-year reevaluations thereafter, if the pole is in a hostile environment, serves critical customers, or is part of a system serving a large number of customers. Proactive maintenance and management using these sorts of metrics may extend the life of a pole well beyond its expected 40 years or may result in a more frequent replacement schedule if the risk to customers is great.

Asset management is a current utility best practice because it provides greater flexibility for operations and maintenance (O&M) scheduling. Regardless, even the best maintenance practices cannot extend the life of an asset forever. Accordingly, utilities budget for both routine and emergency replacement of components, although the list of assets is not based on simple chronological age metrics, and specific assets slated for replacement are subject to change.

2.3 Utility Ratemaking

2.3.1 Regulatory Overview

Electric utilities are subject to regulation at both the federal and state level. Federal regulation of the electricity sector is based on the Commerce Clause of the constitution (Article I, Section 8, Clause 3), which authorizes Congress to “regulate commerce among several states.” The primary federal electric utility statutes are the *Federal Power Act* the *Public Utility Holding Company Act of 2005*, the *Public Utility Regulatory Policies Act of 1978*, the *Energy Policy Act of 1992*, and the *Energy Policy Act of 2005*.[16] The primary federal body for electric utility regulation is the Federal Energy Regulatory Commission (FERC), which regulates hydropower planning and licensing, electricity transmission and wholesale sales in interstate commerce, mergers and acquisitions of electric utility companies, electric reliability, and organized electricity markets.[17]

The Federal Power Act expressly reserves the regulation of distribution and retail sales to the states. Although federal regulations would appear to have little relevance to distribution systems small-scale generation and customer-operated generation, storage, and demand management connected to distribution systems have the potential to bid into wholesale power markets where FERC regulations may apply.

States primarily regulate utilities with respect to safety, retail service and rates, resource planning and siting, and finances. Power plants are regulated for air emissions, water use, and wastewater disposal by federal, state, and local regulators.[18] For IOUs, regulation of rates and finance is through a commission typically called a Public Utility Commission (PUC) or Public Services Commission (PSC). State statute creates the legal framework for this regulation. Recently, state legislatures have been active in areas including renewable portfolio standards (RPS), retail customer choice, net energy metering, and feed-in and other tariffs that impose new demands on utility distribution systems.

2.3.2 The Regulatory Compact

In the early days of the electricity industry, utilities used market-based pricing. However, the “regulatory compact” evolved as consumer demand grew rapidly. The term “regulatory compact” refers to the method of regulation whereby the state grants a utility company a monopoly franchise in exchange for the obligation to serve all customers within the service territory and submission to regulatory oversight by the state PUC. Under the regulatory compact, utilities charge regulated rates based on the actual cost of providing service to customers. Utilities pay for new construction as needed and can recover prudent costs of providing service. Utilities recover costs (including a fair return on capital investment) from ratepayers through utility bills.[19] The term “regulatory compact” emerged from regulation of IOU rates and services, but the same basic framework — a sanctioned monopoly service provider subject to an obligation to serve and cost-of-service rate setting — are applicable to utilities that are not subject to PUC rate regulation, including municipal and cooperative utilities and other government-chartered utilities.

The primary difference between regulation of IOUs and municipal and cooperative utilities is that state PUCs regulate IOUs, whereas municipally owned utilities are subject to oversight by city government and cooperatively owned utilities are typically overseen by a customer-elected board. Government-owned utilities have inherent authority to expropriate private property for public purposes through eminent domain and are less likely than private firms to discharge financial obligations through bankruptcy.[20] State law typically extends eminent domain authority to IOUs on a conditional basis. Consequently, ensuring IOUs have adequate revenues to service outstanding financial commitments is an essential element of the regulatory compact. Other elements of the compact, such as service obligations and rate fairness, are equally relevant to investor-owned, municipal, and cooperative utilities.

In brief, the utility regulator typically grants the regulated utility the following rights:

- A conditional, exclusive franchise for a specified service territory.
- Protection from direct competition and antitrust.
- Rights of eminent domain.
- Recovery of prudently incurred costs through cost of service rates.
- An opportunity to earn a fair return on useful investment.

In return, the utility accepts the following obligations:

- Provide all paying customers with access to safe, adequate, reliable, convenient, and nondiscriminatory service on just and reasonable terms.
- Assume certain business and market risks.
- Subject itself to regulatory review and oversight.[21]

2.3.3 Ratemaking

IOUs can finance utility investments using stockholder equity or borrowing. Municipal and cooperative utilities, which have no stockholders, rely on cash flow, retained earnings, or borrowing to finance utility investments. Investment in corporate stock carries no guaranteed return. The regulatory compact accommodates utility stockholders by providing an allowed rate of equity (ROE) on their investment in capital assets. The ROE is set during the rate process and applies to stockholder equity cumulated in the rate base.

> **Rate base:** The value of property upon which a utility is permitted to earn a specified return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.[22]

Anticipated returns on the rate base make utility stock attractive to investors who are looking for steady dividends. Steady returns following from PUC oversight set utility stocks apart from other, more speculative investment options and gives utility stock the reputation of being a relatively safe investment.

2.3.4 Rate Cases

In practice, investor-owned distribution utilities are subject to comprehensive oversight by the state-designated regulator. When a utility makes a new major investment or when costs change significantly, that utility asks the regulator to recover these costs through a process called a rate case. Rate cases are public proceedings. The public and interested parties are alerted to participate in the review of the utility's rate case. Interested parties, often called intervenors, might include individuals, consumer advocates, environmental groups, and large energy users such as grocery stores or industrial firms. Currently, intervenors also include advocates for energy efficiency program incentives, renewable energy alternatives, and other distributed energy resources. PUCs generally do not set rates for municipal and cooperative utilities in most states. Nevertheless, municipal and cooperative utilities follow a similar rate-development process governed by their board of directors or municipal government.

The utility may initiate a rate case with a request of the PUC to approve a change to the annual revenue requirement, or the PUC may initiate it to ensure rates are just and reasonable and that allowed RORs are appropriate. Parties in the case, including PUC staff, typically scrutinize the company's proposed revenue requirement. Ultimately, the PUC determines an annual revenue requirement. Rate cases require detailed review of the utility's accounts and expenses and projections of future costs. They typically require a great deal of effort on the part of the utility and PUC staff and of parties who may intervene in opposition or support.

In a rate case, the PUC must determine the revenue requirement, which is the amount of money the utility can collect from customers to cover expenses and earn a fair return on its investment,. The PUC must also determine rate design, which specifies how the utility will collect the revenue requirement from the various classes of residential, commercial, and industrial customers.[23]

The utility's revenue requirement is the amount of annual revenue necessary to recover the annual cost of providing service and to allow an opportunity for the utility to earn a reasonable return on its investment. The following formula summarizes the revenue requirement:

$$\begin{aligned} \textit{Revenue Required} &= \textit{Operating Expenses} + \textit{Depreciation} + \textit{Taxes} \\ &\quad + (\textit{Rate of Return} \times \textit{Rate Base}) \end{aligned}$$

There are two components to revenue requirements: expenses and return on rate base. Expenses consist of operating and maintenance costs and other charges (e.g., taxes and gross revenue fees).[24] Depreciation is treated as an expense. The second component is the allowable ROR applied to the utility rate base. As described above, the utility's rate base is the value of a utility's capital investments minus any depreciation.[25] Once an asset is fully depreciated, it is no longer part of the rate base and therefore, no longer earns the utility a ROR.

Distribution system expenses and return on investments deemed by the PUC to be prudent are rolled into the company's revenue requirement. Distribution costs that have traditionally been included in revenue requirements include sub-transmission circuits, distribution substations, primary circuits or feeders, distribution transformers, poles, pads, underground vaults, secondary circuits, capacitor banks, service lines, and utility meters. Section 2.4 and Appendix A contain descriptions of these assets and their roles in electricity distribution.

2.3.4.1 Cost Allocation

The full utility revenue requirement is determined based on what the utility needs to spend on its entire system. FERC has a system of accounts that utilities within its jurisdiction are required to use to facilitate monitoring rate setting and comparison across utilities. Utilities not regulated by FERC often use the same system of accounts as well. The total revenue requirement is broken down by FERC accounts.[e] FERC accounts are specific in terms of costs categorized in each of the following categories:

- Production/generation
- Transmission
- Distribution
- General and administrative (G&A) expenses.

Within the distribution expense category, FERC requires utilities to break down distribution plant value into several sub-categories. For each, the utility must specify how much money it has spent on each subcategory, how much has been depreciated, and how much value remains.

Costs are then allocated across classes of customers to ultimately be recovered. Traditionally, utility customers are divided into similar classes based on presumed consumption characteristics that correspond to their use of utility infrastructure and services. There are three major customer classes: residential, commercial, and industrial. Within each rate class, there are often subclasses based on usage type and levels of energy use (e.g. large versus small commercial). Additionally, most utilities have classes for street lighting while some have classes for major loads that warrant their own class, such as irrigation. The purpose of sub-classification is to more closely allocate the cost of service for customers in the sub-class compared to other sub-classes. This allows the utility to charge similar customers using the same rates, which simplifies customer metering and billing. The resulting rate design is called a "postage stamp" rate: the same rate charged to each customer in a sub-class regardless of variations in use.

2.3.4.2 Rate Design

Specific tariffs or rates are designed once costs that need to be collected by each subclass are established. The specific tariffs detail how and what different customers are charged each month. Rate design is also accomplished as part of the rate case proceeding.

Utility costs fall into three broad categories; the fixed costs of maintaining and operating the system, variable costs associated with power production and delivery, and G&A expenses. These are allocated to customer classes and sub-classes through rate design. Power production and G&A costs are similar for all customers and are more easily allocated by apportioning costs to each customer class. Fixed system costs are primarily associated with the transmission and distribution (T&D) system and generating reserves. Large customers use these assets in widely varying amounts compared to smaller customers. To ensure more equitable cost recovery, large customers are often charged for use of these assets based on their peak demand (kW) measured with a demand meter as opposed to energy use. There are a number of ways to quantify demand, such as by the monthly maximum, maximum for specific hourly intervals during a day, or continuously. The choice of quantification method depends on the sophistication of the customer's meter and the specifics of the rate design.

Residential and small commercial customers have similar demand and typically do not rely on demand meters. The fixed cost of the system for these customers is included as part of the

[e] Utilities are required to fill out FERC Form 1 annually, and this information is publicly available (40 CFR 141). Although utilities use standardized systems of accounts, the reporting categories used vary across utilities, adding a degree of error when using Form 1 data for utility expense comparisons.

volumetric per kilowatt-hour (kWh) rate. For example, a customer may pay $0.11/kWh for the energy he or she uses. Of the $0.11/kWh, potentially $0.01/kWh is to cover transmission costs, $0.04/kWh is to cover distribution system costs, and $0.06/kWh is to cover generation or production costs; the latter may include costs of energy purchased on the wholesale market rather than generated by the utility. In addition, they may pay a monthly customer charge to cover the costs associated with service drops, meters, meter reading, and billing.[f] Regulators may impose additional fees on customers as surcharges to fund specific activities such as regulation, energy planning, energy efficiency programs, and nuclear decommissioning.

Rate designs provide consumers with price information; consequently, the design can act as a price signal to guide the quantity and timing of electricity use. Historically, customer meters were mechanical and had monthly readings, which restricted the ability of the utility to charge rates that varied based on time of day or days of month. Electronic meters have replaced mechanical meters in many major utilities. Advanced meters enable rate designs that vary by time-of-use (TOU) on an hourly or more frequent basis, which in turn enables use of a suite of time-varying rate designs that more accurately reflect the cost of service. Critical peak pricing and real-time pricing are examples, as shown in Table 2.3.

[f] Often, the customer charge does not recover all of these costs. It's typical for what remains of these costs to be picked up as part of the per-kWh distribution charge.

Table 2.3. Examples of Common Time-Varying Rate Designs

Implementation of time-varying rates can provide powerful price signals that significantly reduce peak demand; however, more complex rate designs require advanced meters that are able to monitor and record energy use consistent with the time periods specified in time-varying rates and other tariffs.

Form	Description	Requires Smart Meter?
Critical Peak Pricing (CPP)	Charges customers a higher rate in a small percentage of critical peak periods, in return for lower prices throughout the rest of the year.	✓
Peak Time Rebates (PTR)	Offers customers a rebate for conserving during these same critical peak periods. Rates remain constant otherwise.	✓
Real-Time Pricing (RTP)	Offers customers the chance to respond to prices that change with wholesale rates on an hourly basis (or in some pilot projects even more frequently).	✓
Time of Use (TOU)	Offers a lower rate during certain hours of the day when energy is cheaper to produce and at a higher rate during peak periods when it is the most expensive. These rates and hours are established in advance.	
Variable Peak Pricing (VPP)	Similar to TOU, except the peak rates vary with market conditions.	✓

Sources: Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly 152(8)*, August 2014, p. 26, online at http://www.fortnightly.com/fortnightly/2014/08/smart-default; AEP Ohio, *gridSMART Demonstration Project: A Community-Based Approach to Leading the Nation in Smart Energy Use, Department of Energy (DOE) Smart Grid Demonstration Project (SGDP)*, Final Technical Report, June 2014, p.128; ComEd, *The ComEd Residential Real-Time Pricing Program Guide to Real-Time Pricing*, 2013–2014, p.5. Available at https://www.comed.com/Documents/customer-service/rates-pricing/real-time-pricing/RRTPProgramGuide.pdf.

2.3.5 Metering

The ability to use time-varying or demand-based rates is limited by the capabilities of the electricity meter. Simple kWh meters only offer a cumulative measure of electricity use. Advanced electronic meters that can be read automatically are classified as automated meter reading (AMR) devices. Meters that have two-way communication capability, which requires an associated communication infrastructure, are classified as advanced metering infrastructure

(AMI). These features can be used for more sophisticated rate designs. Conversion to advanced meters is a process that is well underway, as shown in Figure 2.5.

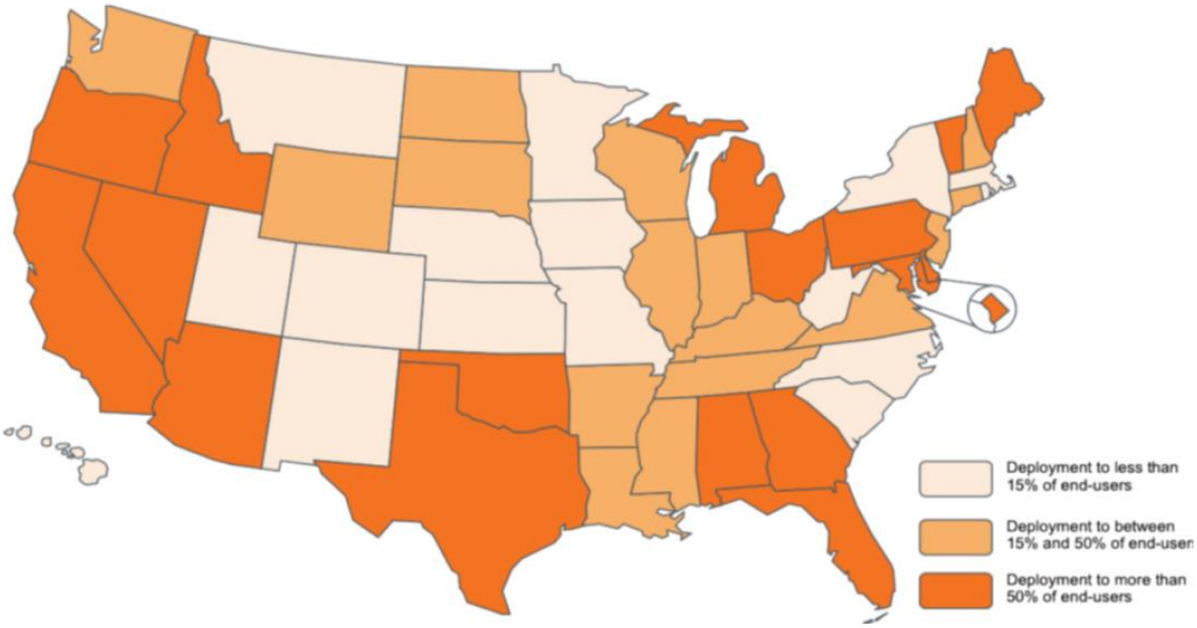


Figure 2.5. Smart Meter Deployment Expected by 2015, State-by-State[26]

This map demonstrates the deployment of smart meters among utility users across the nation. States with deployment to less than 15 percent of end users are in pink, states with 15 percent–50 percent deployment are in light orange, and states with 50 percent deployment or higher are in dark orange.

2.3.6 Rates and Public Policy Goals

2.3.6.1 Net Energy Metering

Net Energy Metering (NEM) allow any retail customer to host distributed generation (DG) at his or her location and use the power produced to displace utility purchases. NEM tariffs allow customers to "net out" utility-provided power by an equivalent amount of DG production, regardless of when it is produced. For example, a solar array may produce three times more energy than the amount that a customer uses during daylight hours but less than the customer uses during the entire day. In this case, excess daytime production is credited against the customer's nighttime power purchases from the utility. Customers can

rollover credits from one day to the next, generally for up to a year, after which they typically expire. Most states have requirements for NEM, as shown in Figure 2.6.

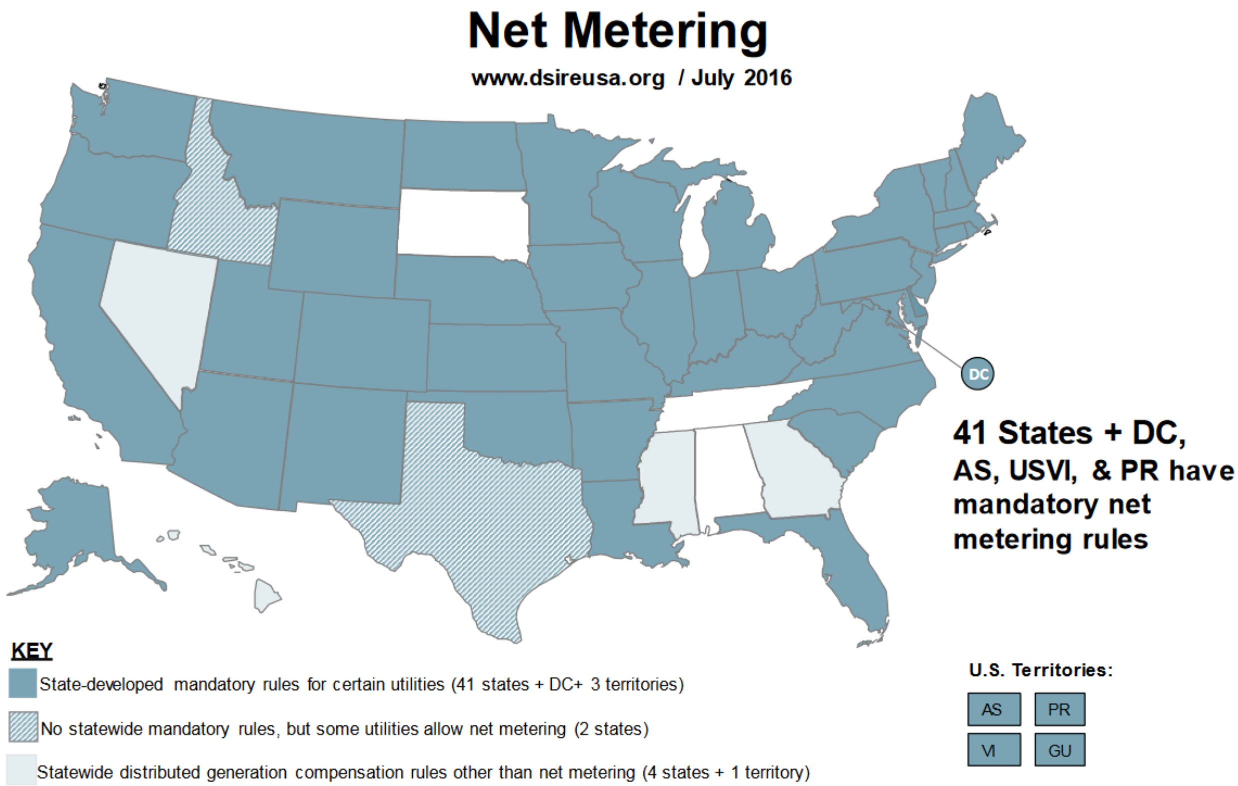
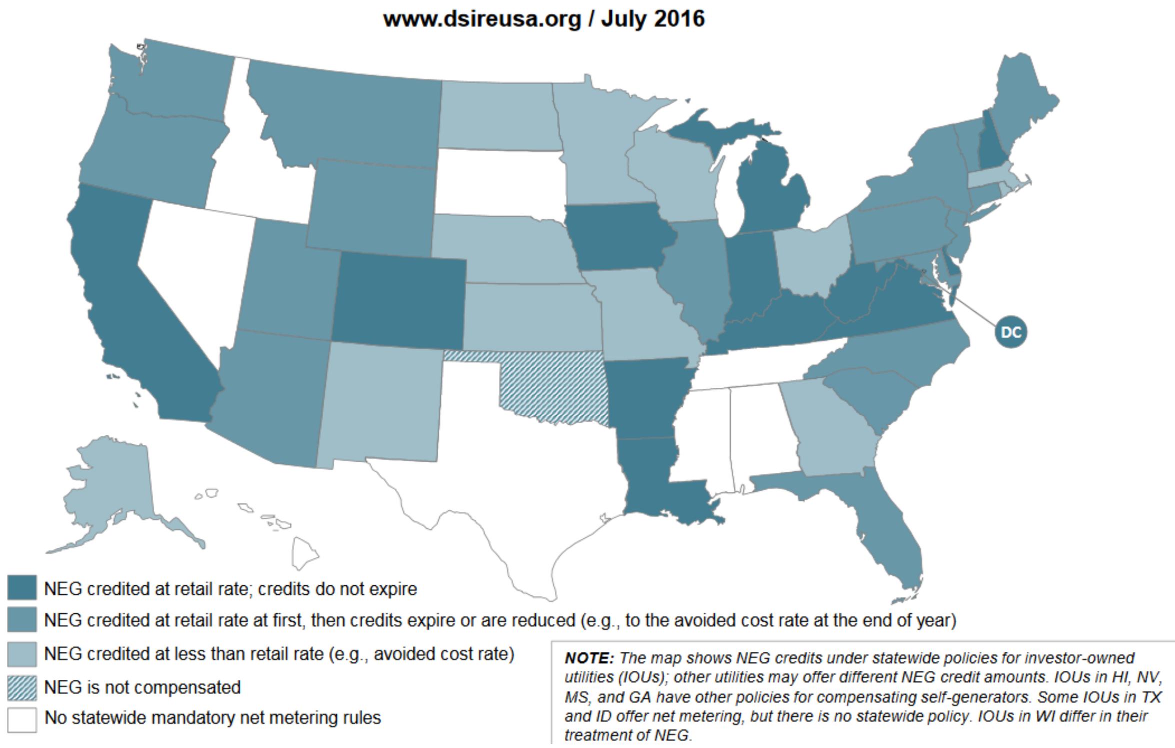


Figure 2.6. Status of State Net Energy Metering Programs[27]

Forty-one states plus the District of Columbia have adopted NEM programs.

Utility NEM tariffs vary in their treatment of billing credits. Most utility NEM tariffs allow DG production to offset utility purchases on a kWh-for-kWh basis. An issue that separates one NEM program from another is compensation for "excess" production, typically generation that exceeds use within the same month. Most states allow credit for any excess to rollover to subsequent months for up to a year, as shown in Figure 2.7. In other cases, the customer receives credit at the utility's avoided cost—what the utility would pay for energy on the wholesale market. These alternatives are similar to what utilities typically pay if a customer opts to provide power to the utility under a feed-in tariff.[28, 29] Figure 2.7 shows state policies regarding treatment of monthly excess generation under NEM.

Figure 2.7. Customer Credits for Monthly Net Excess Generation under Net Metering by State[30]



The policies for providing customer credits for monthly net excess generation vary widely by state. While some provide credits at retail rates that do not expire, others reduce credits' value over time or impose expiration dates. Some provide credits only below the retail rate, and a few provide no compensation at all.[g]

2.3.6.2 Rate Design and Incentives for Energy Efficiency

Utility revenue collection based on volumetric charges is variable depending on the weather, economic business cycles, and customer energy conservation actions. When customers use less energy, they pay less toward fixed T&D and G&A costs. A utility that relies on volumetric charges has an inherent interest in customers using as much energy as possible to increase the utility's revenues, potentially at the expense of more cost-effective demand management solutions.[31]

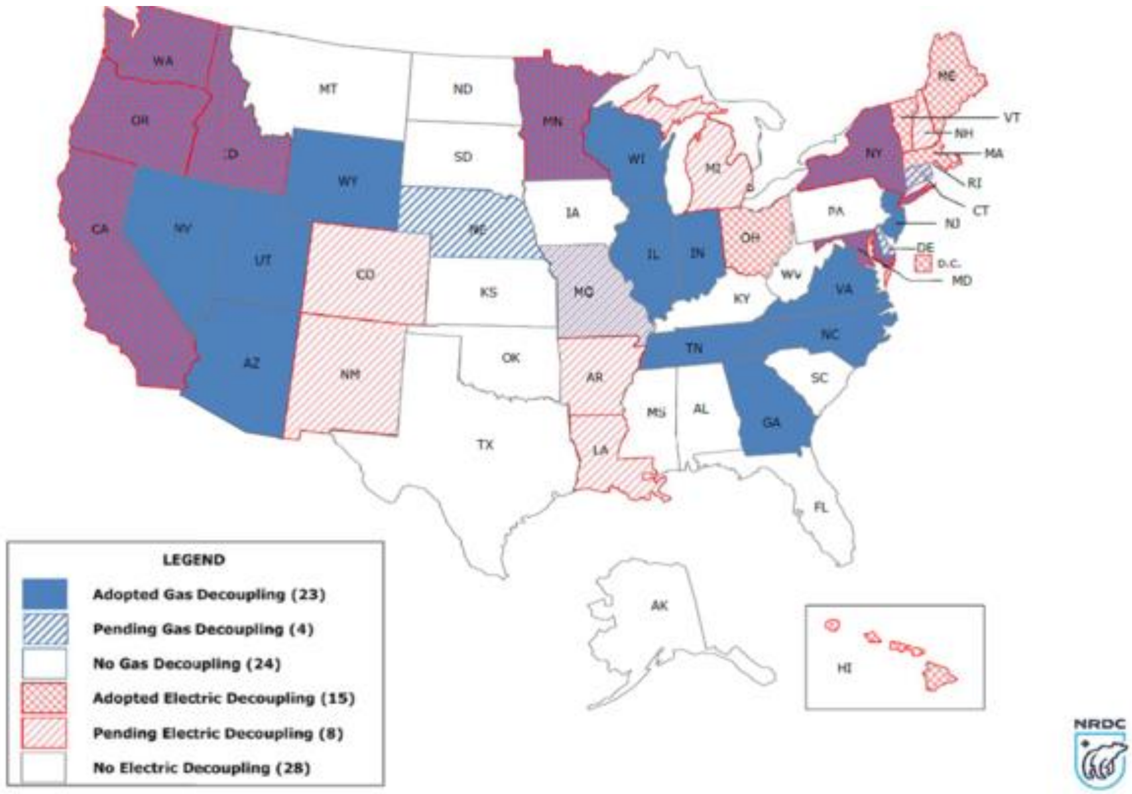
The utility interest in customers consuming more electricity can be addressed directly by decoupling utility revenues from energy sales. Decoupling is a true-up mechanism that adjusts rates between rate cases based on the over- or under- recovery of revenues based on an accepted revenue target. Under traditional rate regulation, there is little oversight of earnings between rate cases. Total revenues are based on actual sales, rather than the sales that were forecasted, which can lead to more or less revenues depending on sales.

In a traditional rate case, the rate is set by determining the revenue requirement and dividing it by the expected sales. With decoupling, rates are re-computed on a regular basis to ensure a utility collects its target revenue based on actual sales volumes. If sales are lower than planned, rates are increased to compensate and vice versa. If designed and implemented correctly, decoupling

[g] Data accurate at time of publication. Some states may have altered policies post publication.

should have the effect of stabilizing the revenue stream of the utility because its revenues are no longer dependent on variable sales.[32] Fifteen states have implemented some form of decoupling for regulated electric utilities, as shown in Figure 2.8.

Figure 2.8. Status of Utility Decoupling State-by-State as of January 2016[33]



Currently, decoupling is not widespread. There are 11 states are engaging in both electric and gas utility decoupling, seven states are engaging in gas utility decoupling, and only five states and the District of Columbia are implementing electric utility decoupling.

Some PUCs favor changing the design of retail rates in order to reduce these utility incentives by increasing fixed monthly customer charges to provide more stable revenues.[34] Others have adopted revenue decoupling mechanisms and performance-based rates that increase the allowed ROR for specific utility investments in demand management.[35] Though increased customer charges reduce utility incentives to increase total sales, this rate design decreases customers' incentives to reduce their energy use by reducing the marginal price of each unit of electricity.[36]

Incentive regulation is similar to decoupling in that the revenues that the utilities earn are at least partly decoupled from sales and tied to meeting performance goals. A utility may earn a higher than normal return, or incentive, by meeting or exceeding some or all of the agreed upon goals. These goals can relate to efficiency measures, generation costs reduction, or other utility financial objectives, among others.[37]

2.3.6.3 Rate Design and Incentives for Utility Over-Investment

The assumption is that the conventional regulatory framework provides IOUs with an incentive to favor capital investments that add to the utility rate base, so as to increase stockholder earnings from the allowed return on equity. For example, utilities may favor owning generation rather than acquiring power from a third party through long-term power purchase agreements or attempt to increase total sales in order to justify additional capital expenses that those increased sales would require. The incentive to over-invest in utility infrastructure was identified in a 1962 paper by Averch and Johnson and therefore is known as the Averch-Johnson effect.[38]

Decoupling and incentive ratemaking do not directly address the issue of utilities potentially favoring their own financing of infrastructure over other options. The most common way regulators have addressed this issue is to require utilities to solicit competitive bids for new generating infrastructure rather than defaulting to making the investment with their own capital.[39] This approach may address the potential for utilities favoring their own investment over alternatives, but it may not address the potential bias for capital investment in lieu of other alternatives, such as demand side management. Integrated resource planning is a common way for regulators to address these potential biases.[40]

2.3.7 Average Utility Rates

The average electricity rate for U.S. customers in 2013 was 10.1 cents/kWh, divided between generation, transmission, and distribution costs as seen in Table 2.4.

Table 2.4. Average U.S. Electricity Rate and its Components for 2013[41]

The table below shows the relatively high cost of generation compared to the costs of transmission and distribution.

	Generation	Transmission	Distribution	Total
Cost/kWh (cents/kWh)	6.6	0.9	2.6	10.1
Fraction of total cost (percent)	65	9	26	100

The cost of power varies by utility type and customer class, as shown in Figure 2.9.

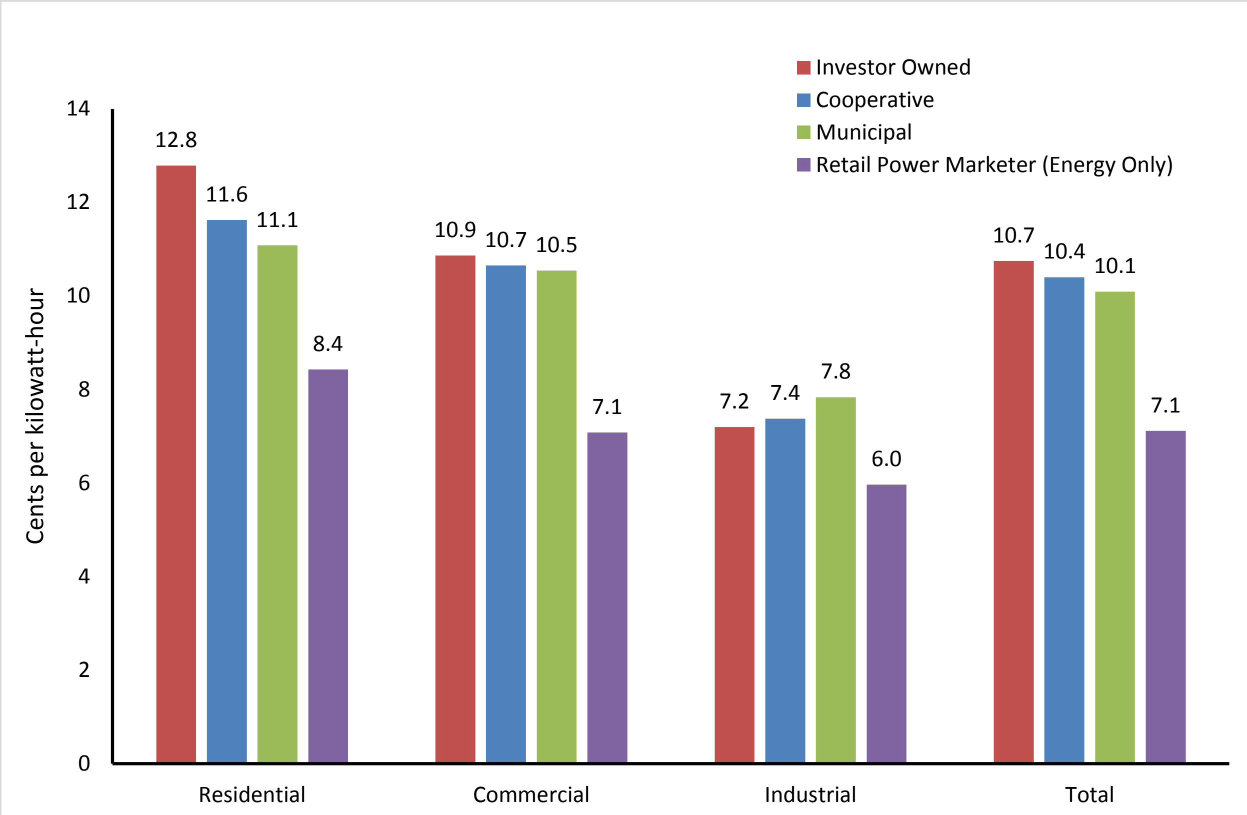


Figure 2.9. Average Retail Electric Rate by Customer Class for 2014[42]

Rates at which different types of utilities charge customer classifications for electricity vary from group to group. Generally, retail power marketers have the lowest rates for all categories.

The rates in Figure 2.9 represent both bundled and unbundled power rates. Bundled rates are shown for investor-owned, cooperative, and municipal utilities and include the cost of generation, transmission, and distribution. Rates for customers served by retail power marketers in unregulated retail markets[h] are shown "unbundled," or energy-only, without the addition of T&D and G&A costs.

Across all utility types and across customer choice states, industrial customers pay the lowest rates, as shown in Figure 2.9. Industrial customers use fewer T&D resources and have lower administrative costs (on a per-kWh basis) than other customer classes, which may explain the cost differential between the three customer classes. Another possible explanation is that utility commissions are allowing rate cross-subsidization on the grounds of economic development or jobs creation that industrial customers can provide.[43]

Figure 2.9 shows that rates for municipal and cooperative utilities are slightly lower than those of IOUs for residential and commercial customers, but higher for industrial customers. Averaged across consumer classes, IOUs have higher rates than municipal and cooperative utilities. IOUs are for-profit entities, so IOU rates include profits as an additional cost. In addition, municipal and cooperative utilities enjoy the benefit of lower financing costs because municipal utilities can issue tax-exempt bonds (i.e., the interest on the bonds is not taxable to bondholder), and

[h] Section 2.3.2 discusses Retail Power Marketers and customer choice further.

cooperatives have access to low interest loans or loan guarantees from the Rural Utilities Service. Moreover, they may not pay federal, state, and local taxes and, therefore, do not need to collect for them in rates. On the other hand, as discussed previously, IOUs may have significant scale economy advantages over municipal and cooperative utilities, which should translate into a lower overhead burden on each unit of electricity sold.

2.4 Distribution System Anatomy

Historically, distribution lines have served a critical, but limited, role within the utility system, delivering power from central generators to customers' power meters within standard voltage ranges. This role is being challenged by the expectations of 21st century utility stakeholders. To put these desires in context, this section summarizes the historic expectations for, and operation of, this critical utility infrastructure.

At the most basic level, the traditional role of local distribution systems is to deliver power to consumers consistent with their demand and expectations for quality and reliability. To do so, power from remote generators is transformed from high-to-low voltage in a distribution substation. The rest of this section adds to this story. Appendix A provides a more detailed discussion; however, for a thorough treatment, one must consult a distribution engineering textbook.

Figure 2.10 shows a diagrammatic overview of a typical distribution feeder circuit. The following system description will discuss key components of this typical system in detail.

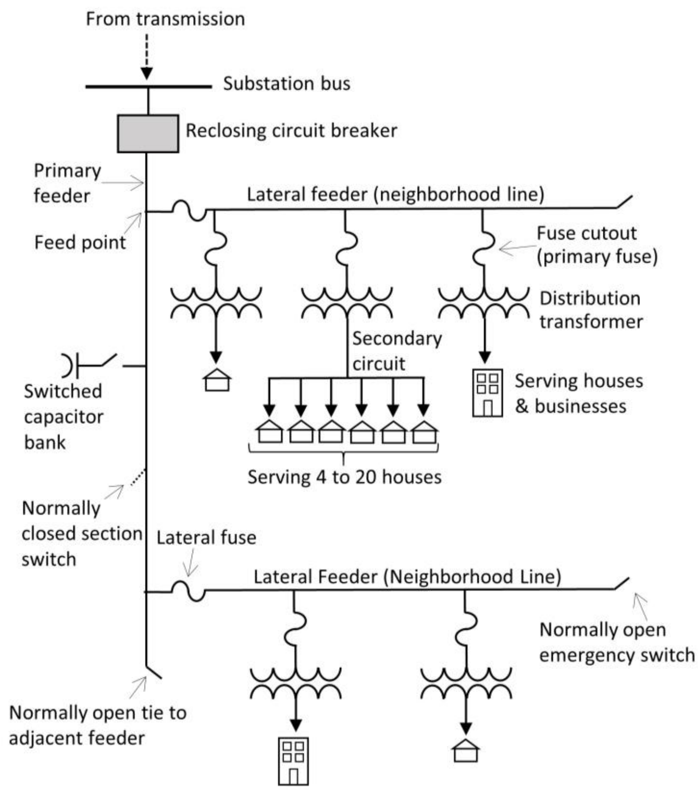


Figure 2.10. Diagram of a Typical Feeder Construction[44]

The diagram above shows the route of a typical distribution feeder circuit beginning with the transmission of power from the substation.

2.4.1 Distribution System Operation

The substation is the intersection of the bulk electrical energy transmission system and the local neighborhood distribution system. Generators deliver electrical energy over the high-voltage (hundreds of kilovolts or kV) transmission network to the substation where a transformer reduces the voltage to a lower voltage (tens of kV). The transportation of electricity results in lost energy, called line losses. The proportion of electricity lost is lower when voltage is higher, which is why transmission systems use high voltages. However, high voltages are not needed to operate most electrical end uses. High-voltage transformers are large and expensive. Accordingly, distribution substations reduce high voltages to a lower voltage more appropriate for power distribution using smaller, lower-cost transformers that reduce the voltage appropriately for use in commercial and consumer equipment.

Alternating current power lines deliver consumer power. The distribution voltage level is high enough to avoid excessive losses in the distribution system wiring, but low enough that the separation and insulation between power lines can be more physically compact compared to the transmission system with its tall tower, wide arms, and dedicated right-of-way. Within the distribution substation, reduced voltage is provided to a common "bus" to which multiple distribution circuits are attached. A recloser provides electrical protection of the substation and feeders; the recloser acts like a household circuit breaker that will automatically trip off if it senses irregularities on the feeder. All customers on that feeder will momentarily lose power. The recloser will turn on again to test if the fault was momentary (e.g., a tree branch or animal causing a short circuit). If the recloser still senses a problem, it will trip off and remain in that state until corrective action is taken. This is what happens when a car or storm knocks down a distribution power pole. It prevents power from continuing to flow to a downed power line as well as from a short circuit damaging substation transformers.

The main distribution wires (circuits) originating in the substation typically contain all three phases supplied by the transmission system, each phase on a separate wire. These wires serve as the main trunk of the distribution system from which smaller branches (e.g., laterals and feeders) can be tapped to serve the full range of consumers (i.e., industrial, commercial, and residential). A lateral runs through a portion of a geographic area or neighborhood to provide service to each customer in that area. Residential and small commercial customers typically require single-phase power. A single-phase lateral can serve these customers to avoid having to use three-phase feeder lines and transformers for every customer. Accordingly, a lateral serving a cluster of residential customers may only tap one of the three phases (three wires) of power on the distribution feeder. The efficiency and quality of power from a distribution line is higher if the load on each of the three phases is balanced. Consequently, the phase for each single-phase lateral is chosen in such a way that the total load on the feeder is roughly balanced across the three phases, despite different customers being serviced by different phases of the feeder.

To service an individual customer, lateral lines are attached to a transformer that reduces distribution voltage to the standard consumer voltage (e.g., 120 V, 240 V, or 480 V). A "service drop" connects the individual customer to this transformer and through it to the entire power grid. It is increasingly common that service to residential structures runs underground from the power pole. If the lateral is already underground, transformation occurs in a pad-mounted transformer on the surface. In dense residential areas, several homes may share the same pole- or pad-mounted distribution transformer. Service to larger customers (i.e., those requiring three-phase service) is similar to that described for a single-phase customer, although power must be transformed from the lateral voltage for each leg (wire) in the service drop for the customer. Underground service to commercial and industrial customers may use an underground vault instead of an aboveground pad-mounted transformer. The last utility connection to a customer is the meter base.

Electricity use varies widely across customers, from a few hundred kWh a month for some households to hundreds of megawatt hours (MWhs) for industrial customers. To facilitate metering of energy use across this range of consumption, power meters are designed to be compatible with a small number of standard meter bases. Current transformers attached to the service drop are used to sense power flowing to the customer. That power flow induces a proportional current to flow to the meter, which is multiplied to reflect the actual power flow. The use of standard meter bases and current transformers for metering has facilitated the development of power meters that can accommodate complex rate designs.

2.4.2 Components of the Distribution System

Consumers may have seen power plants in the distance, but few have visited one. However, most consumers are familiar with how that power travels along tall, high-voltage power lines to their neighborhood distribution substation and then along overhead power lines along the road to their home. At their home, they may see a pole-mounted transformer and a single wire running to their power meter or a pad-mounted transformer in a locked steel case that provides an underground link to the grid. Reliably providing sufficient power to the distribution substation is the responsibility of the bulk power system of central generators and transmission lines. Delivering that power when and where customers need it and with expected reliability and power quality is the role of the distribution system. There are many things that can interfere with this process. Anticipating and addressing potential problems is a part of distribution system design and operation. The most critical of these is ensuring that power to customers is within standard voltage ranges. If voltage varies outside the normal range, a light bulb, for example, may glow too bright, too dim, or flicker and deteriorate too quickly; the light bulb may go dark if there is an outage on the distribution line.

To understand how the distribution system reliably delivers power with uniform voltage, it is necessary to understand the various distribution system components, their role, and how they work together to ensure reliable power delivery. Because visual representations help describe distribution system infrastructure, this section begins with the identification and description of major distribution system components and follows with a description of their operation. This primer will also facilitate understanding of how the smart grid could affect traditional distribution systems and operations.

2.4.2.1 The Distribution Substation and Primary Distribution Circuits

Power enters the distribution substation from the high-voltage transmission system, where it is transformed to a lower voltage to distribute to customers from a bus, or point of common connection for lower-voltage facilities. A lower voltage is used to provide power to customers because the transformers, substation equipment, insulators, lines, and all devices used at the distribution system voltage level are smaller, lighter, and less expensive. Multiple distribution circuits radiate out from the substation bus. There are four common distribution circuit voltages: 4.8 kV, 12.47 kV, 22.9 kV, and 34.5 kV, sometimes rounded to 4 kV, 12 kV, 23 kV, and 34 kV or 5 kV, 15 kV, 25 kV, and 35 kV respectively.

Distribution circuits with different voltages can come from the same substation off different buses. Conductors and transformers for higher-voltage distribution circuits can be more expensive than those for lower-voltage circuits. Consequently, cost is a factor in distribution system design. Nevertheless, higher-voltage circuits may be needed to serve industrial customers because higher-voltage circuits have greater capacity to serve large loads than lower-voltage circuits. Higher-voltage circuits may also be used in areas where growing demand is expected and construction of new, low-voltage distribution lines is difficult. Figure 2.11 illustrates a single three-phase distribution circuit exiting the substation bus. This and subsequent figures use a single line to represent distribution circuits; however, primary distribution circuits have three conductors, one for each phase. Feeders that branch off these circuits to serve a cluster of residences may carry just a single phase.

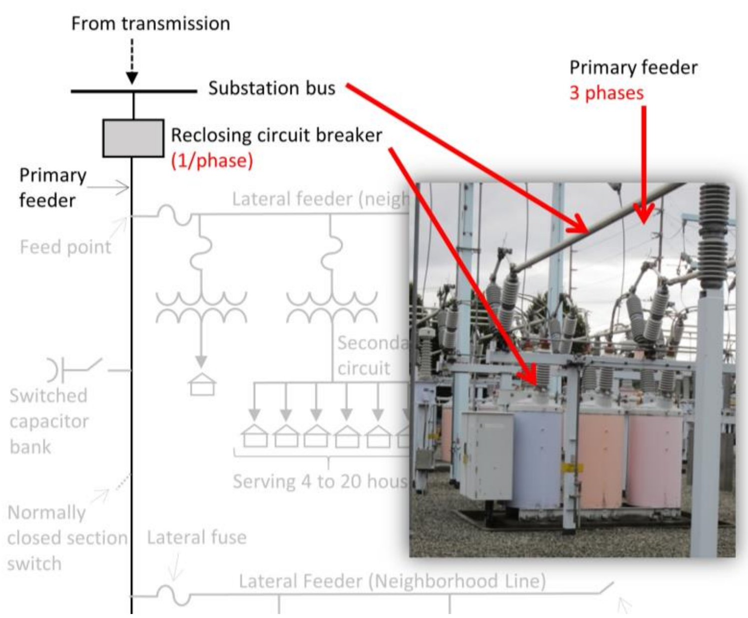


Figure 2.11. A 12.47 kV Distribution Circuit where It Exits the Distribution Substation

This photo illustrates the point in the distribution circuit diagram where the three-phase distribution circuit exits the substation bus.

A three-phase circuit breaker is attached to the line in the substation. Its purpose is to protect the substation in case there is a short circuit, also called a fault, further down the distribution line. This is similar to a household circuit breaker in that it can be reset; it doesn't "blow" like a fuse requiring replacement. The distribution line can exit the substation either as an overhead line or as an underground line.

2.4.2.2 Lateral Feeders from Primary Distribution Circuits

Multiple lateral feeders are attached to primary distribution circuits, as shown in Figure 2.12.

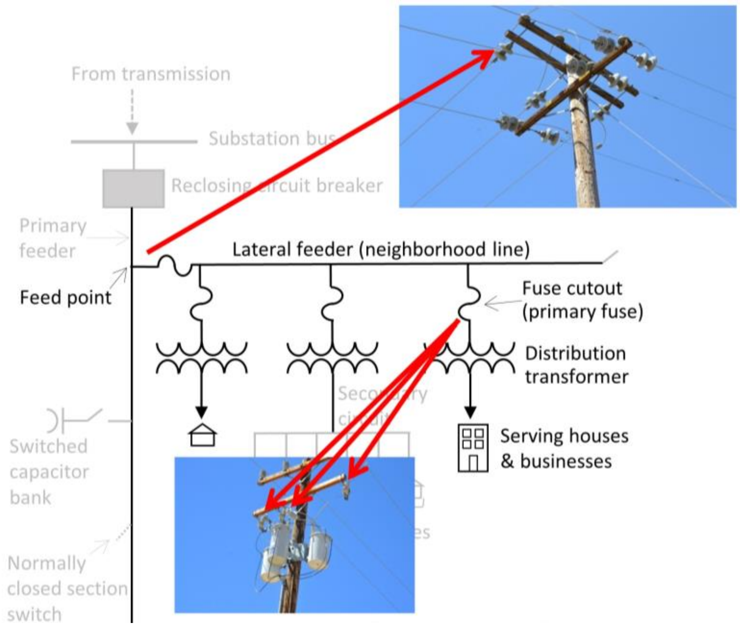


Figure 2.12. Connection between Primary Distribution Circuit and Laterals Serving Customers

This picture illustrates how multiple lateral feeders attach to primary distribution circuits.

Lateral feeders from primary distribution circuits are often transformed to a lower voltage than the primary circuit. Lower voltages require less separation between the bare conductor wires used for overhead distribution lines. The shorter separation distance means cross arms for lower voltage feeders can be smaller and shorter, saving money. Lateral feeders connect to primary distribution circuits with a fuse that provides protection from short circuits or overloads on the lateral from tripping the circuit breaker on the primary line. Similar fuses are used where lines connect to customers.

2.4.2.3 Reclosers

The lateral protection pictured in Figure 2.13 is a recloser-type circuit breaker.

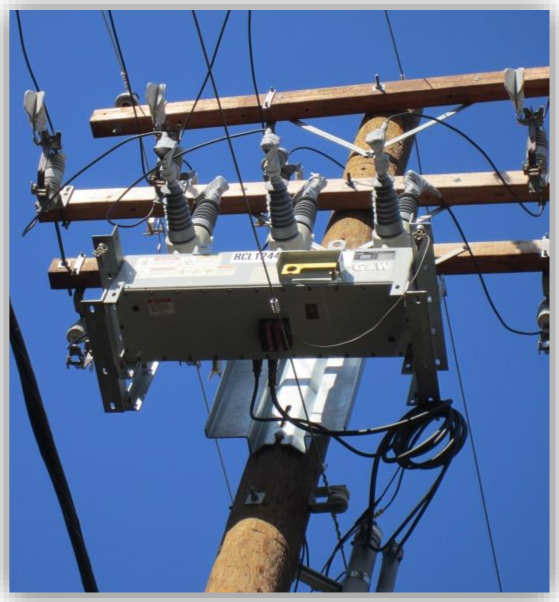


Figure 2.13. Location of Recloser-Type Circuit Breakers on Distribution Lines

This picture illustrates the recloser circuit breaker's location on a typical electrical pole.

In contrast to a regular fuse, when a recloser detects a short circuit, it will open and then reclose. If the fault clears in the interim, it will stay closed, and service to the lateral will continue. This mode of operation reduces power outages in cases where a tree branch momentarily contacts a power line in a strong wind or when a clumsy squirrel touches a grounded item while it is on a "hot" wire.

2.4.2.4 Secondary Circuits

A lateral feeder may serve an entire neighborhood or subdivision. It may include secondary circuits to serve a portion of that area, such as a cul-de-sac or block of townhomes that share a transformer. These circuits may use only one of the three phases. This transformer may be mounted on the overhead pole with individual service drops going to each individual address and meter, or it may be mounted on a pad on the ground so individual service lines can run underground to customer meters, as shown in Figure 2.14. Customer service lines are single phase unless they serve commercial and industrial customers.

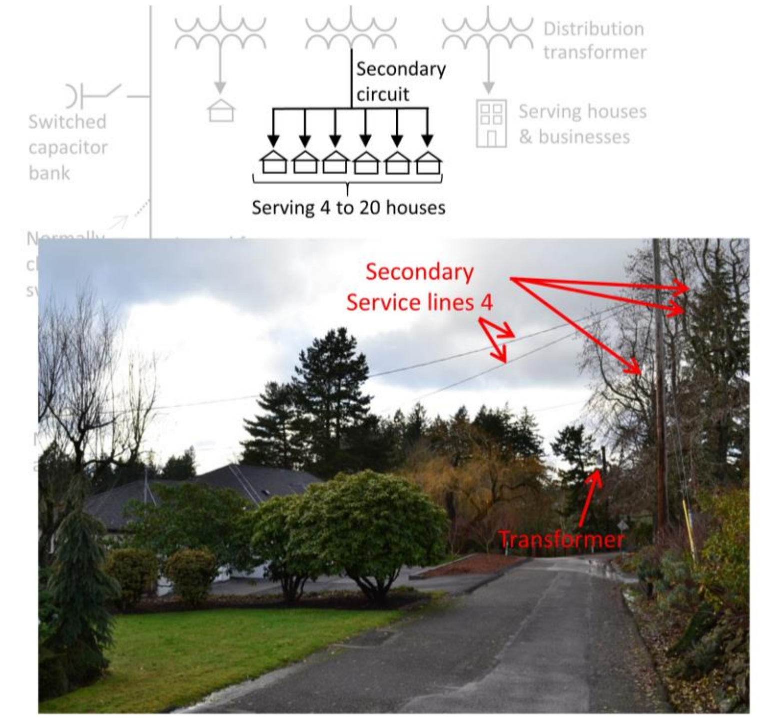


Figure 2.14. Secondary Circuit Serving Adjacent Houses or Townhomes

The distribution transformer serving this circuit is fuse protected as indicated in Figure 2.12.

2.4.2.5 Capacitors

Electricity-using equipment utilizes a combination of real and so-called imaginary power. Purely resistive loads, such as electric heaters, ranges, and water heaters only use real power. Inductive loads, including most motors and anything with a transformer, create magnetic fields that are out of phase with real power. Out-of-phase power still places demand on the electrical grid; however, it doesn’t register on a conventional power meter, hence the imaginary label. This presents two problems. First, the additional load on the power grid must be managed, typically by “correcting” it, using capacitors. Second, users of large motors may use energy they aren’t paying for. Conventional power meters can register this power if they are coupled with phase-shifting transformers.

Induction motors change the phase angle of the power (from real power to apparent power, known as power factor) such that it must be corrected. Capacitors can be used to correct power factor. Banks of capacitors can be attached to distribution circuits or laterals, as shown in Figure 2.15. These may be always on (static) or switched depending on the source of the reactive power, such as an industry working only a single shift versus all day.

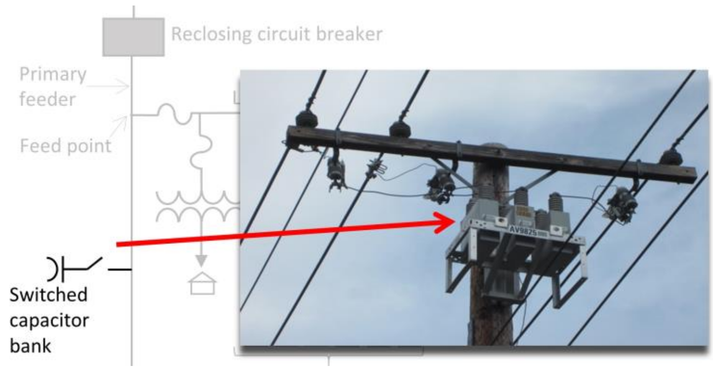


Figure 2.15. Interconnection of a Switched Capacitor Bank to a Distribution Circuit Line

Banks of capacitors can be attached to distribution circuits or laterals.

2.4.2.6 Sectionalizers

Distribution lines may radiate out from a substation and terminate. These are called radial lines. Distribution systems can also be planned so lines can connect at the terminus forming a loop with the distribution substation. This may form a network of interconnecting distribution lines over a wide area or, in dense urban environments, within a single block or even a single high rise building. This connection is made with a sectionalizing switch. During normal operations, the switch is in normally open or normally closed position, and power flows along each line as designed, as shown in Figure 2.16. However, if there is a fault on one line, a normally open switch can be closed to allow power to flow past the normal terminus of the distribution feeder onto the adjacent feeder. If the fault is on a circuit between the substation and the terminus of that circuit, the fuse or circuit breaker on the circuit will open and power to that line will be lost. In that case, a sectional switch that is normally closed can be opened and a sectionalizing switch on an adjacent, networked circuit can be closed to provide power to the first circuit up to the location of the now open sectional switch on the first circuit. This reduces the number of customers on the circuit experiencing the fault that will be without power.

Historically, a lineman manually operated sectionalizing switches; however, they can be replaced with automated switches that operate based on sensors and are logic controlled with wireless or fiber optic communications systems. These systems are often called supervisory control and data acquisition (SCADA) systems. Sectionalizing switches are not needed on radial distribution lines, because they do not connect to adjacent distribution circuits. Although data on distribution circuit configurations are difficult to find, radial circuits are presumed to be the most common configuration as a legacy from early electrification of non-urban areas.

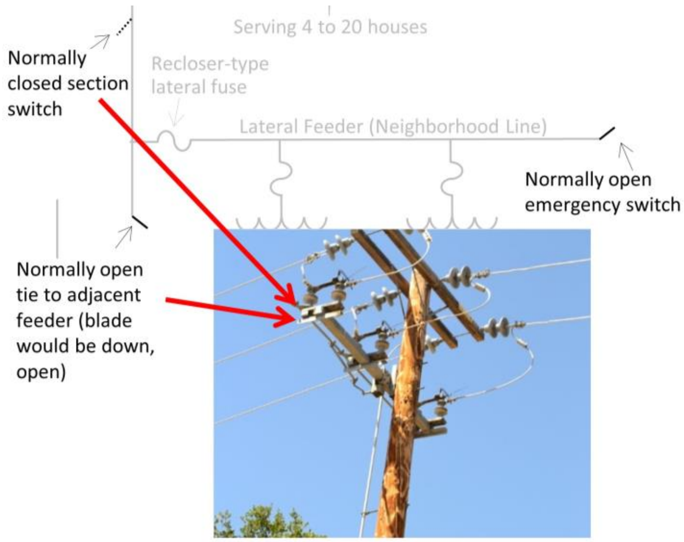


Figure 2.16. Sectional Switches on Circuits Can Be Normally Open or Closed

Under normal circumstances, the switch is in the normally open or normally closed position, and power flows along each line.

2.5 Distribution Power Management

Management of power flowing to customers over the distribution system historically was governed largely by rules of thumb. The primary objective was to ensure voltage remained within the standard range established by the American National Standards Institute (ANSI) as ANSI C84.1, as shown in Table 2.5.

Table 2.5. Sample Utility Engineering Reference to ANSI Voltage Standard for Utility Service to Retail Customer Delivery Point[45]

The table below exemplifies minimum/maximum voltage standards per ANSI based on the type of wire used.

Nominal Service Voltage	Range B Minimum	**Range A Minimum**	**Range A Maximum**	Range B Maximum
		Single-Phase		
120/240, 3-wire	110/220	**114/228**	**126/252**	127/254
		Three-Phase		
240/120, 4-wire	220/110	**228/114**	**252/126**	254/127
208Y/120,4-wire	191/110	**197/114**	**218/126**	220/127
480Y/277,4-wire	440/254	**456/263**	**504/291**	508/293
2.4 to 34.5 kV % of nominal	95%	**97.5%**	**105%**	105.8%

Voltage standards are necessary because voltage decreases over the length of a power line, both due to line losses and to use by customers along the line, as shown in Figure 2.17.

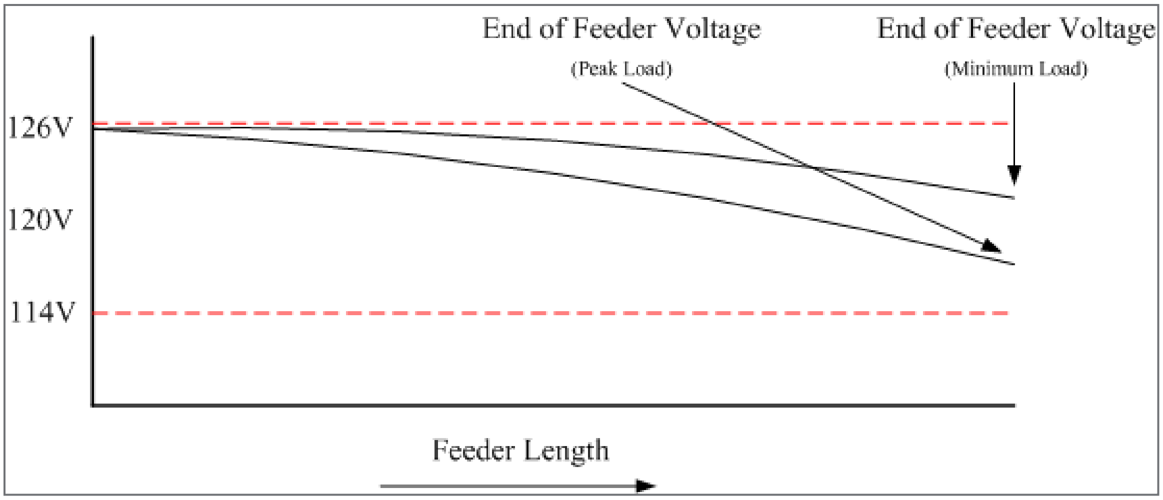


Figure 2.17. Voltage Decrease Over the Length of a Distribution Feeder[46]

This graph shows the correlation between peak and minimum loads and the decrease in voltage as the distribution feeder's length increases.

Service voltage is required to be within the range of 114 V and 126 V for a single-phase customer. Increased use by customers on the line (peak load) causes voltage to decrease, or sag, more than when use is light. The challenge for distribution system operation is to ensure voltage during heavy-use periods is above the minimum voltage for the last customer on the line, but not so high that the customer closest to the substation has voltage over the limit, especially during periods when demand is light. Both over- and under-voltage can reduce the life of consumer equipment. Typically, voltage is regulated at the substation. Substation voltage regulators can be adjusted for heavy and light load periods to maintain voltage standards using a power transformer device called a tap changer, as shown in Figure 2.18.

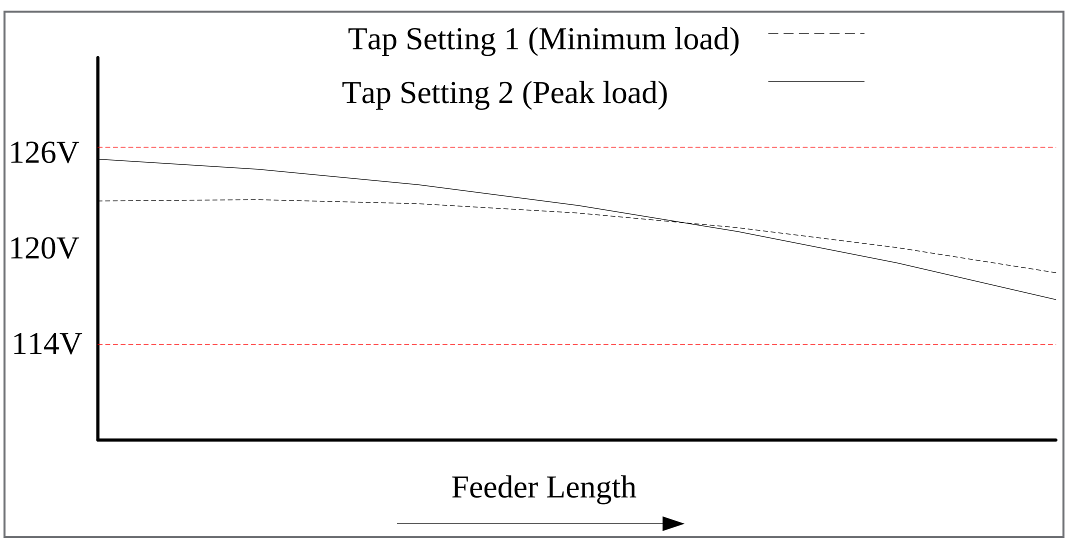


Figure 2.18. Illustration of Two Regulator Tap Changer Settings to Manage Voltage Sag during Peak and Minimum Demand Periods[47]

Tap changers can adjust substation voltage regulators for heavy and light load periods to maintain voltage standards.

If voltage cannot be regulated satisfactorily at the substation, it will be necessary to adjust voltage downstream, using voltage regulators or changing transformer settings, as shown in Figure 2.19.

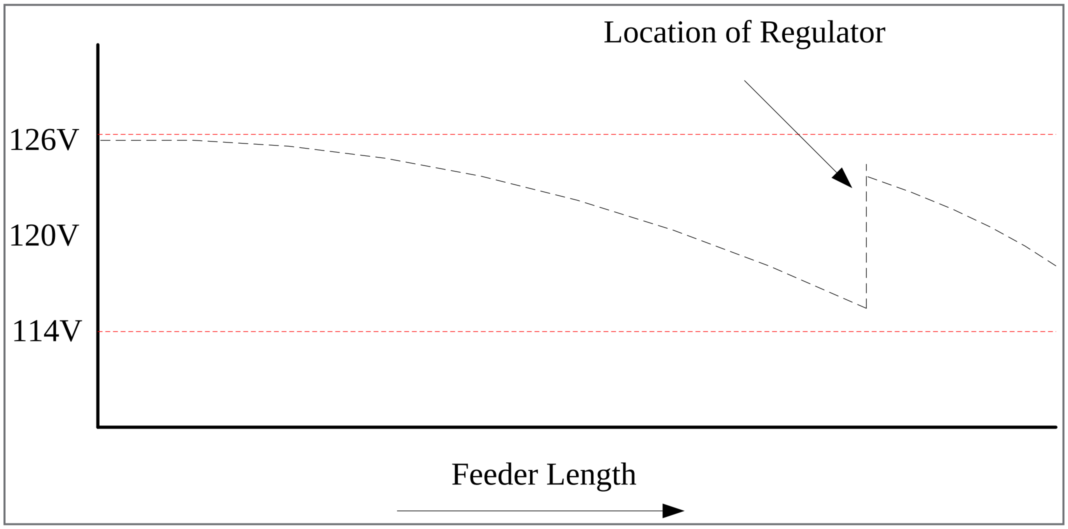


Figure 2.19. Illustration of Voltage Regulation on a Feeder with Voltage Sag Outside of the Standard Range[48]

Using voltage regulators to adjust voltage downstream is necessary if voltage cannot be regulated satisfactorily at the substation.

Providing higher-than-necessary voltage to customers requires additional power generation and therefore is inefficient. Voltage can be regulated more effectively if power system managers are able to monitor voltage in real-time. This kind of situational awareness is superior to traditional rule of thumb practices, but requires sensors on the distribution system and a communication network to report system status and to control voltage regulators and other power quality control devices. Supervisory control and data acquisition systems (SCADA) are deployed to provide this kind of monitoring and control.

Historically, few substations were connected to real-time SCADA systems. The lack of instrumentation in the feeder was primarily driven by cost because comprehensive instrumentation and communication systems are expensive to implement and produce large amounts of data that must be managed and consulted routinely to provide value. Until recently, most utilities had staff responsible for managing substation operations. Most substations are now unmanned, and the need for remote monitoring for safety, as well as for efficient operation, has increased the deployment of SCADA at the substation level; this includes the automation of operations that previously required manual control. A 2005 survey indicated that about 70 percent of utilities had deployed SCADA systems to substations and 84 percent of utilities had substation automation and integration plans underway.[49]

Outside of the substation, equipment controlled by SCADA can include voltage regulators, reclosers, and switched capacitors. In most cases, the state of this equipment, along with the substation instrumentation, facilitates a reasonable estimate of the state and condition of the substation circuits; however, a substation-only view has limitations. Faults and equipment failures on distribution circuits may not be able to be localized with any great precision based on SCADA data. Preventable failures and faults based on equipment health may not be included in the SCADA data set. In the past, failures of equipment that affect only a few customers may not have made a significant enough difference to the general system to be noticed, although that is no longer the case. Widespread penetration of AMI can provide system operators with near real-time notice of abnormal distribution system conditions, such as voltage swings or outages. This can shorten response times to address these issues and reduce the number of customers affected by outages and outage duration. Distribution management systems (DMS) that encompass downstream voltage regulators, capacitors, and sectionalizers provide the ultimate in control. These allow system operators to redirect power flowing through looped or networked distribution lines to isolate faults and minimize the number of customers affected as well as the duration of any outage.

2.5.1 Indicators of Reliability

The Institute of Electrical and Electronics Engineers (IEEE) has developed metrics to measure and monitor system reliability from a customer perspective. One of these is the system average interruption duration index (SAIDI), which is an aggregate measure of the number of minutes a customer is without power for each interruption. All interruptions are summed to derive an annual index. IEEE has used this index to benchmark utility outage rates over time, as shown in Figure 2.20.

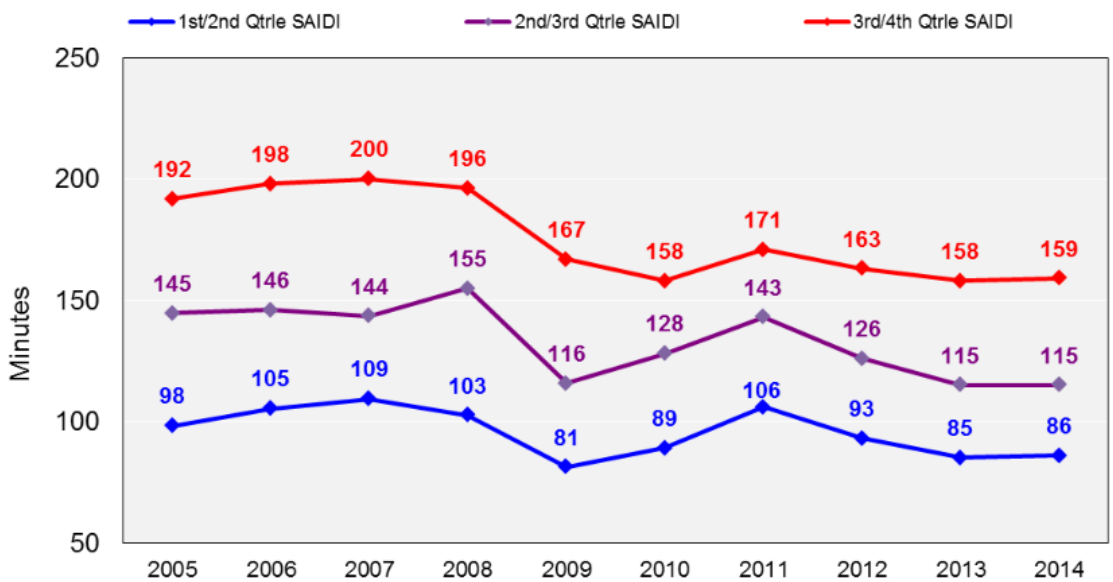


Figure 2.20. IEEE SAIDI Benchmarks by Utility Performance Quartile, 2005–2014[50]

This shows benchmarks in minutes for the first through fourth SAIDI quartiles from 2005 through 2014.

For reference, the total minutes of outage is equivalent to what utilities commonly refer to as reliability and is expressed as a percentage. Two hundred minutes of outage over a year is equivalent to 99.96 percent reliability. Outage time of 150 and 100 minutes are equivalent to 99.97 percent and 99.98 percent respectively. Most IOUs claim 99.9 percent reliability or better.[51]

Although IEEE cautions against drawing conclusions about trends from the data due to changes in utility survey participants from year to year, Figure 2.23 shows a gradual reduction in outage rates over the benchmark period. Detailed data from the IEEE report indicate large utilities (more than 1 million customers) have lower outage rates than smaller utilities and their year-over-year improvement is less significant. On the other hand, the trend for medium and small utilities is significant. Coupled with the SCADA survey trend noted previously, this suggests that as more medium and small utilities deploy SCADA and similar systems, outage rates improve.

2.6 Losses in Electricity Distribution Systems

Electricity is lost as it flows from generation to end use. Up to 6 percent of electricity is consumed as loss in the system, with the majority of the losses attributed to the distribution system.[52] EIA collects data on system losses, but only reports cumulative transmission and distribution losses.

2.6.1 Losses in Distribution Lines

Overhead and underground distribution lines have different physical properties that lead to distinct loss mechanisms. Loss mechanisms, and opportunities to reduce loss through those mechanisms, include conductor losses, dielectric losses, reactive current losses, and sheath losses.[53]

Conductor losses include ohmic loss from resistive heating of the cable, skin effect losses caused by electrical current concentrating on the surface of the conductor, and proximity effect losses formed by magnetic fields on one conductor influencing the charge carriers in an adjacent conductor. These are the predominant cause of losses in overhead distribution cables. A common solution is to use copper for wires instead of aluminum, though copper is substantially more expensive than aluminum.[54]

Underground cables use dielectric materials for insulation, while overhead cables often use the air as insulation. Dielectric materials can cause a small current loss in the line, called dielectric loss, but they are often small enough to be considered negligible.[55]

A reactive current is caused due to the capacitance between the conductors and the sheath of underground wires, and also contributes to losses. While these losses are small for short cables, the reactive current and the losses that result can be mitigated using reactors—an inductive element placed in parallel with underground cables— in longer cables.[56]

The magnetic field of the phase conductors in underground cables induces eddy currents within the moisture-blocking outer casing, called the sheath, that result in sheath losses. These are considered minimal and unavoidable.[57]

2.6.2 Losses in Power Transformers

Transformer losses are the single largest cause of losses in the distribution system. DOE regulations exist to reduce the roughly 2 percent loss rates of distribution transformers, and they are expected to save 3.6 quads of energy over 30 years starting in 2016. There are two types of transformer losses. Load loss is proportional to the load on the transformer, and mainly relates to resistive losses in the internal cables and eddy currents. No-load losses are caused by the eddy currents induced by the magnetic core of the transformer.[58]

2.6.3 Additional Opportunities to Reduce Distribution System Losses

Distribution automation collectively refers to several operational approaches to reducing distribution losses. Despite the opportunities that these approaches present, they are currently not widely adopted due to inadequate command and control infrastructure in distribution systems.[59]

Load management, or the reduction of peak loads by active or passive load control, is a long-standing approach to reducing generation needs and is increasingly relied upon for targeted loss reduction in transmission and distribution systems. Demand response and DG can both contribute to reduced system demand, thereby reducing load-related distribution system losses.[i][60]

System reconfiguration, or changing the topology of the distribution system in real time, can alleviate load on a heavily loaded line and necessitate the use of larger distribution lines that have inherently lower losses. However, this requires significant investment in system management assets and control systems.[61]

Load balancing ensures that each of the three phases of the distribution feeder are equally loaded. System losses from unbalanced phases occur in the transformers and are exponentially proportional to the percentage of the phase imbalance. Reducing phase imbalances lowers transformer losses and reduces resistive losses along the neutral wire that becomes inadvertently loaded in an unbalanced feeder system.[62]

Losses are inversely proportional to voltage level of the line: higher voltage lines have lower losses compared to lower voltage lines carrying the same amount of power. Though the low voltage side of transformers is required to be kept to either 120 V or 240 V, the voltage level of the higher side of the transformers are often unregulated. Increasing the voltage of these lines would reduce total system losses.[63]

There are several solutions to reducing the myriad losses that occur at the distribution substation. One primary approach to reducing substation-related losses is to locate the substation closer to the end-use load, thereby reducing the resistive losses associated with long cable lengths between the substation and load. Gas-insulated substations have smaller footprints and are easier to locate in small locations close to load than air-insulated substations.[64]

Low-power factors for end-use devices, or the ration between real power and apparent power, increase system losses associated with reactive power. Most utilities include a surcharge or adjustment to the bills of large industrial customers to account for the losses caused by uncorrected power factors. Residential and commercial customers are usually not charged for their impact on power factors. Appliances that use motors are the main source of distorted power factors, though new appliances are designed with power factor correction technology or added capacitance to reduce the reactive current.[65]

Conservation voltage reduction (CVR) uses automated distribution technology to actively lower voltage levels to improve efficiency on distribution lines. Voltage management techniques, including CVR, are discussed in more detail in the appendix, Section A.1.3.

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[i] Demand response may also include actions that increase net load, electric vehicles or commercial ice storage are two examples.

2.7 Distribution System Planning

Distribution systems are planned to accommodate demand growth both from a larger number of customers due to population growth and from increased use per customer from new electricity uses. Greenfield planning for distribution lines, or planning for completely new construction in an area without existing electricity distribution facilities, is less common than planning for changes to the existing system. When new lines are planned, they are designed to serve customers anticipated to occupy that service area, such as new plants in industrial parks or residential subdivisions with associated commercial centers. The distribution services required by each class of customer are anticipated based on historic experience and utility studies of customer class energy use profiles used for setting utility rates.

2.7.1 Serving Customers

Utilities typically divide customers into three classes based on patterns of use, service voltage, and other characteristics.

Residential customers are typically provided with 240/120 V service from a local distribution feeder. Their use tends to be dominated by ambient temperature-sensitive loads, (e.g., heating, cooling, and water heating) and they follow a similar use schedule of high demand in the morning and evening with lighter demand during the daytime. Service is typically provided via overhead wires to a pole-mounted service transformer. Newer developments and subdivisions may require underground service, in which case individual buildings may be served from a pad-mounted transformer on the ground. Per-customer consumption estimates are derived from utility records and other sources and used to predict near- and long-term demand on distribution infrastructure.

Industrial customers can be defined by function (e.g., manufacturing) or scale of electricity demand. They are typically large electricity users and often require dedicated service facilities or are in areas developed or zoned for industrial use that are served with dedicated facilities directly off a transmission or distribution substation. Very large industrial firms are served off the transmission grid rather than through the distribution system and typically transform and distribute power within their facility. They may also employ combined heat and power (CHP) or other power-generation equipment. Industrial loads tend to be fairly constant during the day and annually.

Commercial customers fall in between residential and industrial based more on function than usage. Retail storefronts can use less electricity than an average home; however, an office building may use as much as some residential feeders. The commercial load profile is typically characterized as daytime and weekday with winter heating demand in the morning and summer cooling in the afternoon.

The distribution planner uses these customer class electricity usage characteristics to estimate the number, size, and class of customers and associated demand for wholly *new* distribution facilities. A reserve for future growth is included, and facilities are sized and sited accordingly. Planning for additional loads in an *existing* distribution network uses similar customer demand profiles in conjunction with historic use patterns on current circuits or feeders. Projections of future demand are used to determine if customer needs can be met by shifting customers from one line to another or if a new line must be built. In either case, a transmission interconnection study may be required to evaluate how additional demand interacts with the available transmission network.

Planning for distribution facilities is typically predicated on standardized designs for equipment, components, lines, and substations. The use of uniform materials and standard demand assumptions leads to “by the book” distribution design and operating procedures. It also reduces distribution costs and complexity, which are assets during outages where repair materials can be retrieved from stockpiles of spares and restoration crews from other utilities who are familiar with those materials can be recruited to accelerate service restoration. This conservative approach may delay adoption of innovative solutions, at least until they become generally accepted practice. This is reflected in a saying within the utility research community that even progressive utilities prefer to be “the first to be second.”

2.7.2 Service Area Planning

Distribution assets are a significant fraction of a utility’s infrastructure investment and operating expense; therefore, cost minimization is essential to keep retail rates at reasonable levels. This is reflected in differences in how distribution systems are planned, constructed, rebuilt, and maintained across rural, urban, and suburban utility service areas.

The least costly way to extend power distribution to customers on a per-circuit-mile basis is at a low-distribution voltage using overhead lines. A lower voltage (e.g., 14 kV) requires less spacing between each feeder line and obstructions on the ground. That translates into smaller conductors, shorter power poles, and smaller cross arms—all of which reduce cost versus service at higher voltage (e.g., 34 kV). This is an advantage in areas where customer density is relatively low (e.g., rural areas). In contrast, providing distribution services in urban areas is challenged by the lack of right-of-way access, more highly concentrated power demand in small areas, and interference from urban structures (e.g., buildings, traffic signals, overpasses, and railroad and transit lines). Higher distribution voltage is often a lower cost option in this environment due to the higher density of customers per circuit mile. The service voltage decision depends on the area served, number of customers, growth expectations, and customer requirements, with initial cost and future O&M cost being primary considerations.

Overhead lines are common in towns and villages and for serving rural communities. With overhead lines, construction and maintenance are less expensive, faults and damage are easier to find, and air circulation naturally cools conductors and pole-mounted transformers thereby reducing the chance of thermal overloads. However, accessible poles and overhead lines increase the number of distribution outages due to vehicular accidents, animal-related short circuits, and storm damage from falling tree limbs and flying debris.

Low customer-density feeders are generally radial in layout and rarely have connections to other feeders. In those cases where interconnection with other feeders is an option, the radial lines typically have open sectionalizers or fuses to allow power transfers from one feeder to the other for line maintenance or to reduce outage duration. Where there are heavy loads some distance away from the substation, a three-phase mainline is often run directly to the area of those loads, with laterals to nearby homes or businesses. There is still another scheme for higher reliability that can be used for critical loads (e.g., hospitals) called the primary loop. A primary loop is routed through each critical customer transformer so the customer can still be fed from the substation by reconfiguring switches. These loops can also improve service with regard to momentary interruptions or voltage sags.

Areas with high density of customers or demand—typically urban areas—are more likely to have distribution circuits that are placed underground in a meshed, or networked, configuration. Instead of overhead wires, feeder cables are buried or in concrete conduits underground. Transformers and switches are in underground vaults or building basements and typically connect to other feeders using sectionalizing switches to form a mesh so that power can be fed to loads through multiple paths (i.e., to different substations, different feeders, and circuits). These systems are complex and expensive to maintain and, because they are difficult to expand, may be subject to overloading when met with unexpected load growth. Network protectors provide fault protection on the primary circuits, so as to limit outages to the minimum number of customers possible if there is a failure. High-rise towers may be served vertically, with multiple feeders networked so that an outage of one will not lead to a whole building outage. Most central city loads tend to be commercial with residential uses increasing with the expansion of mixed-use development.

Suburban areas use a mixture of overhead and underground distribution systems. Underground distribution systems with pad-mounted transformers and switchgear are often installed where aesthetics are valued. In those cases, it is common for developers to bear the additional initial costs. Underground systems are less vulnerable in certain storm situations and may be required for those reasons. The cost of moving an overhead system to underground burial in concrete-encased ducting can be three to four times the cost of overhead line construction, as shown in Figure 2.21.

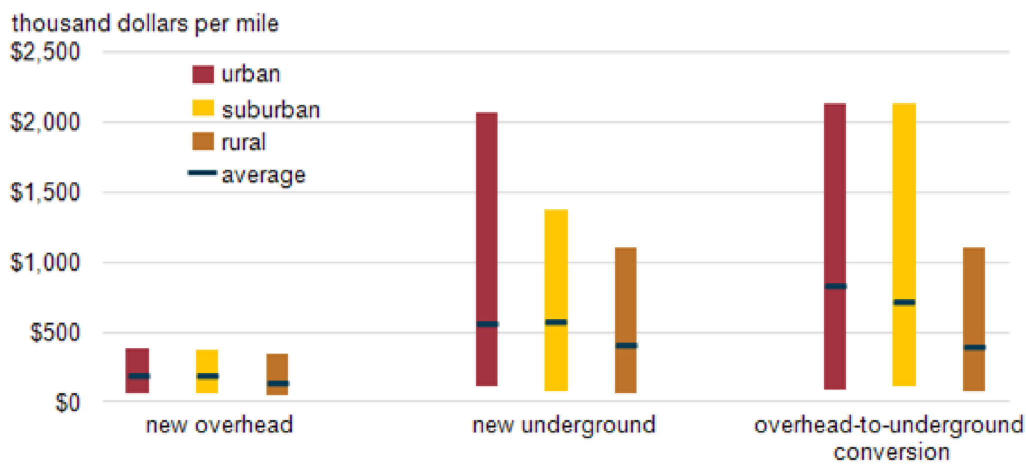

Figure 2.21. Cost per Mile for Distribution Lines: Overhead versus Underground[66]

This bar graphs shows the cost in thousands of dollars per mile for new overhead lines, new underground lines, and the conversion of overhead to underground lines.

Underground distribution facilities have benefits in terms of reduced outages from storms and vehicular accidents and reduced vegetation-management costs; however, fault detection and repair times are generally longer and more costly. Cost-benefit analysis for overhead transmission versus underground transmission can be complex and politically charged depending on the state, regulator, and funding entity.[67]

3.0 Toward a 21st Century Utility

Utilities, regulators, customers, technology providers, and research institutions, including the U.S. Department of Energy (DOE) through its grid modernization and *Quadrennial Energy Review* (QER) programs are all anticipating a different kind of utility that will meet customer needs in the 21st century. Several projects seeking to define the future utility are shown in Figure 3.1.

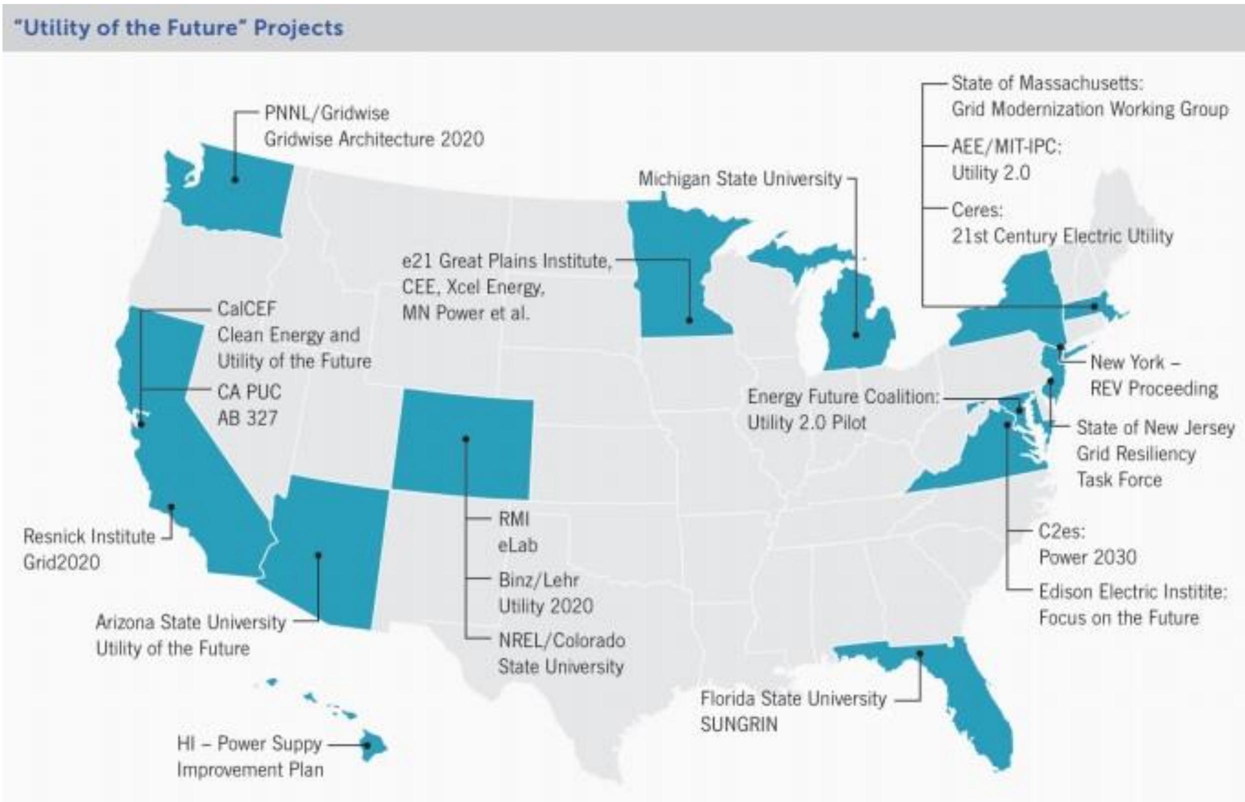

Figure 3.1. Sample of "Utility of the Future" Studies across the United States[68]

This map highlights specific projects looking to define the future of the electric utility being completed by states across the country from the West Coast, to New England, and all the way to Hawaii.

Visions for the future utility vary widely; however, they are all based on a perceived need for some or all of the following improvements:

- Efficiency, in terms of energy production, use, and retail procurement
- Sustainability
- Resilience
- Customer choice.

These benefits are expected to be achieved through innovation in both technology and regulation enabled by smart grid infrastructure. The expectation is that both utilities and customers will collaborate to meet future power requirements through increased penetration and use of distributed energy resources (DER). DER include conventional energy efficiency (EE) measures, demand response (DR) actions, distributed generation (DG), and distributed storage (DS) including storage in electric vehicles. Generally, DER is expected to be deployed in strategic ways to supplant grid-supplied energy and energy services, thereby optimizing use of bulk power resources including central generators, the transmission grid, and local distribution line capacity.

Implicit in this expectation is that the grid will be populated with sensors that communicate grid conditions in a manner that allows utilities, energy service providers, and consumers to make decisions in real time that optimize energy production and delivery. Metering devices are already providing some of these grid sensing technologies: automated meter reading (AMR) electricity meters can transmit energy by time-of-use one way to the utility, and more advanced metering infrastructure (AMI) permits two-way communication with the potential for remote control of customer end-use equipment.

The roadmap leading to this new utility is unclear and the timeline even more so; nevertheless, utilities and regulators have adopted policies, implemented changes in tariffs, launched demonstration projects, and taken other actions to progress along this path. Whatever route is chosen, significant changes will be required to the physical distribution system, distribution planning, and operations to enable integration of DER. This chapter discusses some of these changes.

3.1 Changes to the Physical Distribution System

Figure 3.2 provides a smart grid perspective that is compatible with the previous discussion of the physical distribution system in Section 2.4.

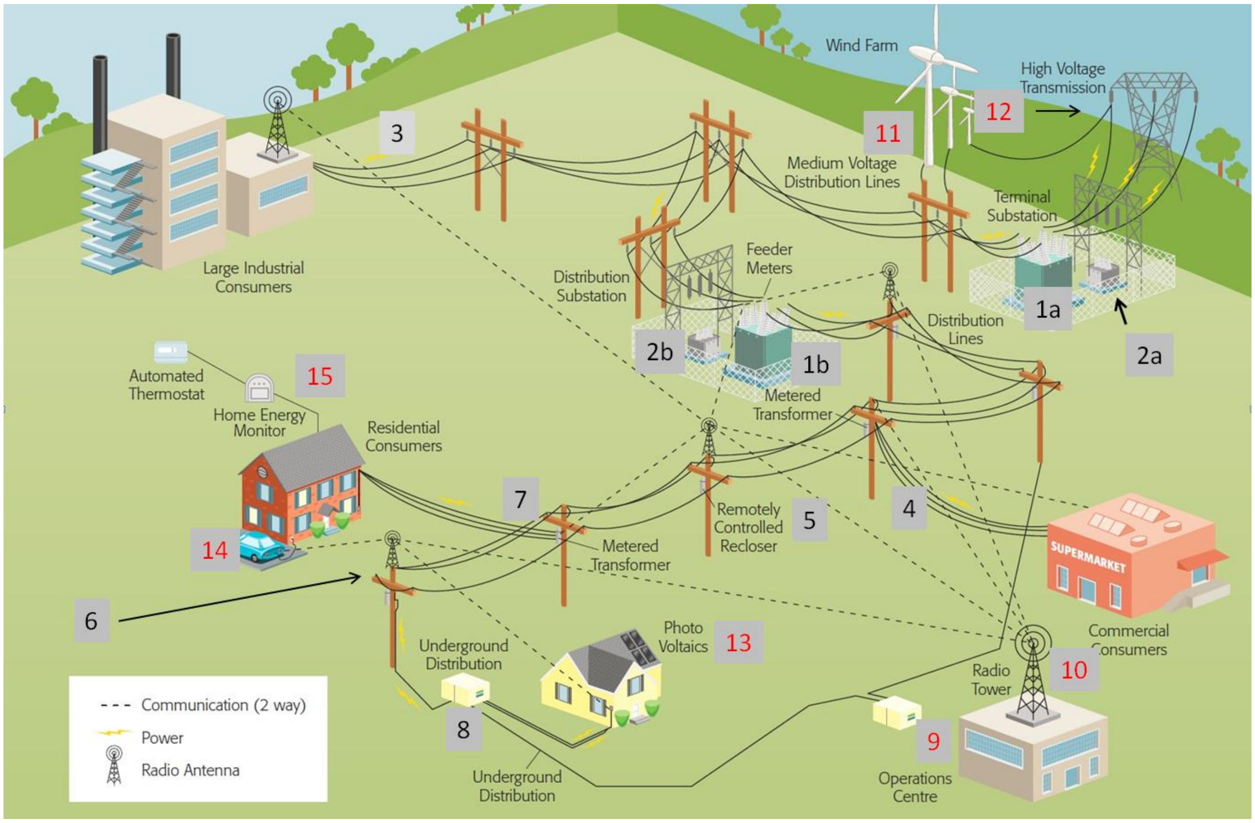

Figure 3.2. Conceptual Schematic of 21st Century Utility Distribution System Topology[69]

The illustration includes all end users of the distribution system, including residential, commercial, and industrial users.

The major components of this 21st century distribution grid include familiar legacy infrastructure.

- Power is supplied to the distribution system from the High Voltage Transmission system (1a) to the Terminal Substation where it is stepped down to medium voltage for distribution to large, high-voltage customers and to area substations serving low-voltage customers via Distribution Substations (1b). Voltage regulators and capacitor banks would be located in the substation yard as well as along feeders with sensitive loads and high penetration of DER (2a and 2b).
- The large industrial customer has three-phase service directly at medium substation voltage (3).
- The commercial customer has three-phase service off the low-voltage distribution circuit (4).
- A recloser mounted on a power pole can sectionalize the residential customers from the commercial customer in case of a fault in the residential area (5). A second recloser on a

feeder from off the page can be used to provide service to the residential area and through it to the distribution substation in case this circuit is out of commission (6).

- The first residential customer is served off the low-voltage feeder via a pole-mounted transformer and overhead service drop (7). The second residential customer is served via a pad-mounted transformer on the ground (8).

The legacy system is transformed to serve 21st-century customers through the addition of smart infrastructure and a proliferation of DER.

- At the core of this smart grid is an operations center (9) and distribution system supervisory control and data acquisition system (D-SCADA) coupled to a central communications system—in this illustration, using radio signals (10). This enables two-way information flows among customers, customer meters, and control infrastructure on the grid, including the recloser, voltage regulators, tap changing transformers, and capacitor banks noted in Figure 3.2.
- Distributed renewable generation, such as distributed wind systems (which tend to use smaller turbines) and photovoltaic (PV) arrays, are connected to the distribution grid (11). Utility-scale renewable energy systems connect directly to the transmission system (12).
- Micro-scale distributed generators, like rooftop PV arrays, connect to the distribution system through the same lines serving their host customer (13).
- Energy storage systems, some in the form of electric vehicles (14), also connect through the host customer service drop.
- Among customers, there are home area networks (HAN) that control end-uses and thermostats that can be addressed over the communication system to regulate end uses to provide demand response or reduce the cost of power by shifting the use schedule and provide needed ancillary services to the utility grid in some cases (15). A few utilities provide HANs to customers as part of their AMI system; however, many more customers have purchased individual smart devices that can be organized behind a customer-owned HAN.[70] The Nest thermostat is a recent example.

The 21st century utility system will distinguish itself from the legacy 20th century system by its ability to interact with grid components responsible for maintaining voltage and reliability and for the ability of end users to interact with the bulk power system to provide energy and ancillary services that would otherwise come from central generation and transmission. This is expected to result in increased efficiency and resilience and reduced environmental impacts and lower energy costs.[71] The foundation for this capability is SCADA that extends beyond the distribution substation to provide situational awareness of distribution system status, automation of critical distribution system management components, and a communication system that can interact with individual customers and their addressable end uses. When distribution-level SCADA is coupled with a distribution management system (DMS), formerly manual operations can be conducted remotely, increasing the speed at which a utility can identify and locate faults on the distribution system and restore service as well as manage voltage and reactive power to reduce energy losses and integrate distributed generation and storage technologies.

3.2 Measurements of Progress

Several technologies and programs are essential to enable a two-way distribution system for the 21st century. Snapshots of progress along the path to a 21st century utility are provided in analyses of data collected by the U.S. Energy Information Administration (EIA) and others on the penetration of key technologies and programs.[72]

Technologies and operational capabilities that indicate progress toward a 21st century utility include the following:

- Automated meter reading (AMR) involve meters that collect data for billing purposes only and transmit these data one way, usually from the customer to the distribution utility. Aggregated monthly kWh data captured on these meters may be retrieved by a variety of methods including drive-by vans with short distance remote reading capabilities or communication over a fixed network such as a cellular network.
- Advanced metering infrastructure (AMI) are meters that measure and record usage data hourly or more frequently, and that provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.
- Home area networks (HANs) consist of software and hardware that permit the HAN to monitor energy use and to communicate with devices within a customer's premises. HAN integrated into the AMI meter provides a gateway and is a subset of AMI.

Smart meters enable a variety of dynamic pricing programs, also known as time-based rate programs, which are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Common dynamic pricing programs include the following:

- Time-of-use pricing (TOU) is a program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedules are fixed and predefined, based on season, day of week, and time of day.
- Real-time pricing is a program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.
- Variable peak pricing is a program in which a form of TOU pricing allows customers to purchase their power supplies at prices set on a daily basis with varying on-peak and constant off-peak rates. Under variable peak pricing, the on-peak price for each weekday becomes available the previous day (typically late afternoon), and the customer is billed for actual consumption during the billing cycle at these prices.
- Critical peak pricing is a program in which the rate or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10–15 per year). Prices can be three to ten times as much during

these few hours. Typically, critical peak pricing is combined with a TOU rate, but not always.

- A critical peak rebate is used in a program in which rate or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure, the energy provider can call event days (often limited to 10–15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.

Demand side management (DSM) includes both EE programs that reduce total energy use as well as those that reduce peak demand. Utilities have used both for decades. Active management through direct load control by the utility and voluntary DR programs are also common.

- Energy efficiency (EE) measures consist of installing more efficient devices or implementing more efficient processes that exceed current standards. An energy efficiency resource must achieve a long-term continuous reduction in demand for electricity and be available without a requirement of notice or dispatch from the grid operator.[73] Examples are replacing light bulbs with more efficient technology or replacing older heating, ventilating, and air conditioning HVAC systems with high efficiency systems that exceed current codes and standards.
- Demand response (DR) programs encourage a temporary reduction in demand for electricity at certain times in response to a signal from the grid operator or market signals. Examples are dimming lights, turning on backup generators, or shutting down industrial processes. Direct load control is a subset of DR, by which the program sponsor remotely shuts down or cycles a customer’s electrical equipment (e.g., air conditioner or water heater) on short notice. A utility or third party may offer direct load control programs primarily to residential or small commercial customers.

The use of these tools will continue as part of 21st century utility operations, along with DG and DS facilitated by tariffs such as net energy metering (NEM) and feed-in tariffs (FITs). Distribution system efficiency programs will be increasingly common as the feeders become smarter and allow active management of voltage and reactive power, or volt/var optimization (VVO).

- Net energy metering (NEM) tariff arrangements permit a facility to offset utility purchases from their own DG, usually using a renewable resource. Conceptually, a single meter reads inflows and outflows of electricity. The tariff allows the customer to sell excess power generated over its load requirement back to the electrical grid, typically at a rate equivalent to the retail price of electricity, although the utility’s avoided cost may be used instead. The utility may not be obligated to compensate for excess production over the customer’s annual requirements, depending on the rate design.
- Volt/var optimization (VVO) is a process used by electric distribution companies to actively manage voltage levels and reactive power on distribution circuits in order to reduce energy losses, improve reliability, and increase power quality. VVO is typically achieved through the use of real-time information and controls that activate capacitor

banks, voltage regulators, and transformer load-tap changers, and in some cases, distributed generation to adjust volt-ampere reactive (VAR) power levels on primary and secondary distribution circuits.

A 2015 survey of a cross section of 198 utilities attempted to measure technologies and capabilities that enable the smart grid and 21st century utility functions based on the penetration of the following technologies:[j]

- MDMS – Meter data management systems
- DRMS – Demand response management systems
- OMS – Outage management systems
- DER – Distributed energy resources
- DMS – Distribution management system
- VVO – Volt/var optimization
- FDIR – Fault detection, isolation, and restoration
- PMUs – Phasor measurement units (primarily deployed on transmission)
- Substation automation
- Two-way SCADA
- Microgrids.

The survey results suggest that most of the utilities have the same capabilities (MDMS, OMS, substation automation, and two-way SCADA) in place, as shown in Figure 3.3. These technologies provide capabilities for management of conventional distribution systems that are valued by utilities, customers, and regulators irrespective of the contribution they may make to the transition to the 21st century utility. That makes them easier for investor-owned utilities (IOUs) to justify to regulators and for municipal and cooperative utilities to justify the investment to their customer owners. In contrast, most of the utilities do not appear to be moving to deploy technologies that are expected to be essential for active management of a smart distribution system (DER, DMS, VVO, FDIR, and microgrids).

[j] The utilities spanned 43 states, and included 38 IOUs, 64 municipal utilities, and 96 cooperatives. The response rate was 15 percent for municipal utilities, 15 percent for cooperatives, and 25 percent for IOUs.

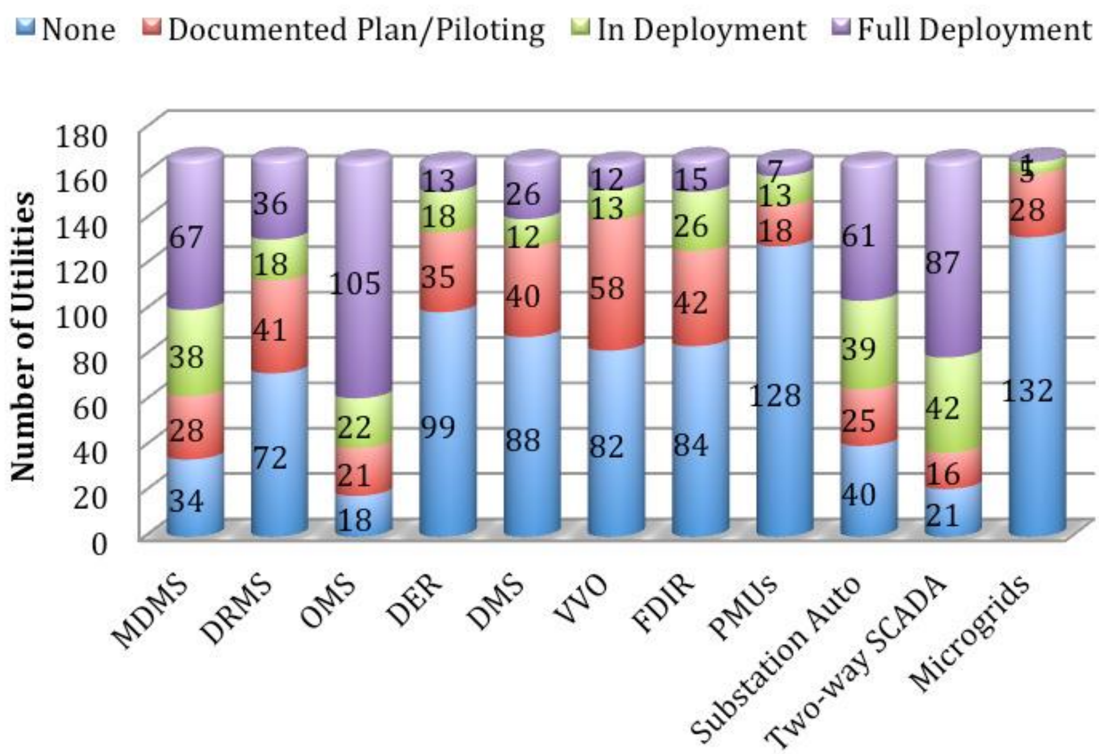

Figure 3.3. Deployment Status of Smart Grid Indicator Technologies and Capabilities[74]

Utilities employ a wide range of smart grid technologies.

This contrasts with survey results for AMI, where a majority of utilities report having an almost fully deployed capability, as shown in Figure 3.4.

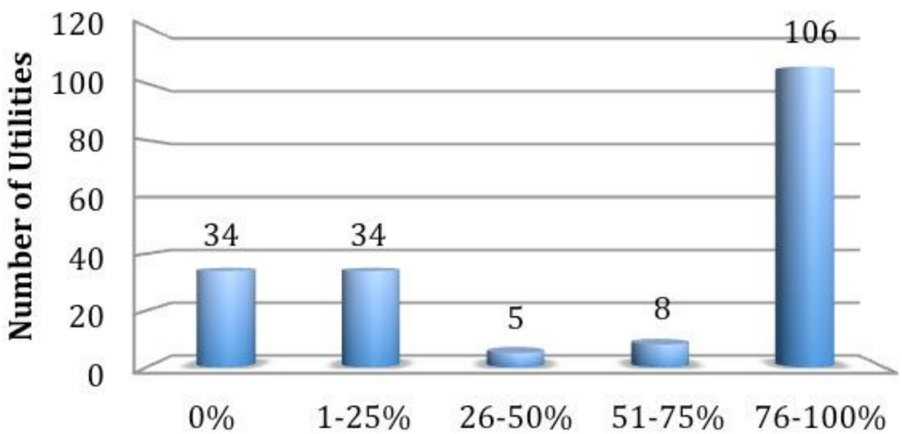

Figure 3.4. Reported Deployment of AMI[75]

The survey results show that 106 utilities report having an almost fully deployed capability of AMI.

The smart grid requires integration of the various enabling technologies and capabilities, rather than their deployment in isolation from one another. The survey results confirmed the earlier supposition that existing capabilities were more likely integrated for conventional operational objectives than for transitioning to the grid of the future, Figure 3.5. For example, the first pairing of AMI and MDMS allows data collected for billing to be captured in some form of database where it may be made available for other purposes, such as rate design and distribution system planning. Use of AMI information to respond to outages using OMS is a similarly natural pairing of the functions of two different technologies. Pairing metering data available from MDMS with DSM and/or VVO to optimize distribution operations may also be valuable; however, survey responses in Figure 3.6 suggest that utilities may not be taking advantage of this opportunity. Because Figure 3.5 indicates deployment of DSM and VVO is lagging behind AMI, this difference may be due to slower deployment of DSM and VVO, although the survey also indicates roughly half of utilities are not even evaluating DSM or VVO, which may confirm the earlier supposition that these technologies are being justified on their individual merits rather than as components of an integrated smart grid strategy.

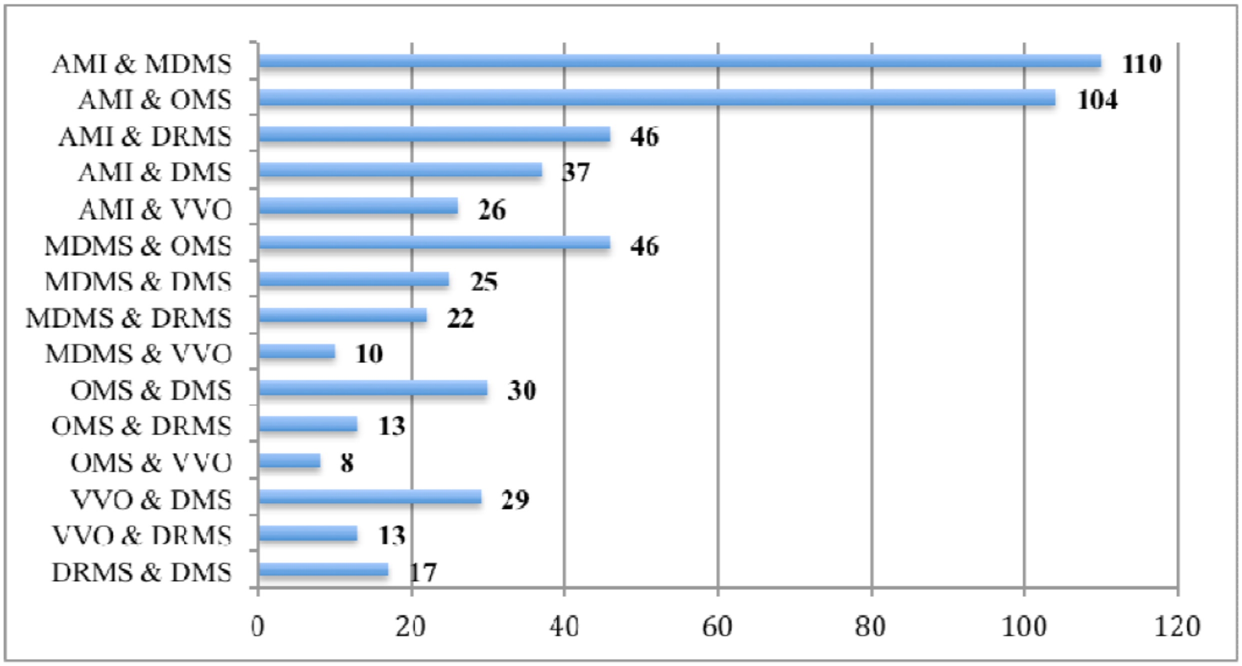

Figure 3.5. Which Smart Grid Capability Is Integrated with Another (Number of Utilities Responding)?

AMI & MDS and AMI & OMS are the most common combinations for integrated smart grid capabilities.

When utilities were questioned about their motives for implementing enabling technologies, they further confirmed the impression that immediate benefits to conventional operations were the basis, as shown in Figure 3.6.

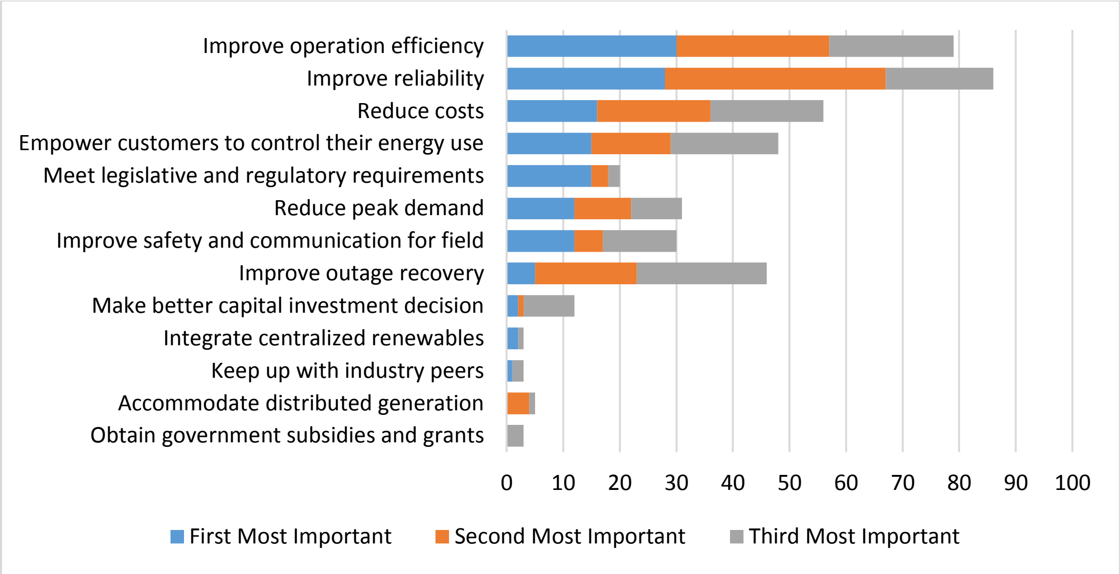

Figure 3.6. Motivation for Smart Grid Enabling Technology Adoption (Number of Utilities Responding)[76]

Improving operation efficiency and reliability were the top motivators for utilities in adopting enabling technologies.

Among utilities that responded, reliability, efficiency, and cost reduction were primary motivations, with customer empowerment, outage recovery, demand management, and safety trailing behind, although these are expected to be major benefits from the smart grid. Reasons given for less aggressive smart grid technology adoption potentially reveal underlying attitudes about adopting new technologies, as shown in

Figure 3.7.

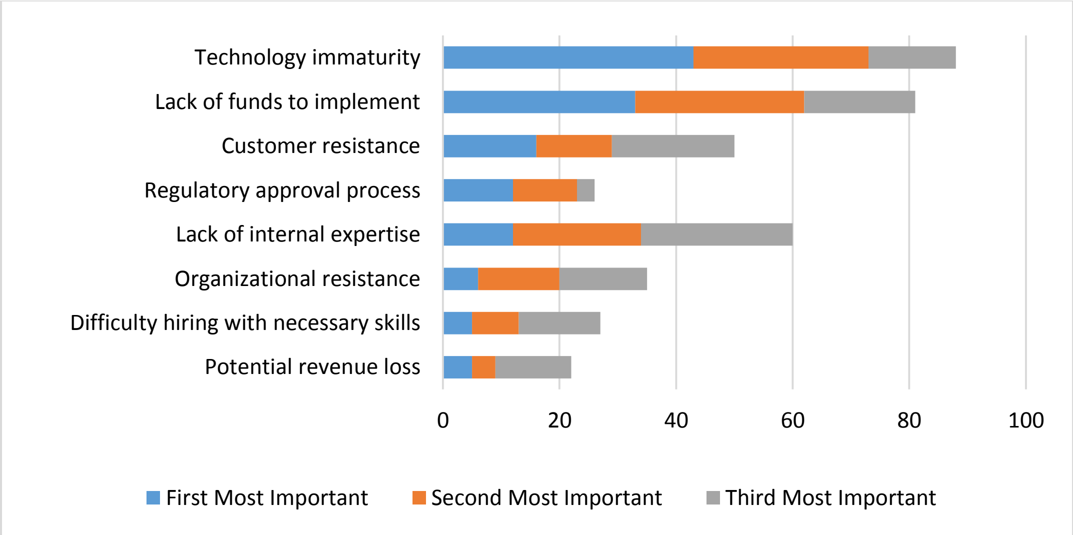

Figure 3.7. Obstacles to Smart Grid Technology Adoption[77]

Technology immaturity and lack of funds to implement are the two leading causes for resistance to adopting smart grid technology.

3.2.1 The Survey

Utilities' responses of *lack of funds to implement* and perceived *technology immaturity* as being the primary obstacles to smart grid technology adoption may be related to one another, because it would not be prudent to invest in immature technology. Because municipal and cooperative utilities do not have to justify investments to a regulator, the barriers may be less for them than for IOUs.

Comparisons of the responses across utility types showed that deployment rates for AMI were similar, but IOUs had significantly higher levels of deployment of MDMS, OMS, DER, DMS, VVO, PMUs, and microgrids. IOUs also had higher levels of HAN, electric vehicles, and dynamic pricing. The greater reliance on automation (e.g., MDMS, DMS, and OMS) by IOUs may be a reflection of efforts to reduce workforce expenses. The smaller size and geographic expanse of most municipal and cooperative utilities, as well as their community service ethos, may allow them to rely more on manual operations.

An earlier survey by the same author identified five information technology (IT) challenges specific to utilities.[78] Quotes from respondents best represent the findings in the paper. The five challenges with appropriate respondent statements are as follows:

> **New technology risks**: "*The first thing we want to do is make it work in a testing environment. And, then, we will move into a small pilot and make sure we can replicate what we do in the testing environment. And make sure we can replicate that pilot stage and work with the (whole) system. It's a long process to get things put together and move forward. You need to make sure that people are comfortable with it, (and) the regulators like what we are doing."* Neither utility managers nor regulators want to be responsible for authorizing a failed project. Unfortunately, the utility industry has experienced some very high-profile generating project failures, which tends to make managers and regulators more cautious about even lower-risk projects. Nevertheless, the step-wise process described seems appropriate for technologies that are expected to be deployed enterprise-wide. This statement can describe most utility investments in new technologies. There is a saying within the utility research community that utilities like to be "the first to be second." In other words, even leading utilities prefer another utility to take the first step.
>
> **System integration**: "*That (integration) is a challenging stage for all the utilities because of all the facilities in our history we installed, the IT systems were chosen for their own merits and didn't necessarily link with other systems. Now, with increased technology capability and ability to link one system to another, you really need to link them together."* Integrating different software platforms is one of the most challenging IT tasks. Even interfacing existing records with fully integrated software suites from vendors, such as SAP, is a significant logistical challenge for a utility.
>
> **The "big data" challenge**: As the saying goes, "you can't manage what you don't measure;" nevertheless, measurement by itself is insufficient without a data management and analysis strategy. MDMS, MDS, and DMS can collect huge quantities of measurements, which presents the "big data" challenge of data management, analysis, and application. It is imperative to manage and archive all of the data from these various management systems so that they are available for useful analyses. *"(We can) utilize the AMI data for some of the…more operational activities such as outage notification and verify restoration after repairs have been made…but also being able to roll that up to a transformer and*

understanding a little bit more accurately what type of loads or demands our equipment is experiencing. Then, we did our distribution automation project in which we deployed about 1200 automated switches on our 12 kV system that have the smart locating, isolation, and service restoration capabilities." Each additional measurement system provides another mass of data; data that can be used with other sources of information to produce even more data. Ideally, there is a strategy in place to manage these data flows and provide actionable analyses in a timely manner.

New business processes: As smart grid technologies are integrated with legacy systems, IT is built into daily operations, entailing new business processes and work routines. Current processes and related skills, such as meter reading, can become obsolete. This requires utilities to develop new business processes as well as new management structures.

Project management: For utilities, smart grid investment involves managing a number of projects in parallel. This requires utilities to develop strong multi-project management skills to meet project goals on time and on budget.

Data management, analysis, and application and the integration of both systems and data from disparate systems are the greatest challenges to utility management according to this survey. To unlock the benefits of the smart grid, it is crucial that these challenges be adequately addressed, as effective utilization of data is required. Ultimately, it will be critical as the grid depends more and more on two-way information flows along with power from DG and DS and load reduction from DR and EE flowing back to the bulk power system. As one interviewee stated; "*What we've got is four different systems: we've got an Itron meter data management environment, we've got a customer service billing environment, we've got the HAN environment, which you know is the thermostat's environment, and then we have the substation automation and distribution automation environment. So, all those systems are different platforms that we have to somehow connect to be able to do analytics. Maybe we don't want to connect them all, but that's our challenge now*." This challenge is even greater in an environment where the traditional hardware and software vendors are being supplanted with new firms with limited track records and occasionally, insufficient financing. The loss of a critical vendor can cripple an enterprise management strategy for a prolonged period until a replacement is found. This is a lesson the utility industry has learned previously, such as during the switch from manual to automated meter reading and billing and with the adoption of customer communications software for use with billing systems—particularly utilities that transitioned to customer choice.[79]

3.3 Measuring Progress across Utilities

Utilities, independent DSM program managers, wholesale power marketers, energy service providers, and electric power producers are required to report annually to the EIA using the Annual Electric Power Industry Report form (Form 861). This information provides annual snapshots of changes in the penetration of selected smart grid technologies and capabilities and allows for comparison across utility types.

The reporting requirement is limited to utilities with annual sales in excess of 100 gigawatt-hours (GWh) and excludes those reporting through the Tennessee Valley Authority or WPPI Energy.[80] More than 2,000 of the 3,000+ distribution utilities respond using the long form, which includes a wealth of information. Data from their responses is not exhaustive of all utilities and shows a bias toward larger and less rural utilities. The remaining smaller utilities (with annual sales of less than 100 GWh) report on a short form, which provides significantly less information. Nevertheless, this is the only comprehensive source of information from all utilities that allows for cross tabulation by utility type. Those cross tabulations provide snapshots of where the industry is with respect to deployment of smart grid technologies and practices, at least to the extent they are captured in the EIA data.

3.3.1 Advanced Metering

Advanced metering is foundational to the smart grid because electricity meters are used in conjunction with rate design to send price signals to customers to influence electricity use by volume, time of day, and season. Furthermore, advanced metering can provide system management benefits including outage detection and aggregated loading estimates for feeder components. The capabilities of the electricity meter limit the ability to perform these functions. Advanced electronic meters have time-recording and two-way communication capabilities. These features can be used for more sophisticated rate designs and for triggering end-use demand limits. The transition to advanced meter reading (AMR) and the associated two-way metering and control infrastructure (AMI) has accelerated this decade, and conversion to AMR and AMI is well underway, as shown in Table 2.3 (and Figure 2.5 in the previous chapter).

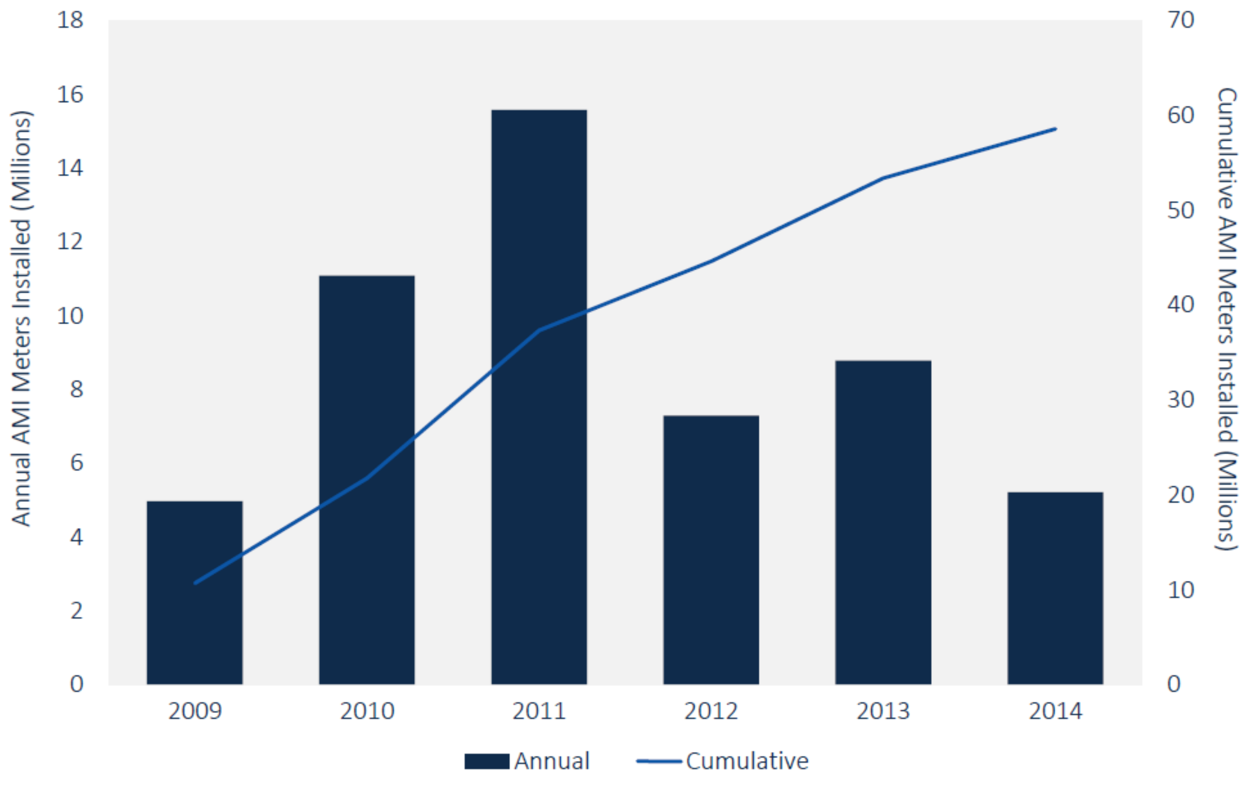

Figure 3.8. Estimates of Advanced Meter Penetration in the United States[81]

Though the number of AMI meters installed per year has declined a bit after 2011, the cumulative number of installations continues to rise.

The penetration of AMR, AMI, and HAN is uneven across utility types (IOUs versus municipal utilities versus cooperatives) and customer classes (Table 3.1). The figures for AMR and AMI may not total 100 percent because utilities can respond positively to the question regarding AMR if they have installed AMR as part of AMI. In other words, AMR counts may be included with AMI. HAN applies only to home networks integrated with AMI. AMR is more commonly deployed among residential and commercial accounts than industrial users. This is likely a result of the higher expense ratio for the cost of manual meter reading and billing relative to the average customer bill, as well as the fact that industrial customers may have more complex metering and billing requirements. This observation is consistent with the higher penetration of AMR and AMI among cooperatives compared to municipal utilities, as rural cooperatives would be expected to have higher meter reading costs than municipalities with customers closer together.

Table 3.1. AMR, AMI, and HAN Penetration Rates by Utility Type and Customer Class, as a Percent of Total Customers[82]

There is significant variance of AMR, AMI, and HAN penetration rates among customer classes and utility types.

Utility Type	AMR %	AMI %	HAN %
Residential			
Investor-Owned	59	51	3
Municipal	39	22	2
Cooperative	41	53	1
Commercial			
Investor-Owned	50	44	1
Municipal	32	25	2
Cooperative	38	48	1
Industrial			
Investor-Owned	30	33	1
Municipal	40	17	0
Cooperative	40	41	1

3.3.2 Price Signaling through Rates

Although conventional power meters can implement time-varying rates, AMI facilitates rate designs that more accurately signal to customers options how to manage their energy use in ways that reduce costs of utility operations, primarily by avoiding use of generation that costs more during certain hours than others. Time-varying rate examples were discussed in Chapter 2, as shown in Table 2.3.

The effectiveness of time-varying rates to manage peak load is well established, as shown in Figure 3.9.

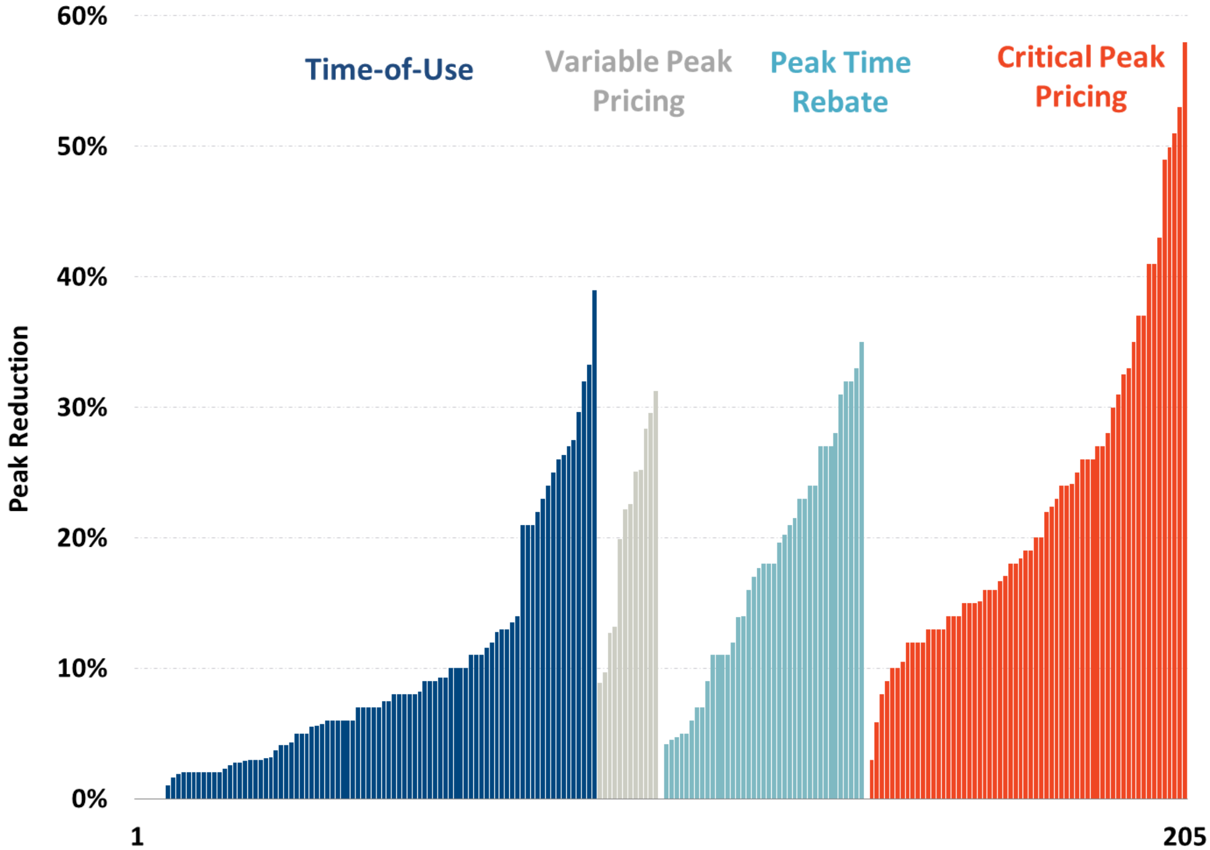

Figure 3.9. Survey of Proportionate Peak Reduction for Various Time-Varying Rate Designs. Each bar represents the result of one study.[k]

Time-varying rate designs are well established.

Most utilities use time-varying rates to some extent, although the fraction of customers in each class using these rates varies, as shown in Table 3.2. The EIA data suggest IOUs offer time of use (TOU) and critical peak tariffs for all customer classes and real-time pricing primarily for commercial and industrial customer classes. Municipalities and cooperatives apparently offer TOU rates for all customers, but use other rate designs significantly less than IOUs. This may be explained for municipalities by the comparatively low deployment of the necessary advanced metering infrastructure indicated in Table 3.1. In contrast, the higher deployment of AMI among cooperatives would appear to support greater use of advanced, time-varying rates.

[k] All data are current as of March 2015 and are obtained from The Brattle Group's Arcturus Database. The figure shows the distribution of impacts from 205 pricing pilots using TOU, VPP, PTR, and CPP rate structures.

Table 3.2. Fraction of Customers with Access to Time-Varying Rates by Utility Type and Customer Class, As a Percent of Total Customers[83]

Though most utilities offer time-varying rates, the kind of rate offered and its availability varies widely based on utility type and customer classification.

Utility Type	TOU	RTP	Time Varying Peak	CCP	CCP rebates
Residential					
Investor-Owned	64	0	3	23	36
Municipal	82	0	14	2	2
Cooperative	97	1	1	6	0
Commercial					
Investor-Owned	98	52	1	78	1
Municipal	88	0	4	6	1
Cooperative	63	6	0	10	0
Industrial					
Investor-Owned	65	77	2	66	0
Municipal	1	0	0	9	1
Cooperative	0	20	0	13	5

3.3.3 Integrated Resource Planning

Integrated resources planning (IRP) is typically associated with vertically integrated utilities—utilities with continued responsibility for planning, owning, and operating new generation. Many states require utilities to compete new generating additions, requiring utilities to consider contracting for future power supplies from third parties. The application of IRP in those states has evolved into long-term planning, which encompasses strategies and schedules for acquisition of new power sources as needed. This includes incumbent utilities in retail access states. The combination of IRP and long-term plan requirements extends to most states in the United States, as shown in Figure 3.10.

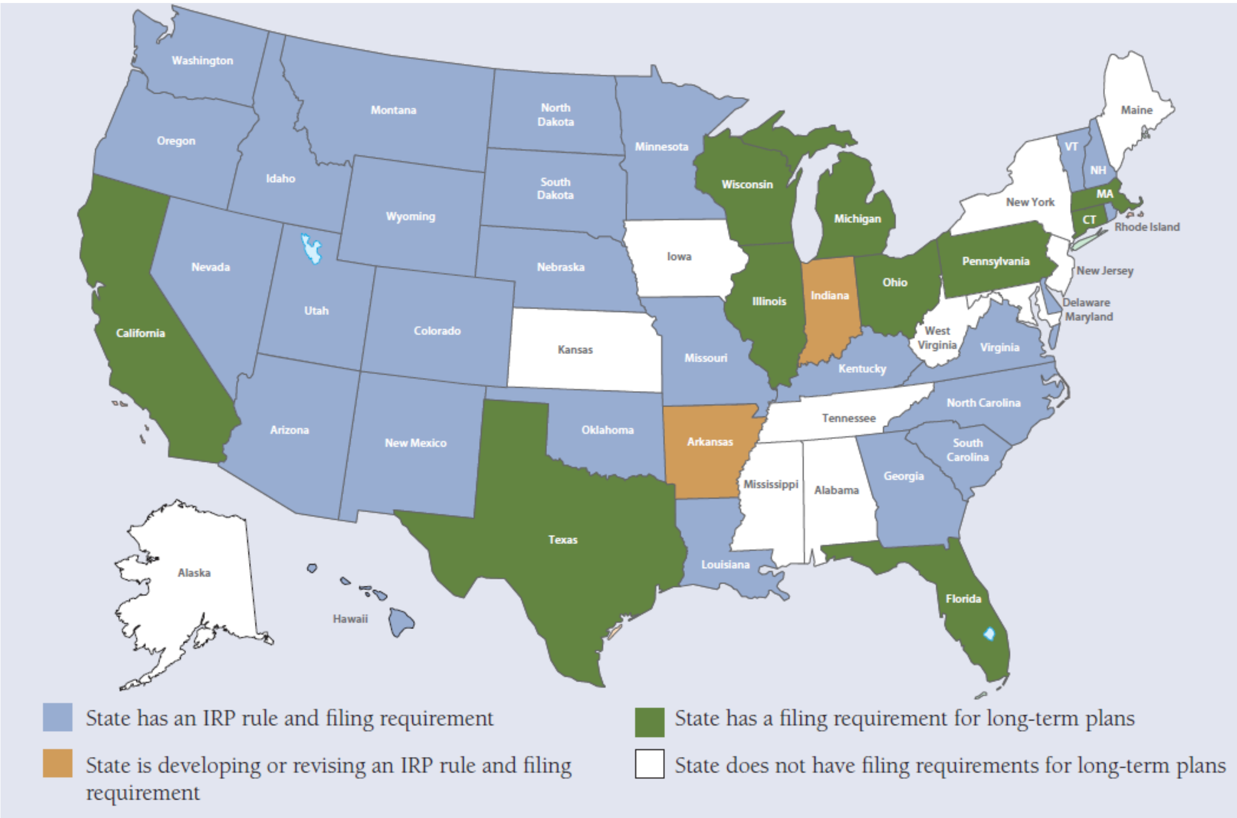

Figure 3.10. States with Integrated Resource and Long-Term Procurement Planning Requirements[84]

The combination of IRP and long-term plan requirements extends to most states in the United States (as indicated in blue).

3.3.4 Energy and Peak Demand Reduction

Utilities have offered demand-side management programs (DSM), including energy efficiency efforts to conserve energy and reduce peak demand, since the 1970s. Energy efficiency programs generally target overall reductions in energy consumption while other DSM programs focus on time specific load reductions or shifting of peak load to non-peak times. These programs are a hallmark of utility IRP, which most state PUCs or legislatures now require of IOUs.

DSM programs are comparatively widespread as indicated by the number of rebates and other incentives offered across the United States. The American Council for an Energy-Efficient Economy annually ranks states based on their number of DSM policies and programs, as shown in Figure 3.11. DSM rebates and incentives vary from a single program to as many as 116 programs in one state.

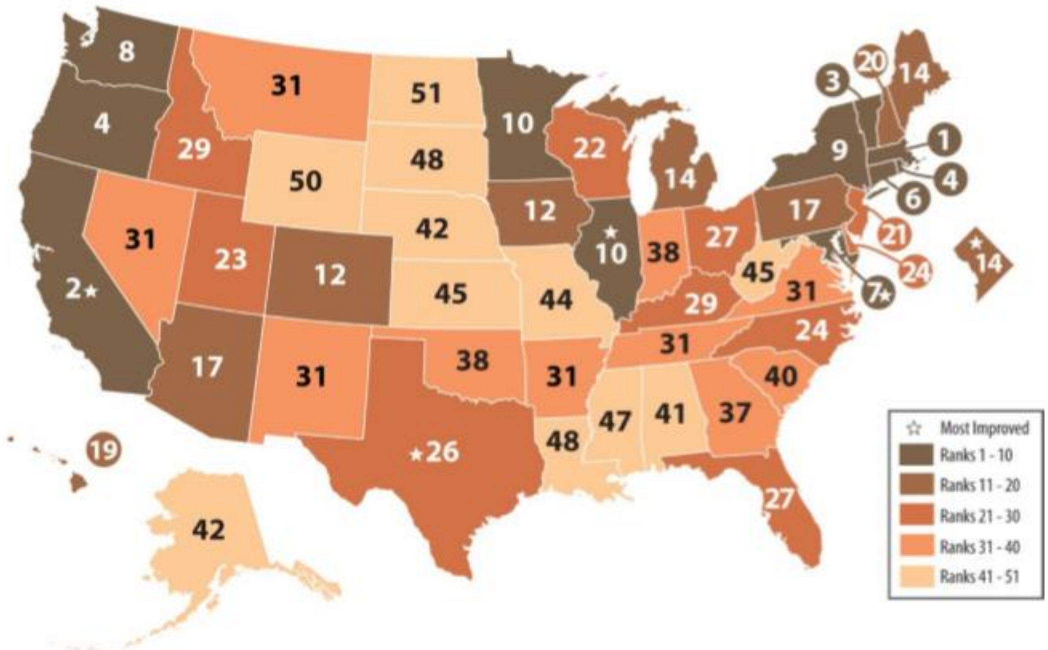

Figure 3.11. Number of DSM Rebates and Incentives Offered by State[85]

California, the District of Columbia, Illinois, Maryland, and Texas were among the most improved states for offering DSM rebates and incentives.

DSM programs may include enhanced building codes and appliance standards as well as rebates and other incentives. Utilities often sponsor their own rebate and incentive programs such as rebates to replace air conditioners with the most efficient models, which both saves energy and reduces peak demand. Utility incentives and rebates are customer-class specific, resulting in wide variation in participation and resulting reductions in energy use and peak demand across utilities and customer classes, as shown in Table 3.3.

Table 3.3. Annual Energy Efficiency Program Participation Rates and Impacts, 2014 Data[86]

The table below shows both the potential and actual energy savings for each utility type and customer class participating in energy efficiency programs offered by utilities in 2014.

Utility Type	Participation Rate (%)	MWh Saved	Potential MW Saved	Actual MW Saved
Residential				
Investor-Owned	5.6	747,832	5,294	1,773
Municipal	2.8	5,230	306	173
Cooperative	8.8	107,668	2,318	1,106
Commercial				
Investor-Owned	3.2	392,076	4,513	1,466
Municipal	0.8	5,368	259	153
Cooperative	2.7	25,482	965	624
Industrial				
Investor-Owned	3.9	31,478	10,412	3,158
Municipal	5.6	1,046	373	230
Cooperative	7.6	20,407	1,953	704

3.3.5 Distribution System Efficiency

Moving power through a distribution network causes losses. These losses are proportional to the voltage on the distribution line; maintaining voltage at the lower end of the required band of acceptable voltage levels will reduce line losses. Intentional reduction in voltage to reduce losses is accomplished through regulating voltage (volt) and reactive power (var) along the distribution feeder using capacitor banks, which is called volt/var optimization (VVO). Typically, distribution system operators use SCADA or DMS for VVO. EIA collects data on the penetration of VVO on distribution circuits, as shown in Table 3.4.

Table 3.4. Penetration of Volt/Var Optimization (VVO) on Distribution Circuits, by Utility Type[87]

Municipal utilities had the highest percentage of penetration of VVO on distribution circuits.

Utility Type	Total No. Circuits	Total with VVO	Penetration of VVO (%)
Investor-Owned	121,337	26,054	22
Municipal	25,285	7,764	35
Cooperative	45,548	10,535	23

3.3.6 Distributed Generation

Industrial customers have relied on their own generating plants since the dawn of the electricity age, when utility service to remote sawmills, mines, and other facilities was not available. That tradition continued for manufacturing facilities that require steam, which can be produced jointly with electricity using combined heat and power (CHP) generation.

Legislation, regulation, and utility programs have recently facilitated small-scale DG to reduce conventional generating requirements and to stimulate the renewable energy industry.

Government initiatives for DG include cash grant and rebate programs, tax incentives, and requirements that utilities purchase power from certain DG projects. Programs implemented by utilities or through regulation typically take the form of special tariffs, either net energy metering (NEM) or feed-in tariffs (FIT) (see Section 2.3.6.2).

PV is the most common form of customer-sited DG because of its locational flexibility, tax incentives, and innovative ownership models pioneered by the solar industry as well as the stimulus provided by NEM and FIT. Figure 3.12 shows annual PV installations in the United States.

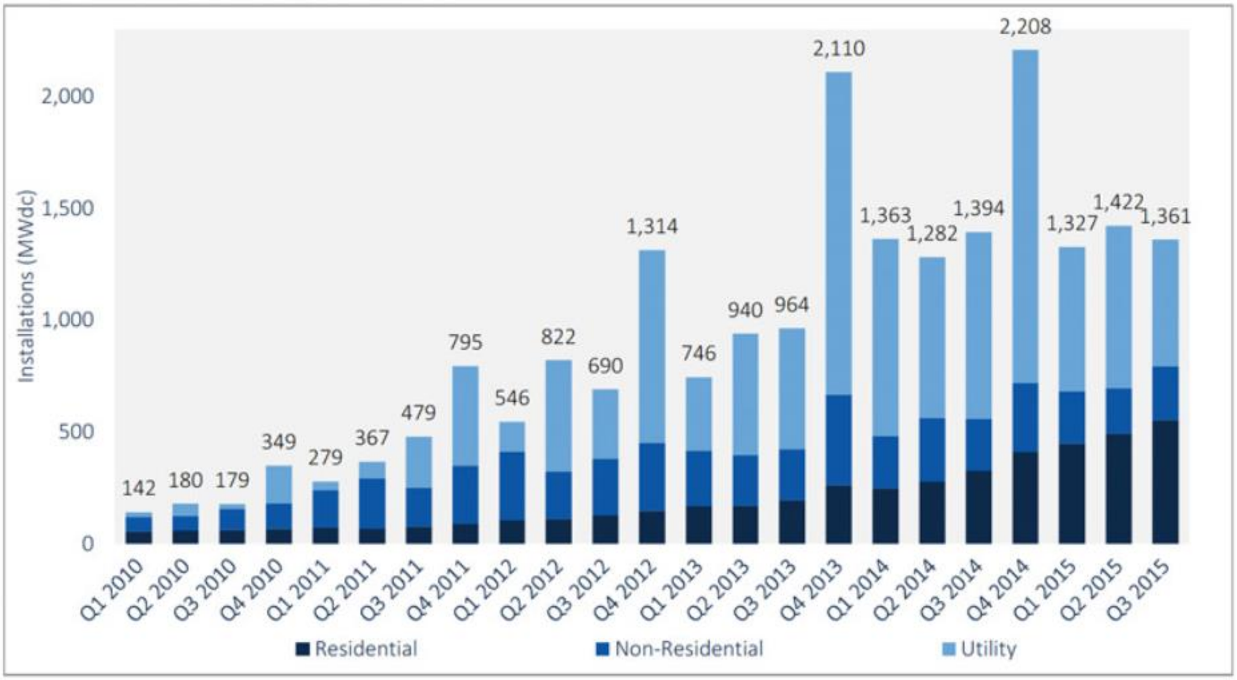

Figure 3.12. Solar PV Installations, 2010–2015[88]

Solar PV installations were more common among utilities than non-residential and residential users.

Figure 3.12 indicates the current installed capacity of utility PV is roughly equal to customer-sited PV and is increasing rapidly. This category reflects utility-scale PV installations, which range from a few megawatts to over 100 MW, in contrast to residential projects in the 1–4 kW range and non-residential DG project that may be a few megawatts at most. Utilities purchase utility-scale PV projects for several reasons: to comply with Renewable Portfolio Standard goals, because they are part of the least-cost resource mix from an IRP or other long-term plan, or because their purchase is required under the "qualifying facility" regulations of the *Public Utility Regulatory Policies Act of 1978* (PURPA). Although PURPA focuses on generation, rather than distribution, its purpose is to facilitate utility acquisition of energy from small-scale power projects, many of which may interconnect through the distribution system. PURPA requires utilities to purchase power from qualifying facilities at their avoided costs. The long history of PURPA has resulted in a body of regulations that define avoided costs, which is relied upon, in part, for setting compensation for FIT projects.

Access to and participation in NEM programs varies by utility and customer class. NEM is another metric monitored by EIA, as shown in Table 3.5.

Table 3.5. Participation in NEM and Installed Capacity[89]

IOUs had the highest rates of customer participation among all customer classes.

Utility Type	Customer Participation (%)	MW
Residential		
Investor-Owned	0.49	3,006
Municipal	0.27	154
Cooperative	0.13	139
Commercial		
Investor-Owned	0.24	2,865
Municipal	0.16	134
Cooperative	0.09	48
Industrial		
Investor-Owned	0.43	770
Municipal	0.14	17
Cooperative	0.03	8

Customer participation in Net Energy Metering (NEM) rates varies across utility type and customer class, though no customer segment has a participation rate higher than 1 percent.

Customer participation in NEM programs is low (less than 1 percent) despite the fact that 44 of the 50 states have utility NEM tariffs (Figure 2.6). However, customer installations of DG are sensitive to economic considerations, including installed cost, net costs after any incentives, and avoided energy purchases as well as credits through NEM and other tariffs. Participation rates are higher in utilities where available incentives, solar potential, DG costs, and utility rates are aligned.

3.4 Emerging Smart Grid Features

There are two emerging trends that bear discussion as potential components of the 21st century utility: microgrids and distribution system platforms and distribution system operators (DSOs).

3.4.1 Microgrids

DOE characterizes microgrids and their role in the grid of the future as follows:

> Microgrids, which are localized grids that can disconnect from the traditional grid to operate autonomously and help mitigate grid disturbances to strengthen grid resilience, can play an important role in transforming the nation's electric grid. Microgrids can strengthen grid resilience and help mitigate grid disturbances because they are able to continue operating while the main grid is down, and they can function as a grid resource for faster system response and recovery.
>
> Microgrids also support a flexible and efficient electric grid by enabling the integration of growing deployments of renewable

> sources of energy such as solar and wind and DER such as CHP, energy storage, and demand response. In addition, the use of local sources of energy to serve local loads helps reduce energy losses in transmission and distribution, further increasing efficiency of the electric delivery system.[90]

There are currently four concepts for microgrids—single customer, partial feeder, full feeder, and full substation— each of which is represented in the schematic below, as shown in Figure 3.13.

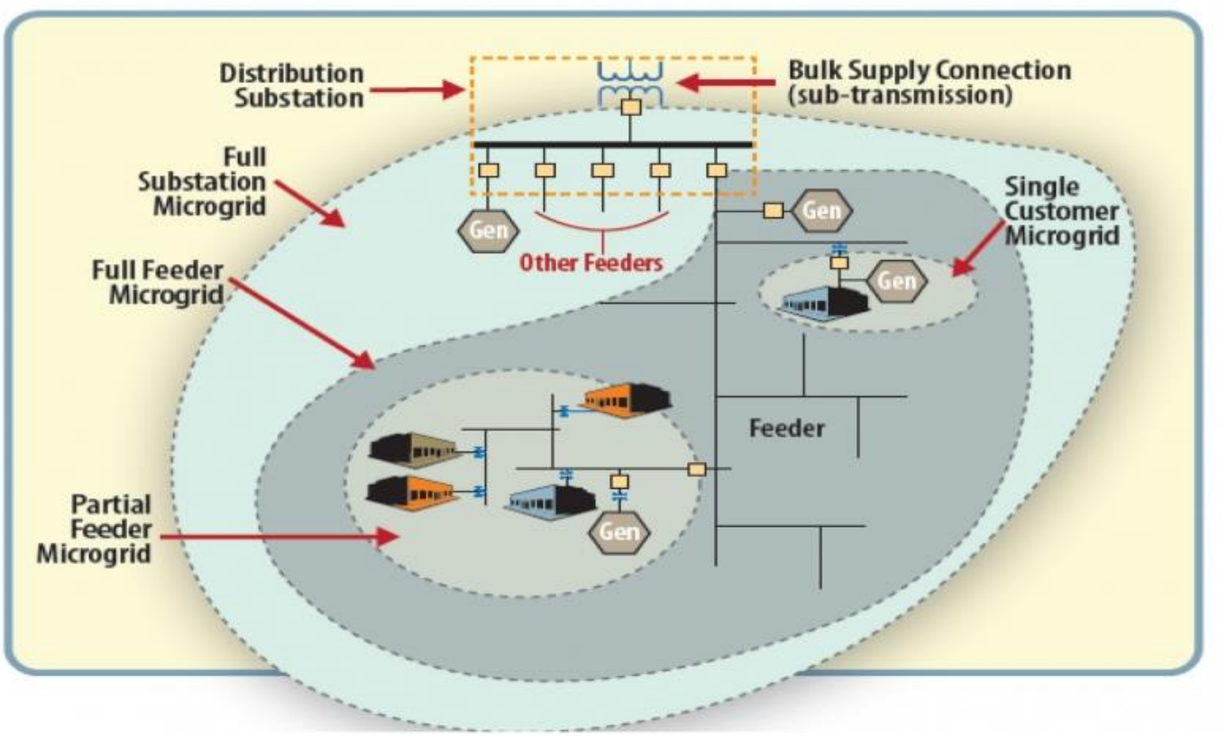

Figure 3.13. Three Microgrid Schemes[91]

This diagram shows all four concepts for the microgrid: single customer, partial feeder, full feeder, and full substation.

3.4.1.1 The Single Customer Microgrid

The distinguishing feature of the single-customer microgrid, also called an independent microgrid, is that it can be isolated from the utility system and potentially operate independently during grid outages, although it may not be able to supply all of the power requirements of the site during an outage. The independent microgrid has an analogy in the campus heating, cooling, and power districts of universities, hospitals, military installations, and industrial complexes; the central energy plant for the University of Oregon is one example.[92] The University of Oregon plant was designed to minimize utility costs and provide for continuity of utility services during power outages. The system was designed around thermal energy requirements, which limited power production to roughly 30 percent of campus needs. Additional power was available from the local municipal utility at rates that made expansion of power production capability uneconomic for the University. Power and thermal energy is distributed throughout the main campus on university-owned and operated infrastructure. U.S. military faculties relied on similar systems until recently, when on-base energy infrastructure was privatized and many of the aging central plants were replaced with distributed heating and cooling systems for improved efficiency. Although the University of Oregon campus and most military bases provide energy to unaffiliated entities on their sites, they maintain the customer relationship with the local utility, thereby retaining rights as a single utility customer to self-generate power and recover the associated costs from on-site users. This is an exception to state utility regulations prohibiting non-utilities from providing retail energy service to unaffiliated customers.

3.4.1.2 The Partial Feeder Microgrid

The distinguishing feature of the partial feeder microgrid, sometimes called a community microgrid, is that it is formed to serve a community of customers on the same feeder using existing utility infrastructure to transfer power from a shared generation source and manage energy requirements as a single entity. Establishment of this type of microgrid may have to comply with applicable state law regarding establishment of a retail electric utility, especially if customers move power from one customer to others using a utility distribution feeder, as is anticipated for a partial feeder microgrid. Aggregate purchases of power on behalf of microgrid participants would need to conform to applicable utility deregulation and customer choice regulations. Coordination of demand across multiple customers is a traditional energy services company activity generally allowed under current state laws.

3.4.1.3 The Full Substation Microgrid

Concepts for substation-level microgrids are at least a decade old.[93, 94] Then, as now, there was recognition that distributed generation had the potential to create power flow congestion on distribution lines along with uncontrolled voltage fluctuations. Controlling these on an independent grid, separated from the rest of the grid by a substation, is conceptually easier because potential problems are geographically confined. Widespread deployment of distributed generation across substation circuits redefines the control problem to the substation area as a whole, with or without a formal microgrid. A formal microgrid at the substation level would require independent operation during outages as an objective, with associated targets for local generation and load control.

3.4.1.4 Growing Interest in Large Microgrid Deployment

Existing campus-like microgrids are being improved to comply with more stringent environmental and operational requirements—as is the case at the University of Oregon[95]—or scaled back if required changes are uneconomic. However, a new generation of modern microgrids is in development. These tend to be driven by requirements for a more resilient and reliable electricity supply incorporating renewable generation in contrast to older systems based on CHP. Most of these are in the planning or pilot development stage as shown in Figure 3.14.

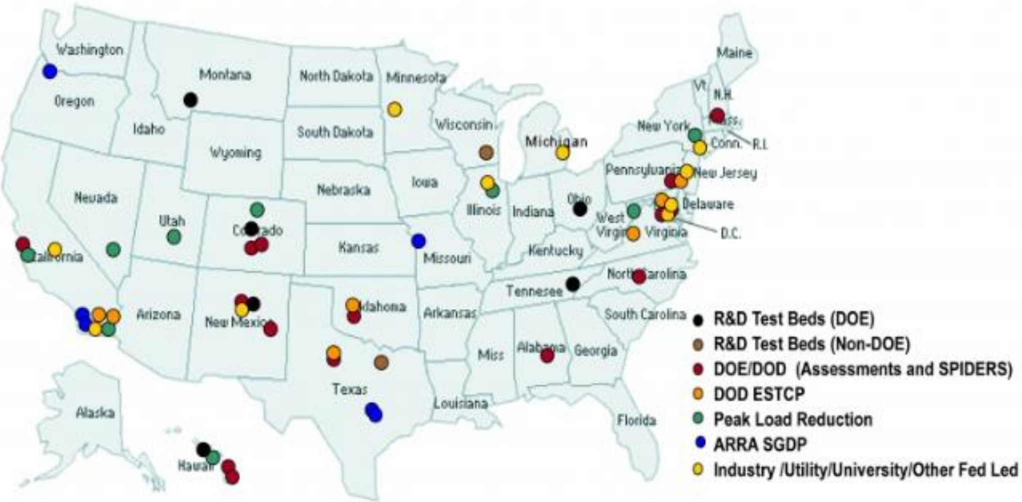

Figure 3.14. Map of New U.S. Microgrid Projects[96]

New microgrid projects are springing up across the country, including the East Coast, southern California, and the Southwest.

Many of the new microgrid projects are being sponsored, in part, by state-level initiatives. Among the Mid-Atlantic States, microgrids are seen as a bulwark against the widespread grid outages caused by events like Superstorm Sandy. In California, they are seen as a natural extension of the state's RPS, sustainability, and deregulation policies. The U.S. Department of Defense is motivated by the need for secure energy to sustain operations during grid outages at permanent bases as well as more efficient ways to provide power when operating outside of the United States. Exactly how they will interface with the bulk power system operations remains to be seen, although technical standards development to do so is underway.[97]

Within any of the microgrid models, there will be a need to coordinate the operation of microgrid-generating resources to supply power to the associated customer loads. In essence, the microgrid will have to perform like a mini-utility providing reserves, volt/var, and frequency support. The bulk power system can provide these, which is the case for campus systems like the one at the University of Oregon. However, one of the benefits claimed by microgrid proponents is their ability to provide these same services back to the bulk power system. The microgrid could be operated so that loads and resources are balanced using the generating resources available and direct management of individual end-user demand, with any unmet demand being scheduled with the local utility as a utility requirement. This is essentially how small utilities with limited local generation arrange service with their generating and transmission providers. A similar requirement is expected of microgrids, which will require a "microgrid operator;" a single responsible party to coordinate with the local distribution utility and other grid providers (power suppliers and transmission operators). The presence of such an operator and the fact that a microgrid is a single, large, semi-autonomous load/resource makes it easier to integrate into utility operations at the substation level than an equivalent amount of smaller, distributed generators scattered across distribution feeders.

3.4.2 Distribution System Platforms and Distribution System Operators (DSO)

One premise of the smart grid is that the full potential of DG, storage, and demand response resources is untapped due to the design of current tariffs, DR programs, and state/federal jurisdictional issues. Once these issues are addressed, DR can reduce peak demand on transmission and distribution systems along with wholesale generators to reduce the cost of providing generation and transmission during peak periods and, in some cases, deferring the need for new generation and transmission capacity. As the grid gets smarter, greater coordination of customer-sited DER will be required to optimize its use by the grid and value to customers. Regulators in Hawaii, New York, and elsewhere are struggling with this issue as they look towards the 21st century grid.

In April, 2014, the New York Public Service Commission (NYPSC) proposed the creation of a Distribution System Platform Provider (DSPP) role for the utility as part of the Reforming the Energy Vision process. The DSPP would be responsible for "…actively managing and coordinating distributed resources and providing a market in which customers are able to optimize their priorities while providing, and being compensated for, system benefits.".[98] Also in April 2014, the Hawaii PUC attached a paper in an open docket titled, "Commission's Inclinations on the Future of Hawaii's Electric Utilities." It suggested that "the utility's traditional role in power supply is changing with high penetrations of renewable energy resource, the retirements of existing fossil generators, and the need to incorporate new smaller, more flexible and efficient generators. The utility's role in energy delivery is also evolving to effectively become that of a network systems integrator and operator."[99]

New York is a deregulated state, so an incumbent IOU's role in power supply has diminished while its role facilitating retail distribution of power supplied by third parties has increased. Although Hawaii is not formally deregulated, it has the highest penetration of DG in the nation; currently more than 12 percent of customers have rooftop PV systems. Consequently, as the Hawaii quote suggests, the Hawaii PUC envisions a DSPP role for its incumbent utilities substantially similar to that of the NYPSC. In the Hawaiian context, there is a pressing need for this new role given the high penetration of PV, the state's goal of a 100 percent RPS by 2045, and the utility's recent determination that it can manage as much as 250 percent of daytime capacity from PV on selected distribution circuits if the system is optimized to do so.[100] Optimization is the function of a DSPP.

The discussion of the DSPP role in New York and Hawaii raised the concern that the incumbent utility may not be sufficiently impartial or creative in that role. Both states concluded that the inherent responsibilities of the incumbent utilities justified it retaining the role because it would continue to be central in any configuration of a distribution system of the future. The alternative to utility management would be a DSO that is independent of the grid owner, which has an analogy in the division between transmission owners and the independent regional transmission operators (RTOs). Extension of RTO management to distribution and a DSO are compared, conceptually, in Figure 3.15.

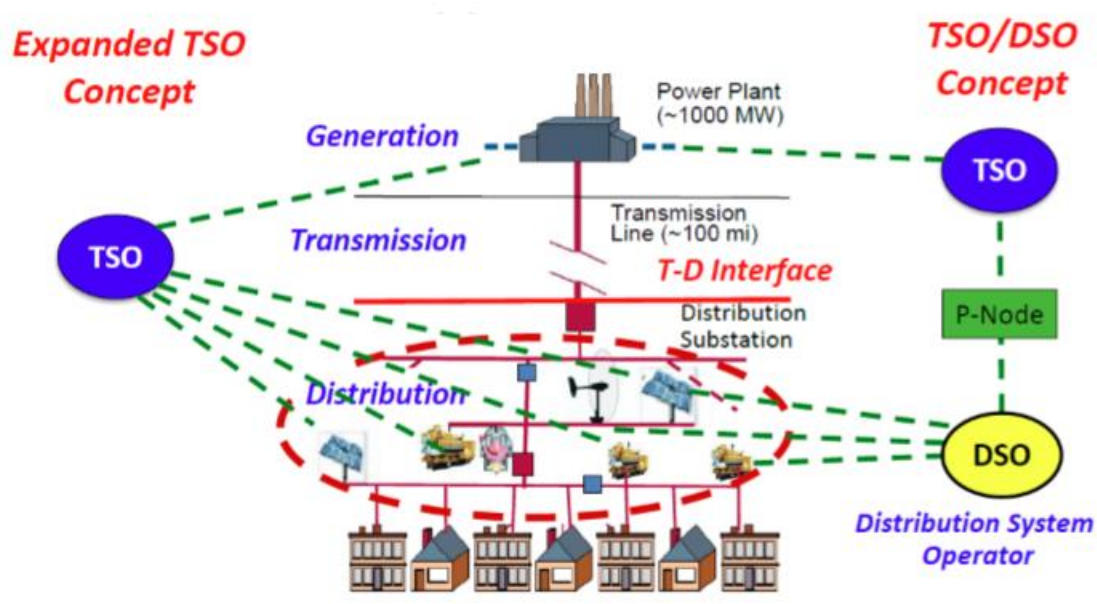

Figure 3.15. Two Concepts for Independent Coordination of Distributed Energy Resources[101]

This graphic compares the expanded transmission system operator with the distribution system operator. Note that TSO is equivalent to a regional transmission operator.

Acronyms: TSO = transmission system operator; P-Node = pricing node.

This figure was included in a submission solicited by the Solar Electric Power Association to construct a utility management/regulation model for an imaginary 51st state without the constraints of a legacy utility/regulator model. Significantly, a submission from a team that included Jon Wellinghoff, the former chair of Federal Energy Regulatory Commission, also proposed an independent DSO.[102]

3.5 Monitoring Regulatory Progress

Edison Electric Institute (EEI), the IOU trade association, prepared a survey in 2011 of regulators' decisions related to the smart grid. The survey identified 21 states that had taken some kind of enabling action.[103] These actions fell into the following categories:

- Establishing data-exchange, sharing, security, and privacy policies. These are essential for the inclusion of information from AMR/AMI and other sensors in communications among smart grid participants.
- Adopting smart grid plans and strategies. These provide a framework for the timing and cost of future smart grid investments so utilities can proceed but regulators can exercise control. Most of these plans apply to installation of smart meters and associated two-way communication and customer-engagement infrastructure.
- Launching energy storage demonstration projects and approving energy storage investments for operations.
- Supporting "smart city" demonstration projects, including microgrid demonstrations.

- Developing new tariffs that take advantage of smart meter capabilities, including potential sale of ancillary services to grid operators.
- Adopting advanced distribution automation systems (i.e., sensors, controls, hardware, and software) on both a demonstration and system-wide basis.
- Demonstrating dynamic pricing using smart meters and distribution automation to integrate intermittent or variable renewables.
- Incorporating smart grid impacts into utility long-term planning.
- Investing in customer-sited energy storage demonstration projects.

In most cases, the utility initiated the request to the PUC so as to take advantage of stimulus funding through DOE for smart meters, storage demonstrations, and similar projects.

The 21st century distribution grid is commonly expected to do the following:[104]

- Enable informed participation by customers, including customer sale of services to the grid.
- Accommodate all options for generation and storage.
- Enable new products and services and markets for them.
- Provide power quality for a range of needs.
- Optimize asset utilization and efficient operation.
- Operate resiliently during disturbances, attacks, and natural disasters.

All of these expectations require changes to operations at the distribution system level, which are likely to require regulatory approval for IOUs. Some will also require regulatory reforms.

DOE and smart grid stakeholders track progress toward these aspirations using specific metrics. A snapshot from 2014 provides a summary, as shown in Table 3.6.

Table 3.6. Smart Grid Metrics Assessment, 2014[105]

The table below lists the 21 metrics being used to assess the development of the smart grid and the 2014 assessment of their progress.

*Trends refer to the rate of change in the metric over time.

#	Metric Title (*Type: build or value*)	Penetration/ Maturity	Trend
1	Dynamic Pricing (*build*): fraction of customers and total load served by RTP, CPP, and TOU tariffs*	low	moderate
2	Real-Time System Operations Data Sharing (*build*): total SCADA points shared and fraction of phasor measurement points shared*	moderate	high
3	Distributed-Resource Interconnection Policy (*build*): percentage of electricity service providers with standard distributed-resource interconnection policies and commonality of such policies across electricity service providers	moderate	high
4	Policy/Regulatory Recovery Progress (*build*): weighted-average percentage of smart grid investment recovered through rates (respondents' input weighted based on total customer share)	moderate	high
5	Load Participation Based on Grid Conditions (*build*): fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives	low	low
6	Load Served by Microgrids (*build*): percentage of total summer grid capacity	low	low
7	Grid-Connected Distributed Generation (renewable and non-renewable) and Storage (*build*): percentage of distributed generation and storage	low	high
8	EVs and PHEVs (*build*): percentage shares of on-road light-duty vehicles comprising EVs and PHEVs*	nascent	low
9	Non-Generating Demand Response Equipment (*build*): total load served by smart, grid-responsive equipment	nascent	low
10	T&D System Reliability (*value*): CAIDI, SAIDI, SAIFI, MAIFI*	mature	flat
11	T&D Automation (*build*): percentage of substations having automation	moderate	high
12	Advanced Meters (*build*): percentage of total demand served by AMI customers	low	high
13	Advanced Measurement Systems (*build*): percentage of substations possessing advanced measurement technology	moderate	high
14	Capacity Factors (*value*): yearly average and peak-generation capacity factor	mature	flat
15	Generation and T&D Efficiencies (*value*): percentage of energy consumed to generate electricity that is not lost	mature	improving
16	Dynamic Line Ratings (*build*): percentage of miles of transmission circuits being operated under dynamic line ratings	nascent	low
17	Power Quality (*value*): percentage of customer complaints related to power quality issues, excluding outages	mature	worsening
18	Cybersecurity (*build*): percentage of total generation capacity under companies in compliance with the NERC critical infrastructure protection standards	low	low
19	Open Architecture/Standards (*build*): interoperability maturity level – weighted-average maturity level of interoperability realized between electricity system stakeholders	nascent	low
20	Venture Capital Funding (*build*): total annual venture capital funding of smart grid startups located in the United States.	low	high
21	Grid-Connected Renewable Resources (*build*): percentage of renewable electricity, in terms of both generation and capacity	low	moderate

*RTP = real time pricing; CPP = critical peak pricing; TOU = time-of-use pricing; SCADA = supervisory control and data acquisition; EV = electric vehicle; PHEV = plug-in hybrid electric vehicle; CAIDI = customer average interruption duration index; SAIDI = system average interruption duration index; SAIFI = system average interruption frequency index; MAIFI = momentary average interruption frequency index; NERC = North American Electric Reliability Corporation

Enabling customer engagement in distribution operations and new energy markets requires smart meters, utility tariffs that reward dynamic load control, and access to markets beyond utility tariffs (i.e., metrics 1, 2, 5, 9, and 12). Researchers note an increase in use of tariffs requiring more dynamic control, in contrast to historic demand management programs that rely on a limited number of on/off switching actions. Providing customers with greater control over how they produce and use energy behind the meter requires clear interconnection standards and supporting tariffs, such as NEM and FIT (i.e., metrics 2, 3, 5, 6, 7, 8, and 12).[106] The report notes most utilities now have interconnection standards in place or in process (metric 3). Recovery of utility investment and third-party funding (metrics 4 and 20) are also of interest because of the significant expense required to modernize the grid.

Another measure of smart grid progress is provided by the GridWise Alliance. The Alliance is a membership organization comprised of stakeholders that "design, build and operate the electric grid." Its Grid Modernization Index (GMI) provides an annual review of progress toward the smart grid ranked by state and utility.

GMI is a scorecard that ranks states on activities that impact grid modernization, which includes the following three GMI components:[107]

- State Support – state policies and regulatory mechanisms that facilitate grid investment.
- Customer Engagement – investments throughout a state in customer-enabling technologies and capabilities.
- Grid Operations – investments throughout a state in grid-enhancing technologies and capabilities.

California and Texas ranked at the top of the GMI survey in both 2013 and 2014, as shown in Figure 3.16.

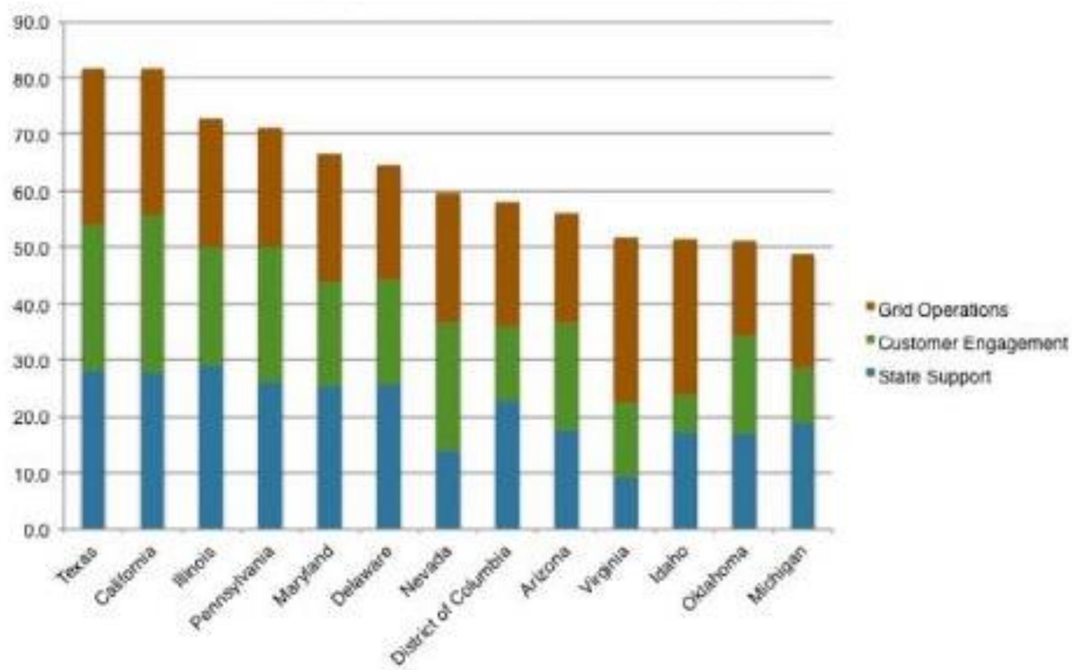

Figure 3.16. Top 25 percent of States Based on GridWise Alliance Scorecard Points from 2013 Grid Modernization Survey

California and Texas, the two most populous states in the United States, were ranked at the top of the GMI survey in 2013 and 2014.

DOE conducted an in-depth survey of five states to evaluate specific state and utility actions and their impact on the change in GMI ranking from 2013 to 2014. This study provided DOE with recommendations for how it could best assist states and utilities with smart grid actions to advance GMI rankings across the country. The five states studied were Florida, Hawaii, Illinois, Maryland, and Minnesota, representing a diversity of GMI rankings—rankings that both increased and decreased between 2013 and 2014. The ranking for two states (i.e., Florida and Maryland) decreased largely due to reduced state-level support for utility programs to encourage EE and DER. Three states (i.e., Hawaii, Minnesota, and Illinois) increased their ranking. Illinois' ranking increased the most of any state (i.e., from tenth to third place), largely due to more favorable support for utility smart grid investments by the state legislature. Illinois utilities requested legislative support to automatically recover costs for AMI investments over the subsequent two-year period. The state PUC will retain authority to review the costs to ensure they are prudent. Wholesale conversion to AMI can be jeopardized if cost recovery is at risk. This maneuver by the Illinois utilities significantly reduces that risk and will likely accelerate AMI deployment in the state.[108]

3.6 Jurisdictional Issues

3.6.1 Jurisdictional Issues for Distribution System Operations

Under the Federal Power Act FERC regulates the rates, terms and conditions of transmission service in interstate commerce. That same legislative act reserves authority to states to regulate local distribution. As technologies have advanced, however, more distributed generation and storage is interconnected with the distribution system. As these distributed resources seek to participate in wholesale markets, they must use distribution facilities to access these markets. The potential for jurisdictional conflict or confusion is evident in Figure 3.15, which illustrates two pathways to provide support to the bulk power system from facilities located on the distribution system, such as demand response services, power from distributed generators, and ancillary services from generators or storage.

As Figure 3.15 indicates, transmission system operators (TSOs) could procure services for the bulk power transmission system from retail customers just like RTOs currently do. However, distribution-connected generators wishing to bid into RTO markets may find that doing so is complicated by state/federal jurisdictional questions.

3.6.2 Potential for Operational Conflicts

Opening opportunities for retail customers to offer DR and potentially other services directly to the RTO market increases opportunities for retail customers to benefit from their investments in DER. It essentially gives retail customers the "right" to offer the services their DER devices can provide to any buyer. This creates the potential for conflicts with utility plans to use retail customer DER to meet utility needs and may decrease the certainty that those resources will be available when needed in utility operating and long-term plans. It may also require utilities to increase incentives to secure rights to these resources. On the other hand, increased competition and compensation may stimulate increased customer participation. Resolution of these conflicts may require the kind of distribution system operator envisioned by the Hawaii and New York PUCs.

4.0 Key Findings

Below are key findings that emerge from this comprehensive overview of distribution systems grouped by theme.

4.1 Distributed Energy Resource (DER) System Integration

- DER deployment is growing rapidly and is forecasted to increase over time. Traditional distribution system functions and physical architectures that enable passive one-way electricity delivery from central power plants to end-use customers are unlikely to be adequate for a high-DER future. Distribution utilities will need new approaches for system operation, grid planning, interconnection procedures, and coordination with transmission system and wholesale markets to handle forecasted increases in DER penetration.
- Proliferation of distributed generation (DG) and home area networks (HANs) has been largely driven by customer choice, which is in turn influenced by state and local policies, utility rate design, and technology cost-effectiveness. Some consumer-focused DERs, like smart thermostats and Internet-connected electric vehicle-charging infrastructure that constitute HANs, allow a more hands-off approach to energy management and greater response to dynamic price signals than what was once available. The automated nature of these devices lowers barriers for sustained household participation in demand response programs and dynamic pricing structures.
- According to one study, rural cooperatives and municipal utilities, which together serve roughly 30 percent of the nation's customers, are less likely to have distribution management system (DMS) equipment in place, thereby increasing their incremental DER integration costs relative to investor-owned utilities (IOUs), which tend to be larger. Higher incremental costs threaten to inhibit adoption of advanced grid technologies thereby excluding some, largely rural, customers from full participation in advanced grid technologies, in turn raising potential ratepayer equity concerns.

4.2 Proliferation of Advanced Grid Technologies

- Utility adoption and use of advanced grid technologies—including physical components, grid-monitoring software, and grid-management tools—vary by utility type and size. IOUs reported investment in significantly more advanced grid technologies than municipal and cooperative utilities, which are usually much smaller than IOUs. Municipal utilities are more likely than cooperatives to have implemented advanced grid technologies. The lesser degree of investment by municipal and cooperative utilities suggests that there may be significant barriers to their adoption and/or that the net benefits of these new technologies are not [yet] applicable to municipal and cooperative utilities' system characteristics. No matter the cause, the lag in advanced grid technology implementation could cause persistent differences in customer access to DER and total system costs between IOUs, which are usually large and serve urban customers, and municipal and cooperative utilities, which are usually smaller and serve rural customers. There is still a need, however, for more analysis to understand barriers and implications for the lack of small utility adoption of advanced grid technologies.

- Utilities have installed various advanced grid management systems, though these systems are rarely integrated with one another, potentially limiting their full contribution of system benefits. One survey of utility professionals found that data management, analysis, application, and integration of both systems and data from disparate systems is their greatest challenge to utility management.
- A foundational technology to enable the grid of the future is Supervisory Control and Data Acquisition (SCADA). SCADA extends beyond the distribution substation to provide situational awareness of distribution system status, automation of critical distribution system management components, and a communications system that can interact with individual customers and their grid-connected end uses. When distribution-level SCADA pairs with a DMS, formerly manual operations can be conducted remotely, increasing the speed at which a utility can identify and locate faults on the distribution system and restore service as well as manage voltage and reactive power to reduce energy losses and integrate distributed generation and storage technologies. Maximizing the value of DER will likely require the integration of advanced grid software and hardware; utility challenges with integration may prove to be a barrier for efficient proliferation of DER.

4.3 Risk and Regulatory Approval of Advanced Grid Technologies

- Costs of advanced grid technologies, weighed against uncertain financial benefits for utilities and their customers, have stymied utility investment. The impasse stems from utilities' concern about the likelihood of obtaining regulatory approval of advanced grid technologies, costs, and regulators' concern that costs to consumers may not be commensurate with their benefits.
- Utility estimates suggest that initial DER integration costs will largely be for enabling infrastructure—such as two-way communication and control systems, metering, and safety equipment—which is unlikely to provide an immediate financial benefit to offset the initial costs.
- Use of uniform equipment and standard design criteria has lowered utility costs and enabled rapid restoration of service; they have also made it harder to implementing non-uniform parts and procedures in utility systems. Performance risk, or the risk that the product will not perform as expected, is greater for advanced grid components and systems than for comparable traditional assets.
- Stranded costs and risks associated with rapid obsolescence of advanced technology have presented barriers to utilities' and regulators' acceptance of new technologies. Several policy and regulatory options have come into existence to mitigate risk associated with rapid obsolescence of advanced grid technologies. Proliferation of these policy and regulatory measures could facilitate utility adoption of advanced grid technologies.

4.4 Distribution System Planning and Analysis

- Tools that utilities use for long-term resource planning, short-term power management, transmission planning and operations, distribution planning and monitoring, revenue forecasting, and rate setting are purpose-specific and generally not integrated with one another. This lack of integrated-analysis tools complicates the integration of advanced grid technologies. The complexity and costliness of integrated systems modeling tools may stymie utility-by-utility development; the industry may benefit from flexible and specifiable shared modeling resources.

4.5 Distribution System Efficiency

- While the U.S. electric transmission and distribution system is among the most efficient in the world, roughly 6 percent of total generated electricity is lost in the system.
- One of the largest sources of loss is distribution transformers, which contribute roughly a third of total losses, or 2 percent of all generated electricity in the United States. However new federal efficiency standards are expected to reduce these losses significantly, saving 3.6 quads of energy over 30 years.
- Further efficiency improvements are possible with both upgrades to more efficient equipment as well as new technologies that allow for the more efficient management of power flows to reduce losses.
- No one has undertaken a comprehensive, national study of the economic potential for efficiency upgrades in the U.S. distribution system. Studies of loss-reduction potential for specific technologies have estimated what losses each technology could reduce; however, these studies predominantly focus on the technical potential of either full deployment of a technology or optimizing operations to minimize losses. These results are likely to overstate the potential for loss reduction when improvements must also be subject to cost-benefit tests or other network-specific operational constraints.
- Replacing existing infrastructure for loss-reduction purposes alone is typically not justifiable on economic grounds. However, there can be positive net benefits for incorporating loss-reduction considerations into the design or planning of new capacity or reliability investments being made for other reasons.
- Efforts to invest in cost-effective efficiency improvements are likely further constrained in part by regulatory policies that do not allow recovery of the cost of the full capture of efficiency benefits by the operators who would incur the costs. For example, most states that require utilities to meet energy efficiency resource standards allow only end-use efficiency to count toward the target, meaning that there is no incentive for transmission and distribution (T&D) investments, which could have the same impact of reducing the level of generation needed to meet demand.

4.6 Microgrids

- Although a number of microgrid systems are being demonstrated, it will be difficult to increase the utility industry's average reliability. Most IOUs claim 99.9 percent availability or better. Large utilities, like those serving urban areas, tend to have lower outage rates than smaller utilities. Despite the high reliability and relatively low cost of utility-provided power, in some cases, the added expense of a microgrid will justify the associated benefits of increased reliability.

- Motivations for building microgrids vary regionally and among entities with different goals. Among the Mid-Atlantic states, microgrids are seen as a bulwark against the widespread grid outages caused by events like Superstorm Sandy. In California, they are seen as a natural extension of the state's RPS, sustainability, and retail choice policies. The U.S. Department of Defense's motivation is its need for secure energy to sustain operations during grid outages at permanent bases as well as more efficient ways to provide power when operating outside of the United States.
- Microgrid operators coordinate load and generation within their own system and with the utility. This coordination can make it easier to integrate DER than it would be with an equivalent collection of dispersed resources.

4.7 Utility Business Models

- The conventional regulatory framework has been assumed to provide IOUs with an incentive to favor capital investments that add to the utility rate base, so as to increase stockholder earnings from the allowed rate of return and to promote increased energy sales. The profits from increased energy sales can be a disincentive for fair consideration of energy efficiency or other, more optimal strategies to serve customers. Decoupling revenues from energy sales allows utilities to meet revenue targets via rate true-up mechanisms even if energy sales are low. If designed and implemented correctly, decoupling should have the effect of stabilizing the revenue stream of the utility because its revenues are no longer dependent on variable sales. Sixteen states are now experimenting with decoupling. Incentive regulation is similar to decoupling in that the revenues utilities earn are at least partly decoupled from sales and tied to meeting performance goals. However, decoupling and incentive ratemaking alone do not directly address the issue of utilities potentially favoring their own financing of infrastructure over considering other, potentially less costly, options.
- The number of IOUs continues to decrease through mergers to form ever-larger utilities and utility holding companies spurred by the hope of benefits from economies of scope and scale, and ultimately motivated by the expectation of increased investor returns. If municipal and cooperative utilities cannot take advantage of economies of scope and scale, this may increase differences between IOUs and municipal and cooperative utilities in terms of relative system costs and the ability to adapt to changing requirements of an advanced grid future. More analysis is needed to understand if there are systematic barriers to grid modernization facing smaller utilities.
- Several states are considering how to redefine the roles, responsibilities, and incentives of regulated utilities. In some cases, as in Hawaii and New York, the redefinition, in part, explicitly addresses the challenges and opportunities of DER. Even utilities in the states that are not currently redefining the role of electric utilities will need to develop new business processes to harness opportunities presented by advanced grid technologies, especially those related to information technology systems.

4.8 Data and Analysis Needs

- Information on distribution infrastructure by utility type is difficult to collect due to inconsistencies in reporting. For example, the U.S. Department of Energy's (DOE's) Energy

Information Administration (EIA) provides summaries of data from the Annual Electric Power Industry Report Form EIA-861, including the number of distribution circuits for each responding utility. However, information on circuit voltage and length is not provided. Although Form EIA-861 data is the most comprehensive, statistical summaries drawn from it are sometimes at odds with surveys using better data collection protocols, clearer definitions and directions, fewer yes/no response categories, and follow-up clarifications. EIA also exempts utilities with fewer than 100,000 megawatt-hours (MWh) in annual sales from full reporting. The short version of Form EIA-861, which exempt utilities use, has very limited information and doesn't permit cross tabulation by utility type or customer class. This is a segment of the industry about which little is known and, from its responses, appears to have invested less in grid modernization than its peers. More and better data, through targeted surveys of utilities by type and size, would facilitate a better understanding of the unique challenges presented by the comparatively small size of municipal utilities and geographic scale of cooperative utilities.

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Appendix A

20th Century Distribution System Operation

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20th Century Distribution System Operation

The essential elements of the electrical distribution system have been used for much of the 20th century to provide reasonably priced, reliable power to customers. The component technology used in operating the distribution system has not changed much over the decades, seeing more evolutionary and incremental changes. While the components have improved, the design and operating techniques have remained largely the same.

The beginning of the 21st century is seeing changes in incentives and technology that are challenging the established assumptions about the nature of the distribution system. The digital revolution and increased concerns over emissions and system efficiency are enabling a greater level of control and granularity of operation, while also placing greater expectations on and requiring higher levels of service from the distribution system operators. To provide context for understanding the challenges distribution system operators face as they move into the next century (both literally and metaphorically), this appendix seeks to explain and illuminate the state of the existing distribution system—the 20th century distribution system as it has existed and operated for decades. For the purposes of this discussion, this distribution system will be described in terms of three essential services it provides: customer voltage (A.1), service reliability and protection (A.2), and harmonic mitigation (A.3).

A.1 Distribution System Voltage Management

In conjunction with maintaining system frequency (a job traditionally left to the wholesale transmission system), maintaining system voltage is of central importance to the operation of the electrical system. Equipment that connects to the system expects and requires a defined voltage to operate properly. In the distribution system, the responsibility of managing the system voltage falls to the local utility. This section will describe not only the cause of voltage problems in the distribution system but also the techniques traditionally employed for managing them.

A.1.1 Causes of Varying Voltage in the Distribution System: Losses

Fundamentally, electrical current flowing over the distribution system wiring causes a reduction in voltage in the distribution system. The delivery of any amount of power over a wire or cable of any resistance will cause energy loss in the form of heat. This lost power is proportional to the square of the current and directly proportional to the resistance along the path the current flows; this lost power is called the technical loss of the system. (Non-technical losses such as unmetered energy consumption and energy theft are not considered here.) These losses manifest themselves as reduction in voltage as seen at the point customer's connection to the system.

A.1.1.1 Distribution System Circuit Resistance

One of the primary contributions to the resistance in a circuit is the wiring or cabling used to transport the electrical energy. The resistance of the conductor is a function of the size of the conductor; larger diameter wire sizes have less resistance.[1] Though larger conductors reduce losses, they are more expensive and heavier, leading to further distribution system infrastructure expenses. Part of the challenge of designing any particular circuit well is weighing the trade-offs between these and other factors to minimize losses while also minimizing expenses.[2]

The majority of the technical losses in the distribution system come from the transformers.[3] There are typically two transformers along the distribution system energy delivery path for any given customer: the substation and distribution transformers (the latter is discussed below).[4] Each of these transformers has internal-conductor windings that are resistive—as well as a transformer core that produces losses as it facilitates the change in voltage.[5] As with the conductor sizing in distribution system wiring, larger transformers with more efficient cores are available, but they are more expensive and, depending on the distribution system architecture, may be difficult to install.[6]

A.1.1.2 Distribution System Current

To reduce the technical losses, distribution system operators use a relatively high voltage (as compared to the voltage delivered to customers) in most of the distribution system. Since power is the product of the voltage and the current, using a higher distribution voltage (typically somewhere between 9 kilovolts (kV) and 35kV, often around 13kV) reduces the current on the distribution lines proportionally and thus the resistive technical losses as well.

High distribution system voltage requires a transformer to step the voltage down to the service voltage used by the customers. This distribution system transformer is placed as close as possible to the customers' service connection and reduces the voltage down to 480 volts (V) and 240V/120V for commercial/industrial and residential customers, respectively, in the United States. The distribution transformer is designed to provide the customer two 120V connections that are 180 degrees out of phase with each other with a common neutral wire (center-tap transformer offering split-phase service). This configuration allows for safer, lower-voltage (120V) connections for most customer applications, while still allowing higher-voltage (240V, and thus lower current) connections for high-power loads (e.g., electric heaters and air-conditioners).[7] It is common for a single distribution transformer to serve multiple customers.[8]

Some customers—particularly heavy commercial or industrial customers—will have loads that require all three phases from the main feeder. These three-phase loads are typically motor loads for industrial processes or larger, commercial air-conditioning units.[9, 10] Providing three-phase service is not technically difficult; however, it is more expensive and, thus, not common for residential customers.[11]

The largest current demands in the distribution system come from the energy loads, or end uses, on the system. This is the current that power distribution systems are fundamentally intended to provide, the current that loads are made to use and that the utility company bills for. This current results in real power, is billed by the utility, and has common units of kilowatt-hours (kWh). However, not all of the current that flows through the distribution system results in real power consumption. Depending on the types of loads, some of the current draw is out of phase with the voltage; this is called reactive current/power. Reactive current/power is drawn by a variety of loads, the most common being motors. Because it is out of phase with the voltage, a motor does not actually do any work and, as such, does not count toward the customer's bill for the month.[12] Unless other provisions are made, the bulk power system generators supply this reactive current/power, which then travels all the way from those generators to the motor load, adding to the total current on the conductors and, hence, the losses in the system. Though the physical units are the same as real power, reactive power is given a different unit name, volt-amps reactive, to aid in technical discussions.

A.1.2 Effect of System Losses on Voltage

The resistance and current in the distribution system result in a reduction in voltage. Under typical conditions, as the length of the distribution circuit increases, the total resistance of the conductors increases, the total current increases (assuming the addition of more customers), and the reduction in voltage increases. The American National Standards Institute's (ANSI's) established standards define an acceptable voltage range for electrical power in the United States. For customers at the end of the distribution circuit, the losses in the system can be significant enough to move a customer outside the acceptable range, which can result in customer equipment that fails to operate or is damaged. This low-voltage condition may be a function of the total load on the circuit, manifesting only during times of high load on the distribution system. During the overnight hours or in the fall and spring when loads on the circuit are low, the voltage may be within limits and cause no problems. In the heat of a summer afternoon when air conditioners have heavily loaded the circuit with both real and reactive power demands, the voltage may drop below the acceptable lower limit for some customers along the distribution line.

ANSI standard C84.1 defines operating limits for distribution systems. The ANSI limits apply to the voltage at the point of delivery for the end-use customer:

- Range A (normal steady-state): 114V–126V (RMS)[1]
- Range B (emergency steady-state): 107V–127V (RMS)
- < 3 percent voltage unbalance at the utility meter.

The voltage supplied to the customer is generally maintained within the limits set by ANSI C84.1. This is done by setting the voltage at the head of the feeder at the high end of the band, to ensure that the voltage drop at peak load does not exceed limits.

The voltages shown in Figure A.1 below are the example voltages seen by a representative end-use customer.

[1] "The root-mean-square (rms) phase-to-phase voltage of a portion of an alternating-current electric system," as defined by ANSI.

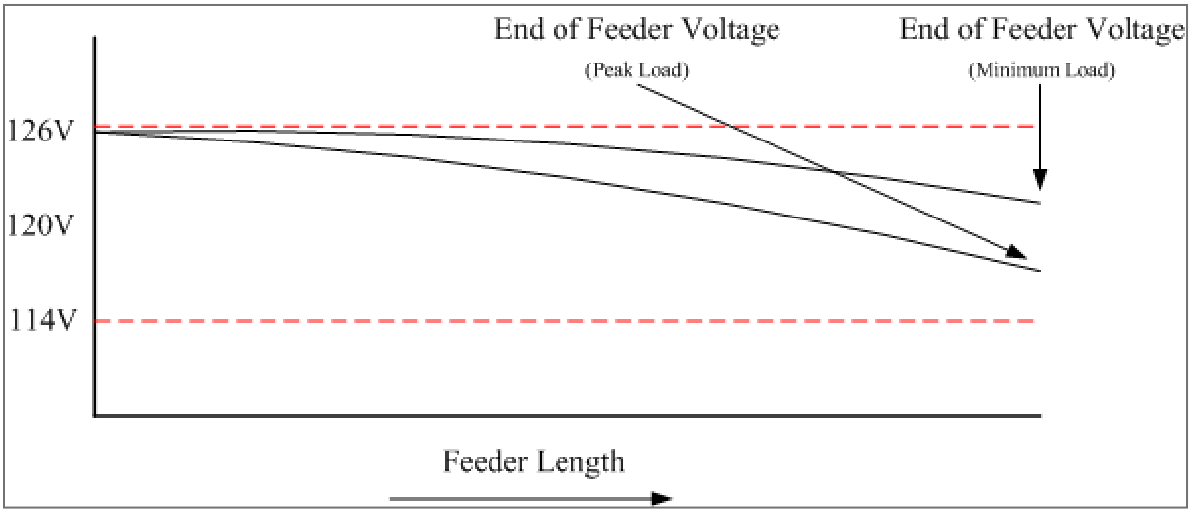

Figure A.1. Example Voltages as Seen by a Representative End-Use Customer[13]

The figure shows example voltages seen by a representative end-use customer.

Figure A.2. Transmission Lines Tie into a Substation Transformer (center) and Voltage Regulator (right) (Photo credit: Kevin Schneider, PNNL)

A photograph shows a real-life example of transmission lines tying into a substation transformer.

Figure A.2 shows high voltage lines from a transmission system attached to a substation transformer and voltage regulator. (Not shown in the image is the connection to the distribution system feeders.)

A.1.3 Solutions in Voltage Management

Given the aforementioned losses in the system, the effects they have on distribution system voltage, and the regulatory requirements of maintaining acceptable distribution system voltage levels, a few standard methods of managing and maintaining voltage have been developed— the most common being voltage regulators and capacitor banks. Another option would be the replacement of the distribution system lines with larger, lower-resistance options. In most cases, replacing distribution system lines would be much more costly than the voltage management methods discussed below and, unless there is another compelling reason to consider doing so, it is generally not considered.[14] Another option would be increasing the distribution system voltage level, for example, from 12 kilovolts (kV) to 34 kV. Such a change would require an increase in conductor size.

A.1.3.1 Voltage Regulator

As the load on the distribution feeder increases, points further from the substation can experience lower voltage than those that are closer, especially when customer loading is heavy (e.g., during peak demand periods). Under high-load conditions, the voltage at the far end of the feeder may exceed the American National Standards Institute -specified range of acceptable voltage.[15] One method of correcting this problem is the installation of a tap-changing transformer, also known as a voltage regulator.

A voltage regulator is a variable transformer with the ability to self-adjust its output and alter the downstream voltage.[16] The transformers discussed elsewhere in this report have been used to make large changes in voltage between the higher distribution system voltage (often around 13 kV) and the customer voltage (480V, 240V, or 120V). However, a voltage regulator is a transformer that makes relatively small changes in voltage and can vary the difference between the input and output voltage. Generally speaking, voltage regulators have the ability to adjust their output voltage to be slightly higher or slightly lower than the input voltage.

Voltage regulators are commonly located at the top, or head, of a feeder as a part of a substation's infrastructure. When placed at the head of a feeder, a regulator works to ensure the voltage at the beginning of the feeder is high enough (while still staying within acceptable limits) to ensure that loads at the end of the feeder do not fall out of the acceptable range. The need for voltage regulators often occurs because the transmission system voltage that feeds the substation transformer (and the rest of the distribution system feeder by extension) also experiences variation as the system condition changes. A regulator at the substation head is often essential to make sure the feeder starts out at the designed voltage level.[17]

Another common location for a voltage regulator is at the midpoint of a feeder. If the voltage on a feeder drops to an unacceptable level at a certain point distant from the substation, the best solution may be to install a voltage regulator midstream (Figure A.3). Such an installation would raise the voltage from a potentially unacceptable low level to a level appropriate to serve the rest of the feeder (Figure A.4). The high cost of voltage regulators ensures that this is an action of last resort; however, it may be the case that installing one or more regulators becomes essential to maintaining a reasonable voltage profile.[18]

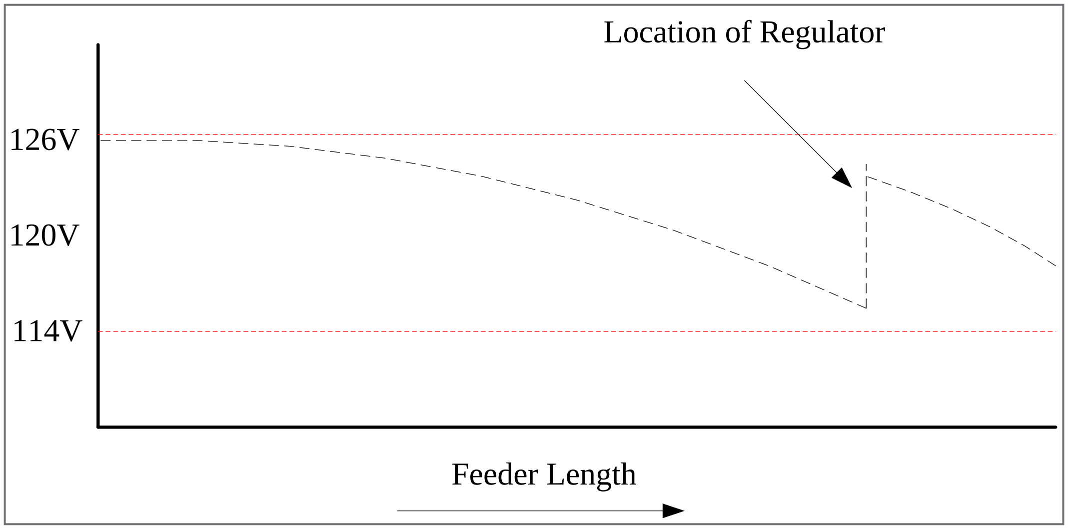

Figure A.3. Voltage Regulation Using Supplemental Regulators[19]

The graph shows the change in voltage that occurs with a regulator.

Figure A.4. Photo of Distribution Voltage Regulator (Photo credit: Kevin Schneider, PNNL)

A voltage regulator at the midpoint of a feeder.

A.1.3.2 Capacitor Banks (Switched or Fixed)

For systems with motors making up a significant portion of the total load (e.g., air-conditioners), some of the current on the feeder that causes a low-voltage condition is called reactive current or reactive power.[20] The substation normally supplies this reactive current, which flows from there to the motor load, contributing to the voltage drop along its entire path.[21]

For high reactive current flows, a common and relatively inexpensive solution is to install capacitor banks, which act as sources of the reactive current that motor loads provide. By choosing judicious installation locations, the path the reactive current must flow through can be greatly reduced, which, in turn, reduces the losses caused by the extra current on the distribution lines and increases the voltage (Figure A.6).[22]

Depending on the nature of the motor loads on the system, some capacitor banks may be permanently connected to the system (fixed) and some may have the ability to switch in (switched). Switched capacitor banks are often set up to provide reactive current support during periods when air-conditioning load is high. It is not uncommon in these cases for switched capacitor banks to automatically switch into place based on measured voltage, or ambient temperature[23] if air-conditioners are the cause of reduced system voltage.[24]

It is important to note that capacitors only provide voltage support for reactive or motor-based loads. If the load is mostly resistive, such as in the case of electric furnaces, heaters, or consumer electronics, the use of capacitors will not improve the voltage profile. These loads are not drawing substantial reactive current, and thus, a reactive current source will not reduce the voltage drop on the line.

If a feeder is heavily loaded, the installation of a shunt capacitor (Figure A.6) can reduce the reactive power flows, and thus, reduce the voltage drop, as shown in Figure A.5.

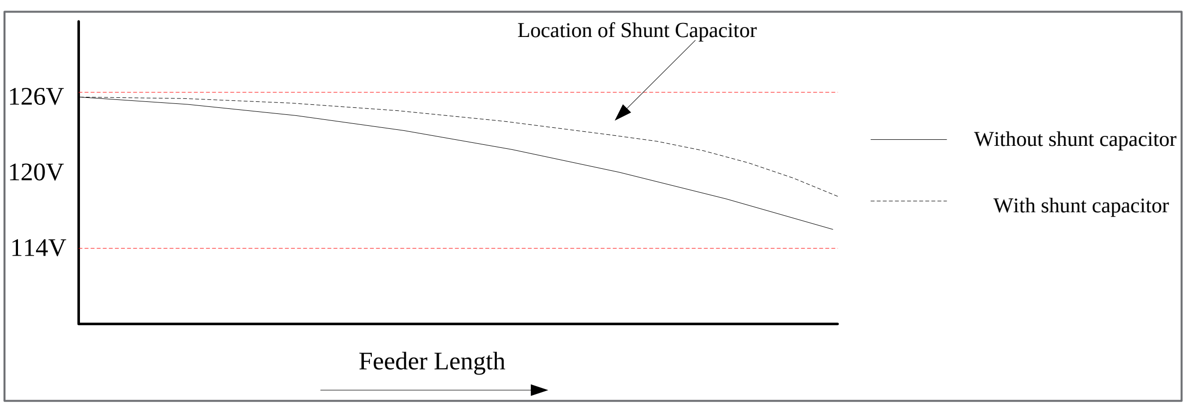

Figure A.5. Location of Shunt Capacitor[25]

Above, the chart shows the difference in voltage drops with and without a shunt capacitor.

Figure A.6. Photo of Shunt Capacitor (Photo credit: Kevin Schneider, PNNL)

Shunt capacitors can reduce the reactive power flows, and thus, reduce the drop in voltage.

A.1.3.3 Load Reduction

The last and most direct way to reducing system losses and improve the voltage profile on a feeder is to reduce the total amount of current flowing through the distribution feeder. Generally, the utility operating the distribution system has very little direct control over when and to what extent customers use energy; thus, most traditional methods for reducing losses are indirect.

The most common technical approach to reducing load is conservation voltage reduction (CVR). CVR equipment draws slightly less current when there is a reduction in the voltage that is powering it. The effectiveness of CVR varies depending on the loads and customers' behavior; however, the general reduction in load is a few percent with no perceived change in service to the customer.[26] A more recent term of art for this concept is voltage optimization. The electricity utility industry is recognizing voltage optimization, defined as a combination of distribution system efficiency and CVR, as a valuable low-cost resource for energy conservation.[27]

A.2 System Protection and Outage Management

A common failure in the distribution system is a short circuit or fault, in which two parts of the system that are normally not connected become connected, causing a large and potentially dangerous amount of current to flow through the distribution system. Possible causes of a short include a tree limb falling and breaking a distribution line, a storm knocking over utility poles, or equipment overheating and failing. These large currents can lead to damaged distribution equipment, incite catastrophic failures in connected or related equipment and systems, and pose a safety hazard to the general public. To prevent these fault conditions from persisting, there are a few established techniques for containing the damage caused by unexpected failures.

A.2.1 Fuses and Circuit-Breakers

Protection of the distribution system equipment (and by extension, customer equipment) is a fundamental concern for utilities. The most common forms of protection are fuses and circuit-breakers, as shown in Figures A.7 and A.8, both of which cause the circuit to open in the presence of too much current, thus removing power from part of the system.[28] It is common to have multiple layers of protection. The first layer involves fuses located closer to the customers, on poles, that are designed to open at lower levels of over-current or with shorter fault times. The second layer of protection is circuit-breakers located in the substation. This tiered approach is prevents the smallest number of customers from losing service during an over-current condition and ensures that the failure of a single fuse or circuit breaker does not damage the entire circuit.[29]

Both fuses and circuit-breakers have traditionally required manual intervention (replacing the fuse, which can lead to relatively long outage times or resetting the circuit breaker) to re-connect the circuit. Now, circuit-breakers are often under supervisory control and data acquisition (SCADA) control. Fuses are also the least expensive forms of circuit protection available, and system designers have a lot of experience in using them in designs and understanding how they will perform relative to circuit-breakers located in the substation.[30]

Figure A.7. Three-Phase Line Fuses with Lightening Arrestors between Fuse and Overhead Line (Photo credit: Mike Hoffman, PNNL)

One of the most common forms of protection of the distribution system equipment is a fuse.

Figure A.8. Circuit Breaker: Able to Interrupt Fault Current and Disconnect Feeder Line Faults from the System (Photo credit: Kevin Schneider, PNNL)

One of the most common forms of protection of the distribution system equipment is a circuit breaker.

A.2.2 Reclosers

Many types of over-current faults are temporary in nature, such as a tree limb shorting out two phases of a feeder. In such cases, the limb will quickly burn up, causing the fault condition to clear. In other situations, a temporary fault may continue due to the establishment of an arc. The flow of current through an arc ionizes the surrounding air and provides a continued path of low resistance allowing the arc to survive and continue. In either case, the temporary removal of power from the circuit will cause the problem to clear and immediately restore electrical service. Reclosers are located either in the substation at the head of a distribution feeder line or on the distribution feeder line, usually halfway or further along the feeder (Figure A.9).

Reclosers are circuit breakers that detect fault conditions and attempt to interrupt and clear them by automatically opening and closing the circuit a number of times. On each reclosing of the circuit, equipment internal to the recloser evaluates the system, and, if a fault is still detected, it opens and closes again. After a predefined number of recloser cycles, the device will open and stay open until manually reset.[31] Reclosers are more expensive and complex than fuses or circuit-breakers, and could benefit from additional research to determine optimal settings.[32] Reclosers do, however, have the potential to eliminate a trip by a service technician to replace a fuse or reset a circuit breaker.

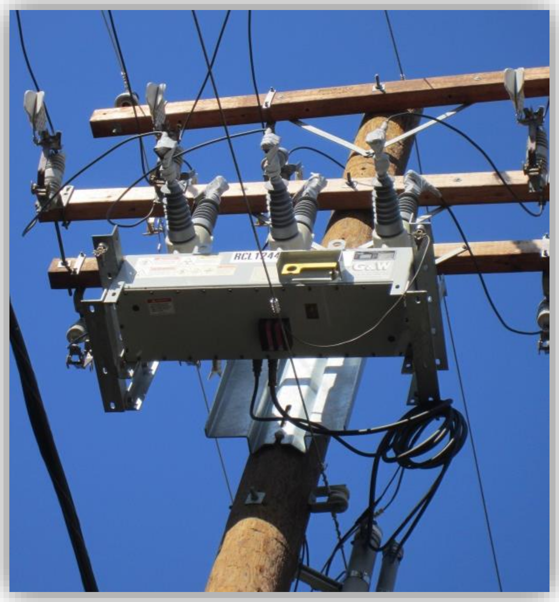

Figure A.9. Distribution Feeder Line Recloser (Photo credit: Kevin Schneider, PNNL)

Reclosers are circuit breakers that detect fault conditions and attempt to interrupt and clear them by automatically opening and closing the circuit a number of times.

A.2.3 Fault Localization

Once the protection system has activated and isolated the fault from the rest of the system, the distribution system operator needs to determine the location of the fault and the nature of the repairs to be made. Because of the general lack of instrumentation in the distribution system, the amount of automated data readily available to determine the location and nature of the fault is very limited. SCADA would likely provide enough information to determine which feeder is affected and any down-feeder instrumentation that exists may provide additional information; however, this is typically insufficient to determine the extent of an outage.[33]

To handle this information gap, utilities have traditionally relied on customer reports of loss of service as a primary data path for determining the extent of an outage. Utilities mark the locations of customer reports on a map of the system, allowing crews to determine the precise location and nature of the fault.

A.2.4 Sectionalizers

Sectionalizers are manually operated switches designed to sub-divide a distribution line to allow service technicians to perform maintenance or make repairs without having to de-energize the entire feeder or lateral (Figure A.10). After a fuse or circuit breaker has de-energized a portion of the circuit and the exact location and nature of the fault determined, sectionalizers may be opened to isolate the fault in the circuit. While crews repair the fault, they can replace the fuse or reset the circuit-breaker to restore service to the upstream customers on the affected circuit.[34, 35]

Figure A.10. Photo of Sectionalizers (Photo credit: Mike Hoffman, PNNL)

Sectionalizers are manually operated switches designed to sub-divide a distribution line to allow for repairs.

A.2.5 Alternative Circuit Connections

In some cases, geographically adjacent feeders or laterals sourced from a different substation or feeder may have normally open switches that can provide an alternative path of electrical energy. If there is a loss of power from the primary energy source and any appropriate sectionalizers have isolated the fault, this switch can be closed to re-energize the circuit from this alternative source. Such switches allow for increased reliability of service by providing a redundant source of energy, but they also increase the complexity of the system design by requiring different operating and protection schemes depending on the direction of energy flow.[36]

A.2.6 Reliability Metrics

As a means of measuring the performance of the utilities in their jurisdiction, state regulators and utility commissions have developed and commonly use a number of standardized metrics. Among the more popular are the following (Figure A.11):

- System Average Interruption Frequency Index (SAIFI) = Total number of customer interruptions /Total number of customers served.
- System Average Interruption Duration Index (SAIDI) = Sum of all customer interruption duration /Total number of customers served.
- Customer Average Interruption Frequency Index (CAIFI) = Total number of customer interruptions /Number of distinct customers interrupted.
- Customer Average Interruption Duration Index (CAIDI) = Sum of all customer interruption durations/Total number of customer interruptions.

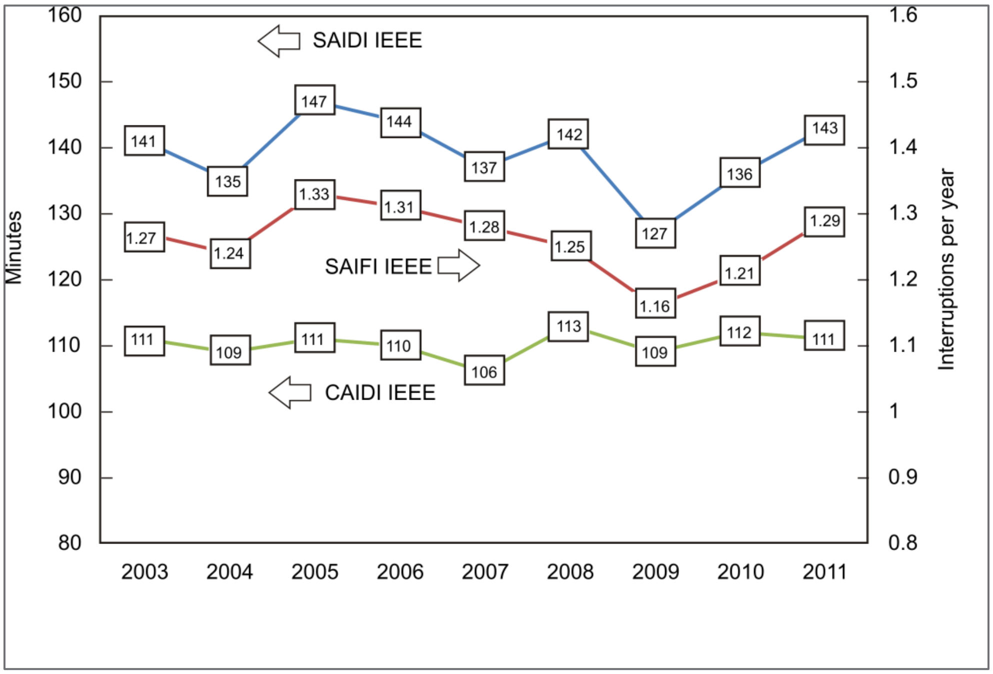

Figure A.11. SAIDI, SAIFI, and CAIDI Reported in 2003-2011 Institute of Electronics and Electrical Engineers (IEEE) Benchmarking Reliability Studies[37]

Benchmarking reliability study data reported to IEEE by SAIDI, SAIFI, and CAIDI from 2003–2011.

Each of these metrics attempts to capture a certain aspect of outage patterns of the distribution system and the utility's ability to correct the failure and restore service. For example, SAIFI and SAIDI look at the outages in terms of the size of the total system while CAIFI and CAIDI consider outages from the perspective of individual customers. Many other similar metrics have been developed to bring out certain aspects of the outage patterns in a system.

A.3 Harmonics

A harmonic is a multiple of a base of fundamental frequency. They are a common feature of all systems where frequency plays a vital role, such as music or radio communication systems. In the electrical system, the fundamental frequency is 60 hertz (Hz); thus, the harmonics are multiples of 60 (e.g., 120, 180, and 240 Hz). These harmonics are undesirable for reasons explained in the following sections, and although utilities have little control over their creation, utilities are partly responsible for managing them. The following sections describe common causes, complications, and mitigation of harmonics in the distribution system.

A.3.1 Harmonic Sources

If all loads and generators on the system were entirely linear, the only frequency that would ever exist on the distribution system wires would be the fundamental 60 Hz. Due to non-linearities in the system though, harmonics develop. One of the primary causes of harmonics (sometimes called “harmonic distortion” referring to its effect on the 60 Hz waveform) are non-linear loads. Many traditional electrical system loads are highly linear, namely incandescent lighting and (to a lesser extent) electric motors. Because solid-state technology is non-linear, as solid-state loads increase so do harmonics.[38] Computers, televisions, printers, radios, and variable frequency motor drives (from industrial customers) all inject harmonics back into the electrical distribution system.

In addition, transformers operating with their cores saturated (typically an abnormal state) can generate harmonics due to the non-linearities in the transformer core.[39] A similar condition can occur in electric motors.

A.3.2 Common Complications Due to Harmonics

A.3.2.1 Increased Neutral Wire Current in Three-Phase System

Many harmonic-causing loads are single-phase loads that increase harmonic currents on the neutral or return path of a three-phase system. These harmonic currents, when flowing through the resistance of the neutral wire in the power distribution system, cause a voltage to develop on the neutral conductor due to the resistance of the conductor. This is potentially dangerous because the neutral conductor is assumed to be to be very close to or at zero potential (“grounded”) throughout the system. High voltage caused by harmonic currents may pose home safety risks to service technicians.[40]

A.3.2.2 Damage-Causing Resonance

Inductance in lines and transformers, when combined with power factor correction from additional capacitance, can lead to unexpected resonance in the distribution system. This resonance can occur at any one of the system harmonic frequencies, making the system impedance appear much lower than it would otherwise. Lowered impedance leads to higher total current levels, which leads to increased system losses and potential damage to distribution equipment.[41]

A.3.2.3 Motor Losses and Overheating

For customers using alternating current (AC) motors, harmonics can create multiple problems. Because the harmonic current flowing in the windings of the motor is not at the electrical frequency of the motor (i.e., 60 Hz), the torque on the shaft of the motor can increase or decrease. In addition, the harmonic current in the windings and core can increase system losses and the potential for overheating or premature equipment failure.[42]

A.3.2.4 Transformer Losses and Overheating

Harmonics in transformers cause issues similar to those in AC motors (See Section A.3.2.3). Harmonic currents in transformer windings contribute to the total current in the windings without being productive to the distribution system. In addition, these harmonic currents generate harmonic fluxes in the transformer core, producing eddy currents that lower transformer efficiency and can potentially lead to premature failure.[43]

A.3.3 Harmonic Mitigation Techniques

The most basic method of mitigating harmonics is to replace affected equipment or wiring in the distribution system. Installing comparable equipment with higher power ratings will not remove the harmonics from the system but will eliminate the problems they are causing with that specific equipment.[44] Beyond that, the Institute of Electrical and Electronics Engineers Standard 519 provides guidance on mitigating harmonics.[45] A discussion of two traditional methods of mitigating harmonics is below.

A.3.3.1 Filters

By definition, the frequency of the harmonics is distinct from that of the fundamental frequency. Thus, frequency filtering techniques similar to those used in communications or audio applications are applicable. Filters greatly reduce the amplitude of the harmonic content above the fundamental frequency. Note that to be used in the power system, filter components must be rated to handle the relatively high power requirements (as compared to low-level communications filters).[46]

A.3.3.2 Three-Phase Transformer Configuration

Although most harmonics are generated in end-use equipment, reconfiguration of laterals may mitigate them.[47] There are two common configurations in a three-phase distribution system: delta and four-wire wye. The delta configuration reduces harmonics on the system; however, its use to mitigate harmonics may require transformers to have higher ratings than would otherwise be necessary to avoid overheating."[48, 49]

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