Chapter II

MAXIMIZING ECONOMIC VALUE AND CONSUMER EQUITY

Technology-enabled changes on both the consumer and utility sides of the electric meter are creating significant economic value for the Nation's electricity consumers. Technology is also altering the role of consumers and their relationship with utilities and related service providers. These changes are creating new challenges in rate design, the role of markets, and Federal and state jurisdictional roles; enabling new business models; and creating electricity end-use and grid-management opportunities. They could also have disproportionate impacts—both positive and negative—on vulnerable populations and communities.

FINDINGS IN BRIEF:
Maximizing Economic Value and Consumer Equity

- Advanced metering infrastructure has had a profound impact on the nature of interactions between the electricity consumer and the electricity system, allowing a two-way flow of both electricity and information and enabling the integration of assets behind the meter into the larger electric grid.
- Interconnection standards and interoperability are critical requirements for seamless integration of grid-connected devices, appliances, and building energy-management systems, without which grid modernization and further energy efficiency gains may be hindered.
- Evolving consumer preferences for electricity services are creating new opportunities.
- The convergence of the electric grid with information and communications technology creates a platform for value creation and the provision of new services beyond energy.
- There is enormous potential for electric end-use efficiency improvement based on (1) technical analyses, and (2) the differences in energy efficiency performance between states and utilities with and without ambitious electric end-use efficiency policies and programs.
- Tribal lands have the highest rates of unelectrified homes in the contiguous United States and Alaska. The extreme rurality of some tribal communities coupled with high levels of poverty present an economic challenge for the electric utilities trying to serve them.
- Optimization of behind-the-meter assets will require the design of coordination, communication, and control frameworks that can manage the dispatch of these devices in a way that is both economical and secure, while maintaining system reliability.
- Mobile, internet-connected devices foster new ways of consumer engagement, as well as enable consumers to have more efficient and real-time management of their behind-the-meter assets.
- Consumers and third-party merchants who produce electricity can provide economic, environmental, and operational benefits.
- New grid services, modern technologies, and evolving system topologies and requirements are straining traditional methods of valuation. Appropriate valuation of the grid services by various technologies is technically and administratively challenging, and it may depend on spatial and temporal variables unique to different utilities, states, and regions.
- Currently, about 90 percent of residential, 60 percent of commercial, and 30 percent of industrial energy consumption are used in appliances and equipment that are subject to Federal minimum efficiency standards implemented, and periodically updated, by the Department of Energy. Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quads, and reduce carbon dioxide emissions by over 2.26 billion metric tons.
- Miscellaneous electric loads—devices that are often inadequately addressed by minimum standards, labeling, and other initiatives—are expected to represent an increasing share of total electricity demand, particularly for the residential and commercial sectors.
- Connected devices and energy-management control systems are decreasing in cost and improving in functionality, although their market penetration is still low, particularly in residences and small-to-medium-sized commercial buildings. These new technologies and systems, as well as the broader 'Internet of Things,' provide a wide range of options for consumers to manage their energy use, either passively using automated controls or through active monitoring and adjustment of key systems.

FINDINGS IN BRIEF:
Maximizing Economic Value and Consumer Equity (continued)

- Energy-management control systems with communication capabilities are increasing opportunities for demand response services in support of grid operations. Third-party aggregators and other business models are facilitating the expanded use of demand response, but the regulatory environment remains unsettled in many states.
- Lower-income households use less energy but pay a considerably higher fraction of their after-tax income for electricity services.
- Insufficient broadband access in rural areas could inhibit the deployment of grid-modernization technologies and the economic value that these technologies can create.

Maximizing Economic Value and Consumer Equity

The electricity sector has been an economic engine for the United States for more than a century, providing reliable and competitively priced electricity that is critical for the United States' productivity. The vast majority of American consumers—including households, businesses, and institutions—enjoy reliable and affordable electricity that enables a modern economy and a high standard of living. The United States relies on electricity to illuminate schools, heat and cool homes, power manufacturing facilities, and support nearly all forms of economic activity. Some American households, however, still lack basic access to electricity.

Electricity customers can now both produce and consume electricity. This is fundamentally changing the relationship between the customer and his or her utility from that of a consumer who simply pays for electricity services to a "prosumer"—a customer who can also sell electricity supplies and services to the grid. New technologies that enable the two-way flow of both electricity and information have expanded the value proposition of the grid by enabling the integration of assets behind the meter into the larger electric grid. These consumer assets can provide energy, capacity, and ancillary services, and they have the potential to provide new services in the future.

This changing relationship is further driving the convergence of systems, business models, services, policies, and new technologies through a development/feedback loop. Consumers can now adopt a wide array of technologies and program options. These options include: rooftop solar, electric battery storage, electric vehicles (EVs), grid-controlled thermostats and appliances, allocations from community wind and solar projects, locally produced or 100 percent renewable energy plans, alternative pricing regimes, and demand response (DR) and energy efficiency programs and incentives. Mobile, internet-connected devices foster new consumer-engagement modes and enable efficient and real-time management of behind-the-meter assets. Uptake of these advanced options is limited but rapidly growing. Consumers have great latitude in their level of engagement with electricity technology and programs. In some situations, consumers make a one-time decision to adopt a technology or rate structure, eliminating the need for continuous decision making.

Increasingly, the convergence of the electric grid with information and communications technology (ICT) is creating a platform for value creation and the provision of new services beyond electricity, which may or may not require more consumer engagement. In the last several years, for example, major companies have invested in intelligent thermostat software and hardware products to both manage building temperatures and serve as control centers for smart home platforms.[1] The myriad changes taking place at the consumer level are challenging some electric utilities' business models and forcing them to modernize physical infrastructure to maintain high-quality service. Innovative and potentially disruptive changes for different consumer classes are taking place. Policy makers, utilities, and other stakeholders must consider these changes in order to ensure the continued security, affordability, and environmental performance of the electricity system.

Emerging patterns of asset ownership and consumer behavior are challenging existing regulatory structures, institutions, and utility business models, as well as creating new business opportunities. This, in turn, establishes the need for new designs for integrating information networks with the physical grid; these designs must securely and reliably manage distributed communications, control, and coordination among the various participants and intelligent grid assets. Policies, regulations, and business models could and should support distribution system platforms that aim to maximize the full benefit of consumer assets, while compensating utilities and other service providers, including the electricity consumer, for generation, transmission, storage, distribution, and end-use services. Thoughtful regulation in the electricity sector presents an opportunity to improve service, support technology growth, increase consumer equity, and maximize the grid's value. To ensure the continuous affordability, security, and performance of the electricity system, policy makers, utilities, and other stakeholders must consider the key needs and potential disruptive changes taking place across the range of customer classes.

The 21st-Century Energy Consumer

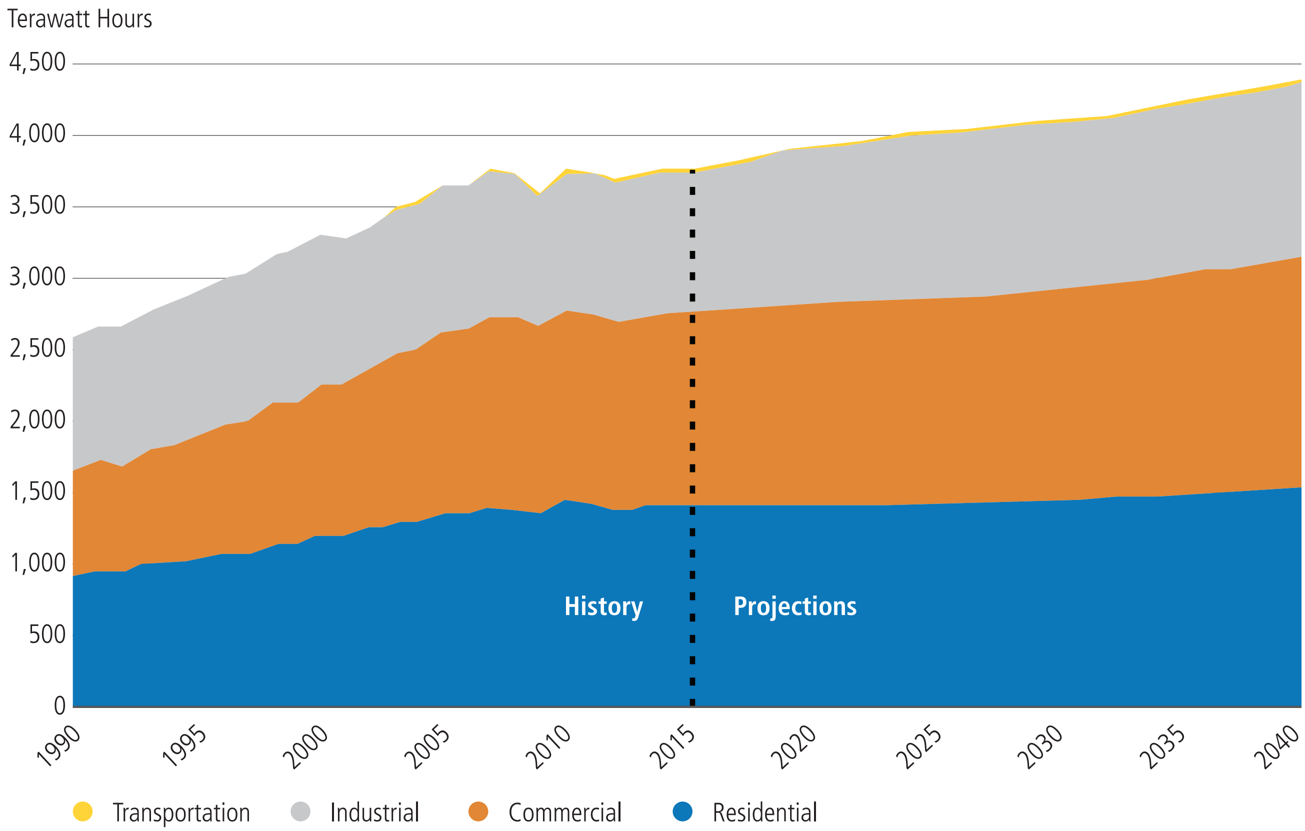
Policy, technology, markets, and consumer preferences are complex, interrelated drivers of change in the electricity system. New policies can influence changes in consumer behavior, like incentives for energy efficiency or distributed solar, or they can stifle consumer choice by limiting competition or raising costs through fees. Conversely, consumer preferences can drive adoption of new technologies or policies. It is hard to separate, for example, the influences of rapidly declining costs for renewable technology from the consumer demands that led state legislatures across the country to adopt renewable portfolio standard (RPS) policies. Regardless of its genesis, the changing nature of the electricity consumer is a powerful force that is shaping the electricity sector. Electricity consumption is an important part of this change (Figure 2-1). The highest growth is projected for the transportation sector—an increase of 134 percent—although it will still make up less than 1 percent of total consumption. Electricity consumption in the residential sector is expected to grow most slowly, by 13 percent. Commercial and industrial electricity consumption are expected to grow by 22 and 32 percent, respectively.[2]

Industrial Consumers of Electricity: Price-Sensitive, Onsite Generation

The industrial sector is extremely diverse, comprising a wide variety of small- to very large-sized facilities. Primary subsectors include manufacturing, mining, construction, and agriculture. Industrial electricity consumption accounts for 26 percent of total annual U.S. electricity consumption.[3]

Industrial electricity sales were relatively flat between 1990 to 2014, due in part to continued improvements in energy efficiency and to the continued shift of the U.S. economy to less energy-intensive industries.[4, 5] Industrial consumers typically use large amounts of electricity and place high value on affordability as electricity costs impact their bottom line. These customers typically pay less for electricity than other consumer classes. Data from the Energy Information Administration (EIA) show a national 12-month rolling average price for industrial customers of 6.74 cents per kilowatt-hour (kWh) versus 12.57 cents/kWh for residential customers and 10.40 cents/kWh for commercial customers as of September 2016.[6] If the industrial customers' electricity needs are large enough, the focus on price can lead them to purchase electricity directly from regional power markets rather than through the local incumbent utility, where the state allows. Large industrial consumers may even be members of a regional transmission organization (RTO) or independent system operator (ISO) to allow them to participate in wholesale markets.

Figure 2-1. U.S. Electricity Consumption Actuals and Projections, 1990–2040[7]



In 2014, the residential sector consumed the most electricity of any sector (1,415 terawatt-hours [TWh], 38 percent of total consumption), followed by the commercial sector (1,358 TWh, 36 percent of total consumption), and the industrial sector (959 TWh, 26 percent of total consumption), with transportation using just 7.6 TWh (less than one percent of total consumption). Overall, electricity consumption is expected to grow by about 18 percent between 2014 and 2040, based on business-as-usual assumptions.

Electricity productivity in the industrial sector (measured in kWh per dollar of output produced) has improved rapidly over the last 15 years,[a] and continued improvement will depend on persistent attention to efficiency. Energy-intensive subsectors (e.g., metals and chemicals manufacturing) represent the greatest opportunities for targeted efficiency improvements. In the manufacturing subsector, which accounts for over 80 percent of total industrial grid-electricity consumption (Figure 2-2), machine drives[b] make up half of industrial electricity use. The next biggest end use, process heating and cooling, makes up just over one-tenth of total industrial electricity use. The focus on price also provides a natural incentive for an industrial customer to self-finance economic energy efficiency measures in order to take advantage of reduced costs and greater productivity.

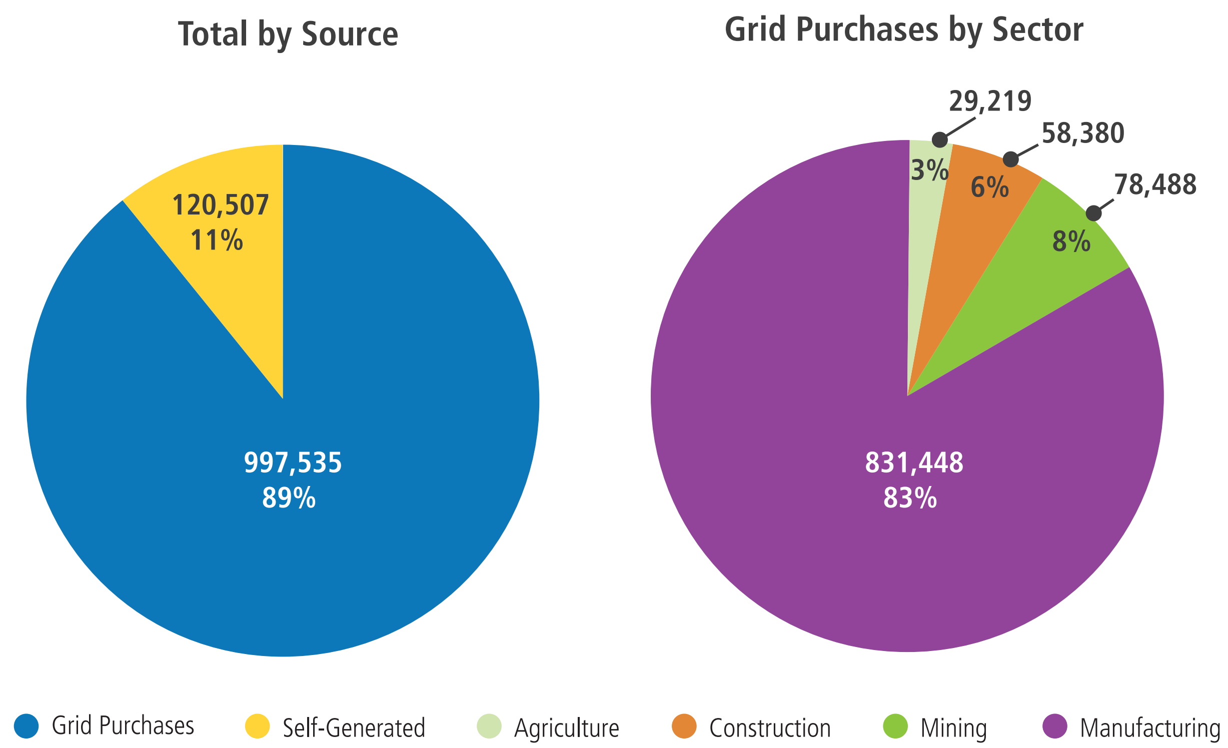
A recent change among some industrial customers, especially among those with retail customers, is the development of corporate sustainability goals. Achieving these goals may involve self-generation, purchase

[a] Electricity productivity, measured as dollars of gross domestic product produced per kilowatt-hour, nearly doubled between 1990 and 2014, while industrial electricity sales were flat.

[b] Machine drives convert electric energy into mechanical energy and are found in almost every process in manufacturing; they comprise motors and the process systems they drive.

of credits, or wholesale power purchases involving low- or zero-carbon generation, such as from renewables (Figure 2-2). For example, General Motors, a very large consumer of electricity, is currently the largest automotive user of solar power and is among the top 25 solar-powered U.S. companies.[8]

Figure 2-2. U.S. Industrial Electricity Consumption, 2014



The chart on the left shows the industrial sector's purchased electricity consumption, combined heat and power self-generation by source. The chart on the right shows purchased electricity by industrial subsector.

For many industrial facilities, energy is not actively managed. While some facilities implement stand-alone energy efficiency projects that save energy, many do not implement these projects as part of a comprehensive strategy to continually improve energy performance. For example, while nearly 30 percent of U.S. manufacturing facilities report setting goals for improving energy efficiency,[10] only about 7 percent of facilities report employing a full-time energy manager. Strategic energy management approaches, such as ENERGY STAR for industrial energy management, ISO 50001, and Superior Energy Performance help individual businesses identify operational efficiency opportunities.[c] Cost-benefit assessments for Superior Energy Performance find annual savings between $36,000 and $938,000, with paybacks of less than 1.5 years for large energy-consuming facilities (those with annual energy costs of more than $2 million.)[11] In its Energy Bandwidth Studies, the Department of Energy (DOE) has identified potential energy savings for selected

[c] ISO 50001 is an international energy management standard, and Superior Energy Performance is a program that helps companies to incorporate ISO 50001 into their production management practices and motivates them to set and reach savings goals. More information on Industrial Energy Management through ENERGY STAR is available at https://www.energystar.gov/buildings/facility-owners-and-managers/industrial-plants.

industrial sectors by calculating differences between typical energy consumption levels for specific processes and lower consumption levels required by state-of-the-art technology, as well as technology currently under research and development (R&D).[12]

DR (shifting or decreasing electricity use in response to time-based rates or other forms of financial incentives) also helps make U.S. manufacturers more competitive. In the PJM Interconnection (PJM) region, large industrial customers often bid DR into the market as a resource.

In addition, industrial combined heat and power (CHP) represents opportunities for near-term solutions to reduce energy intensity.[d] CHP-generating capacity is equivalent to about 8 percent of U.S. generating capacity from utility-scale power plants in 2015.[e, 13] By concurrently producing electricity and heat at the site of use, CHP systems use 25 percent to 35 percent less primary energy than grid electricity plus conventional heating end uses (e.g., water heaters and boilers), with a typical 75 percent overall efficiency versus 50 percent with conventional generation. In regions where the emissions intensity of central electric generation is high, switching to CHP will have the biggest emissions impact. DOE estimates that there is technical potential for roughly 241 gigawatts (GW) of CHP capacity in the United States, including industrial and commercial CHP, as well as waste heat to power.[14]

Overall growth in CHP capacity has stalled since the early 2000s due to upfront equipment costs, technical complexity, and policy changes. There are significant, ongoing deployment efforts to promote this technology, including DOE's CHP Technical Assistance Partnerships,[15] as well as several active state incentives, such as incorporating CHP generation in RPS and utility incentives for CHP systems.[16] The highest number of CHP installations in 2013 and 2014 occurred in states with multi-year CHP-incentive programs, such as New York and California.

Commercial Consumers: Optimizing Building Design, Lighting, and Space Conditioning

There are about 87 billion square feet of commercial space in the United States, spread across more than 5 million commercial and institutional buildings.[17] Commercial electricity consumption accounts for about 36 percent of total U.S. electricity demand. This sector is very diverse and includes office, retail, health care, education, warehouse, and several other building types, ranging in size from a few thousand to millions of square feet per building. Four types of commercial buildings account for more than 50 percent of total delivered electricity consumption—office, retail, education, and health care.[f, 18]

Recent analysis shows that in states consistently adopting the most current versions of model building energy codes, homeowners, building owners, and tenants are projected to save $126 billion on energy bills between 2010 and 2040 if codes continue to be strengthened.[19] Many of the high-efficiency technologies, building envelope designs, and energy-management practices that enable significant energy savings and greenhouse gas (GHG) reductions beyond today's building codes have been demonstrated and are commercially available.

Commercial-sector square footage and energy use has grown steadily, although electricity intensity (kWh/square foot) is improving, largely driven by increases in energy efficiency across end uses. Recent analysis indicates that the major contributing factors to the change in commercial electricity consumption from 2008 to

[d] Within the manufacturing subsector, the Manufacturing Energy and Carbon Footprints analysis estimates that 7,228 trillion British thermal units (Btu), or 51 percent of the 14,064 trillion Btu of total delivered energy to the U.S. manufacturing sector, was wasted as efficiency losses in 2010.

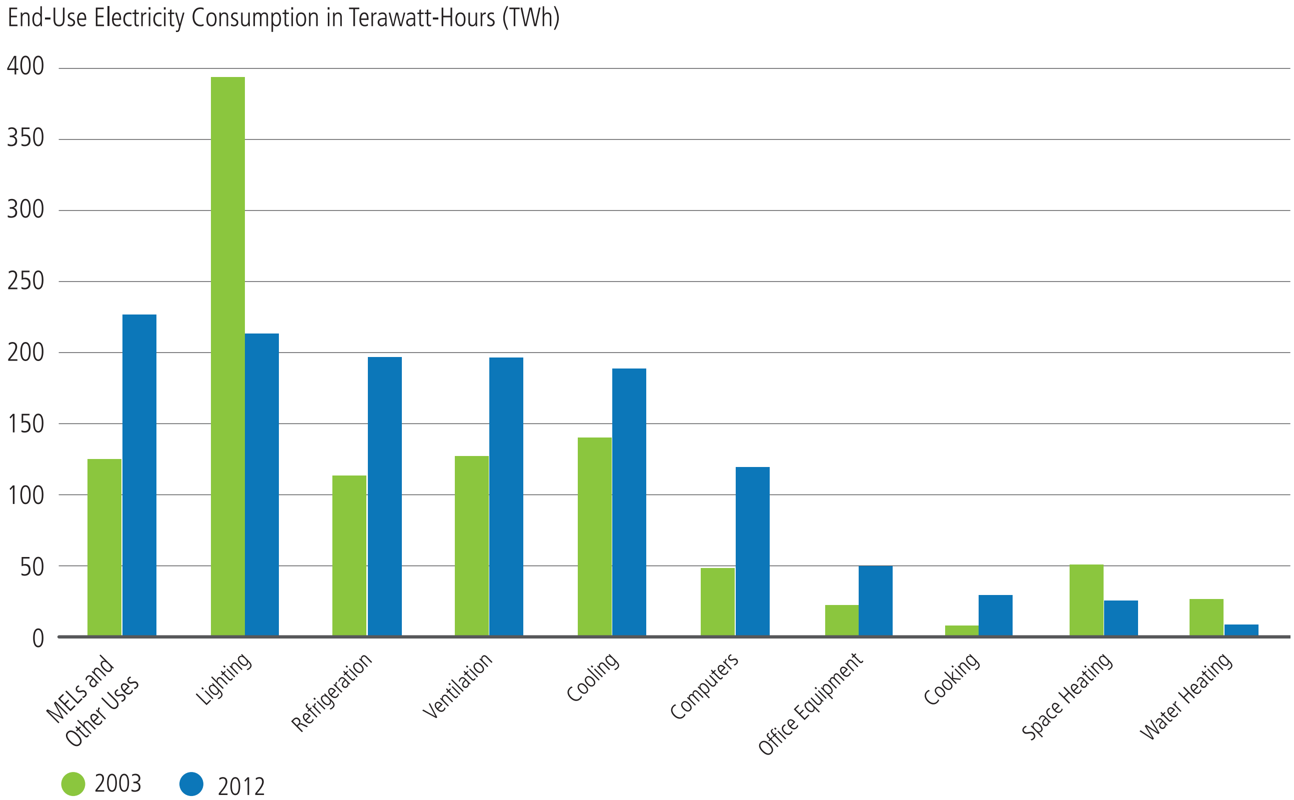
[e] CHP is often considered a form of energy efficiency, but it can also be considered a form of distributed generation.

[f] For a total of 56.4 percent, offices account for 20.4 percent, mercantile (malls and non-mall retail) accounts for 16.6 percent, education accounts for 10.8 percent, and health care accounts for 8.6 percent.

2012 were savings from appliance and equipment standards and utility energy efficiency programs.[20] Moving forward, these efficiency trends will continue to make a significant impact. From 2013 to 2040, commercial end-use intensity, measured in kWh/square foot, is projected to decrease by about 8 percent.[21] This decrease is led by a significant decline in the electricity intensity of lighting,[22] but it is also offset by a significant increase in miscellaneous electric loads (MELs) (Figure 2-3).[g]

The efficiency of most commercial end uses is increasing with the deployment of advanced lighting, space conditioning, electronics, and building designs. The retrofit of existing commercial buildings and the adoption of new energy-management tools are also significantly contributing to meeting environmental goals and reducing consumer electricity costs. The efficiency programs that utilities and Federal, state, and local agencies are now implementing have helped enable these trends.[23]

Figure 2-3. Comparison of Commercial End-Use Electricity Consumption, 2003 and 2012[24, 25]



Consumption across most end uses is increasing, including MELs, refrigeration, computing, cooling, and other uses. Lighting and space-heating consumption have each decreased by about 50 percent between 2003 and 2012.

[g] MELs represent a range of electric loads outside of a building's core end uses of heating, ventilation, air conditioning, lighting, water heating, and refrigeration. Sample MELs include televisions, pool heaters and pumps, set-top boxes, and ceiling fans.

"Dispatchable" Smart, Green Buildings

An important trend with implications for the electricity system is the increasing digitization of commercial office space and the resulting opportunities to use buildings themselves as part of the electric system. Building loads are becoming "dispatchable" by utilizing DR technologies, markets, and the growing industry for peak-load DR through aggregators.[26] A recent report estimates that the global market for building energy-management software will grow from $2.4 billion in 2015 to $10.8 billion in 2024.[27] Energy-management systems are increasingly able to control room temperatures, humidity, ventilation rates, plug loads, and dimmable lights, and in the future, capabilities to control windows and louvers may exist.[28] Similarly, lighting; windows; heating, ventilation, and air conditioning (HVAC) equipment; water heaters; and other building equipment can be equipped with smart controllers and wireless communications capabilities.[29] High-performance building attributes are increasingly factoring into tenants' decisions about leasing space and buyers' decisions about purchasing properties. For both small commercial customers and households, there are information and first-cost barriers that limit penetration of these communicating devices. In 2012, about 70 percent of commercial buildings larger than 100,000 square feet, for example, had some kind of energy management or control system for HVAC, but only about 15 percent of buildings smaller than 25,000 square feet used them.[30]

Meeting Sustainability Goals through Direct Procurement of Renewable Energy

In some states, large electricity consumers are able to purchase electricity from providers other than the local incumbent utility. In recent years, some large commercial customers, particularly those that are consumer-facing, have adopted corporate sustainability goals that include renewable electricity (Figure 2-4). In 2015, corporations (both commercial and industrial) contracted nearly 3.4 GW of renewable energy[31]—up significantly from the 650 megawatts (MW) contracted between 2008 and 2012.[32]

There are several ways in which corporations can voluntarily procure renewable energy, including power purchase agreements (PPAs). In areas where market structures preclude PPAs for direct corporate procurement, some utilities and retail electricity service providers offer green choice or green tariff programs; for example, some energy providers in Texas offer 100-percent wind plans to customers.

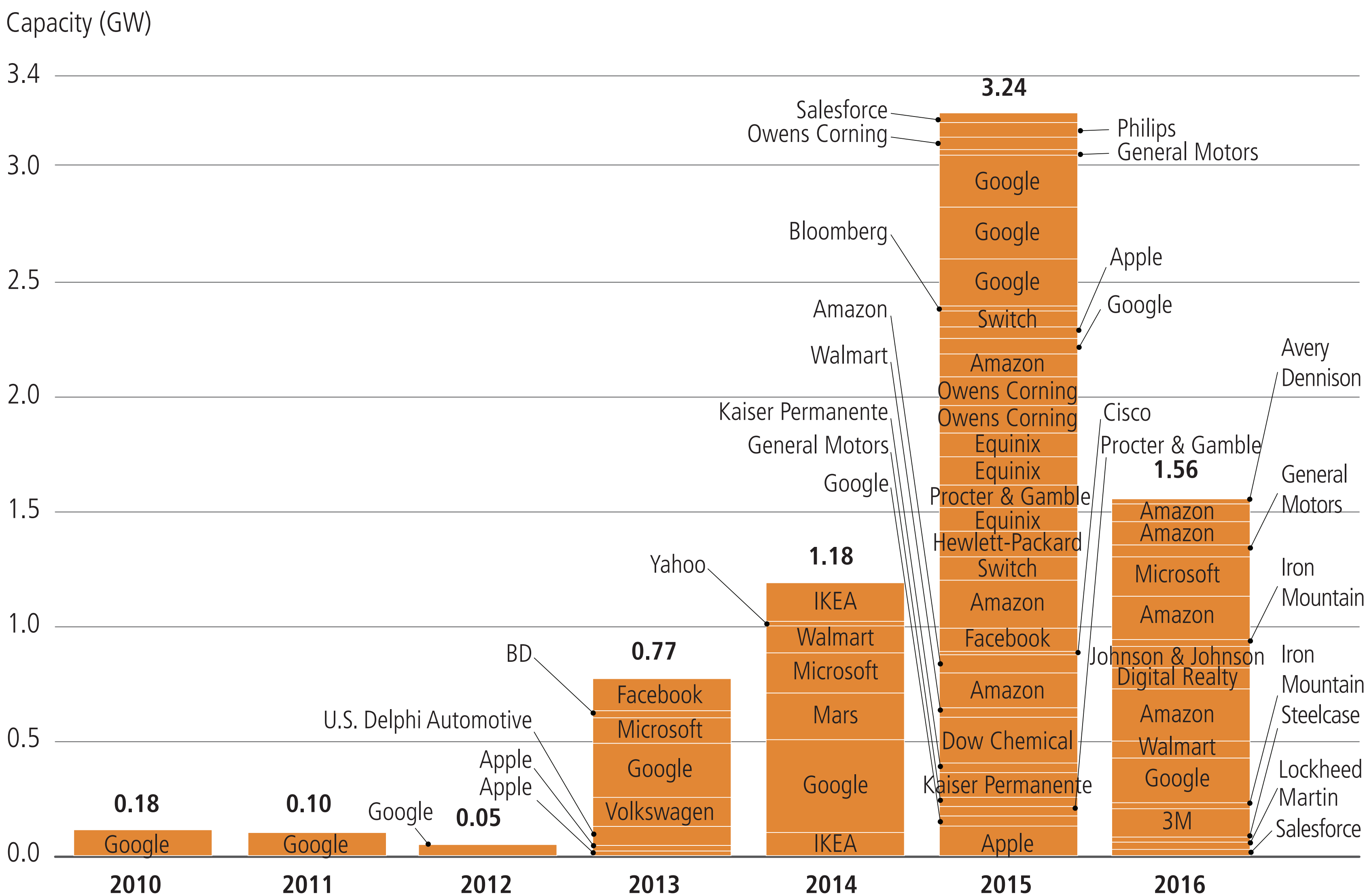
Some companies are going beyond direct purchase of electricity. In 2010, the Federal Energy Regulatory Commission (FERC) granted Google Energy the authority to sell wholesale electricity.[33] In another innovative arrangement, Amazon's cloud computing division, Amazon Web Services (AWS), signed a new type of PPA with Dominion Virginia Power. The agreement allows the utility to manage AWS' existing and future investments in solar and wind projects; charges AWS a retail rate for electricity close to the wholesale rate that their investments earn in the market; and prevents the costs of AWS' renewable energy investment from shifting to other consumers.[34]

Federal Agencies

With more than 350,000 buildings in use, the Federal Government is the Nation's largest energy user.[35] The Federal Government used 947 trillion British thermal units in 2015.[36] Electricity made up 19.9 percent of Federal energy use, behind only jet fuel at 44.2 percent.[37] Most Federal buildings have GHG-reduction goals, and Federal law encourages Federal agencies to implement all cost-effective energy efficiency measures. Federal law also requires agencies to use life-cycle cost analyses when considering building systems.[38]

Executive Order 13514 requires Federal agencies to reduce GHG emissions by 2025 by 40 percent compared to a 2008 baseline. It also requires Federal facilities to meet a 30-percent renewable electricity standard by 2025,[39] and facilities can meet the standard in one of four ways (listed in order of priority) (1) installing agency-funded renewable energy onsite at Federal facilities; (2) contracting the purchase of energy, which includes the installation of renewable energy onsite and offsite at a Federal facility; (3) purchasing renewable electricity; and (4) purchasing Renewable Electricity Credits.[40] Fifteen percent of existing agency buildings must be green buildings, either by number or square footage.[41]

Figure 2-4. Corporate Procurement of Renewable Energy-Based Electricity, 2010–2016[42]

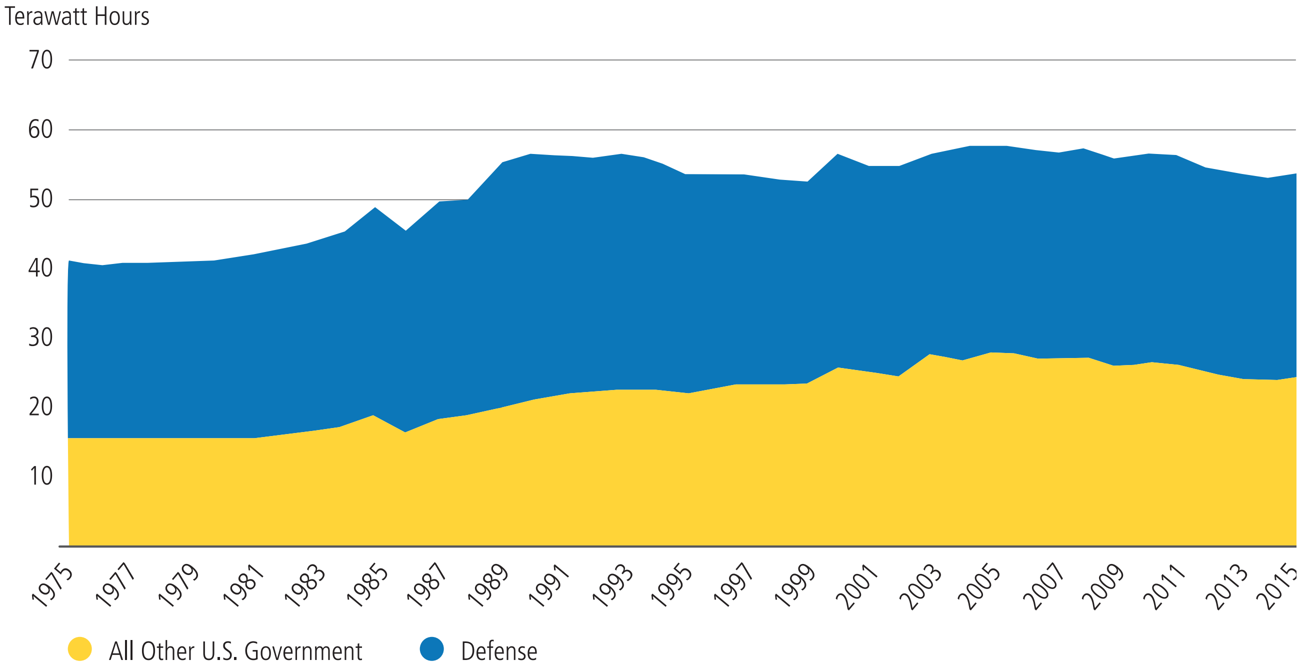


Large corporate customers (including commercial and industrial customers) can specify the type of generation underlying the electricity they consume through power purchase agreements, green tariffs, and direct project ownership. Corporate procurements represent an important new mechanism for developing renewable energy projects. The table illustrates individual procurements; last modified December 15, 2016.

Department of Defense Is Single-Largest Consumer of Electricity

The Department of Defense (DOD) is one of the largest energy consumers in the United States, is the largest customer of the electric grid, and uses more than all other agencies combined (Figure 2-5). DOD requires electricity to support its missions both directly by energizing the facilities and systems that fuel fleets of trucks, tanks, and ships, and indirectly by energizing other supporting infrastructure, such as the communications systems that deliver information across the globe. To ensure it can perform its mission, DOD invests in numerous advanced technologies that improve energy efficiency and increase energy supply resilience; however, it faces many of the same challenges as other public institutions.

Figure 2-5. Electricity Use by the U.S. Government and Department of Defense, 1975–2015[44]



DOD uses more electricity than the rest of the U.S. government combined. This relationship has remained relatively steady for the past 40 years.

DOD has been an early and active user of energy savings performance contracts to implement energy efficiency projects that save money and reduce electricity demand.[h, 45] DOD also pursues renewable energy to advance its energy resilience. Roughly 2 percent of DOD's total energy consumption came from renewable sources in fiscal year 2015. Onsite operational projects (mostly geothermal, biomass, and municipal solid waste) accounted for 82 percent of the Department's renewable energy supply, while purchased renewable energy credits represented the other 18 percent. In 2015, DOD had over 1,390 operational renewable energy projects, compared to 1,130 in 2014.[46] Geothermal electric power is, by far, the most significant renewable energy source in DOD, accounting for over 41 percent of the Department's renewable energy generation portfolio. Biomass makes up about 19 percent, while municipal solid waste, which is used for both electricity and steam production, accounts for 15 percent. There are 810 solar photovoltaic (PV) systems throughout the

[h] An energy savings performance contract is a financial arrangement whereby an energy service company (ESCO) identifies and invests in energy savings investments on behalf of an end user, guaranteeing that the resulting energy cost savings are sufficient to fully pay for the investments over the life of the contract. Additional savings are shared between the ESCO and the end user, and all cost savings after the contract ends accrue to the end user.

DOD system that contribute approximately 13 percent. In October 2016, the U.S. Navy and Sempra Energy opened the 150-MW Mesquite Solar 3 project to supply approximately one-third of the electricity required by 14 Navy and Marine installations—the largest Federal purchase of clean energy in history.[47, 48]

DOD is also exploring cost-effective ways to incorporate microgrid applications to reduce energy demand, increase energy surety, and provide distributed generation (DG) and storage. Smart Power Infrastructure Demonstration for Energy Reliability and Security (SPIDERS) Joint Capability Technology Demonstration (JCTD) is a groundbreaking program designed to bolster the cybersecurity and energy efficiency of U.S. military installations and transfer the know-how to non-military, critical infrastructure.[49] DOD launched the SPIDERS JCTD program in response to growing concern about the military's energy infrastructure's vulnerability to natural disasters and computer-borne cyber attacks, which could impact the grid.

Municipalities, Universities, Schools, and Hospitals

Public and institutional consumers, such as municipalities, universities, schools, and hospitals, often called the MUSH market, are another growing category of electricity customers. These customers, especially cities, are considered to be engines of economic growth as they support large, concentrated populations with complex infrastructure and specific electricity demand needs.[50] While the electricity demand needs of these consumers are vital to economic prosperity and security, the MUSH market often faces constrained maintenance budgets and limited access to capital; public entities are also not eligible for clean energy tax credits that entities with tax liability can use to apply toward certain projects. As a result, these customers take creative approaches to meet all their needs, while acting as the locus of innovation in an array of sectors that drive technological change, including transportation, defense, and public health.

The electricity bill for a municipal government covers electricity for operating municipal buildings, and providing public services like water treatment, street lights, and traffic signals.[51] New equipment and efficiency measures can save energy and reduce carbon pollution, and retrofitted buildings provide healthier and more productive workplaces.[52]

To reduce pollution and save tax dollars, municipal and tribal governments have adopted energy efficiency measures, entered into agreements to purchase renewable energy, and installed their own renewable energy sources. The 30 top municipal and tribal governments in the Environmental Protection Agency's (EPA's) Green Power Partnership (a voluntary program that encourages organizations to use clean energy) used 3.9 billion kWh of clean energy annually, roughly equivalent to the electricity use of 360,000 average American homes.[53] The City of Houston, Texas, was number one on the list, with 951,799,375 kWh in solar and wind energy purchased from Reliant Energy and generated onsite, equivalent to 80 percent of the city government's total electricity use.[54] The City of Detroit is replacing wasteful, high-pressure sodium streetlights, about half of which are no longer working, with modern light-emitting diode (LED) street lighting that will save energy costs and improve reliability and security.[55, 56]

Other cities have developed waste-to-energy projects to dispose of municipal waste while also producing electricity or steam for heating buildings. As of 2013, there were 80 waste-to-energy plants that disposed of 12.9 percent of the Nation's municipal waste while producing 14 billion kWh of electricity—roughly the same amount used by 1.3 million U.S. households.[57]

Updated, networked streetlights can also provide other benefits to city governments, in addition to energy savings. Networked LED systems with wireless internet and sensors can alert management when an outage occurs, monitor traffic or air quality, and publicize the availability of parking spaces.[58] GE's new smart streetlights will combine LED lighting with acoustic sensors to detect and locate gunfire and automatically notify police.[59]

Advancements in ICT are enabling improvements throughout the electricity system, including how city governments use electricity and provide public services. The Smart Cities Initiative, a $160 million program for technology at the local level, has improved the collection, aggregation, and use of data, allowing local governments to better deliver public services.[60] Through the initiative, more than 20 cities are partnering with Federal agencies, universities, and technology companies in research and demonstration projects involving smart energy devices, the Internet of Things (IoT), transportation solutions, and energy efficiency programs.[61] For example, one research award will support research into the integration of self-driving cars and smart buildings, while another will investigate novel approaches to integrating distributed power sources and battery energy storage.[62]

Municipal Water Efficiency Opportunities

Conveyance, initial treatment, distribution, and wastewater treatment all require energy input, and some have potential energy outputs (such as energy from wastewater bio-solids). The national energy demand for drinking water and wastewater treatment increased by more than 30 percent between 1996 and 2013. This increase is primarily due to population growth (about 17 percent) and more stringent water quality regulations, such as the Safe Drinking Water Act.[65, 66, 67, 68] For a typical water resource-recovery facility, electricity accounts for nearly 23 percent of its operating costs.[69]

There are a number of ways to significantly improve the energy efficiency of electric water pumps used in municipal systems through efficiency standards. DOE has regulatory authority over pumps, including water pumps. In 2016, DOE set minimum standards for certain categories of water pumps and the adoption of variable speed drives; DOE required compliance starting in 2020.[i] Moreover, requirements for compliance with these standards could have the ancillary benefit of enhanced data collection on energy use by pumps.[70] Other management techniques to reduce pumps' electricity demand are growing. For example, because water pumps used for irrigation and municipal water systems can be temporarily turned off to reduce load during periods of peak demand, a number of utilities already offer incentives for water system operators to participate in DR programs.

In addition, treatment facilities have numerous opportunities to become net producers of energy.[71] Municipal wastewater contains 5 to 10 times as much chemical and thermal energy as the law currently requires for water treatment to meet discharge standards.[72, 73, 74]

Residential Consumers

The residential sector accounts for about 38 percent of total U.S. electricity demand. Single-family detached homes consume 74 percent of electricity across the Nation's total stock of 113.6 million residences. While residential electricity demand increased between 1990 and 2006, in more recent years, there has been little, or even negative, annual electricity consumption growth in the residential sector. Improvements in the electricity intensity (megawatt hours [MWh]/household) of the residential sector, largely attributed to the increasing efficiency of most end uses, have contributed to this recent low growth.

The number of U.S. households has been increasing, and this trend is expected to continue. Per household, 2040 electricity usage is projected to be lower than 2013—10 percent lower per household, 8 percent lower per capita, and 18 percent lower per square foot. Continued improvements in energy efficiency and other energy technologies, like onsite generation and storage, are likely to accelerate in new and existing homes and across appliances, lighting, water heating, heating and cooling equipment, and electronics, putting downward pressure on load growth. Renewable energy and efficiency programs implemented by utilities and Federal, state, and local governments have played an important role in enabling these trends.

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[i] 10 C.F.R. 429, 10 C.F.R. 431. The Energy Policy and Conservation Act of 1975, as amended, sets forth a variety of provisions designed to improve energy efficiency. Part C of Title III establishes the "Energy Conservation Program for Certain Industrial Equipment." The covered equipment includes pumps.

Energy Management through DR, Automation, and Smart Homes

Since the 1980s, a number of utilities have operated retail DR programs using radio and powerline carrier communications. Now, utilties are also using smart meter-enabled, central air-conditioning and electric water-heater switches. Both electric utilities and private companies now aggregate residential loads in retail and wholesale electricity markets. While it is growing, the widespread and deep use of residential customer loads as part of electric grid operations is still relatively nascent in relation to its potential.

As of 2016, most residential buildings are equipped to automate only a small number of tasks since affordable automation technology, with some exceptions, is not commercially available or widely used. In addition, smart meters, a key enabler of such activities, have only recently been widely deployed and are at an early stage of development for consumers.

Programmable thermostats are widely available and are present in 37 percent of housing units; however, only 53 percent of households with these thermostats use them to lower temperatures during the day, and only 61 percent use them to lower temperatures overnight.[39]

Also, "smart" thermostats, which can learn from occupant behavior and adjust settings to minimize energy use, are now available. These devices can also enable automated DR through a home's smart meter, adjusting thermostats during peak load events to shave usage.[40] Some smart thermostats can now use wireless communications to control appliances and other smart devices within homes; they may even serve as the control platform for "smart homes." Homeowners can also integrate these devices with residential solar output and, along with storage or EVs, use them to react to price signals to optimize EV battery charging and overall system performance. EVs could act as mobile battery resources that consume electricity or provide it back to the grid as energy or frequency management services where incentives exist.[j]

Consumer Preferences for New Technologies and Services

Utilities and other service providers are increasingly segmenting broad consumer classes into smaller, more-specific groups based on preferences for marketing purposes.[k]

Technology itself can help utilities better understand the needs and interests of consumers. Electric utilities are beginning to use "big data analytics" to better meet their customers' needs and deliver services to them.[75, 76] As more residential types emerge, electric utilities and third parties are no longer treating residential customers as monolithic. Utilities are adjusting their product offerings—all of which have implications for the electric power system.

Implications of new technology for the electric power system include the types of generation that are built; how distribution systems are designed and operated; how fast distribution outages are restored; retail rate design and the resulting customer bills; and how utility industry business and regulatory models evolve. A central question for state electricity regulators, consumer advocates, and electric utilities is how to balance the utility's need to recover fixed costs and provide safe, reliable, and affordable energy to all consumers with electricity consumers' small, albeit growing, desire for more products and services.[77]

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[j] Chapter III (*Building a Clean Electricity Future*) discusses EVs and the need for charging infrastructure to provide more charging options to consumers.

[k] See Edison Foundation's Institute of Electric Innovation, "Thought Leaders Speak Out: Key Trends Driving Change in the Electric Power Industry, Volumes I, II, and III," December 14, 2015, June 14, 2016, and December 14, 2016, respectively. http://www.edisonfoundation.net/iei/.

Retail Electric Choice Markets

In the late 1990s and early 2000s, some state legislatures passed legislation opening the retail electricity market to firms beyond the incumbent distribution utility. Currently, 14 states and the District of Columbia have programs that allow end-use customers to buy electricity from competitive retail suppliers.[l, m] Under this structure, the regulated distribution utility still manages and provides the distribution of electricity through wires, with retail marketers procuring and selling the commodity itself. States' retail open-access policies typically apply only to investor-owned utilities, though some states conditionally require it for electric cooperatives as well. States with retail open access typically do not require it for public power utilities, leaving competition policy to their local governing boards. Some states, such as Michigan, cap retail open access as a percentage of electricity sales (i.e., alternative retail electric supplies, besides the incumbent distribution utility, can provide up to 10 percent of retail electric sales).

The outcome of retail electric choice has been mixed. Retail choice has introduced dynamic pricing programs and new services, and it has encouraged the growth of renewable energy. However, electricity prices in areas with retail choice have been more variable and possibly even higher than in areas without it.[n, o] Most states with retail choice also rely on the distribution utility that serves as the default energy commodity provider, with administratively determined rates for customers who choose not to participate in the retail market.

[l] In 2014, 20 percent of electricity sales (MWh) to ultimate consumers were by competitive retail suppliers. Source: 2016–2017 Annual Directory and Statistical Issue, American Public Power Association, 51, derived from EIA Form 861 data.

[m] Matthew J. Morey and Laurence D. Kirsch, *Retail Choice in Electricity: What Have We Learned in 20 Years?* (Washington, DC: Christensen Associates Energy Consulting LLC for Electric Markets Research Foundation, 2016), v, https://www.hks.harvard.edu/hepg/Papers/2016/Retail%20Choice%20in%20Electricity%20for%20EMRF%20Final.pdf.

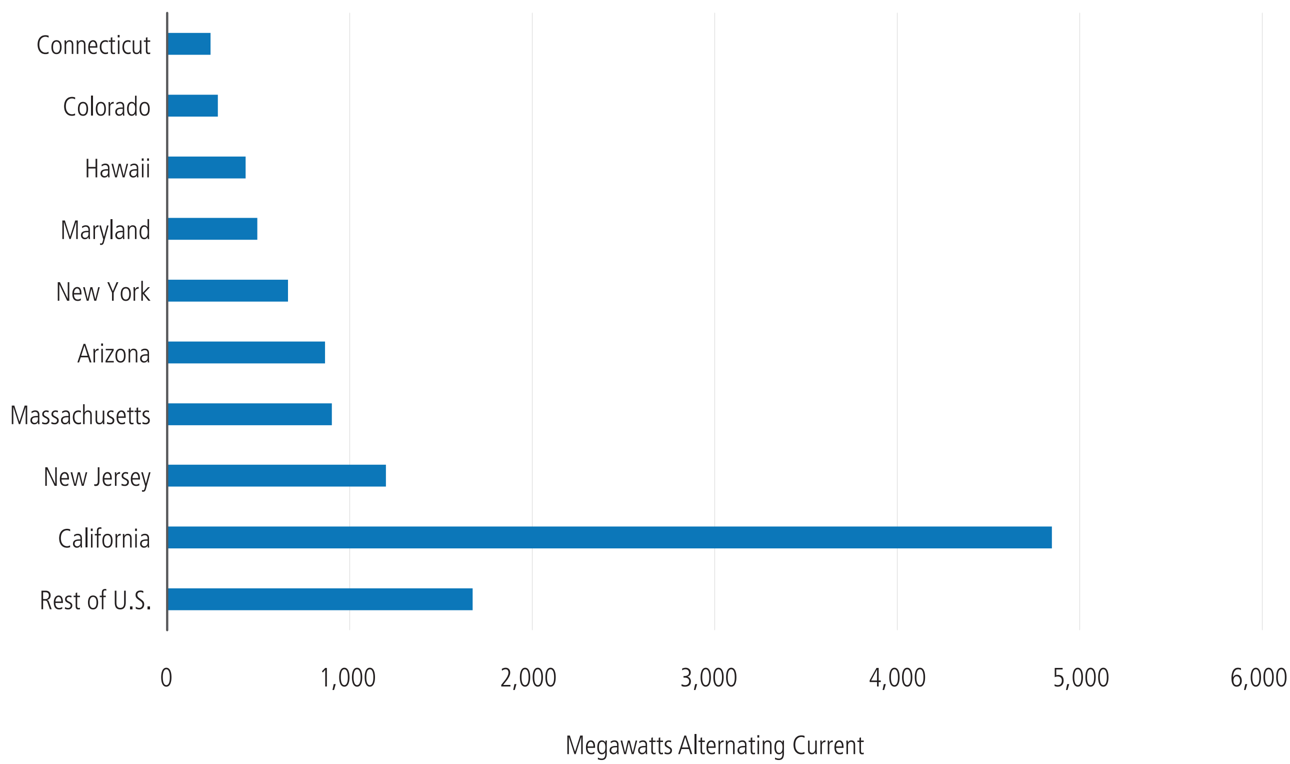
[n] Matthew J. Morey and Laurence D. Kirsch, *Retail Choice in Electricity: What Have We Learned in 20 Years?* (Washington, DC: Christensen Associates Energy Consulting LLC for Electric Markets Research Foundation, 2016), vi, https://www.hks.harvard.edu/hepg/Papers/2016/Retail%20Choice%20in%20Electricity%20for%20EMRF%20Final.pdf.

[o] Severin Borenstein and James Bushnell, *The U.S. Electricity Industry after 20 Years of Restructuring* (Berkeley, CA: University of California, Berkeley, Energy Institute at Haas, May 2015), 18–20, https://ei.haas.berkeley.edu/research/papers/WP252.pdf.

Distributed Generation: A Consumer Choice

In recent years, there has been significant growth in DG, particularly rooftop solar PV, which has been fostered by lower installation and hardware costs and supportive policies, such as net metering (discussed in greater detail later in this chapter), self-generation tariffs, and RPS with set-asides or multipliers for DG.

Figure 2-6. Distributed Solar PV Capacity, Top 10 States, August 2016[78]



Distributed solar PV capacity is unevenly distributed in the United States. As of August 2016, roughly a third of capacity was installed in California, followed by New Jersey and Massachusetts.

Distributed solar PV generating capacity grew by a factor of over 80 between 2004 and 2014,[79] while distributed wind increased by about a factor of 14.[80] The price of installed residential solar PV is projected to fall below $2 per watts of DC in the next 10 years, and distributed solar PV electricity generation is projected to grow by a factor of nearly 19 from 2015 to 2040.[81, 82] Most distributed wind is installed at commercial facility sites, including institutional and government facilities.The majority of distributed wind capacity is at industrial (37 percent), institutional (24 percent), and commercial (20 percent) facilities.[83] Total capacity grew steadily from 2003 to 2012, but growth decreased significantly beginning in 2013, primarily due to the changes in Federal and states incentives.[84] Despite the rapid growth of distributed PV, these resources contribute a small portion of generation to the overall U.S. electricity supply. As shown in Figure 2-6, they play a larger role in some states. The penetration of distributed solar PV in 2015 was about 0.34 percent of total U.S. generation.[85]

Some states and utilities are adjusting their net metering policies as the distributed PV market grows. States with longer-term policies (e.g., targets, incentives) have seen more DG adoption. Future growth will continue to be highly dependent on local and state policies, as well as retail electricity price and resource availability.

Small-Scale Distributed Storage

Small-scale distributed electricity storage (DES) is becoming more widely available and can reduce peak load, improve electrical stability, reduce power quality disturbances, and facilitate increased penetration of variable wind and solar resources. Under some circumstances, DES can reduce residential electricity bills (Figure 2-7). There are numerous distributed technologies available, including stationary battery storage, thermal energy storage (creating ice or chilled water), and plug-in electric vehicles (PEVs) with onboard batteries. Though the technology options for DES are increasing, there is currently only about 350 MW of distributed storage capacity available in the United States, which represents less than 2 percent of total electricity storage capacity and less than 0.1 percent of total electricity generating capacity.[p, 86, 87] Declining costs for storage technology, driven by greater production of batteries for EVs and state-level storage mandates,[q] will drive greater adoption of DES. Between 2007 and 2014, the cost of lithium-ion battery packs declined by almost 60 percent,[r] helping to contribute to forecasts showing rapid growth in DES over the next decade.[88]

DES, including adoption of PEVs with battery storage, could be a transformative technology.[89] Key policy considerations include identifying types of policies and regulations that could facilitate pairing DES with DG or DR to provide value to both utilities and customers. In addition, policies, regulations, and protocols could help integrate mobile DES (i.e., PEVs) into the distribution system to facilitate electrification of the transportation sector. Considering policies and programs that target barriers to deployment of cost-effective energy storage is an additional important step.

Residential Electricity Bill Savings from Distributed Electric Storage[90]

This project analyzed over 45,000 utility rates for more than 4,500 utilities covering all regions of the country.[s] To identify the electricity bill savings opportunities from the use of distributed energy storage (DES), two operational strategies are modeled:

- Flattened: Load profile flattened to minimize demand changes
- Arbitrage: Reduced energy use during peak and increased energy use during off-peak periods to take advantage of time-of-use rate designs

This analysis found that customer investment in DES can provide electricity bill savings for over 80 million residential customers. However, electricity bill savings opportunities are geographically heterogeneous and highly dependent on local rate structures, and the savings in all cases are significantly lower than the normalized cost of the DES. Furthermore, the electricity bill savings that customers realize are not commensurate with the net system benefits that DES provides as estimated by current technical literature. The shortfall between net system benefits, or the social value of DES, and customer electricity bill savings, or the private value of DES, suggests that traditional utility rate design does not adequately reflect the net benefits that a customer with DES provides to the system, and additional remuneration methods may be needed to bridge that shortfall.

[s] "Utility Rate Database," Open Energy Information, accessed January 19, 2017, http://en.openei.org/wiki/Utility_Rate_Database.

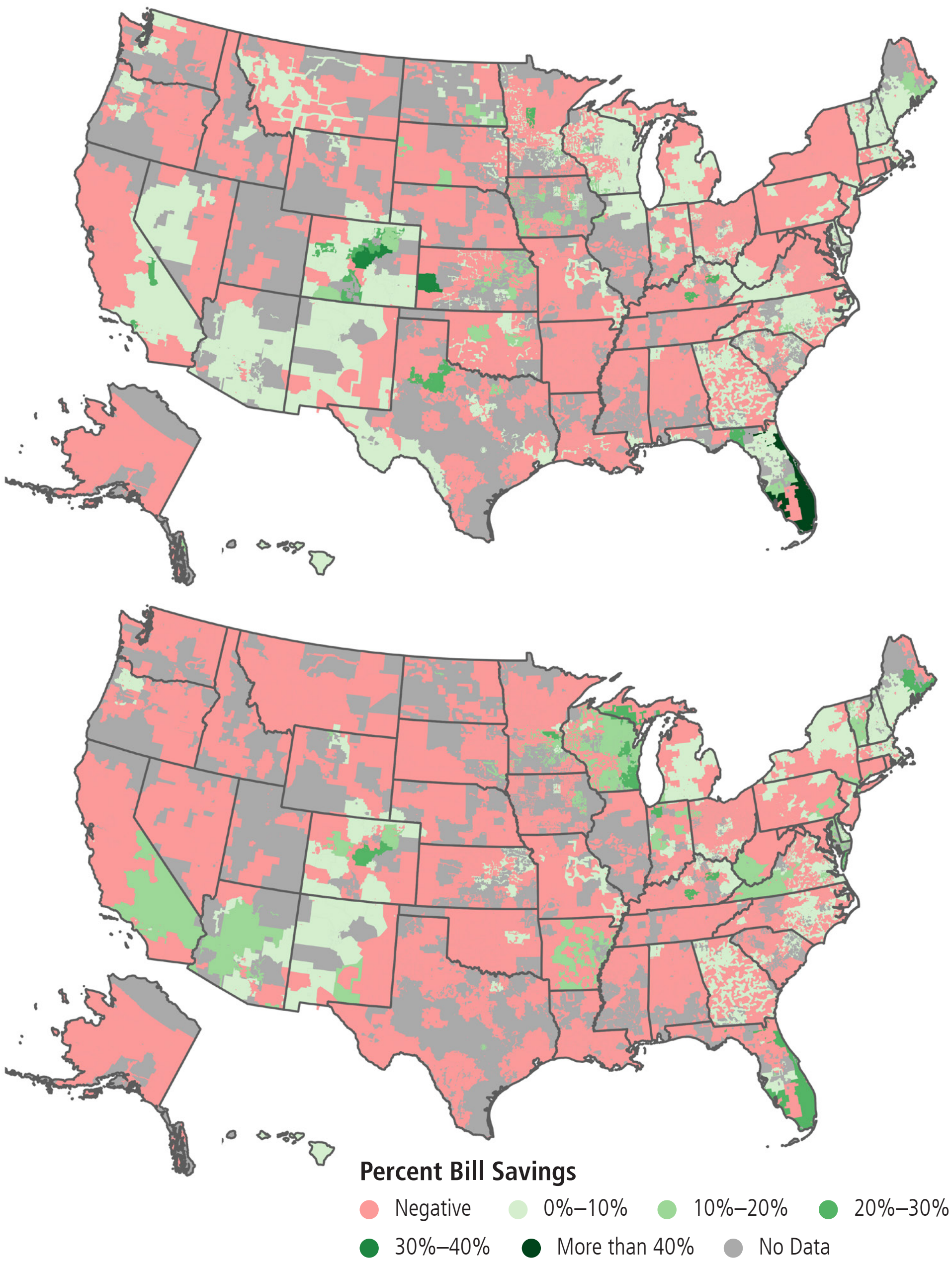
[p] The vast majority—about 98 percent—of total grid-connected energy storage capacity in the United States is pumped hydropower, which is traditionally considered grid-based storage and is not included in this report. https://www.energy.gov/sites/prod/files/2015/04/f22/Hydropower-Market-Report-Highlights.pdf

[q] In 2013, California passed Assembly Bill 2514, which mandates the state to install 1.3 GW of energy storage to their electricity grids by 2020.

[r] Between 2007 and 2014, lithium-ion battery packs decreased in cost from $1,000/kWh to $410/kWh.

Residential Electricity Bill Savings from Distributed Electric Storage[90] (continued)

Figure 2-7. Gross Residential Customer Electricity Bill Savings for the Flattened and Arbitraged Demand Profiles. Top: Bill Savings from Flattened Load Profiles; Bottom: Bill Savings from Arbitraged Load Profiles



Estimated electricity bills for residential customers with DES ranged from showing no savings to a more than 40-percent reduction in electricity bills. The opportunities for customers to save on their electricity bills are geographically similar for the flattened and arbitraged demand profiles, but they appear to lack geographic correlation with urban or rural areas. Each service territory may have several utility rates applicable to that area, so only the largest electricity bill savings available are shown in the figure (where data exist).

Challenges to Electricity Affordability

Across all households, the mean expenditure on home electricity was $1,936.[91] Electricity use and its share of total household expenditures, however, vary by region and household demographic. The average household energy consumption is, for example, higher in the West and South census regions.

The affordability of electricity service remains a challenge for many low-income residential consumers. An important indicator of the need for energy assistance is *energy burden*, usually calculated as a household's annual spending on energy as a percentage of its gross annual income.[92, 93] In 2011, the median electricity burden for *all* households was 4 percent;[94] for households not in the low-income category, it was just 2.9 percent, *but for low-income households, energy burden averaged 8.3 percent*.[95] Relatively more spending on energy bills translates into less spending on other expenses, including food.[96]

Low-income Americans are more likely to use electric heat than the national average, which tends to be more expensive than gas.[97] Electric heat use among low-income households has more than doubled from 12 percent in 1980 to 33 percent in 2005.[98] By occupant demographic, lower-income households use less electricity (kWh/household) compared to higher-income households, but they pay a considerably higher fraction of their after-tax income on electricity expenditures.[t, 99] Renters pay 26.7 percent more on electricity expenditures per square foot compared to homeowners.[u, 100] In addition, renters who pay their own utilities and have incomes less than $15,000 per year pay on average 21 percent of their income on home energy (electricity and natural gas combined).[101] There are almost 7 million U.S. households in this category. This underscores the "Heat or Eat" dilemma faced by many households with high energy burdens. The United States does not have energy poverty or high energy burden standards.

The Federal Low Income Home Energy Assistance Program (LIHEAP) provides funding to pay the electricity bills of low-income families, but the program cannot serve all eligible families, and many experience service disconnections.[102, 103] In 2011, the most recent year for which there are data, only one in six LIHEAP-eligible households received LIHEAP assistance.[104] Since the program cannot serve the entire income-eligible population, states must prioritize which vulnerable households they serve, and set their own additional standards and eligibility requirements when they apportion LIHEAP assistance. A portion of LIHEAP funds can be used for weatherization to help reduce consumers' bills, but there is wide variation in state weatherization programs' structure and quality. There are no nationally aggregated data on service disconnections associated with customers' inability to pay. State-level data suggest that instances of electricity service terminations vary widely, ranging from 5 to nearly 20 percent of low-income consumers experiencing disconnections annually.[105, 106]

The Federal Government, states, cities, and utilities offer a range of essential assistance to low-income Americans. The cost of public-purpose programs like energy efficiency programs, low-income assistance programs, and R&D programs, are collected from utility customers and usually paid for with dedicated public benefit charges or are included in a utility's general cost recovery. Both of these revenue streams are based on volumetric (per kWh) rates, and customers contribute based on their total energy consumption. For example, Ohio's Percentage of Income Payment Plan, a concessionary rate for low-income electricity consumers, is paid for by counting the revenue not collected from low-income consumers as uncollectable arrears and reimbursing the utilities out of general revenue streams.

[t] For example, electricity accounts for 4.2 percent of after-tax income for households earning between $30,000 and $40,000 annually. Households with annual after-tax income of $100,000–$120,000 spend only 1.8 percent on electricity expenditures. Source: EPSA Analysis: Lisa C. Schwartz, Max Wei, William Morrow, Jeff Deason, Steven R. Schiller, Greg Leventis, Sarah Smith, et al., *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline* (Berkley, CA: Lawrence Berkeley National Laboratory, January 2017), 25, https://energy.gov/epsa/downloads/electricity-end-uses-energy-efficiency-and-distributed-energy-resources-baseline.

[u] Note that total energy expenditures include non-electricity sources such as natural gas and heating oil.

Utilities in most states administratively determine a public benefits surcharge, such as $0.002/kWh. These funding structures mean that any reduction in a consumer's per kWh payments reduces that consumer's contributions to these programs; energy efficiency measures that reduce overall consumption may similarly reduce funding for assistance programs. Revenue decoupling can prevent the underfunding of these programs but not the shift of their costs among consumers.

Access to Distributed Energy Resources and New Energy Services for All Consumers

Low-income communities stand to benefit from energy efficiency and clean energy more than other communities because these residents have higher energy burdens and often bear disproportionate impacts of pollution[107] and climate change.[108] Current modes of promoting energy efficiency and clean energy, however, are not always designed to benefit low-income communities. In addition to low-income consumers having less energy-efficient homes on average, it is much more expensive for utilities to provide energy efficiency programs to those consumers than to average-income residential or commercial consumers.[109]

Low-income households are often renters, creating a split-incentive problem for energy efficiency investments. The landlord sees no incentive to make energy efficiency investments since the benefit goes to the tenant who pays the electricity bill; the tenant, on the other hand, sees little incentive to make expensive, long-term energy efficiency investments since future benefits will accrue to future tenants. The split incentive problem leads to declining energy efficiency over time when compared to owner-occupied housing, compounded by the tendency for low-income Americans to occupy older buildings.[110] Finally, low-income consumers often lack access to capital for home energy improvements and have limited access to the most modern and efficient appliances and electricity service. DOE's Weatherization Assistance Program (WAP) funds low-income energy efficiency upgrades, but unfortunately, the needs dramatically exceed WAP funding.

The California Public Utilities Commission (CPUC) recently found that, since 1999, rooftop solar customers had a median household income of $91,000, while the median income in California was $54,000 and that of the investor-owned utility (IOU) customers was $68,000.[111] A survey conducted by the National Renewable Energy Laboratory found that solar adopters in San Diego County had an average household income of $165,000, compared to $115,000 for non-adopters.[112] In principle, lower-income consumers could benefit from installing distributed solar and other clean energy technologies in their homes in the same way that higher-income consumers do, but many barriers have prevented this, including lack of funding or financing, lack of ownership, or a rooftop being in poor repair.[113] In addition, many low-income Americans and businesses in low-income communities rent their homes and offices, making upgrades harder to arrange and pay back through energy or bill savings.

Utilities and other energy-service providers can make solar PV-market participation available to low-income customers through arrangements like community solar, which may provide cash-flow-positive solutions to address the needs of a large down payment, favorable credit rating, or owner-occupied single-family home. One common model is for community solar project developers to form PPAs with the utility for a solar development located in a community or offsite. A specified number of customers can then subscribe to the program for a monthly fee and receive a virtual net metering bill credit for a portion of energy produced. In some cases, onsite, community, and shared solar programs can use Federal low-income energy assistance through programs like LIHEAP, WAP, and Low-Income Housing Tax Credits to benefit consumers who would otherwise be deemed ineligible for energy efficiency upgrades. The Clean Energy Savings for All Americans Initiative is a cross-agency initiative with participation from DOE, EPA, Department of Housing and Urban Development, Department of Agriculture (USDA), Department of Labor, Corporation for National and Community Science, and Department of the Treasury. The initiative focuses on ensuring that low-income households have access to solar options through a variety of these mechanisms.

Electricity Issues in Small, Rural, and Islanded Communities

Rural and islanded electricity systems are microcosms of the larger electricity grid, but they also face unique challenges being isolated from the grid or being located in low-population areas. Rural electricity systems have a smaller customer base but more miles of distribution line to maintain than utilities serving urban areas. Rural electric cooperatives (co-ops) cover three quarters of the country's land mass, with a total membership of approximately 42 million people.[114] Per mile of distribution line, co-ops serve an average of 7.4 consumers and collect annual revenue of about $15,000, while IOUs serve an average of 34 customers and collect $75,500. This disparity in customers and revenue per line-mile poses a challenge for investments in rural electricity infrastructure.[115]

Islanded systems can be actual islands or "islanded" by being isolated from the larger electricity grid (e.g., electricity systems serving small villages in rural Alaska). Islanded systems also have small customer bases, with high capital costs and high shipping costs for infrastructure and fuel supplies. They may also require a high level of redundancy due to extreme weather conditions and general isolation.[116]

Grid operators face the challenge of delivering reliable, affordable electricity in remote areas. Assistance with financing electricity infrastructure and improved telecommunications, such as broadband, could help provide more affordable, reliable electricity in rural and islanded communities. Improved access to broadband in rural communities would help the deployment of DR, storage, DG, and other technologies.

In addition, education and training may be required to enable residents of small, remote communities to operate and maintain their electricity systems when new technologies are deployed. Co-ops and utilities providing electricity in rural and islanded communities can provide technical assistance with integrating renewable electricity, storage, or other improvements in electricity delivery.

The Federal Government plays a role in encouraging renewable energy and economic development in rural areas. DOE and other Federal agencies have several energy efficiency and renewable programs available to residents in rural areas, even if these programs are not specifically designed for rural communities; these include the National Community Solar Partnership, WAP, the Better Buildings Challenge, and others.[117, 118, 119] USDA's Rural Utilities Service (RUS) provides financing for electric utilities (wholesale and retail providers of electricity) that serve customers in rural areas.[120] RUS loans include financing for generation and transmission technologies and distribution modernization. In recent years, however, the RUS loan program has been undersubscribed.

Powering Isolated Communities in Alaska

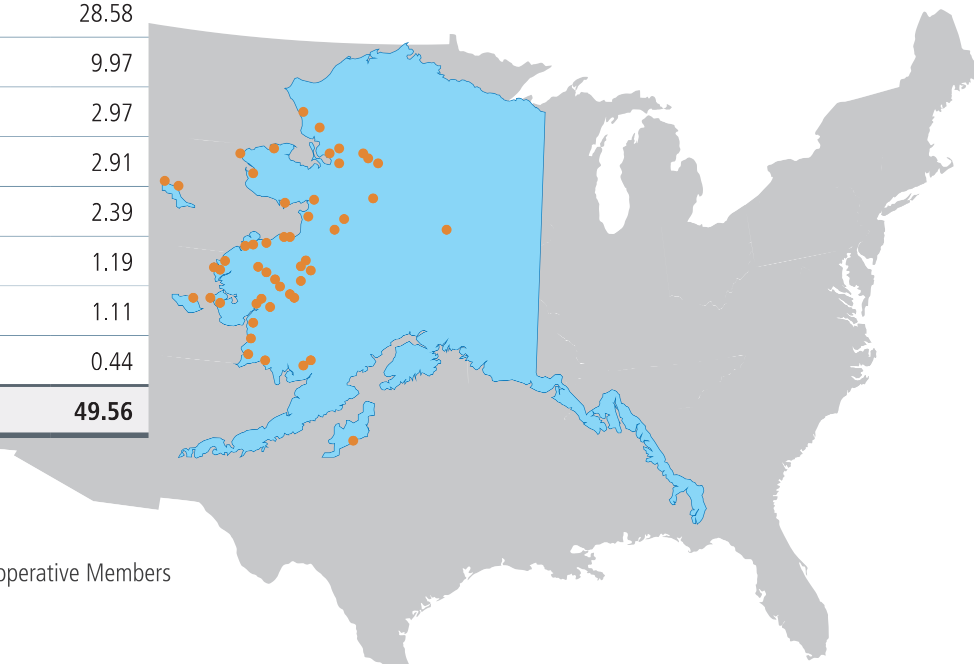
Rural Alaskan communities have high seasonal load peaks, with high demand in the winter for heating and lighting. Many smaller Alaskan communities rely on diesel fuel for electricity generation and pay $0.50 to $0.80 per kWh because of the high cost of fuel and shipping, higher capital costs due to the small scale of generation, and the greater need for redundancy in generation (Figure 2-8).[121]

Battery storage has improved reliability in Alaska communities connected to the larger grid in the central part of the state,[122] where batteries have been installed primarily for frequency and voltage regulation, not to store intermittent renewable energy.[123] As a result, Alaskans have experienced fewer outages, and grid operators use less spinning reserve capacity with the addition of large-scale battery storage.[124]

Figure 2-8. Electricity Costs in Rural Alaska

Average Alaska Village Electric Cooperative Village Electricity Cost (¢/kWh)

Fuel	28.58
Power Production	9.97
Administration and General	2.97
Depreciation	2.91
Consumer Accounts	2.39
Distribution	1.19
Interest	1.11
Taxes	0.44
Total	**49.56**



Alaska Village Electric Cooperative Members

The Alaska Village Electric Cooperative serves more than 50 small communities dispersed across large distances and in remote regions with harsh climatic conditions. These factors contribute to average electricity prices being approximately five times the U.S. national average.

Alaskan co-ops are installing more wind energy and improving power-control technology in rural areas to better manage electricity systems that primarily run on diesel fuel.[126] The Alaska Center for Energy and Power has studied ways to reduce reliance on diesel generation, while recognizing the difficulty in eliminating diesel generators because they provide important services beyond electricity generation,[127] including waste heat and inertia for local electricity systems.[128] Systems that use both diesel and wind energy have reduced fuel costs and emissions but are more complex and require more training for operators.[129] Also, improved broadband access to the large data streams necessary for managing these complex systems would make it easier to run them in remote areas and on islands.[130]

Innovative Rural Electric Co-Op Programs

While energy efficiency is more cost-effective than building new infrastructure, rural energy efficiency programs face a unique challenge. Rural communities have a greater proportion of low-to-moderate-income families who may have problems financing energy efficiency investments. Also, seasonal demand peaks related to agriculture can make the payback time longer for energy efficiency investments, and co-ops serving rural communities may have less access to capital and technical expertise than IOUs.[131] In spite of the challenges of operating in rural areas, co-op sales grew 3.3 percent in 2014 compared to 1.1 percent growth across the entire retail electricity sales industry.[132]

Co-ops have installed the greatest percentage of advanced metering infrastructure (AMI), with 51 percent penetration, compared to 41 percent for IOUs and 26 percent of publicly owned utilities.[133] Rural electric co-ops have the advantage of being smaller and more nimble than large IOUs regulated by public utility commissions (PUCs). In addition, they can more easily adopt energy efficiency or renewable energy programs tailored to their members. Some rural co-ops are adding biodigesters to convert solid waste from dairy cows to electricity, smart electric water heaters to store wind energy, improved forecasting for solar and wind energy, and other DR technologies that take advantage of resources in rural areas. Many of these DR and storage technologies could be expanded with improved telecommunications access.[134]

The RUS partners with cooperatives to finance improvements in rural communities, many of which are low-income.[135] Roanoke Electric Cooperative implemented a program to make investments tied to each meter that are funded by an RUS loan.[136] The co-op paid for installation of improved insulation, duct and air sealing, heat and water pump upgrades, and efficient lighting. The co-op recovers its efficiency investment through a tariff on the bill from co-op members, who still see savings on their bill from the reduced electricity use.[138] After efficiency upgrades, the average savings was $120, which the member and the co-op would split; an average member would save $60 per month on his or her bill, and the co-op would pay off the efficiency upgrade in 10 years.[139] Improvements to RUS loan programs, many of which are undersubscribed because of the programs' complexity or the inability to refinance to lower interest rates, could accelerate the development of renewable energy and energy efficiency projects in rural areas.

Electricity as a Driver of Economic Growth in Tribal Communities

Electrification in the United States is among the highest in the world, but there is not universal access to electricity on Indian reservations. The interdependencies of electricity access, economic well-being, and quality of life underscore the importance of electrifying tribal lands.

According to the 2010 census, 1.1 million American Indian or Alaska Native people lived on reservations and Alaska Native Village Areas. While current data are limited, an EIA study in 2000 found that 14.2 percent of Native American households on reservations did not have access to electricity; the Navajo Reservation represents about 75 percent of this total.[v, 140] Across all tribes, one in seven Indian households living on reservations was without electricity service.[141] A combination of EIA's electrification rates and 2010 census data would suggest that there could be as many as 160,000 Native Americans without electricity. Data from the 2007–2011 U.S. Census American Community Survey also concludes that, on tribal lands, thousands of Native Americans are still living without basic electricity services.

There are significant challenges to addressing electricity access on Indian lands. These challenges include remote locations, widely dispersed homes, and the prohibitive cost of utility distribution lines. Despite reductions in wind and solar costs, many tribes have not been able to take advantage of their wind or solar resources.[142] Tribes have limited access to private capital for projects in Indian Country.

DOE's Office of Indian Energy Policy and Programs recently modernized its technical assistance strategy to better assist tribes in improving energy access and services by recognizing that the questions of today's grid are more complex and sometimes require longer-term partnerships. The Bureau of Indian Affairs at the Department of the Interior has several programs that provide technical assistance to American Indian tribes for energy development. USDA's RUS offers low-cost loans to rural utilities, including tribal initiatives for increasing grid access, and state programs also exist. For example, in New Mexico, the Tribal Infrastructure Fund, created by the Tribal Infrastructure Act in 2005, recognizes that many of New Mexico's tribal communities lack basic infrastructure including, but not limited to, water and wastewater systems, roads, and electrical power lines. Through this competitive funding, all Federally recognized tribes, nations, and pueblos

[v] The 2000 EIA study is the most current study on the availability of electricity on reservations. A study from DOE's Office of Indian Energy Policy and Programs is forthcoming.

within New Mexico have an opportunity to submit a robust project proposal for their communities. At each funding cycle, the project proposal is evaluated and, based on scoring, is awarded funds through the 13-person Tribal Infrastructure Board, which is administratively attached to the New Mexico Indian Affairs Department.

Tribes also face regulatory challenges and limitations. The tax-exempt, non-profit status of Federally recognized tribes precludes them from taking advantage of the Federal Production Tax Credit or Investment Tax Credit without costly and complicated corporate structures.[143] These tax credits have supported a dramatic expansion of renewable energy production on non-tribal lands. Lengthy regulatory processes also make it more difficult to develop energy resources and electricity transmission projects.[144] Siting and permitting rules for transmission rights-of-way on tribal lands were simplified and clarified in 2015. These changes may offer opportunities for tribes to build out grid access to unconnected rural areas and increase connections to renewable energy projects.

Indian Lands have over 9 million MW of renewable energy potential,[145] but only 125–130 MW has been installed on tribal lands, due to the lack of capital.[146] Making renewable energy tax credits refundable and providing loan guarantees would help tribes develop their renewable energy resources. Some tribes have also expressed interest in improving their capacity to run energy programs by developing tribal energy offices, comparable to state energy offices that run energy efficiency and energy security programs.[147]

The Federal Government has a trust responsibility to protect tribal treaty rights, land, and resources, and it has a longstanding policy of encouraging economic development in Indian Country. In addition to supporting improved access to electricity and incentives for renewable energy development, the Federal Government should improve consultation with tribal governments on infrastructure projects. Frequently, tribal consultation takes place near the end of the siting and permitting process, too late to allow for meaningful input from tribes. Federal agencies have different procedures and definitions for consultation, and some tribes lack the staff or technical expertise to review permitting documents. The Federal Government should implement procedures that ensure early and meaningful consultation with tribal governments, and Federal staff should receive training about how to provide meaningful consultation to tribes to identify and addresses concerns.

The availability of programs, new tools, and technical assistance does not change the reality that providing access to electricity is very expensive for tribal utilities. Indeed, the electrification of rural America in the 1930s was achieved through economic transfers from urban customers to rural customers, e.g., through high levels of interest-free loans and grants from the Federal Government. Prioritizing universal electricity access for tens of thousands of Americans without electricity may again require significant Federal intervention.

Maximizing the Value of Energy Efficiency

Energy efficiency, often referred to as the "first fuel," provides benefits for the electricity system, including avoided costs for energy, as well as generation, transmission, and distribution capacity; less volatile electricity market prices; reduced service disconnections due to arrearages on bill payments; and improved system reliability (Figure 2-9). While energy efficiency reduces electricity, natural gas, and other home-heating fuel consumption, it equally supports a host of non-energy benefits for individual participants and society as a whole;[148, 149] benefits for individuals include reduced energy bills and more disposable income, increased property values, improved comfort, lower maintenance costs, higher productivity, and positive health impacts.[w] For society as a whole, non-energy benefits include improved energy security and independence; reduced air emissions, greater water savings, and other environmental benefits; reduced costs to operate public facilities; job creation and local economic development; and broad health benefits, such as reduced asthma cases from cleaner air.

[w] For information on how to quantify the multiple benefits of energy efficiency, see EPA's *Assessing the Multiple Benefits of Clean Energy: A Resource for States* (2011), https://www.epa.gov/statelocalclimate/assessing-multiple-benefits-clean-energy-resource-states.

Figure 2-9. Multiple Benefits of Energy Efficiency Improvements[150]

Energy efficiency improvements include energy and non-energy benefits for individual participants, the electricity system, and society as a whole.

Regulatory approaches such as decoupling, incentives, or lost revenue adjustments can be used to promote utility investments in energy efficiency. Building owners can also use a variety of financing mechanisms to implement energy efficiency improvements, including energy savings performance contracts, property-assessed clean energy loans, or energy-focused loans from national lenders.

Energy efficiency policies—such as building energy codes, appliance and equipment standards and labeling, and targeted incentives—have played a significant role in slowing the growth of electricity consumption. Incremental annual energy savings from utility customer-funded electric efficiency programs in the utility sector are expected to reach about 0.8 percent per year in the United States by 2025, driven primarily by compliance with statewide savings or spending targets typically focused on energy efficiency programs.[151]

Efficiency programs funded by electric utility customers, as well as energy efficiency standards for appliances and equipment and more efficient building energy codes, are likely to continue to offset the majority of electric load growth. Advances in technology and the continued growth of the broader energy efficiency and energy-management industry have also played important roles in achieving significant levels of energy savings.

A broad range of policies and programs can help the American economy capture value from energy-efficient technologies and practices. At the Federal level, DOE supports cost-shared R&D of new energy-efficient technologies and practices applicable to all end-use sectors including lighting; refrigeration, air conditioning, and heat pump technologies; new building design and construction tools and materials; sensor and controls; industrial processes and materials; EVs; DG and DES technologies; and others. Technology development efforts are usually accompanied or followed by technology demonstrations and the development of test methods to facilitate market acceptance. Labeling and technical assistance (for example, through EPA's and DOE's ENERGY STAR and DOE's Better Buildings programs), provide the information necessary for consumers to identify opportunities for reducing the costs of electricity through investments in new, more energy-efficient products, or improvements to the performance of existing buildings and processes. Green building-certification programs promote energy-efficient buildings. Incentives, financing, and targeted procurement programs implemented by governments and utilities help enable or motivate investments in higher-efficiency products and accelerate the market penetration of new, more energy-efficient and clean energy technologies. Finally, energy efficiency building codes and standards for equipment and appliances ensure consistent market adoption of cost-effective efficiency technologies. The primary objective of these efforts is to enable consumers to obtain the same or improved end-use services at a lower total cost, while also yielding environmental and economic benefits. Today, such programs are effectively stimulating efficiency gains in all new buildings and vehicles, and most appliances and equipment.

Substantial electric efficiency gains are possible in all end-use sectors. The National Academies found that full deployment of cost-effective energy-efficient technologies in buildings could eliminate the need to build new electric generating capacity in the United States through 2030.[152] If buildings were to adopt today's best available technologies, energy-use intensity (thousand British thermal units per square foot) could decrease by at least 50 percent for single-family homes and by 42 percent for commercial buildings.[153] New electricity savings and DR opportunities are being unlocked by the digitization of end-use devices and the build-out of layers of communications infrastructure to allow them to both communicate their state and be controlled—further enabling grid-system-wide efficiencies and functionalities. Developing effective technologies and strategies for realizing these value-creation opportunities will require improved data on the actual performance of more energy-efficient appliances, equipment, and buildings; variation among different categories of consumers; and the constellation of product and service providers that serve and influence the decisions of consumers.

Miscellaneous Electric Loads Are a Growing Share of Electricity Demand

The shares of end-use electricity demand in residential and commercial buildings in 2014 are seen in Figure 2-10. Most building-sector end uses are expected to represent declining shares of future electricity demand, with only MELs,[x] residential air-conditioning, and commercial office equipment expected to increase their shares.[y] The energy consumption of MELs is projected to increase significantly from 2014 to 2040, from 42 to 48 percent in the residential sector and from 46 to 58 percent in the commercial sector.[154] The increased share of energy used by MELs follows the continued emergence of new electricity services and the less effective

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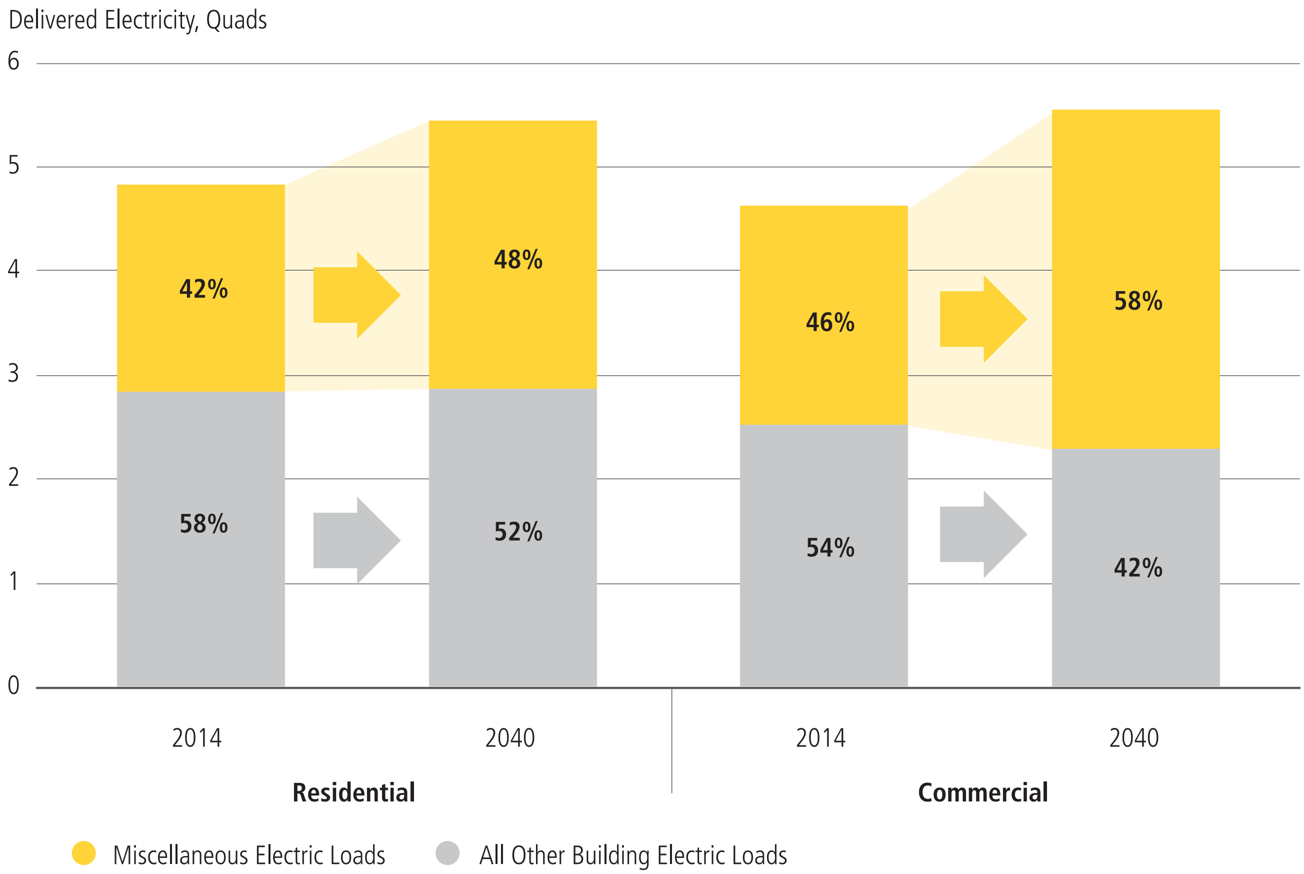
[x] For a more detailed discussion of MELs, see: http://energy.gov/eere/buildings/downloads/bto-investigates-miscellaneous-electric-loads.

[y] MELs represent a broad range of electric loads that do not fall within a building's core end uses of heating, ventilation, air conditioning, lighting, water heating, and refrigeration. MELs include a portion of 'unknown' electricity loads meant to align discrepancies between supply- and consumption-side data sources.

coverage of major loads by existing policies designed to accelerate efficiency gains. Additional action is needed to improve data collection and to further expand technology development, product testing, labeling, and minimum standards programs to better cover MELs.

Figure 2-10. Share of Miscellaneous Electric Loads Compared to All Other Building Electric Loads, Residential and Commercial Sectors, 2014 and 2040[155]



Compared to other loads, MELs are projected to increase significantly in their share of total delivered electricity in residential and commercial buildings. Projections are based upon the business-as-usual assumptions in the EPSA Base Case.[z]

Energy Efficiency Codes and Standards Help Reduce Consumption and Save Money

Energy efficiency policies—such as building energy codes; equipment efficiency standards; mandatory, as well as voluntary, labeling like ENERGY STAR; and targeted incentives—have played a significant role in slowing the growth of electricity consumption. Because buildings often have lifetimes of 75–100 years, policies and market forces that improve efficiency in base building systems can have lasting benefits. Advances in technology and the continued growth of the broader energy-management industry have also played roles in creating significant value through energy savings.

[z] For additional detail on the EPSA Base Case, see Table 3-3 "Summary of DOE QER Analysis Cases using EPSA-NEMS."

Building energy codes, energy conservation standards, and the voluntary ENERGY STAR program for appliances and equipment set a minimum level of energy efficiency performance as well as leadership efficiency levels. Codes and standards address market barriers related to information and transparency, materiality, and split incentives.[aa] These policies have the goal of cost-effectively reducing energy consumption to provide value to customers and meet long-term energy goals.

States and developers of model codes point to two opportunities to increase the impact. The first is the long-standing interaction between energy codes and ratepayer-funded efficiency programs. While these codes and programs often share similar policy goals, increasingly stringent energy codes may create a challenge where, by increasing the baseline efficiency of all buildings, they limit the energy savings that can be captured by efficiency programs. Maximizing value to consumers and other parties requires state policymakers to align goals for all parties. Such alignment will help ensure that modern energy codes and voluntary programs complement each other to achieve cost-effective energy efficiency for all.

The second opportunity lies in the increasing connectivity and controllability of consumer devices. Expanding connectivity may increase the energy used by consumer devices, while also offering opportunities to provide value through improved energy management and greater flexibility of electricity demand. Encouraging the use of connected digital devices in ways that save energy and provide flexibility to the grid has not historically been a consideration in building energy codes. But, codes that encourage effective use of building and device connectivity and controls could directly provide value to building occupants, as well as increase the value of the building as a grid asset.

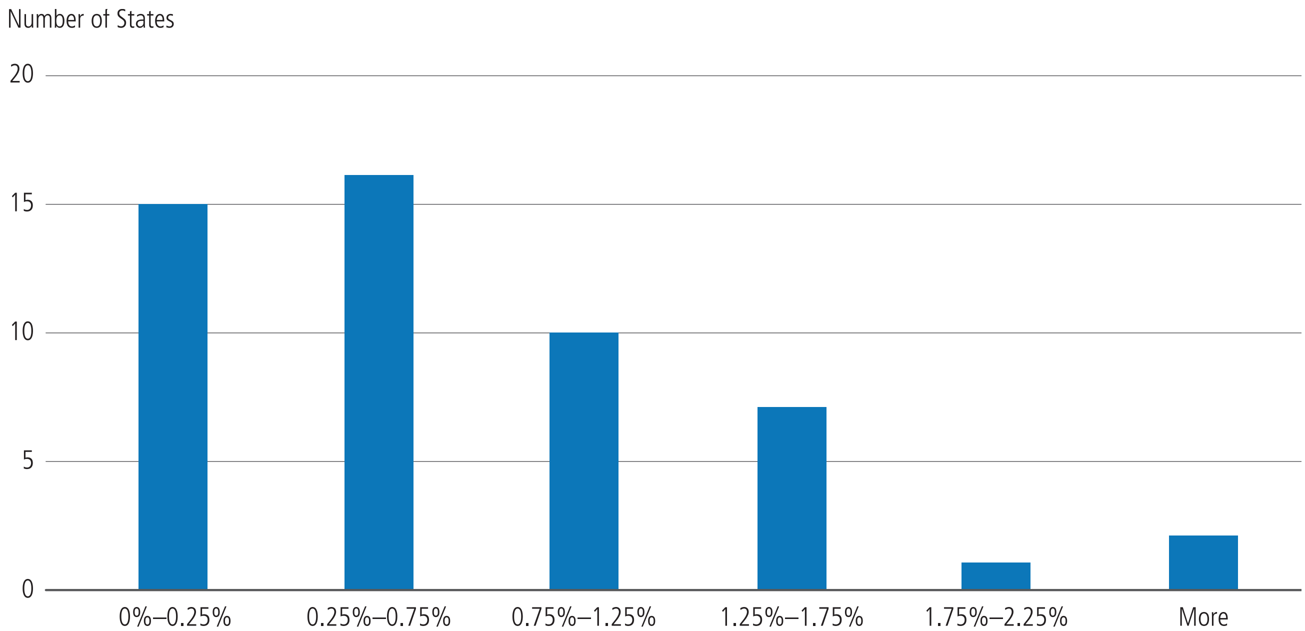
State and Local Energy Policies and Programs Deliver Efficiency

Nearly a third of states are saving at least 1 percent of electricity consumption each year through programs funded by utility customers. Roughly another third of states—most relatively new to energy efficiency—are saving between 0.25 percent and 0.75 percent (Figure 2-11).[156] Many states are increasing their efficiency targets as they meet initial goals and are on track to achieve even higher savings. Energy efficiency programs funded by utility customers spent $6 billion in 2013.[157] It is estimated that the average total cost of saving electricity among U.S. utility efficiency programs across all market sectors for the period 2009 to 2013 is 4.6 cents per kWh saved, split roughly in half between the utility (or other program administrator) and program participants.[158, 159] This is much lower than the average price of electricity in the United States in 2014, which was 10.44 cents per kWh.[160] Another way to view the cost-effectiveness of efficiency is to compare the cost of energy efficiency and the cost of a new power plant. The average levelized cost of saved energy from energy efficiency programs in the United States is estimated at $46/MWh, versus the levelized cost of energy for natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52 to $78/MWh.[ab, 161]

[aa] Chapter III (*Building a Clean Electricity Future*) discusses the potential for building energy codes and appliance standards.

[ab] This comparison has some limitations. For example, the cost of saved energy usually is calculated at the meter of the end-use customer, while the levelized cost of energy supply is calculated at the busbar of the power plant, which typically does not reflect energy lost in transmission and distribution (i.e., line losses) between the generator and end-use customer.

Figure 2-11. Percent Electricity Savings from Energy Efficiency Programs Funded by Utility Customers, 2014[ac, 162]

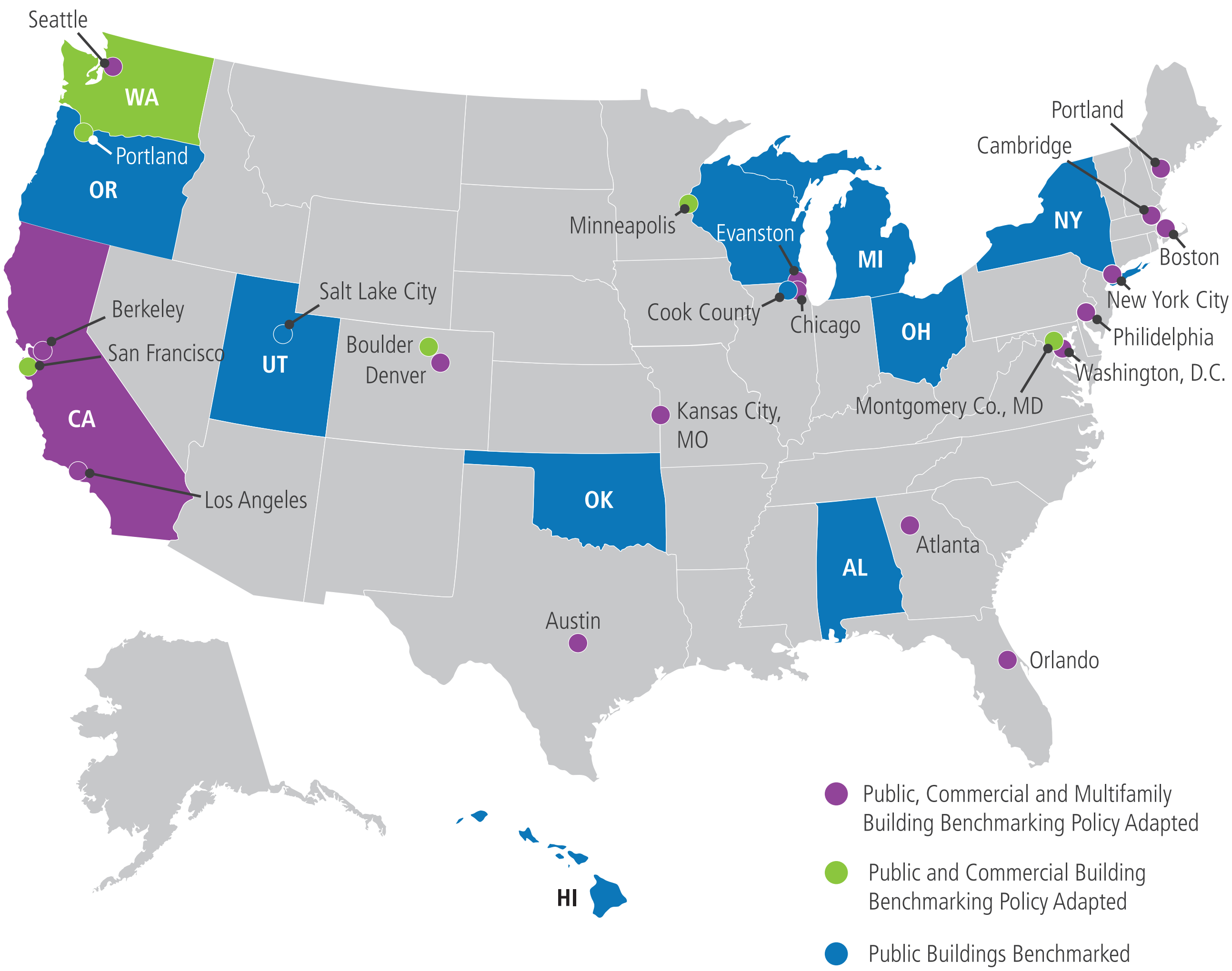


Nearly a third of states are achieving savings of at least 1 percent per year and another third of states are saving between 0.25 percent and 0.75 percent of retail sales. On average, national savings reported in 2014 from utility and public benefits electricity programs were equal to 0.7 percent of sales.

Recent research indicates that inefficient buildings may yield a reduced mortgage value due to energy price risk.[163] Improving energy efficiency can help protect against this potential loss of financial value. Many states and cities that require reporting of buildings' energy performance have implemented energy benchmarking and transparency policies for buildings. This reporting increases building owners' knowledge of properties' energy usage; provides greater transparency for current and prospective tenants; highlights cost-effective, energy-saving opportunities; and provides market data to enhance deployment of efficiency efforts on behalf of relevant agencies.[2] Building benchmarking and auditing data provide a database of information that supports better valuation of energy efficiency measures in commercial buildings for future owners and investors. Regulations that require building energy benchmarking, periodic energy audits, corrective actions (e.g., retrocommissioning), or point-of-sale disclosure or upgrades (or both) for commercial buildings have been adopted by 8 states and 14 cities (Figure 2-12).

[ac] This figure was adapted from *The 2015 State Energy Efficiency Scorecard* (American Council for an Energy-Efficient Economy, 2015) http://aceee.org/research-report/u1509.

Figure 2-12. U.S. Building Benchmarking and Disclosure Policies[165]



A growing number of states and communities are adopting building information transparency policies. These include building energy benchmarking, periodic energy audits, corrective actions (e.g., retrocommissioning), and point-of-sale disclosure or upgrades (or both).

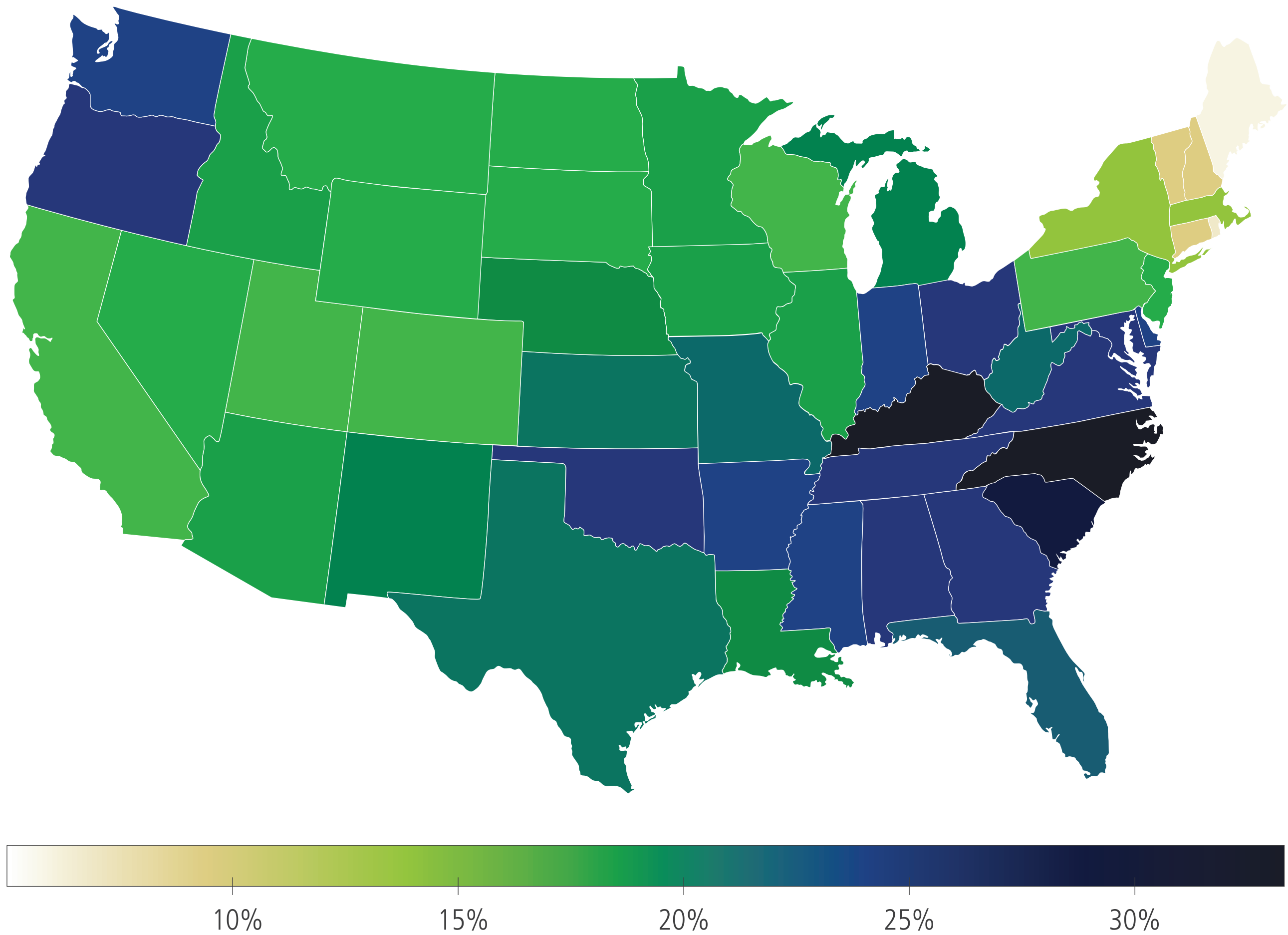
Many states and localities have policies in place to lower barriers to financing energy efficiency projects. Examples of financing initiatives include on-bill financing, state revolving loan funds for clean energy projects (including energy efficiency), other state energy office programs,[166] utility financing programs, and local property-assessed clean energy programs[167] for residential and commercial buildings. While a majority of states have at least one type of energy efficiency financing program, the availability of multiple programs and the percentages of the states' population with access to these programs vary significantly.[168] At least 23 states have an on-bill financing program, which is intended to decrease the financial hurdle for making energy efficiency investments by allowing customers to pay for the upgrades through their monthly utility bill.[169]

While efficiency opportunities are large in all states, the most cost-effective measures vary regionally based on factors such as climate, energy prices, and building practices. One example comes from the residential sector, where DOE analysis identified a suite of cost-effective energy efficiency upgrades to the current stock of U.S. single-family detached homes with total potential savings of 245 terawatt-hours per year (~6 percent of the total annual national electricity consumption in 2014). Initiatives to upgrade HVAC systems, particularly replacing electric furnaces with variable speed heat pumps, could produce substantial electricity savings in the South Census regions (West South Central, East South Central, and South Atlantic), where both average household electricity consumption and population growth rate are higher than other regions.[170] Additional analyses can help states, utilities, and consumers understand which measures offer the greatest net benefits in their region.

State and local governments, as well as the utilities that they regulate or own, lead the effective implementation of many energy efficiency policies and programs. Many state and local governments manage the development and implementation of ratepayer-funded utility programs that incentivize and provide technical support to capture value through increasing energy efficiency investments by consumers. Ratepayer-funded programs directed at improving end-use efficiency and management are now funded at $6–7 billion per year.[171] Twenty-six states have enacted an Energy Efficiency Resource Standard (EERS), which requires utilities to reduce their customers' energy consumption by a certain percentage of annual sales. According to the American Council for an Energy Efficient Economy, "in 2014, states with an EERS achieved incremental electricity savings of 1.2 percent of retail sales on average, compared to average savings of 0.3 percent in states without an EERS."[172] EERS policies, or similar requirements, are projected to be a key driver of future energy efficiency programs, accounting for nearly three quarters of all investment.[173] Additionally, by 2020, these state EERS are estimated to reduce electricity consumption in those states by 8 percent to 10 percent below projected business-as-usual.[174] Analysis of over 2,100 program-years of data indicates that these programs cost an average of 4.6 cents per kWh saved, making energy efficiency a cost-effective approach for lowering consumer energy bills.[175]

There is significant, remaining potential for creating value to consumers and others through cost-effective electricity savings. As an example, Figure 2-13 shows cost-effective electricity savings in single-family residential housing across every state. This analysis suggests that most states can cost-effectively save 15–30 percent of electricity used in single-family dwellings through efficiency programs.

Figure 2-13. Potential Electricity Savings from Residential Energy Efficiency Upgrades, by State[176]



Modeling indicates that homeowners in most states can reduce their electricity consumption by 15 to 30 percent after implementing net present value positive energy efficiency measures, compared to current consumption.

Zero Energy Buildings

In concept, zero-energy homes (and zero-energy buildings [ZEBs] in general[ad]) are "energy-efficient buildings where, on a source energy basis, the actual annual delivered energy is less than or equal to the onsite renewable exported energy." Other definitions use site-energy-based criteria—a less-stringent definition than source-based, which includes the site energy plus the energy used to provide and distribute it. And, others use time-dependent, valuation-based definitions, which seek to assign a valuation of energy produced or consumed to better reflect the actual costs of energy, as adopted by the California Public Utilities Commission. The difficulty in meeting ZEB criteria varies between definitions. Furthermore, the cost-effectiveness of ZEBs depends highly on the age and type of building, location (climate), incentives (e.g., utility rebates), electricity rate and structure, and the cost of renewable energy generation.

[ad] The term "zero-energy–building" (ZEB) used here is considered to have the same meaning as similar terms such as zero-net energy building (ZNEB) or net-zero energy building (NZEB).

Zero Energy Buildings (continued)

Recent studies demonstrate that many new ZEBs in the commercial sector can be cost-effective, with overall costs falling within the same range as conventional, new construction projects. The explicit goal of net-zero energy throughout the design process is critical to minimizing construction costs. In California, for example, it is feasible for many commercial buildings to be ZEB using a time-dependent, valuation-based definition. However, several building categories, such as sit-down restaurants, hospitals, and large offices cannot reach ZEB designation using rooftop solar—though they might reach that designation using parking lot photovoltaic (PV) systems. Having enough available roof space for onsite PV is often a challenge. Contracting with offsite renewable energy systems or participating in virtual net-metered or community-scale solar projects provide greater flexibility for buildings to be ZEB or ZEB-ready. This is an active area of policy discussion.

Other challenges to the adoption of ZEBs are the lack of integrated design practices, cost barriers, lack of skilled and knowledgeable workforce in design and construction, additional design and construction cost, improper building management, user behavior, and integration of solar PV, either as part of the building construction process or as a parallel step during that process.

Policies that encourage zero-energy homes increase demand for not only energy efficiency but also other distributed energy resources, such as distributed generation and battery storage. High levels of market penetration could have significant impacts on the grid, reducing overall grid electricity consumption. More distributed energy resources driven by zero-energy targets can potentially lead to higher levels of demand response. California has announced a target of making all new residential buildings net-zero energy by 2020. It is likely that a significant fraction of existing residential buildings would struggle to attain zero energy onsite due to roof angles, poor insulation, insufficient roof area (particularly in the case of high-rise buildings), and other factors. This may place a premium on finding a way to procure offsite sources to offset whatever amount of site energy remains.

Using government-owned buildings, especially schools, to demonstrate the multiple benefits that ZEBs can help realize (such as improved student health and reduced operating costs) could lead to more widespread adoption of such building construction, renovation, and management practices. For example, one study showed that improved heat-pump air conditioning in relocatable classrooms could simultaneously reduce the energy needed for heating, ventilation, and air conditioning by 50–70 percent and significantly improve indoor air quality. More studies are needed on the cost-effectiveness of new ZEBs, considering an integrated package of energy efficiency measures rather than analysis of discrete measures, as well as a better understanding of the cost-effectiveness of ultra-low energy or ZEB retrofits. Some of the key adoption issues that need to be resolved for "shared solar" or offsite renewable generation include a lack of uniformity and standardization of consumer contracts, rate design, and program structure, and the need for a framework to track and match offsite renewable resources to specific buildings claiming an offset. Thus, an analysis of the policy choices, impacts, and cost implications of ZEBs would be helpful.

Maximizing the Value of Dynamic Consumer Assets

Advances in communications, metering, sensors, controls, and storage technologies are enabling consumers, utilities, and other service providers to more actively or passively manage electricity loads in response to price and other system constraints. This is in contrast to energy efficiency measures that result in static reductions in energy consumption by an appliance, equipment, or building. The value derived from dynamically managing consumer assets can be economic, as well as environmental, and can accrue to the consumer, utility, and others. DR, which allows utilities, grid operators, or other intermediaries to call for specific changes in demand when needed, offers benefits in flattening load curves and supplying essential reliability services, such as frequency regulation. Smart meter infrastructure, sensors, and communication-enabled devices and controls give electricity consumers and utilities new abilities to monitor electricity consumption and potentially lower usage in response to time, local distribution, or price constraints. Smart meters also provide a number of other consumer benefits, including enhanced outage management and restoration, improved distribution system monitoring, and utility operational savings.[177] Other benefits include improvements in building user satisfaction and greater worker productivity. Taking full advantage of the value of consumer assets depends on minimizing the risks associated with them—in particular, cyber threats and privacy concerns.

Modern Communications Networks Provide the Backbone for Maximizing Value of Electricity Assets

New technologies supported by private-sector vendors and government R&D are making their way onto bulk power and distribution systems. On the utility side of the meter, power quality monitors, substation instrumentation, faulted circuit indicators, phasor measurement units, advanced meters, and other devices are providing data to system operators and planners.[178] On the consumer side of the meter, products such as grid-connected inverters, thermostats, appliances, and machines are increasingly connecting to each other and to the internet or the IoT. The interplay of these various devices on the grid through the IoT is generating dramatically increased volumes of data. Grid operators and power dispatchers need better visualization of behind-the-meter resources for capacity planning and grid operations. Grid operators also need to understand the degree to which they can rely on customer-sited assets' power production to offset capacity requirements.

One meta-analysis estimated that the effective use of ICT has the potential to reduce total U.S. energy consumption by 12 to 22 percent by 2020.[179] While ICT devices consume electricity, they also increase economic productivity and can improve energy efficiency. For every kWh consumed by ICT systems, it has been estimated that 10 kWh are saved elsewhere in the economy.[180] However, deployment of ICT, AMI, and grid communication infrastructure also raise issues concerning data privacy, ownership, and access.

The broader community served by the utility may increasingly use utility communications networks—a convergence of systems that can create new value to the economy. For example, Chattanooga's municipally owned utility, the Electric Power Board (EPB), built a fiber network throughout its service territory to offer the fastest broadband service to its customers and to enable a smart grid system that would save energy and be more reliable.[181] EPB installed fiber optics throughout its service territory, including rural areas at the end of distribution lines, which enabled EPB to automate control of its distribution and subtransmission systems.[182] In 2009, DOE awarded EPB $111.6 million through the Smart Grid Investment Program, funded by the American Recovery and Reinvestment Act, to install 170,000 smart meters and grid-automation technologies to improve reliability and reduce consumer electricity bills through energy savings.[183] The upgraded system has already allowed EPB to quickly restore power after two major weather-related outages, saving millions of dollars for EPB and the community.[184]

In 2010, EPB announced it would offer the first 1-gigabit-per-second (Gbps) service in the country, which is 10 to 20 times faster than the broadband EPB had been offering.[185] The availability of 1-Gbps internet service has helped grow Chattanooga's economy and encouraged businesses to invest in the city.[186] The Federal Communications Commission (FCC) has attempted to remove barriers to broadband expansion and promote competition in Tennessee by allowing EPB to expand outside its service area; however, a Federal appeals court recently held that the FCC did not have authority to do so.[187]

According to the FCC, 10 percent of Americans and 39 percent of rural Americans lack access to advanced telecommunications.[188] The Federal Government, through the Rural Electrification Act, has a long history of expanding access to affordable electricity and communications services in rural America.[189] The Federal Government has also supported granting loans to rural electric co-ops at interest rates that allow them to achieve rural electrification goals—including improving electricity generation, transmission, and distribution facilities in areas with high electricity costs.[190, 191] USDA's RUS administers these electricity financing programs and also finances rural investments in broadband and smart grid technologies. Coordinated expansion of electricity and broadband infrastructure in rural America, supported by Federal financing from RUS, would serve the dual purposes of increasing access to advanced telecommunication technologies and improving the functioning of rural utility systems.

Customer Engagement with New Electricity Services

As discussed in Chapter I (*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*), the electricity system is becoming more digital, connected, and integrated. These trends, and the new services and assets on the system including distributed energy resources (DER), home automation, and DR, are changing the physical electricity system, while also altering customers' interest and engagement with their energy use. One study of grid modernization found that consumers with a smart meter in their home expect more from their utility in terms of notifications on potential bill savings or excesses.[192] While many customers will continue to desire "plain vanilla"[193] electricity service, increasingly, utilities are working to better engage and inform their more energy-involved customers and are moving toward more customer-centric business models.

Engaging customers has distinct benefits for utilities—engaged households add $40–$90 annually to a regulated utility's bottom line (Table 2-1), and residential customers report up to a 9 percent increase in satisfaction with their utility.[194] Utilities further benefit from robust customer-engagement initiatives as the grid and the utility business model continually evolve and modernize to meet new technology demands, system changes, and policy goals. Utilities with more satisfied customers are more likely to be approved for rate increases for new investments than those with lower customer-satisfaction ratings.[195] According to a survey of 144 power sector executives, only 2 percent think their utility has good customer outreach programs,[196] but more utilities are investing in new market and communications programs and technologies. Increasingly, low-touch interaction, self-service, and social media engagements are three common customer preferences for interacting with their utility.[197] These engagements can include smart phone applications for real-time monitoring of home energy use and e-billing for monthly electricity bills.

Table 2-1. Potential Annual Cost Savings from Customer Engagement Solutions[198]

Value Source	Annual Savings Per Regulated Household
Effective marketing of new offerings	**$4–5**
Reduced cost-to-serve	
Reduced call volume, decreased escalations, etc.	$3–16
Increased adoption of e-billing	$3–5
Improved payment discipline	$1–4
Improved cost-effectiveness of energy efficiency (EE) program portfolio	
EE program cost savings via Behavioral EE	$2–5
EE program cost savings via Thermostat EE	$20–35
Behavioral DR capacity and energy cost savings	
Behavioral demand-response capacity savings	$7–20
Potential aggregate value, $/household, per year	**$40–90**

Customer engagement can provide cost savings to utilities across several functions: program marketing, customer care, energy efficiency, and demand response.

Privacy Concerns Could Limit Utilization of Consumer Data

Policymakers, utilities, and third-party providers must address privacy considerations as the amount of data generated about consumers' electricity usage grows. For residential consumers, concerns revolve around control of when, where, how, and with whom an individual shares his or her own personal information, as well as the right to access personal information given to others, to correct it, and to ensure it is safeguarded and disposed of appropriately.[199] Other aspects of privacy include privacy of the person, privacy of personal behavior, and privacy of personal communications.[200] Some consumers are resistant to AMI due to the specificity of data collected on energy-use data in smaller and shorter time increments. For example, actual appliances can be identified by their load profile (refrigerator, toaster, washing machine, kettle, plasma TV, oven, etc.) and times of usage. These data can reveal building occupancy, behavioral patterns, and individual preferences.

Privacy concerns are not limited to residential consumers. Smart buildings may adjust building controls, including HVAC, lighting, and security systems based upon occupancy levels and occupancy migration throughout the building. Larger commercial and industrial customers may have legitimate concerns about similar data usage, such as knowing how much and when a specific type of the customer's equipment is operational, is being intercepted, or is available to their competitors. Competitors, potential suitors, and even astute investors could be keen to learn facility utilization, production rates, and other salient operational details before such information becomes public after products' sales volumes are announced or disclosed. Similarly, governmental customers, especially national defense agencies or their contractors, may have concerns about unfriendly parties or foreign governments understanding an agency's or contractor's grid vulnerabilities and requirements, usage, and patterns.

Launched in 2012 by the Federal Government, the Green Button Initiative[201] is a partnership with the electric utility industry to provide consumers with easy, secure access to their own energy-usage information in a consumer-friendly and computer-friendly format.[202] More than 60 million households and businesses can utilize Green Button to access energy-usage data from their electric utility. While this program provides individuals with their own energy-use data, streamlined sharing of data with third parties, as exists with global positioning system (GPS) data, is still not available. The 2016 Orange Button program builds on Green Button and establishes solar data.

DOE has published a voluntary code of conduct for data privacy related to end users' energy-consumption data. Utilities can demonstrate their commitment to customers' data privacy through voluntary adherence to the DataGuard Energy Data Privacy Program's standards. These standards ensure customers and regulators that individuals who use customer data adhere to a minimum and well-articulated level of data privacy. A company's claim of adherence to the DataGuard principles is enforceable by the Federal Trade Commission and state consumer-protection agencies.

Demand-Side Options Can Be Used to Avoid Costs of New Infrastructure

Many utilities are facing the prospects of large capital investments in transmission and distribution system upgrades. The Edison Foundation projects that total U.S. distribution capital investments for the period 2010 to 2030 will be $582 billion in nominal terms.[203] Geographically targeted energy efficiency and DER have the potential to cost-effectively defer, reduce, or replace capacity upgrades for distribution and transmission systems by reliably reducing maximum demand in specific grid areas and increasing utilization of existing assets. In addition to cost savings, potential benefits of non-wire alternatives include mitigating siting concerns related to transmission lines; engaging consumers and their agents (e.g., aggregators) in distribution and transmission solutions; enabling gradual implementation (reducing the impact of incorrect load projections); improving reliability and resilience through a diversity of measures; and accelerating development time frames. These alternatives can be identified through distribution and transmission planning for specific geographic areas. Orders 890 and 1000 by FERC (discussed in greater detail in Chapter III [*Building a Clean Electricity Future*]) require transmission providers to comparably treat all resources in a transmission planning process. For example, transmission providers may have to identify how they will treat demand resources on a comparable basis with transmission and generation solutions for purposes of transmission planning.[204, 205, 206] The Bonneville Power Administration and some states (e.g., Maine and Vermont) and utilities have been early DER adopters.

The Brooklyn Queens Demand Management project is an example of a utility plan using demand-side options, along with utility resources, to avoid spending $1.2 billion for new substations, feeders, and switching stations to meet a 69-MW shortfall in the growing Brooklyn and Queens boroughs of New York City. Consolidated Edison's (ConEd's) Brooklyn Queens Demand Management project will cost an estimated $200 million, which includes 17 MW of infrastructure investment and 52 MW of demand-side solutions on both the utility and customer sides of the meter. Demand-side options include energy efficiency programs with residential and commercial customers, DR auctions, and a CHP-acceleration program. ConEd held its first DR auction in early August 2016 and awarded 10 contracts that would result in 22 MW of peak demand reductions in 2018. Payments to providers ranged from $215–$988/kW/year depending on the amount of power reduction and demand management technology used. The awarded companies are responsible for signing up ConEd customers who are willing to reduce their usage during peak hours or deploy technologies like solar or storage to cut their consumption. The utility will also be deploying several DER, including solar generation, fuel cells, battery storage, and voltage-optimization technology, to reduce peak demand and save energy.

More than 250 electric cooperatives in 35 states use large-capacity electric-resistance water heaters to shift demand away from peak hours.[207] These large, insulated water heaters store water heated with low-cost power during times of off-peak demand for use during times of high-cost peak energy demand, enabling co-ops to optimize operation of the grid. Large water heaters also contribute significant and consistent amounts of load, making them ideal candidates for utility DR programs.[208] Basin Electric Co-Op, which relies on these larger water heaters for many DR programs, estimates that these grid-tied water heaters help reduce 500 MW of annual peak demand in the United States.[209]

The application of DER to offset traditional system upgrades presents a new value proposition and challenges how utilities are typically compensated. According to the New York Reforming the Energy Vision order on ratemaking and the utility revenue-model framework,[210] the New York Public Service Commission expects that new earning opportunities for utilities in the near term will be a combination of outcome-based incentives and revenues earned directly from the facilitation of consumer-driven markets.

Aggregation of Individual Consumer Transactions Can Create Economies of Scale and New Business Models

Aggregation can be of either load (i.e., consumers joining together to aggregate purchases of electricity) or of some combination of supply and demand side resources. Changes in technology as well as state policy have led to the evolution of two newer forms of aggregation, in addition to DR: virtual power plant aggregation and community choice aggregation.

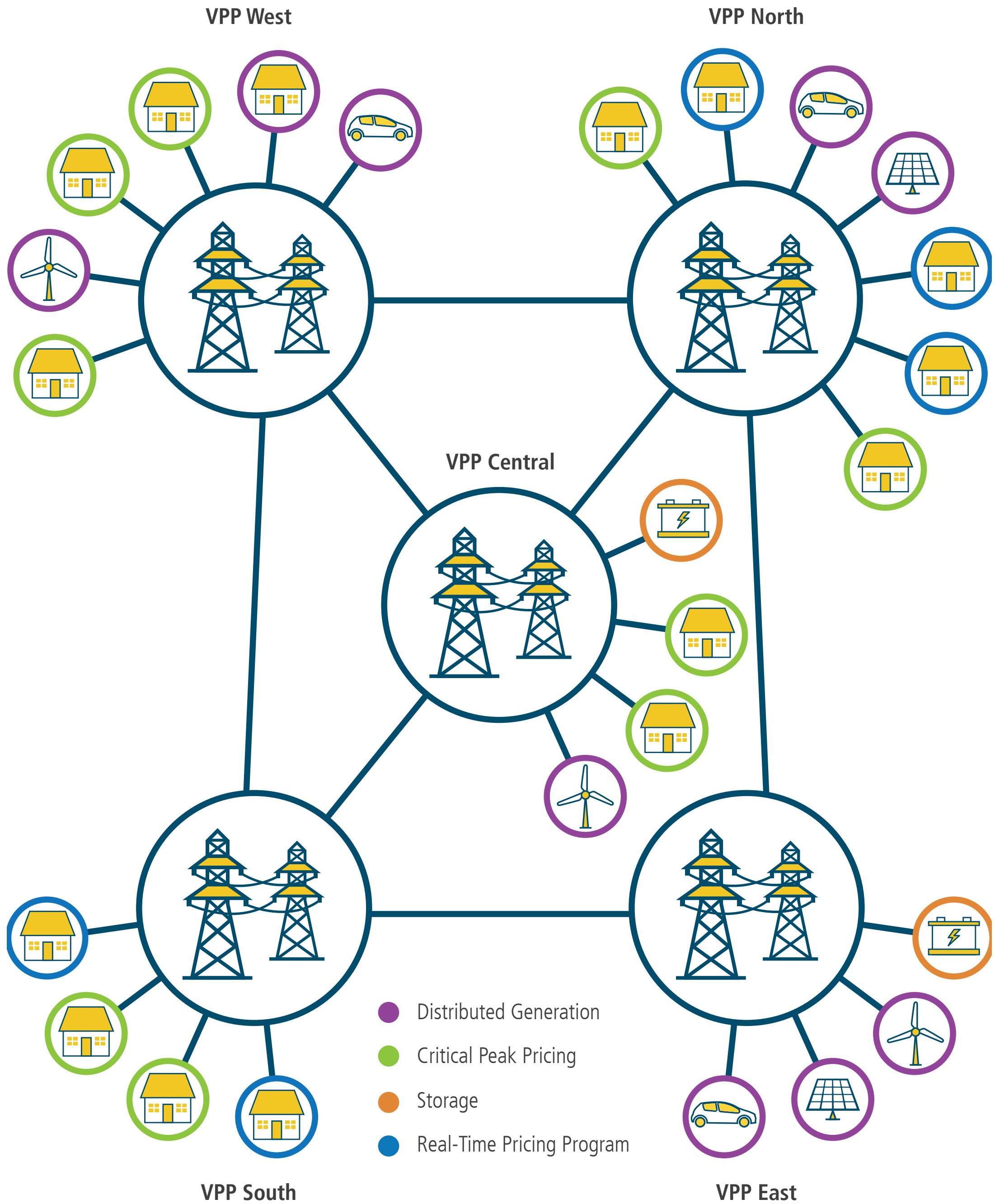
DR aggregation is being pursued by both electric utilities and companies, who then take the aggregated DR and bid it in RTO/ISO wholesale markets, such as PJM, ISO New England, Midcontinent ISO, California ISO, and New York ISO, or deliver it to contracted utilities.[ae] DR in these wholesale markets helps lower wholesale prices and adds to resource diversity, which can help reliability and help integrate other resources such as wind and solar. One estimate is that 32 GW of DR resources are now available, all of which are bringing the customer directly into wholesale electricity markets.[211]

The use of aggregated DR in RTO/ISO markets was greatly aided by FERC's issuance of Order No. 745, which said that a "demand response resource *must be compensated* for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price."[212] Since there is a mixing of retail-level services with wholesale-level services, FERC's Order No. 745 raised a number of state and Federal jurisdictional issues, which the Supreme Court addressed.[213]

Virtual power plants (VPPs), pioneered in the 1980s in Austin, Texas, are systems that integrate a wide variety of power resources, such as smaller, local renewable or gas-fired generation, energy storage, and energy efficiency DR programs. They do this by aggregating many diverse customers from different customer classes "under one type of pricing, demand response, or distributed energy resource program."[214] Customers are not necessarily grouped by program or type, but they can also be aggregated by another defining characteristic, for example, location (Figure 2-14). By remotely controlling these VPPs and aggregating different types of products, utilities are able to better forecast energy supply and demand and increase the flexibility and reliability of the system. In addition, aggregation of DR programs allows participation in a wholesale market. Utilities in several states are beginning to focus on today's newer version of VPPs. In Kentucky, for example, the Glasgow Electric Plant Board is installing a system of batteries that can release power during peak demand times.[17] Similar programs are being piloted in New York and Vermont.[18] Today, technology and ICT are enabling the consideration of more elaborate forms of VPPs.

[ae] Chapter III (*Building a Clean Electricity Future*) discusses states regulatory actions that impacted DR.

Figure 2-14. Aggregations of Demand Response and Distributed Generation[217]



Aggregators acting as VPPs collect power and services from distributed resources, including community solar, rooftop solar, EVs, distributed storage, and grid-controlled and price-reactive household devices. Aggregators are then able to bid these services collectively into wholesale electricity markets to meet system operation needs.

Community choice aggregation (CCA) enables local governments to aggregate the buying power of individual customers in order to secure alternative energy supply contracts on a communitywide basis, while maintaining the existing electricity provider for transmission and distribution services.[218] Seven states—Massachusetts, New York, Ohio, California, New Jersey, Rhode Island, and Illinois—passed CCA laws as part of electric-restructuring legislation in the late 1990s and early 2000s. In 2013, CCAs were able to secure more than 9 million MWh of renewable energy for approximately 2.4 million customers. Most CCAs are "opt-out" entities, meaning that the customer is, by default, part of the aggregation unless the customer opts out.

The **community solar model** is an additional method of organizing the installation of solar facilities. In this structure, solar facilities supply power to multiple customers, enabling the placement and sharing of solar installations by a diverse group of customers. This model is mentioned separately because it can be developed via multiple ownership forms, including joint, municipal, and utility.

Interconnection and Interoperability Standards

Interconnection standards—the sets of rules that determine the requirements for DG or storage to connect to the distribution grid—prescribe the capabilities that technologies must possess in order to be allowed to interact with the grid. These standards are voluntary, but many state PUCs require their jurisdictional utilities to adopt them and thus have become de-facto industry standards.

In 2013, the Institute of Electrical and Electronics Engineers (IEEE), which authors the standards, launched a full revision of its Standard 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems," with experts at National Renewable Energy Laboratory and Sandia National Laboratories leading the Standard Technical Panel.[219] The revision, which is currently underway, should clarify functions for distributed storage, DR, interoperable backup generation, and distributed PV related to advanced inverter functionality, communications capabilities, controls, and interoperability, among other topics. These capabilities are foundational for using distributed storage, backup generation, and PV generators to support the functioning of the grid in the long term. In the short term, they will enable greater hosting capacity and mitigate some integration challenges.

The primary challenge to completing the interconnection standard, known as IEEE Standard 1547 revision, is circulating the proposed revised standard throughout the industry and arbitrating comments through the ballot process. If the average monthly rate of distributed solar PV adoption from April 2015 to April 2016 remains the same, an additional 10 GW will be added to the grid by the end of 2018, more than doubling the current capacity.[220] However, even after IEEE adopts the revised standards, PUCs and utilities will need to consider and adopt them in order to facilitate advanced interconnected and interoperable operation of grid-connected devices. Notably, the current published standard (1547.a) encompasses aspects of extended interoperability capabilities,[221] but it has not been widely adopted. Expediting the completion and adoption of the 1547 Standard revision will improve some operational characteristics of pre-existing systems. It will also allow a greater percentage of near-term capacity additions to incorporate many important grid functions and capabilities that current standards do not address.

In addition to IEEE standards, National Electrical Code standards for grid-connected devices have changed significantly with each update to the standards in recent years. This change has been in response to the continued evolution of solar technology and the need for a stable market environment to ensure the proliferation of safe, reliable, and cost-effective solar PV.

Interoperability is also a critical requirement for seamless integration of grid-connected devices.[222] The National Institute of Standards and Technology (NIST) defines interoperability as "…the capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user."[223] Interoperability standards increase the cost-effectiveness of grid-modernization investments by mitigating the risk of diverse grid technologies becoming prematurely obsolete; accounting for backward compatibility with already deployed technologies; enabling technology innovations for the hardware and software of grid-connected devices; and ensuring the security of devices connected to the grid.[224] The Energy Independence and Security Act of 2007 mandated that NIST develop a framework and protocols for interoperability standards of smart grid devices. NIST, in cooperation with the industry-led Smart Grid Interoperability Panel, developed initial standards and continues to develop standards with the participation of DOE and industry groups.

The Federal Government does not mandate the uptake of interoperability and interconnection standards, but it supports and can speed up the development processes for standards in order to animate national markets for grid-connected devices. Many consumer-level and grid-level devices are either on the market or under development. When connected through electric utilities' distribution grids, these devices can offer benefits to the customers who use them and can support the stability of the broader grid system. However, in order to realize benefits, devices must be able to coordinate and communicate their operations with the grid operators' control systems and other devices.

The Changing Preferences of Electricity Consumers: Impacts on Rates and Business Models

The new grid and end-use technologies described in QER 1.2 have different operational characteristics and can provide new and different grid services. In many instances, these new technologies can provide benefits to the grid but do not necessarily provide essential reliability services; this raises cost-benefit issues and points to the need for adequate valuation of new consumer options.

Vertically integrated utilities provide the full range of grid services (energy, ancillary services, etc.) necessary to ensure reliability for the consumer. With the advent of competitive markets, energy and other services can now be acquired from other utilities and third-party providers. Despite increasing customer participation, the responsibility of ensuring reliability on an increasingly complicated system falls to the grid operator.

The proliferation of dynamic, consumer-owned assets that generate power and provide DR services also presents challenges to the Federal and state regulatory structures that govern compensation for energy infrastructure and grid services. In addition, state and local electricity regulators and policymakers are working to both sustain and transform an industry where there are new technologies, consumer demands, and regulations. Public officials and small utility managers are working to evaluate the costs and benefits of emerging technologies. This process is often highly technical and demands a significant, changing knowledge base and skill set. Also, new compensatory models to incent the appropriate mix of resources on the grid and new tools for coordinating across jurisdictions will be required to align the policy and regulatory frameworks that ensure secure, reliable, and affordable electricity.

Compensating Providers of Grid Services

The accurate characterization and valuation of services that new technologies provide to the grid can contribute to clearer price signals to consumers and infrastructure owners. This clarity ensures that tradeoffs among system attributes like affordability, sustainability, and reliability are systematically considered, and that desirable properties are compensated appropriately in a rapidly evolving system. Utilities are increasingly attempting to quantify the relative cost of demand-side energy efficiency and load-management investments compared to supply-side, transmission, or distribution investments in utility and regional planning processes, as well as interconnect-wide and national policy making.[225, 226, 227, 228] Often, investments in demand-side energy efficiency to balance supply and demand on the electricity system are less expensive than additional supply and provide a range of quantifiable benefits.[229, 230] However, current methods for considering benefits of and procuring energy efficiency differ from supply-side investment decisions, including how participant costs are considered and the ability of a utility to acquire resources outside its service territory to meet demand.[231]

Valuation of Grid Services

There are gaps in how markets, incentives, and regulations compensate and value services provided by emerging technologies and system topologies. Closing these gaps often requires specific efforts to address finance, market rules, incentives, and policies. While valuation continues to be a high-level discussion in the electricity sector, opportunities exist to fill current, clearly defined gaps related to the environmental, reliability, security, and resilience benefits of new services.

The value that new energy resources provide, both individually and in aggregate, depends on the following:

- **Type of resource:** Different resources will be able to provide different values in different situations. For example, while energy storage and PV will be able to provide reactive power to the grid, other devices (e.g., efficient windows) will not.
- **Location:** The value that a resource can provide depends on its location on the distribution or transmission system. For example, placing efficiency measures on PV near points of congestion may have much more value to the electric grid than places with no congestion.
- **Time:** When the resource provides the service is important. For example, if energy efficiency measures reduce periods of peak load, those measures may be able to defer building new generation or distribution/transmission upgrades.

Currently, many valuation efforts focus on the contributions of specific energy technologies, but to be fully effective, valuation must be done in a system context, and estimating the value of an individual technology outside the system context is suboptimal.[232] Changes to the system, whether regulatory changes or technology changes, can have both locational and temporal system impacts. Quantifying the value of an individual technology should involve comparing the states of the system before and after the technology was installed.

Rate Designs for Valuing New Services

Electricity rates are the schedule of prices that utilities charge end users for the provision of service. Ratemaking, the process of establishing rates, is an administrative process designed to recover expected costs and provide the utility an opportunity to earn an allowed rate of return. Through cost-of-service rates, utilities earn a fair return on invested capital and recover the cost of depreciation, operating expenses, and taxes. Additionally, the recovery of costs in ratemaking introduces behavioral incentives to utilities. The structure of electricity rates determines the nature of price signals to consumers. Rates are the primary mechanism by which utilities provide information to customers to inform their consumption and investment behavior. Supreme Court precedents that frame the legal requirements of regulation help shape ratemaking.[af]

[af] For example, in *Knoxville v. Knoxville Water Company, 212 U.S. 1 (1909)*, the U.S. Supreme Court recognized the right of a utility to recover the initial cost of infrastructure investment through depreciation charges. In *Bluefield Water Works & Improvement Company v. Public Service Commission, 62 U.S. 679 (1923),* the U.S. Supreme Court established the principle that "the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate…to maintain and support credit…"

The ratemaking process begins first with the determination of the utility revenue requirement and follows with the design of rates. The revenue requirement is a forecast of the budget that the utility will require to meet expected customers' electricity needs during a past or future test year. The basic formula for determining the utility revenue requirement is:

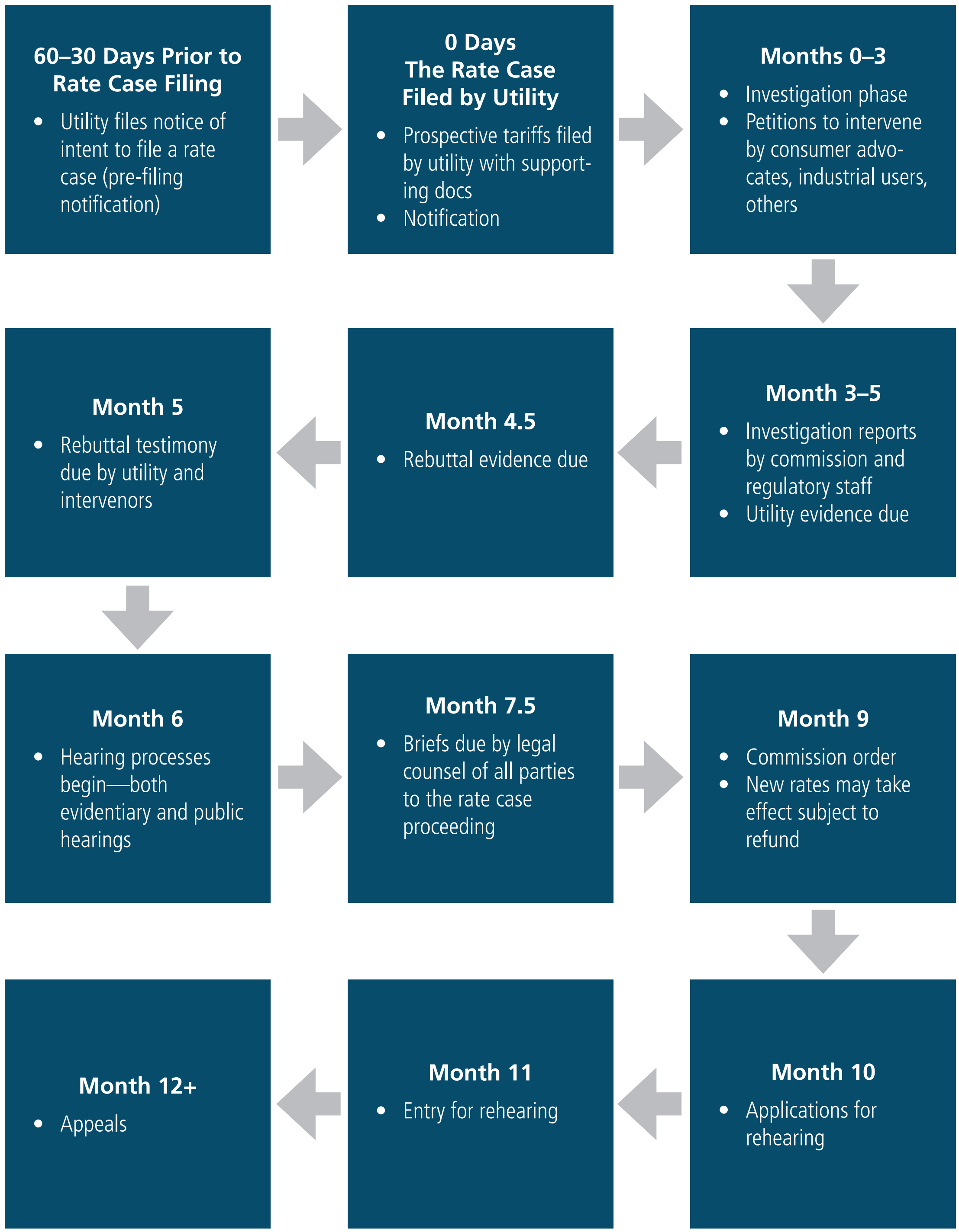
$$\textit{Revenue Requirement} = (\textit{Rate of Return} \times \textit{Depreciated Rate Base}) + \textit{Depreciation}$$
$$+ \textit{Operations and Maintenance (including Fuel)} + \textit{Taxes}$$

The rate-design process balances the prices customers see with the utility's ability to recover its revenue requirement. The process requires allocating utility costs to different customer classes (e.g., residential, commercial, industrial) and to different rate categories (e.g., energy charges, demand charges). A key step in the rate-design process is the determination of cost causation (the underlying rationale for incurring that cost), which helps develop rates whereby different customers pay the cost of providing the service they use. Various elements of costs (e.g., distribution costs, metering, and transmission) are thus allocated to each customer class. Ideally, each customer would pay only the cost of providing services that the customer uses. As discussed, this is an aspirational goal that utilities often do not achieve in practice.

Some jurisdictions may have rates in effect for a specific time period, such as 3 years, while other jurisdictions may allow rates to remain, in effect, indefinitely, unless the utility, the PUC, or a third party with standing seeks a rate adjustment via a complaint.

Considerations include the needs of current versus future ratepayers; the geographic or demographic characteristics of ratepayers; funding for any public benefit programs, like efficiency, R&D, or low-income assistance programs; evolving technology; and social goals like environmental performance. Figure 2-15 on the folowing page illustrates the order and timeline of a typical state rate-case proceeding.

Figure 2-15. Timeline of a Typical Rate Case Proceeding



Rate cases are lengthy and complex, often lasting a year or more. Depending on how utilities calculate their costs, this often leads to "regulatory lag," wherein rates come into effect long after utilities have made investments. Thus, utilities are typically recovering past, not current, costs.

Typically, the rate-design process begins with a cost study that characterizes the elements of the utility's cost for providing service to customers and determines cost causation. Note that the *costs* of providing service are the quantifiable values of assets and policies that accrue to the utility; the *price or charge* is the cash value of the service determined by rate regulation, including subsidies—the utility recovers *costs*, while the customer sees *prices and charges*. Elements of cost fall into three basic categories:

1. **Fixed costs** are the basic costs of providing service that do not vary with the level of electricity consumption. An example of a fixed cost is the cost of a meter, a necessary element for providing service that is functional whether the customer uses very little or a great deal of energy.
2. **Capacity costs** measure the impact of usage on system infrastructure, where increases in customer consumption can trigger the need for additional investment. For example, increases in air conditioning use can necessitate distribution investment, where the size of a substation supporting a residential distribution lateral power line is driven by the need to reliably serve the peak usage, typically propelled by air conditioning on the hottest day of the year. Capacity (demand) charges can be designed to signal customers' expected contribution to new investment and provide a mechanism for recovering those costs, once incurred.
3. **Variable costs** are primarily the energy costs associated with providing a service, such as fuel. Variable costs change based on the customer's electricity demand and the types of generation capacity available in the system.

In an ideal ratemaking scheme, the elements of cost would fit naturally into the three components of rates: (1) fixed (customer) charges, (2) capacity (demand) charges, and (3) energy (variable) charges. The fixed customer charge would reflect the fixed costs of providing a service. The variable energy charge would represent the cost of energy, determined either through an electricity market or by the fuel and other variable costs required to operate the utility's own generation. Capacity costs vary by demand and are driven by the maximum system usage because electrical systems are designed to meet peak energy consumption. The demand charge is a mechanism for both recovering capacity costs and providing a price signal to customers about their contribution to costs at the peak. Typically, the demand charge is set annually, serving as a ratchet on the customers' bills.[ag]

Traditionally, utilities recouped their costs from customers by charging a two-part rate that consisted of a volumetric charge component and a fixed charge component. Volumetric charges are based on the amount of electricity a customer actually uses and generally are assessed per kWh. Customers pay the fixed charge regardless of how much electricity they consume.[ah] Analysts have generally broken down the fixed costs that the utility incurs into two categories: system-wide fixed costs and customer-specific fixed costs. A customer-specific fixed cost is the cost the utility incurs when it is servicing the customer—for example, the costs to meter the customer and issue a bill. This cost is independent of the customer's usage. A system-wide fixed cost is the cost of having, running, and maintaining the electricity grid—regardless of how many customers it is serving.[233] Historically, consumer demand allowed utilities to securely recoup most of their fixed costs through

[ag] A ratchet is a circumstance in which the rate will not decline until an appropriate period elapses (often, 1 year). Thus, a demand charge, based on a demand of 3 kilowatts set in month one (say, January), might increase if a higher demand, 5 kilowatts, for example, is set in month two (February); but lower demand in subsequent months will not reduce the demand charge until the period has expired.

[ah] Fixed charges may vary by class of consumer—industrial, commercial, or residential—but the volume of usage per billing period may not determine the classes.

the volumetric rate. Utilities were able to assess only a limited fixed charge to each customer, which generally did not accurately reflect the true fixed costs that a utility was incurring. For typical residential customers, fixed costs make up a much larger proportion of total costs for utilities than the customer's electricity bills reflect.[ai]

While consumers only see a small fixed charge on their electricity bill and most of their bill comprises the variable charge based on the electricity consumed, utilities' costs do not reflect this breakdown. Utilities' costs for a typical bill are divided into variable and fixed costs. Although, historically, customer demand allowed utilities to securely recoup most of their fixed costs through the volumetric rate, the current stagnant or declining demand is causing utilities to undercover fixed costs.

However, the current trend of stagnant or declining demand and the resulting drop in revenue from volumetric charges has rendered this strategy ineffective, leaving utilities to find new methods to recover their fixed costs. Some utilities have proposed converting system-wide fixed costs into fixed charges to consumers, but this is not without controversy. As the Rocky Mountain Institute concluded: "If increasing portions of customer bills are collected in the form of fixed monthly charges—and less in the form of volumetric charges or other types of charges that the customer has the ability to influence—the incentive to conserve could be diminished."[234] However, raising fixed costs for all customers can disproportionately impact low-usage customers for whom high fixed costs would comprise a relatively larger portion of the bill. High fixed costs similarly impact low-income customers and other vulnerable populations.[235]

Time-Varying Rates Can Shift Demand

Historically, volumetric charges to end users have been uniform in time, but system costs vary by season and by hour of day, reflecting the marginal cost of generation, the cost of maintaining capacity, and impacts on congestion on physical infrastructure. Time-varying pricing is one way to induce consumers to shift their demand to less-expensive times, and it has the potential to shift value from owners of generation assets to consumers.[236, 237] Variations in consumer prices can be scheduled in advance or can reflect real-time wholesale energy prices. The most common time-varying rate is time-of-use (TOU) pricing, which uses a predetermined schedule of seasonal and daily price variations. Some utilities are moving toward implementing TOU as the default rate.

TOU pricing usually does not reflect the small number of hours that have the very highest wholesale prices and congestion problems. Two rate structures that do reflect those times are real-time pricing (RTP), through which consumers experience wholesale prices directly, and critical peak pricing, which gives consumers occasional large rate jumps at short notice when system costs are particularly high. RTP provides the most economically efficient incentives, and it could increase the economic efficiency of the system substantially. One estimate found that increasing the number of PJM customers on RTP from 10 to 20 percent could improve economic efficiency by $120 million per year.[aj, 238] However, RTP and critical peak pricing introduce the risk of volatile wholesale prices to the consumer, though financial instruments can mitigate risks.

Consumer advocates have opposed time-varying pricing on the grounds that it disadvantages low-income residential consumers, but there is not clear evidence to support that claim. A survey of multiple TOU programs found low-income consumers to have both flatter demand profiles and less ability on average to

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[ai] "A typical residential customer uses 982 kWh of electricity per month, with a bill averaging $110. The bill is made up of three cost components: $70 can be allocated to generation, $30 to distribution, and $10 to transmission. Nearly all the distribution and transmission costs are fixed (or capacity-type) costs that do not vary based on hourly customer loads, while approximately 80 percent of generation costs are variable. This means that $54 of the typical bill is related to capacity or fixed costs, and $56 can be attributed to energy-related or variable costs. Yet, a typical residential fixed charge is around $10 per month." Source: Paul Zummo, *Rate Design for Distributed Generation: Net Metering Alternatives* (Washington, DC: American Public Power Association, 2015), 3, http://www.publicpower.org/files/PDFs/Rate_Design_for_DG-_Net_Metering_final.pdf.

[aj] For comparison, the total retail price of electricity transacted through PJM in a year is about $60–70 billion.

shift their demand in response to price.[239] This meant that, on average, low-income consumers benefitted from TOU without any change in their behavior. However, they were less able than other consumers to recoup additional benefits by changing behavior. Across the five TOU programs studied, the net effects on low-income consumers could be positive or negative.[240]

Locational Pricing Difficult to Implement

Traditionally, locational impacts on electricity cost do not inform retail rates, which is analogous to uniform charges at the post office for mailing a letter to an urban or a rural home. Whether living in a dense urban neighborhood or in the only house at the end of a country road, all consumers in a service territory pay the same charges for the distribution system. However, system planning and operations are now reaching a level of sophistication that allows engineers to estimate the locational and temporal costs of electricity depending on the localized technical attributes of the physical distribution system like feeder infrastructure, line constraints, and local demand.

Recent policies from several state PUCs have suggested regulatory interest in location-based pricing for ratepayers down to the feeder level. Regulators in Minnesota currently allow utilities to incorporate the location-specific net benefits of DG into prices charged for particular ratepayers.[ak, 241] Regulators in New York, Hawaii, and California have recently expressed interest in location-based rates.[242, 243]

However, most determinants of locational value are not within customers' control, or even within the consumer's knowledge. For example, if a secondary transformer is close to its reserve margin and someone who lives nearby buys an EV, the utility may have to upgrade the transformer, incurring a very substantial local cost. If that utility is applying locational prices, all of the customers on that feeder would see their prices go up in response to one neighbor's decision. Locational costs may reflect physical geography, local economic characteristics, and legacy planning decisions made by utilities, and these complexities introduce opportunities for inequities to consumers. A feeder-by-feeder economic and engineering analysis of the value of distributed PV in Pacific Gas & Electric Company's service territory found that 90 percent of feeders had neither costs nor benefits from distributed PV. The analysis also found that the highest locational value on any feeder was only about $60 per kW per year, suggesting that there may be limited benefit to instituting locational prices.[244]

Net Metering for Distributed Generation

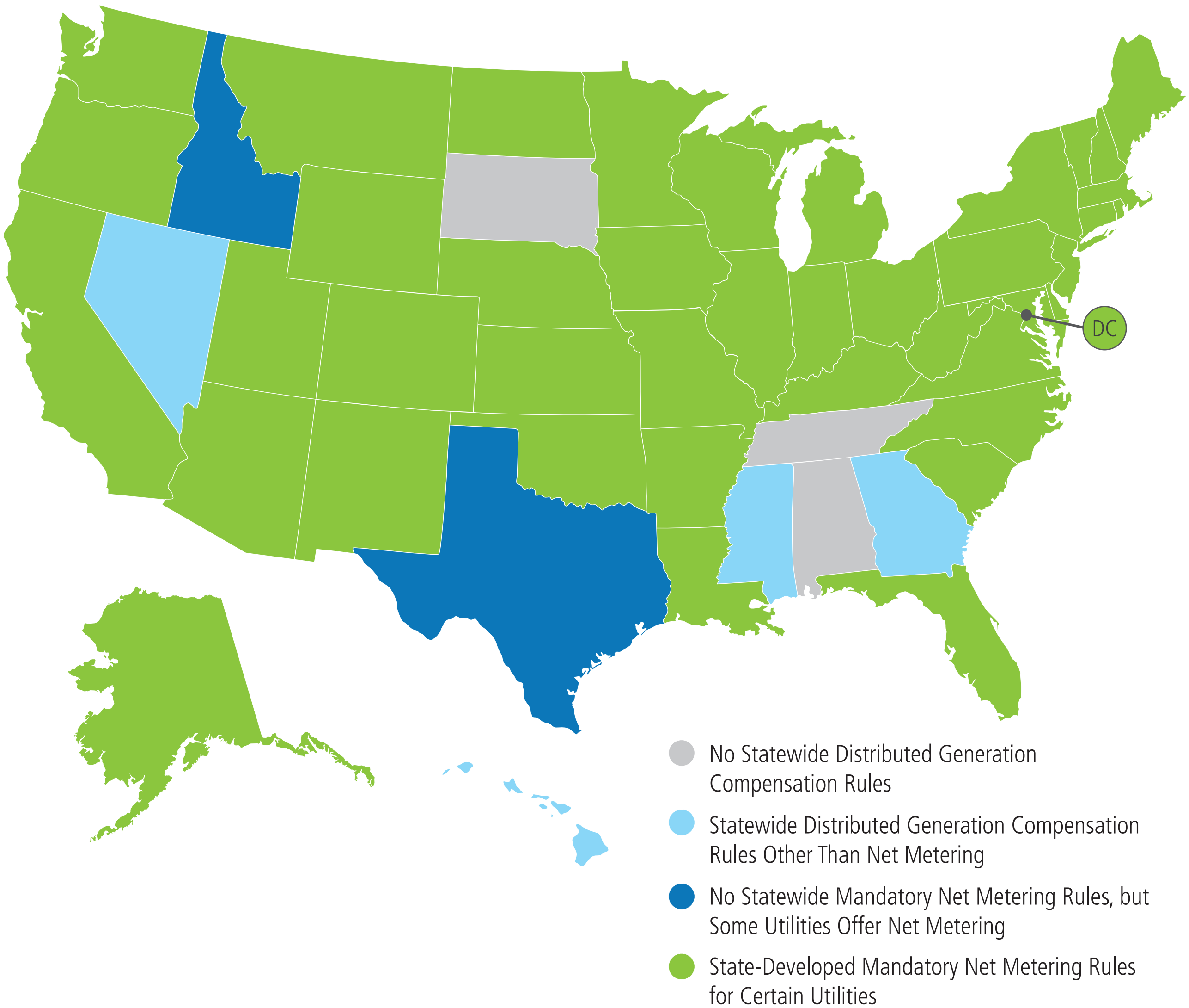
Net metering is a rate mechanism wherein customers with onsite generation like rooftop solar are charged for the value of their net consumption (electricity consumed less electricity produced by solar), crediting onsite generation at the full retail rate. A provision in the Energy Policy Act of 2005 required states to consider net metering as an option for compensating owners of DG. Currently, 41 states and the District of Columbia have a statewide net metering policy, and 6 states have alternative compensation mechanisms for DG (Figure 2-16). States that adopted net metering policies were likely motivated by a desire to generate electricity from zero- or low-emitting sources, to support deployment of a new technology, and to give consumers the option of generating their own power.[245] As of September 2016, the policy has contributed to the deployment of 12,300 MW of installed distributed PV in the United States.[246]

Consumers with DG are still connected to the main grid, allowing them to benefit from the physical connection to the grid that provides balancing services, reliability, and base load and peaking generation for electricity when the DG source is not producing electricity. In addition to onsite PV hosts, many utilities have expanded net metering to customers who participate in offsite solar generation, such as community

[ak] The Minnesota Value of Solar Methodology allows for incorporating the location of the DER in determining its value to the grid, but it is not clear that utilities have actually exercised that discretion.

solar, through virtual net metering.[al] Such programs extend the bill savings to consumers who do not have appropriate space for solar on their own premises or who are unable to finance solar on their own (e.g., low-income consumers).

Figure 2-16. Current Net Metering and Distributed Generation Compensation Policies[247]



Georgia, Hawaii, Mississippi, and Nevada offer alternative compensation mechanisms for DG such as net billing, which typically provides a rate of compensation for grid exports below the retail rate.

There are a wide variety of methods for valuing DG. Net metering values DG at the retail rate. At low penetration levels and with few options for alternative metering, net metering is a reasonable approach to provide value to the customer and the utility. As DG penetration increases, this assumption becomes less valid. There are external benefits associated with the development of DG. Solar PV displaces carbon-emitting sources. It can also reduce congestion on distribution lines, although it can also increase congestion—the net effect being location- and configuration-specific.

[al] Virtual net metering calculates a share of net metering for all participants in a group; it is usually administered through a subscription program, where consumers can easily withdraw from the program.

DG hosts receive the retail rate for exported electricity, leading to concerns by some that net metered customers avoid paying the full ongoing costs of providing and maintaining distribution-system infrastructure, as well as the costs of providing power when the distributed generators are not generating (as at night with solar).[248] Moreover, because volumetric rates as designed are generally not a true representation of the utility's variable costs (they typically include a substantial portion of the utility's fixed costs, as well), net metered customers who reduce the volumetric portion of their bill will likely pay a lower amount toward the utility's fixed costs. Efficiency measures can have similar effects. This can lead to revenue shifts from low-demand and net metered consumers to others depending on location and configuration.[249] Contentious discussions around the results of net metering include whether rates structured in this manner can contribute to inadequate valuation of grid services, revenue shifts, and cost shifts for maintaining the grid from DG participants to or from non-participants. These shifts can be significant, with a recent study performed for the CPUC forecasting that the cost shift associated with net metering would be $1.1 billion per year by 2020.[250]

If, as the evidence suggests, net metered customers are in some cases covering their costs while creating a revenue shift to other customers, rates may need to be better aligned with costs and benefits across the system. Some studies have suggested that the presence of revenue shifts does not necessarily imply that net metered customers do not fully compensate for the utility's cost of serving them. Studies of net metering in Nevada and California suggest that a number of classes of net metered customers have been paying more than it costs to serve them.[am, 251, 252] In contrast, a study performed for the Louisiana Public Service Commission concluded that net metered customers do not cover their cost of service.[253]

In some instances, the benefits of distributed solar may exceed the retail rate from net metering programs and result in a shift of benefits from net metered customers to other households.[254] Many studies have also attempted to quantify not just how DG adds costs to the electricity system but how distributed PV increases social benefits by reducing GHG emissions, air pollution, exposure to fuel price volatility, and the need for electricity generation at times of peak load.[an, 255] Depending on the method used and the current generation technologies considered, the environmental benefits have been estimated at more than 10 cents per kWh and the fuel price risk reduction at a similar value.[256] By including environmental benefits, several states have found that the total value of distributed PV exceeds the retail rate.[257] Many of these costs and benefits are "externalities" that are now not typically part of utility consideration. However, it should be noted these environmental and system benefits accrue equally from both distributed PV and utility-scale solar generation; but, in general, utility-scale solar generation is not eligible for net-metering-like compensation structures.[ao]

Considering the complexity of evaluating distributed energy investments, some state regulators are reevaluating compensation models for utilities. They are exploring innovative ways to value the costs and benefits of DER to the grid and improve market mechanisms that align investments, behavior, and operations. Net metering only compensates for energy services without provisions for payments for grid services such as volt/var (volt-ampere reactive) support and other ancillary services. New compensation arrangements could incent customers to provide these services, but without new payment arrangements, customers are disincentivized to provide grid services that may reduce the amount of energy exported to the grid. As of October 2015, 25 states are reviewing their net metering policies.[258] Table 2-2 lists some alternatives to net metering under consideration. Early movers will serve as test beds to guide other states considering alternatives. As this happens, however, consumers who have already invested in distributed PV may face

[am] The CPUC study found that in 2011 non-residential net metered customers (56 percent of net metered systems) paid 112 percent of the cost to serve them, while residential net metered customers paid 81 percent of the cost to serve them.

[an] Generation at times of peak load is particularly valuable when there is little solar installed; this value declines for subsequent installations.

[ao] Additionally, total system costs for utility-scale solar generation are lower than for an equivalent capacity of distributed PV due to economies of scale.

substantial economic loss if they are not grandfathered and receive substantially reduced rates for the electricity they provide to the grid. Regulatory uncertainty can also make it more difficult to secure financing and can drive up the cost of capital for DG. Educating and informing residential and small commercial consumers about potential regulatory risks associated with DER investments should be a priority. As technology and markets evolve, states can build their capacity to value DG, distributed storage, DR, and energy efficiency, and to effectively include them in resource planning.

Table 2-2. Alternative Rate Options for Distributed Solar

Structure	Description	Utility Example
Value of Solar	Utilities and other stakeholders attempt to calculate the full social value of distributed PV, including its environmental benefits, and use that to develop a tariff for all electricity exported to the grid from a distributed PV facility.	Austin Energy; Minnesota's statewide value of solar tariff has not yet been implemented.
Net Billing	Distributed PV host receives neither credit nor charge for electricity consumed onsite but receives compensation for exported power at an administratively determined rate, often set at the cost of procuring utility-scale solar power.	Imperial Irrigation District
Self Supply and Grid Supply	Consumers choose to supply all of their own power, in which case they are excused from some charges but not compensated for any exported electricity. Or, they must buy all of their power at retail rates and sell all of their onsite generation at a lower rate.	Hawaiian Electric Company
Increased Fixed Charges	Net energy metering is maintained, but its value and any associated cost changes from infrastructure upgrades (not counting externalities) are reduced by increasing fixed charges and decreasing volumetric charges.	Wisconsin Utilities

The increasing penetration of rooftop solar and advanced metering is driving and enabling regulatory changes. Regulators and utilities are considering alternative rate options for compensating customers for grid services while continuing to support new technology, maintain infrastructure, and ensure affordability for all customers.

Net metering is a first step in developing methods to compensate customers for the services and generation they provide to the grid. Some of the limitations of net metering may be addressed by creating separate rate classes for DG participants and incorporating elements of net metering into more sophisticated rate structures for that customer class. Moving forward, states and utilities will likely look to use more robust valuation methods. Accordingly, new rate structures and consumer-compensation policies for some consumers—more precise tools than current net metering policies—will enable efficient compensation for a wider array of distributed resources. The group of technologies eligible for compensation may likely grow to include more flexible convertors, DES, load-controlled hot water heaters, and other smart grid-controlled devices that could provide ancillary and load-shifting services. When redesigning rates that enable customers to pursue options that provide them and the utility value-based options, recovering the cost of providing distribution services is of critical importance. As such, an issue is the proper identification and valuation of the costs and the benefits provided by the growing array of customer options.

Consumers who want to maintain their existing service options sometimes get lost in the process. These consumers pose considerations for relevant regulators and marketplace operators. The implementation of new technologies and services present opportunities for enhanced flexibility to help meet consumer expectations.

However, in achieving this increased flexibility, regulators and market operators should actively minimize negative impacts on non-participating consumers, though public policy objectives may expand the scope of impacts considered. Net metering is the most common rate for distributed PV, but many utilities are exploring alternative structures.

Providing Incentives through Ratemaking

Cost-of-service ratemaking creates unique incentives for the utility. Regulation can be a substitute for competitive market pressures; it creates a variety of incentives, driven by the unique treatment of different cost elements, in the determination of rates.

As noted, the rate-making process determines how much a utility can earn, based on the two primary factors: (1) the allowed return on capital, and (2) the utility rate base. Utilities earn profit from a return on capital. Thus, if it costs a utility less to raise money than it earns on its investment, it will have an incentive to over-invest. A reverse bias is created if the cost of capital is set too low or regulation creates obstacles to fully recover capital; for example, promoting energy efficiency without a fixed-cost recovery true-up, a mechanism by which a utility evaluates over-recovery and under-recovery of revenues and either returns funds or levies charges to customers.

Regulatory incentives will play an important role in the enthusiasm with which utilities pursue different activities and the relationships between utilities and third-party providers pursue. For example, to encourage utility participation in energy efficiency programs, regulatory commissions have used three approaches:

1. Cost recovery for energy efficiency expenses
2. Compensation for lost margins associated with lower energy sales
3. Incentives, such as share–the-savings approaches, to motivate utilities to pursue energy efficiency.

The industry is now facing an analogous situation with DER, for example, where net metering is viewed as a mechanism by which utilities would lose revenues. It is one of the factors that complicates the ability of utilities to provide customers the services that unregulated competitors can also provide. The structure of new business models will create incentives that guide utility operation and investment decisions in the future. In the process of developing this new regime, it is important to provide incentives for utilities to both pursue and enable non-utility service providers to meet national goals of a secure, reliable, and affordable electricity system.

Providing Resources to Inform Rate Design

Regulators must design rate structures that support electricity service to customers, incent desired policy outcomes, allow for a fair return on investment, and maintain affordable electricity for the consumer. Regulators find themselves in a new environment characterized by rapidly changing technologies, vast amounts of data being produced throughout the system, and a suite of new stakeholders participating in rate cases. An important Federal role may be to facilitate best analytic practices related to ratemaking and to ensure full transparency to costing exercises in both IOU-regulation forums and public entity forums. Information is a growing key factor in all aspects of electricity service, from power plant management to customer interfaces, and customer-side-of-the-meter devices and applications. The importance of information makes it a key valuation factor, as well. The right information applied in the right way can have significant value-enhancing effects. For instance, information essentially creates value in the following ways:

- Increasing transparency and identifying new opportunities with high potential rewards improve economic profitability by recognizing risks and thereby reducing the cost of capital.

- Reducing uncertainty, such as lowering initial costs, maintaining a lower life-cycle cost, reducing the perception of risks by increasing the control of risks, or reducing constraints—barriers that limit growth, innovation, and improved performance.
- Exploiting the relative advantage of having superior information, such as saving time and effort, or reducing lag times, or increasing the scale and immediacy of rewards.

DOE has begun a process of evaluating the costs and benefits of DER, providing a taxonomy of costs, and framing the disputes associated with valuation of each cost element.[259] The costs and benefits of many smart grid applications were also captured through the Smart Grid Investment Grant Program and Smart Grid Demonstration Program of the American Recovery and Reinvestment Act of 2009.[260] In addition, a consortium of National Labs, the Tennessee Valley Authority, the National Association of Regulatory Utility Commissioners, and planning collaborations in the Eastern Interconnect is developing a grid-services and technologies-valuation framework under the DOE Grid Modernization Lab Consortium.[261] As part of its integrated grid effort, Electric Power Research Institute is developing a benefit-cost framework for quantifying the impact of DER on the distribution and bulk power systems. Importantly, sharing information nationally on valuation of costs and methods of developing rates does not imply a nationally prescribed method of determining costs and rates; such determination is a state responsibility.

There has been a great deal of innovation in the role of the customer, rate design, and technologies used to provide service to customers. Cost drivers are shifting, new costs are being considered, and the importance of rate design has increased—both for engendering customer response and as a method of encouraging component and system efficiency and DER. The National Association of Regulatory Utility Commissioners has framed many of the issues that need further exploration in its recently released rate-design manual.[262] Given the importance of rates—not only for compensating utilities, but, increasingly, as a vehicle for providing price signals to customers who provide transactive load and DER—it would be very valuable for the Federal Government to facilitate a national review of retail rates and the creation of a national repository of rate information.

Adapting the Distribution Utility Business Model

The electric distribution utility now faces a fundamental transformation. The emergent role of the consumer as prosumer and new imperatives, such as resilience, a cleaner energy future, and grid security, are driving the current evolution. Additional investments to support enhanced services are required, including the new transactive role for customers and the higher levels of flexibility and reliability that will support the digital economy.

It is important to understand that alternative utility business models and regulatory practices are inextricably linked. Modification of the traditional ratemaking-based utility business model must be acceptable to state regulators, responsive to customers, financially tenable to utility shareholders—all while supporting innovation (whether by the utility or third-party providers). The business model is part of a triad of interrelated elements, which includes the regulatory structure and economic/market structure that determine the nature of customer service.[263]

Many people have proposed models that represent potential evolutions of the distribution utility, including one that represents endpoints on a spectrum between two models: the Smart Integrator and the Energy Services Utility.[6] The Smart Integrator is described as an operator of the distribution grid in much the same way that an ISO operates the transmission grid and wholesale power markets. It is a platform for transactions, but it does not participate in energy transactions. The Energy Services Utility shares the basic functions of the

Smart Integrator, but it is also a provider of services. It is an extension of the vertically integrated utility. Two questions will determine how the utility business model evolves:

1. What services can (and should) the distribution utilities provide now and in the future?
2. How should utility rates be designed to provide price signals to customers and to compensate utilities for the services they render, including incentives to provide both traditional and nontraditional services?

At issue is the nature of the entities that provide services at the customers' premises, the terms of compensation, and the effect on the ability of utilities to recover the cost of acting as the conduit to the grid.

Models for Provision of Demand-Side Services

There are alternative vehicles for delivering services to customers. An essential question in drawing the future scope of the utilities is whether they will provide energy efficiency services and under what terms. The answer will also play a large role in determining the business models of competitive providers. There are four basic approaches to the provision of energy efficiency:[ap]

1. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective energy efficiency) and administered by the utility
2. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective energy efficiency) and administered by a third party operating under a state or utility program
3. A market-based approach, in which third-party providers seek profit by selling energy efficiency services to customers
4. A market-based approach, in which individual customers act in response to electricity price signals.

In the first two approaches, the utility collects funds for programs through customers' bills. Customers directly finance the last two approaches above. Interacting with the four approaches to the provision of energy efficiency listed above, several business models are possible depending on the particular approach that a utility and its regulator take (Table 2-3).

[ap] Energy efficiency standards have played a vital role in transforming the efficiency of available products. This section is concerned with the choice and acquisition of those products.

Table 2-3. Energy Efficiency Business Models[265, 266]

Utility Programs	Utility energy efficiency programs are part of a resource-acquisition process in which a utility plans for resources that it expects to need in order to provide reliable service.
Independent Entities	Some states use independent entities to administer energy efficiency programs. Their purpose is to invest in services and programs that save money and conserve energy. The fee is based on integrated resource plans that consider both environmental and economic costs.
State Agency Administered	Some states, such as New York, employ a blended approach, whereby some the New York State Energy Research and Development Authority implements the efficiency programs, and the utilites implement others.
Market-Based Providers	Some non-utility companies provide value by serving as the interface between customers and the market (e.g., Comverge).
Energy Service Companies	Energy service companies (ESCOs) offer both private provision of energy efficiency services and a vehicle for implementation. They typically use performance contracts in which the ESCO guarantees energy and/or dollar savings for the project, linking ESCO compensation to the performance of the project.

An array of actors in the electricity sector including utilities, private-sector companies, and state agencies offer energy efficiency programs. Energy efficiency programs are available both in wholesale electricity market areas and within regulated vertically integrated utility areas.

Models for Integrating Distributed Generation

DG delivers power into the distribution grid near the load center. Typically, DG is on the customer side of the meter: the customer installs generation, storage, or a controllable load and ties into the grid via the distribution utility. Utilities can integrate DG using a variety of business models (Table 2-4). These models could be on the customer side, where utilities sell DG products directly to the consumer or on the utility-side, where DG providers sell energy directly to the utility. Although as DG provides more electricity, the generation and management of electricity may become a shared responsibility among utilities, customer-owned DG, and other DG-service providers.

Today, most DG installations occur on the customer side of the meter.[267] Except in rare cases, the customer remains connected to the distribution grid, which serves any load unmet by the DG. When the DG system produces power in excess of customer needs, that power may be sold into the distribution system. The majority of this DG is on the customer side, with very few customers selling power back to the grid. Sales to the interconnected utility could occur under a net metering arrangement, a value of solar tariff, a feed-in tariff,[aq] a Public Utility Regulatory Policies Act contract, or as a negotiated wholesale sale.

[aq] Feed-in tariffs are set prices paid by utilities to customers for production of renewable energy.

Table 2-4. Business Models for Distributed Generation

Customer Ownership	The customer finances the installation, keeps any renewable energy credits associated with solar production, enjoys the tax benefits of the investment, and keeps the bill credit from net metering (or revenue stream from an alternative compensation scheme, such as a value-of-solar or feed-in-tariff).
Power Purchase Agreements	PPAs are standard contract vehicles for long-term power purchases from a third-party developer.
Utility Affiliate Model	The utility invests capital in developing DER through an affiliate. Codes of conduct bar affiliates from competing in markets in which their parent (franchised) utilities do business, or subject affiliates to special restrictions and oversight.
Utility Provided Customer-Premises Model	Where allowed, utilities may offer DER systems to customers and, like other utility generation investments, include the capital cost in the rate base. The utility (as opposed to an affiliate) is the supplier.
Aggregators	Aggregators are companies that group customer load or generation assets together to facilitate their participation in the markets.
Utility-Owned DER	Utility-owned DER can be located either on a customer's premises or on utility property.
Utility-Provided DER	Utility-provided DER is, essentially, small-scale, utility-owned generation. This model alleviates the issue of high, upfront and installation costs that leave customers unable to participate.
Third-Party Merchant Model	Independent third parties can connect DER directly to the distribution system with no onsite customer involvement.

Utilities can integrate DG using a variety of business models to accommodate varying local and regional circumstances, market and infrastructure topologies, and consumer preferences.

Limitations on the Scope of Utility Activities

The scope of utility services defines the lines of business that it can pursue. There are two fundamental reasons for limiting scope. The first is to effectively prevent cross-subsidization of utility affiliate activities, in which ratepayers subsidize non-core utility activities. FERC and state PUCs largely formalized regulatory authorities to prevent cross-subsidizations. The second reason to limit utility activity, which is most important in framing the future distribution utility model, is to preserve consumer benefits of competition by enabling competitive power and services providers to effectively participate in the market. The latter rationale is important for determining which activities utilities are allowed to pursue.

Utility restructuring greatly altered the electric utility business model in some states by breaking up vertically integrated utilities and introducing competition and customer choice.[268] Utilities' divestiture of generation allayed concerns about anti-competitive behavior, such as cross-subsidies between affiliates and favored treatment of affiliates in the new market.

PUCs in restructured states frequently encouraged or required divestiture of generating assets so that the utilities no longer controlled their own generation. As was the case in New York, the primary rationale for divestiture was to break the economic ties between electricity distribution, transmission, and generation services to create a competitive wholesale electricity market. Between 1998 and 2001, utilities divested more than 300 electric-generating plants in the United States, nearly 20 percent of total generating capacity.[269] In 1997, only 1.6 percent of U.S. electricity was produced by non-utility generation, rising to 25 percent by 2002 and nearly 35 percent in 2012.[270]

Ultimately, the question is not what the utility affiliate is permitted to do, but which functions the utility itself is allowed to perform. Some basic questions should be addressed in the process of determining the scope of utility activities:

- Does prohibiting utility activity mean giving up economies of scale and scope?
- Which option provides customers with the lowest cost of service?
- How can the utility expand consumer choice?

California's policy is a hybrid approach, allowing net metering with third-party development through PPAs and utility investment in PV. State IOUs are allowed to own and operate solar PV facilities and execute solar PV PPAs with independent power producers through a competitive solicitation process.[271] California has also pursued a hybrid approach to utility/market provision. This approach promotes storage technology that enhances grid optimization, the integration of renewable energy, and the reduction of GHG emissions, and explicitly provides a role for the utility. Under California State Law Assembly Bill 2514, the CPUC is required to establish procurement targets for the state's three IOUs to acquire viable and cost-effective storage. In October 2013, the CPUC established procurement targets that required the three IOUs to procure 1,325 MW of storage by 2020, with targets divided among three industry segments: transmission-connected, distribution-level, and customer-side-of–the-meter applications. In contrast with the state's policy on rooftop solar installations, utilities are allowed to own up to 50 percent of their cumulative targets.[272] The State of New York's Reforming the Energy Vision initiative is also seeking to reform the utility business model. The New York Public Service Commission in 2014 issued a proposal that would establish the utility as a distribution system platform (DSP) provider. The proposal is divided into two tracks. Track 1 addressed the development of DER with the utility as DSP providers, and Track 2 addresses reform of utility ratemaking and revenue streams to adapt to the DSP model.

Nature of Consumer Protection Changing with New Players

The nature of consumer protection is changing. Historically, the regulatory structure was established to oversee the relationship between the utility and consumers, and PUCs have the authority and obligation to protect consumers through the administration of the regulatory compact. PUCs assure reasonable prices and act as an arbiter of consumer complaints. Consumers can acquire electricity from on-premise DG, either through direct purchase or long-term transactions with third-party providers where permitted. Non-utility entities can also provide other energy services, like energy efficiency retrofits. These third-party providers create new relationships with the consumer that the regulatory compact did not envision. The relationship between the consumer and these non-utility entities are usually governed by contract law. In cases where such contractual relationships include fraudulent conduct, the Federal Trade Commission and state attorneys general—not PUCs—have oversight authority.

When customers decide to develop solar resources on their premises, they must make two important decisions. These include (1) whether to buy, lease, or enter into a PPA and (2) the size of the solar facility. Typical customers tie these decisions to the property they occupy, and they may not have adequate information about risks and impacts since that information primarily comes from the vendors who want to either sell or enter into long-term contracts.[273, 274]

There are two types of long-term contracts: (1) a customer signs a traditional lease and pays to use a solar system, or (2) a customer signs a PPA and pays a set monthly rate for the electricity that is generated. The lengths of the contracts are typically 20–30 years (although some are shorter) and contain the provision that any excess power produced will be sold to the grid at the retail rate (net metering). By 2014, 72 percent of the residential solar in the United States was sold under solar leases and PPAs.[275, 276] Different states have different policies on third-party financing. As of March 2016, 25 states, plus the District of Columbia and Puerto Rico allowed third-party solar

PPAs; 8 states prohibited third-party solar PPAs; and the legal status was unclear in 16 states.[277] The Solar Energy Industries Association published the Solar Business Code and best practices for consumer protection in 2015, by which member companies must abide.[278]

Retail open access allows customers to shop for electricity from competitive, alternative providers. Electricity is not a typical good that lends itself to comparison shopping, given that there are different terms that affect the ultimate delivered price of electricity. As a consequence, low-income and vulnerable populations are particularly susceptible to unscrupulous behavior. The staff of the New York Public Service Commission recently found that since 2014 residential customers paid alternative energy suppliers $817 million more than if they had remained with their utility for gas and electric supply.[279, 280, 281] The New York Public Service Commission is now re-exploring its role in monitoring and protecting consumers who purchase power from alternative providers.

The transformation of the electric markets has focused on competition and the offering of new service options to customers—largely by non-utility providers. This focus has increased innovation, but it has also made the role of customer protection more ambiguous, creating the need to develop mechanisms to increase transparency. Part of the transformation requires new tools for monitoring third-party interactions with customers—from fraudulent claims to failure to meet contractual obligations. State PUCs may require new powers to fulfill their historic role of protecting customers.

Federal and State Jurisdictional Issues

Rapid changes in the electricity sector raise questions about who should regulate new services and market entrants and the growth of long-distance transmission across state and RTO boundaries. There is increased potential for tensions between existing regulatory bodies at the state and Federal levels, and the Federal Power Act's (FPA's) bright line delineating Federal and state jurisdiction authorities is increasingly blurred. Certain new technologies, such as DG, sophisticated load controls that facilitate demand management, microgrids, and storage, are not as clearly delineated as being solely within the realm of wholesale or retail jurisdiction. These technologies have different attributes than the electricity technologies that existed when the FPA was enacted, and they are capable of providing multiple services across the traditional generation, transmission, and distribution boundaries.

Growth in Distributed Generation Raise Jurisdictional Questions

Over the past 15 years, FERC has issued a series of orders largely disclaiming jurisdiction from resources participating in net metering programs. FERC's interpretations of its jurisdiction essentially allow state net metering programs to continue without triggering Federal regulatory applicability that could stymie state initiatives. These decisions rest on a regulatory construct that consumers with onsite generation are "offsetting" consumption and thus are not engaged in making wholesale sales regulated under the FPA.

The overall system impact of DG is also increasing as its deployment expands. More often, DG is being combined with other technologies such as onsite storage, DR, and enhanced technical controls, and it is being used to serve wholesale capacity, energy, and ancillary services markets through aggregation. If the distributed generators providing these resources are still connected close to load and within the state-regulated distribution system, then coordination between the wholesale and retail markets and Federal and state regulators will be necessary to avoid and resolve conflicts.

One application of DG is for microgrids, which raises new jurisdictional issues. In areas where a single electricity provider is granted a monopoly franchise, regulations may prohibit any other entity from constructing new electricity-related infrastructure or providing electricity to end users.[282, 283] Other regulatory issues may arise in the case where a microgrid operator purchases electricity from owners of distributed resources in their system and resells that electricity to other users within the microgrid. The FPA could consider such a transaction as a sale for resale, which Federal law prohibits.[284] Despite lingering regulatory and jurisdictional uncertainties, the number and diversity of microgrids continue to grow.[285]

Demand Response and Wholesale Energy Markets

In 2008,[286] FERC issued Order No. 719 to, among other objectives, ensure the comparable treatment of DR to other resources in organized markets and to permit DR aggregators to participate in markets on behalf of retail customers.[287] However, with this order, states can also opt out of FERC's DR policy and foreclose DR participation in markets.

FERC issued FERC Order No. 745 in 2011, requiring that DR resources receive compensation for the services they provide to the energy market at the locational market price for energy.[288] FERC experienced pushback from utility and generator competitors to DR, but the Supreme Court ultimately upheld the order in *Elec. Power Supply Ass'n v. FERC*. The Court found that Order No. 745 did not directly regulate retail electricity sales and thus was within FERC's jurisdiction. The ability of end-use customers to offer DR commitments in the wholesale market, and to receive compensation for those commitments, is made possible by technology changes that allow those customers to be aggregated, monitored, and metered. Thus, the participation of end users (to whom sales are clearly within state jurisdiction) in wholesale energy markets, which were subject to FERC oversight, ultimately presented a rationale for regulation under the FPA jurisdictional provisions.

Electricity Storage: Multiple Services Complicate Jurisdictional Issues

Electricity storage capabilities include any facility that can receive electric energy from the grid and store it for later injection of electricity back to the grid.[289] A variety of technologies fit into that category including batteries (grid scale or those in EVs), flywheels, compressed air, and pumped hydro. These technologies vary in capacity and may be connected directly to the transmission grid, a distribution system, or behind-a-customer meter. Energy storage is unique because it can take energy or power from the grid, add energy or power to the grid, and supply a range of grid services on short (subsecond) and longer (hours) time scales. In certain cases, a single storage resource or an aggregation of storage resources can provide multiple services simultaneously, such as frequency response or other ancillary services, dispatchable output akin to generation, or dispatchable load reduction somewhat like DR.

State-jurisdictional retail rates for some utilities include demand charges for industrial and commercial residential customers. Battery storage is expected to become an economical means to manage customer demand charges as system prices drop and the value of flexibility increases with a changing resource mix.[290]

However, deploying storage resources solely using the existing regulatory classifications (wholesale energy and ancillary services markets, transmission, and distribution) can limit the available "use cases." It can also constrain the services that a particular storage resource can provide and the revenue sources that owners or operators can obtain. One particular regulatory complication is that storage may be selling multiple services, some of which are subject to market-based prices and others that are sold at cost-based rates. The ability to "stack" these services to achieve sufficient revenues may require action from both FERC and state regulators.[291] State regulators and FERC recognize these regulatory constructs, and FERC is currently exploring the barriers to full participation of storage in organized markets. FERC recently issued a notice of proposed rulemaking to address electricity storage participation in markets operated by RTOs and ISOs.[292]

Potential Tools to Coordinate across Jurisdictions and Align Regulatory Approaches to Emerging Energy Technologies

In many policy areas, FERC has tread softly where it might have a claim of jurisdiction but did not want to preempt state regulation; in these instances, it has chosen to exercise its jurisdiction in line with state policy goals. Several tools are at FERC's disposal to deal with future potential jurisdiction challenges, impacting new and emerging technologies and the integration of markets for those technologies.

One way forward is through new frameworks that, for example, could establish rate-setting models that consider revenues from both state and Federal jurisdictions simultaneously. These models would allow resource owners to "stack" revenues from services they provide across state and Federal jurisdictions. It would also guard against the potential for over-recovery and unjust and unreasonable rates. In addition, FERC could explore including costs of additional technologies in rate design.

While rarely used, FERC has authority to establish joint hearings that would permit FERC and the states to hear cases together, but without a joint decisional procedure.[293] FERC can also delegate certain roles to "joint boards" made up of state commissioners (with no Federal representation).[294] More generally, FERC and state commissions can collaborate on policy matters of common interest.

Another possible approach is to redraw the line between Federal and state jurisdictions to better accommodate today's regulatory needs. In particular, this redraw should reflect the broader regional nature of electricity markets and the ability of new and emerging technologies to provide service across both Federal and state jurisdictional lines.[ar]

Another option would be to authorize jurisdictional agreements, which would permit a consensual resolution of potential conflicts between state agencies and FERC. Under this option, an amendment to the FPA would include provisions similar to those in several other Federal statutes[as] authorizing FERC and state commissions to enter into agreements that rationalize their respective state and Federal regulatory jurisdiction. The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

[ar] See e.g., National Labor Relations Act of 1935, Pub. L. No. 74-198, §§ 10(a), 14(c), 49 Stat. 449, 453, 457 (codified as amended at 29 U.S.C. §§160(a), 164(c)); Atomic Energy Act of 1954, Pub. L. No. 83-703, § 244, 68 Stat. 919, 958-59 (codified as amended at 42 U.S.C. § 2021 (2005)); Clean Air Act § 111(c), Pub. L. No. 91-604, § 111(c), 84 Stat. 1676, 1684 (1970) (codified as amended at 42 U.S.C. § 7411(c) (1977)).

[as] See e.g., National Labor Relations Act of 1935, Pub. L. No. 74-198, §§ 10(a), 14(c), 49 Stat. 449, 453, 457 (codified as amended at 29 U.S.C. §§160(a), 164(c)); Atomic Energy Act of 1954, Pub. L. No. 83-703, § 244, 68 Stat. 919, 958-59 (codified as amended at 42 U.S.C. § 2021 (2005)); Clean Air Act § 111(c), Pub. L. No. 91-604, § 111(c), 84 Stat. 1676, 1684 (1970) (codified as amended at 42 U.S.C. § 7411(c) (1977)).

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