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Electricity end uses, energy efficiency, and distributed energy resources baseline: *Distributed Energy Resources Chapter*

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Any remaining errors, omissions, or mischaracterizations are the responsibility of the authors.

Scope and Organization

This report was developed by a team of analysts at Lawrence Berkeley National Laboratory, with Argonne National Laboratory contributing the transportation section, and is a DOE EPSA product and part of a series of "baseline" reports intended to inform the second installment of the Quadrennial Energy Review (QER 1.2). QER 1.2 provides a comprehensive review of the nation's electricity system and cover the current state and key trends related to the electricity system, including generation, transmission, distribution, grid operations and planning, and end use. The baseline reports provide an overview of elements of the electricity system. This report focuses on end uses, electricity consumption, electric energy efficiency, distributed energy resources (DERs) (such as demand response, distributed generation, and distributed storage), and evaluation, measurement, and verification (EM&V) methods for energy efficiency and DERs.

Chapter 1 provides context for the report and an overview of electricity consumption across all market sectors, summarizes trends for energy efficiency and DERs and their impact on electricity sales, and highlights the benefits of these resources as well as barriers to their adoption. Lastly it summarizes policies, regulations, and programs that address these barriers, highlighting crosscutting approaches, from resource standards to programs for utility customers to performance contracting.

Chapters 2 through 5 characterize end uses, electricity consumption, and energy efficiency for the residential, commercial, and industrial sectors as well as electrification of the transportation sector. Chapter 6 addresses DERs—demand response, distributed generation, and distributed storage.

Several chapters in this report include appendices with additional supporting tables, figures, and technical detail. In addition, the appendix also includes a separate section that discusses current and evolving EM&V practices for energy efficiency and DERs, approaches for conducting reliable and cost-effective evaluation, and trends likely to affect future EM&V practices.

This excerpt from the report focuses on Distributed Energy Resources. The table of contents included here shows the detailed scope of topics in the complete report. The full report is available at https://emp.lbl.gov/publications/electricity-end-uses-energy.

Description of Energy Models[a]

Unless otherwise noted, this report provides projections between the present-day and 2040 using the "EPSA Side Case," a scenario developed using a version of the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS). Since the EPSA Side Case was needed for this and other EPSA baseline reports in advance of the completion of EIA's Annual Energy Outlook (AEO) 2016, it uses data from EIA's AEO 2015 Reference Case, the most recent AEO available at the time. However, since AEO 2015 did not include some significant policy and technology developments that occurred during 2015, the EPSA Side Case was designed to reflect these changes.

The EPSA Side Case scenario was constructed using EPSA-NEMs,[b] a version of the same integrated energy system model used by EIA. The EPSA Side Case input assumptions were based mainly on the final release of the 2015 Annual Energy Outlook (AEO 2015), with a few updates that reflect current

[a] Staff from DOE's Office of Energy Policy and Systems Analysis authored this description.

[b] The version of the National Energy Modeling System (NEMS) used for the EPSA Side Case has been run by OnLocation, Inc., with input assumptions by EPSA. It uses a version of NEMS that differs from the one used by the U.S. Energy Information Administration (EIA).

technology cost and performance estimates, policies, and measures, including the Clean Power Plan and tax credits. The EPSA Side Case achieves the broad emissions reductions required by the Clean Power Plan. While states will ultimately decide how to comply with the Clean Power Plan, the Side Case assumes that states choose the mass-based state goal approach with new source complement and assumes national emission trading among the states, but does not model the Clean Energy Incentive Program because it is not yet finalized. The EPSA Side Case also includes the tax credit extensions for solar and wind passed in December 2015. In addition, cost and performance estimates for utility-scale solar and wind have been updated to reflect recent market trends and projections, and are consistent with what was ultimately used in AEO 2016. Carbon capture and storage (CCS) cost and performance estimates have also been updated to be consistent with the latest published information from the National Energy Technology Laboratory.

As with the AEO, the EPSA Side Case provides one possible scenario of energy sector demand, generation, and emissions from present day to 2040, and it does not include future policies that might be passed or unforeseen technological progress or breakthroughs. EPSA-NEMS also constructed an "EPSA Base Case" scenario, not referenced in this report, which is based primarily on the input assumptions of the AEO 2015 High Oil and Natural Gas Resource Case. Projected electricity demand values forecast by the EPSA Base Case and Side Case are very close to each other (within 3% by 2040). However, the values forecast by the EPSA Base Case are closer to those that were ultimately included in the AEO 2016 Reference Case.

EPSA Side Case data also are used when most-recent (2014) metrics are reported as a single year or are plotted with future projections. Doing so ensures consistency between current and forecasted metrics. Overlapping years between historical data and data modeled for forecasts are not necessarily equal. Historical data are revised periodically as EIA gathers better information over time, while forecasted cases, which report a few historical years, do not change once they are released to the public.

List of Acronyms and Abbreviations

Acronym / Abbreviation	Stands For
ACEEE	American Council for an Energy-Efficient Economy
AEO	Annual Energy Outlook
AMI	advanced metering infrastructure
AMO	DOE Advanced Manufacturing Office
ARRA	2009 American Recovery and Reinvestment Act
ASHRAE	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
BEV	Battery Electric Vehicle
CAFE	Corporate Average Fuel Economy
CAISO	California ISO
CBECS	Commercial Buildings Energy Consumption Survey
CFLs	compact fluorescent lamps
CHP	Combined Heat and Power
CO^2	carbon dioxide
CPP	Clean Power Plan
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CSE	cost of saved energy
CUVs	crossover utility vehicles
DCLM	Direct Control Load Management
DER	Distributed Energy Resources
DOE	U.S. Department of Energy
DSM	demand side management
DSO	Distribution System Operator
EAC	DOE's Electricity Advisory Committee
EERS	energy efficiency resource standard
EIA	U.S. Energy Information Administration
EM&V	Evaluation, Measurement, and Verification
EMCS	Energy Management Control Systems
EPA	U.S. Environmental Protection Agency
EPSA	DOE Office of Energy Policy and Systems Analysis
ERCOT	Electric Reliability Council of Texas
ESCOs	energy service companies
FCTO	DOE's Fuel Cell Technology Office
FCV	Fuel Cell Vehicle
FEMP	Federal Energy Management Program
FERC	Federal Energy Regulatory Commission
FFV	Ethanol Flex-Fuel Vehicle
FITs	feed-in tariffs
FRCC	Florida Reliability Coordinating Council
GDP	gross domestic product

Acronym / Abbreviation	Stands For
GHG	greenhouse gases
GWP	global warming potential
HEVs	hybrid electric vehicles
HOV	high-occupancy vehicle
HVAC	heating, ventilation, and air-conditioning
Hz	hertz
ICEs	internal combustion engines
ICLEI	International Council for Local Environmental Initiatives
ICT	information and communication technologies
IDM	Industrial Demand Module
IECC	International Energy Conservation Code
IEMS	Industrial Energy Management Systems
IL	Interruptible Load
INL	Idaho National Laboratory
IRP	integrated resource planning
ISO	Independent System Operator
ISO-NE	ISO-New England, Inc.
ITC	investment tax credit
kWh	kilowatt-hours
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of electricity
LCR	Load as a Capacity Resource
LDV	light-duty vehicle
LED	light emitting diode
LEED	Leadership in Energy and Environmental Design
Li-ion	Lithium-ion
LMP	locational marginal pricing
LR	learning rate
LSE	load serving entity
MATS	Mercury and Air Toxics Standards
MECS	Manufacturing Energy Consumption Survey
MELs	Miscellaneous Electric Loads
MISO	Midcontinent Independent System Operator
MMWh	million megawatt-hours
MRO	Midwest Reliability Organization
MRO-MAPP	Midwest Reliability Organization-Mid-Continent Area Power Pool
MUSH	municipalities, universities, schools, and hospitals
NEMS	National Energy Modeling System
NERC	North American Electricity Reliability Council
NPCC	Northeast Power Coordinating Council
NPCC-NE	NPCC-New England

Acronym / Abbreviation	Stands For
NPCC-NY	NPCC-New York
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
ORNL	Oak Ridge National Laboratory
PACE	Property Assessed Clean Energy
PC	personal computer
PCTs	programmable communicating thermostats
PEV	plug-in electric vehicle
PHEV	Plug-in Hybrid Electric Vehicle
PJM	PJM Interconnection, LLC
PTC	production tax credit
PV	photovoltaic
QER	Quadrennial Energy Review
QTR	Quadrennial Technology Review
R&D	research and development
RD&D	Research, development, and deployment
RECS	Residential Energy Consumption Survey
RETI	Real estate business trust
REV	"Reforming the Energy Vision"
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
RTP	real-time pricing
SDG&E	San Diego Gas and Electric
SEIA	Solar Energy Industries Association
SERC	Southeast Electric Reliability Council
SERC-E	Southeast Electric Reliability Council -East
SERC-N	Southeast Electric Reliability Council -North
SERC-SE	Southeast Electric Reliability Council -Southeast
SGIG	Smart Grid Investment Grant
SPP	Southwest Power Pool, Inc.
SSL	solid-state lighting
TBtu	trillion British thermal units
TOU	time-of-use pricing
TRE	Texas Reliability Entity
TRE-ERCOT	TRE-Electric Reliability Council of Texas
TWh	terawatt-hours
USDA	U.S. Department of Agriculture
V2B	vehicle-to-building
V2H	vehicle-to-home
VAR	volt-ampere reactive
VOS	value of shipments
VTO	DOE's Vehicle Technologies Office

Acronym / Abbreviation	Stands For
WECC	Western Electricity Coordinating Council
WECC-CA-MX	WECC-California-Mexico Power
WECC-NWPP	WECC-Northwest Power Pool
WECC-RMRG	WECC-Rocky Mountain Reserve Group
WECC-SRSG	WECC-Southwest Reserve Sharing Group
ZEV	Zero Emission Vehicle
ZNEB	Zero-Net Energy Building

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6 Distributed Energy Resources—Distributed Generation, Distributed Energy Storage, and Demand Response

This report focused on the distributed energy resources (DERs) of distributed generation, distributed energy storage, and demand response. Definitions for these resources vary in the literature and for policies and programs. DERs include all demand-side management resources (including energy efficiency), but end-use energy efficiency is often reported separately from other DERs, though it technically constitutes a DER since implementation occurs on the premises of an end-user. *Distributed generation* is sometimes defined as generation that feeds into the distribution grid, rather than the bulk transmission grid, or as smaller capacity power sources.[1] In this work, however, a key attribute for identifying distributed resources is proximity to end users.

For example, the Solar Energy Industries Association (SEIA) states that "distributed generation … refers to electricity that is produced at or near the point where it is used." [a] [2] Thus, a large combined heat and power (CHP) facility at a commercial or industrial consumer's site is considered distributed generation even if it connects to the transmission grid, and large microgrids are viewed as distributed resources if their component resources are largely for local use.[b]

Commercial and industrial distributed generation resources include these non-utility scale resources: [3]

- CHP systems
- Solar photovoltaic (PV) systems
- Wind power systems[c]
- Hydropower systems
- Biomass combustion or co-firing in combustion systems
- Municipal solid waste incineration or waste-to-energy plants
- Fuel cells fired by natural gas, biogas, or biomass
- Reciprocating combustion engines, including backup generators, which are fueled by natural gas or other gaseous fuels (e.g., biogas, landfill gas)

DERs in the residential sector today are predominantly rooftop solar PV systems with anticipated growth in distributed battery storage systems, smart appliances, and demand response. Plug-in electric vehicles (PEVs) may also contribute a new distributed storage resource as costs continue to decline and protocols and policies are developed for their controlled charging as well as discharging to the grid in vehicle-to-grid (V2G) schemes.

This chapter provides an in-depth discussion of CHP, solar PV, distributed wind, distributed energy storage, and demand response, with a briefer discussion of other resources (see Section 6.2.1).[d]

---

[a] DOE's SunShot program defines solar PV rooftop systems of any size, and ground-mounted systems up to 5 MW_{AC}, as distributed generation, regardless of whether electricity is delivered to the customer side or utility side of the electrical meter. However, these categories consist mostly of systems installed behind the customer meter. See Barbose et al. 2015, p 7.

[b] Chapters 3 and 4 discuss CHP applications in the commercial and industrial sectors.

[c] DOE's 2015 Distributed Wind Market Report breaks down the distributed wind market into three turbine sizes: up through 100 kW (small wind), 101 kW to 1 MW (mid-size), and greater than 1 MW (large-scale).

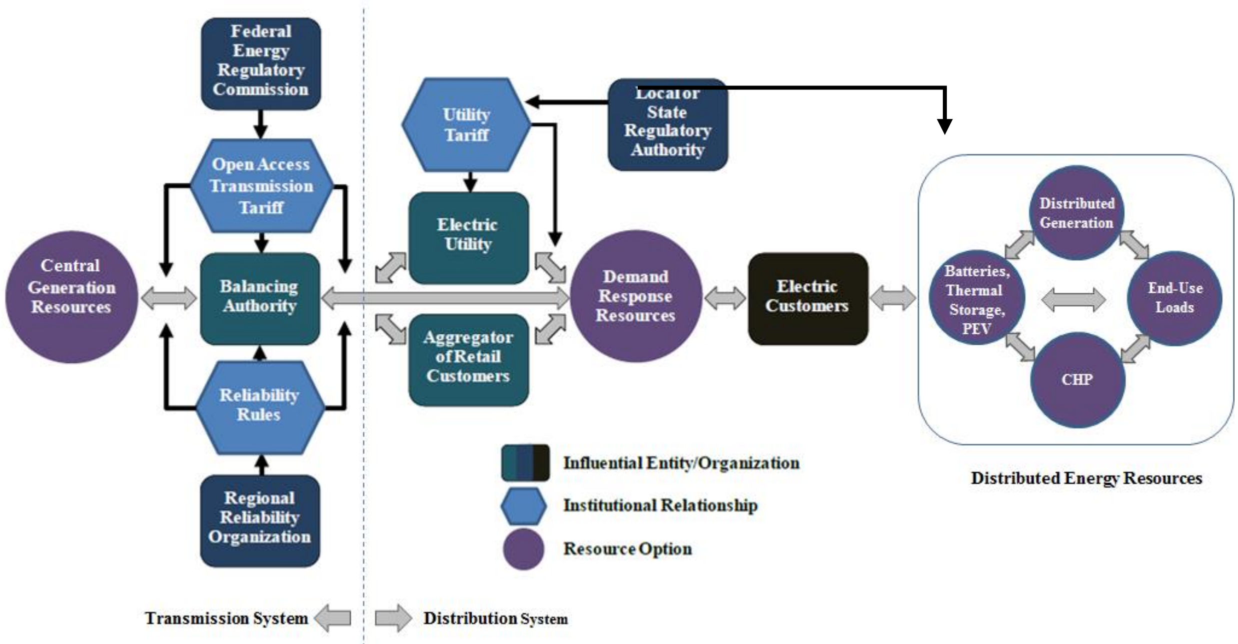
[d] This chapter is not an exhaustive treatment, and not all forms of distributed energy are detailed. For example, solar thermal water heating and thermal storage (e.g., ice storage and firebrick storage) are not discussed.

Distributed energy storage refers to storage devices that are connected to the distribution system or storage that is in close proximity to the end user—e.g., a storage system that is installed in a commercial building. Distributed storage includes electric battery storage and thermal energy storage systems (see Section 6.2.2).

Demand response includes both incentive-based and time-based programs for electricity consumers that allow them to increase or decrease demand at certain times when such action would be helpful to support the utility grid network (see Section 6.2.4).

Figure 6.1 shows key entities involved in the electricity system (grid) and the interplay of DERs. Moving from left to right along the main axis, central generation resources provide power to the transmission system, and power flows to the local distribution system to serve consumers. The DERs are in proximity to the consumers they serve, and some types of DERs are rapidly expanding (e.g., rooftop solar and battery storage). Distributed generation, including solar PV and CHP, can directly serve end-use loads but also could charge energy storage devices such as electric batteries, thermal storage, and PEV batteries which can subsequently serve end-use loads. Both distributed generation and energy storage devices can also feed electricity back into the grid.

Figure 6.1. Entities that influence relationships between distributed energy resources and the bulk power system[4]



Transmission system entities include central generation resources that supply power via balancing authorities to electric utilities in the distribution system. Demand response resources are supplied by electric consumers and may be aggregated by third-party providers. Behind-the-meter DERs include distributed generation, energy storage, CHP, and end-use loads (demand response). Also shown are the main regulatory bodies and tariff-setting entities: the Federal Energy Regulatory Commission and Regional Reliability Organization for the transmission system and local or state regulatory authorities for the distribution system and DERs.

Demand response can be thought of as a resource that controls or aggregates a collection of flexible loads that change in response to information communicated through signals from the market, utilities, or regional reliability organizations to ensure system stability and reliability at least cost. These can include, for example, direct control of consumer end-use loads, dispatchable standby generators,[a] and third-party aggregation of a collection of grid-integrated residential water heaters.

Figure 6.1 shows three key regulatory entities: (1) the Federal Energy Regulatory Commission (FERC), which regulates the bulk power market; (2) regional reliability organizations that manage and set guidelines for grid reliability; and (3) the local or state regulatory authority (i.e., the city council, rural co-op board, or state public utility commission) overseeing the utility and setting retail electric prices and other terms and conditions of service.

This chapter assumes that DERs will become increasingly widespread and important for electric system planning and for electricity markets, policies, and programs. All projections are from the EPSA Side Case (see the Introduction to this report), except as noted. Historically, the National Energy Modeling System (NEMS), the model used for the EPSA Side Case, has been very conservative in future projections of energy efficiency and new energy technology adoption,[5] and its projections for renewable DERs are too low to be consistent with recent market adoption trends.[6] Thus, DERs may have a higher rate of adoption than what is depicted in the EPSA Side Case.

6.1 Key Findings and Insights

6.1.1 DER Trends, Policies, and Programs

Findings:

- Distributed solar PV generating capacity grew by about a factor of 80 between 2004 and 2014, while distributed wind increased by about a factor of 14 (Section 6.2.1.3). Combined heat and power (CHP) grew 10.3% over the same period, from a much larger starting base (Section 6.2.1.5).
- The price of installed residential solar PV is projected to fall below \$2/watt (W_{DC}) in the next 10 years. [7]
- Distributed solar PV electricity generation is projected to grow by a factor of seven from 2015 to 2040, but it will remain at a low overall percentage of total electricity end use in 2040—about 2.2%.[b]
- Forty-one states have mandatory net metering rules in 2015, but these requirements are highly dynamic with increased pressure from utilities to reduce net metering rates and increase fixed charges for net metering customers. Other rate reform proposals specific to solar PV customers include reduced compensation for grid exports, as well as feed-in tariffs (FITs) and value-of-solar tariffs.[c] [8]
- Most distributed wind is installed at commercial facility sites, including institutional and government facilities. Distributed wind makes up less than 1% of electricity in the commercial sector, with a relative slowing in the last several years (Section 6.2.1.3).

Insight: Past growth in distributed generation has been highly policy-dependent, and future growth may be as well. States with longer-term policies (e.g., targets, incentives) have seen more distributed generation adoption.[9] Future growth may continue to be highly dependent on state policies and thus concentrated geographically. In particular, supportive policy incentives for rooftop solar, coupled with

[a] A dispatchable standby generator is both an example of distributed generation and a resource for demand response.

[b] This is much lower than DOE solar projections, underscoring the uncertainty in future projected deployment, which depends on factors such as continuing reductions in technology and soft costs, rates for solar PV energy and capacity, and the level of retail electric rates.

[c] A FIT offers a guarantee of payments to renewable energy developers for the electricity they produce typically based on project costs, while value-of-solar tariffs provide credit for the electricity generated by a solar PV system, incorporating factors such as energy, capacity, and environmental benefits to the utility system.

dramatic reductions in installed costs, have led to rapid growth in the past few years. Continued cost reductions and new product offerings, such as solar PV bundled with battery storage and utility tariffs that reflect the grid or societal value of these resources, are drivers for greater consumer adoption of DERs, while a reduction in net energy metering policy support will act as a counterforce (Section 6.5.1.1).

Findings:

- CHP at industrial facilities represents about 86% of overall CHP capacity in 2015 (Section 6.2.1.5).
- There has been a considerable slowdown in the rate of new CHP additions since the early 2000s (Section 6.2.1.5).
- The highest number of CHP installations in 2013 and 2014 occurred in states with multiyear CHP-incentive programs (New York and California, Section 6.5.1.3).
- CHP generating capacity is equivalent to about 8% of U.S. generating capacity from utility-scale power plants in 2015. CHP systems use 25% to 35% less primary energy than grid electricity plus conventional heating end-uses (e.g., water heaters, boilers), with a typical 75% overall efficiency versus 50% with conventional generation (Section 6.2.1.5).
- CHP is projected to increase to 10% of total electricity end use by 2040 from about 8% in 2015 (Section 6.3.1).
- The technical potential[a] for additional CHP applications in the United States is significant, at 134 GW, with the most potential in the chemicals sector in industry.

Insight: CHP growth has slowed but has a large untapped potential. The share of CHP-generated electricity in the United States is expected to grow moderately by 2040.

Findings:

- Distributed battery storage is projected to grow rapidly over the next decade.

Insight: Declining costs for storage technology (e.g., due to greater production of batteries for PEVs) and state policies such as storage mandates will drive greater adoption of distributed energy storage. Systems that combine distributed generation and battery storage offer the prospect of greater grid flexibility through aggregation of DERs for load balancing, but the regulatory environment to support such services is still taking shape.

6.1.2 Barriers to Distributed Generation Deployment

Findings:

- Recently the competitiveness of distributed wind has declined with the low relative price of electricity (10% lower price of electricity in the commercial sector from 2007 to 2012), as well as continuing declines in solar PV costs (Section 6.2.1). Other barriers include project financing, lack of a robust vendor supply chain during market downturns, high soft costs (e.g., permitting and insurance costs), and concerns about turbine performance (Section 6.5.1.2).
- Uncertainty in the duration of federal incentives—the investment tax credit (ITC) and production tax credit (PTC)—can drive boom and bust cycles in renewable energy installations. Lack of certainty in

[a] *Technical potential* refers to the amount that is technically possible, not all of which is cost-effective.

federal policy can make it hard for renewable energy companies and suppliers to adequately plan for the future.[a]

- Barriers to distributed solar include the lack of suitable rooftop space for a large fraction of residents, the complexity of PV system purchases (multiple options for payment/ ownership, equipment, system sizes, etc.), and the reluctance to make a long-term energy investment (Section 6.5.1.1).
- Multiple review bodies address permitting and siting of CHP facilities (air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards), adding to project delays and costs.

Insight: Sustained policy support is needed for the continued growth of distributed solar, wind, and CHP resources.

6.1.3 Policies and Programs Enabling Demand Response for Grid Support

Findings:

- Long-standing incentive-based demand response programs include direct load control, interruptible load, demand bidding/buyback, and emergency demand response. Recent additions include demand response participating in capacity markets and ancillary service markets. Demand response programs also include time-based retail rates, which are gaining ground where advanced metering infrastructure (AMI) has been installed (Section 6.2.4.2).
- Overall, the market size for demand response in the United States is estimated at $1.4 billion in 2015.[10] Load as a Capacity Resource (LCR) and Direct Control Load Management (DCLM) are the largest ISO/RTO (Independent System Operator / Regional Transmission Organization) demand response program types, with about 75% of overall capacity (Section 6.2.4.2).
- The largest demand response market is in the PJM RTO, which includes day-ahead or real-time "economic demand response" that provides participants with an opportunity to reduce electricity consumption and receive a payment when locational marginal prices are high in PJM's Energy Market. Estimated revenue in PJM for demand response is $300 million to $500 million per year from 2010–2012. Demand resources can also be bid into several ancillary services markets in PJM, including Synchronized Reserve, Regulation, and Day-Ahead Scheduling Reserves Markets (but the portion of demand response in the ancillary services market is very small).[11]
- Behind-the-meter generation (primarily diesel generators) makes up about 35% of demand response capacity[b] in the Midcontinent Independent System Operator (MISO) RTO and about 15% in PJM (Section 6.2.4.2).
- Some state energy efficiency resource standards set targets for peak demand reduction, encouraging demand response programs, as well as energy efficiency that reduces peak loads (Section 6.5.4).
- The regulatory environment for demand response programs is dynamic and evolving. State-level regulatory actions in support of demand response include such activities as testing new approaches through pilot programs, approving investments in enabling technologies such as AMI, and implementing time-varying pricing (Section 6.5.4).

---

[a] For example, expiration of the federal PTC in 2013 led to a large drop in central wind and a reduction in distributed wind installations. In December 2015, the ITC for solar was extended in full for an additional three years. See Section 5.5.1.1 for more details.

[b] *Demand response capacity* is measured by the total megawatts (MW) registered by program participants available for grid operators to call upon during a demand response event.

Insight: Higher penetration of variable renewable energy resources, both on the distribution system and at the bulk power level, requires greater grid flexibility. More responsive loads through demand response can support grid operations. The ancillary services market is currently relatively small but is expected to grow with higher penetration of wind and solar PV. Third-party aggregators and emerging business models will facilitate demand response, but the regulatory environment is still evolving. Environmental impacts of changes in power plant dispatch and use of on-site backup power generation are important to consider when planning demand response programs.

6.2 Characterization

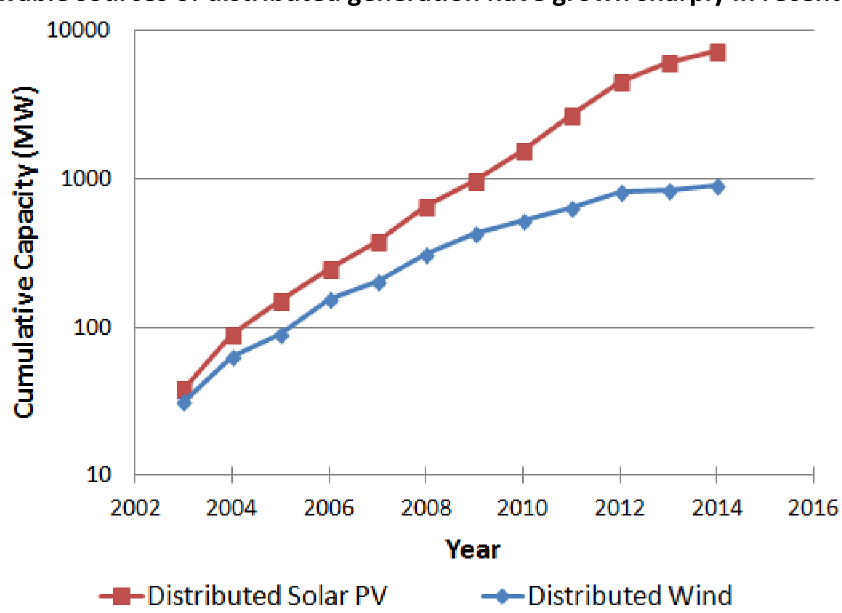
6.2.1 Distributed Generation

The United States has more than 12 million distributed electric generation units, equivalent in capacity to 18% of the nation's utility-scale capacity.[12] Much of the distributed generation capacity is for back-up power, used primarily by end-use customers to provide emergency power during grid outages. This report focuses on distributed generation for primary, nonemergency power—specifically, distributed solar PV, distributed wind, and CHP. Total distributed generation capacity, including CHP (83 GW),[13] distributed PV, and distributed wind (but not including emergency power) was estimated at 91 GW in 2014.[14]

6.2.1.1 *Distributed Solar PV and Wind*

Distributed solar PV and wind refer to solar PV and wind turbines that are located near the point where the generated electricity is used, rather than being defined by project size.[15] Distributed solar PV and wind generating capacity grew sharply over the past decade, as Figure 6.2 shows. Distributed solar PV generating capacity grew by about a factor of 80 between 2004 and 2014, while distributed wind increased by about a factor of 14.

Figure 6.2. Renewable sources of distributed generation have grown sharply in recent years[16]



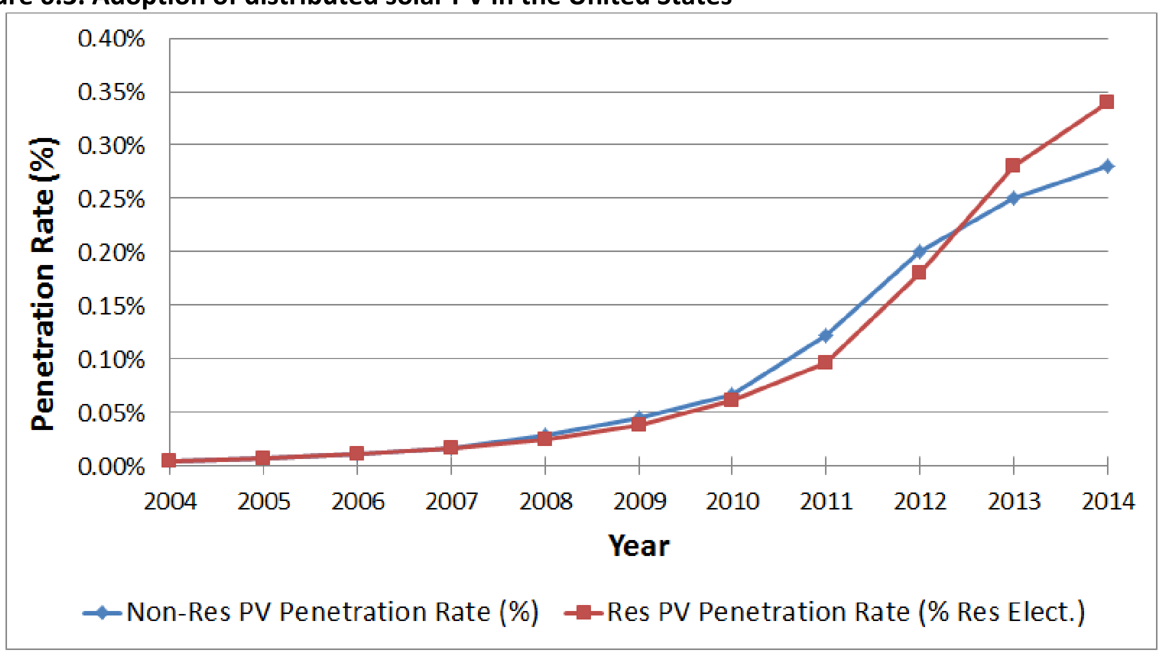
Distributed solar capacity increased by over 8,000% between 2004 and 2014; distributed wind grew by over 1,300%.

Distributed solar PV growth has been driven by a dramatic drop in the total installed cost of solar PV and has been further encouraged by reduced up-front consumer costs due to the greater availability and market adoption of third-party ownership and leasing options.

Despite the rapid growth of distributed PV and wind generating capacity, these resources contribute a very small portion of overall U.S. electricity supply. Figure 6.3 and 6.4 depict recent adoption trends for distributed PV and wind power. The penetration rate of distributed solar PV is expressed as PV electricity generation as a percentage of the total electricity load of each sector (residential and nonresidential). Similarly, the penetration rate of distributed wind is expressed as distributed wind generation as a percentage of total U.S. electricity load in the commercial sector.

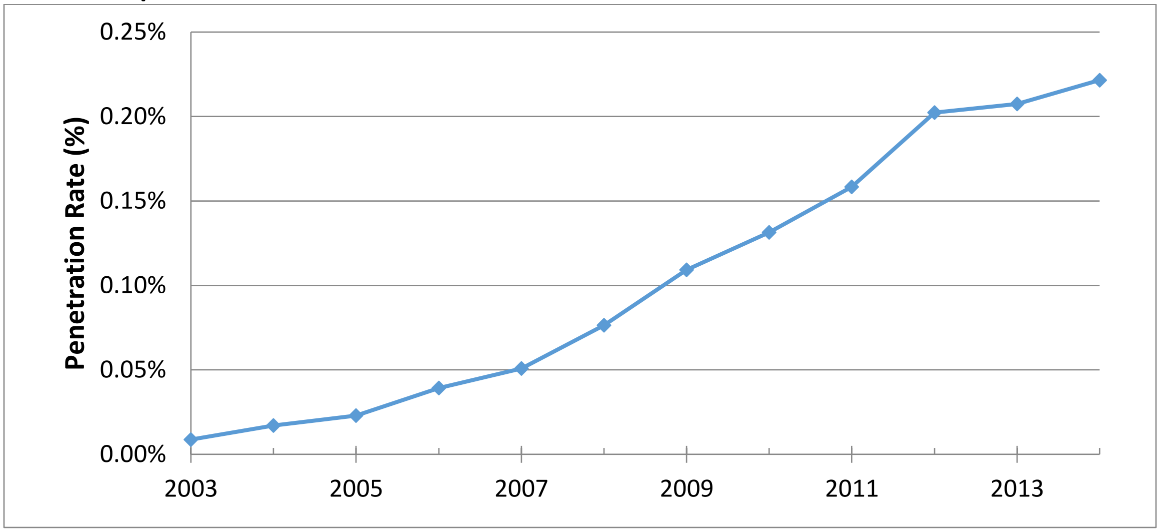
The penetration of distributed solar PV in 2014 was about 0.35% and 0.28% in the residential sector and nonresidential sectors, respectively, with the former overtaking the latter for the first time in 2013. In the United States, California dominates rooftop solar PV, with about 40% of the nation's installed capacity, due in large part to legacy statewide incentive programs such as the California Solar Initiative as well as having retail electricity rates that are among the highest in the nation. New Jersey, Arizona, and Massachusetts follow California, with about 10%, 8%, and 7% of the nation's total installed capacity, respectively (Figure 6.5). Distributed wind penetration is just under 0.25% in the commercial sector, with a leveling off of penetration in the last three years.

Figure 6.3. Adoption of distributed solar PV in the United States[17]



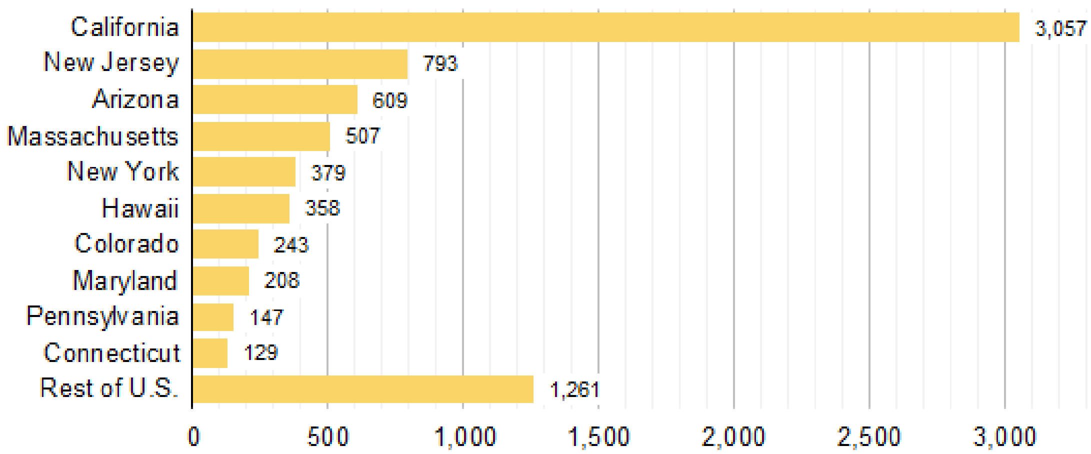
Penetration rates are expressed as PV electricity generation as a percentage of the total electricity load of each sector—residential or nonresidential (commercial plus industrial sectors)—in gigawatt-hours (GWh), assuming a solar PV capacity factor of 20.3%. Distributed solar PV is growing faster in the residential sector, with growth in the nonresidential sector tapering off in recent years.

Figure 6.4. Adoption of distributed wind in the United States[18]



The penetration rate is expressed as wind electricity generated as a percentage of total electricity load in the commercial sector, assuming a wind capacity factor of 36.8%. Distributed wind makes up less than 1% of electricity in the commercial sector, with a relative slowing in the last several years. Most distributed wind is installed at commercial facility sites, including institutional and government facilities.

Figure 6.5. Distributed solar PV installed capacity in MW_{AC}[19]



The figure ranks the top 10 states in terms of distributed solar PV capacity as of September 2015.

"Smart inverter" technologies[a] [20] for solar PV systems can help provide voltage regulation and reactive power support to address voltage and frequency fluctuations, and may help to increase the amount of solar PV that can be connected to the distribution grid. For example, Hawaiian Electric Company is developing and enabling smart inverter functionality at consumer-owned sites that could allow a doubling of the amount of PV installed on heavily utilized circuits.[21] It investigated the impact of high concentrations of solar PV on distribution circuit voltage disruptions and found the primary issues for solar-heavy circuits are the age and quality of power-conducting cable and transformers on each circuit.

[a] In addition to basic DC-to-AC power conversion functionality, smart inverters also offer: (1) reactive power control, with the ability to supply or absorb reactive power in the desired quantity, to operate distribution systems more efficiently and improve power quality and (2) voltage and frequency ride-through responses, to correct fluctuations in distribution system voltage or frequency by modulating reactive or active power, respectively. In many cases, this can allow distributed generation to continue operation through a fault.

Recently the competitiveness of distributed wind has declined with the low relative cost of electricity. Other barriers for distributed wind are project financing, lack of a robust vendor supply chain during market downturns, high soft costs (e.g., permitting and insurance costs), regulatory and planning uncertainty (discussed in Section 6.5.1), and concerns about turbine performance.[22]

6.2.1.2 *Fuel Cell Systems*

Fuel cells are electrochemical energy conversion devices that react hydrogen and oxygen to produce electricity and heat, with water as a by-product. Fuel cells can accept a variety of fuel types (typically natural gas), depending on the type of fuel cell technology, and have very low criteria emissions (e.g., oxides of nitrogen and sulfur oxides).

Several fuel cell technologies are either on the market for distributed generation applications (e.g., molten carbonate fuel cells, phosphoric acid fuel cells, solid oxide fuel cells, low-temperature proton exchange membrane fuel cells) or in development (e.g., low- temperature solid oxide fuel cells, high-temperature proton exchange membrane fuel cells). Fuel cell vehicles are starting to appear on the market as well, although the need for hydrogen fueling stations is a major infrastructure challenge. With potential high penetration of wind and solar resources in the future, large-scale electrolyzers (essentially fuel cells operated in reverse to produce hydrogen and oxygen from water) may enable renewably produced hydrogen[a] that can be stored for future use, used as a transportation fuel, or provide on-site power and heating.

While fuel cells are a small market share of distributed generation today, they are an intensive area of research, development, and deployment (RD&D) in the United States and globally. High system cost is still a major barrier for greater market adoption. Fuel cell systems can be used for distributed generation—e.g. power-only systems or CHP systems.

6.2.1.3 *Small-Scale Hydropower*

While there is no consensus on the definition of small-scale hydropower,[b] a value of up to 10 megawatt (MW) capacity is generally accepted.[23] A recent Oak Ridge National Laboratory (ORNL) study estimated 12 GW of potential hydro capacity in the United States, based on a survey of nonpowered dams. Most of the potential capacity is on waterways with locks and dams for river transportation.[24] [c] Some 90% of the total capacity is on large dams (597 sites with an average of 18 MW per site). The remaining 53,794 sites total 1.26 GW of potential capacity and an average size of 23.4 kilowatts (kW) per site.

6.2.1.4 *Waste-to-Energy Plants*

As of 2014, 84 waste-to-energy plants were in place in the United States, accounting for 2,554 MW of total U.S. capacity, or about 0.3% of power generation.[25] Most of these facilities produce electricity for sale to the grid, but about a quarter of them are cogeneration facilities or steam generators. This distributed subset represents under 0.1% of power generation in the United States. Waste-to-energy facilities face barriers of high capital cost and “not in my backyard” concerns of social equity due to airborne emissions.[26] A recent study by the U.S. Environmental Protection Agency (EPA) and North

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[a] Today, hydrogen is commonly produced by steam methane reforming with natural gas as an input fuel. This process still produces carbon dioxide (CO_2) emissions. In contrast, hydrogen produced by the electrolysis of water would create no CO_2 emissions if produced by electricity from non-polluting renewable energy sources.

[b] EPSA Side Case does not break out small-scale hydro capacity in future electricity projections for renewable power.

[c] This study does not discuss economic viability or the locations of smaller-sized non-powered dams.

Carolina State University found that incinerating garbage is more environmentally friendly than land-filling garbage. Waste-to-energy potential is dependent in part on municipal solid waste diversion rates, as some states and localities have goals for achieving reductions in municipal solid waste sources as well as high diversion rates for recycling and composting.

6.2.1.5 *CHP Systems*

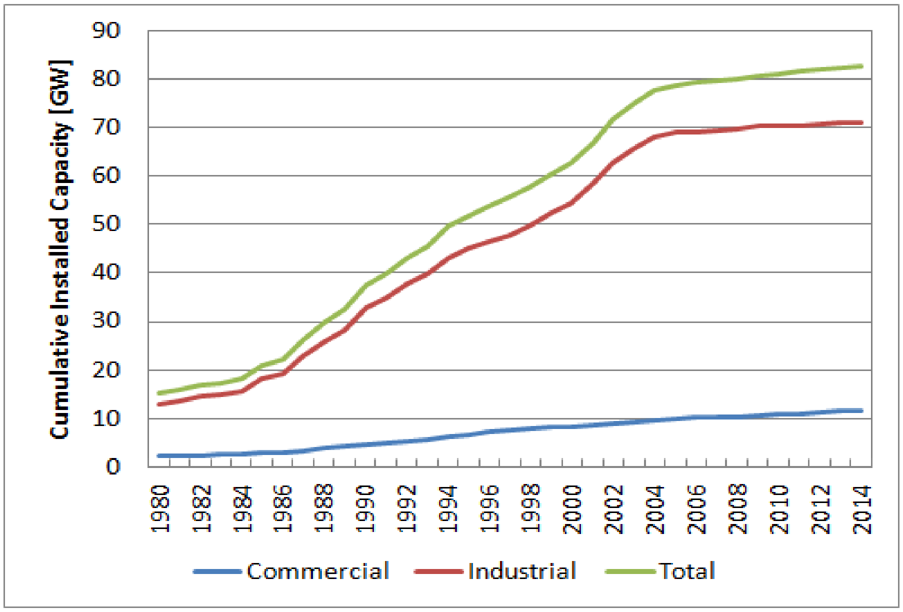
Combined CHP generates useful hot water or steam and electricity from a single system at or near the point of use. CHP systems use 25% to 35% less primary energy than using grid electricity plus conventional heating end-uses (e.g., water heaters, boilers), with typical 75% overall efficiency versus 50% with conventional generation.

CHP capacity is equivalent to about 8% of U.S. utility-scale generating capacity[27]—nearly 83 GW at more than 4,300 industrial, institutional, and commercial facilities,[28] most commonly in industrial applications with continuous processing and high steam requirements. After a period of sustained growth from the mid-1980s to the early 2000s, recent growth in CHP capacity has slowed to less than 1% annual growth since 2006. Market penetration is much lower in commercial buildings, but CHP can be well suited to facilities such as hospitals, hotels, laundries, nursing homes, educational institutions, prisons, and recreational facilities.[29]

Direct benefits of CHP to end-use consumers include reduced energy consumption and lower energy costs. CHP can offer additional benefits of increased reliability, decreased risk of power outages with additional power supply, enhanced economic competitiveness, reduction in air pollutants, and lower demand on transmission and distribution systems.

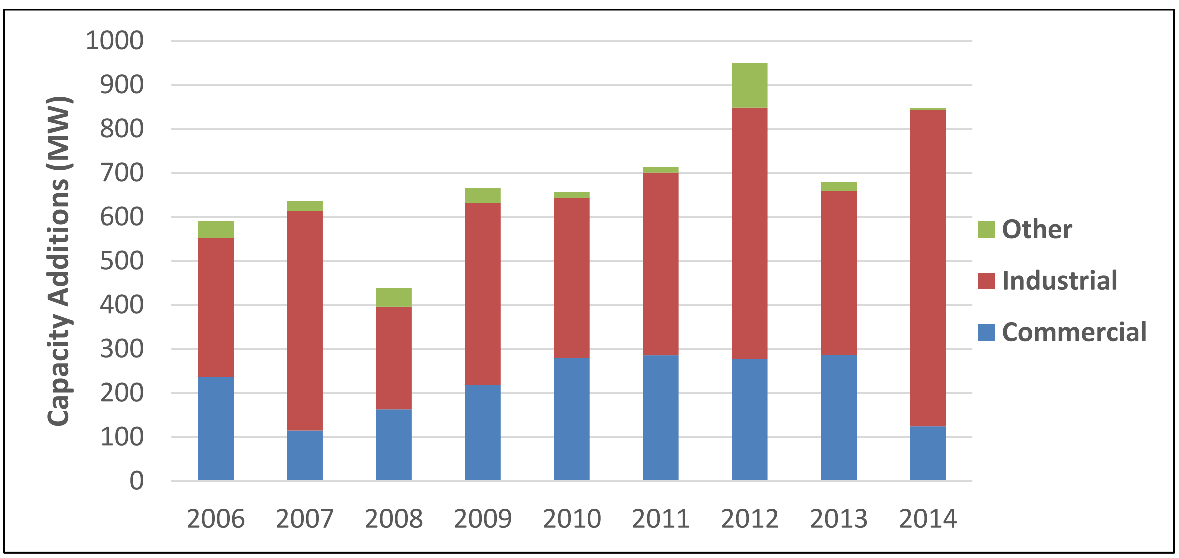
Figure 6.6 shows the increases in CHP capacity over time. Most CHP capacity is at industrial sites that have high energy demands and a generally steady demand for manufacturing process heating. Capacity additions slowed in the early to mid-2000s. Other prime mover types include combustion turbines, reciprocal engines, waste-heat-to-power, fuel cells, and microturbines. Figure 6.7 shows annual CHP capacity additions over time. The market is dominated by industrial applications, with the chemicals, refining, paper, and food subsectors making up 61% of installed CHP capacity.[30]

Figure 6.6. CHP capacity sharply increased in the late 1980s and 1990s[31]



CHP facilities at industrial sites represented about 86% of overall CHP capacity in 2014. There has been a considerable slow down in the rate of new CHP additions since the early- to mid-2000s due to changes in policy.

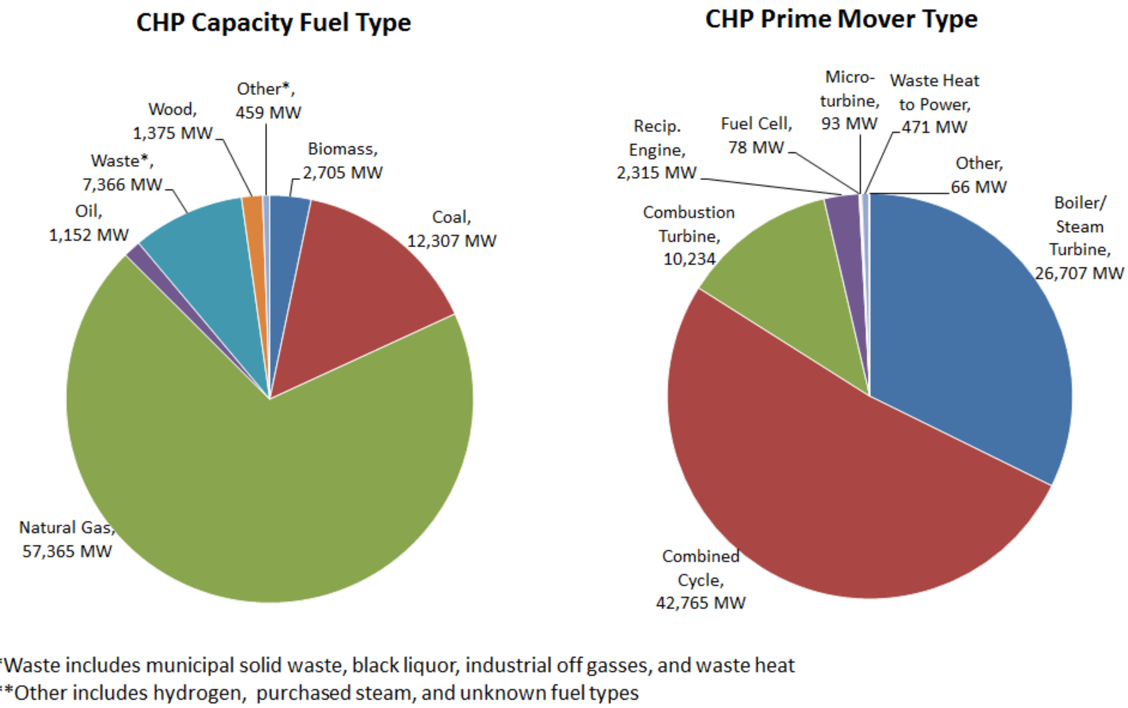
Figure 6.7. CHP capacity additions in the United States from 2006–2014[32]



Capacity additions varied from 430 MW to 940 MW annually during the period of 2006 to 2014, with most of the additions in the industrial and commercial sectors. This is down from peak annual installation of 5,000 MW to 6,000 MW earlier in the 2000s.

Figure 6.8 shows that 69% of CHP is fueled by natural gas, with combined-cycle comprising 57% and boiler/steam turbines making up 32%.

Figure 6.8. CHP capacity fuel mix and prime mover type, 2015[33]



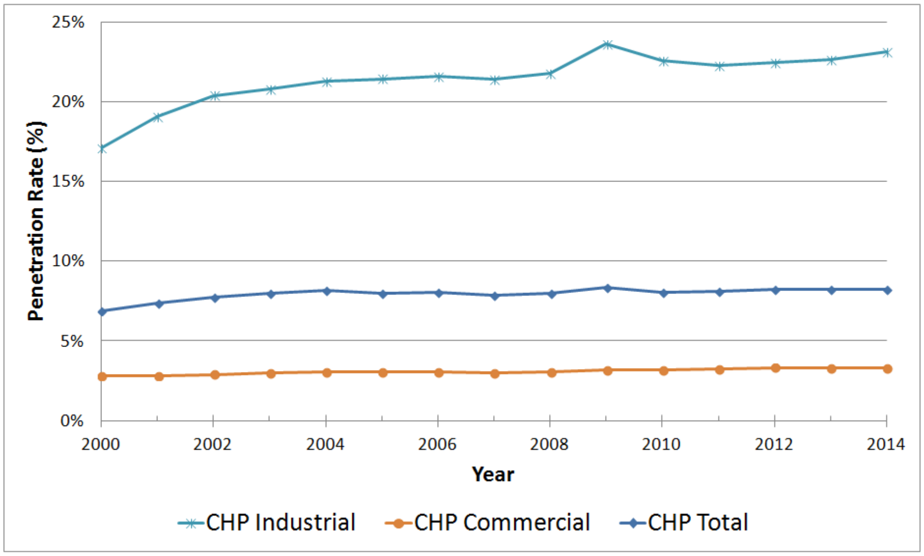
Natural gas dominates the fuel mix while combined-cycle and boiler/steam turbines make up the bulk of the capacity.

CHP is found in every state, but with uneven distribution of capacity among states. Texas and California have the most CHP installed capacity at 21.3% and 10.6% of national CHP capacity, respectively (see Distributed Energy Resources Appendix, Figure 7.33. and Figure 7.34.). Some 70% of total CHP capacity is in 10 states (Texas, California, Louisiana, New York, Florida, Pennsylvania, Alabama, Michigan, New Jersey, and Oregon), while 32 states have less than 1 GW each comprising 12.4% of total U.S. CHP capacity.

CHP cost-effectiveness depends on many factors, such as equipment cost, the matching of CHP system output with facility load profiles, overall system efficiency and availability, the price of electricity and fuel, and the price of any excess electricity sold back to the grid. The large drop-off in CHP installations in the mid-2000s was due in large part to a change in Public Utility Regulatory Policies Act (PURPA) regulations reducing the reimbursement rate for power sold back to the grid (from the "avoided cost" of new utility generation to prevailing wholesale market rates for energy and capacity). (See Section 6.5 for a discussion of CHP barriers and policies.)

In Figure 6.9, adoption of CHP is expressed as CHP electricity generation for a particular sector as a percentage of the total electricity load of the sector. The CHP share of total electricity load has been steady at about 8% since 2002.

Figure 6.9 CHP in the industrial and commercial sectors[a] [34]



CHP steadily supplied an estimated 22%–23% of electricity for the industrial sector over the last decade. This penetration rate represents the estimated CHP electricity output divided by the total electricity load of that sector, expressed as a percentage. CHP total penetration is the sum of CHP generation in the commercial and industrial sectors divided by the total electricity load in the United States for all sectors.

6.2.2 Distributed Energy Storage

Energy storage can contribute to energy security, balancing electricity loads and integrating variable energy resources (VERs, e.g., wind and solar). The U.S. Department of Energy (DOE) has recognized several grid-scale energy storage issues that also are relevant to distributed energy storage: "The future for energy storage in the U.S. should address the following issues: energy storage technologies should be cost competitive (unsubsidized) with other technologies providing similar services; energy storage should be recognized for its value in providing multiple benefits simultaneously; and ultimately, storage technology should seamlessly integrate with existing systems and sub-systems leading to its ubiquitous deployment." [35]

DOE's strategic goals for meeting this vision are: (1) energy storage should be a broadly deployable asset, to enable higher penetration levels of renewable resources; (2) energy storage should be available to industry and regulators as an effective option to resolve issues of grid resiliency and reliability; and (3) energy storage should be a well-accepted contributor to realization of smart-grid benefits—specifically, enabling confident deployment of electric transportation and optimal utilization of demand-side assets.

DOE outlined four key challenges that must be addressed to meet these goals:[36]

- Cost-competitive energy storage technology – Overcoming this challenge requires cost reduction, improvement of performance factors (e.g., round-trip efficiency, energy density, cycle life, capacity fade), and the capacity to realize revenue for all the grid services that storage provides.
- Validated reliability and safety – Validation of the safety, reliability, and performance of energy storage is essential for greater consumer adoption.

[a] Residential CHP is a very small fraction (0.2%) of total CHP in the United States and is not included.

- Equitable regulatory environment – Achieving value streams from energy storage depends on reducing institutional and regulatory hurdles to levels comparable with those of other grid resources.
- Industry acceptance – Greater adoption by industry requires confidence that energy storage will deploy as expected and deliver as predicted and promised.

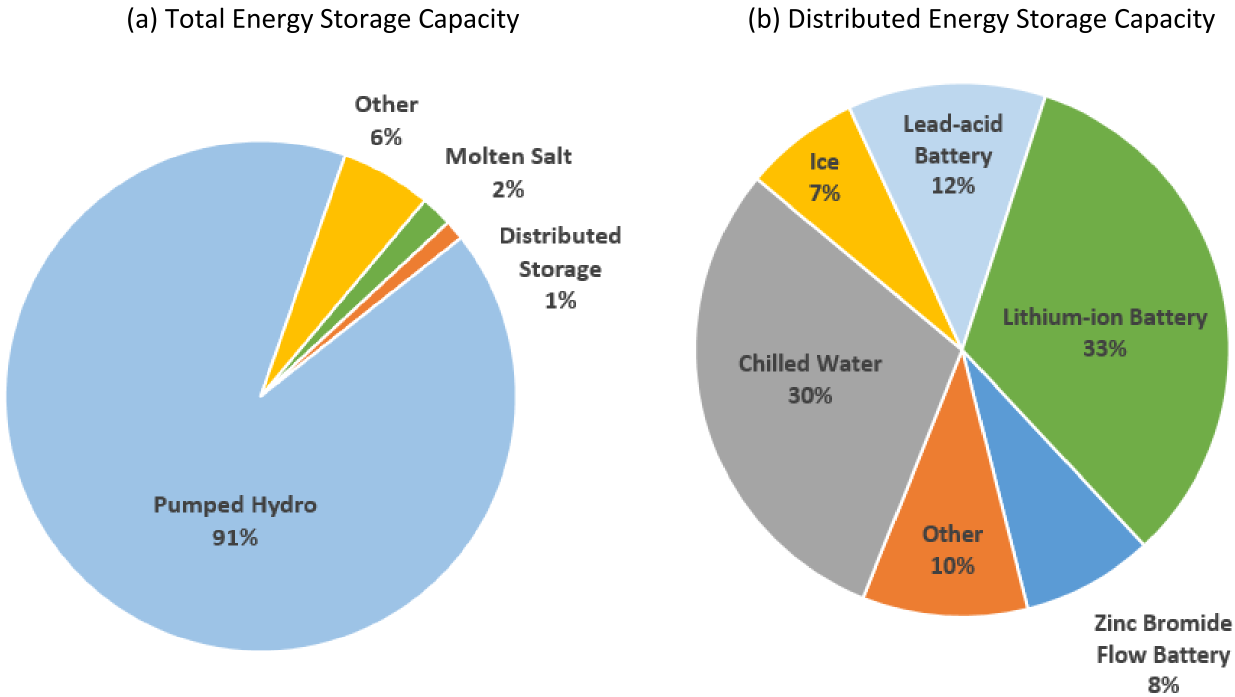
DOE's Electricity Advisory Committee (EAC) recently highlighted that the "most recent and potentially significant trend is in the identification of emerging applications for distributed energy storage … and the committee recommends that applications for storage interconnecting at the distribution level should be an area of increased focus."[37]

Distributed storage at the facility or campus level can improve power quality, provide bridging power in an emergency outage, and facilitate responsiveness to utility demand programs and time-varying rates to cut peak demand costs.[38] At the residential level, storage can provide greater on-site use of electricity produced by distributed generation systems and enable optimization of energy usage as time-varying pricing becomes more widespread.

Distributed energy storage technology options include the following:

- Batteries are electrochemical devices that can store electricity. Batteries are the most mature and available option for small- to medium-sized electric storage, but their relatively high cost has limited their wider deployment. Battery technologies must also ensure that any risks to human health and safety are carefully managed. Batteries contain toxic chemicals in their components and have the potential, however slight, to overheat, ignite, and explode. These issues can be mitigated through appropriate designs, proper installation procedures and fire protection. Demonstrations of safe operation in the field in pilot studies can also help to assuage concerns about battery safety.
    - *Lithium-ion (Li-ion) batteries* are a leading battery technology with much higher power density than the common lead-acid battery. Many other electrochemical battery types are in the research and development (R&D) phase.
    - *Sodium sulfur batteries* tend to be larger battery installations and can be used for transmission grid support, as well as on the distribution system. Size ranges from 1 MW to tens of MWs.
- Plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs) have onboard electric batteries, which can store electricity and release electricity at a later time.
- Hydrogen can be produced by electrolyzing water. Hydrogen can be stored in gas, liquid, or metal hydride form. Energy can be released in a fuel cell as electricity for powering hydrogen fuel-cell vehicles or for stationary power or CHP applications.
- Thermal energy storage includes generating ice or chilled water during hours when electricity rates are low. The stored energy can meet cooling demand during hours of peak electricity use. Electric water heaters equipped with advanced controls and two-way communication devices can act as an excellent storage medium by heating water during times of low electricity demand. Appropriate design and use of thermal mass in buildings can also improve comfort and save on energy bills.
- Supercapacitors use electric charge storage on parallel plates and offer high power density and efficiency, but have high costs and low energy density. Supercapacitors have been proposed for home use in conjunction with DC buses and microgrids.[39]

Figure 6.10. Total storage capacity (a) and distributed storage capacity (b), as of September 2015[40]



Total storage capacity of 29.6 GW is 91% pumped hydro. About 1%, or 364 MW, of total storage capacity is distributed, of which thermal storage (both ice and chilled water) makes up the largest share at 37%, followed by lithium-ion batteries at 33%.

Energy storage in the United States is dominated by grid-scale pumped hydro (91% of capacity) and relatively little is distributed storage (7% of capacity) (See Figure 6.10a).[a] Distributed storage capacity in the United States as of September 2015 is 364 MW with median storage system capacity of 152 kW.[41] Figure 6.10b shows the allocation of distributed storage by technology. Thermal storage (both ice and chilled water) and Li-ion batteries each account for about one-third of distributed storage in the United States. Currently the demand for storage is largely driven by a mandate in California to add 1.3 GW of storage (both distributed and transmission grid–connected) by 2020.[42]

Energy storage on the grid can mitigate peak load problems, improve electrical stability, and eliminate power quality disturbances.[43] Standardized control strategies are needed to better facilitate interoperability and aggregation of resources. Distributed generation deployed with energy storage can help optimize use of distributed generation, improve electric system flexibility, and increase energy security during grid outages.

Today, a primary source of value of storage systems for large utility customers is to reduce utility demand charges. These charges, tied to the customer's peak electricity demand (in kW) in the billing period, comprise up to 30% of a commercial customer's electricity bill. Recently, partnerships of solar PV and storage companies have been formed to develop market offerings combining PV and battery storage, including Stem and SunPower, Green Charge and SunEdison, and Tesla and SolarCity.

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[a] This "Other" category in the DOE database is made up of 18% capacity with reported distribution interconnection, 45% with reported transmission interconnection, and 37% with no reported interconnection.

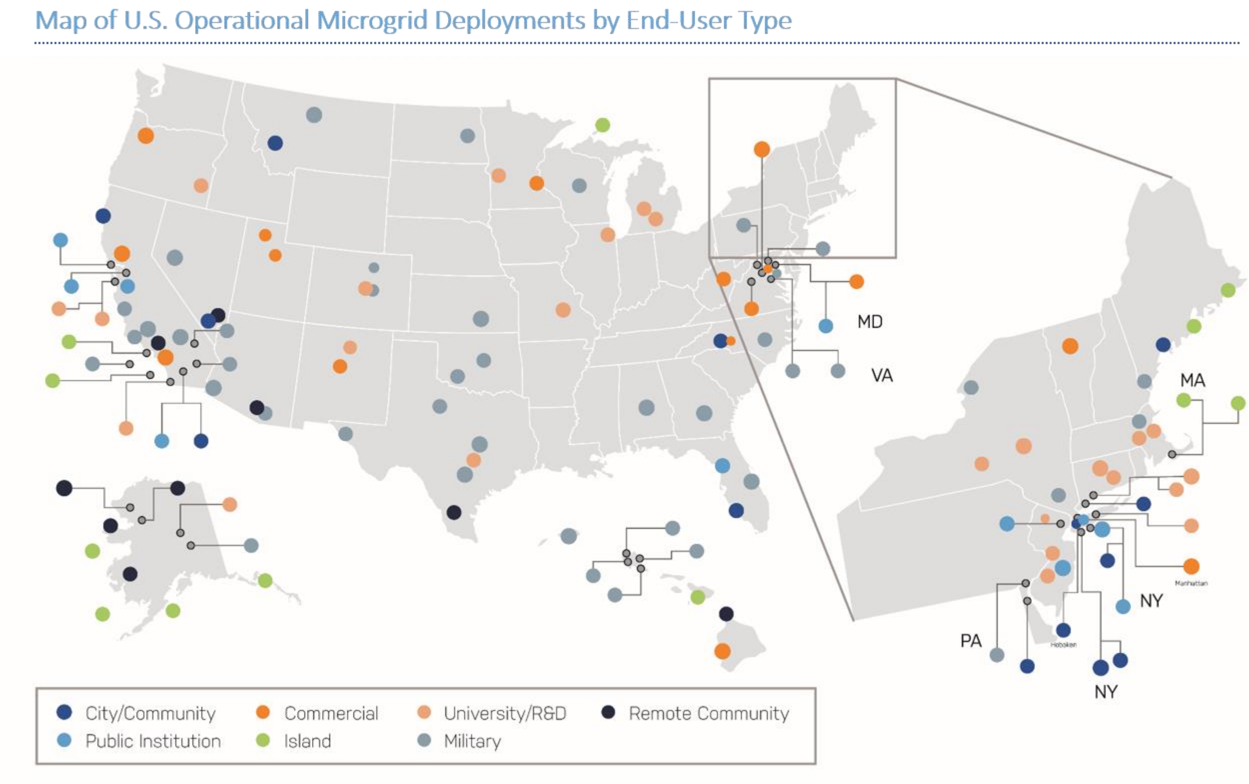
Community energy storage refers to the deployment of modular distributed energy storage at points in the utility distribution system close to residential and commercial customers. These installations can help manage the effects of distributed generation and PEVs by protecting power quality and ensuring grid stability. Community energy storage offers better economies of scale compared to individual consumer installations and where on-site consumer site storage is not practical. Community energy storage is still in the early stage of demonstration and deployment. Two early demonstration projects are (1) American Electric Power investigations that started in 2005 with a 2 MW sodium sulfur battery connected to a substation and later added many smaller units (25 kW) located near end-user sites, and (2) Detroit Edison's community storage project with units just under 1 MW, coupled with utility-scale solar PVs—a $10.9 million project with support from the 2009 federal stimulus.

6.2.3 Microgrids

A *microgrid* is a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. Microgrids can connect and disconnect (or "island") from the grid. Configurations are flexible and varied, including various DER types and microgrid sizes. Microgrids can include CHP, solar PV systems, wind turbines, thermal storage, battery storage, and fleets of PEVs. Such a collection of resources can provide a wide range of energy system design and operating practices with potential greater power quality, flexibility, and reliability for economic or emissions optimization. Microgrids can offer energy security for grid outages and natural disasters.

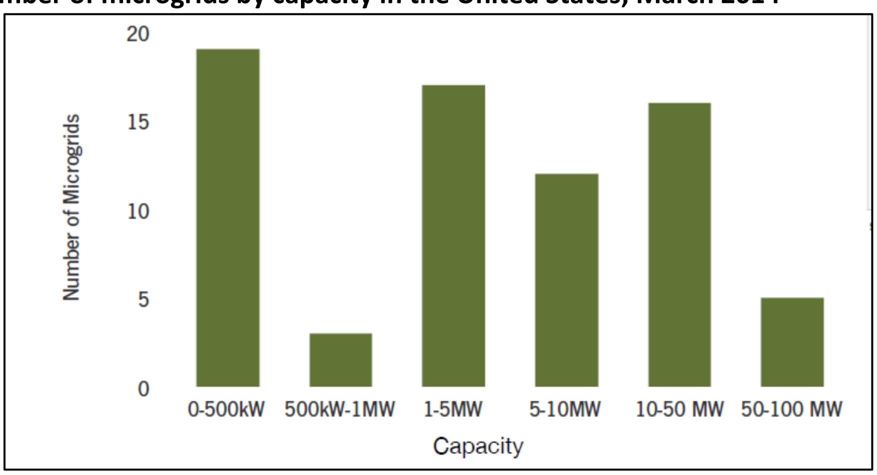
As of August 2015, the operational microgrid power capacity in the United States is 1.2 GW, with approximately 50% of the capacity commissioned after January 2013.[44] United States microgrids are dispersed around the country, with hotspots in California, Hawaii, and the Northeast (Figure 6.11). Figure 6.12 shows the distribution of microgrids by capacity, with sizes ranging from 100 kW to 100 MW. Military installations and university/research facilities currently make up the majority of current operational microgrid capacity (Figure 6.13). However, a growing share of planned microgrid installations are for commercial and public institution settings. Microgrids for commercial applications and third party-owned microgrids also are entering the market, subject to the regulatory constraints discussed in Section 6.5.3. Microgrids also have important off-grid applications in remote rural areas.[45]

Figure 6.11. Microgrids in the United States as of Q3, 2016[46]



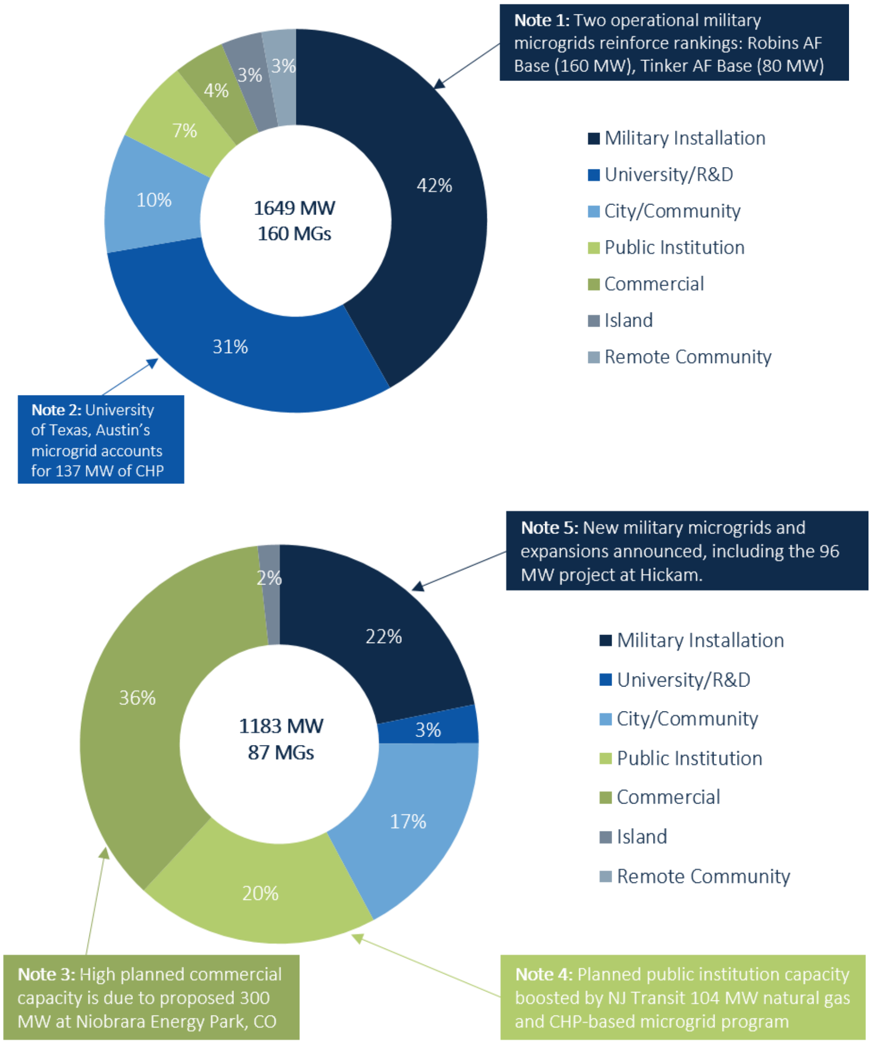
Microgrids are distributed around the country with hotspots in California, Hawaii, and the Northeast.

Figure 6.12. Number of microgrids by capacity in the United States, March 2014[47]



Most microgrids are either less than 500 kW or between 1 MW and 50 MW.

Figure 6.13. Known (top) and Announced (below) Microgrids in the United States by End User, as of Q3, 2016[48]



Some 160 microgrids were in operation (left), with 87 planned (right). Among the key trends is third-party ownership.

6.2.4 Demand Response

Demand response programs have been under way for several decades, traditionally administered and managed by utilities to manage peak load. FERC defines *demand response* as "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentivize payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[49] These changes in consumption of grid-produced electricity can be done in three ways: (1) reducing electricity usage at peak demand times or times of high electricity rates; (2) shifting energy use consumption in response to price signals or demand response program incentives; and (3) using on-site back-up or emergency generation.

Historically, demand response has had two primary purposes: (1) for emergency response (a few times a year) to ensure system stability and (2) to reduce consumption during times of high prices (50–100 hours a year). Demand response is beginning to play a greater role in facilitating integration of VERs (e.g., wind and solar), which could occur on a year-round, more automated basis at varying times of day. Demand response services in support of renewable energy integration could include increasing end-use demand—for example, during periods of high renewable energy ramp rates, not just the traditional reduction during hours of peak demand.

The benefits of demand response include improved system reliability, reduced need for capital investments to serve peak demand, reduced electricity market prices, and better utilization and integration of renewable energy.

The continuum from demand response to energy efficiency has been discussed in other reports.[a] For example, an energy efficiency program may reduce energy consumption throughout the year, while a demand response program may be invoked only a few days a year to reduce peak demand and have a far smaller impact on overall energy consumption. "Coordinating energy efficiency and demand response could provide customers with better tools to understand, manage, and reduce their electricity use,"[50] and greater coordination of energy efficiency and demand response is occurring in state programs and plans as described in Section 6.5.4.

Today, the confluence of AMI, greater capabilities in building and end-use equipment sensors and controls, and advances in IT (e.g., big data, advanced data analytics, and cloud computing) has facilitated increased demand response capabilities. More automated demand response capabilities will enable greater flexibility of demand-side resources, improved integration of variable renewable energy resources, and improved opportunities for system optimization.

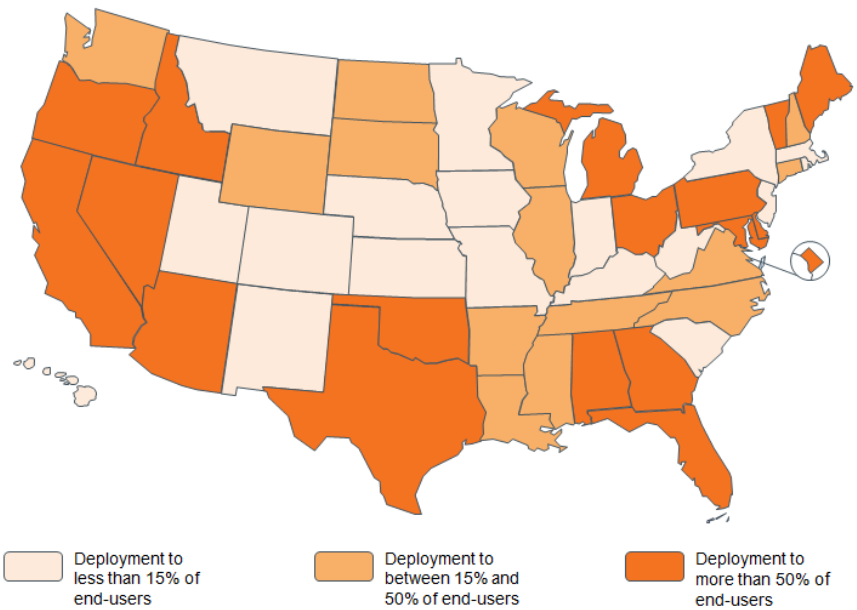
6.2.4.1 *AMI and Smart Devices That Enable Demand Response*

Advanced metering infrastructure (AMI) provides two-way communication between the utility and the end-use customer and, with a customer's permission, access to end-use equipment and appliances for direct load control by the utility, or a customer's preprogrammed, automated responses to time-varying electric prices. AMI enables time-based rates and facilitates the integration of distributed generation systems, among other capabilities.

More than 50 million smart meters have been deployed in the United States, covering 43% of U.S. homes (See Figure 7.32.). Utilities have installed about 70% of their target number of meters (Table 6.1). Figure 6.14 shows the distribution of installations by state.

[a] See, for example C. Goldman, M. Reid, R. Levy, and A. Silverstein, *Coordination of Energy Efficiency and Demand Response,* Berkeley, CA: LBNL (Lawrence Berkeley National Laboratory), 2010, LBNL-3044E.

Figure 6.14. Smart meter deployments by state for investor-owned utilities, large public power utilities, and some cooperatives: Completed, under way, or planned as of 2014[51]



Deployment in 17 states exceeds 50% of end users.

Table 6.1. Smart Meters Installed by Utility Type, 2014 [a] [52]

Utility Type	Meters Installed	Target Number of Meters	% Installed vs. Target	Target Number as a Percentage of Total Customers
Investor-Owned Utilities	43,115,000	60,126,000	72%	59%
Municipal and Cooperative Utilities	6,963,000	9,874,000	71%	24%
Total as of July 2014	50,078,000	70,000,000	72%	49%

As of July 2014, utilities were about 70% of the way to their goal of 70 million smart meters. Note that data on Smart Meter installation for municipal and cooperative utilities can be limited so these values may under-represent actual deployment values.

Table 6.2 indicates that smart meter penetration is fairly evenly spread between the residential, commercial, and industrial sectors. (See Figure 6.15 for a map of North American Electricity Reliability Council [NERC] regions.) Penetration has already exceeded 50% in Texas, Florida, and the Western United States. The 2009 American Recovery and Reinvestment Act (ARRA, federal stimulus bill) provided significant funding to assist utilities with deployment of AMI assets (Table 6.3). Some 63% of AMI expenditures funded under the ARRA went toward smart meters, with 37% of overall cost supporting other AMI assets such as IT hardware, systems, and applications. Smart meters help facilitate the integration of DERs and new customer services such as more frequent notifications of energy use. In addition, AMI systems help to provide enhanced outage management and restoration and improved distribution system monitoring and utility operational savings.[53]

[a] The target number of meters will continue to evolve as more regulatory proceedings are announced for future AMI deployments. The smaller target for municipal and cooperative utilities is partly due to the cited report's focus on larger utilities.

Table 6.2. Estimated Penetration of Smart Meters by North American Electricity Reliability Council (NERC) Region and Customer Class in 2013[54]

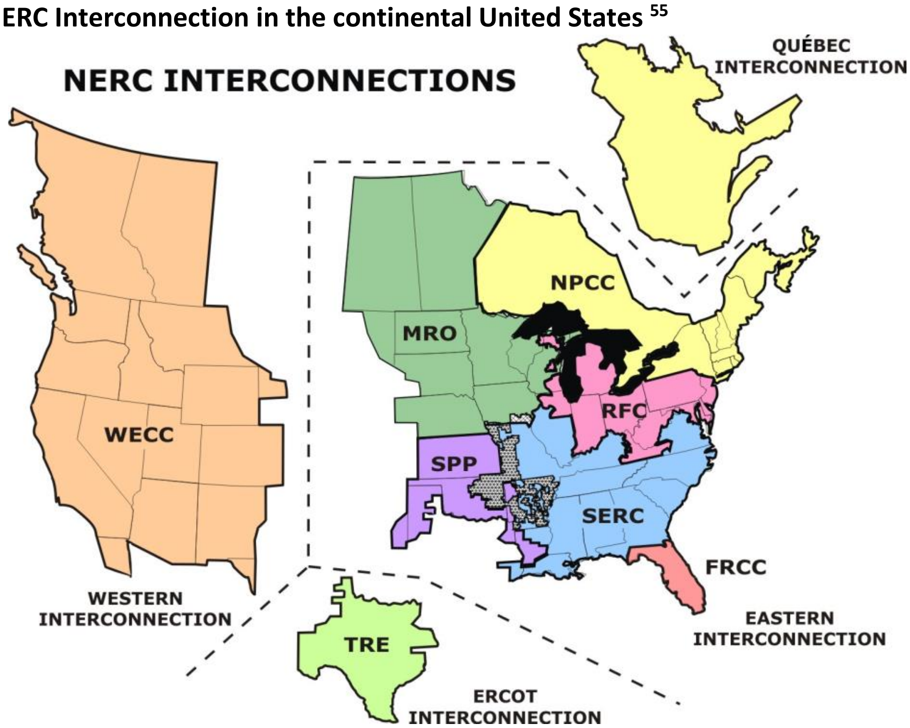
NERC Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
AK	5.2%	2.3%	0.0%	4.8%
FRCC	59.3%	63.2%	80.2%	59.6%
HI	22.5%	28.7%	57.5%	23.3%
MRO	18.0%	14.7%	19.9%	17.7%
NPCC	10.8%	13.7%	23.2%	11.1%
RFC	24.8%	18.0%	16.1%	24.0%
SERC	26.9%	24.0%	20.7%	26.5%
SPP	34.8%	35.8%	41.4%	35.1%
TRE	79.0%	81.4%	48.1%	79.1%
WECC	61.7%	60.4%	52.0%	61.5%
Unspecified	15.7%	17.5%	70.2%	17.0%
All Regions	**37.8%**	**36.1%**	**35.2%**	**37.6%**

Sources: EIA, 2013 Form EIA-861 Advanced_Meters_2013 data file.

Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. The "unspecified" category represents respondents to the EIA-861 short form, which were not required to report a NERC region. Commission staff has not independently verified the accuracy of EIA data.

Penetration varies widely by region, with overall penetration highest in Texas, Florida, and Western states.

Figure 6.15. NERC Interconnection in the continental United States [55]



The eight regions are Western Electricity Coordinating Council (WECC), Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), Southeast Electric Reliability Council (SERC), ReliabilityFirst Corporation (RFC), Florida Reliability Coordinating Council (FRCC), and Northeast Power Coordinating Council (NPCC). AK (Alaska) and HI (Hawaii) are two additional regions not shown.

Table 6.3. Smart Grid Investment Grant (SGIG) Program Expenditures for Advanced Metering Infrastructure (AMI) Deployments, as of December 31, 2014 [56]

AMI Assets	Quantity*	Incurred Cost**	Number of Entities Reporting***	Cost per Unit	% of Overall Cost
AMI smart meters****	16,322,970	$2,744,872,492	81	$168	63.0%
Communications networks and hardware that enable two way communications		$585,918,713	78		13.4%
IT hardware, systems, and applications that enable AMI features and functionalities		$666,314,859	75		15.3%
Other AMI-related costs		$362,052,698	105		8.3%
Total AMI cost		$4,359,158,762	105		100.0%

Notes:
**In some circumstances, costs are incurred before devices are installed resulting in a reported cost where the quantity is zero. Projects only report data on devices they plan to install. Each project installs equipment that best supports their individual goals. Therefore, the number of projects reporting is expected to vary by equipment category. The individual project reporting pages show what equipment that project is installing.*
***All dollar figures are the total cost, which is the sum of the federal investment and cost share of the recipient (the recipient cost share must be at least 50% of the total overall project cost).*
****In some cases the number of entities reporting is greater than the total number of projects funded by the Recovery Act because some projects have multiple subprojects that report data.*
*****SGIG recipients are also required to submit monthly reports to DOE through SIPRIS (the SGIG project reporting system) that include the number of smart meters they have installed. DOE reports both numbers. The count provided here includes meters that are installed AND functioning (i.e., they are transmitting information to the utility in support of their primary function). The SIPRIS numbers report the number of meters installed.*

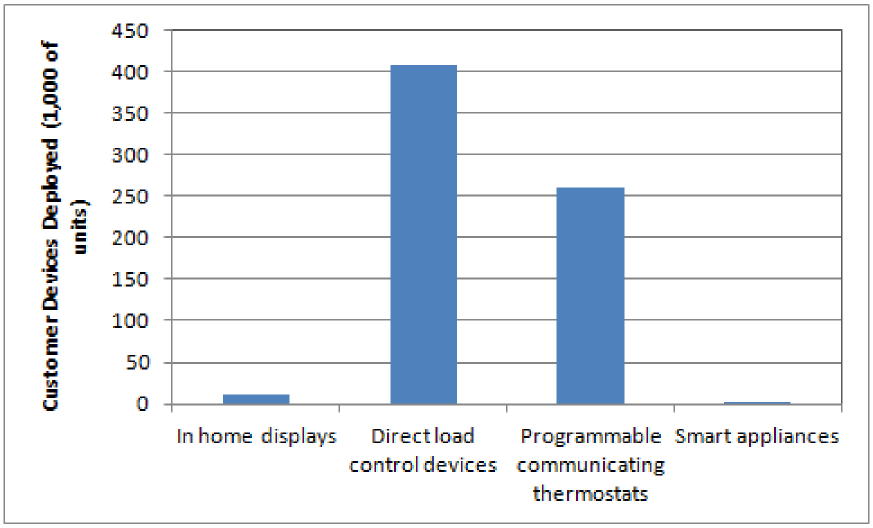
DOE's Smart Grid Investment Grant (SGIG) program also provided incentives for deployment of smart devices at customer premises (Figure 6.16).[a] Customer devices can be used with smart meters to provide information that enables customers and utilities to better manage electricity use. Devices include: [b]

- In-home displays—Small devices that provide consumers with real-time information on their energy use.
- Energy management devices—A device in the customer's premise, including hardware and software, designed to control the operation of energy-consuming devices according to customer preferences and objectives, such as reducing energy costs or maintaining comfort. Examples of controlled devices are thermostats, lighting, and smart appliances. Energy management devices can accept energy pricing signals from a utility or third-party energy services provider.
- Direct load control devices—A remotely controllable switch that can turn power to a load or appliance on or off or can be used to regulate the amount of power that a load can consume.
- Programmable communicating thermostats—Thermostats with communications capabilities can modify set temperature start-up points and load consumption based on signals from the utility or another provider.

[a] National sales data for these devices are not readily available.
[b] These definitions are largely drawn from OpenEI Wiki, accessed on November 20, 2015, http://en.openei.org/wiki/Main_Page.

- Smart appliances—Appliances that include the intelligence and communications to enable automatic or remote control based on user preferences or external signals from a utility or other provider. A smart appliance may communicate with other devices in the customer's premise or use other channels to communicate with utility systems. For example, a smart refrigeration or air conditioning system could communicate automatically with the utility to stay within a narrow band of slightly higher temperatures that are acceptable to the customer during periods of peak demand.

Figure 6.16. Customer devices installed and operational through the Smart Grid Investment Grant program as of March 2015 [57]



6.2.4.2 *Types of Demand Response Programs*

Demand response programs can be classified in various ways. EIA identifies two major classes:[58]

- Incentive-based demand response programs ("dispatchable") include direct load control, interruptible load, demand bidding/buyback, emergency demand response, and demand response participating in capacity markets and ancillary service markets.
- Time-based rate programs ("non-dispatchable") include real-time pricing (RTP), critical peak pricing (CPP), variable peak pricing, and time-of-use (TOU) rates administered through a tariff.

As described in NERC, "controllable and dispatchable demand response requires the system operator to have physical command of the resources (controllable) or be able to activate it based on instruction from a control center. Controllable and dispatchable Demand Response includes four categories: Critical Peak Pricing (CPP) with Load Control; DCLM; LCR; and Interruptible Load (IL)."[59]

Dispatchable refers to demand response capacity as a resource that is called upon only when needed and by a prescribed amount. Non-dispatchable programs curtail load solely according to a retail tariff structure, not in response to instructions from a responsible entity.[60] Demand response programs include the following,[61] as depicted in Figure 6.17:

- Capacity products
    - Direct control load management (DCLM) –The utility directly controls customer end use to use a lower consumption setting or turn off appliances and equipment during pricing or system reliability events (mostly residential).
    - Interruptible tariffs or interruptible load – Consumers receive an incentive payment for agreeing to reduce consumption, by a prespecified amount or to a prespecified setting, during system reliability events (mostly large industrial).
    - Critical peak pricing (CPP) – The utility sets a prespecified high price during designated critical peak periods triggered by system contingencies or high wholesale market prices (residential and commercial).
    - Load as a capacity resource (LCR) – The consumer commits to making prespecified load reductions when system contingencies arise (industrial and commercial).
    - Voluntary energy products, such as "emergency" demand response – These programs provide incentive payments to consumers for load reductions achieved during an emergency event (industrial and commercial).

- Ancillary services
    - Spinning reserves – Operating reserves from resources that are synchronized to the grid and can respond to instructions from the system operator (commercial and industrial).
    - Nonspinning reserves – Operating reserves that can be started, synchronized, and loaded within a specified time period in response to instructions from the system operator (mostly industrial).
    - Frequency regulation – Incremental load that ideally needs to respond within seconds to balance out the frequency on the grid (residential, commercial, and industrial).

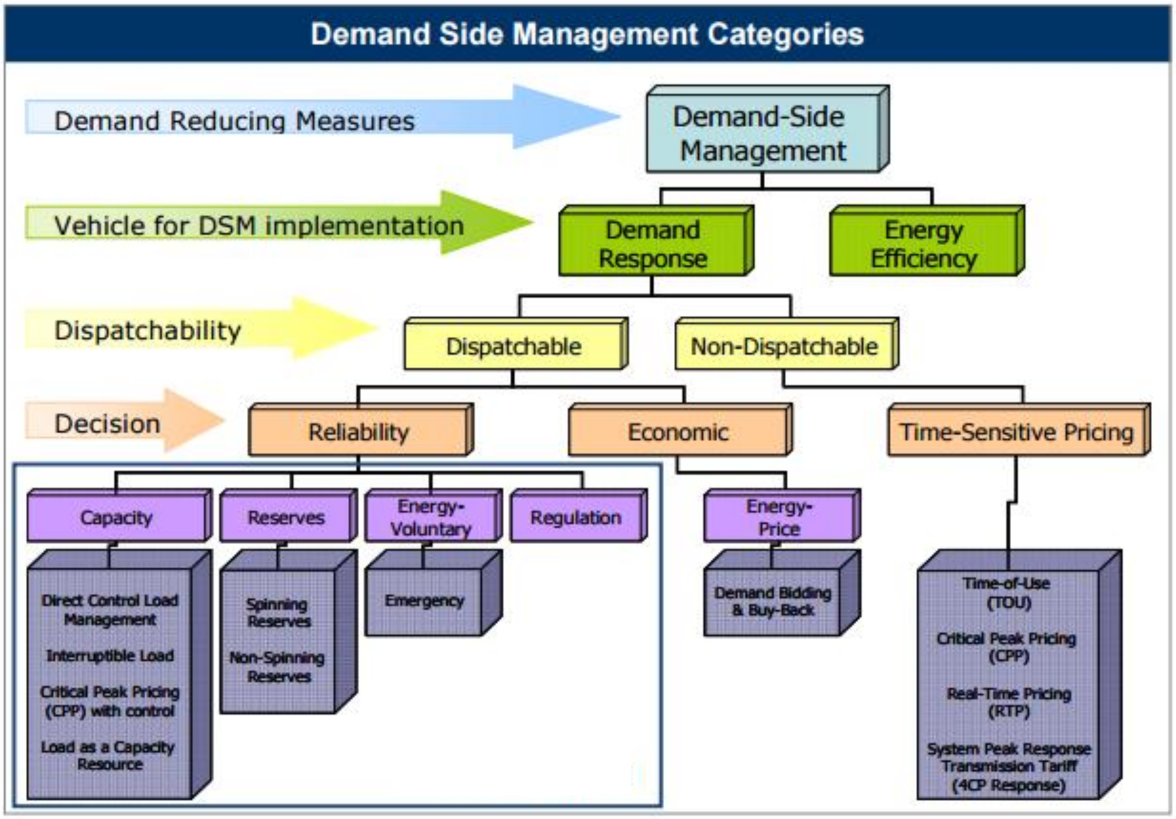
- Economic demand response – Demand bidding (e.g., day-ahead market) and buy-back allow consumers to offer load reductions in retail and wholesale markets at a bid price or at a price established by the utility or system operator.

- Time-sensitive (also called time-varying or time-based) pricing – Includes TOU pricing, CPP, RTP, and variable peak pricing.[62] [63]

    - Time of Use (TOU) rates – Electricity unit prices vary by more than one time period within a 24-hour day. Daily pricing blocks may include, but are not limited to, on-peak (highest price), mid-peak, and off-peak prices (lowest price) for nonholiday weekdays.
    - Critical Peak Pricing (CPP) – Price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of hours and days, typically in a defined season (e.g., summer).
    - Real Time Pricing (RTP) – A rate in which the price for electricity fluctuates frequently (e.g., every hour) to reflect changes in market prices.
    - Variable Peak Pricing – Variable peak pricing is a hybrid of TOU and RTP. The peak period is defined in the tariff, but the price established for the on-peak period varies by system or market conditions.

Utilities and grid system operators offer demand response programs to reduce peak load constraints, improve reliability of the electricity grid, or reduce price spikes.[64] Utility programs are referred to as "retail" programs and programs administered by ISO/RTO regions as "wholesale" programs, though in practice, both utilities and ISO/RTO regions can administer products that address similar issues. For example, some utilities may offer programs that address bulk power reliability, which is the primary charter for ISO/RTO programs, and programs that use LCR are offered in both the retail and wholesale markets, albeit with different participation rules and compensation schemes.

Figure 6.17. Demand-side management categories[65]



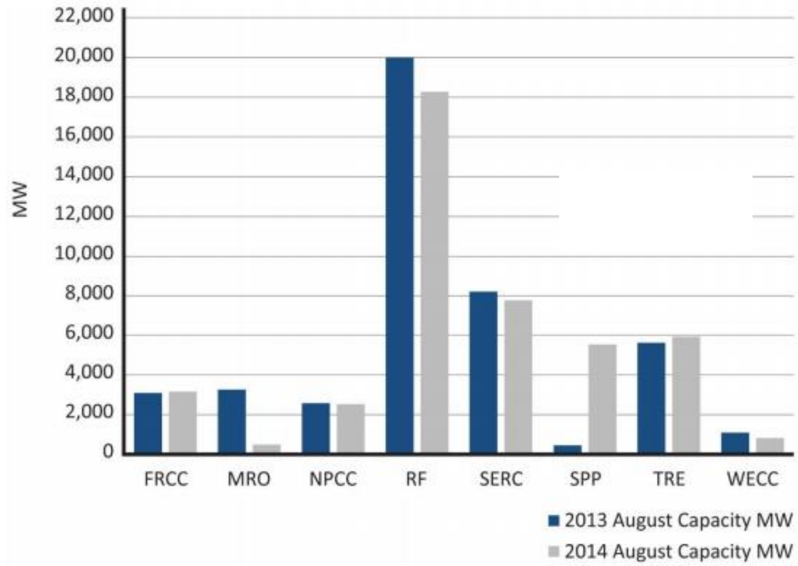
Demand response categories can be classed into dispatchable and non-dispatchable resources, and further into programs based on reliability provisions, economic considerations, and time-sensitive pricing. See text for definitions and further details.

In the following subsections, demand response capacity is presented according to three reporting frameworks: (1) by NERC region for both retail and wholesale programs, (2) by NERC region for utility retail programs only, and (3) by ISO/RTO region for wholesale programs. For each case, the types of demand response programs included in the quoted demand response capacity are specified.

Overall Demand Response Capacity[66]

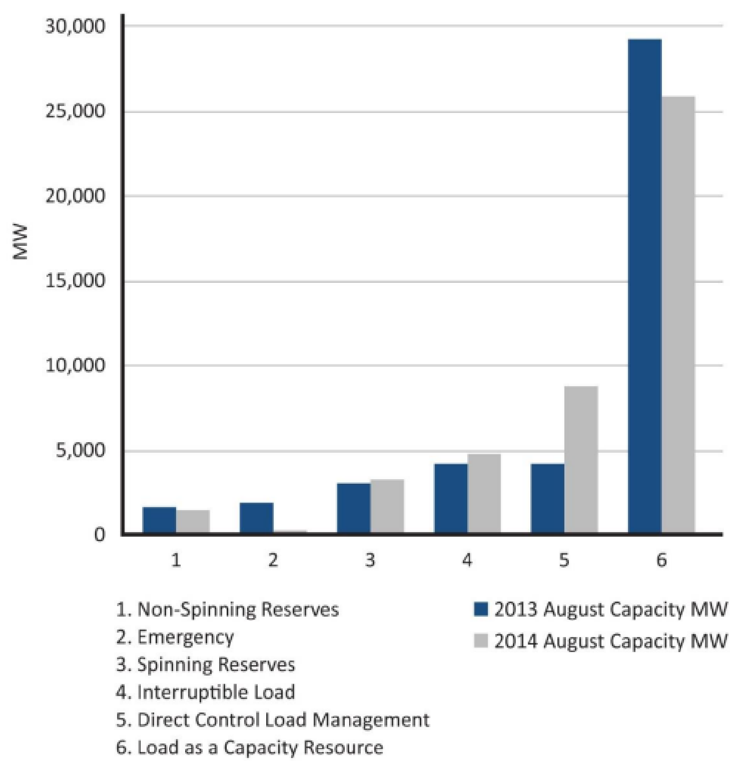
Total capacity in NERC regions for retail and wholesale programs was about 44 GW in both 2013 and 2014[67] (Figure 6.18), with the largest capacity in the ReliabilityFirst Corporation (RFC), Southeast Electric Reliability Council (SERC), and Texas Reliability Entity (TRE) regions. Figure 6.19 shows that LCR and DCLM are the two program types with the largest capacity.

Figure 6.18. Registered demand response capacity (in MW) for all product service types by NERC region[68]



Demand response capacity is measured by the total MW registered by program participants available for grid operators to call upon during a demand response event. In August 2013 and 2014, demand response capacity in all NERC regions was 44,285 MW and 44,583 MW, respectively, including both retail and wholesale programs.

Figure 6.19. Registered capacity in MW for all NERC regions by service type in August 2013 and 2014[69]



Load as a Capacity Resource and Direct Control Load Management made up about 75% of overall capacity, including both retail and wholesale programs.

Demand Response Capacity (MW) by NERC Region

Table 6.4 shows potential peak reduction from incentive-based demand response programs by NERC region in 2012 and 2013. Four regions accounted for about 80% of demand response in 2012: the SERC, RFC, Midwest Reliability Organization (MRO), and Western Electricity Coordinating Council (WECC). The table also illustrates annual changes in demand response capacity. Demand response decreased by 4.9% between 2012 and 2013, with large drops in the Florida Reliability Coordinating Council (FRCC) and MRO offset in part by a large increase in the SERC region, due to a large increase in reported savings from industrial programs operated by the Tennessee Valley Authority.

The FRCC and MRO saw significantly lower potential peak savings in both magnitude and percentage from much lower reported savings from Florida Power & Light's demand response programs, and from programs operated by Nebraska Public Power District and Northern States Power Company (Minnesota), respectively.

Table 6.4. Potential Peak Reduction Capacity from Retail Demand Response Programs by NERC Region in 2012 and 2013[70]

NERC Region[a]	Annual Potential Peak Reduction (MW)		% of Overall Potential for All Regions	Year-on-Year Change	
	2012	2013	2013	MW	%
AK	27	27	0.10	0	0.0
FRCC	3,306	1,924	7.10	-1383	-41.8
HI	42	35	0.13	-7	-16.8
MRO	5,567	4,264	15.74	-1303	-23.4
NPCC	606	467	1.72	-139	-23.0
RFC	5,836	5,362	19.79	-475	-8.1
SERC	6,046	8,254	30.46	2209	36.5
SPP	1,323	1,594	5.88	271	20.5
TRE	480	459	1.69	-21	-4.3
WECC	5,269	4,681	17.28	-588	-11.2
Unspecified	0	28	0.10	28	--
Total	28,503	27,095	100	-1,408	-4.9

Demand response programs include direct load control, contractually interruptible (curtailable load), and Load as a Capacity Resource. SERC, RFC, MRO, and WECC each account for about 20% of the overall demand response potential for all regions, with about a 5% decrease in potential peak demand reduction from 2012 to 2013. Note: Figures from source data are rounded to the nearest MW. The percentage change is calculated based on the unrounded figures. Although some entities may operate in more than one NERC region, EIA data use only one NERC region designation per entity.

[a] **Acronyms**: **AK**—Alaska; **FRCC**—Florida Reliability Coordinating Council; **HI**—Hawaii; **MRO**—Midwest Reliability Organization; **NPCC**—Northeast Power Coordinating Council; **RFC**—ReliabilityFirst Corporation; **SERC**—Southeast Electric Reliability Council; **SPP**—Southwest Power Pool; **TRE**—Texas Reliability Entity; **WECC**—Western Electricity Coordinating Council.

Table 6.5. Potential Peak Capacity Reduction (in MW) from Retail Demand Response Programs, by NERC Region and Customer Sector in 2013[71] [a]

	Customer Sector (MW)				
NERC Region	Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	817	750	357	0	1,924
HI	20	15	0	0	35
MRO	1,865	801	1,598	0	4,264
NPCC	38	256	160	13	467
RFC	1,545	684	3,133	0	5,362
SERC	1,348	810	6,095	1	8,254
SPP	213	324	1,057	0	1,594
TRE	88	341	31	0	459
WECC	1,037	1,130	2,361	154	4,681
Unspecified	28	0	0	0	28
All Regions	7,003	5,124	14,800	168	27,095
NERC Region	By Percentage of Total DR Capacity (%)				
AK	19	48	33	0	100
FRCC	42	39	19	0	100
HI	57	43	0	0	100
MRO	44	19	37	0	100
NPCC	8	55	34	3	100
RFC	29	13	58	0	100
SERC	16	10	74	0	100
SPP	13	20	66	0	100
TRE	19	74	7	0	100
WECC	22	24	50	3	100
Unspecified	100	0	0	0	100
% of total	25.8	18.9	54.6	0.62	100

Demand response programs include direct load control, contractually interruptible (curtailable load), and Load as a Capacity Resource. Industrial demand response makes up over half of the overall demand response capacity.

[a] Note: Demand response capacity is measured by the total MW registered by program participants available for grid operators to call upon during a demand response event. Figures from source data are rounded to the nearest MW. The percentage change is calculated based on the unrounded figures. Although some entities may operate in more than one NERC region, EIA data use only one NERC region designation per entity.

Table 6.5 shows potential peak reduction from retail (typically utility-administered) incentive-based demand response programs.[a] The residential, commercial, and industrial sectors account for 30%, 23%, and 47% of total demand response potential, respectively. There is considerable variation in sector distribution by NERC region. The commercial sector accounts for most of the demand response in Alaska (AK), Hawaii (HI), Northeast Power Coordinating Council (NPCC), and TRE. Industrial demand response is the largest sector in MRO, RFC, SERC, Southwest Power Pool (SPP), and WECC, and overall accounts for the largest amount of demand response capacity. FRCC is the only region where residential demand response is the largest sector, with 53% of the demand response potential.

Total enrollment in incentive-based programs grew rapidly from 2011 to 2013, with 9.18 million customers (Table 6.6), or about 6.2% of total electric industry customers.[72] Part of this increase in demand response deployment is attributed to utility investments supported by SGIGs under ARRA for the deployment of advanced meters and associated infrastructure. The 240% increase in enrollments in WECC from 2012 to 2013 occurred for several utilities in California, Arizona, and New Mexico.
New devices and device capabilities such as smart thermostats have enabled innovative new demand response programs. One such set of programs are known as "Bring Your Own Thermostat," which first appeared in 2012. Instead of direct installation of control hardware by the sponsoring utility, these programs allow consumers to purchase their own devices and participate in utility-managed demand response programs. There are an estimated 50,000 customers in Bring Your Own Thermostat programs in the United States, and this market is expected to grow rapidly in the future.[73]

Table 6.6. Enrollment in Incentive-Based Demand Response Programs by NERC Region, 2011-2013[74]

NERC Region	Enrollment in Incentive-Based Programs			2011 to 2013 Change	
	2011	2012	2013	Customers	%
AK	2,460	2,432	2,468	8	0.3%
FRCC	1,283,904	1,328,487	1,554,830	270,926	21.1%
HI	37,304	36,703	36,332	-972	-2.6%
MRO	714,669	795,345	1,248,723	534,054	74.7%
NPCC	46,368	54,413	62,631	16,263	35.1%
RFC	1,546,608	1,398,341	1,852,985	306,377	19.8%
SERC	652,940	715,225	1,084,449	431,509	66.1%
SPP	112,041	91,585	193,507	81,466	72.7%
TRE	67,113	109,875	138,613	71,500	106.5%
WECC	903,063	884,299	3,002,607	2,099,544	232.5%
Unspecified	0	15,004	10,205	10,205	-
Total	5,366,470	5,431,709	9,187,350	3,820,880	71.2%

Incentive-based demand response programs include direct load control, interruptible load, emergency demand response, and Load as a Capacity Resource. Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. FERC staff have not independently verified the accuracy of EIA data.
Sources: EIA, EIA-861 dsm_2012, utility_data_2012, and Demand_Response_2013 data files.

[a] Potential peak reduction (or potential peak demand savings) refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called." EIA (U.S. Energy Information Administration). *Form EIA-861 Annual Electric Power Industry Report Instructions.* Washington, D.C., 2016, 15. https://www.eia.gov/survey/form/eia_861/instructions.pdf.

The 5.98 million customers enrolled in time-based programs in 2013 (Table 6.7) represent about 4% of total electricity industry customers, with the largest increases compared to 2012 in RFC and SPP. RFC saw large increases in residential program enrollment for several utility service territories, while SPP saw program enrollment increases across all customer classes.

Table 6.7. Customer Enrollment in Time-Based Demand Response Programs by NERC Region in 2012 and 2013[75]

NERC Region	Enrollment in Time-based Programs		Year-on-Year Change	
	2012	2013	Customers	%
AK	38	43	5	13%
FRCC	27,089	16,203	-10,886	-40%
HI	323	365	42	13%
MRO	82,310	108,527	26,217	32%
NPCC	293,721	258,426	-35,295	-12%
RFC	433,879	1,977,536	1,543,657	356%
SERC	180,619	236,662	56,043	31%
SPP	61,618	1,143,774	1,082,156	1,756%
TRE	604	968	364	60%
WECC	2,601,112	2,146,548	-454,564	-17%
Unspecified	57,435	88,229	30,794	54%
Total	**3,738,748**	**5,977,281**	**2,238,533**	**60%**

Sources: EIA, EIA-861 dsm_2012,utility_data_2012, and Dynamic_Pricing_2013 data files.
Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

Time-based programs include time-of-use rates, critical peak pricing, real-time pricing, and variable peak pricing.

Demand Response Capacity (MW) by ISO/RTO Region

Demand response potential for ISO- and RTO-administered programs remained flat overall from 2013 to 2014, with a large increase in ISO New England, Inc. (ISO-NE) but decreases in New York ISO (NYISO) and SPP (Table 6.8).[a] The increase in ISO-NE is attributed in part to greater spending on demand-side management programs by utilities in New England states. The sharp drop in the SPP region is due to reclassification of certain behind-the-meter resources, cogeneration facilities, and industrial loads as special case generation resources. Overall the FERC 2015 report observes little net change in the contribution of demand response to meeting peak demand since 2009. For reference, Figure 6.20 is a map of ISO/RTO regions.

Several ISOs/RTOs allow demand response resources to participate in the markets they administer.[b] For example, PJM has created three demand response products for capacity, based on availability of the resource: Limited Demand Response (10 days for six hours per day during the summer peak period), Extended Summer Demand Response (unlimited days during the summer peak period for 10 hours per

[a] Note that the sum of demand response capacity in Table 6.5 and Table 6.8 for 2013 is 56 GW, which is larger than the 44 GW shown in Figure 6.18. This is attributed to sampling issues. For example, Table 6.8 includes some utility programs (in MISO, for example), and thus there is some double-counting with the NERC data in Table 6.5.

[b] Note that most markets require a certain size resource to participate (e.g., 150 kW minimum bid for a capacity market), which means that some potential resources are not able to participate unless they can be aggregated into a larger resource.

day), and Annual Demand Response (unlimited number of days for 10 hours per day, any time of the year).

The largest demand response market is in PJM, followed by MISO. Of the 9,901 MW of capacity in 2013, 2,660 MW was day-ahead or real-time economic demand response that provided participants with an opportunity to reduce electricity consumption and receive a payment when locational marginal prices were high in PJM's Energy Market. The remainder of the capacity was emergency demand response, where program participants received two streams of revenue: capacity payments for contributing to reserve capacity and an energy payment to compensate for the hours during which they reduced their consumption. About 1,550 MW of emergency demand response was provided by diesel-powered, behind-the-meter generation. Demand resources can also bid into ancillary services markets in PJM, including reserve and regulation markets. Capacity payments dominated the revenues in the demand response market.[76]

MISO is the second-largest ISO/RTO demand response market. Behind-the-meter generation (e.g., backup diesel generators) makes up 35% of demand response capacity in MISO. Of the remaining capacity, 78% is interruptible load under regulated utility programs and 14% is emergency demand response.[77] In the California ISO (CAISO), about one-half of the demand response capacity in Table 6.8 is made up of reliability-based programs such as interruptible tariffs, and about one-half is price-responsive economic demand response programs, including day-ahead customer alerts and same-day demand response through air-conditioning cycling programs and curtailment service providers.

Table 6.8. Peak Reduction (in MW) from ISO/RTO (Wholesale) Demand Response Programs in 2013 and 2014[78]

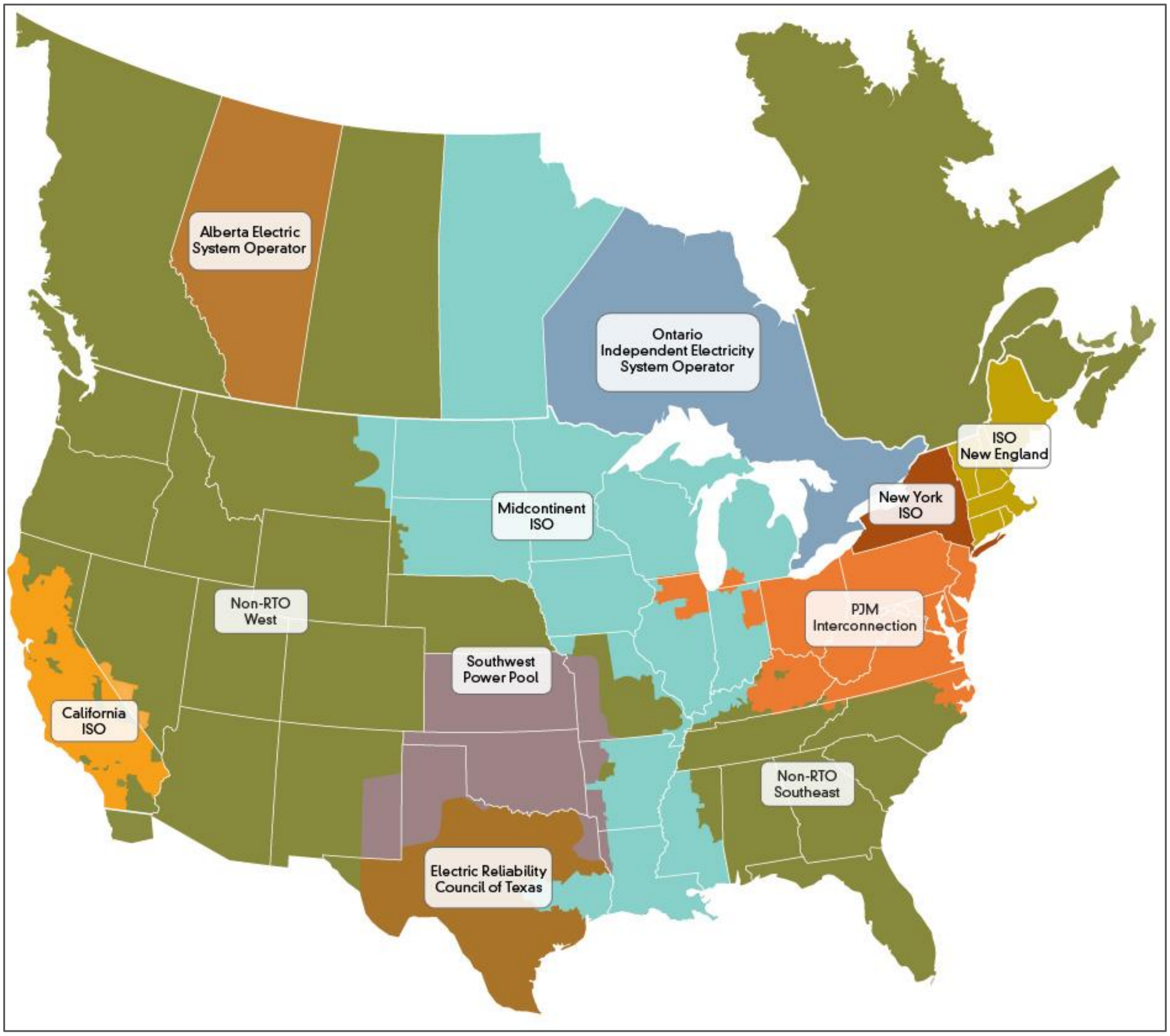
RTO/ISO	2013		2014		2013 to 2014	
	Potential Peak Reduction (MW)	Percent of Peak Demand (%)	Potential Peak Reduction (MW)	Percent of Peak Demand (%)	MW	%
California ISO (CAISO)	2,180	4.8	2,316	5.1	136	6.2
Electric Reliability Council of Texas (ERCOT)	1,950	2.9	2,100	3.2	150	7.7
ISO New England, Inc. (ISO-NE)	2,100	7.7	2,487	7.7	387	18.4
Midcontinent Independent System Operator (MISO)	9,797	10.2	10,356	10.2	559	5.7
New York Independent System Operator (NYISO)	1,307	3.8	1,211	9.0	-96	-7.3
PJM Interconnection, LLC (PJM)	9,901	6.3	10,401	7.4	500	5.0
Southwest Power Pool, Inc. (SPP)	1,563	3.5	48	0.1	-1,515	-96.9
Total ISO/RTO	28,798	6.1	28,934	6.2	136	0.5

Demand response programs include emergency demand response, day-ahead and real-time economic demand response, Load as a Capacity Resource, and, in some regions (e.g., MISO), behind-the-meter generation.

Significant growth in demand response resources has recently occurred for the Electric Reliability Council of Texas (ERCOT) Emergency Response Service. This program includes 10- and 30-minute demand response resources (as well as distributed generation service) and is designed to be deployed in the late stages of a grid emergency, prior to shedding involuntary firm load. Procurement of Emergency

Response Service during the summer peak-time period grew from 422 MW in 2013 to 626 MW in 2014, nearly a 50% increase. LCRs[a] providing ancillary services are also expected to increase due to new rules enabling controllable load resources to bid into the real-time market for nonspinning reserves. [79] CAISO is actively engaged with stakeholders to develop demand response products capable of directly participating in wholesale markets.[80]

Figure 6.20. RTO/ISO regions of the United States and Canada[81]



There are seven ISO/RTO regions in the continental United States (California ISO, Midcontinent ISO, Southwest Power Pool, Electricity Reliability Council of Texas, ISO New England, New York ISO, and PJM Interconnection) and two non-RTO regions (West and Southeast).

6.3 Metrics and Trends

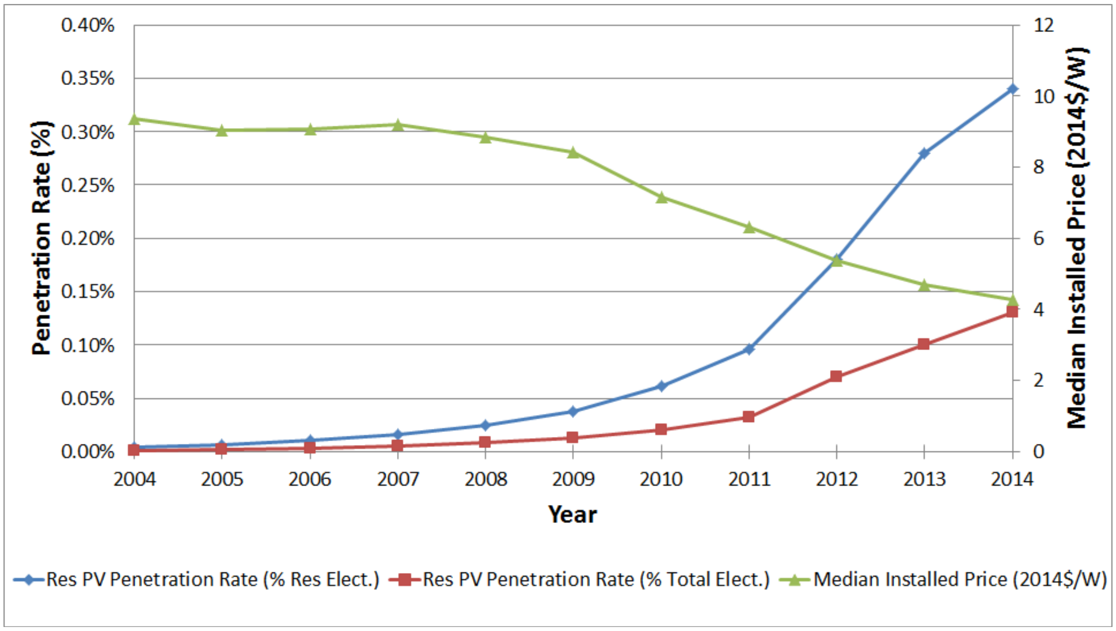
6.3.1 Solar PV and CHP Projections

The median installed price of solar PV declined dramatically over the last decade, with the greatest rate of reduction occurring from 2009-2014.[82] Factors driving price reductions include the drop in polysilicon

[a] A Load as Capacity Resource (LCR) commits to making pre-specified load reductions when system contingencies arise.

feedstock material as well as high-volume, low-cost manufacturers, and incentives and policies encouraging greater adoption (see Section 6.5.1 for further discussion of policies). Figure 6.21 shows a sharp increase in the rate of adoption, coinciding with the rapid decline in median installed price.

Figure 6.21. Penetration rate (%) and median installed price ($\$/W_{DC}$) of U.S. residential solar PV systems[83]



Median installed prices have dropped significantly over the last three years, and the penetration rate in the residential sector has risen sharply but from a low base. Residential solar PV penetration rate is the annual GWh from PV over total residential demand (% residential electricity) or over total electricity demand (% total electricity).

Steep reductions in module prices were the primary driver for installed price reductions from 2008 to 2012, accounting for about 80% of the decline in total installed price. Since 2012, however, module prices have remained relatively flat, and installed price declines have been driven primarily by reductions in nonmodule costs.[84]

Hardware component prices (inverters and racking)[a] have fallen significantly,[85] though they comprise only about 10% to 20% of the total drop in nonmodule costs from 2013 to 2014. However, recent nonmodule cost reductions are associated primarily with declining soft costs. Soft cost reductions stem partly from increasing system size and module efficiency,[b] a maturing industry with consolidation of market share, and widespread policy and industry efforts.[86] The price of solar PV is expected to further decline in the future. Figure 6.22 depicts the projected median installed price of residential solar PV, with the minimum price of $\$1.63/W_{DC}$ for residential PV achieved in 2020 per the SunShot Initiative target.[c] [87]

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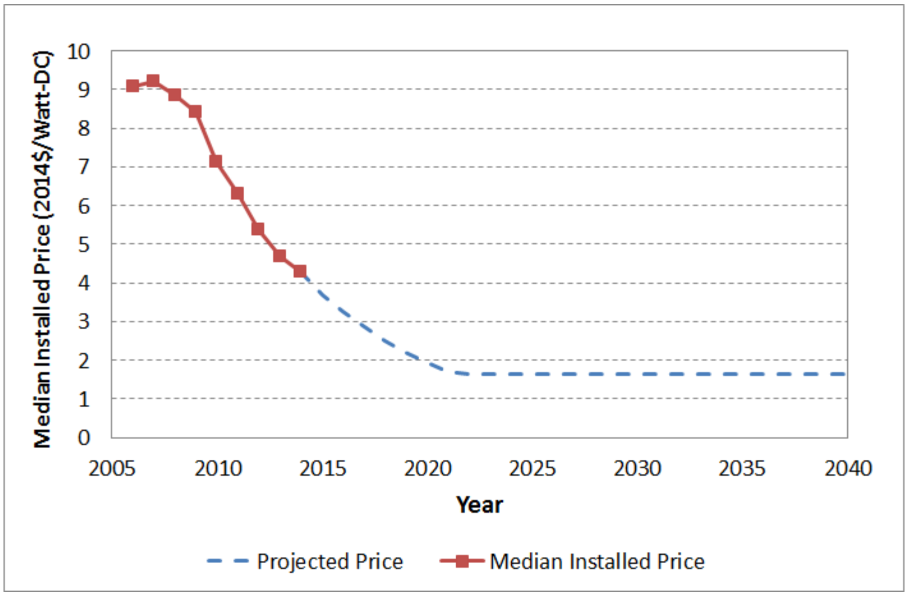
[a] PV racking refers to the mounting systems that are used to attach solar panels to surfaces such as rooftops or building facades.
[b] Increased module efficiency can reduce the footprint of PV systems, thus helping to contribute to lower soft costs.
[c] DOE's SunShot Initiative is a national collaborative effort to make solar energy cost-competitive with other forms of electricity by the end of the decade. See http://energy.gov/eere/sunshot/sunshot-initiative

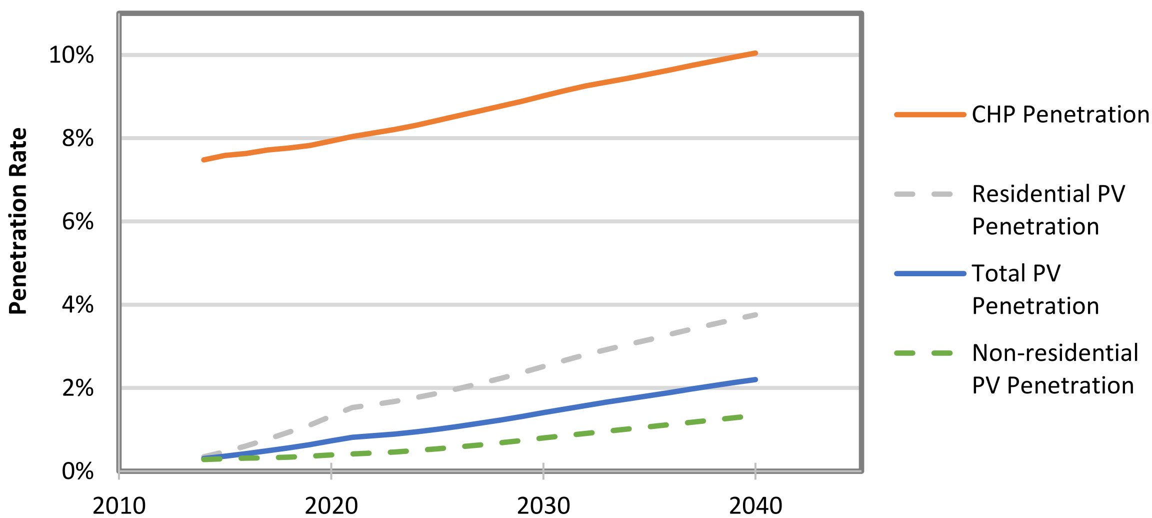
Figure 6.22. Projection of the median installed price ($\$/W_{DC}$) of U.S. residential PV systems[88]



The price after 2020 is assumed to be the SunShot target price for 2020.

Figure 6.23 shows the projected penetration rate of distributed solar PV and CHP from 2015 to 2040. Solar PV is expected to account for about 3.8% and 1.34% of electricity end use in the residential and nonresidential sectors, respectively, and grow to 2.2% of overall sales by 2040. CHP is projected to grow more slowly for the next decade, increasing to almost 12% of total electricity end use by 2040.[89]

Figure 6.23. Projected penetration rates (%) of CHP and distributed solar PV[90]



Distributed PV generation is projected to grow from 0.36% in 2015 of total residential and commercial sector electricity end use to 2.2% in 2040. CHP is projected to grow from 7.6% in 2015 to 10% of total retail electricity sales by 2040.[a]

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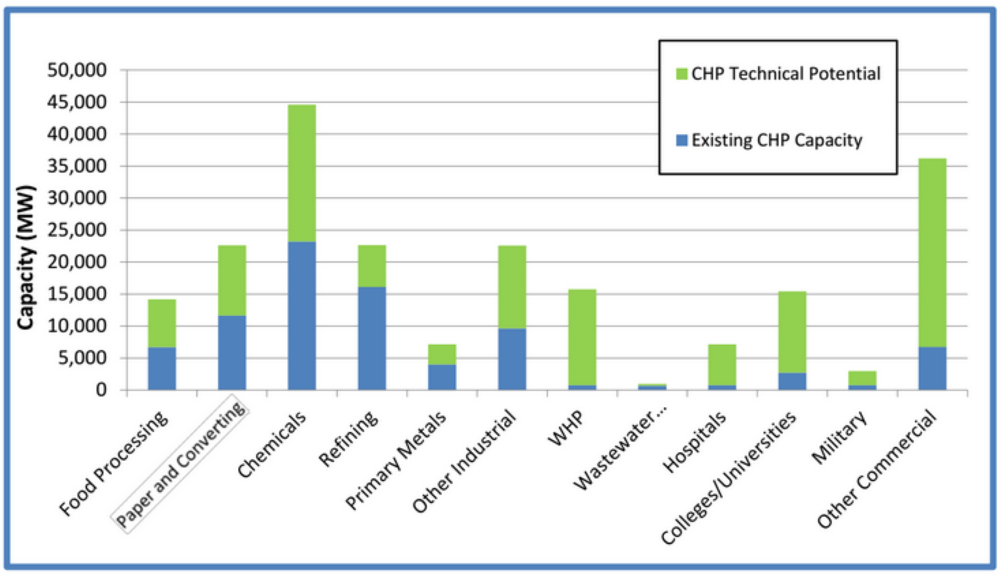
[a] Residential PV penetration is the projected GWh from residential solar PV over total residential demand; non-residential solar PV penetration is the projected GWh from commercial PV divided by commercial demand; total PV penetration is the total projected GWh from solar PV over total demand; CHP penetration is the projected GWh from CHP over total demand.

Time-varying pricing (e.g., TOU pricing) generally increases bill savings for consumers with distributed solar PV, but the degree of savings depends on wholesale electricity market dynamics, surplus generation capacity, and the level of solar energy penetration.[91] The future trajectory of distributed generation installations is highly policy-dependent, and thus any projections are quite uncertain.

The technical potential[a] for additional CHP applications in the United States is significant, at 134 GW (Figure 6.24 and 6.25). About one-third of that potential has an estimated payback time of 10 years or less. The chemicals sector in industry and colleges/universities in the commercial sector have the most technical potential.[92] However, CHP adoption is highly dependent on government policies, incentives, and tariff structures, and significant barriers exist (see Sections 6.5 and 6.5.1.3).

Combined heat and power (CHP) may have a greater role to play in the future if water consumption at utility-scale power plants becomes a critical constraint. Several CHP technologies use negligible amounts of water (reciprocating engines, combustion turbines, microturbines, and fuel cells).

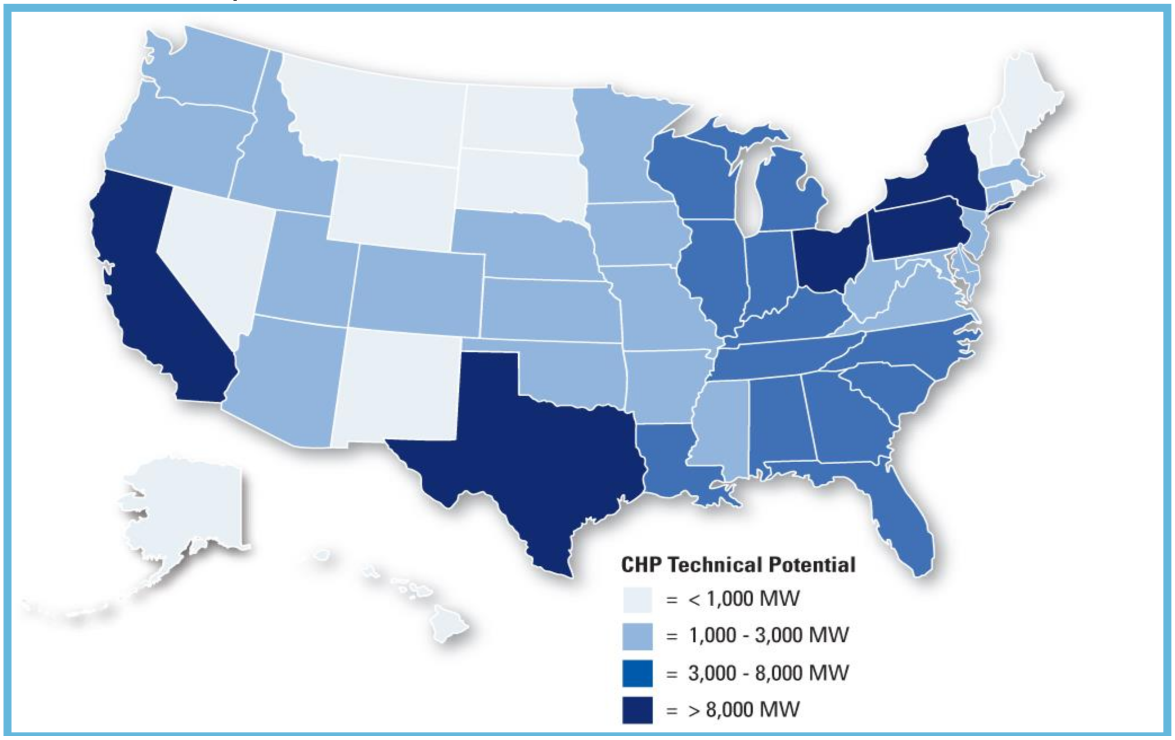
Figure 6.24. Existing CHP capacity and CHP technical potential, by sector[93]



Existing capacity is 83 MW, and technical potential is 134 MW.

[a] *Technical potential* refers the amount that is technically possible, not all of which is cost-effective.

Figure 6.25. Technical potential of CHP[94]

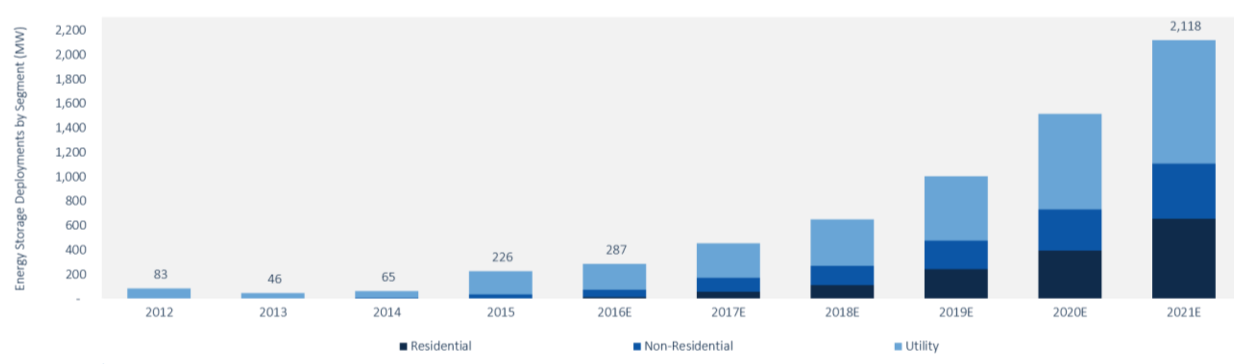


Technical potential for additional CHP applications at existing industrial, commercial, and institutional facilities is 134 GW. Systems smaller than 100 MW comprise nearly all this amount. By sector, some 56 GW of technical potential is projected for industrial CHP applications and 68 GW for commercial or institutional CHP. About 40 GW of the estimated technical potential have estimated paybacks less than 10 years.

6.3.2 Energy Storage Projections

Annual non-utility storage deployment is projected to grow to 700 MW in 2020 from 38 MW in 2015, with an annual growth rate of 80%. Distributed storage is projected to capture over half of the storage market by 2020 (Figure 6.26). Table 6.9 shows storage targets in California, which are driving much of the projected deployment.

Figure 6.26. Projection of energy storage deployment capacity by sector[95]



Some 728 MW of distributed energy storage is projected by 2020.

Table 6.9. California's Energy Storage Targets by Point of Interconnection (or Grid Domain) [a] [96]

STORAGE GRID DOMAIN POINT OF INTERCONNECTION	2014	2016	2018	2020	TOTAL	2014	2016	2018	2020	TOTAL
Units	MW	MW	MW	MW		%	%	%	%	%
Transmission	110	145	192	253	700	55	54	53	52	53
Distribution	67	90	115	153	425	34	33	32	31	32
Customer	23	35	58	84	200	12	13	16	17	15
TOTAL	200	270	365	490	1,325	100	100	100	100	100

California's storage target for 2020 is 1,325 MW. About 47% of the target is at the distribution or consumer level.

Other potential studies include longer-term projections. A study for the Eastern Interconnection projects 2 GW of distributed storage by 2030.[97] Another study, focused on ERCOT, estimates that up to 5 GW of grid-integrated, distributed storage would be cost-effective in the region by 2020.[98]

A recent report shows that the cost of Li-ion battery packs declined from more than $1,000/kilowatt-hours (kWh) in 2007 to about $410/kWh in 2014, or a 14% annual historical decline.[99] The learning rate[b] (LR) was found to be an estimated 6% to 9%, and if the authors' estimated annual cost reduction of 8% is assumed in the future, costs will reach $150/kWh in 2025. The levelized cost of electricity[c] (LCOE) from battery storage will depend on several factors in addition to the capital cost, such as efficiency, maintenance costs, and battery lifetime. For a set of nominal assumptions,[d] the LCOE is estimated to be in the range of $0.19–0.20/kWh for a $410/kWh battery pack, and in the range of $0.12–0.13/kWh for a $150/kWh battery pack.

LR for Li-ion batteries is lower than the LR for other DER technologies such as solar PV (20% LR from 1970–2006) and onshore wind (15% LR from 1990–2004). The LR is a critical parameter in future cost-effectiveness calculations that inform market adoption projections. Several recent works have highlighted the correlation of deployment programs and LRs.[100]

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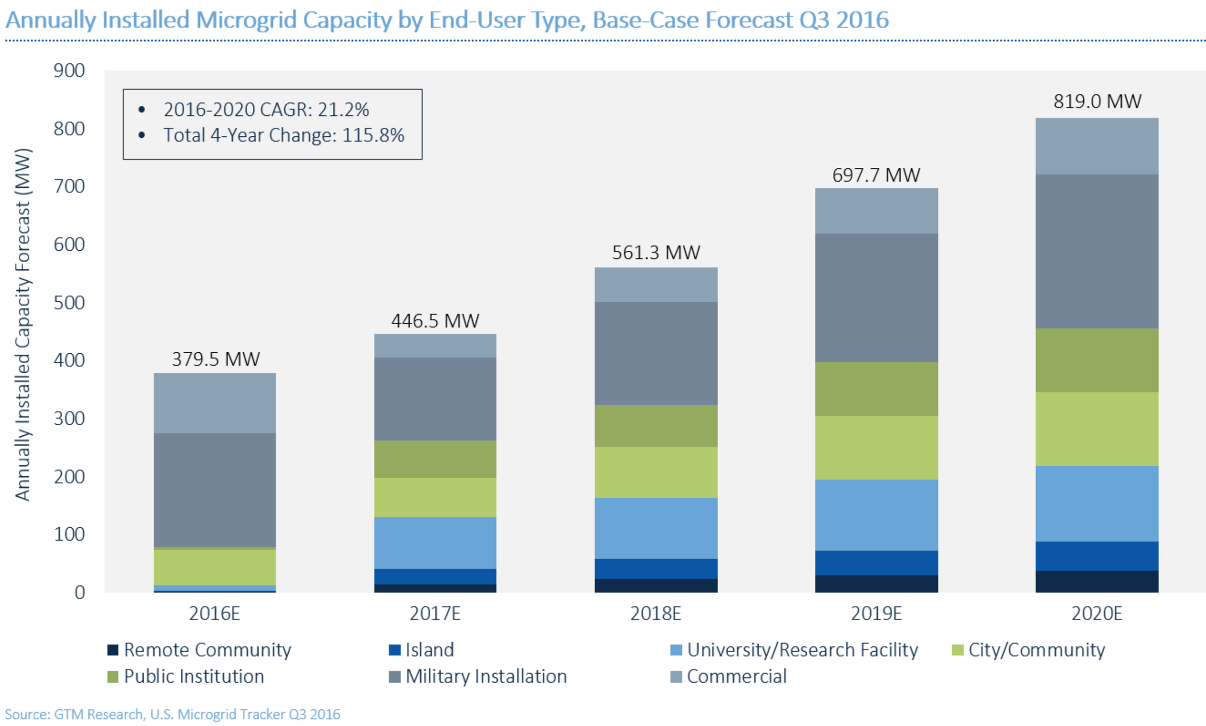
[a] Set by California PUC Decision 13-10-040 for Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.
[b] The *learning rate* (LR) is a figure of merit for the rate of cost reduction of a given technology as a function of its cumulative production. The LR is the cost reduction (typically in percent) for every doubling in cumulative production volume.
[c] "Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type." EIA (U.S. Energy Information Administration), *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015*, last modified June 3, 2015, https://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
[d] Assumptions include: capital costs of $410 or $150/KWh for 6 hours of storage capacity, $.050/kWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75%–85%, and fixed O&M costs of $22.00 to $27.50 per KWh installed per year. See for example, *Lazard's Levelized Cost of Energy Analysis*, Lazard, September 2014, https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.

6.3.3 Microgrid Projections

Microgrid capacity is projected to grow from 1.2 GW in 2014 to 2.9 GW by 2020, with the most capacity in military installations and university/research facilities (Figure 6.27). In some cases, future development may be in concert with utility modernization efforts. Several larger projects of 30 MW to 200 MW are planned in New York.[101]

Figure 6.27. Projected growth in microgrids, 2014 to 2020[102]



Overall capacity is projected to reach 2.85 GW in 2020, with the largest capacity in university/research facilities, followed by military installations.

6.3.4 Demand Response Projections

Greater adoption of variable renewable energy resources is placing greater demands on the electricity system, particularly in some regions (e.g., Texas, California). For example, in the West, renewable resources, including small hydro, are expected to make up nearly 17% of generating resources and almost 20% of capacity by 2024.[103] Increased penetration of VERs will lead to a more dynamically changing grid, and thus require a more frequent and broader array of grid support services—e.g., to address frequency imbalances, supply shortfalls, and over-supply conditions that may be hard to predict.[104] Demand response can facilitate greater amounts of penetration of VERs.

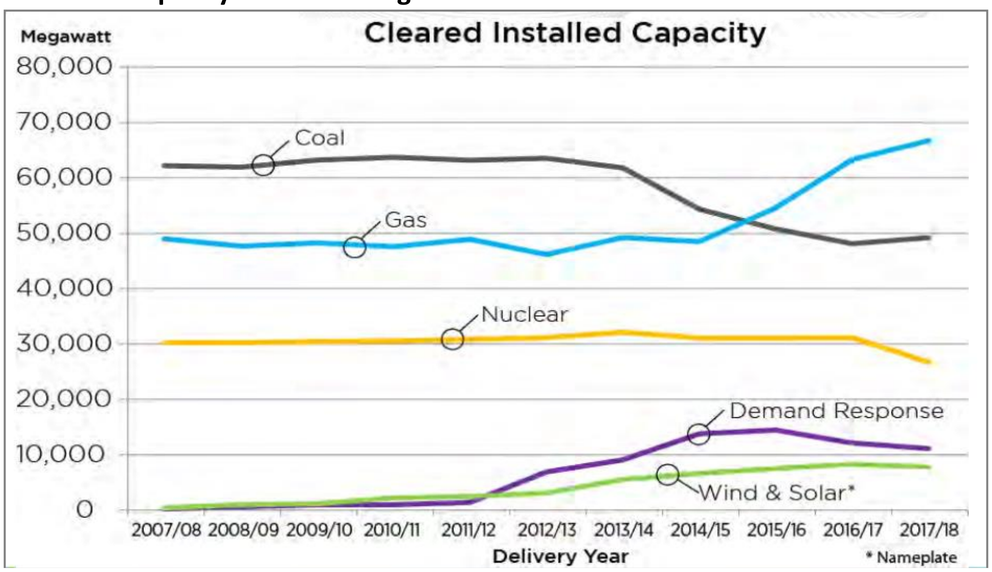
The development of more powerful IT capabilities, communication protocols, smart metering infrastructure, and grid-enabled end-use equipment, and the emergence of more affordable distributed storage[a] provides additional flexibility for demand response and the potential for new business models and new market entrants. Today, demand response programs are typically offered to customers to reduce their load in peak demand situations in exchange for capacity or energy payments.

[a] Distributed storage can be utilized for demand response applications such ancillary services.

In the future, a new class of demand response applications may have wider availability, with faster, more automated response and capability of moving customer loads in both directions. Advanced demand response resources are customer loads equipped with automation equipment that can increase and decrease while being available throughout the year and frequently measured (FERC 2014). Ancillary services typically include three types of products (spinning, nonspinning, and regulation), but high VER penetration is anticipated to add additional flexible capacity products such as maximum continuous ramping and load following products.

Figure 6.28 shows the cleared installed capacity[a] for the next three years in the PJM ISO region as an example of typical capacity changes observed and expected over time for generation: (1) a reduction in coal and nuclear capacity, (2) a sharp increase in natural gas to replace coal, and (3) an increase in wind and solar resources. Demand response capacity is projected to drop over the next several years, after a period of sharp growth.

Figure 6.28. Installed capacity in the PJM region[105]



PJM's relative mix of electricity resources through 2017/2018 is illustrative of trends in the relative mix of generation fuels and demand response for a large ISO region. Coal capacity is reduced by 20% from its peak and replaced largely by natural gas, with levels of wind and solar increasing. Demand response is projected to drop slightly from 2015/2016 to 2017/2018.

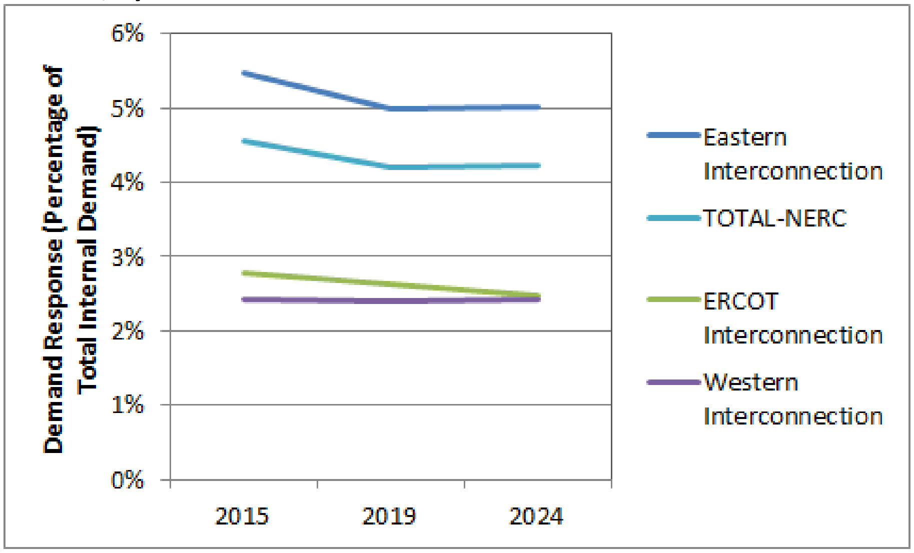
Figure 6.29 and Figure 6.30 show demand response projections[b] for NERC regions. Demand response for all regions is projected to account for less than 5% of overall demand to 2024. Overall, demand response is projected to increase only 1.7%, from 39.4 GW to 40.1 GW. Over the same period, total peak demand is projected to increase by 10%, from 864.3 GW to 950.2 GW. Thus, the percentage of demand response would drop from 4.6% to 4.2%. A breakout by individual NERC regions shows similar trends. Demand

[a] *Cleared installed capacity* refers to the bid-in capacity that was accepted in the PJM capacity auction for delivery in the year as shown on the x-axis of Figure 6.28.

[b] *Demand response* here is defined as "Total Internal Demand in MW - Net Internal Demand in MW," where this difference is the amount of controllable and dispatchable demand response projected to be available during the peak hour. Total Internal Demand includes considerations for reduction in electricity use due to projected impacts of energy efficiency and conservation programs and normal weather.

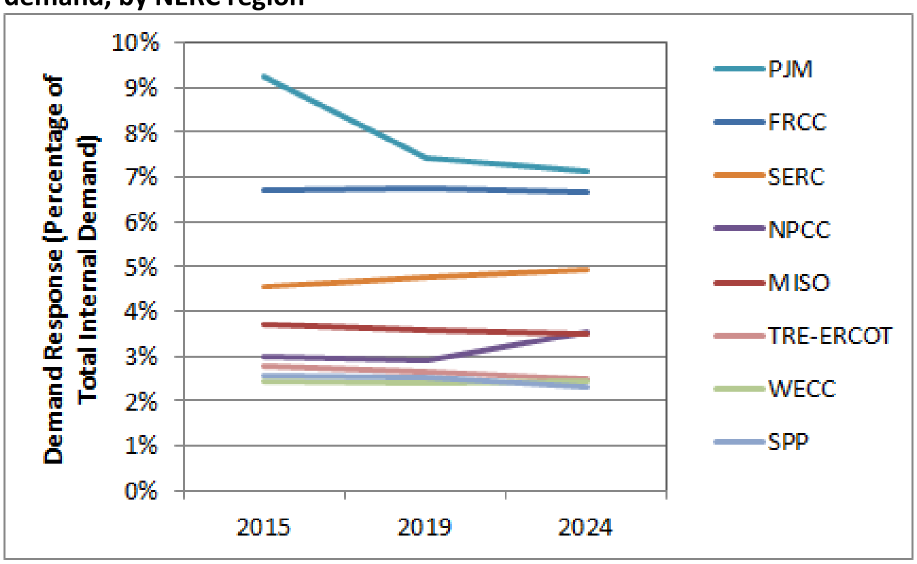
response is projected to increase from 3% to 3.6% of demand in NPCC and from 4.6% to 4.9% in SERC, but it is projected to drop or stay flat in other regions.

Figure 6.29. Total controllable and dispatchable demand response as a percentage of total summer peak internal demand, by interconnection



Overall, demand response is projected to drop slightly in the next 10 years, with a downward trend projected in the Eastern Interconnection and ERCOT and demand response virtually flat in the Western Interconnection.[106]

Figure 6.30. Total controllable and dispatchable demand response as a percentage of total summer peak internal demand, by NERC region[107]



Demand response is projected to decrease in PJM from about 9% in 2015 to 7% in 2024, increase somewhat in SERC and NPCC, and remain flat or trend downward in the five other regions. All regions in the continental United States are summer-peaking except for the WECC-Northwest Power Pool subregion of WECC, which is winter-peaking.

The following factors contribute to projections that overall demand response will decrease or remain flat over the next decade:

- Recent greater deployment of energy efficiency, conservation, TOU rates, and distributed generation have contributed to the lowest annual growth rate on record for NERC-wide summer and winter peak demand. Thus, demand response's contribution to demand reduction has flattened and is projected to remain fairly flat for the next decade, with minimal projected growth in the reference case.[108] NERC-wide controllable and dispatchable demand response is projected to grow by 1.7 GW (increasing from 38.9 GW in 2015 to 40.6 GW in 2024).
- In some regions such as FRCC, a decrease in the cost-effectiveness of demand response programs has reduced its rate of adoption. Projected benefits are lower relative to 2009 levels due to a number of factors, including lower fuel price projections and lower projected costs for environmental compliance, especially for carbon dioxide (CO_2) emissions.[109]

In some subregions, demand response capacity may be higher in the next decade than described above in order to meet reliability requirements for reserve margin at least cost.[a] In particular, five of the 15 NERC subregions in the United States are projected to fall below their reserve margin target with anticipated capacity[b] in the next five years. These five NERC subregions are projected to have less than 5% demand response capacity in 2024, at levels that are flat to 12% down from 2015 levels.

- Midcontinent ISO (MISO)
- Northeast Power Coordinating Council–New York (NPCC-NY)
- Reliability Entity, Inc. – Electric Reliability Council of Texas (TRE-ERCOT)
- Mid-Continent Area Power Pool (MRO-MAPP)
- Southeastern Electric Reliability Council – East (SERC-E)

Among the remaining regions, seven of the 15 NERC subregions are projected to meet their reserve margins through 2024:

- Florida Reliability Coordinating Council (FRCC)
- Northeast Power Coordinating Council – New England (NPCC-NE)
- Pennsylvania-New Jersey-Maryland Interconnection (PJM)
- Southeastern Electric Reliability Council – Southeast (SERC-SE)
- Southwest Power Pool (SPP)
- Western Electricity Coordinating Council – Northwest Power Pool (WECC-NWPP)
- Western Electricity Coordinating Council – Rocky Mountain Reserve Group (WECC-RMRG)

The remaining three subregions are close (within 2%) to meeting their reserve margin target for 2024:

- Western Electricity Coordinating Council – California-Mexico Power (WECC-CA-MX)
- Western Electricity Coordinating Council – Southwest Reserve Sharing Group (WECC-SRSG)
- Southeastern Electric Reliability Council – North (SERC-N)

[a] *Reserve margin* is the primary metric used to measure resource adequacy and is defined as the difference in peak load resources and net demand (both in units of GW), divided by net demand.
[b] Capacity that is under construction or approved.

Thus, the demand response projections for 10 of the 15 NERC subregions are reasonably consistent with meeting system reserve margin requirements from 2015 to 2024, under all of the other assumptions of this NERC study.

Another important consideration is market and regulatory uncertainty for demand response programs. This includes issues of regulatory authority and the treatment of aggregated resources for market participation. On January 25, 2016, the U.S. Supreme Court upheld FERC's authority to regulate demand response programs in wholesale electricity markets (FERC Order 745). This ended a period of multiple years of uncertainty for demand response compensation in energy markets, the impact of which is not captured in the above projections. (See Section 6.5.4 for more discussion.)

Overall these projections indicate that without further regulatory or policy changes, demand response programs are unlikely to grow significantly in the next decade. At the same time, demand response product offerings may broaden as technology and software for the control and aggregation of end-use equipment and DERs improve, DER market adoption increases, new sources of electricity demand are brought online (e.g., PEVs), and more variable energy renewable sources need to be integrated into the grid. The demand response sector, including third parties that aggregate demand response from residential and commercial consumers, may thus have greater opportunities for growth as new demand response resources are identified by utilities and regulators, and these resources participate in retail and wholesale markets.

The following subsections discuss several region-specific demand response forecasts beyond 2024:

ERCOT to 2032[110]

An ERCOT study to 2032 projects a 2.7% to 3.5% demand response load reduction in reference-case scenarios (2.7 to 3.5 GW out of 100.7 GW peak demand). The highest demand response capacity is achieved in the "Environmental EE & DR" scenario with a 10 GW demand response mandate, or 13% of a projected 76.9 GW peak demand. This scenario assumes more aggressive energy efficiency programs, emissions cost adders, continuation of the federal PTC for renewable resources until 2032, and high natural gas prices relative to business-as-usual cases.

Eastern Interconnection to 2030

Table 6.10 provides estimates for peak load reduction resources from a recent demand response study for the Eastern Interconnection.[111] Demand response from conventional demand response programs and smart grid-enabled programs is projected to total 5.4% of peak demand in 2025 and 2030, similar to NERC's estimates cited above. Together with demand response, energy efficiency programs, distributed generation, and energy storage are projected to increase to 19.6% of peak load by 2030.

Table 6.10. Peak Load Impact Projections in the Eastern Interconnection[112]

Resource Category		Projected Total Demand-Side Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Energy Efficiency		3,016	5,650	8,567	11,542	25,956	40,106	53,369
Demand Response	*Conventional Programs*	23,514	26,451	31,245	32,005	31,614	32,412	33,415
	*Smart Grid-Enabled**	929	1,032	1,184	1,322	3,230	4,451	5,639
Energy Storage		64	68	76	79	629	1,253	2,040
DG-Fossil		15,740	15,666	15,663	15,625	16,031	16,695	17,671
DG-Renewables		4,198	4,713	5,289	5,972	10,745	17,007	24,516
Smart Grid (CVR)		353	557	612	1,124	1,481	3,276	4,075
TOTAL		**48,103**	**54,424**	**62,918**	**67,948**	**89,950**	**115,454**	**140,972**
Total Annual Peak Load		*577,087*	*585,752*	*596,594*	*604,471*	*640,249*	*677,684*	*718,217*
% of Peak Load Supported by Demand-Side Resources		**8.3%**	**9.3%**	**10.5%**	**11.2%**	**14.0%**	**17.0%**	**19.6%**

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Demand response programs are projected to contribute 5.4% of peak load support in 2030, up from 4.2% in 2012.

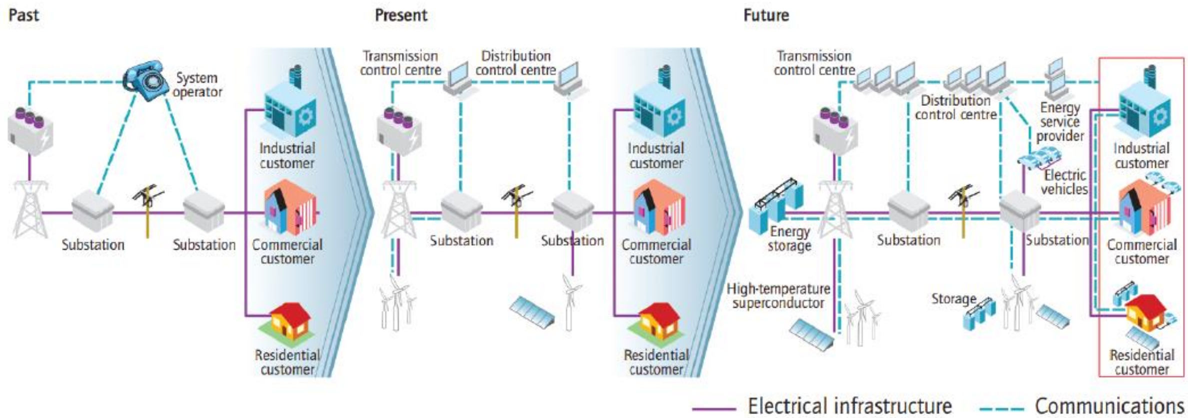
WECC to 2022

A recent Lawrence Berkeley National Laboratory (LBNL) study presents potential estimates for the 11 states and two provinces in the Western Interconnection.[113] The potential estimate is for "traditional" demand response with well-established programs. The "High DSM" case in the study estimates 14.39 GW of potential demand response resource capacity in 2022, or about 8.3% of peak demand. Interruptible programs accounted for the largest demand response capacity at ~5,028 MW (~35%). Pricing programs accounted for ~4,266 MW (~30%) of demand response capacity. The reference case estimated 7.96 GW of potential demand response, or about 4.6% of peak demand—~3,615 MW (~45%) direct load control programs and ~2,714 MW (~35%) interruptible programs.

6.4 Markets and Market Actors

The electricity grid today consists of utility-scale generation, transmission and distribution systems and control centers, relatively low levels of DERs, and end users (See Figure 6.32). Generation, transmission, and distribution are also linked via communications, and recent implementation of AMI allows end-use customers to directly communicate with their utility. Figure 6.31 conceptualizes the electricity system and key market actors and roles. (Modeling is subsumed within the planning layer, and R&D occurs across all areas.) Table 6.11 adapts Figure 6.31 to conceptualize the future grid in a similar manner.

Figure 6.31. Evolution of the electricity grid[114]



The electricity grid is evolving to accommodate more DERs, more extensive flows of information and communication, and new market participants.

The electricity grid of the future is likely to have higher levels of DERs, including two-way power flows between the distribution system and end-use consumers, and new market participants, such as DER aggregators. It is likely that the grid of the future will need to accommodate new or evolving roles for consumers, utilities, grid operators, and regulators, as well as potential new entities. For example, consumers that both produce and consume power through advanced distribution infrastructure will become "prosumers." This denotes a change in the customer-utility relationship from a consumer who only pays for electricity services to a consumer who also sells electricity services to the grid. Another example of change is the greater potential role energy service providers can play in offering DER equipment and integration for customers, as well as aggregating customer-sited DERs to provide energy, capacity, and other grid services.

One emerging business model is partnerships of rooftop solar PV and on-site battery storage vendors. Examples include Solar City and Tesla, Sungevity and Sonnenbatterie, SunPower and Sunverge, Sunrun and Outback Power, and Enphase and Eliiy. Solar PV combined with storage can provide customers with emergency backup power and peak demand reduction.

Another example of new business models is the aggregation of customer-sited storage systems for participation in the wholesale power market, recently demonstrated in CAISO.[115] Storage was installed on commercial building sites (hotels, software companies, and nursing homes). Other key participants in the demonstration include the utility (Pacific Gas and Electric), regulators (California Public Utilities Commission [CPUC]), a network platform provider (Olivine), a start-up company providing real-time analytics and storage dispatch and optimization (Stem), and legislators who enacted the state's storage mandate.

Table 6.11. Market Actors in the Electric Grid of the Future

LAYER	AREA	LEAD MARKET ACTORS	KEY ROLES
CUSTOMER	RESIDENTIAL SECTOR	RATE PAYERS	**CONSUMERS TO PROSUMERS**
	COMMERCIAL SECTOR	BUSINESS OWNERS	**CONSUMERS TO PROSUMERS**
	INDUSTRIAL SECTOR	BUSINESS OWNERS	**CONSUMERS TO PROSUMERS**
DISTRIBUTED ENERGY RESOURCES	RES/ COMM/ IND SECTORS	CHP, SOLAR PV, **DR, STORAGE PROVIDERS**	EQUIPMENT INSTALLATION / SERVICE
ENERGY SERVICE PROVIDER	RES/ COMM/ IND SECTORS	**CUSTOMER DER AGGREGATORS**	**CUSTOMER SERVICE AND GRID SUPPORT INTERFACE**
COMMUNICATION AND SOFTWARE	**SPANNING THE GRID FROM GENERATORS TO CUSTOMERS**	**DISTRIBUTION UTILITY, ENERGY SERVICE PROVIDERS**	**ENERGY SERVICE OPTIMIZATION**
UTILITY	UTILITY	UTILITY	SETS TARIFFS, PROVIDE ENERGY SERVICE AND EE/DR PROGRAMS
DISTRIBUTION	SUBSTATION STEP DOWN TRANSFORMER	DISTRIBUTION CONTROL CENTER **TO DISTRIBUTION SYSTEM OPERATOR?**	SUBSTATION CONTROL, DISTRIBUTION SYSTEM OPERATIONS
GRID SUPPORT	ENERGY MARKETS	REGION-DEPENDENT ISO/RTOs, BALANCING AUTHORITIES	BALANCE SUPPLY AND DEMAND, ENSURE RESOURCE ADEQUACY, **INTEGRATE VARIABLE RENEWABLE SUPPLIES**
	CAPACITY MARKETS		
	ANCILLARY SERVICES MARKETS		
TRANSMISSION	BALANCING AUTHORITIES	ISO/RTOs, **BULK STORAGE PROVIDERS**	INTEGRATES RESOURCE PLANS, MAINTAINS SUPPLY/DEMAND BALANCE, SUPPORTS INTERCONNECTION FREQUENCY IN REAL TIME
GENERATION	MERCHANT POWER PLANT, VERTICALLY-INTEG. UTILITY	POWER PLANT OWNERS	PROVIDE BASELOAD AND FLEXIBLE POWER, **MEET RPS OR EMISSIONS TARGETS**
PLANNING	STATES, FEDERAL GOV'T, ISO/RTOs	STATE PUCS, EPA, ISO/RTOs	RESOURCE AND EMISSIONS TARGETS AND POLICIES; **PLANNING FOR HIGHER DER PENETRATION**
REGULATORY	TRANSMISSION	FERC	BULK ELECTRIC SYSTEM, WHOLESALE MARKETS AND TRANSMISSION, SETS OPEN ACCESS TRANSMISSION TARIFFS; **NEW PLANNING TOOLS AND PROCEDURES**
	RELIABILITY	NERC	ESTABLISHES RELIABILITY RULES; **NEW PLANNING TOOLS AND PROCEDURES**
	NATIONAL, REGIONAL, LOCAL	SPECIFIED JURISICTIONS	NATIONAL, STATE, AND LOCAL POLICIES AND INCENTIVES; **INCORPORATING HIGHER DER PENETRATION**

This table adapts Figure 6.31 to conceptualize the future grid to 10 layers. Some layers are cross-cutting, such as communication and software. These layers span generation, transmission, and distribution layers. Distributed generation and storage can provide more flexibility to both distribution and transmission systems. Energy service providers can use advanced modeling and data analytics to aggregate consumer-hosted DERs for grid support. Consumers can both consume and produce power ("prosumers"). Blue text indicates changes due to greater DER adoption; red text indicates changes due to greater levels of utility-scale renewable generation.

6.4.1 Sources of DER Value

Table 6.12 defines and maps DER value components by beneficiary: utility customers, society, electric utility distribution system, and wholesale electricity markets. For utility customers, potential benefits can accrue from greater market choices, lower electricity bills, improved energy security (backup power in grid outage or emergency), and enhanced property value.

Table 6.12. DER Value Components and Definitions[116]

	Value Component	Definition
Wholesale	WECC Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	System Energy Price	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services	Reduced system operational requirements for electricity grid reliability
	RPS Generation & Interconnection Costs	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Transmission Congestion + Losses	Avoided locational transmission losses and congestion
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges
Distribution	Subtransmission, Substation & Feeder Capacity	Reduced need for local distribution upgrades
	Distribution Losses	Value of energy due to losses bet. BPS and distribution points of delivery
	Distribution Power Quality + Reactive Power	Improved transient & steady-state voltage, harmonics & reactive power
	Distribution Reliability + Resiliency	Reduced frequency and duration of outages & ability to withstand and recover from external threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	Emissions (CO2, Criteria Pollutants & Health Impacts)	Reduction in state and local emissions and public and private health costs
	Energy Security	Reduced risks derived from greater supply diversity
	Water & Land Use	Synergies with water management, environmental benefits & property value
	Economic Impact	State or local net economic impact (e.g., jobs, investment, GDP, tax income)

This list includes potential DER value components for utility consumers, society, the distribution system, and wholesale electricity markets. BPS = bulk power system; LMP = locational marginal pricing; RPS = Renewable Portfolio Standard; LSE = load serving entity.

DERs can provide services to utilities in supporting distribution system operation and can defer or avoid costly distribution system upgrades. Utilities could play a larger role in both DER deployment and DER integration, management, and optimization. This will depend on several factors, including the rate of technology innovation, market evolution, and firm cost structure.[117] For example, San Diego Gas and Electric (SDG&E) recently proposed a storage tariff that would reward consumers who are willing to allow utility control of batteries at their premises.[118] This type of program could help defer distribution grid investments with assets owned by utility customers. Integration and management of DERs represent a potential role for the utility or an independent entity serving as the Distribution System Operator (DSO). DSOs are responsible for planning and operational functions associated with a distribution system that is modernized for high levels of DERs.[119]

Three California utilities recently submitted DER Plans to the CPUC as mandated by state statute (AB 327).[120] The utilities are proposing several hundreds of millions of dollars each over the next several years to integrate DERs (including rooftop PV, behind-the meter storage, and PEVs) in distribution planning and operation. Funding would cover distribution grid and substation automation, communication systems, technology platforms and applications, and grid reinforcement (e.g., upgrading conductors to a larger size and increasing circuit voltage to support increased DER penetration). Proposed automation systems include data collection and management systems.

6.5 Barriers and the Policies, Regulations, and Programs That Address Them

Barriers to DER adoption are listed below. Most of these barriers are applicable for all types of DERs, and many are interrelated. Contracting with a third party (e.g., demand response aggregators, solar leasing entities, energy services companies) can address many of these barriers.

- First costs (including transaction costs) and short payback times—Market actors typically require short payback periods. High capital, installation, and transaction costs can pose barriers to DER investments.
- Information/awareness—Market actors may have imperfect information about the cost, performance, and benefits of DERs and may lack awareness of new technology developments, incentive programs, or third-party service providers.
- Risk aversion/performance concerns—Market actors may be risk averse to new or unfamiliar DER technologies and new operating and maintenance procedures or business practices, and may be concerned about DER performance relative to the status quo.
- Technical staffing and capability—For example, potential CHP customers may lack technical know-how or capability to install and maintain an on-site energy generation system.
- Materiality—When energy costs are small, relative to other costs, it is hard to get building owners to pay attention to energy efficiency and DERs.
- Limited access to capital—Households and companies have limited spending or capital investment budgets, and DERs may not be considered for renovations.
- Lack of monetization of non-energy benefits and price signals—DER prices are set to recover service provider and equipment supplier costs and do not capture the true social costs and benefits of DER adoption (e.g., environmental and health benefits). In addition, tariff structures may discourage consumer investments in DERs.
- Lack of private incentive for R&D—In general, RD&D is undersupplied absent policy intervention because its benefits cannot be fully appropriated by inventors (a "public goods" problem).
- Uncertainty in market and regulatory and nonmarket factors—The uncertainty associated with long-term investment outcomes, future fuel and electricity prices, and utility tariff structures can hamper DER adoption. For example, the price at which commercial and industrial consumers can sell back excess electricity production from CHP systems is a critical factor in the cost-effectiveness of these systems, but this is an uncertain parameter when planning for a 15- to 25-year investment horizon.
- Utility interactions—Utility tariff structures, and in particular standby rates,[a] [121]impact the economics of on-site generation, including CHP. For example, many water and wastewater utilities have reported long, difficult, and expensive processes related to interconnection agreements for distributed generation from a variety of on-site renewable sources, including biogas. Interconnection processes can delay the project development schedule and add expenses by requiring extensive studies and technical requirements.[122] Multiple review bodies and local permitting and siting issues (air and water quality, fire prevention, fuel storage, hazardous waste

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[a] *Standby* (or partial requirements) *service* is the set of retail electric products for utility customers who operate on-site, non-emergency generation. Utility standby rates cover some or all of the following services: backup power during an unplanned generator outage; maintenance power during scheduled generator service for routine maintenance and repairs; supplemental power for customers whose on-site generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class; economic replacement power when it costs less than on-site generation; and delivery associated with these energy services.

disposal, worker safety, and building construction standards) can add delays due to the review body's unfamiliarity with the technology, as well as transaction and legal costs.

- Limited CHP supply infrastructure—The downturn in CHP investment since 2005 has reduced the size and focus of the industry's sales and service infrastructure.

Barriers specifically to greater adoption of demand response include the following (directly quoted from *A National Assessment of Demand Response Potential*, Federal Regulatory Energy Commission, 2009)[123]:

- Regulatory barrier—Some regulatory barriers stem from existing policies and practices that fail to facilitate the use of demand response as a resource. Regulatory barriers exist in both wholesale and retail markets.
    - Lack of a direct connection between wholesale and retail prices
    - Measurement and verification challenges
    - Lack of real-time information sharing
    - Ineffective demand response program design
    - Disagreement on cost-effectiveness analysis of demand response
    - In the traditional utility business model, the opportunity for vertically integrated, investor-owned utilities to earn a return on capital investments, but not expenses. Thus, utilities may view demand response as less preferred to capital-intensive investments in generating plants.
- Technological barriers
    - Lack of AMI
    - High cost of some enabling technologies
    - Lack of interoperability and open standards
- Other barriers
    - Lack of consumer awareness and education
    - Lack of enabling infrastructure investment
    - Revenue availability and revenue capture. [a] [124]
    - Concern over environmental impacts; for example, the use of diesel generators for peak generation reduction

The following table and technology-specific sections describe additional barriers and existing policies and programs that are currently being implemented to address them.

[a] For some markets, "DR [demand response] program providers and the participating customers must assess and decide whether the available revenues from participating in various AS [Ancillary Services] markets are sufficient (*Revenue Availability*) and can be captured with enough certainty (*Revenue Capture*)."

Table 6.13. Major Policies, Regulations, and Programs to Address Barriers to Cost-Effective DERs

Policy, Regulation, or Program	Description and Implemented Examples	Principal Barriers Addressed
Codes and Standards	• Mandatory prescriptive or performance-based energy standards that regulate end-use equipment, controls, or distributed generation, such as provisions for demand response capability (e.g., smart thermostats) or distributed generation equipment • Zero net energy building (ZNEB) codes that mandate on-site distributed generation	*Information/awareness, materiality, split incentives* • Codes and standards set a minimum level of performance, guarding against uninformed or inattentive purchase of lower performance or lower efficiency devices or buildings and limiting the impact of split incentives.
Clean Energy Mandates and Target-Setting	• Renewable portfolio standard (RPS) carve-outs • Public Utility Regulatory Policies Act (PURPA), feed-in tariffs and net metering • Cap-and-trade emission reduction programs • State targets for storage, solar PV, and CHP	*Non-energy benefits, lack of private incentive for R&D, various others* • These policies are enacted for a variety of reasons, including resource diversification, using local resources, reducing carbon and other air pollutant emissions, and other non-energy benefits.
Grants and Rebates	• Payments to consumers or third parties that reduce or offset the incremental cost of DERs	*First costs, short payback requirements, non-energy benefits, materiality, information/awareness* • Grants and rebates lower the incremental up-front cost of efficient technologies, serving as a proxy for nonpriced social benefits of energy efficiency adoption.
Resource Planning	• Utility integrated resource planning (IRP) to ensure system reliability that appropriately factors in distributed energy resources	*Price signals, non-energy benefits* • IRPs can ensure that DERs are valued appropriately in utility planning for energy and capacity.
State Regulations Including Rate Design	• State regulations on peak demand reduction, time-varying pricing, demand response incentive programs, service providers, integrated resource planning, PURPA implementation, standby rates, interconnection, and utility ownership of DERs	*Price signals, non-energy benefits* • These interventions modify costs and returns on DER investments.
RD&D for end-use technologies	• Direct federal support for RD&D • Manufacturer incentives • DOE SunShot program	*Lack of private incentive for R&D* In general, and particularly in the energy industry, RD&D is undersupplied absent policy intervention.

Financing	• Property-assessed clean energy (PACE) programs • PV leasing programs • State financing programs • Green banks	*Lack of capital, first costs, transaction costs, performance risk* Financing programs extend capital and often eliminate up-front cost entirely. Financing is often packaged with other programmatic offerings and potentially removes the need to seek out a source of capital, which can otherwise be a barrier to program participation. Performance contracting transfers energy performance risk to the energy services company. Performance contracting also provides technical expertise and lowers transaction costs.
Tax incentives	• Federal investment tax credits for CHP, fuel cell systems, solar PV, and small wind on-site generation	Tax incentives

6.5.1 Distributed Generation Barriers in Existing Policies

Policy and regulatory drivers that affect the penetration of distributed generation include the following:

- National and state incentive policies—The deployment of renewable energy resources, both utility-scale and distributed, has been highly dependent on availability of financial incentives. However, declining cost and increasing performance have enabled a reduction in incentive levels.
- State renewable portfolio standards with carve-outs for distributed generation—State-level mandates provide certainty to the market and have been a significant driver of solar PV in particular.
- Policies and regulations affecting electricity tariffs, such as net metering, FITs, and retail rate design—Retail electricity rate structures significantly affect net benefits for customers considering installation of distributed generation or storage systems or participation in demand response programs.
- Zero net energy building (ZNEB) policies—Policies requiring on-site generation (or that count participation in offsite generation projects) as part of ZNEBs, which also incorporate deep energy efficiency measures, may serve as an additional driver for distributed generation adoption.

Corporate policies also can contribute to greater demand for distributed generation. Energy efficiency, renewable energy, and sustainability more broadly are a renewed focus that is exemplified in "RE100" initiative.[125] RE100 is a global collaborative of companies committed to 100% renewable electricity in the near term (2015 to 2020) to long term (2050). Participating companies have varying renewable energy goals as a percentage of their overall energy consumption. Microsoft reported 100% renewable electricity in 2014; Goldman Sachs set a 100% target for 2020, and Johnson and Johnson set a 100% target for 2050. The companies meet their renewable electricity with a mix of on-site generation, power purchase agreements, and renewable energy certificates.

6.5.1.1 *Solar PV*

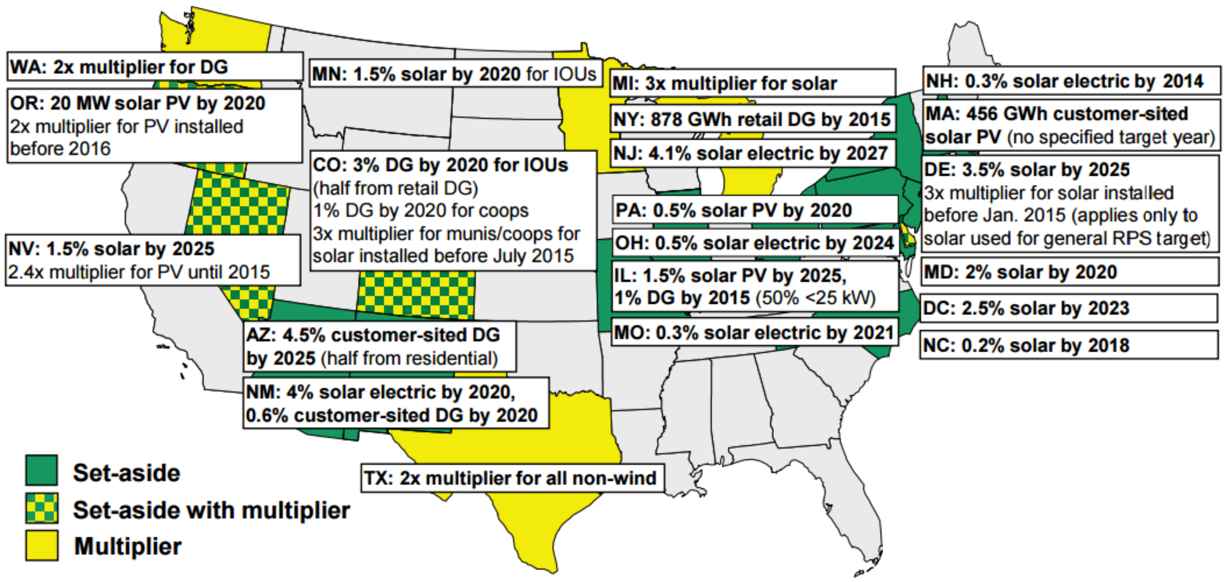
In the past, adoption of distributed solar PV routinely required an up-front investment in hardware and installation costs. This "first-cost" barrier has been the focus of federal and state incentive policies and spurred the growth of third-party leasing providers. Other barriers to distributed solar include the lack of suitable rooftop space for a large fraction of buildings; the complexity of PV system purchases, which include multiple options for payment and ownership, equipment, and system sizes;[126] and the reluctance of consumers to make a long-term energy investment.

The relatively high levels of growth achieved in the U.S. solar PV market in recent years have been aided by financial incentives and other supportive policies. At the federal level, incentives have been provided primarily through the U.S. tax code, in the form of a 30% ITC. In December 2015, the ITC for solar was extended in full for an additional three years. It will now ramp down incrementally through 2021 and remain at 10% beginning in 2022 for businesses and commercial installations and drop to zero for residential owners.[127] Businesses also can use an accelerated, 5-year tax depreciation schedule for solar installation.

State renewable portfolio standards (RPSs) are a major driver of renewable energy deployment. An RPS requires utilities and other electricity suppliers to purchase or generate a targeted amount of qualifying renewable energy or capacity by specified dates. While design details vary considerably, RPS policies typically enforce compliance through penalties, and many include the trading of renewable energy certificates (each representing 1 megawatt-hour [MWh] of qualifying energy). Many states and

Washington, D.C., have RPS policies with specific solar provisions.[128] Figure 6.32 shows states that include such distributed generation "set-asides," multipliers that assign qualifying distributed generation with higher levels of qualifying renewable energy credits, or both.

Figure 6.32. State renewable portfolio standards with distributed generation set-asides and multipliers[129]



Many states support deployment of solar PV and other distributed generation resources through specific energy or capacity targets or additional credits toward compliance with the standards.

The growth in U.S. distributed generation, and in particular residential solar PV, has been facilitated in large part through policies, regulations, and programs that enable third-party ownership.[130] Under this structure, a party other than the consumer or utility invests in, owns, and operates the distributed generation system at a consumer's site. The customer signs a long-term contract to lease the system or purchase the electricity generated by the system. The consumer avoids the up-front investment cost, and the third party takes care of operation and maintenance. In 2013, third-party ownership represented approximately two-thirds of the U.S. residential solar market and a considerable portion of the commercial market.[131] The success of this model is partially due to its economic proposition, where consumers access PV-generated electricity at a price that is competitive with utility retail rates.[132]

The value proposition of rooftop PV is further tied to utility tariff structures, including the level of monthly fixed customer charges (charges that the customer cannot reduce—e.g., through reducing or shifting electricity consumption or demand),[a] net metering policies,[133] and time-varying rates.[134] When setting solar PV-related tariffs, utility regulators balance a host of interests, including ratemaking principles such as economic efficiency and fairness/equity. Such equity issues may arise if solar PV owners are not contributing their fair apportionment of system capacity costs. But similar issues arise absent solar PV. For example, "peaky" customers—those who use more electricity when it is most expensive, relative to the average customer—are subsidized by customers with flatter loads.

[a] Recovery of utility fixed costs through fixed charges and other means is the subject of a forthcoming report in the Future Electric Utility Regulation series: https://emp.lbl.gov/future-electric-utility-regulation-series.

Net Metering Policies [135]

Net metering policies provide a billing mechanism that allows consumers to generate electricity at their homes or businesses using eligible technologies (e.g., solar, wind, hydro, fuel cells, geothermal, biomass), reduce purchases from the utility, and receive a credit on their utility bills for net excess energy. This credit offsets the customer's electricity consumption during other times, typically rolling forward over the course of a year. Net metering has served as a principal policy for increasing market adoption of distributed generation.

State-developed mandatory net metering rules apply to utilities in most of the United States (41 states, Washington, D.C., and three territories[136] (see Appendix Figure 7.35 and Figure 7.36). Due to rapidly falling costs for rooftop solar PV, utilities in several states are approaching or have already hit their previously established net metering caps.[137] Utilities argue that increasing capacity of distributed generation with existing compensation and tariff structures shifts costs unfairly to non-solar customers, and that solar PV owners should pay more for transmission and distribution charges. Distributed solar also represents a potential threat to utilities' existing business model.[138]

Recently, utilities throughout the country have proposed changes in net metering rules, as well as fundamental rate design changes such as increasing fixed charges or adding demand charges—for all customers or just solar PV customers. At the end of last year, Hawaii ended its solar net metering program, and Nevada recently announced sharply increased monthly fixed charges and much lower net metering rates to be phased in over the next four years.[139] In January 2016, the California PUC updated its net metering regulations. The decision upheld compensation at retail rates for net excess generation but also imposed an "aggressive" move to time-of-use electricity consumption rates for net metering customers.[140] The decision will be revisited in 2019, with major efforts ongoing at the CPUC and the state's three largest utilities to better determine the proper valuation and appropriate compensation mechanisms for rooftop solar and other DERs.[141]

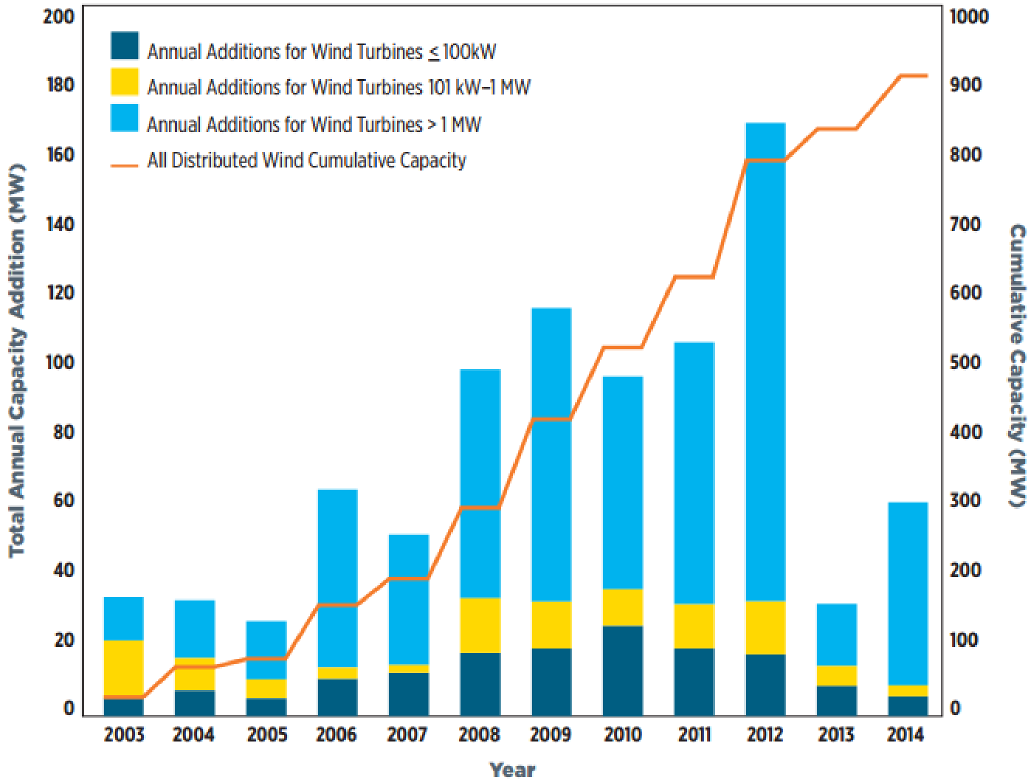
Community or *shared* solar[142] is an emerging model where, instead of being installed at a consumer's site, a solar PV system is installed in a nearby location (e.g., a parking lot or empty lot) to serve multiple consumers. Consumers can buy or lease a portion of the community project, or participate in a utility program where they contribute toward the project through charges on their utility bills (and receive the renewable energy credits and other benefits of the project). Community solar projects provide greater project economies of scale compared to small systems at individual properties, as well as provide an option where roof- or ground-mounted systems are not feasible. While designs vary, typically utility customers are credited with the amount of solar production associated with their share of the PV capacity. Some states have enacted policies to support community solar projects. For example, California SB 43 calls for 600 MW of community solar to be installed in the state by 2019. A barrier that is specific to this business model is the ability of project hosts and participants to benefit from federal or state incentives.[143] Utilities or project developers can overcome this barrier by taking advantage of such incentives. Many utilities, local governments, and others are sponsoring community solar projects.[144]

6.5.1.2 *Distributed Wind*

The wind industry and utility customers have benefited from federal incentives for wind projects, such as ITC. Most distributed wind projects do not use the PTC and therefore have not been as affected by the expiration of the PTC.[a] Figure 6.33 shows the trend for distributed wind in the United States.

[a] The expiration of the PTC has a larger impact for wind installations greater than 1 MW.

Figure 6.33. U.S. distributed wind capacity, 2003–2014 [145]



Annual installations of distributed wind capacity has fallen sharply from its peak in 2012.

The U.S. Department of Agriculture (USDA) provides agricultural producers and rural small businesses grant funding as well as loan financing to purchase or install renewable energy systems.[146] However, wind projects constitute a small and declining amount of funding ($0.4 million in 2014). In addition, several states provide incentives for distributed wind (e.g., Alaska, Iowa, New Mexico, and Oregon).

An important innovation for distributed wind is the third-party leasing model. Leasing and other third-party ownership models for distributed wind are similar to those for solar PV. The model allows a customer to host a wind turbine installed and owned by a third party on the customer's property. The customer then makes monthly payments for wind electricity produced that displaces the customer's electricity consumption. The leasing arrangement can include guaranteed performance, warranties, maintenance, and insurance. Third-party leasing models help transfer key economic and risk barriers from the customer to the lessor, including resource uncertainty, site assessment, performance uncertainty, maintenance and reliability, and avoidance of high initial cost.[147]

6.5.1.3 *CHP*

Many states have targeted CHP deployment using a range of programs and policies that include: [a]

- Setting goals for developing new CHP capacity through legislation or executive order (Figure 7.36.)
- Allowing efficient CHP systems to qualify under energy efficiency resource standards or renewable portfolio standards
- Providing allowance set-asides for CHP in emissions trading programs
- Recognizing CHP's emissions reductions in state air permitting policies by using output-based emissions limits
- Recognizing CHP's emissions reductions in state air quality planning
- Providing incentives for CHP through grants, loans, or tax policies

Currently, 25 states include CHP in their state energy plans, and more than 10 states offer some type of financial incentive for CHP or waste heat and power systems.[148] As of 2014, New York and California added the most new CHP sites (see Figure 7.37.). Both states have had multiyear incentive programs for CHP installations.[149]

To address barriers to CHP in utility regulation, state utility commissions can:

- Establish uniform technical standards, processes, applications, and agreements based on model protocols for interconnecting CHP systems to the electric grid
- Review the electric rates that utility customers with CHP systems pay to stay connected to the grid and receive backup and supplemental power to ensure that all utility charges are based on the utility's actual costs of providing service, to evaluate fixed charges that adversely affect the economics of installing CHP capacity, and to provide incentives for customers to reliably operate and maintain CHP systems.
- Recognize CHP as a solution to needed investments in new generation and distribution system infrastructure
- Consider strategies that enable utilities to invest in CHP facilities at customers' sites while mitigating risk to other ratepayers
- Provide standard offer rates—uniform prices that all CHP systems up to a certain size will be paid for power they sell to the utility, based on actual avoided costs to the utility, recognizing that those costs vary by location, time of day, and other factors—or issue competitive solicitations to determine prices

In particular, state utility commissions can help address barriers to CHP in utility regulation by: (1) establishing uniform technical standards, processes, applications, and agreements for interconnecting CHP systems to the electric grid; (2) by reviewing the electric rates that utility customers with CHP systems pay to stay connected to the grid and receive backup and supplemental power to ensure that all utility charges are based on the utility's actual costs of providing service; and (3) providing standard offer rates—uniform prices that all CHP systems up to a certain size will be paid for power they sell to the utility, based on actual avoided costs to the utility.

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[a] SEE Action Network 2013 describes these policies and programs; also see "Policies and Resources for CHP Deployment," ACEEE, http://aceee.org/sector/state-policy/toolkit/chp, accessed November 10, 2015.

6.5.2 Distributed Storage

As an emerging technology, building owners and operators generally have a poor understanding of energy storage systems, how they operate, and their potential value streams.[150] In addition, storage-related policies are nascent.

High costs and the lack of clearly defined value streams are the most important barriers to the wider-scale deployment of battery storage. Rebates, tax credits, and favorable depreciation treatment can improve the economic viability of storage projects. Demand management programs that provide greater incentives for peak shaving and load shifting can encourage more investment in storage systems.

Permitting and siting barriers are an issue for larger distributed storage applications due to the size and weight of many battery types. In addition, DOE's EAC noted a lack of validated reliability and safety codes and standards.[151] States can adopt best practices from early-adoption jurisdictions—for example, New York's building fire code for Li-ion batteries.

6.5.3 Microgrids

Beyond those barriers that apply to the DER technologies described above, barriers to greater deployment of microgrids are primarily regulatory,[152] as existing regulatory frameworks were set up with the traditional electricity system model of centralized generation, transmission, and distribution.

For a developer, several unique barriers related to microgrids increase project risk and can make the process time-consuming, complex, and expensive:

- Utility franchise rights can lead to litigation.
- The project could be subject to public utility regulation.
- Interconnection procedures and rules governing microgrids' grid-support functions (e.g., volt/volt-ampere reactive [VAR] support) may not be well defined.

Some states are advancing microgrids by providing financial support. Connecticut issued a Microgrid Grant and Loan Program in 2013 and another solicitation in 2014 (allotting $23 million to 11 projects). California, Massachusetts, New Jersey, and New York have microgrid programs and solicitations under way.[153] For example, the New York State Energy Research and Development Authority (NYSERDA) recently funded feasibility studies for 83 microgrid proposals as part of the "NY Prize" ($8.3 million).[154] The next phase will include state assistance in engineering for selected projects, and the final phase will include state funding for construction. The total announced budget for completion is $40 million.

6.5.4 Demand Response

Five policy principles are contained within the QER's "Policy Framework for the Grid of the Future." One of those states that "the future grid should encourage and enable energy efficiency and demand response to cost effectively displace new and existing electric supply infrastructure, whether centralized or distributed."[155]

An *energy efficiency resource standard* (EERS) is a quantitative, long-term energy savings target for utilities that can include targets for peak load demand reduction as well as energy efficiency (see Chapter 1). In addition, state legislation or PUC regulations can establish discrete demand response goals. For example, in Arizona demand response programs are eligible for cumulative electricity sales reduction goals through 2020; California sets goals for peak demand reduction through 2020; and Ohio set peak demand reduction targets through 2018. Delaware, Maryland, Pennsylvania, Texas, and Wisconsin have all set peak demand reduction targets.[156] While interruptible load that participates in real-time energy markets cannot be counted toward these targets, the peak demand requirements in a state's energy efficiency resource standard, or the greater value of energy efficiency at peak times as demonstrated in a utility's integrated resource plan or energy efficiency plan, could provide additional incentives for efficiency measures that reduce load at peak times.

The legal and regulatory environment for demand response is highly dynamic and evolving at both the national and state levels. For example, on January 25, 2016, the U.S. Supreme Court upheld FERC's authority to regulate demand response programs in wholesale electricity markets (FERC Order 745).[157] In May 2014, the FERC order had been vacated by the U.S. Court of Appeals on the basis that the agency was encroaching on the state's exclusive legal right to regulate electricity markets. The FERC order aims to ensure that demand response providers are compensated at the same rates as generation owners. This ruling is also expected to provide a more favorable environment for demand response market growth by facilitating the participation of third parties to aggregate demand response resources.

The following are state and federal activities that are currently being implemented to help overcome barriers to demand response, described at the beginning of Section 6.5:

- Deployment of common information models and protocols such as OpenADR, Smart Energy Profile 2.0, and Green Button
- Continuing evaluation of new demand response programs and rate structures
- Making time-varying pricing more widely available, especially as the default rate design
- Customer education and engagement, such as behavior-based programs for utility customers that combine time-varying pricing with communication strategies designed to engage customers—for example, personalized energy-saving tips, immediate feedback on results, and comparisons with similar households
- Deployment of enabling technologies such as AMI
- Broadening the demand response market beyond existing programs
- New program administration and enrollment models that incorporate third-party (non-utility) aggregators

The following are recent examples of state regulatory actions that have impacted demand response:[158]

- The CPUC will require default TOU rates for residential customers in 2019 and is working with CAISO and the California Energy Commission to create a market for demand response and energy efficiency resources.[159]
- In 2014, Massachusetts ordered its electricity distribution companies to file TOU rates with CPP as the default rate design for residential customers once utility grid modernization investments are in place.[160]
- In 2015, the Michigan Public Service Commission directed DTE Electric to make TOU and dynamic peak pricing available on an opt-in basis to all customers with AMI by January 1, 2016. Similarly, Consumers Energy must make TOU available on an opt-in basis by January 1, 2017.
- Also in 2015, the New York Public Service Commission released a regulatory framework and implementation plan (Reforming the Energy Vision) to align electric utility practices and the state's regulatory framework with technologies in information management, power generation,

and distribution. A related measure in 2014 approved a $200 million Brooklyn-Queens demand management program which includes 41 MW of customer-side measures, including demand response, distributed generation, distributed energy storage, and energy efficiency, to defer cost-effectively approximately $1 billion in transmission and distribution investment.
- In June 2015, the Pennsylvania PUC set a total peak demand reduction of 425 MW for electric distribution companies by 2021, against a 2010 baseline.
- In Rhode Island, demand response is continuing to be tested in pilot programs by National Grid and will be incorporated in analysis for "non-wires alternatives"[a] to traditional utility infrastructure planning.

At higher penetration levels of wind and solar (variable) energy resources, policies and regulations that enable greater penetration of demand response in grid services markets are likely to become increasingly important:[161]

- Allowing demand response providers to participate in energy markets—In many markets, demand response aggregation for participation in energy markets is not allowed.
- Modifying telemetry and metering requirements—Telemetry and metering requirements have been set up historically for generation-side resources and may be too onerous for demand response participation in grid markets.
- Adoption of capacity markets that provide up-front payment to capacity additions that could include demand response resources—Year-ahead capacity markets with up-front payment exist in some ISO/RTO markets such as PJM, but not all markets.

Recent proposals from CAISO are highlighted here to illustrate each of these points. It recently announced plans to create a new class of grid market players, known as *distributed energy resource providers,* to serve grid markets. These could be energy service companies that aggregate many discrete DERs to bid into CAISO energy markets. CAISO has imposed constraints on the size required for bids (>500 kW to participate) as well as proposed modifications to telemetry and metering requirements that would make it easier for energy service aggregators to participate. Specifically, a DER provider participating in the ISO's wholesale energy markets will not be required to provide telemetry if they are under 10 MW in size. However, real-time visibility is required in the case of ancillary market participation.[162]

In terms of metering requirements, instead of requiring each subresource that is aggregated to have a direct metering feed to the ISO, CAISO is allowing a delegation of meter and meter data arrangements to the scheduling coordinator.[163]

Another CAISO proposal would create a demand response auction market. Under the proposal, demand response providers would receive an up-front payment for electricity reductions they promise to deliver in the coming year, providing an attractive incentive for new market entrants. Similar capacity auctions have expanded demand response markets in other parts of the country, including the large-scale capacity auction in PJM, which has supported the nation's largest demand response market. One key difference from the PJM capacity market is that the CAISO proposal would seek to enable flexible capacity—in other words, the ability to shift customer loads in time to provide better matching of load to generation supply, as well as future peak load reductions.[164]

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[a] Non-wires alternatives to distribution and transmission investments include demand response, energy efficiency, distributed generation, energy storage, volt VAR optimization, and dynamic pricing.

6.6 Interactions with Other Sectors

The DER sector is interconnected with all of the electricity market sectors described in this report: residential, commercial, industrial, and transportation. Distributed generation continues to grow for both residential and nonresidential buildings, and more on-site energy storage is projected in the future for all market sectors. ZNEB targets may become a greater driver for distributed generation, and providers of solar PV and storage are emphasizing the greater energy security that integrated generation and storage systems can provide. CHP is already widely deployed in the industrial sector and is a growing presence in the commercial sector as a good fit for campuses, hotels, and hospitals, among other applications.

Demand response programs are active in the residential, commercial, and industrial sectors, and time-varying pricing tariffs for electric vehicle charging are beginning to be developed. Aggregation of demand response for residential consumers is an emerging area with significant potential.

Storage is inherently crosscutting (Table 6.14). For example, in the transportation sector, growing PEV adoption increases the volume of batteries produced, contributing to cost reduction in batteries for stationary applications in the residential and commercial sectors. Further, used PEV batteries could contribute to the supply of batteries for stationary storage applications. In addition, PEV fleets enable aggregation of a collection of batteries as a storage and demand response resource.

Table 6.14. Crosscutting Nature of Energy Storage[165]

Crosscutting theme description	Crosscutting technology	Sectors affected
Energy storage is important to a modernized electric grid, and also for electric vehicles, albeit with vastly different requirements. Flexible, low-cost, high round-trip-efficiency storage technologies can provide short term (frequency support) and long-term (firming, arbitrage) services to the electricity system. Alternatives to hydrocarbon fuels such as hydrogen and batteries are under investigation for electric vehicles. Fundamental research on development and manufacturing of efficient, durable, low-cost, high energy-density storage could enable transformational change across multiple sectors.	Batteries	**Transportation**, Grid, Manufacturing
	Hydrogen	**Fuels**, Transportation, Manufacturing, Power, Grid
	Thermal storage	**Power**, Grid, Buildings
	Flywheels	**Grid**, Transportation
	Pumped hydro, compressed air energy storage	**Grid**, Power

Storage affects all electricity market sectors (residential, commercial, industrial, and transportation) as well the electricity grid itself.

Energy efficiency and DERs have many existing and several emerging interactions. CHP systems can offer much higher system-wide energy efficiency than grid-supplied electricity and conventional heating or steam systems. In the context of ZNEBs, building envelope construction, heating, ventilation, and air conditioning (HVAC) equipment selection, and on-site distributed generation can be optimized for least cost and design objectives. Finally, greater penetration of variable renewable sources of electricity is anticipated to drive the need for more flexible capacity on the supply side and more flexible loads on the demand side.[166] Energy efficiency will continue to be a key focus area in all sectors, and demand response programs that can provide either flexible capacity or flexible loads are expected to grow. In some cases there may be a balancing or trade-off of higher energy losses versus increased flexibility (e.g., pre-cooling a building or pre-heating water can increase energy consumption but reduce peak load and improve system flexibility). To ensure a robust and cost-effective future electricity system operation meeting all service and environmental requirements will require dynamic controls, advanced sensors, and communication systems with sophisticated control software.

6.7 Research Gaps

Fundamental research questions for demand response, distributed generation and distributed storage include the following:

- What changes in policies and regulations, and what types of market designs, are needed to integrate and optimize the use of these DERs in the electric system?
- What frameworks, methods, processes, and tools are needed?
- What are these resources worth, and how should valuation be determined?

Another policy question is how to ensure access to DERs in low-income communities, including programs that provide enabling technology and financial incentives for demand response.

Three other key research themes are described below.

6.7.1 Modeling and Simulation

DOE's 2015 Quadrennial Technology Review (QTR 2015) highlights the need to develop high-fidelity planning models, tools, simulators, and a common framework for modeling, especially based on probabilistic models that can account for uncertainties in demand-side and supply-side resources, technology, markets, and policies. QTR 2015 further points toward the need to perform scenario analysis on potential future energy systems that are radically different from today's systems due to significant uptake of architecture-altering technologies—for example, decentralized electricity systems with high adoption of distributed generation and storage. This may include more detailed and integrated modeling of the distribution system and addressing the following questions:

- What is the optimal locational placement of DERs within the distribution system?
- What are the limits and limitations of DER penetration on the existing distribution system?
- What are the benefits of community solar and storage systems?
- What strategies and approaches lead to least-cost implementation for distribution upgrades and replacements for conventional utility investments?

In addition, climate change is widening the temperature probability distribution toward more frequent and intense heat events, as well as increasing the mean temperature.[167] This could translate into some regions having a higher summer peak load than what is currently modeled in existing projections for peak load. That raises additional research questions. For example, how should predictions for climate change be taken into account in projecting future electricity demand and the potential role of demand response, distributed generation, and distributed storage in meeting those changing demands cost-effectively?

6.7.2 Impacts of Higher DER Adoption on the Electric System and Stakeholders

Developments in DER technology and IT are enabling electricity service with much greater degrees of freedom for both supply and demand. This offers multiple value streams (e.g., energy, capacity, reactive power, frequency support, deferred utility capital expenditures, energy security, and avoided emissions). At the same time, regulators must ensure the safety and reliability of the electricity system and balance the interests of regulated electric utilities, competitive markets, customers, and the public interest.

Key research questions in this area include the following:

- What are the implications of various regulatory mechanisms for DERs on safety and reliability of the electric system?
- What are the financial impacts of high levels of DERs on electric utilities and utility customers? What data, methods, and tools are needed to characterize costs and benefits and optimize deployment strategies, and what changes in ratemaking and regulation are needed to mitigate financial impacts on utility shareholders and customers?
- What tariff designs can appropriately compensate DERs for multiple value streams while maintaining principles of rate design (e.g., economic efficiency, equity/fairness, and customer satisfaction)? What tariff designs appropriately charge DER customers for the services they need from the electric grid?
- Who controls the various streams of (big) data and manages data-sharing among third parties?

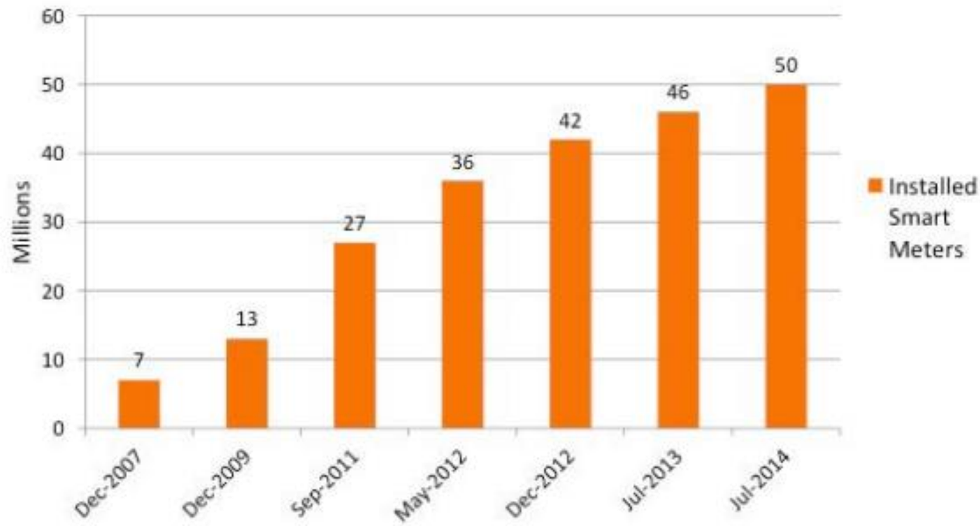
6.7.3 Policies and Regulations for Distributed Storage

Distributed storage, including adoption of PEVs with battery storage, could be a transformative technology.[168] Key policy questions include:

- What policies and regulations would facilitate pairing distributed storage with distributed generation or demand response to provide value to utility customers, utility systems, and society?
- What policies, regulations, and protocols would best help to integrate mobile distributed storage (i.e., PEVs) into the distribution system to facilitate electrification of the transportation sector?
- Beyond mandatory energy storage requirements, what policies, regulations, and programs would remove barriers to deployment of cost-effective energy storage?

Distributed Energy Resources Appendix

Figure 7.32. Smart meter deployment[169]



As of July 2014, 50 million smart meters were deployed in the United States, covering 43% of U.S. homes.

Figure 7.33. CHP is located in every state[170]

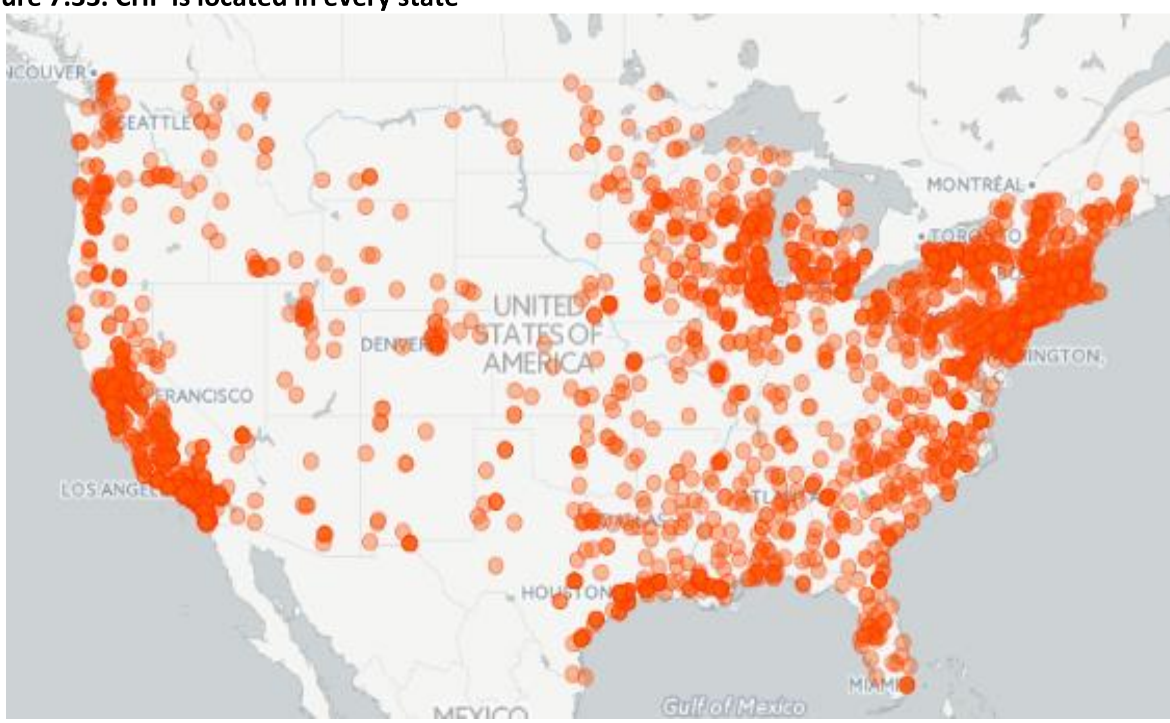
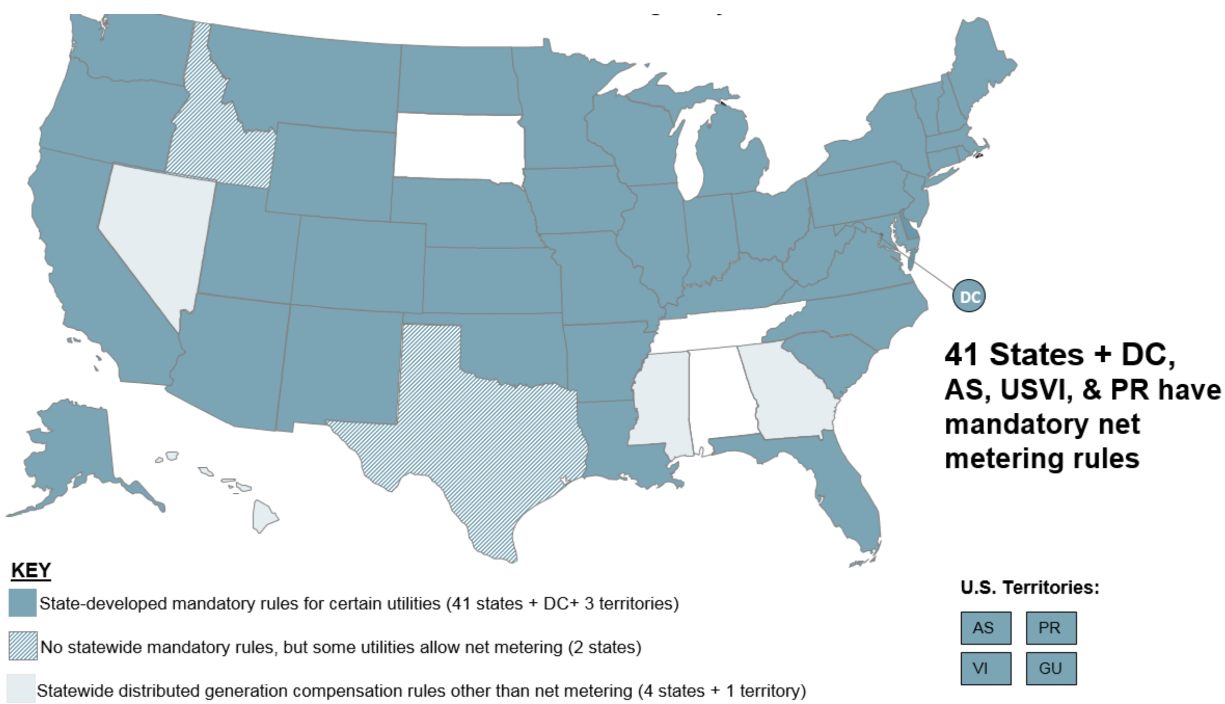


Figure 7.34. Existing CHP capacity by state in 2012[171]

Alaska and Hawaii had 479 megawatts (MW) and 434 MW of CHP capacity in 2012, respectively.

Figure 7.35. States with net metering rules, as of July 2016[172]



Note: states without color do not have net metering rules.

Figure 7.36. Customer credits for monthly net excess generation (NEG) under net metering[173]

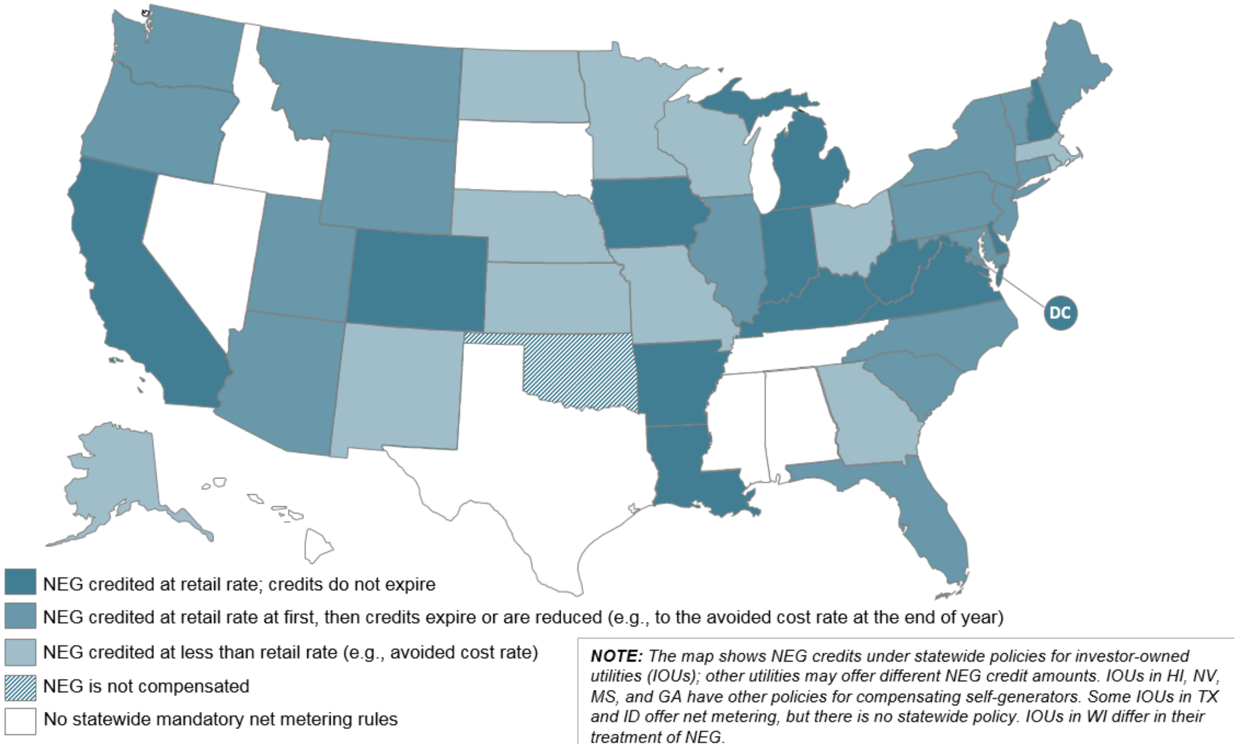
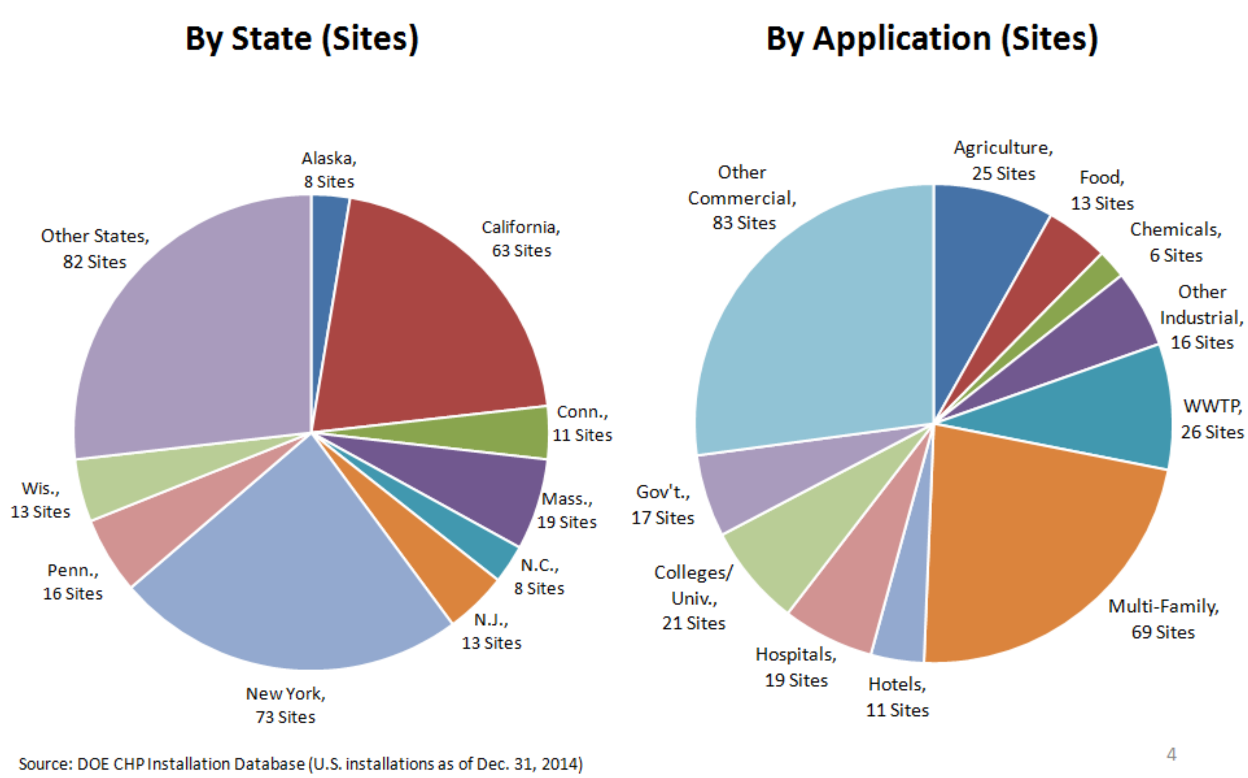


Figure 7.37. CHP additions in 2013 and 2014[174]



CHP was installed at 306 sites in the two-year period. New York and California had the most new sites.

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