

Electricity Generation Baseline Report

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Scope and Organization

The report focuses specifically on U.S. power sector generation. The report limits itself to the generation sector and does not address in detail parallel issues in electricity end use, transmission and distribution, markets and policy design, and other important segments. The report focuses specifically on U.S. power sector generation. The report limits itself to the generation sector and does not address in detail parallel issues in electricity end use, transmission and distribution, markets and policy design, and other important segments.

Chapter 1 provides a brief introduction to the report.

Chapter 2 of the report focuses on the main drivers of change, as well as future uncertainties, in the U.S. generation sector. These include the impact of low natural gas prices; the rise of renewable and distributed generation; recent Federal and State policies impacting generation; the decoupling of gross domestic product (GDP), electricity demand, and greenhouse gas (GHG) emissions; and the electrification of the transportation sector.

Chapter 3 discusses crosscutting metrics and trends in the U.S. generation sector. These attributes include generation roles, capacity factors and heat rates, costs, sustainability characteristics, ownership types, and Federal policy.

Chapter 4 describes recent trends in power generation, focusing on the national and regional levels at the North American Electric Reliability Corporation (NERC) boundaries.

Chapters 5 through 13 focus on individual generation technologies and provide information on technology cost and performance trends, fuel supply, environmental impacts, constraints, existing deployment metrics, and policy and regulatory drivers that have impacted deployment and could affect future development.

Appendix A contains additional information about each generation technology. Appendix B contains details on the levelized cost of electricity (LCOE) methodology used in chapter 3 and throughout.

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Abbreviations

AC	alternating current
AEO2015	<i>Annual Energy Outlook 2015</i>
AMD	acid mine drainage
Btu	British thermal unit
BWR	boiling water reactors
CC	combined cycle
CCS	carbon capture and storage
CO ₂	carbon dioxide
CPP	Clean Power Plan
CSP	concentrating solar power
CT	combustion turbine
CWIP	construction work in progress
DC	direct current
DOE	U.S. Department of Energy
EGS	enhanced geothermal systems
EIA	U.S. Energy Information Administration (DOE)
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EPSA	Office of Energy Policy and Systems Analysis (DOE)
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FERC	U.S. Federal Energy Regulatory Commission
FORGE	Frontier Observatory for Research in Geothermal Energy
FRCC	Florida Reliability Coordinating Council
GDP	gross domestic product
GHG	greenhouse gas
GW	gigawatt
GWd/MTU	gigawatt-days per metric ton uranium
GWe	gigawatt electrical
GWh	gigawatt-hour
HOGR	High Oil and Gas Resource
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IGCC-CCS	integrated gasification combined cycle–carbon capture and storage
IOU	investor-owned utility
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LACE	levelized avoided cost of electricity
LBNL	Lawrence Berkeley National Laboratory

LCOE	levelized cost of electricity
LFG	landfill gas
LWR	light water reactor
MHK	marine and hydrokinetic
MISO	Mid-Continent Independent System Operator
MMBtu	million British thermal unit
MRO	Midwest Reliability Organization
MSW	municipal solid waste
MW	megawatt
MWe	megawatt electrical
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NGCC	natural gas combined cycle
NGCT	natural gas combustion turbine
NMVOC	non-methane volatile organic compound
NO _x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
O&M	operation and maintenance
ORNL	Oak Ridge National Laboratory
PC	pulverized coal
PEV	plug-in electric vehicle
PJM	Pennsylvania, New Jersey, Maryland Interconnection
PMA	Power Marketing Administration
PPA	power purchase agreement
PSH	pumped storage hydroelectric
PTC	production tax credit
PURPA	Public Utilities Regulatory Policy Act of 1978
PV	photovoltaics
PWR	pressurized water reactor
QER	<i>Quadrennial Energy Review</i>
R&D	research and development
RFC	ReliabilityFirst Corporation
RDD&D	research, development, demonstration, and deployment
RPS	renewable portfolio standards
RTO/ISO	Regional Transmission Organization/Independent System Operator
SERC	SERC Reliability Corporation
SMR	small modular reactor
SO _x	sulfur oxides
SPP	Southwest Power Pool
ST	steam turbine
Syngas	synthesis gas

TRE	Texas Reliability Entity
TVA	Tennessee Valley Authority
TWh	terawatt-hour
VER	variable energy resource
WECC	Western Electricity Coordinating Council
WEO	<i>World Energy Outlook</i>
WWTP	waste water treatment plant

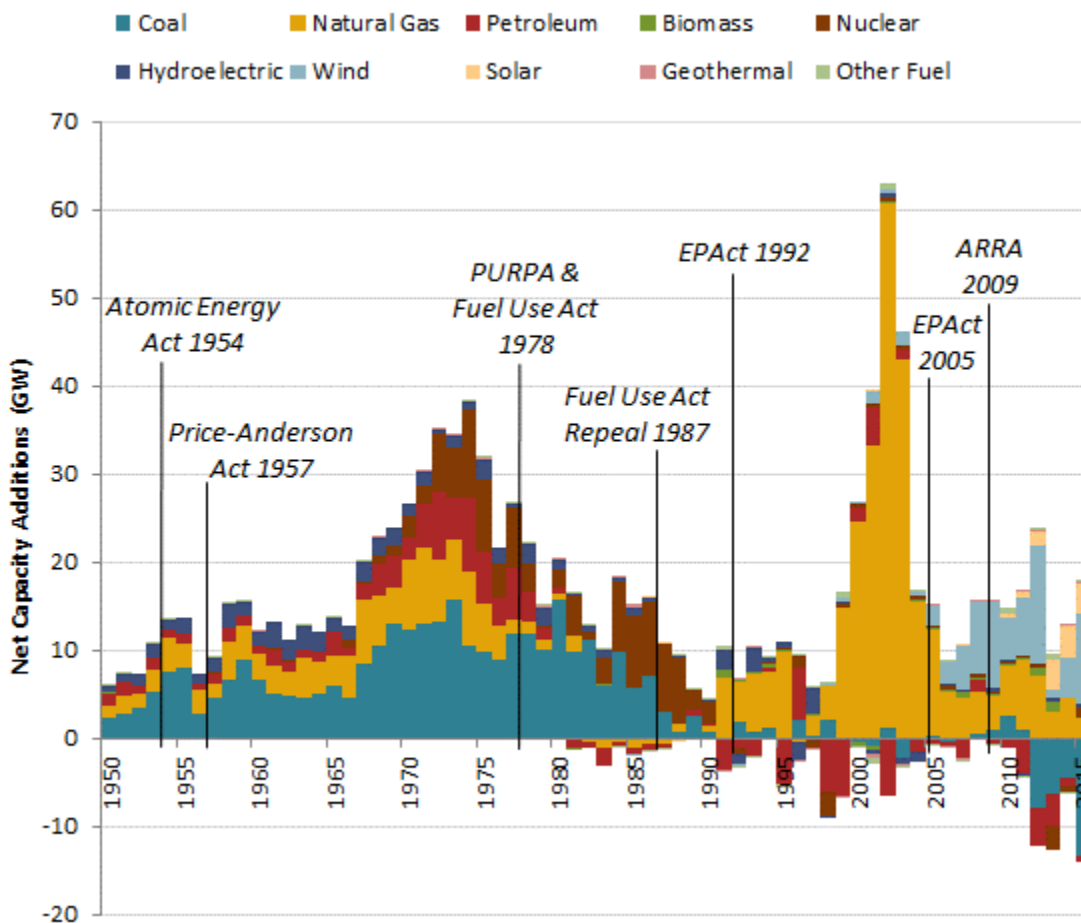
Executive Summary

The share of electricity generation in the United States from different sources has arguably changed more rapidly since 2007 than at any time since 1950. At least three trends are catalyzing these changes: (1) the low price of natural gas; (2) the rise in renewable and distributed generation; and (3) recent Federal and State policies impacting generation. Understanding these trends and phenomena in the context of the history of generation, potential for additional generation, constraints, and comparative characteristics that drive generation investment is essential to identifying policies and measures that will facilitate the development of a generation fleet that meets U.S. objectives for the 21st century. These objectives include the U.S. goal of reducing net GHG emissions 26–28 percent below 2005 levels by 2025.

Set forth below are 15 key findings and supporting information derived from this report.

1. Diversity is a key attribute of generation in the United States, but rather than being the result of a deliberative, long-term national initiative, this diversity has developed through growth spurts of specific generation technologies at different times, often due to a confluence of policies, historic events, fuel cost, and technological advancements¹.
 - As shown in Figure ES-1, most generation sources have enjoyed eras of significant growth: hydro (1930–1950); nuclear (1960–1980); natural gas (1990–2010); and renewables (2005–present).

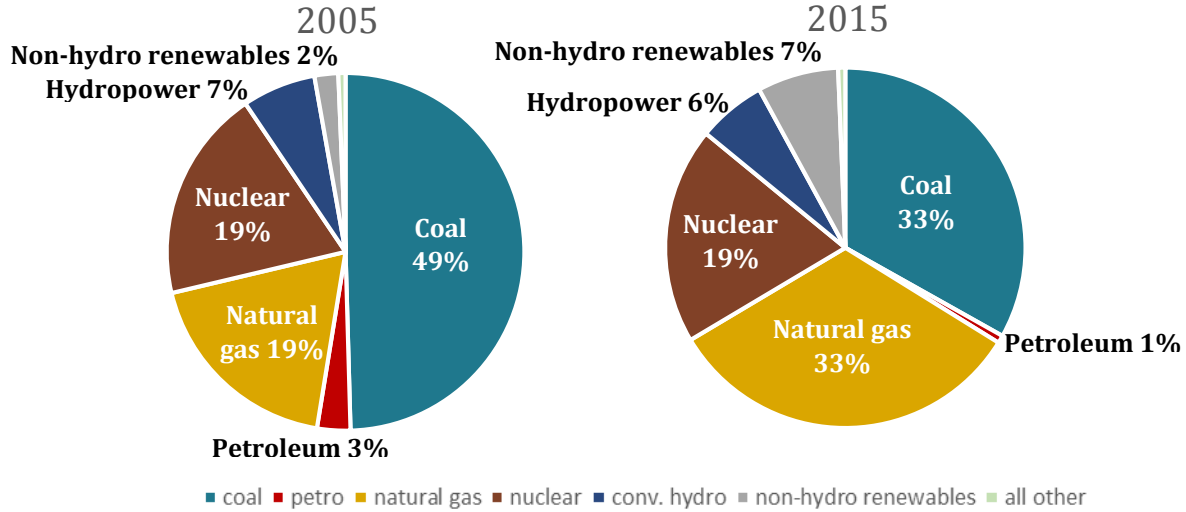
Figure ES-1. Net capacity additions (GW) by fuel type, 1950–2015



Capacity additions came in waves that were largely influenced by policy and technology. The 1930s and 1940s fostered the development of hydropower; nuclear power boomed in the 1960s and 1970s; natural gas additions peaked in the 2000s; and non-hydro renewables have grown in the 21st century. Sources: EIA 1990 and EIA 2016².

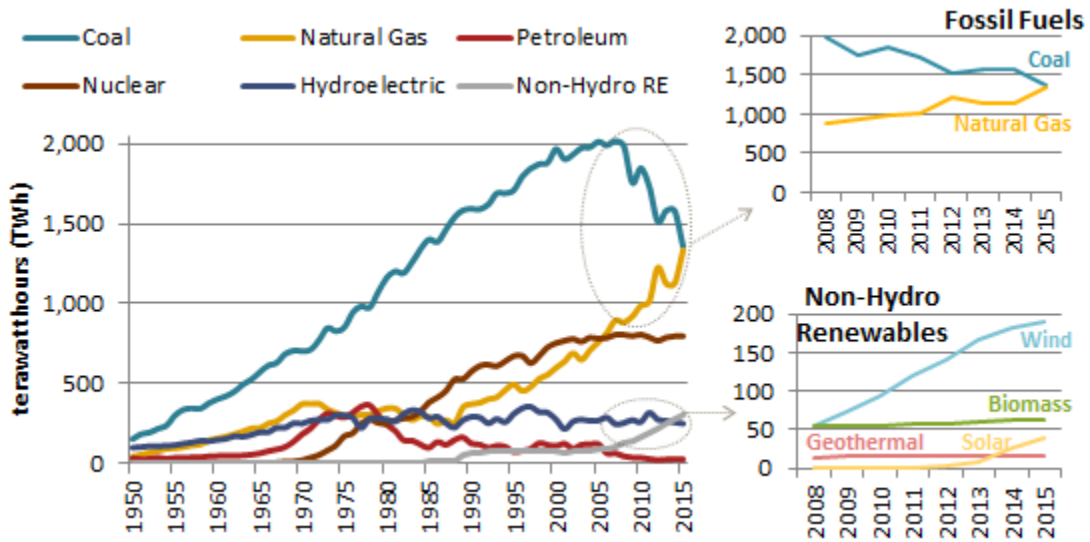
2. The national generation mix has realigned over the past few decades, and continuing significant changes are forecast. The U.S. generation fleet is transitioning from one dominated by centralized generators with high inertia and dispatchability to one that is more hybridized, relying on a mixture of traditional, centralized generation and variable utility-scale and distributed renewable generation³.
 - From 2005 to 2015, the generation mix has changed significantly. In 2005, the top six generation sources in descending order were coal, nuclear, gas, hydro, petroleum, and renewables. By 2015, gas and coal were tied at the top, followed by nuclear, renewables, hydro, and petroleum (Figure ES-2 and Figure ES-3).

Figure ES-2. Annual net generation from all sectors



Natural gas and non-hydro renewable generation grew from 2005 to 2015, while coal and petroleum generation decline. Source: EIA 2016⁴

Figure ES-3. Annual generation from select technologies in the United States, 1950–2015 (left), and generation from coal and natural gas (right-top) and non-hydro renewables (right-bottom), 2008–2015.

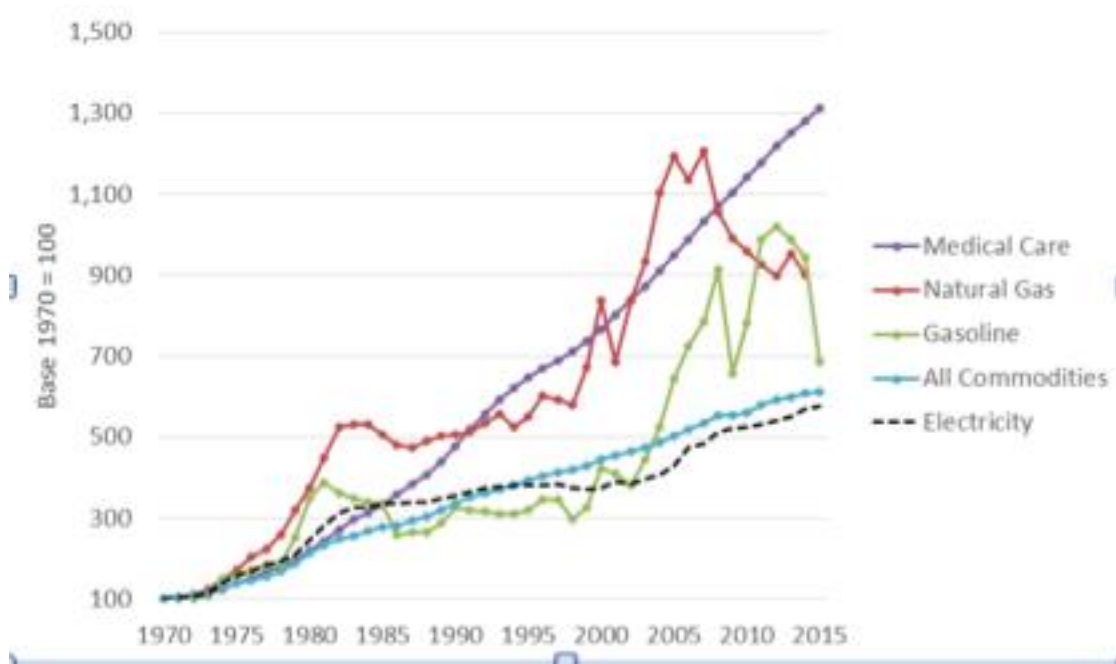


Coal generation began to decline in 2007, and has largely been replaced by natural gas. Although solar and wind make up a much smaller portion of total generation, these technologies have also seen significant growth since 2008.. Sources: EIA 2016⁵.

3. Retail electricity prices have risen over time but have grown more slowly than prices for other essentials for quality of life. However, costs of production vary significantly among generation sources (Figure ES-4).

ⁱ Note that solar data started including generation from distributed PV resources in 2014.

Figure ES-4. Comparison of electricity, natural gas, gasoline, medical care, and all commodities prices, 1970 – 2015 (1970\$)



Electricity prices have risen over time, but less in comparison to other commodities.

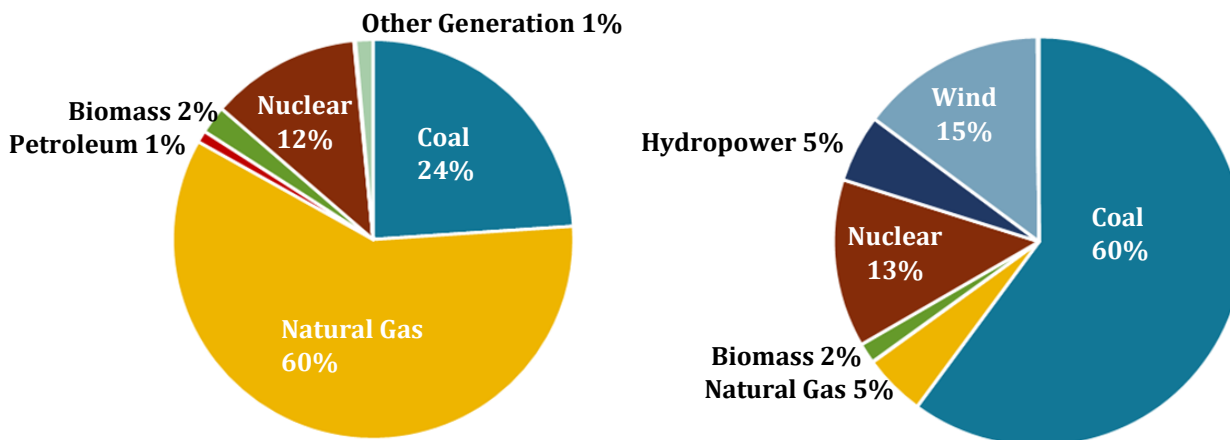
Source: EIA 2016 and BLS 2016⁶

4. Ownership can be a factor in whether Federal and State policies drive generation because incentives and regulatory treatment vary depending on the type of ownership. It should be noted, however, that ownership itself is impacted by federal policy.
 - Federal utilities are not subject to State law; municipally and cooperative-owned utilities often receive different treatment than investor-owned utilities (IOUs) in Federal and State regulations, as well as different financing mechanisms, including eligibility for tax credits for solar and wind.
 - Ownership impacts management, rate setting, financing, and tax status.
 - The Federal Government owns 49 percent of hydropower capacity, but many of the hydropower dams are multipurpose.
 - Examples of ownership created by Federal policy include The Tennessee Valley Authority Act of 1933 and the Public Utility Regulatory Policies Act.
5. Regional generation mixes vary significantly from the national mix, and there are major differences among the regions, both in terms of generation mix and additions and retirements of capacity. Based on announced additions and retirements, there appears to be no trend toward reducing regional variation⁷.
 - The Florida Reliability Coordinating Council (FRCC) and the Midwest Reliability Organization (MRO) vary greatly from the national generation portfolio, with significant differences between them (Figure ES-5). In FRCC, 60 percent of

generation came from natural gas, 24 percent from coal, and 12 percent from nuclear in 2014. That same year, the MRO generated 60 percent of electricity from coal, 15 percent from wind, and 13 percent from nuclear. Nationally, the greatest contribution to the generation portfolio in 2015 was from coal at 33 percent significantly less than the largest source in these regions (Figure ES-2).

- The Western Electricity Coordinating Council (WECC) has the highest shares of renewable capacity and generation among NERC regions. WECC has some of the highest shares of hydro generation, at 22 percent (Figure ES-6). The region’s primary fuel source is natural gas, which represented 30 percent of generation in 2014. WECC has the most diverse portfolio (measured by HH Indexⁱⁱ) at 0.22, with eight generation sources contributing 2 percent or greater to the portfolio. Nationally, the HH Index of the generation portfolio is 0.26, where a lower number indicates a more diverse portfolio.
- The SERC Reliability Corporation (SERC) is the only region with new nuclear capacity expected to come online in the near term (2016–2020), with over 5 gigawatts (GW) expected by roughly 2020 (Figure ES-7).

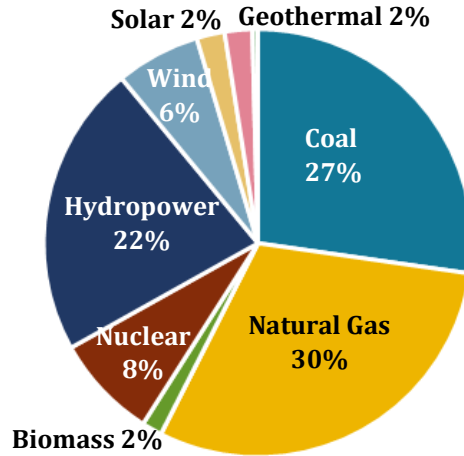
Figure ES-5. Percentage of generation by fuel, 2014: FRCC (left); MRO (right)



In FRCC, 60% of generation came from natural gas, while MRO generated 60 percent of electricity from coal. Nationally, the greatest contribution in 2014 was from coal at 39 percent, significantly less than the largest source in these regions. Source: SNL 2015⁸.

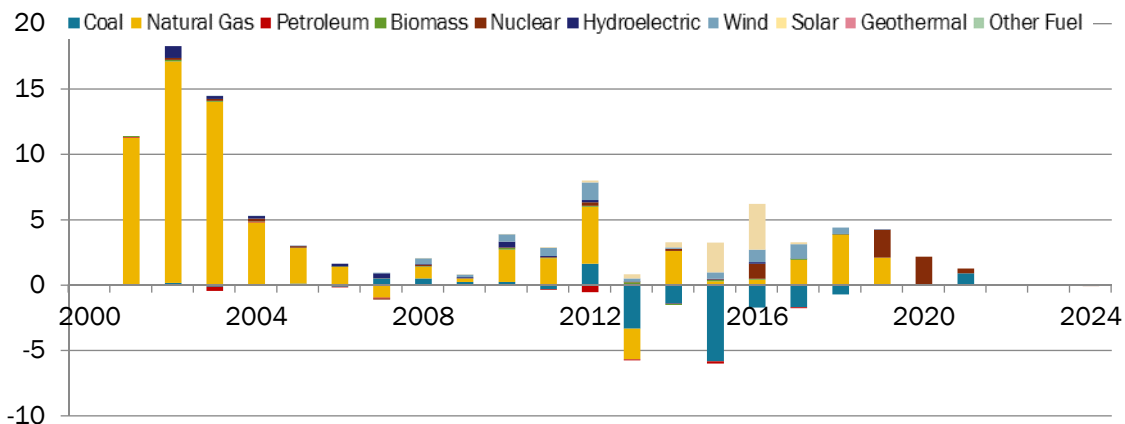
ⁱⁱ HH Index is a market concentration measure used by regulators such as the U.S. Department of Justice to determine whether individual companies have a large enough market share to exert control over prices. It is calculated as the sum of the squares of all of the markets shares of each company within a market.

Figure ES-6. Percentage of generation by fuel in 2014 in the WECC region



In 2014, WECC had the most diverse generation portfolio, with eight generation sources contributing 2 percent or greater to the portfolio. Source: SNL 2015⁹.

Figure ES-7. SERC net capacity additions or retirements (GW) by fuel, 2000–2024



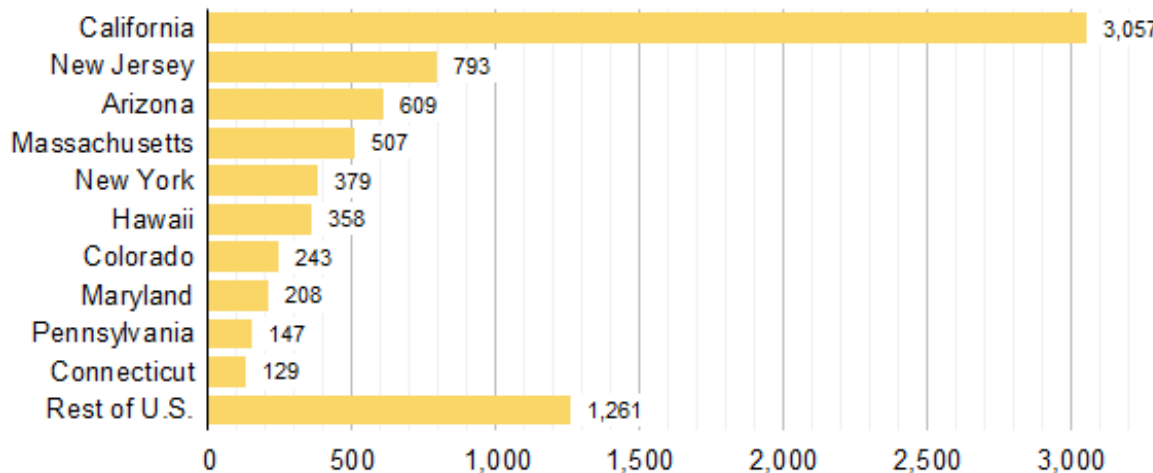
SERC is the only region the United States that has planned nuclear capacity additions. Historical additions/retirements as of 2014 are reported; future additions/retirements are announced. Source: SNL 2015¹⁰.

6. The forecasted shift in generation has positive and negative implications for GHG emissions as there are large variations in growth trends and GHG emissions among the generation sources¹¹.
 - Nuclear power currently provides the largest share of GHG emission-free electricity in the United States. In 2015, nuclear was providing 20 percent of U.S. electricity and 59 percent of its carbon-free electricity. However, more nuclear plants are retiring than being constructed due to low prices in electricity markets and high capital costs.
 - Hydroelectric power, another GHG emission-free source of electricity, contributed 6 percent of electricity generated in the United States in 2015 and is projected to have relatively flat growth, despite significant potential for expansion.

- Non-hydro renewable generation, another GHG emission-free source, is growing exponentially but still represented only 7 percent of total generation as of 2015.
 - Coal generation currently is responsible for the largest share of carbon dioxide (CO₂) emissions from the electric power sector. Coal-fired capacity saw its last notable deployment in 2010 as plants planned before the financial crisis of 2008 came online. There were roughly 25 GW of coal retirements from 2012–2014, and there were 13 GW of coal retirements in 2015. The coal units that were retired in 2015 tended to be smaller and older (average age is 54 years, and the rest of fleet that continues to operate has an average age of 38 years)¹².
 - Natural gas generation has less than 50 percent of the burner-tip carbon emissions compared to conventional coal generation. This has positive implications for replacing coal in the short run but not compared to non-GHG emitting generation options such as nuclear and hydropower. Over the longer term, all emissions from natural gas generation will become more important to consider given expected carbon mitigation needs.
 - Natural gas and coal would need carbon capture and storage (CCS) to achieve nearly zero GHG emissions, and the combined technologies needed to achieve CCS are in the first-of-its-kind phase in the United States.
7. There is significant variation among the states with regard to electricity imports and exports. Where sales exceed generation, the state runs an electricity deficit and must import energy. Several states stand out as large net importers (measured in gigawatt-hours [GWh]): California, Virginia, Massachusetts, Tennessee, and Ohio. Massachusetts is particularly notable for its small size but large quantity of net imports. Proportional to its total sales, Massachusetts far exceeds any other state in net imports. Idaho and Delaware, while not large net importers in terms of total energy, import high percentages of their total sales (section 4.6).
 8. Changes in electricity markets, fleet composition, and usage patterns in recent years have seen power plant operators and engineering, permitting, and construction vendors adapt both coal and nuclear plants for more flexible operation. However, flexible operation can come at a cost: reduced efficiency, higher emissions, and increased wear and tear on the equipment, which increases maintenance costs.
 9. The national average heat rate for natural gas plants shows a significant decline (i.e., improved efficiency) since 2003; however, analysis shows the average heat rate for the fleet of natural gas combined cycle (NGCC) plants has remained steady since 2007. For gas-fired combustion turbines (CTs), heat rate has declined modestly, and the overall decline is due to the increased deployment of NGCC plants¹³.
 10. Wind and solar generation have recently been experiencing exponential growth due to technological advances and reductions in cost, but their national market generation share totaled only 5.6 percent in 2015, and much of their projected accelerated growth is due to recently enacted tax credit extensions¹⁴.
 11. Although distributed solar accounted for less than 0.3 percent of the national generation mix in 2015, it accounted for 31 percent of total photovoltaic (PV) generation, and in some states,

such as California and Hawaii, deployment has been growing rapidly due to favorable conditions and policies (see Figure ES-8).

Figure ES-8. Distributed solar PV installed capacity (MW), top 10 states, as of September 2015



California had more installed distributed PV capacity than the rest of the U.S. combined as of September 2015.

Source: EIA 2015¹⁵.

12. Wind generation represents the highest percentage of non-hydro renewables in the national generation mix, and utility-scale wind represents the highest percentage compared to utility-scale solar, distributed solar, and distributed wind¹⁶.

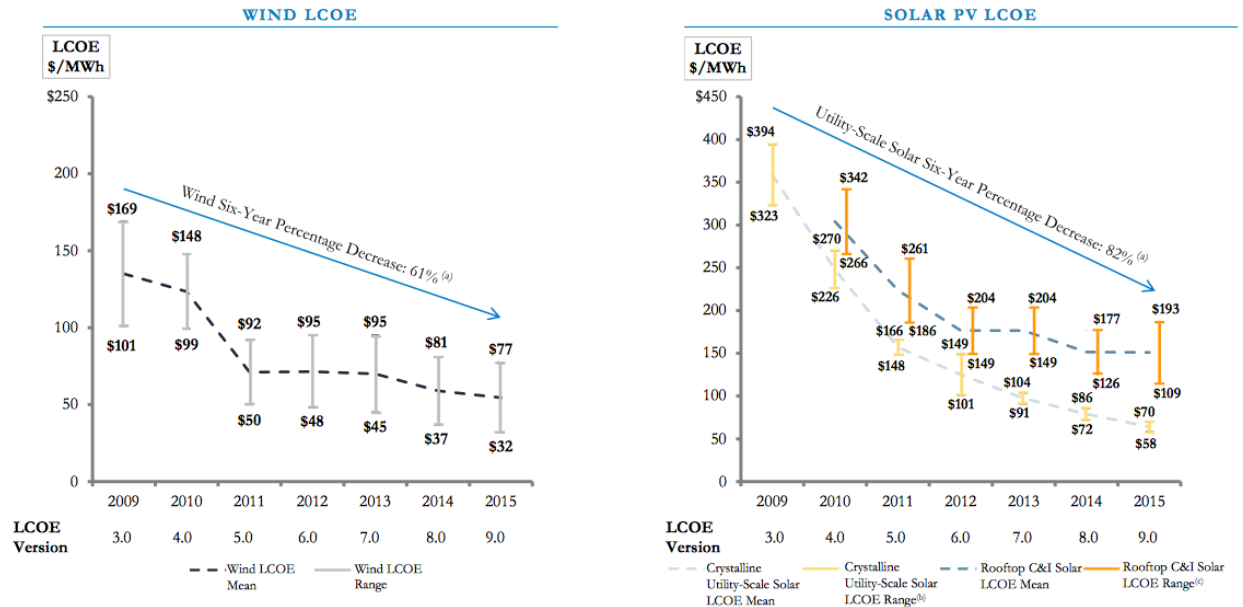
- Wind generation climbed from 18 terawatt-hours (TWh) in 2005 to 191 TWh in 2015, a more than tenfold increase, but still only accounted for approximately 4.7 percent of total net generation at the national level. At the end of 2015, wind generation exceeded 15 percent of net in-state generation in eight states: Iowa, South Dakota, Oklahoma, Kansas, North Dakota, Minnesota, Idaho, and Vermont. The extension of the production tax credit (PTC), passed in December 2015, is expected to further expand the deployment of wind energy in the United States.
- Distributed wind capacity (i.e., turbines of no more than 1 megawatt [MW]) reached a cumulative capacity of almost 1 GW in 2015.

13. Utility-scale solar and wind are experiencing substantial cost improvements and making inroads against other utility-scale generation. While there are emerging opportunities to address intermittency, it remains a significant challenge¹⁷.

- Utility-scale solar PV cost reductions have been significant, with organizations like Lazard reporting a decline in levelized cost of electricity (LCOE) for utility-scale PV projects of 82 percent between 2009 and 2015 (right side of Figure ES-9). Wind generators have enjoyed similar cost reductions and technology improvements (left side of Figure ES-9), with Lazard estimating a 61 percent reduction in LCOE over the same time frame.

- As of November 2015, DOE’s SunShot Initiative is more than 70 percent of the way to achieving SunShot’s cost target of \$0.06 per kilowatt-hour (kWh) for utility-scale solar PV electricity¹⁸.

Figure ES-9. Change in U.S. LCOE for wind and PV, 2009–2015



LCOE for wind and solar have decreased dramatically since 2009, which has increased their deployment across the United States. Source: Lazard 2015¹⁹.

14. Several low-GHG generation types have barriers that result in untapped resource potential, early closures, and/or unvalued grid services:

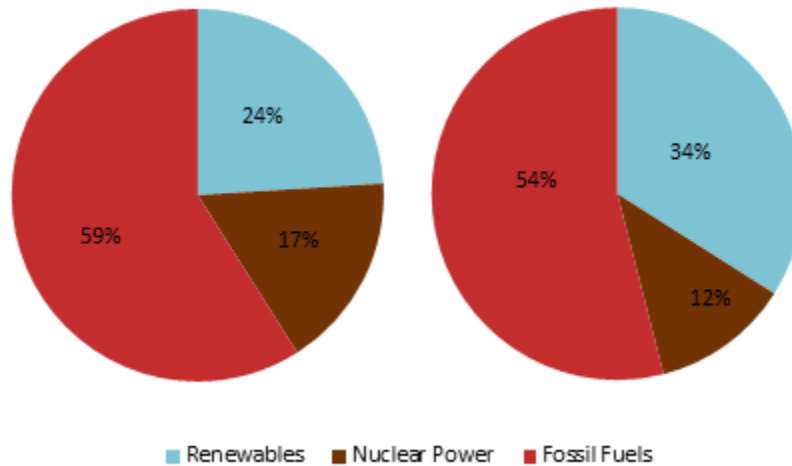
- As of May 2016, five new nuclear plants were under construction, while four plants had retired before the end of their planned operating lifetime and an additional nine have announced that they will retire by 2020.
- Geothermal generators are baseload plants capable of providing valuable services to the grid, such as generation flexibility. As more variable energy resources (VERs) are integrated to the electric system, the flexibility of baseload capacity will grow in importance. The services a geothermal plant can provide include regulation, load following, spinning reserve, nonspinning reserve, and replacement or supplemental reserve. Current ancillary service compensation models in areas with the most geothermal development do not provide sufficient revenue to warrant the increased operational and control retrofitting expenses.
- Prior to 1980, geothermal generation remained below 5 TWh annually. Then, between 1980 and 1989, generation tripled to 15 TWh as new facilities came online. Much of the early growth in geothermal power was driven by Public Utilities Regulatory Policy Act of 1978 (PURPA) incentives, although this driving force has declined over time as the avoided costs of utility generation have fallen (see section

- 12, Figure 12-6). Challenges in exploring new ‘blind’ hydrothermal resources and long drilling times for production wells have led to increased uncertainty for investors in large geothermal projects. Additionally, expiration of tax credit horizons that do not allow enough time for project development (e.g., commence construction clauses that do not take into account the long lead time of geothermal project development), scarcity of power purchase agreement (PPA) opportunities, the need for transmission infrastructure, and low natural gas prices have likely contributed to modest growth in recent years.
- Because the majority of hydropower facilities support multiple purposes such as recreation, flood management, irrigation, navigation, and water supply, requirements for uses other than power generation—such as reservoir elevation rules upstream or dissolved oxygen or flow requirements downstream—can also impact when the plant is able to release or store water.
 - An Oak Ridge National Laboratory (ORNL) report found that the technical resource potential for new hydropower development was 65.5 GW of capacity, when excluding federally protected lands (see section 8, Figure 8-5). Another ORNL report found a technical resource potential of over 12 GW capacity at the more than 50,000 existing nonpowered dams in the United States (see section 8, Figure 8-6).
 - Hydropower provides a variety of ancillary services that are beneficial to the electricity system. One example is regulation and frequency response (including inertia), in which hydropower generators can quickly respond to sudden changes in system frequency. Other ancillary services include spinning and supplemental reserves enabled by high ramping capability, reactive power and voltage support, and black start capability. There has been a renewed interest in the flexibility benefits that many hydropower projects can offer the grid given the growth in variable renewable sources like wind and solar. A recent report notes that about half of all installed hydropower capacity (39 GW) has high flexibility potential, and could play an important role in low-cost integration of variable renewable generators. Pumped storage hydroelectric (PSH) can also be used in peaking and balancing applications to maintain grid reliability and can play a balancing role in areas with high penetrations of VERs.
 - Over the next 10 years, existing U.S. Federal Energy Regulatory Commission (FERC) licenses will expire for nearly 250 hydropower projects, totaling more than 16,000 MW of installed capacity. On average, it takes 8 to 10 years to relicense an existing hydro project, with at least 5 years of pre-filing activity and then at least another 3 years after the application is filed. However, only 2,198 dams are currently used for hydroelectricity—3 percent of the nation’s total dams. (Other uses for dams include navigation, flood control, irrigation, and recreation.) Adding hydroelectricity to these preexisting dams may not face as many siting constraints because some of the environmental impacts from dam construction have already been incurred; this, combined with the ability to leverage existing infrastructure at nonpowered dams, can reduce costs (see section 8).
15. While renewables are expected to gain a significant share of generation, fossil fuels will continue to make up around 50% of both U.S. and world generation. Research,

development, demonstration, and deployment (RDD&D) initiatives that lower costs for clean generation technologies are potential opportunities to both assist the United States to meet its GHG reductions objectives and provide technology export benefits

- Both the U.S. generation mix and the global generation mix are projected to include approximately 50 percent of fossil generation in 2040 (Figure ES-10).
- Commercial low-GHG generation technologies or commercial technologies to control GHG emissions from fossil generation are needed to meet domestic and international climate objectives.
- If U.S. commercial technologies are developed, they could provide competitive advantage and export opportunities.

Figure ES-10. Projected generation mix of the United States (*left*) and world (*right*) in 2040 from the QER 1.2 Base Case and the International Energy Agency's (IEA's) *World Energy Outlook* (WEO) New Policies Scenario

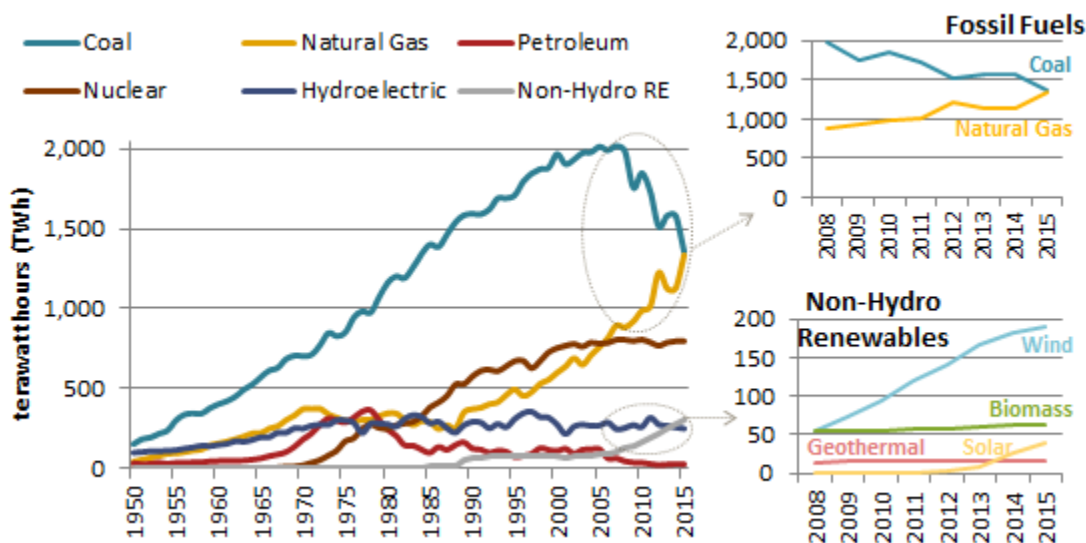


While renewables are expected to gain a significant share of generation, fossil fuels will continue to make up around 55-60 percent of both U.S. and world generation. Sources: EPSA 2015 & IEA 2015²⁰.

1 Introduction: A Changing Generation Sector

The U.S. fleet of electric power generators is undergoing transformational change (Figure 1-1). The share of annual electricity generation from coal-fired resources fell from approximately 50 percent in 2005 to 33 percent in 2015, while electricity generation from natural gas-fired and non-hydro renewable resources increased from 19 to 33 percent and 2 to 7 percent, respectively, over the same time periodⁱⁱⁱ. But not all technologies or regions are experiencing changes equally. Nuclear and hydroelectric generation outputs are relatively flat, and while the shift from coal-fired to natural gas-fired generation is strongest in the eastern half of the country (where growth in renewable electricity is modest), the western half of the country is experiencing rapid growth in renewables²¹.

Figure 1-1. Annual electricity generation by generation technology in the United States, 1950–2015 (left), and generation for coal and natural gas (right-top) and non-hydro renewables (right-bottom) for 2008–2015



The U.S. power generation mix is experiencing rapid change, with natural gas and non-hydro renewable generation growing strongly while coal generation is declining. Solar data include distributed PV starting in 2014. Sources: EIA 2016²².

The share of electricity generation from different sources has arguably changed more quickly since 2007 than at any time since 1950. At least three trends are catalyzing these changes: the low price of natural gas; the rise in renewable generation and distributed generation; and recent Federal and State policies impacting generation. Additionally, the decoupling of electricity demand, GDP, and GHG emissions and the increasing electrification of the economy further contribute to uncertainties and opportunities for the electricity generation sector.

ⁱⁱⁱ Generation is the amount of electricity a generator produces over a specific period of time. Capacity is the maximum electric output an electricity generator can produce under specific conditions (EIA 2016a).

This report:

- Identifies trends and uncertainties impacting the U.S. generation fleet
- Provides a comparison of generation attributes that drive current generation investment and operational decisions
- Provides an overview of generation at the national and regional levels
- Provides a status update on major existing and emerging generation.

The report limits itself to the generation sector and does not address *in detail* parallel issues in electricity end use, environment, transmission and distribution, markets and policy design, security, and other important segments.

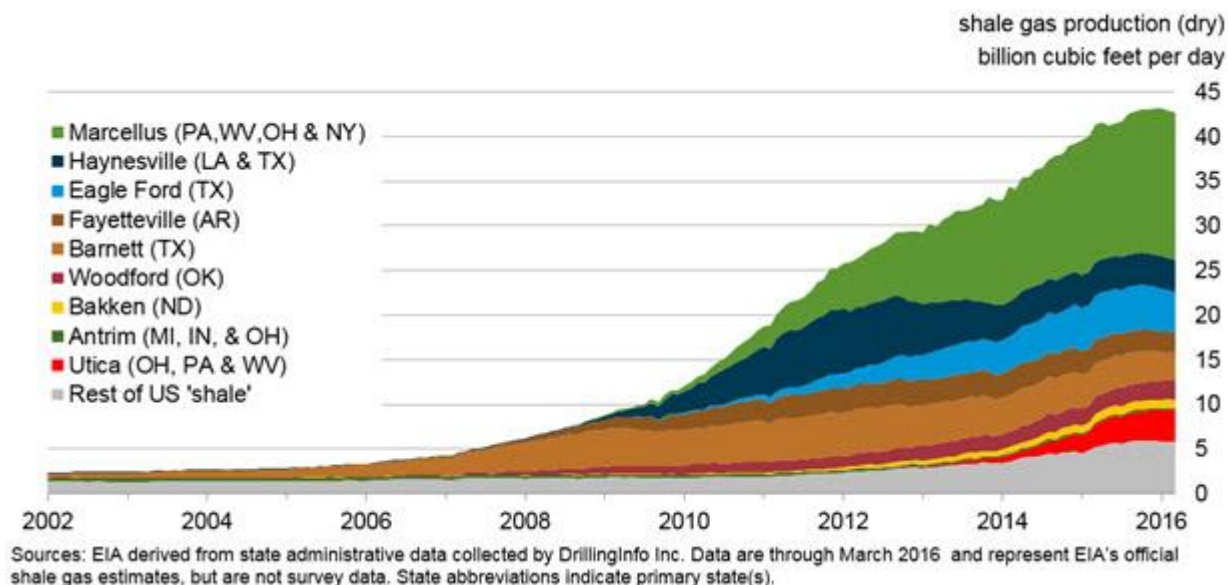
2 Trends and Uncertainties Impacting Generation

2.1 The Impact of Low Natural Gas Prices

From 2000 to 2012, electricity generation from natural gas more than doubled as natural gas prices fell to relatively low levels²³. Low natural gas prices are the result of the surge in natural gas production, largely due to the combination of horizontal drilling and hydraulic fracturing²⁴. These low prices have impacted deployment of electricity produced by natural gas plants, both through increasing use of existing natural gas power plants and driving investments in new natural gas power plants.

Only a decade ago, U.S. energy policymakers were grappling with the challenge of planning and permitting dozens of new liquefied natural gas import terminals. During that time, domestic natural gas production was in decline while demand continued to grow, especially in power generation. That imbalance in domestic supply of and demand for natural gas began to change appreciably in 2007 and 2008 when new domestic supplies of hydraulically fractured natural gas began to enter the market (Figure 2-1). Gradual improvements in the economics of producing shale gas had occurred throughout the decade²⁵ and by 2010 the game-changing nature of the cumulative breakthroughs was apparent²⁶.

Figure 2-1. U.S. dry shale gas production, 2002-2016



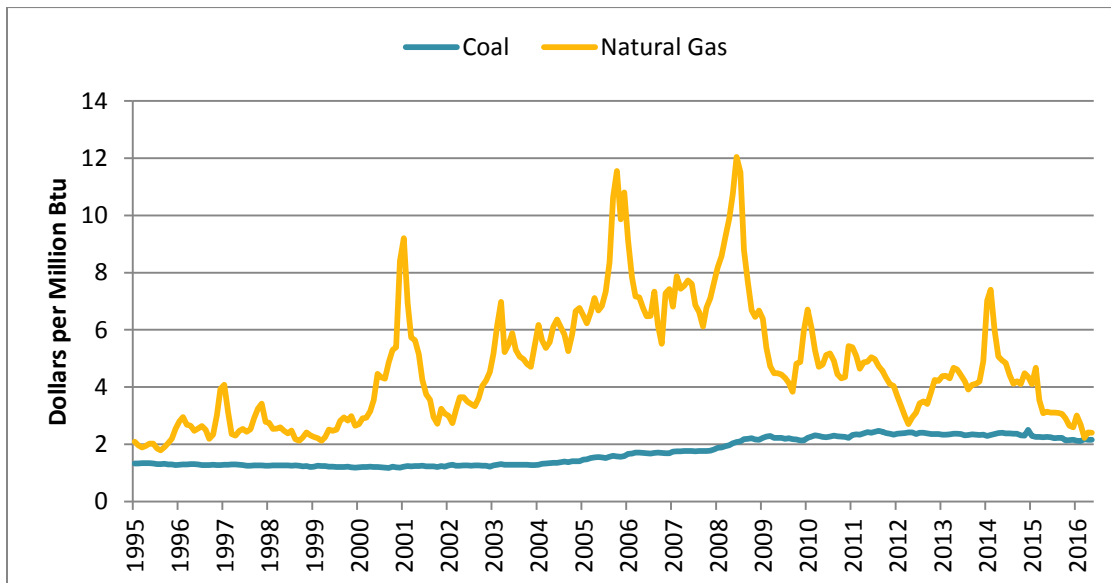
The production of gas from the Marcellus and Eagle Ford plays, enabled by advances in hydraulic fracturing, contributed largely to the U.S. gas surge. Source: EIA 2016²⁷.

In fact, by 2010, the United States surpassed Russia as the world's largest producer of natural gas²⁸. Total domestic natural gas production grew from approximately 18 trillion cubic feet in 2005 to nearly 27 trillion cubic feet at the end of 2015²⁹. In 2015, over 55 percent of total U.S. natural gas production was coming from hydraulically fractured wells, up from less than 5 percent a decade earlier³⁰. Although natural gas prices have remained somewhat volatile over the

past 7 years—briefly spiking during the winter of 2013–2014 due to unusually cold temperatures—they are down sharply from the summer peak of 2008 when they exceeded \$13 per million British thermal units (MMBtu) at the Henry Hub. As of August 26, 2016, natural gas inventories stood at 3,401 billion cubic feet (8% higher than the previous year) and month-ahead futures prices were at \$2.70/MMBtu. Natural gas stock levels remain higher than year-ago and five-year averages due to high inventories from warm winter weather in 2015-2016³¹.

A comparison of the average cost of fossil fuels per unit of heat available (MMBtu) delivered to electricity generators in the United States since 2006 shows the dramatic drop in natural gas prices both overall and compared to coal (Figure 2-2). Coal prices rose slowly from 2000 to 2011 and have since declined slightly, while petroleum prices first fell after the impact of the recession of 2008 and then rose again following economic recovery, before falling again in mid-2014 due to global oversupply. Natural gas prices, on the other hand, declined after the recession and stayed low due to the surging output from many domestic shale gas plays, a number of warm winters³² and low overall electricity demand growth.

Figure 2-2. Average monthly cost of delivered fossil fuels in the U.S. power sector, 1995-2016



The drop in natural gas prices since 2008 has made natural gas more competitive with coal for electricity generation. Source: EIA 2016³³.

There have been two main “surge” periods during which generation fleet owners ramped down dispatch of their coal plants in favor of more natural gas generation: 2011–2012 and again in 2014–2016. These periods of low delivered fuel prices have resulted in the increased utilization of existing NGCC units, with the capacity factor for NGCC plants increasing from an annual average capacity factor of 40 percent in 2009 to 48 percent in 2013 and 2014, and 56 percent in 2015³⁴. This increase in natural gas generation, due to low fuel prices and the low cost of new NGCC units, has corresponded to a reduction in coal power plant utilization, declining from pre-recession (2003–2008) levels of 73 percent to 60 percent in 2013–2014 and 55 percent in 2015 as well as coal plant retirements³⁵.

Trends of increasing natural gas generation are due to delivered natural gas prices approaching the price of coal. Although delivered natural gas prices have remained above those for coal on a

per unit basis, the average efficiency of a combined-cycle natural gas plant is higher than that of coal, making the former fuel currently more economic in some regions of the country to generate electricity on a dollar per megawatt-hour (MWh) basis. The future of the ongoing surge of natural gas generation remains uncertain as gas prices could rise relative to coal depending on a number of other supply and demand factors.

As natural gas prices are often the fuel for the marginal generating unit, they usually determine the marginal cost of electricity. Low-priced natural gas is putting downward pressure on wholesale electricity prices in some competitive wholesale markets (Mid-Continent Independent System Operator [MISO] and New York Independent System Operator [NYISO], for example). While low gas prices are positive for consumers, they are potentially one factor threatening the continued viability of certain generators, especially coal and nuclear.

This newfound abundance of natural gas has been a major contributor to a shift from coal to natural gas in new and projected power generating capacity additions. Additional factors, such as the comparatively low capital cost and scalability of NGCC units, as well as the costs of compliance with Clean Air Act regulations, have also played a role^{iv}. The competitiveness and continued high utilization of natural gas units depends largely on continued low natural gas prices;^v however, other factors, such as the reduced carbon footprint of gas, as well as market and regulatory drivers, may also impact the competitiveness of this electricity source.

2.2 The Rise in Renewable and Distributed Generation

Advances in technology and cost reductions for renewables and distributed generation are spurring exponential growth in most non-hydro renewables. In 2014, generation from non-hydro renewables surpassed that from hydropower for the first time, contributing 7.0 percent and 6.1 percent to total U.S. generation, respectively. In 2015, this trend continued as non-hydro renewables grew to 7.5 percent of generation and hydro to 6.3 percent. The increase in renewables is in part due to a large buildout of wind turbines since 2009, which has largely been driven by State renewable portfolio standards (RPS) and the availability of the PTC. Solar installments have also grown rapidly, with generation nearly tripling from 2013 to 2015³⁶. Solar differs from wind and other renewables in that approximately one-third of new capacity is in the form of small-scale, distributed installations. In 2015, over 12 TWh were generated by distributed solar panels, about 30 percent of total solar generation and 0.3 percent of total generation in the United States³⁷.

Technological advancements also contributed to increased non-hydro renewable deployment. The cost and performance profiles of certain renewable sources of generation began to improve significantly around 2008³⁸. As shown on the right side of Figure 2-3, utility-scale solar PV cost reductions have been widely reported as the most significant, with organizations like Lazard reporting a decline in LCOE^{vi} for utility-scale PV projects of 82 percent between 2009 and

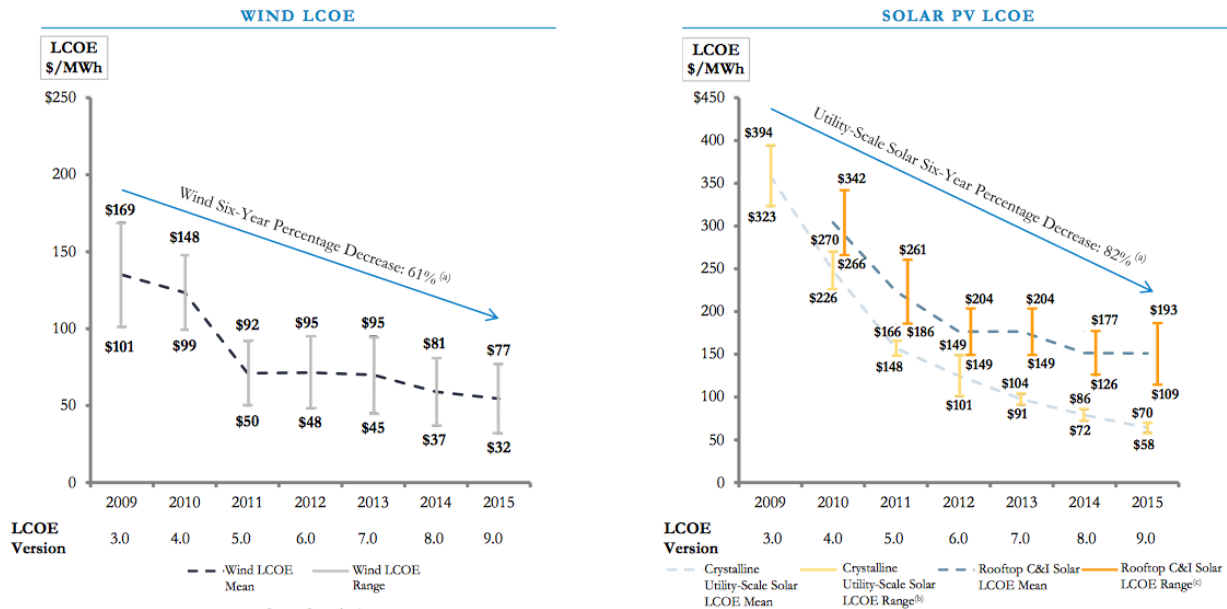
^{iv} The relatively low capital cost of NGCC units, in conjunction with their short construction times, results in a lower financial risk to utilities when evaluating capacity choice additions.

^v The competitiveness of a natural gas power plant is very sensitive to the delivered price of natural gas, which constitutes a large portion of the levelized cost of electricity (LCOE). High prices can therefore have strong impacts on whether these plants dispatch and on the outlook for such plants. Difficulties in obtaining long-term supply contracts, lack of long-term onsite storage options, and historical price volatility can exacerbate these concerns. See NETL 2015; NETL n.d.[b]; FERC n.d.; EIA 2014c.

^{vi} LCOE is a convenient summary measure of the overall competitiveness of different generating technologies, but it does not represent all cost or investment considerations. None of the LCOE numbers presented in this report include tax incentives. The EIA summarizes important limitations of LCOE metrics here: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

2015³⁹. While PV technology advancements have continued to improve more modestly, much of the cost reduction is attributed to larger economies of scale in the manufacturing process, especially in China⁴⁰. Several recent PPAs in the United States report utility-scale PV contracts being offered at less than \$40/MWh, which includes the benefits of the 30 percent investment tax credit (ITC)⁴¹. In comparison, nationwide wholesale power prices ranged from approximately \$29/MWh to \$65/MWh in 2014⁴².

Figure 2-3. Change in U.S. LCOE for wind and PV, 2009–2015

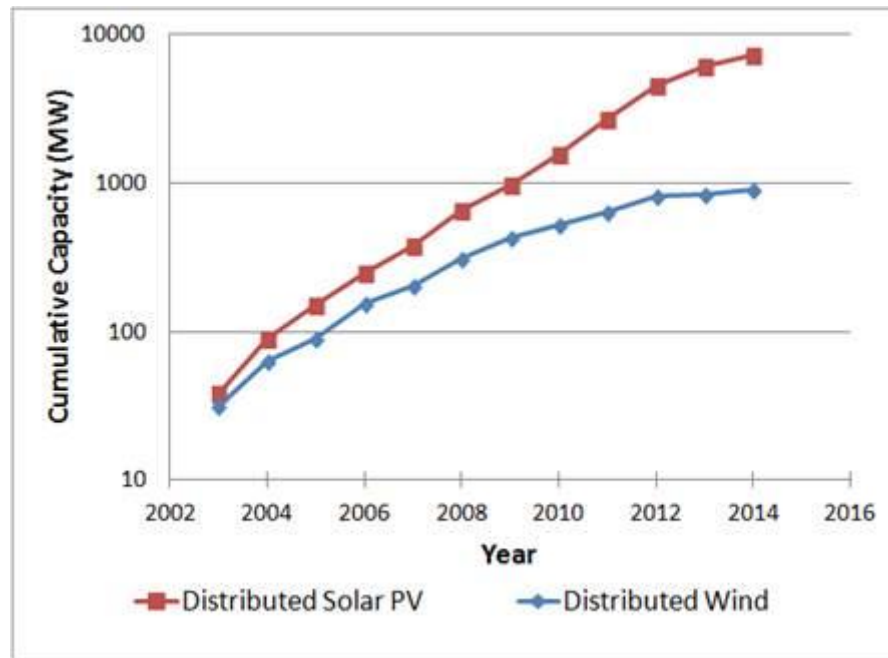


Wind and solar generation costs have declined significantly over the past 6 years, helping drive deployment to higher levels. Source: Lazard 2015⁴³.

Distributed solar PV is also growing rapidly due to Federal and State incentives, a greater number of commercial offerings, and more robust financing options.

Figure 2-4 shows growth of distributed solar PV and distributed wind (below 1 MW) on a logarithmic scale, indicating that distributed solar PV generating capacity grew by almost a factor of 100 between 2004 and 2014, while distributed wind increased by about a factor of 14⁴⁴. In other words, distributed solar capacity increased by over 8,000 percent between 2004 and 2014; distributed wind grew by over 1,300 percent.

Figure 2-4. Installed capacity (MW) of distributed wind and distributed solar PV, 2002-2014



Renewable sources of distributed generation have grown sharply in recent years. NOTE: Cumulative capacity given in MW-DC (direct current) for distributed solar. Sources: LBNL 2016.

Distributed PV accounted for 12.1 TWh of generation in 2015, or 0.3 percent of total national generation, according to newly released data from the U.S. Energy Information Administration (EIA)⁴⁵, although the percentage of distributed PV generation can be much higher in regions of the country where deployment has grown rapidly (California and Hawaii, for example). While utility-scale PV is less expensive than distributed PV, the latter is still expected to continue growing rapidly due to factors such as tax and rate incentives and third-party ownership options that simplify financing⁴⁶

Wind generators have experienced similar cost reductions and technology improvements (Figure 2-3), with Lazard estimating a 61 percent reduction⁴⁷ in the LCOE between 2009 and 2015. Wind LCOE reductions are much more prominent pre-2009, however, as costs declined from over \$600/MWh in 1980 to less than \$100/MWh in 1997⁴⁸. Much of the cost reduction for wind generators comes from reduced commodity prices^{vii} in the post-recession global economy, larger turbine diameters that increase efficiency, and increased turbine heights that allow capture of stronger winds⁴⁹. Wind PPAs that include the effects of the PTC are now routinely contracted at less than \$30/MWh, which is competitive with new combined cycle (CC) natural gas plants and, in some cases, existing natural gas plants⁵⁰.

Importantly, grid operators in many regions of the country are becoming familiar with the integration challenges of more variable renewable sources of electricity in their systems⁵¹. Some of the early concerns about the difficulty and expense of integrating variable renewable

^{vii} Reduced commodity prices are typically not mentioned as a reason for lower wind costs, but the global price of steel, copper, and many other inputs rose significantly between 2000 and 2008 before the recession hit. These increases were correlated with rising wind capital cost estimates, as illustrated in Wisner and Bolinger (2015). Wind turbine costs have since declined, partly due to the drop in commodity prices, but also due to technological improvements.

generation into the grid^{viii} have been allayed, although operational hurdles to maintaining reliability with higher penetrations of variable renewables still exist⁵².

Longer-term challenges for variable wind and solar are the decreasing marginal economic value they provide to the grid at increasing penetration levels⁵³ and the need for provision of essential reliability services, such as frequency and voltage support and ramping moderation⁵⁴. While cost reduction is a continued focus of ongoing research and development (R&D) and installation best practices, system impact mitigation methods are subject to ongoing debate among industry, regulators, and independent system operator/regional transmission organization (ISO/RTO) market operators. DOE, FERC, NERC, the Electric Power Research Institute (EPRI), and others have begun to pay critical attention to the need for variable renewables to provide essential reliability services, particularly in the area of frequency response and voltage support. Recent actions by FERC and NERC on the design of variable renewable generators represent the first steps toward addressing the longer-term challenges for variable renewable generation; however, new market designs, policy measures, and technologies would be required to help completely overcome these concerns. For example, in December 2015, NERC issued five general recommendations^{ix} as part of its *Essential Reliability Services Task Force Measures Framework Report* that focus on the incorporation of these services into the design of variable generating resources in the future⁵⁵. Shortly thereafter, on February 18, 2016, FERC issued a Notice of Inquiry, Docket RM16-6000, seeking comment on the need for market reforms to support the provision of essential reliability services by all generators⁵⁶.

Recent research into other impacts, such as accounting for integration costs or the operational and maintenance impacts on generators that maintain grid stability, will continue to be critical to grid operators, policy makers, and researchers in identifying the most efficient policy, market, and technical solutions to increased deployment⁵⁷.

^{viii} These include the claim that an equal amount of fully dispatchable generating capacity be installed to “back-up” the variable generation, and that storage is required to maintain reliability in a system with significant (up to 30 percent) variable renewable electricity production. For more on this subject, see Milligan et al. (2009) and Palchak (2015).

^{ix} The NERC recommendations are:

1. “All new resources should have the capability to support voltage and frequency. Automatic voltage regulators and governors have been standard on conventional generators for decades, and comparable capabilities are currently available for new VERs and other resources. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
2. Monitoring of the Measures and investigation of trends. The Measures are intended to highlight aspects of reliability that could suggest future reliability concerns if not addressed with suitable planning and engineering practices.
3. Planning and operating entities should use the Industry Practices. While the results of Industry Practices will be system specific and difficult to quantify or compare between different regions, they will help ensure that emerging concerns are addressed with suitable planning and engineering practices.
4. While beyond the formal scope of the ERSTF, the task force recognized that Distributed Energy Resources (DERs) will increasingly affect the net distribution load that is observed by the BPS. The ERSTF recommends coordination of NERC Reliability Standards with DER equipment standards such as IEEE 1547. Pursuant with NERC’s reliability assessment obligations, the ERSTF further recommends that NERC establish a working group to examine the forecasting, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating and engineering practices, and policy oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.
5. Open sharing of experiences and lessons learned. The reliability of the system can be maintained or improved as the resource mix evolves, provided that sufficient amounts of essential reliability services are available”

2.3 Recent Federal and State Policies Impacting Generation

In addition to low natural gas prices, Federal and State regulations have also played a significant role as drivers of change in the generation mix over the last decade. Federal and State policies such as tax credits for renewables, energy efficiency measures, and RPS are among the key policy drivers. In addition, compliance costs associated with Federal and State environmental regulations coupled with low natural gas generation costs have impacted electricity generators.

In 2015 alone, approximately 14 GW of coal-fired generators retired⁵⁸. A number of coal plants chose to retire rather than comply with the Mercury and Air Toxics Standard due to aging infrastructure and the difficulty of recovering capital expenditures in an environment of low natural gas prices and low demand growth⁵⁹. Given the market environment, the effect of the Federal and State regulations have also played a significant role in moving forward in time as opposed to increasing the overall long-term level of retirements. Select other rules impacting generation include the Cross States Air Pollution Rule,^x coal combustion residuals,^{xi} water intake structures,^{xii} and New Source Performance Standards for air pollution from power plants.^{xiii} Ground-based ozone concentration requirements were recently reduced from 75 parts per billion to 70 parts per billion, which could impact power generation options in some regions of the country.^{xiv} The Clean Power Plan (CPP) is projected to achieve a 32 percent reduction in power sector CO₂ emissions from 2005 levels by 2030^{60,xv}. Even if some states are on their way to meeting the carbon standards defined in the CPP due to factors unrelated to the CPP, many states will need to make changes to their electric sector to comply⁶¹.

^x § 110(a) of the Clean Air Act of 1963, 42 U.S.C. §7401.

^{xi} Subtitle D of the Resource Conservation and Recovery Act of 1976, 42 U.S.C. §6901.

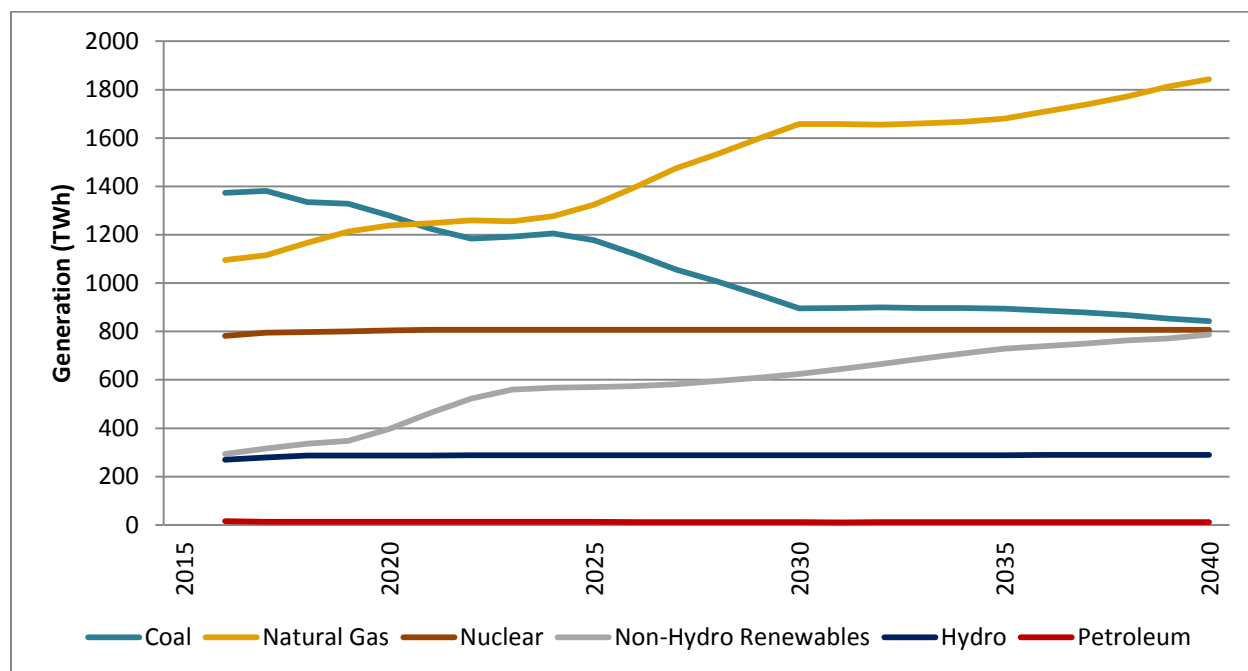
^{xii} §316(b) of the Clean Water Act of 1972, 33 U.S.C. §1251.

^{xiii} §111(b) of the Clean Air Act of 1963, 42 U.S.C. §7401.

^{xiv} More information on this is available here: <https://www.epa.gov/ozone-pollution/setting-and-reviewing-standards-control-ozone-pollution>

^{xv} On February 9, 2016, the U.S. Supreme Court stayed the rule implementing the CPP until the current litigation against it concludes. *Chamber of Commerce, et al. v. EPA, et al.*, Order in Pending Case, 577 U.S. ____ (2016), http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf. As of that date, a challenge to the rule was pending before the United States Court of Appeals for the District of Columbia Circuit.

Figure 2-5. Projected generation (TWh) under the QER 1.2 Base Case, 2016-2040



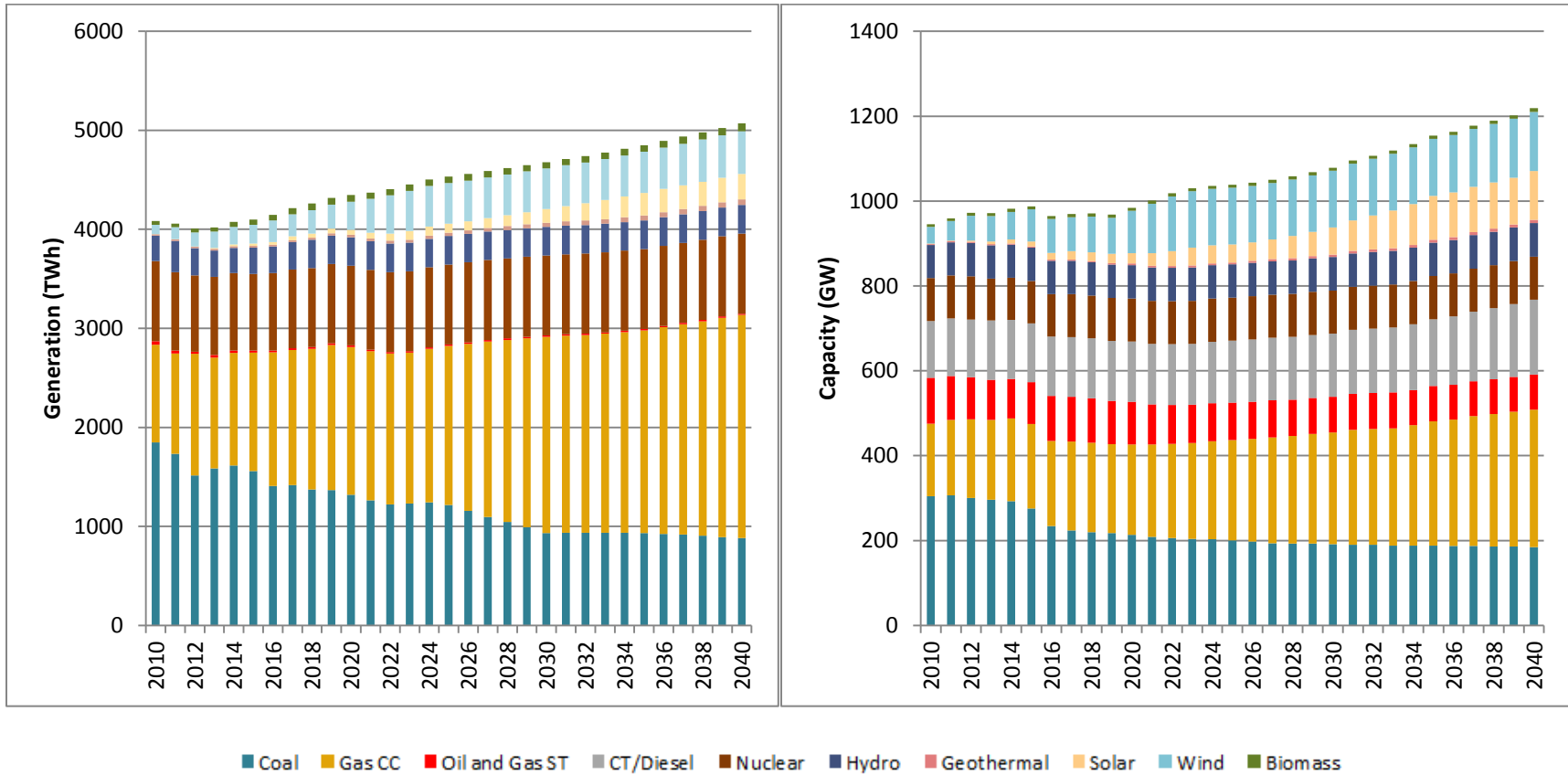
The QER 1.2 Base Case projection, including the CPP, shows that the generation mix will undergo significant changes in the 2040 timespan. Renewables and natural gas are projected to see the largest growth in generation, while coal sees almost a 40% decline. Source: EPSA 2016⁶²

The QER 1.2 Base Case presents outputs developed with the EPSA-NEMS (National Energy Modeling System) model (DOE 2015h). The analysis uses a modified version of EIA’s NEMS model that EPSA maintains (conducted by OnLocation) with *Annual Energy Outlook 2015* (AEO2015) High Oil and Gas Resource Case with the following changes:

- Mass-based implementation of the CPP with new source complement to 2030 (goals assumed constant post-2030). The implementation covers all existing (except CT) and all new fossil generation, assumes national trading (no banking or borrowing), includes energy efficiency using EIA’s rebate code, and excludes the Clean Energy Incentive Program.
- Recent renewable tax credit extension legislation passed in late 2015
- Updated CCS cost and performance numbers
- Updated renewable energy cost and performance data.

Summary graphics of generation and capacity from each technology out to 2040 are provided in Figures 2-5 and 2-6. The latter plots show that coal capacity will continue retiring out to 2040, and will be replaced by new natural gas, solar, and wind capacity to meet increasing demand. In this Base Case, solar and wind capacity make up roughly 14 percent of national generation in 2040. This Base Case assumes no new policies between now and 2040

Figure 2-6. Projected U.S. generation (TWh) and capacity (GW) under EPSA's QER 1.2 Base Case

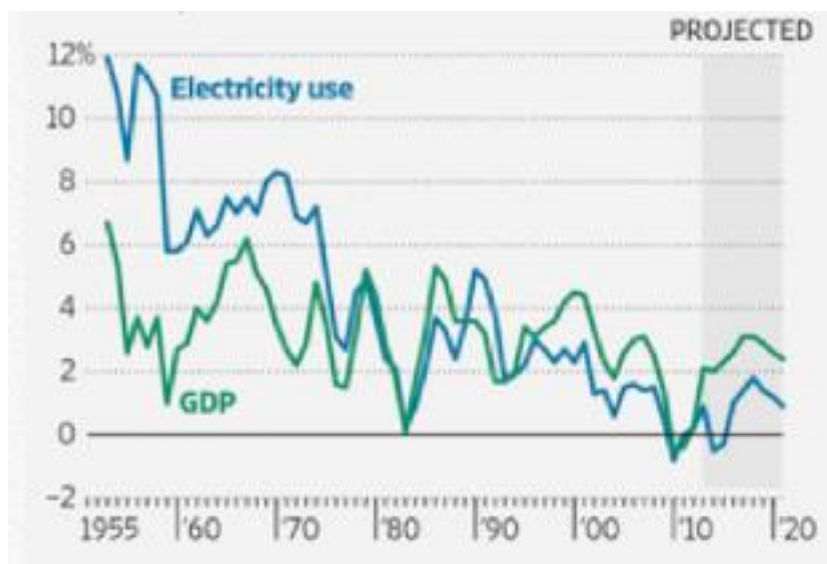


EPSA designed a scenario to estimate the reference case for the electricity sector. This Base Case includes existing policies, including the CPP and tax extenders. Generation under the Base Case is on the left, and capacity is on the right. New capacity out to 2040 comes primarily from natural gas, wind, and solar installations. Source: EPISA 2015⁶³.

2.4 Changing Relationship among GDP, Electricity Demand, and GHG Emissions

The relationship between the growth of the economy and the growth of electricity demand is changing. Between 1950 and 1995, the U.S. economy and electricity demand growth were strongly correlated, with growth in GDP occurring alongside growth in electricity demand, as shown in Figure 2-7. Prior to 1995, there is a 40-year correlation between the growth rate of GDP and electricity, especially between 1975 and 1995 when the two measures were nearly equal, with each reflecting about 2–3 percent growth per year⁶⁴. However, in the past decade, electricity demand growth has slowed disproportionately to GDP growth, slowing to less than 1 percent annually. Going forward, these two indicators are likely to continue to be correlated—increased production of goods will still lead to increased power use—but the growth rate for electricity demand will be far below that of GDP growth⁶⁵. There are many drivers for this trend, including energy efficiency standards, slowed population growth, and fundamental change in the economy away from energy intensive industries toward a service economy⁶⁶. However, this trend suggests that decreased electricity use and GHG emissions are not inconsistent with a strong economy. While the U.S. economy has grown by 10 percent since 2007, electricity demand growth has been flat⁶⁷.

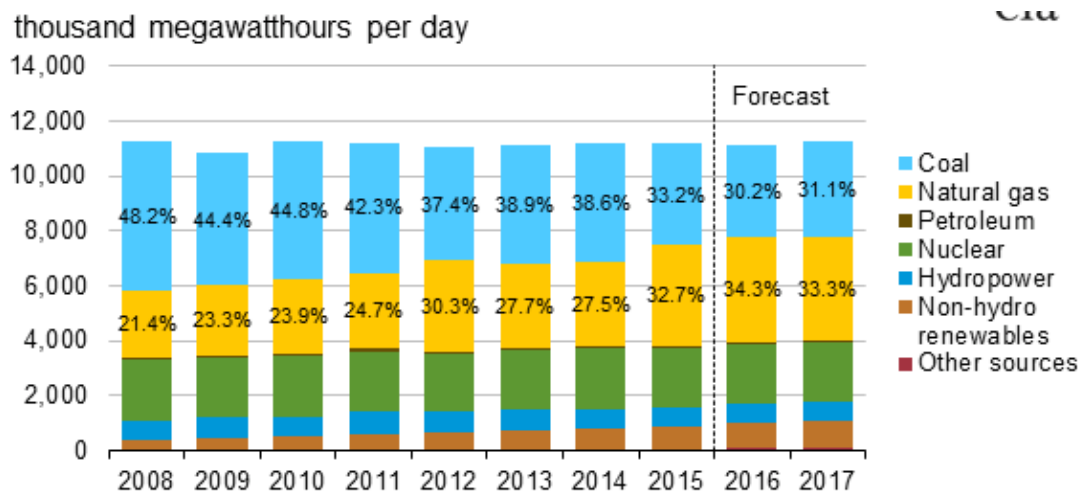
Figure 2-7. U.S. electricity use and economic growth, 1950–2020



Between 1950 and 1995, GDP growth and electricity demand growth were strongly correlated, but after 1995 to the present they have begun to diverge with electricity demand growth remaining lower than GDP growth. Source: DOE 2015⁶⁸.

Power sector carbon emissions in 2015 had declined by nearly 21 percent since 2005 equivalent to an average decline of roughly 2 percent per year⁶⁹. These changing relationships have positive implications for the United States' ability to enjoy economic growth while reducing GHG emissions in the absence of significant demand growth.

Figure 2-8. U.S. electricity generation by fuel for all sectors, 2008-2017



Note: Labels show percentage share of total generation provided by coal and natural gas.

U.S. power generation since 2006 shows a decline of coal generation (*light blue*) as both natural gas (*yellow*) and new renewables (*brown*) rose; nuclear (*green*) and hydro (*dark blue*) remain flat. Source: EIA 2016⁷⁰.

The 2007–2008 global financial crisis had a profound impact on energy use around the world. In the United States, electricity demand, transportation fuel demand, and industrial energy use declined significantly after the recession. This initial drop, coupled with energy efficiency improvements and structural shifts in the U.S. economy, has resulted in slowed demand growth⁷¹. Although in 2014 total electricity demand in the United States did top the 2007 peak, national electricity generation growth has slowed on average to less than 0.5 percent annually from 2012–2015 compared to 1.4 percent on average from 2000–2007⁷². The need for new generation supply has thus been muted given the lack of additional demand, although generation retirements have driven new capacity investments to some degree.

The reduction in overall electricity use is not only a result of the recession. Spending on Federal and State energy efficiency programs has continued to grow in recent years, and consumers have changed behavior to reduce their energy use and have invested in more efficient lighting, insulation, and heating equipment to cut consumption⁷³. The emergence of distributed generation—primarily solar PV—at the residential level has also begun to cut into utility electricity sales, although as noted previously, distributed PV generation accounted for only 0.3 percent of total net generation in 2015.^{xvi}

The changing relationship among GDP, electricity demand, and GHG emissions has positive implications for the health of the U.S. economy and U.S. efforts to address climate change.

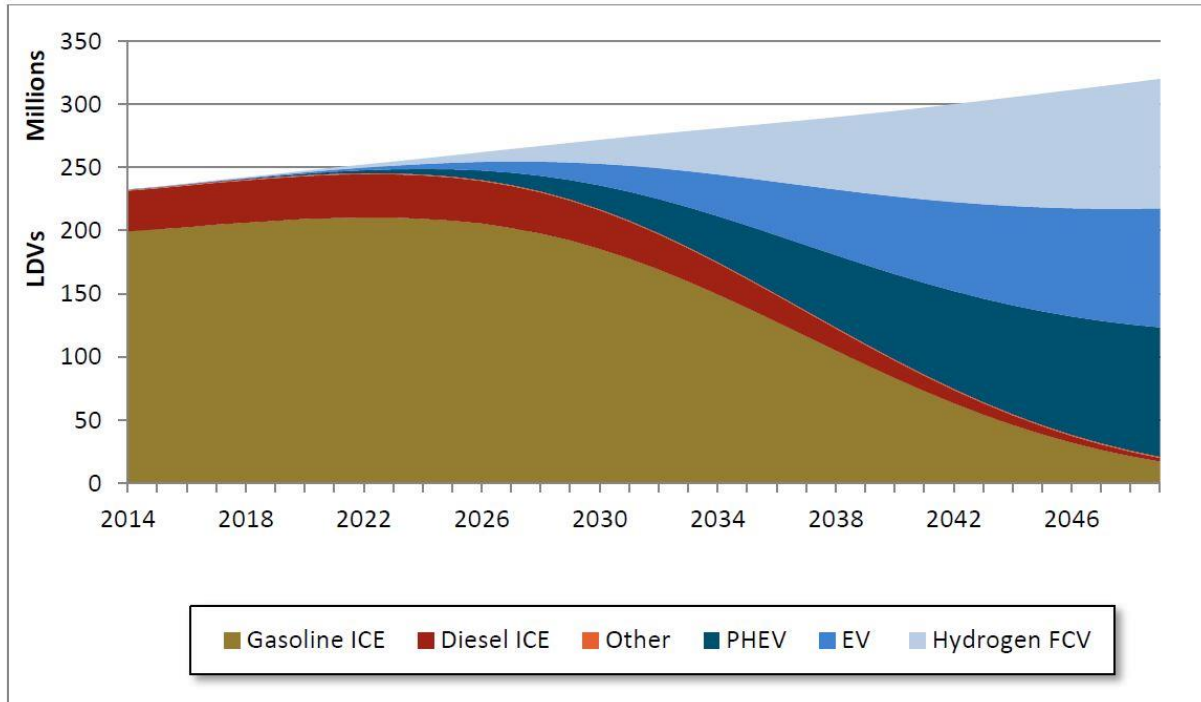
2.5 Future Uncertainty: Electrification of the Transportation Sector

A future uncertainty is the impact on electricity demand growth by potential electrification of the transportation sector. In 2015, electricity consumption in the transportation sector represented only 0.2 percent of total U.S. electricity consumption⁷⁴. Future trends for increased electricity use in the transportation sector depend upon a variety of factors, including the rate of market adoption of electric passenger vehicles (EVs) and whether EVs are charged in relation to peak or

^{xvi} The EIA began reporting distributed PV generation data in its *Electric Power Monthly* in November 2015.

non-peak periods. Forecasts of future market adoption vary significantly indicating long term planning challenges. The AEO2016 Reference Case projects that plug-in EVs (PEVs) will account for 4 percent of new light-duty vehicle sales in 2040⁷⁵. Alternatively, some analysts forecast the market penetration of PEVs to be as high as 50 percent in 2040 (Figure 2-9).

Figure 2-9. Projected annual light-duty vehicle stock, 2014-2050

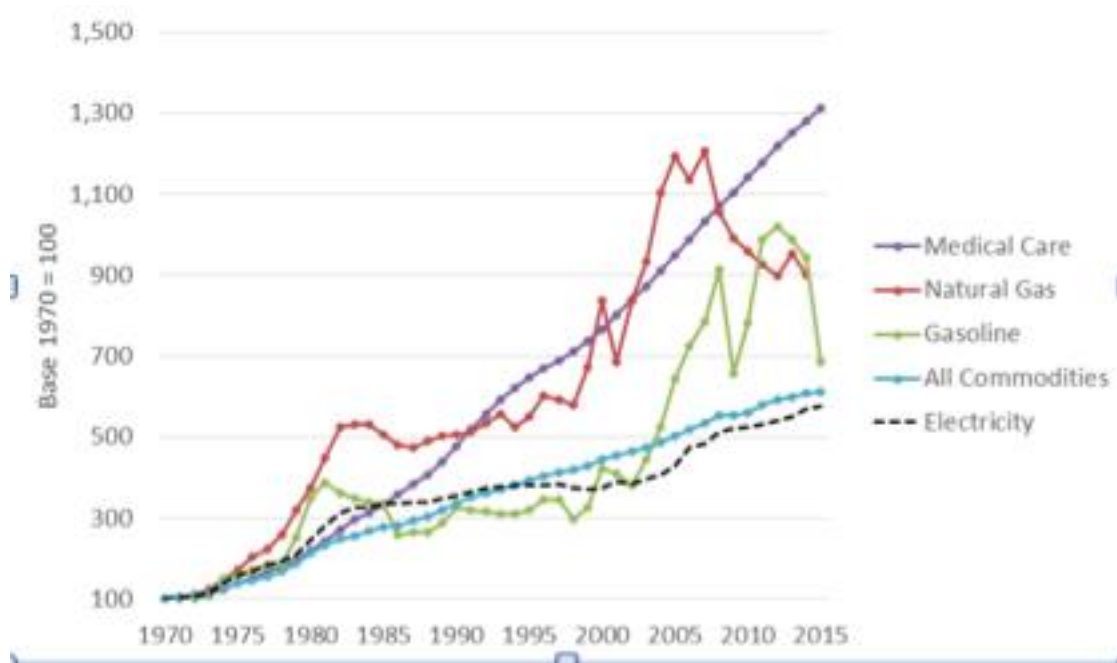


One scenario shows that plug-in hybrid EVs and PEVs will make up nearly 50 percent of the light-duty vehicle fleet by 2040. Source: Williams et al. 2015⁷⁶.

2.6 Future Uncertainty: Prices of Electricity

Although the price of electricity increased between 1970 and 2015; the rate of increase has been slower than that for medical care, natural gas, gasoline, and other commodities (Figure 2-10).

Figure 2-10. Comparison of electricity and other consumer price trends, 1970-2015



Electricity prices have risen over time, but less in comparison to other commodities.

Source: EIA 2016 and BLS 2016⁷⁷

However, over that same period of time, electricity prices have been steadily rising. The generation fleet in particular is sensitive to current and predicted changes, including reductions in nuclear power, increases in renewable energy, reductions in the coal fleet, and natural gas vulnerabilities.

3 Crosscutting Attributes of the U.S. Power Generation Sector

This chapter presents a high-level discussion of generation attributes and compares generation technologies by key factors that can impact investment decision making. This section summarizes and compares the information contained in chapters 5–13. Please see these chapters for more details regarding specific fuels or technologies.

3.1 Physical System Overview

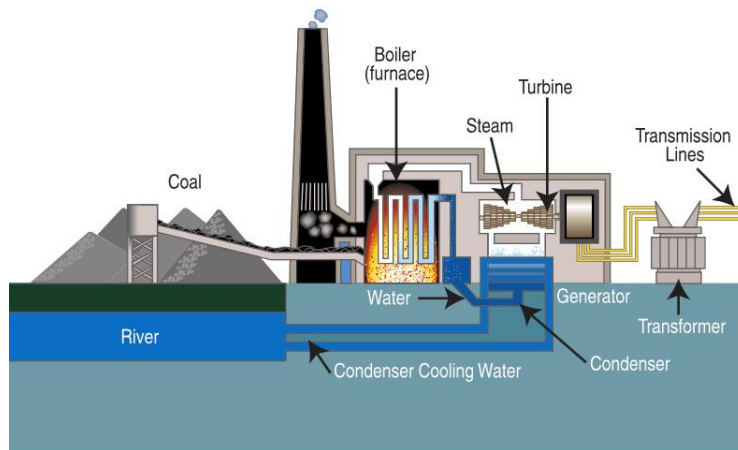
In 2014, there were over 6,500 operational power plants of at least 1 MW^{xvii} in the U.S. electric power sector^{xviii},⁷⁸. These generators deliver electricity to end users through one of the most complex “system of systems” in the world: the North American electricity grid.

There are a variety of techniques used to generate electricity, although three-phase synchronous generators that rely on electromagnetic induction (i.e., rotation of a magnet within closed loops of a conducting material like copper wire) dominate the market. The vast majority of generators use rotary axis turbines (a series of blades that spin around a central shaft connected to the rotating magnet, or rotor) and are typically classified as either thermal or non-thermal, although other categories also exist. Thermal plants create steam or air under pressure by (1) using a heat source from combusting fossil or biomass fuels, (2) accessing heat beneath the surface of the earth (geothermal), (3) creating heat through the nuclear fission process (nuclear energy), or (4) concentrating solar energy. This heat is used to create high-temperature steam or air under pressure that is then expanded through a turbine connected to a generator. A simplified schematic of a coal-fired steam turbine (ST) generation unit is shown in Figure 3-1. Note that for most large generators, a transformer steps up the voltage of the alternating current (AC) power so that it can be transmitted across high-voltage lines with fewer losses.

^{xvii} Only units of 1 MW and greater are considered utility-scale generation, which is the primary subject of this report.

^{xviii} The electric power sector is defined by the EIA as an energy-consuming sector that consists of electricity-only and combined-heat-and-power plants whose primary business is to sell electricity, or electricity and heat, to the public and includes both electric utilities and independent power producers. See EIA, “Electric Power Monthly,” 2016, <http://www.eia.gov/electricity/monthly/>.

Figure 3-1. Simplified representation of a coal-fired steam boiler and generator



In thermal plants like the coal-fired steam boiler above, a fuel is used to heat water, generating steam. The steam then spins a turbine that is connected to a generator, which generates electricity through induction. Source: TVA 2013⁷⁹.

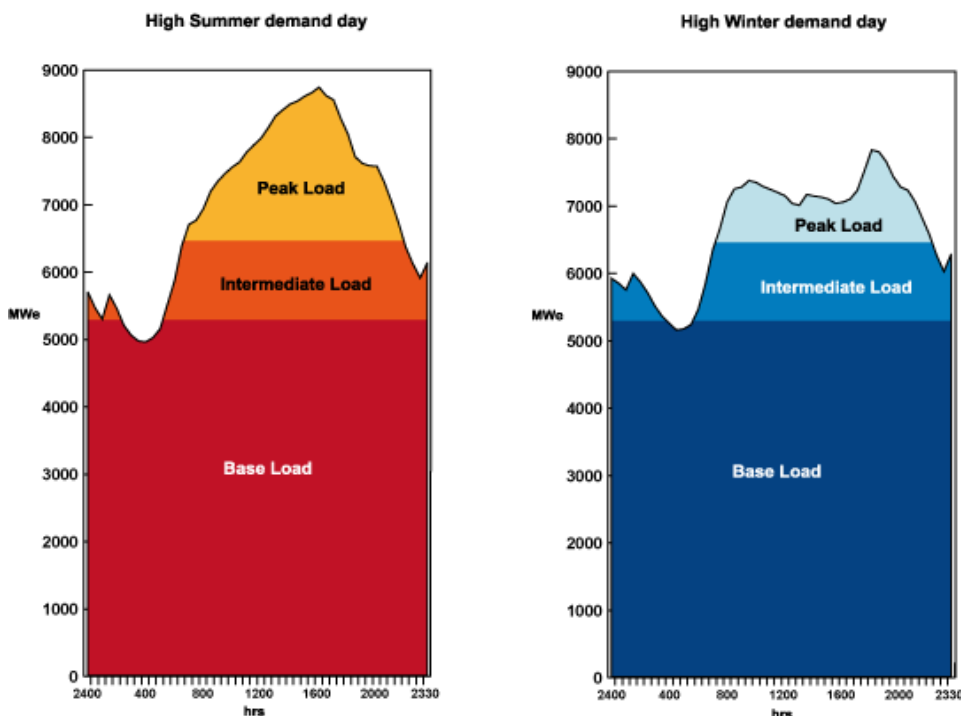
Non-thermal plants have no heat source and rely on capturing some of the potential pressure and/or kinetic energy associated with a working fluid (e.g., water or air) as it passes through a turbine to similarly turn a generator shaft that produces electricity. Wind turbines extract some of the kinetic energy in the wind, so the air, and hence wind, slows down on passing through the turbine. For hydroelectric power, the kinetic energy of water flowing through the penstock drives a turbine, which converts some fraction of this energy to electricity.

Solar PV is a rapidly growing form of power generation that directly converts sunlight into electricity through the PV effect. Concentrating solar power (CSP) works by heating a working fluid that drives a steam turbine. Electrochemical generators, such as batteries and fuel cells, are other ways to produce electricity, although these technologies account for a small percentage of total generation today in the United States.

3.2 Operational Attributes and Requirements

Electricity is generated near-instantaneously to meet demand. The consequence of flipping a light switch or changing a thermostat that controls an air conditioner leads to a generator somewhere on the grid either ramping up or ramping down in near-real time to meet the change in demand. The most electricity is generated during the middle of the day, as illustrated in Figure 3-2. Different fuel and technology types serve different parts of this load.

Figure 3-2. Representative traditional electricity demand profiles in summer and winter



A variety of generation types contribute to keeping electricity supply in balance. While grid operators are accustomed to variability in the demand for electricity, they are now learning to deal with variability in supply as well. Source: WNA 2015⁸⁰.

For example, nuclear power plants are large generators with high inertia that perform most efficiently when operating continuously at full power. They generally have limited ramping capability, meaning it takes them a long time to turn up or turn down the amount of electricity they are producing. These characteristics have contributed to nuclear power being used to function primarily as baseload power generators.

Other technologies, such as CTs, are more expensive to operate, and therefore are only used during times of peak load, where demand is the greatest. They typically have faster ramping capability and therefore are quicker to respond to instantaneous changes in demand.

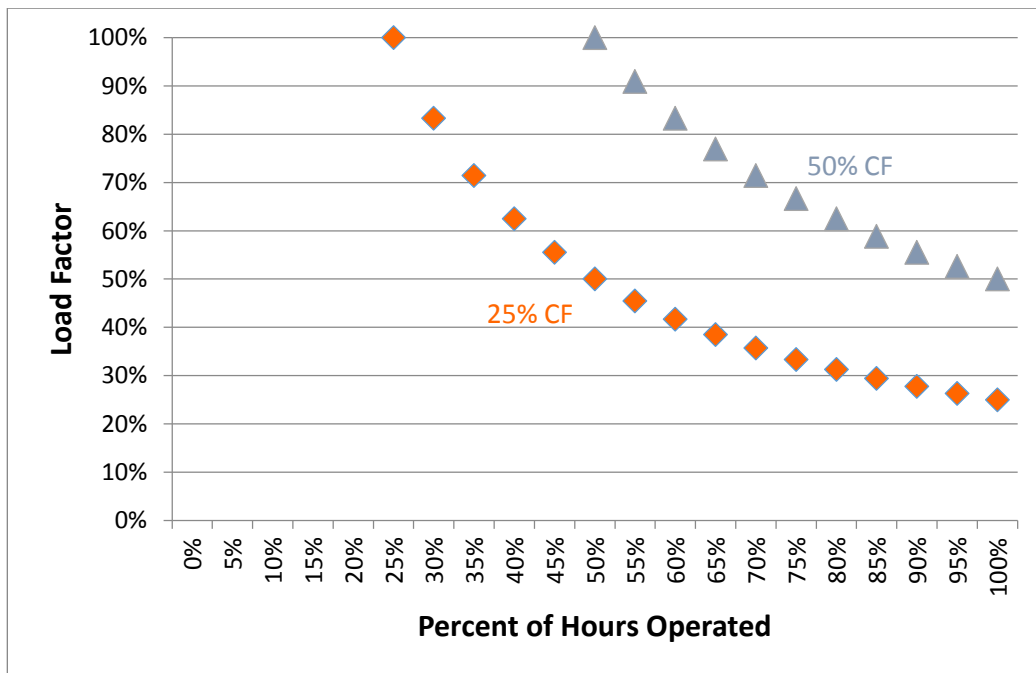
Some renewable technologies, such as wind and solar, have been classified as variable generators. This means that operators have limited capability to dispatch on demand. For example, wind speeds at any given location vary widely over an array of time slices, and PV can be impacted by the weather (e.g., clouds) and can only produce power during the day without storage. Since renewable technology fuel sources are free, the technologies tend to operate whenever they are capable of generating electricity. There have been times when these sources generate more electricity than grid operators anticipated or more than the grid itself can handle; in these cases, either the variable generators are turned down or off, or other existing generators are ramped down to compensate. Which scenario occurs depends on a number of factors, including regulatory requirements, tax incentives, RPS requirements, and grid reliability constraints. When renewable generation is turned off, it is referred to as curtailment. However, a number of variable renewable energy grid integration tools are now able to help operators reduce curtailment and lower the cost of integrating variable renewable energy into the grid⁸¹

The U.S. generation fleet is transitioning from one dominated by centralized generators with high inertia and dispatchability to one that is more hybridized, relying on a mixture of traditional, centralized generation and variable, nondispatchable utility-scale and distributed renewable generation with synthetic inertia⁸².

3.3 Capacity Factors and Heat Rates

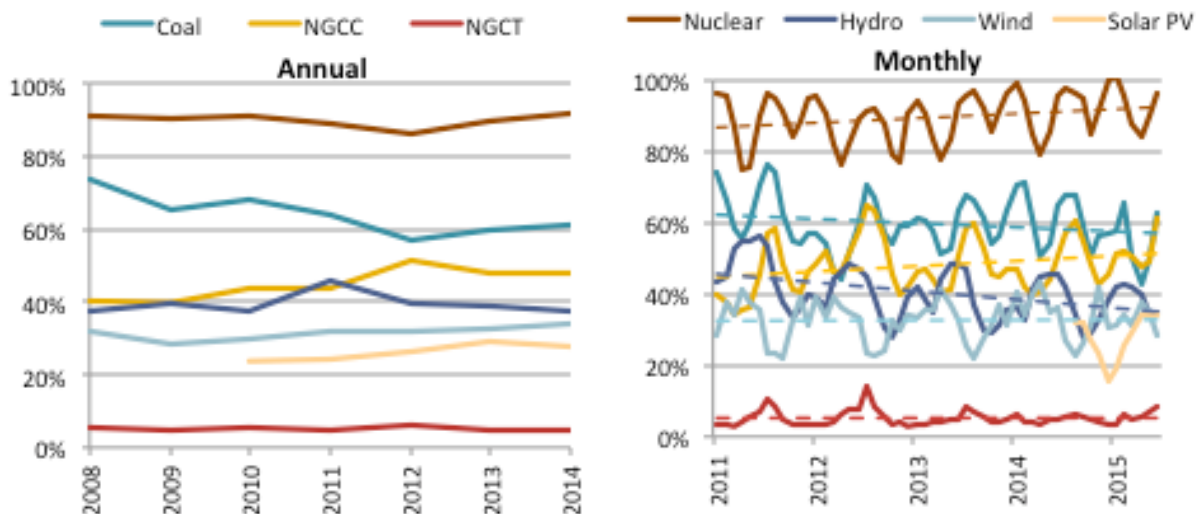
This section reviews two different characteristics of generation technologies: capacity factors and heat rates. Capacity factors measure the overall utilization of a generation facility or fleet of generators. Capacity factor is the annual generation of a plant (or fleet of generators) divided by the product of the capacity and the number of hours over a given period of time. In other words, it measures a plant’s actual generation compared to the maximum amount it could generate in a given period of time without any downtime. As power plants sometimes operate at less than full output, the annual capacity factor is a measure of both how many hours in the year the plant operated, and at what percentage of its full output (Figure 3-3). The annual capacity factor of a power plant is therefore a measure of availability (how many hours it is available to generate electricity) and an indirect measure of the marginal cost of generation (for nonvariable sources) and other characteristics such as flexibility and startup times. Recent trends in both annual and monthly capacity factors of major fuel and technology types are shown in Figure 3-4.

Figure 3-3. Capacity factor as a function of hours operated vs. percentage of full output



A power plant with a rated output of 500 MW electrical (MWe) that operates at 100 percent load factor will output 500 MW of electricity to the grid. If this power plant operates all 8,760 hours of the year, it will have a capacity factor of 100 percent. If it operates only 4,380 hours of the year (50 percent of 8,760) at 100 percent load factor, it will have a 50 percent capacity factor. Alternately, if it operates at 50 percent load factor (250 MWe output) for 8,760 hours of the year, it will also have a 50 percent annual capacity factor.

Figure 3-4. U.S. annual and monthly capacity factor by major fuel and technology combinations



The utilization of coal plants has declined significantly since abundant, low-priced natural gas supply became available beginning around 2010. The capacity factor from the fleet of coal generators fell from over 70 percent in 2008 to under 60 percent in 2015. NGCC units grew from about 40 percent in 2008 to over 50 percent in 2015. Nuclear generators continue to have fleet-wide capacity factors of 90 percent. Source: SNL 2015⁸³.

Technologies such as nuclear and coal have historically had the highest capacity factors because they have high levels of availability and had the lowest marginal cost generators. Nuclear units also have long startup and shutdown times dictated by regulatory procedures required to ensure power plant safety. Consequently, these units typically limit their scheduled outages to every 18 to 24 months.

While coal plants have greater flexibility than nuclear units for startup and shutdown, operating at high capacity factors has been historically desirable as it limits the wear and tear of power plant components caused by thermal expansion and contraction during startup/shutdown or ramping between different load points. Reduced wear not only ensures reduced maintenance costs, but improves the likelihood of the power plant being available during times of peak demand.

Changes in electricity markets, fleet composition, and usage patterns in recent years have seen U.S. power plant operators and engineering, permitting, and construction vendors adapt both coal and nuclear plants for more flexible operation. This has come out of necessity in some cases—units have begun to operate as peaking or load-following units, and modifications have been required to maintain unit availability—or in anticipation of being able to compete in the changing market⁸⁴.

NGCC and natural gas combustion turbine (NGCT) plants have significantly different capacity factors, due primarily to operating characteristics and costs, which dictate their roles in dispatch. NGCT plants are less efficient and therefore have higher operating costs and emissions than NGCC units. However, the short startup times and fast ramp rates of NGCT units make them important for maintaining grid reliability, and their low capital costs make them well suited to use at low annual capacity factors. The flexibility of NGCT plants is useful in complementing

variable generation such as wind and solar because it allows these generators to follow variable generators and load.

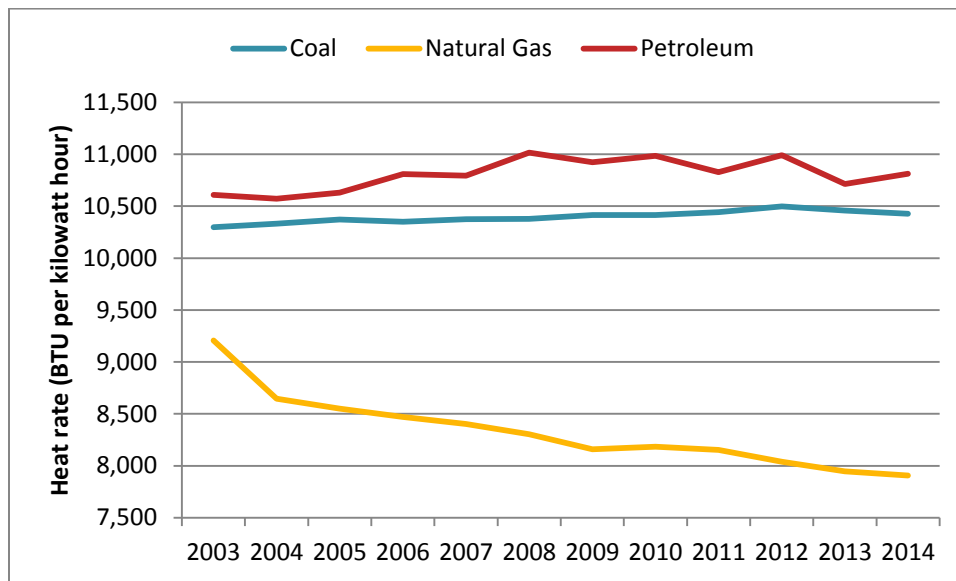
Whereas NGCT units contribute primarily to peak load and only need to be operated a few hours out of the year, NGCC plants operate throughout the year. NGCC plants retain many of the flexible characteristics of NGCTs, but operate at higher efficiency and, therefore, lower cost. Consequently, these units dispatch more frequently than NGCTs; although, before recently sustained low natural gas prices, most NGCC units were utilized for intermediate and peak loads, rather than baseload power. However, flexible operation can come at a cost: reduced efficiency, higher emissions, and increased wear and tear on the equipment, which increase maintenance costs⁸⁵. Vendors now offer NGCC units specifically designed for flexible operation, and these can reduce the maintenance impacts (in particular), but these units cost up to 30 percent more than the standard commercial offering⁸⁶.

Fuel prices have a significant impact on how existing power plants are used. For example, when natural gas prices become competitive with coal prices, as they currently are in the low U.S. gas price environment, the U.S. NGCC fleet operates at a higher capacity factor. For example, in 2015, NGCC plants in the United States operated at an average 56 percent capacity factor, relative to an average 36 percent capacity factor in 2005⁸⁷.

Capacity factors also change significantly on a monthly basis, as shown in the right side of Figure 3-4. Most dispatchable U.S. generators operate at the highest level in the summer, when demand for electricity is highest. U.S. solar generation is also highest in the summer months due to stronger solar availability. Wind generators, which are nondispatchable, produce more electricity in the winter months than in the summer on average in the United States⁸⁸. Wind generators may also produce more power at night than during the day in some regions. In such cases, wind and solar may be good complementary sources of electricity, up to a given level of penetration.

Heat rates are a way to measure the efficiency of a power plant. The heat rate is the amount of input energy used by an electrical generator or power plant to generate 1 kWh of electricity⁸⁹. Figure 3-5 illustrates the heat rates for fossil fuel-fired generators over time. Heat rates are inversely related to efficiency: a lower heat rate means a plant is more efficient. Natural gas heat rates have been decreasing over the past decade, most likely due to the recent increase in new NGCC plant installations, which tend to have lower heat rates or higher efficiencies.

Figure 3-5. U.S. annual heat rates for fossil fuel technologies, 2003–2013



Generator heat rates measure the efficiency of fuel use in producing power, and natural gas generation heat rates have varied significantly over the past decade. Source: EIA 2016⁹⁰.

3.4 Generation Costs and Comparisons

Generation costs in the electric power sector vary by fuel and technology. Comparing generation technologies based only on their capital costs is limiting because some are more capital intensive, but have lower operation and maintenance (O&M) or fuel costs, which may make them more cost competitive when considering the plant’s generation across its economic lifetime. To compare across the economic lifetime of these technologies, LCOE is the metric often used.

3.4.1 LCOE

LCOE^{xix} analysis is widely used to compare generation costs of different technologies, although doing so on a true “apples to apples” basis can be complex given the different roles and characteristics that generators have. While LCOE is a convenient summary measure of the overall competitiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors, including the projected utilization rate, generator availability, and the existing resource mix in a region. The capacity value of a resource, which depends on both the existing capacity mix and load characteristics in a region, can also be important: since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less controllable units (nondispatchable technologies). Furthermore, LCOE values do not typically capture external costs or valuations, such as environmental costs or flexibility attributes. Also, caution should be used when comparing LCOE values for dispatchable and nondispatchable technologies, particularly when costs elsewhere in the bulk power or distribution system must be separately

^{xix} Appendix B contains details on the methodological approach and assumptions used in calculating the LCOE values shown in Figure 3-6.

incurred and, typically, are ultimately paid by the end-use customer^{91, xx}. LCOE should not be used to compare distributed and utility-scale generation technologies due to different regulations and electricity prices.

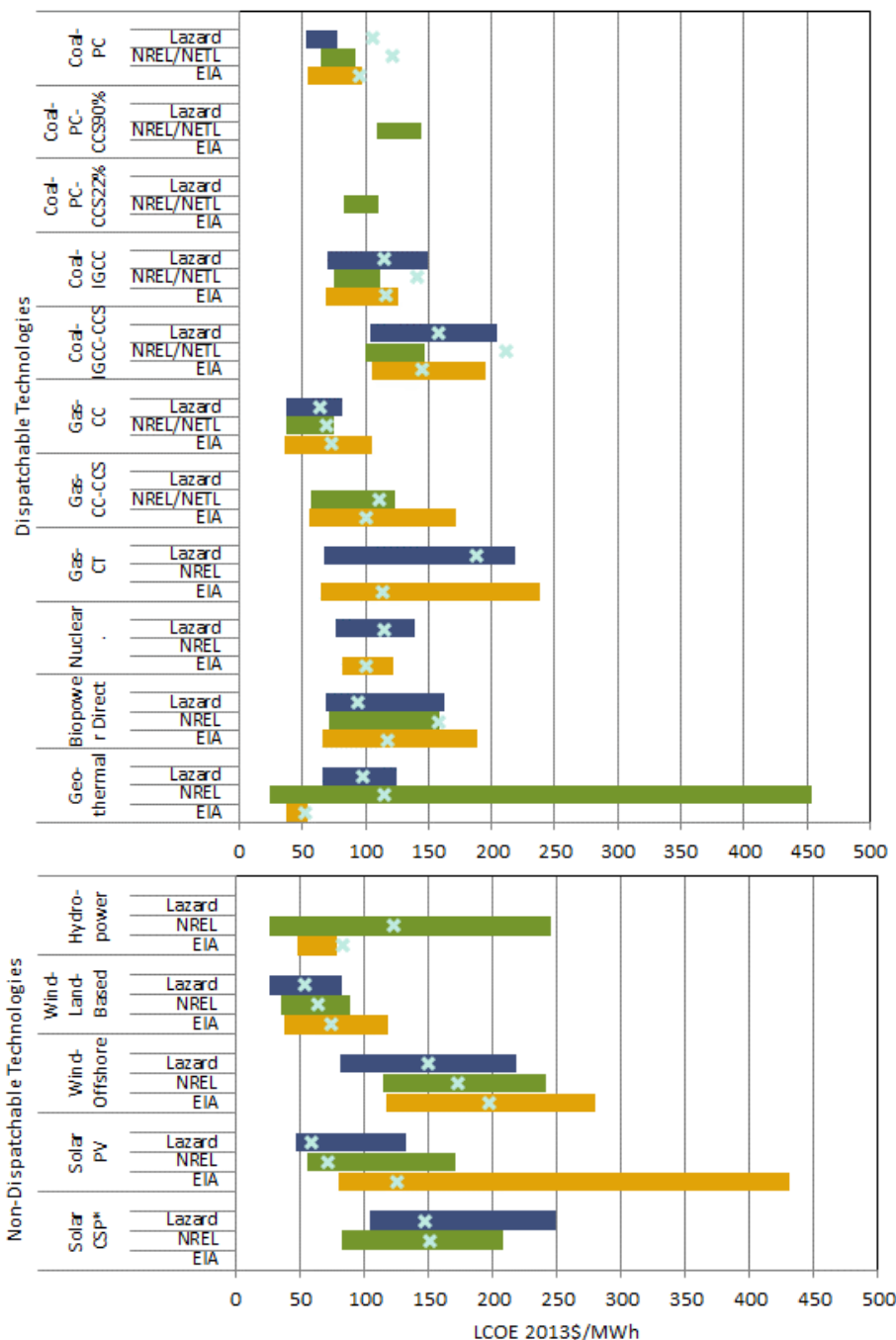
Figure 3-6 illustrates LCOEs for selected generation technologies from three sources used in the analysis: EIA, the National Renewable Energy Laboratory (NREL) or National Energy Technology Laboratory (NETL), and Lazard⁹². These sources were chosen based on their wide-scale use and referencing in other publications, data transparency and range, and range of assumptions. This effort tries to eliminate some confusion in comparing LCOE across sources by controlling for financial and other non-technology factors by harmonizing certain variables used in the different LCOE calculations to better control for distinctions. As a result, the re-estimated LCOEs better reflect the key differences in technology cost assumptions among the three sources examined; however, they do not reflect different costs of financing different projects. Figure 3-6 shows estimates for LCOEs by fuel type using the cost and heat rate data and then uses a fixed range of financial and operational assumptions. These values represent a broader range than values estimated in the respective reports because of the shared set of assumptions. The “X” symbols represent the reported values from each of the respective reports and may differ from the median or average of the ranges due to difference between the shared set of assumptions and individual report assumptions. For EIA and NREL, these are the national 2020 values; for Lazard, they are the midpoints that represent technologies starting construction in 2015. While this approach allows for a more neutral understanding of LCOE estimates across technologies, ranges are greater than what is reported in individual reports.

As seen in Figure 3-6, there is considerable variation in range for some LCOEs and notable differences in reported values. Note that LCOE values shown do not include tax credits. For example:

- For dispatchable generation, NGCC is the lowest cost with the narrowest price spread, while for nondispatchable technologies, wind is the lowest cost with the smallest price spread.
- NGCC with CCS and nuclear have similar LCOE values as low- or no-carbon, dispatchable generation sources, with utility-scale solar PV (with the exception of EIA) falling within the same price range for nondispatchable generation.
- While cost is not the only consideration in adding new generation, these trends correspond with what has been observed for capacity additions in recent years once tax credits are included, with land-based wind, NGCC plants, and solar PV making up the majority of capacity additions at 41 percent, 30 percent, and 26 percent of total additions, respectively⁹³.

^{xx} Caution should be used whenever comparing LCOE between systems that do not have the same duty cycle because the value of energy (or cost of displaced energy or “avoided cost”) of the systems are different. One shouldn’t compare a CT to a coal plant, since one is a primarily used to serve peak load and the other baseload. Similarly, wind has its own, distinct duty cycle derived from the diurnal and seasonal output characteristics of the wind, making it difficult to compare its LCOE to other technologies.

Figure 3-6. Reported (x values) and estimated (range) LCOE values for dispatchable and nondispatchable technologies



While LCOE values are an imperfect metric to compare electricity generation costs across all technologies, they can provide important insights over time and within ranges of technologies. NGCC plants typically have the lowest LCOE among all dispatchable generation types, while land-based wind, hydropower, and utility-scale solar PV have the lowest costs among not-fully-dispatchable technologies. Sources: NREL 2015a; EIA 2015; Lazard 2015.

Notes: X values represent published values. For EIA and NREL, that encompasses plants coming online in 2020; for Lazard, values encompass those starting construction in 2015. These values do not reflect any subsidies, including the PTC or ITC. Lazard capital cost ranges for coal IGCC and coal IGCC-CCS were estimated by using the midpoint between the IGCC range, the low end representing IGCC and the high end representing IGCC-CCS. EIA's CSP capital cost estimates do not include storage; NREL and Lazard estimates include storage. The LCOE range for EIA CSP without storage is 254–748 2013\$/MWh. Solar PV is utility-scale only. Hydro is considered nondispatchable due to multiple-use obligations and seasonal variability. The low end of the geothermal range for EIA represents expansion of an existing facility and is not representative of development of a new facility.

3.4.2 LCOE and LACE

In this section, we consider two economic metrics to shed light on the relative changes in competitiveness of electric generation technologies over time. As noted previously, LCOE is designed to allow comparison across different technologies that have much different capital and operational cost profiles, although it does not capture all costs or considerations. For example, LCOE does not take into account the variable nature of wind and solar generation. It also does not value other attributes of generation such as capacity value and the ability to provide ancillary services. Similarly, the levelized avoided cost of energy (LACE) attempts to focus on value that a particular technology offers by representing the avoided costs that would have been incurred by the existing resources had they been used to generate the new marginal unit of electricity instead. To achieve this, LACE calculations use the modeled wholesale electricity price for a region with the existing generation mix and the projected capacity that a new unit would add. Like LCOE, LACE is limited in that it may not fully capture all the factors that ultimately inform a decision. EIA, however, believes that when used in tandem, the two metrics can provide greater insight than either one alone. For a more complete discussion of the methodology, advantages, and limitations of the LCOE and LACE metrics, see EIA (2015I) and Namovicz (2013)⁹⁴.

We limited our LCOE and LACE comparisons to only EIA estimates since no other organization publishes LACE estimates. It should be noted that other estimates of LCOE can vary significantly from EIA⁹⁵, but the intent here is to consider how the cost and performance of technologies may change over time—not how they differ at a point in time.

LACE and LCOE estimates are provided below in Table 3-1 for generation technologies entering service in 2020 and 2040. When the LACE value exceeds the LCOE value, the particular technology may be considered attractive to build, although again other considerations are excluded in this representation. Focusing first just on LCOEs, EIA projects that biopower, utility-scale PV, and offshore wind will see the largest reductions in LCOE between 2022 and 2040. This is due to the learning curve for these technologies, which is part of the model. Some technologies like conventional geothermal are projected to have increased LCOEs over time. This can be due to factors such as increasing fuel costs and the quality of the available resource.

Next, looking at the difference in LACE and LCOE, the larger the negative number, the less attractive the technology might be as this represents “delivered value less cost”. A positive number may indicate that the technology is cost-effective to deploy, all else being equal. In 2022, conventional geothermal is the only technology with a positive LACE-LCOE, according to EIA estimates, although this likely reflects only a few cost-effective sites and does not capture development risks associated with geothermal power. NGCC is the only technology with LACE and LCOE differences that are only slightly negative. By 2040, geothermal continues to have a positive LACE-LCOE value; joined by NGCC, utility-scale PV, and onshore wind with positive LACE-LCOE values. Most technologies by 2040 will have less negative LACE-LCOE values than in 2020, except geothermal, which indicates both a drop in technology costs, as well as an increase in the delivered value of electricity. Again it is important to note that, although many technologies have a negative LACE-LCOE value, it doesn’t indicate there won’t be new builds, as neither number captures all the relevant factors, such as future policies, for deciding whether to build.

Table 3-1. Reported LCOEs for Deployment of Select Generation Technologies in 2022 and 2040 (2015\$/MWh)

	LCOE			LACE-LCOE		
	2022	2040	Difference (percent)	2022	2040	Difference (percent)
Dispatchable Technologies						
Biopower	101	79	-22	-35	-15	57
Advanced Coal with CCS	140	126	-10	-108	-62	43
Conventional Geothermal	45	57	27	15	7	-53
NGCC, Advanced	57	56	-2	-8	8	200
NGCC, Advanced with CCS	84	81	-4	-33	-17	48
Advanced Nuclear	103	93	-10	-52	-29	44
Not Fully Dispatchable Technologies						
Solar PV, Utility	85	71	-16	-28	5	118
Water, Hydro	68	65	-4	-18	-3	83
Wind, Land-Based	65	59	-9	-17	0	100
Wind, Offshore	158	133	-16	-139	-69	50

Source: EIA (2015)^{xxi, 96}

3.5 Environmental Impacts

Life-cycle analysis of electricity generation considers the full supply chain associated with producing the materials and fuels that go into constructing and operating the generator, and it also often factors in downstream issues such as decommissioning. In this section, we look at the following life-cycle factors: life-cycle GHG emissions, select air emissions, water withdrawal and use, and land use. These metrics can be important tools for decision makers when planning investment and licensing for power plants. For a more in-depth discussion of GHG emissions and other environmental impacts, please see the QER 1.2 Environment Baseline Vol. 1 – *Greenhouse Gas Emissions from the U.S. Power Sector: Baseline and Outlook to 2040*, and the QER 1.2 Environment Baseline Vol. 2 – *Environmental Quality and the U.S. Power Sector: Air Quality, Water Quality, Land Use, and Environmental Justice*.

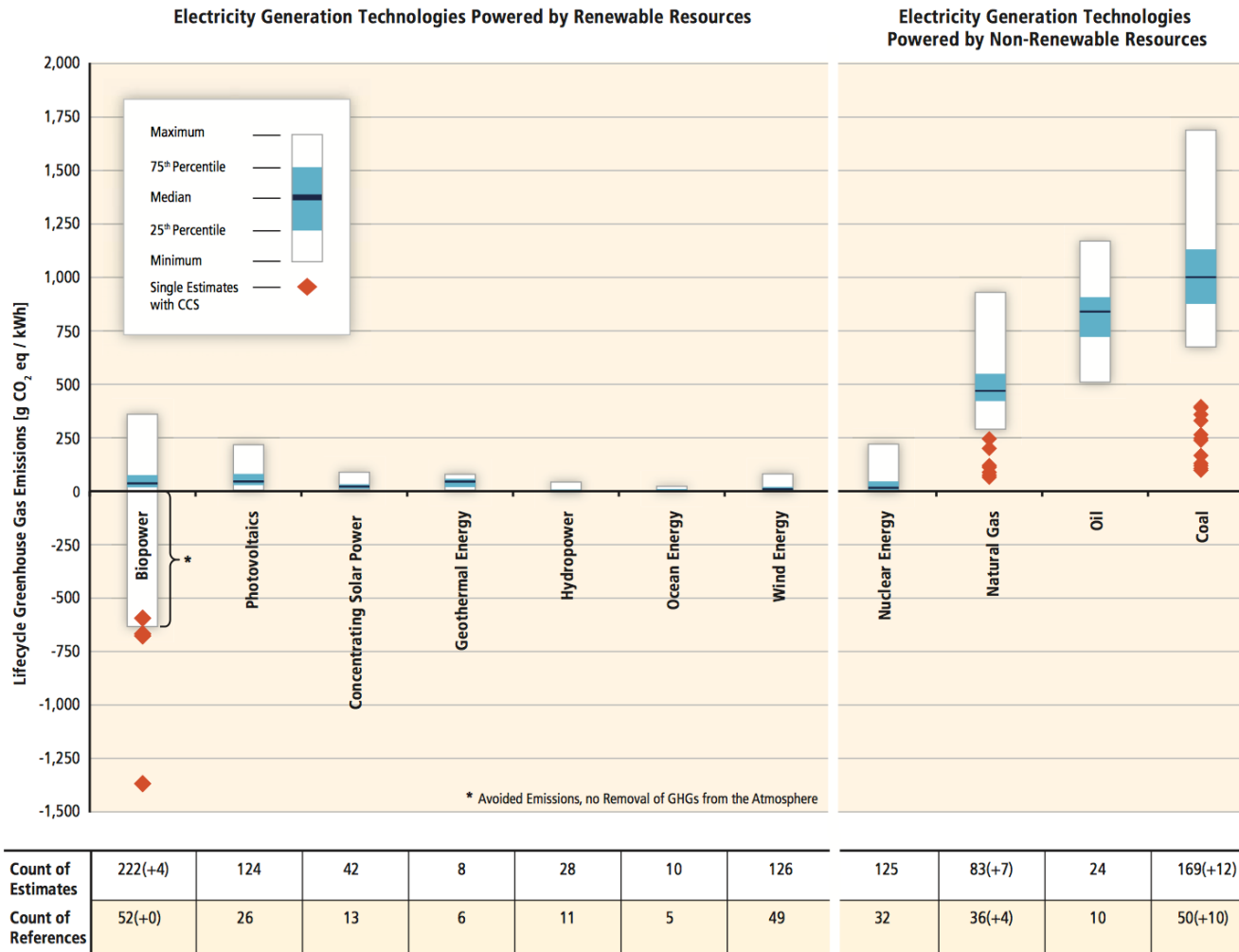
^{xxi} Note that these numbers were not harmonized and were taken directly from AEO 2016 report. Simple average of regional value LCOE and LACE numbers were used due to data missing for technologies in capacity weighted average tables.

3.5.1 *GHG Emissions*

Life-cycle GHG emissions estimates for a variety of generation technologies are summarized in Figure 3-7. The illustration was derived from a meta-study of more than 2,000 published reports on life-cycle GHG emissions of both conventional and renewable generation technologies, only some of which passed a set of screening criteria to be included in the final results⁹⁷. A range of life-cycle GHG emissions are provided for each generation option, including the median, upper, and lower quartiles, and maximum and minimum values. Point estimates are provided for options that include CCS (orange diamonds). The number of published studies and estimates from each are provided at the bottom of the figure.

Coal generators report a median value of approximately 1,000 g CO₂ equivalent (CO₂ eq) per kWh of generation. Oil and natural gas have median values approximately 20 percent lower and more than 50 percent lower, respectively. All other generation options have median values below 50g CO₂ eq/kWh. Biopower generation exhibits a wide range of potential emissions, primarily reflecting the assumptions used in calculating land-use change impacts. Biopower with CCS, also referred to as bioenergy with CCS, is also the only generation option that can exhibit significant negative emissions, although there is debate over methodological approaches to characterizing biopower emissions⁹⁸. Coal and natural gas with CCS report average values approximately 75 percent lower than estimates that do not assume CCS.

Figure 3-7. Life-cycle GHG emissions for select generation technologies based on a meta-study literature review



Over 2,000 published studies were analyzed to estimate the full life-cycle emissions of electric generating options in this meta-study. Coal emissions were highest, with median natural gas emissions just over 50 percent lower. Nuclear and most renewable generators had median values less than 50 g CO₂ eq/kWh. Biopower with CCS is the only generation option that can achieve negative emissions. Source: Sathaye et al. 2011⁹⁹.

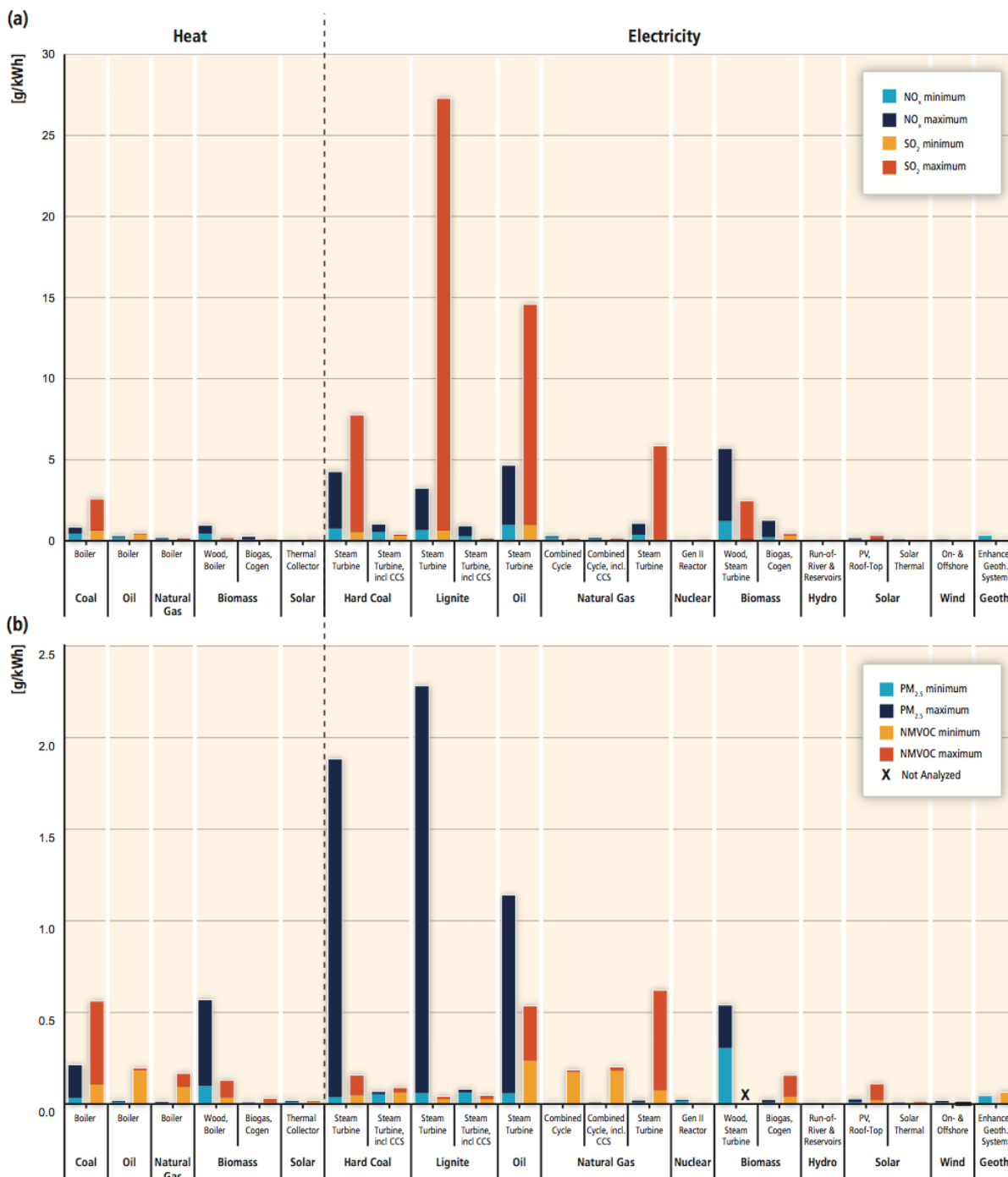
3.5.2 *Non-GHG Life-Cycle Emissions*

Electricity generators also exhibit a wide range of emissions of non-GHG air pollutants, which have a range of human health and environmental impacts. Life-cycle emissions of oxides of nitrogen and sulfur dioxide for a variety of generating options and fuels are shown in the upper half (a) of Figure 3-8, while life-cycle emissions of particulate matter 2.5 micrometers or less and non-methane volatile organic compounds (NMVOCs)^{xxii} are shown in the lower half (b). This figure offers a measure of the emissions intensity (g/kWh) for different generation technologies and fuel types and does not reflect the relative total emissions from these technologies in the United States (i.e., when accounting for the current fuel mix).

Life-cycle sulfur dioxide emissions are highest for fossil fuels, especially lignite, combusted in STs (Figure 3-8). Nitrogen oxides follow a similar pattern, although biomass combusted in STs can produce high emissions as well. For particulate matter 2.5 microns or less (PM_{2.5}), which is considered especially dangerous to human health¹⁰⁰, the direct emission characteristics are similar to those for nitrogen oxides, with fossil STs and, especially, biomass STs capable of the highest intensity levels. NMVOC emissions are greatest for oil used in STs and across the range of natural gas generation technologies.

^{xxii} NMVOCs are ubiquitous organic chemicals that readily evaporate or sublime from the liquid or solid forms from which they originate. They contribute to the formation of ground-level ozone and can also pose dangers in indoor environments. Examples of NMVOCs that are harmful to humans or the environment include benzene, formaldehyde, chlorofluorocarbons, and methyl chloride.

Figure 3-8. Life-cycle air emissions for select generation technologies



Air emissions from electricity generators vary widely depending on fuel and technology type. Coal and oil generators typically have the highest emissions of sulfur oxides, while biomass, oil, and coal have the greatest emissions of nitrogen oxides. Similarly, coal and biomass have high particulate emissions, while natural gas, oil, and coal have the highest levels of NMVOC emissions. Source: Sathaye et al. 2011¹⁰¹.

3.5.3 *Water Withdrawal and Consumption*

All electricity generation technologies use water throughout their life cycles, but water withdrawal and consumption factors vary across and within fuel technologies. Total life-cycle water use across generation technologies is typically lowest for solar PV and wind, and highest for CSP with wet cooling, conventional coal technologies and nuclear¹⁰², but the specific type of cooling technology used impacts the results. Non-thermal renewable generation technologies have no water requirements associated with fuel extraction, and use almost no water for operational purposes, but require some water for construction and manufacturing.

Across all generation technologies, operations dominate life-cycle water use with the exception of solar PV, wind, and dry-cooled thermoelectric technologies¹⁰³. On the other hand, water use for solar PV is largely dominated by manufacturing relative to other life-cycle stages. For example, estimates of water withdrawals for solar PV power plant equipment life cycles range from 1 to 1,600 gallons/MWh with a median of 94 gallon/MWh. However, water use for operations is minimal as few operators actually wash PV panels in practice¹⁰⁴. For wind, the median water withdrawal is 26 gallons/MWh with consumption around one gallon/MWh. Because wind turbines require no fuel and little washing or maintenance, operational water use is minimal.

Thermoelectric power plants, such as coal, natural gas, nuclear, geothermal, and CSP, require significant volumes of water for power generation, ranging from hundreds to thousands of gallons per MWh. Water use is reported in water withdrawals—the amount of water withdrawn from the water source, some of which may be returned to said source—and water consumption (generally consumed by evaporation into the atmosphere). Water withdrawals and consumption vary substantially by cooling technology.

In once-through cooling systems, water is withdrawn from a river or other body of water, used for cooling, and then returned to the water source. In general, there is a trend to move away from once-through cooling for power generators in the United States, where large withdrawals are required¹⁰⁵.^{xxiii} Instead, recirculating and dry cooling are becoming more commonly used. Recirculating, or “closed-loop” cooling, has greatly reduced water withdrawal requirements compared to once-through cooling, but it consumes more water. Dry cooling requires no water use but comes with an energy penalty, reducing the efficiency of the power plant. Plant efficiency also affects water use: a plant that is more efficient will use less water than a similar plant that is less efficient.

One meta-study that reviewed the literature on water withdrawal and consumption found that CSP power plants consume the most water, followed by nuclear, coal, and geothermal, when using the same cooling system¹⁰⁶. Water consumption from natural gas plant operations is the least of all thermoelectric power plants, ranging from one-half to one-third of the water consumption for coal according to the meta-study.

Finally, water use by hydro plants varies considerably depending on the site features and plant configuration. Hydroelectric plants with large reservoirs, for example, may consume large amounts of water due to evaporation, although such reservoirs have other uses besides power

^{xxiii} Greater withdrawals are required because of the limited capabilities of sensible heating compared to latent heat transfer (evaporation) of water, along with environmental requirements limiting how much the temperature of the water can be changed prior to returning it to the environment.

generation (recreation, flood control, etc.), so attribution can be complex. Water use characteristics of different electricity generation technologies are discussed more in the QER 1.2 Environment Baseline Vol. 4 – *Energy-Water Nexus*.

3.5.4 Land Use

Estimating life-cycle land use for power generation is complex, mainly due to the difficulty of quantifying “upstream” footprints, such as mining of coal or uranium (for nuclear generation), or determining how much land is actually “used.” As a result, few comprehensive analyses have received widespread support among the research community¹⁰⁷. For renewable energy generators, the operational footprints account for most or all of the land used, while the upstream impacts are relatively low since there is no mining required for fuel. For nonrenewable generators, the opposite is typically true, although waste disposal for nuclear and coal generation can increase the operational footprint substantially¹⁰⁸. The operational land needs of renewable energy generators can be misleading, though, because the land is usually not completely taken out of production for other uses. Turbines for onshore wind farms, for example, are estimated to take up about 1–5 percent of the actual land used by the entire project. The other 95–99 percent of the land can thus often be used to grow crops or raise livestock¹⁰⁹. For solar PV, the quality of the solar resource available can have a significant impact on the amount of land needed to produce a unit of electricity. In Arizona, for example, land use is estimated at 250 m²/GWh/year, while the average for the entire United States is more than twice that level¹¹⁰. Land use characteristics of different electricity generation technologies are discussed more in the QER 1.2 Environment Baseline Vol. 2 – *Environmental Quality and the U.S. Power Sector: Air Quality, Water Quality, Land Use, and Environmental Justice*.

3.6 Generation and Ownership Types

The role of ownership impacts generation under a number of Federal electricity policies. For example, Government and nonprofit generation owners are either not eligible or have limited benefits from Federal tax credits. Municipally owned utilities can issue tax-exempt bonds; electric cooperatives receive loans from sources such as the U.S. Department of Agriculture Rural Utilities Service; and investor owned utilities (IOUs) can finance generation through stocks and private bonds (see, for example, California Energy Commission 2016; USDA 2016). The Tennessee Valley Authority’s (TVA’s) power system financings consist primarily of the sale of debt securities and secondarily of alternative forms of financing such as lease arrangements. As a wholly owned Government corporation, TVA is not authorized to issue equity securities¹¹¹.

Non-utility generators, or independent power producers, own 42 percent of the U.S. electric generation fleet capacity, followed by IOUs at 36 percent, public power (non-Federal) entities at 10 percent, and Federal entities and cooperatives at 6 percent each (Figure 3-9). The generation types are:

Non-utility generators: (also referred to as independent power producers): Entities that own power plants and sell their power into the wholesale market. They may be owned by an investor-owned holding company.

IOUs: Generating entities that are privately owned and regulated by State authorities

Federal agencies: Government agencies with the authority to deliver energy to end-use customers

- *Federally owned utilities* include TVA and the four Power Marketing Administrations (PMAs): the Bonneville Power Administration, the Western Area Power Administration, the Southeastern Power Administration, and the Southwestern Power Administration.
- *PMAs* are primarily marketers of electricity generated by federally owned generating facilities. PMAs do not directly service residential or commercial customers, nor do they generally own electric generating facilities (there are some exceptions such as Bonneville Power Administration owning the Columbia Nuclear Generating Station). With the exception of Southeastern Power Administration, PMAs own and operate transmission systems to market power¹¹². They make wholesale electricity sales to municipal and cooperative utilities and some direct sales to large industrial customers. The electricity generating facilities are primarily owned and operated by the U.S. Department of the Interior's Bureau of Reclamation, the U.S. Army Corps of Engineers, and the International Boundary and Water Commission.
- *TVA* is a corporate agency of the United States that provides electricity for business customers and local power distributors serving 9 million people in parts of seven southeastern states. TVA receives no taxpayer funding, deriving virtually all of its revenues from sales of electricity. In addition to operating and investing its revenues in its electric system, TVA provides flood control, navigation, and land management for the Tennessee River system and assists local power companies and State and local governments with economic development and job creation.

Publicly owned utilities (non-Federal):

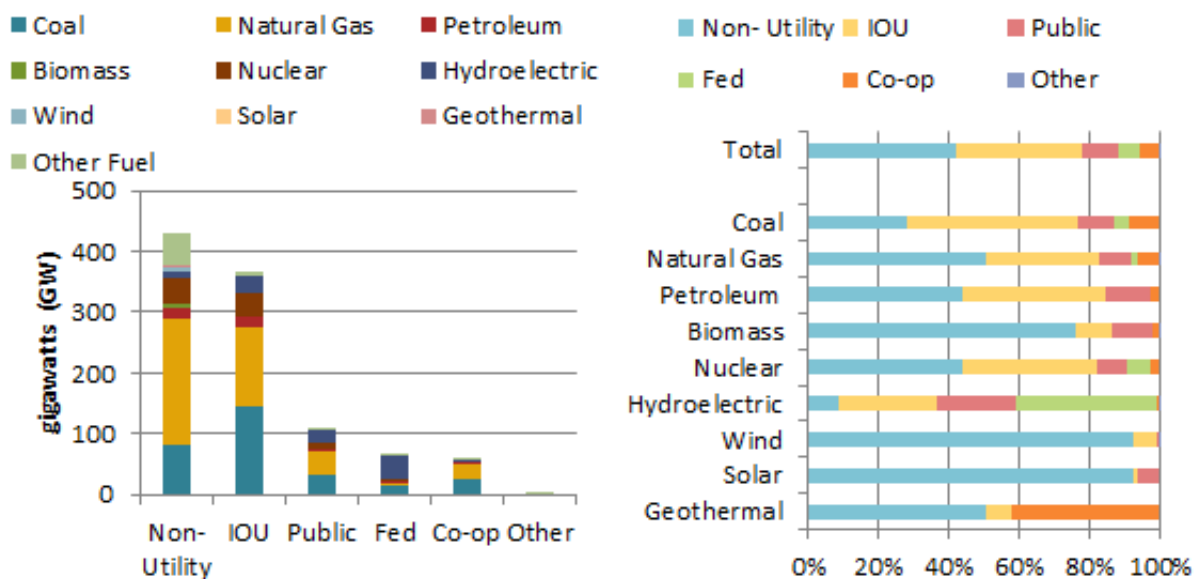
- *State*: Entities that own or operate facilities or provide a public service
- *Municipal*: Entities that are voted into existence by the residents of a municipality and organized under authority of State statute to provide a public service to its residents
- *Joint action agencies*: Entities that are formed by a group of municipal utilities to provide reliable and competitively priced energy or energy-related services, typically through asset ownership
- *Political subdivision*: Independent of city or county government, entities voted into existence by a majority of the residents of any given area for the specific purpose of providing the utility service to the voters

Cooperatives: Member-owned electric utilities

Other ownership types: These entities may participate in different parts of the electricity transaction process, for example:

- *Power marketer*: Entities that do not own generating facilities but buy and sell power in the wholesale market or market power to retail customers in states that allow retail competition
- *Transmission-only*: Entities that provide bulk power services over high-voltage transmission wires
- *Behind-the-meter provider*: Entities that directly supply electricity to an end-use customer site without a distribution provider involved, or customers that generate electricity to serve their needs or supply back to the grid
- *Non-utility demand-side management administrator*: Only involved with demand-side management activities¹¹³
- *Community solar*: Multiple entities (individuals or organizations) that jointly own a distributed solar facility.

Figure 3-9. U.S. generation fleet capacity (left) and share of capacity (right) by ownership and fuel type, 2014



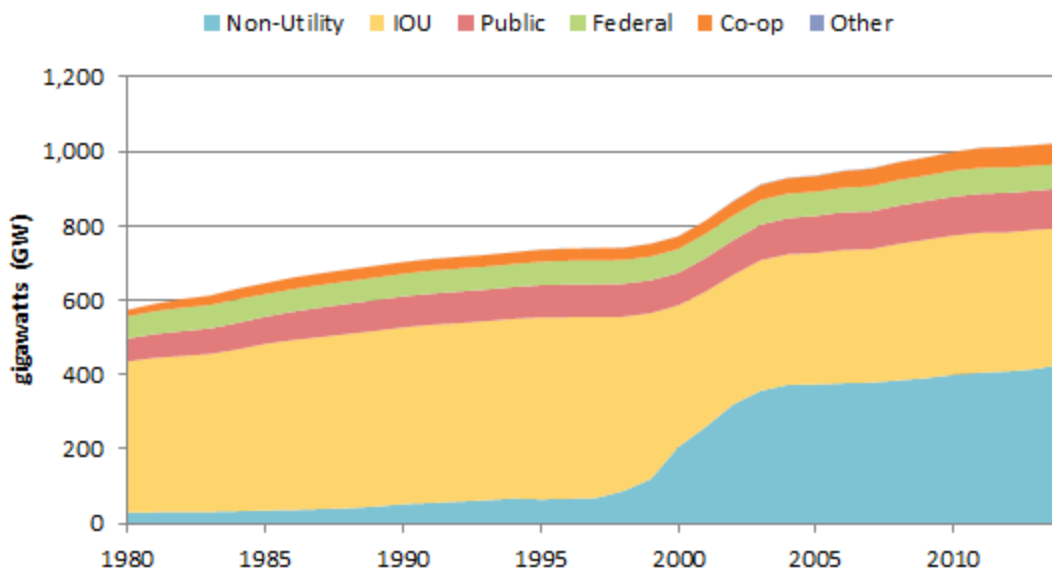
Non-utility generators, or independent power producers, own more of the U.S. electric generation fleet capacity than IOUs. Non-utility generators own the majority of most renewable capacity, with the exception of hydro. IOUs own the majority of coal, while non-utility generators own the majority of natural gas, nuclear, and petroleum. Source: ABB Velocity Suite 2015¹¹⁴.
 Note: Solar is utility-scale only.

The share of fuel type across ownership varies; 2014 data are shown in Figure 3-9 (right). Non-utility generators and non-Federal public power entities are predominately natural gas, at 48 percent and 37 percent, respectively, while IOUs are predominately coal at 40 percent, and Federal entities predominately provide hydroelectric capacity at 59 percent. Cooperatives own almost exclusively coal (45 percent) and natural gas (46 percent). Non-utility generators own

most of the non-hydro renewable sources, such as biomass (76 percent), wind (93 percent), solar (93 percent), and geothermal (50 percent), as shown in Figure 3-9 (left).

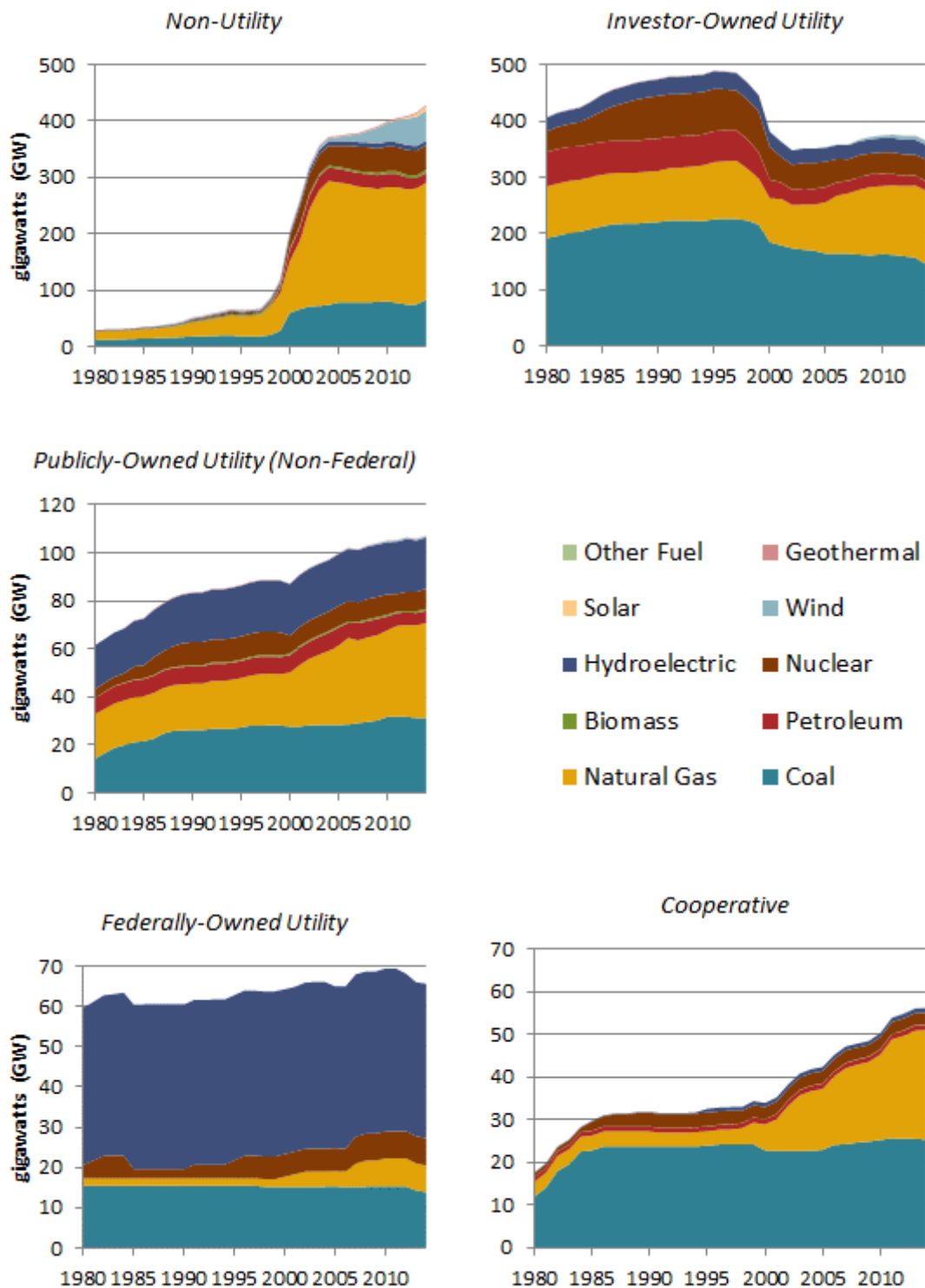
Ownership over time has also changed significantly as illustrated in Figure 3-10 and Figure 3-11. Specifically, there was a dramatic shift in the late 1990s and early 2000s from IOUs to non-utility generators, as well as additional buildout. This change in ownership type was influenced in part by market restructuring within certain regions of the United States. More recent growth in non-utility generation ownership is primarily in non-hydroelectric renewable capacity, while all other ownership types have grown primarily in natural gas-fired capacity.

Figure 3-10. U.S. generation fleet by ownership type, 1980–2014



Non-utility ownership of generation capacity grew rapidly from 1998 to 2004 as vertically integrated utilities shed ownership of their generation assets in some regions of the country to comply with new market designs. Many independent power producers built new NGCC units at the time as the technology had improved significantly. Source: ABB Velocity Suite 2015¹¹⁵.

Figure 3-11. U.S. generation by fuel type for various ownership types, 1980–2014



Generation sources vary significantly by type of ownership. Source: ABB Velocity Suite 2015
 Note: Solar is utility-scale only.

Non-utility generators and non-Federal public power entities are predominately natural gas, at 48 percent and 37 percent respectively, while IOUs are predominately coal at 40 percent. Federal entities predominately provide hydroelectric capacity at 59 percent. Cooperatives, once dominated by coal capacity, have seen strong growth in natural gas capacity since 2000. Publicly owned utilities, State agencies, and cooperatives own 24 percent of hydropower capacity¹¹⁶. Forty-nine percent of hydropower generation capacity is owned by the Federal Government, including the U.S. Bureau of Reclamation, U.S. Army Corps of Engineers, and TVA. The U.S. Army Corps of Engineers’ multipurpose dams are the largest producers of hydropower in the United States. However, electricity production is just one of the purposes. For example, the Flood Control Act of 1944 led to the establishment of the Pick-Sloan Missouri Basin Program, which has six purposes: hydropower, recreation, water supply, navigation, flood control, and fish and wildlife. Federal hydropower must be sold at the lowest possible cost by TVA and the PMAs with a statutory right of first refusal granted to nonprofit entities, including public power systems and rural electric cooperatives.

Table 3-2. Differences between Publicly Owned Utilities (POUs) and IOUs in California

	POU	IOU
Ownership	A local government body and/or customers/members of the utility. Usually limited to the service area.	Shareholders or investors. Not limited to the service area.
Structure/ Management/ Regulation	Nonprofit public entity managed by locally elected officials/ public employees.	Private company. Shareholder-elected board appoints management team of private sector employees. Regulated by California Public Utilities Commission (CPUC).
Rates Setting and Regulation	Customer rates are set by each utility's governing body-board or city council in a public forum.	Customer rates are set and regulated by the California Public Utilities Commission through a public process that includes some customer participation.
Mission/Goals	Optimize benefits for local customer owners, usually in the form of lower energy rates.	Optimize return on investment for shareholders.
Financing	Public utilities have access to tax-free bonds and co-ops have access to low-interest loans usually at the local level.	Stockholders (investors), the sale of bonds, and bank borrowing help finance the utility's operations.
Power Generation	Operate their own generation facilities or purchase power through contracts.	Purchase power through contracts and operate their own generation facilities. After the energy crisis, IOUs resumed electricity procurement in 2002 (Public Utility Code 454.5). Every 2 years, the California Public Utilities Commission holds a Long Term Procurement Plan proceeding to review and adopt the IOUs's 10-year procurement plans. The Long Term Procurement Plan proceeding evaluates the utilities's need for new fossil-fired resources and establishes rules for rate recovery of procurement transactions.

	POU	IOU
Profit/Net Revenue	Rates are set to recover costs and earn additional return to maintain bond ratings and invest in new facilities.	Utility rates are set to recover costs and earn a reasonable return as profits for investors in return for the risk they bear for investing in new facilities.
Size/ Heterogeneity	Although POU's dramatically differ in size and number of customers they serve, most are small or midsized with an exception of LADWP and SMUD.	Very large in size and number of customers. Complex, heterogeneous customer mix.

Source: California Energy Commission 2016.¹¹⁷

3.7 Federal Policy and Generation^{xxiv}

Federal policies have played a significant role in the development of power generation in the United States. In general, Federal policies in the 1930s and 1940s fostered the development of hydropower; Federal policies in the 1940s and 1950s led to the transformation of nuclear technology to electric generation; the Fuel Use Act favored coal-fired over gas- and oil-fired generation from the 1970s to the 1980s; natural gas-fired generation took off in the late 1980s; and non-hydro renewables have seen the most growth in the 2010s. Federal policies combined with key historic events—such as the Great Depression and World War II—and technological advancements—such as shale gas technology and advances in solar and wind generation—have had especially significant impacts. Below are some examples of the impact of Federal policies on power generation in the United States. Figures 3-12 and 3-13 show generation and capacity additions, respectively, over time, with selected legislation overlaid.

Hydropower

The Great Depression and widespread floods and drought in the West during the 1930s led to the creation of TVA in 1933, the extension of the Federal Power Commission's authority over hydropower in 1935, the enactment of the Rural Electrification Act of 1936, and the establishment of the Bonneville Power Administration in 1937. This was the “big dam” period¹¹⁸ when public policy supported harnessing the nation's resources for the public good, i.e., providing low-cost hydropower to the public through nonprofit entities¹¹⁹.

At the outbreak of World War II, Germany, Italy, and Japan had three times more power generating capacity than the United States, and energy demand associated with the war program soared. Hydropower proved to be one of the best ways to meet this demand, which was estimated in 1942 to be 154 billion kWh of electric energy annually, an amount that exceeded the total production capacity of all existing generation in the United States¹²⁰.

Nuclear

Prior to and during World War II, nuclear research focused mainly on weapons development. Later, the focus shifted to peaceful applications of nuclear technology, including power generation. The Atomic Energy Act of 1946 created the Atomic Energy Commission to regulate nuclear energy development and to explore and promote peaceful uses of nuclear energy. The

^{xxiv} This section is intended to be illustrative of the relationship between federal policies and generation development rather than a comprehensive treatment of the subject.

Atomic Energy Act of 1954 provided increased access for the civilian program to nuclear technology. The Price-Anderson Nuclear Industries Indemnity Act facilitated the development of nuclear powered generating capacity by establishing a program for covering claims of members of the public if a major accident occurred at a nuclear power plant and by providing a ceiling on the total amount of liability for nuclear accidents. The Energy Reorganization Act of 1974 divided the AEC into the U.S. Energy Research and Development Administration (combined in 1977 with the Federal Energy Administration to become DOE^{xxv}), which focused on R&D efforts to address the nation's growing need for additional sources of energy, and the U.S. Nuclear Regulatory Commission (NRC), which focused on the regulation of civilian uses of nuclear energy. More recently the Energy Policy Act of 2005 included a number of measures for existing and new nuclear plants, including a 20-year renewal of Price-Anderson, updating tax treatment of decommissioning trust funds, creating a loan guarantee program for new nuclear plants, and authorized additional R&D.

Coal

Coal-fired generation grew every year between 1949 and 2007 except for 1986, 1991, and 2006. In 2015, coal-fired generation and natural gas generation each made up roughly 33% of U.S. electricity generation, representing the first time in the modern electricity system that coal was not the dominant fuel of choice for electricity generation¹²¹. However, coal's share of electricity generation has begun falling. Nearly 15 GW of coal-fired electric generating capacity were retired in 2015, a relatively high amount compared with recent years. In 2016, EIA expects lower natural gas prices will result in natural gas fueling 33.4 percent of U.S. electricity generation in 2016 compared with 32 percent for coal¹²².

The decline of coal-fired generation has largely been due to competition with low natural gas prices, an aging fleet, and environmental regulations. About 30 percent of the coal-fired capacity that retired in 2015 occurred in April, which is when the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards rule compliance period expired. The coal units that were retired in 2015 tended to be smaller and were mainly built between 1950 and 1970. The average age of the retired units is 54 years. The rest of the coal-fired fleet that continues to operate is relatively younger, with an average age of 38 years¹²³.

Natural Gas

The Powerplant and Industrial Fuel Use Act was enacted in 1978 in response to concerns over national energy security related to the 1973 oil crisis and the natural gas curtailments of the mid-1970s. The act restricted construction of power plants using oil or natural gas as a primary fuel and instead encouraged the use of coal, nuclear energy, and alternative fuels. Falling natural gas demand and prices led to repeal of the Powerplant and Industrial Fuel Use Act in 1987, which allowed the use of natural gas and oil for large, new baseload electric power plants.

Natural gas consumption for electric generation increased from 2.6 trillion cubic feet in 1988 to 5.7 trillion cubic feet in 2002, an increase of almost 119 percent. In 2016, EIA predicts that natural gas will become the largest source of power generation¹²⁴.

^{xxv} The Department of Energy Organization Act of 1977, Pub. L. 95-91, 91 Stat. 565 (1977). See: <https://www.gpo.gov/fdsys/pkg/STATUTE-91/pdf/STATUTE-91-Pg565.pdf>.

Renewable Energy (Non-Hydro)

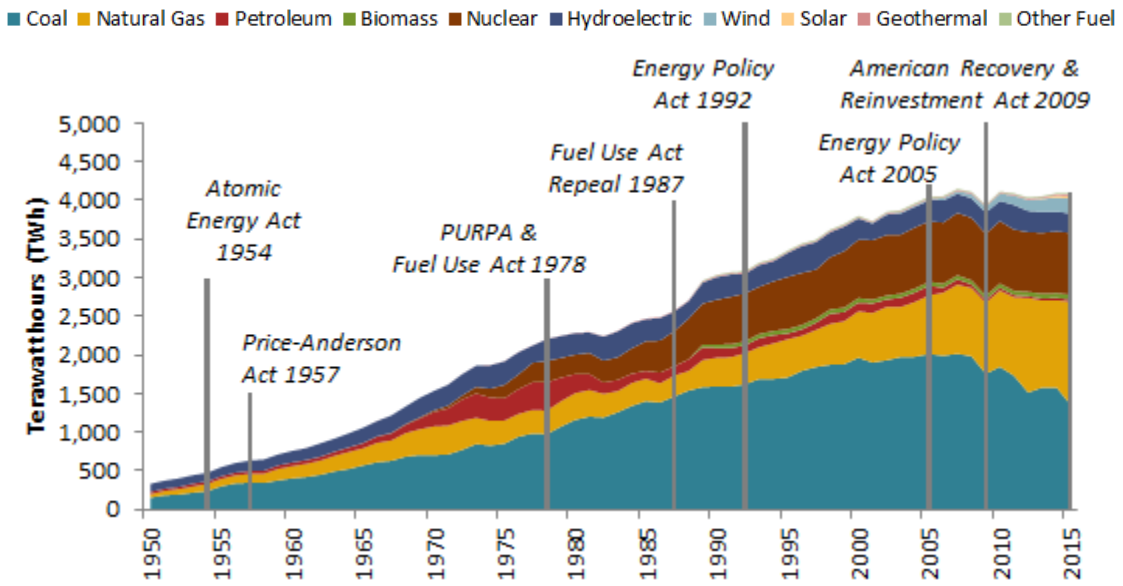
Growth in renewable generation has been driven by improvements in technology, high and volatile fossil fuel prices, Federal tax incentives, State RPS, and consumer preference for renewable energy¹²⁵.

Originally enacted in the Energy Policy Act of 1992, the PTC provides an inflation-adjusted tax credit per kWh of electricity generated for 10 years after a plant is placed in service. In 2014, the PTC was \$0.023/kWh for wind, closed-loop biomass, and geothermal energy resources and \$0.012/kWh for open-loop biomass, landfill gas, municipal solid waste (MSW), qualified hydroelectric, and marine and hydrokinetic (MHK) energy resources¹²⁶. The PTC has been renewed and expanded numerous times, most recently by the American Recovery and Reinvestment Act of 2009, the American Taxpayer Relief Act of 2012, the Tax Increase Prevention Act of 2014, and the Consolidated Appropriations Act of 2016. The Consolidated Appropriations Act of 2016 instituted a stepped phase down of the PTC from 100 percent for plants starting construction by the end of 2016 to 60 percent of the credit for plants starting construction by the end of 2019. Development of certain renewable generators, especially wind, has been particularly dependent on the availability of the PTC, as discussed in sections 8–12.

The Energy Tax Act of 1978 established a residential energy tax credit for solar and wind energy equipment but the credit was allowed to expire at the end of 1985. The Energy Policy Act of 2005 established a 30 percent residential solar credit with a cap at \$2,000, which expired at the end of 2007. The Tax Relief Act of 2006 extended the credit through the end of 2008 and established a 10 percent business tax credit for solar, wind, geothermal, and ocean energy equipment. The Energy Policy Act of 2005 increased the solar business credit to 30 percent through the end of 2007. It was extended to the end of 2008 by the Tax Relief Act of 2006¹²⁷.

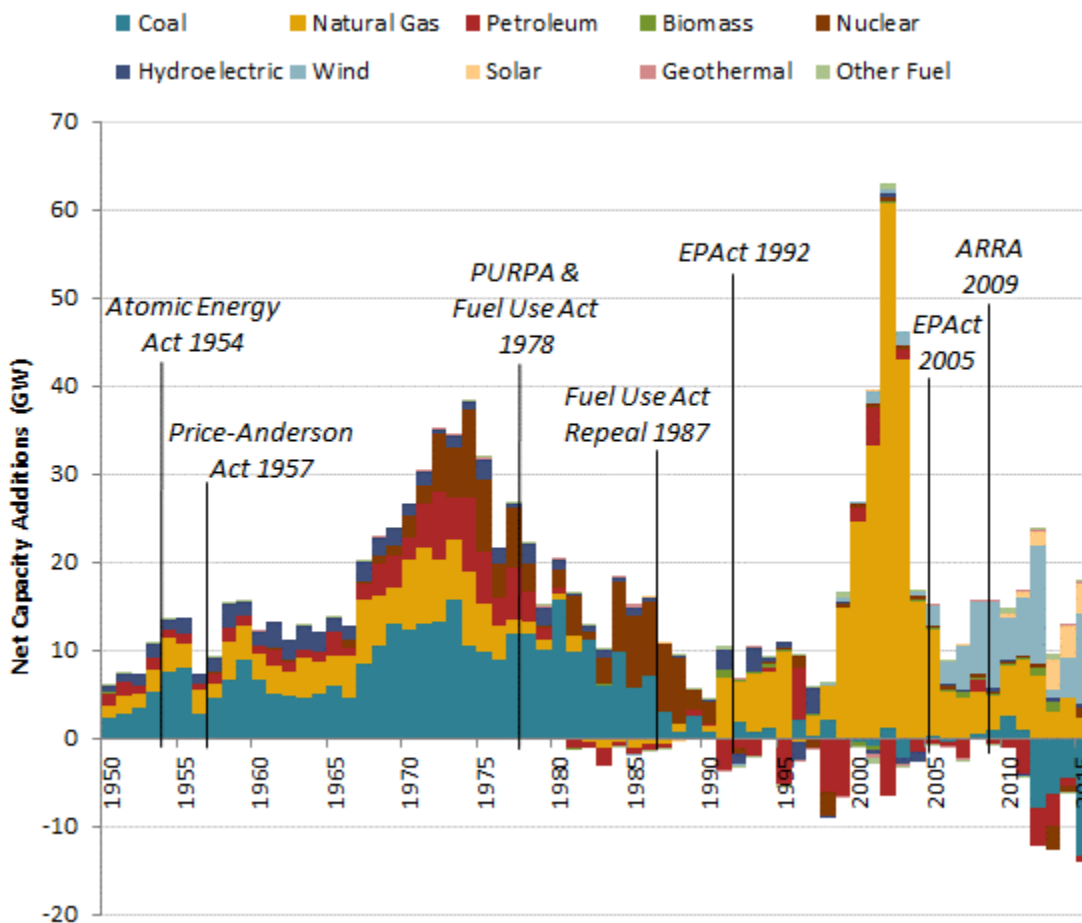
The Federal business energy ITC was expanded significantly by the Energy Improvement and Extension Act of 2008. This law extended the duration— by 8 years—of the existing credits for solar energy, fuel cells, and micro-turbines; increased the credit amount for fuel cells; established new credits for small wind-energy systems, geothermal heat pumps, and combined heat and power systems; allowed utilities to use the credits; and allowed taxpayers to take the credit against the alternative minimum tax, subject to certain limitations. The credit was further expanded by the American Recovery and Reinvestment Act of 2009. Most recently, the Consolidated Appropriations Act of 2016, signed in December 2015, included several amendments to this credit that apply to solar technologies and PTC/ITC-eligible technologies. Notably, the expiration date for these technologies was extended, with a gradual step down of the credits between 2019 and 2022¹²⁸.

Figure 3-12. U.S. generation (TWh) by fuel type, 1950–2014



A wide variety of energy and non-energy legislation has helped shape the U.S. power sector. Source: EIA 2016¹²⁹.

Figure 3-13. Net capacity additions (GW) by fuel type, 1950–2015



Capacity additions came in waves that were largely influenced by policy, as well as technology and market trends. The 1930s and 1940s fostered the development of hydropower; nuclear power boomed in the 1960s and 1970s; natural gas additions peaked in the 2000s; and non-hydro renewables are quickly growing in the 21st century. Source: EIA 2016¹³⁰.

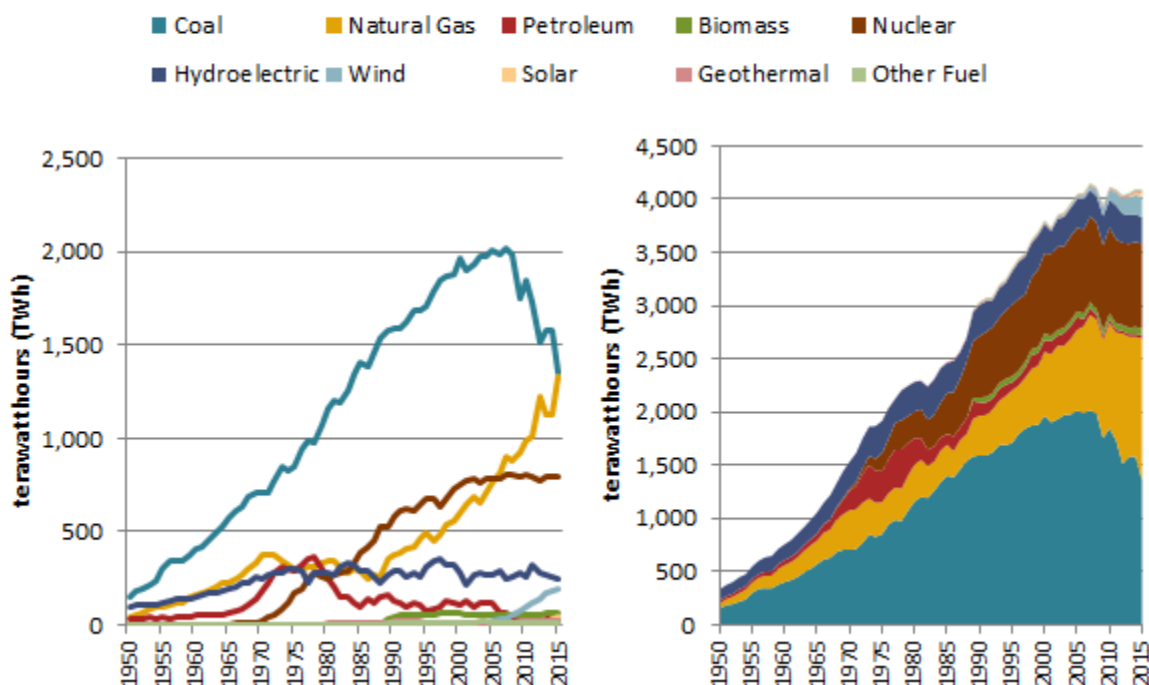
4 National and Regional Generation Data

This chapter reports on common metrics used to characterize power generation and uses them to identify trends. It begins with a summary of generation and capacity trends at the national level. Section 4.2 addresses similar trends at the regional level.

4.1 National Generation and Capacity

The U.S. electric power system has evolved significantly over the past 60+ years. Most notably, electricity generation within the United States has grown more than ten-fold, from 334 TWh in 1950 to 4,087 TWh in 2014. During this time frame, the generation fleet and the fuels that supply it have also shifted, sometimes in dramatic ways. The primary fuels and sources that make up the U.S. electric power sector include coal, natural gas, petroleum, nuclear, hydropower, biomass, wind, solar, and geothermal, as shown in Figure 4-1. The share of generation by fuel type has also changed over time, as shown in Figure 4-2.

Figure 4-1. U.S. electricity generation (TWh) by fuel type, 1950–2014

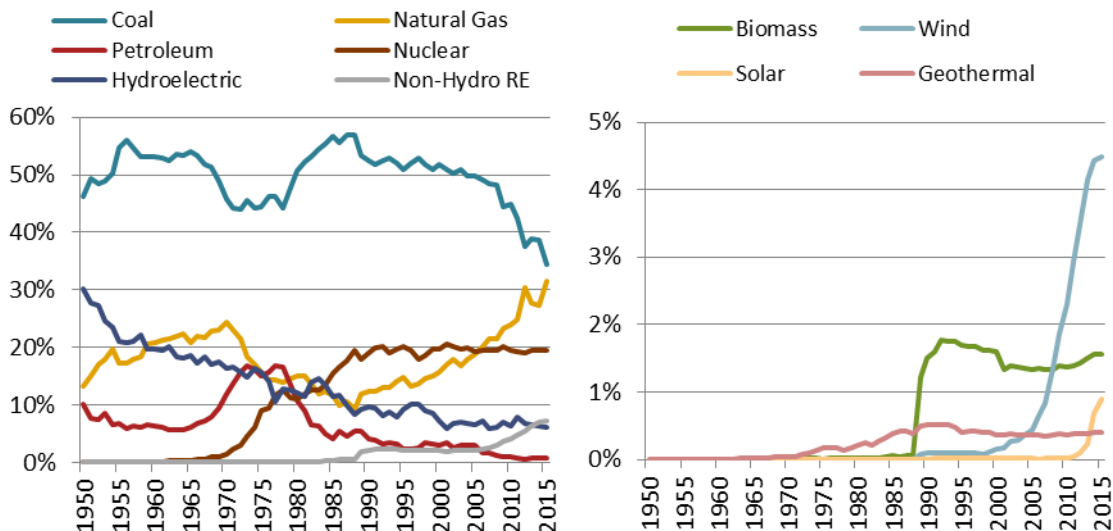


Coal generation has declined significantly since its peak in 2007, while natural gas and renewables have largely replaced the lost coal. Source: EIA 2016¹³¹.

As seen, coal-fired generation has declined substantially from its peak in 2007, with much of the lost generation made up by natural gas-fired and non-hydroelectric renewable sources. The breakout of non-hydro renewable generation, as shown to the right in Figure 4-2 is composed

mostly of biomass, wind, utility-scale solar^{xxvi}, and geothermal. Although these fuel types have grown significantly in recent years, individually, each represented less than 5 percent of total U.S. generation as of 2014. Total non-hydro renewable generation surpassed conventional hydroelectric generation for the first time in 2014.

Figure 4-2. Share of U.S. electricity generation by fuel type in percent, 1950-2015



The share of coal generation declined to approximately 33 percent in 2015, nearly tying that from natural gas, while wind and solar shares grew rapidly, but from a small base. Source: EIA 2016¹³².

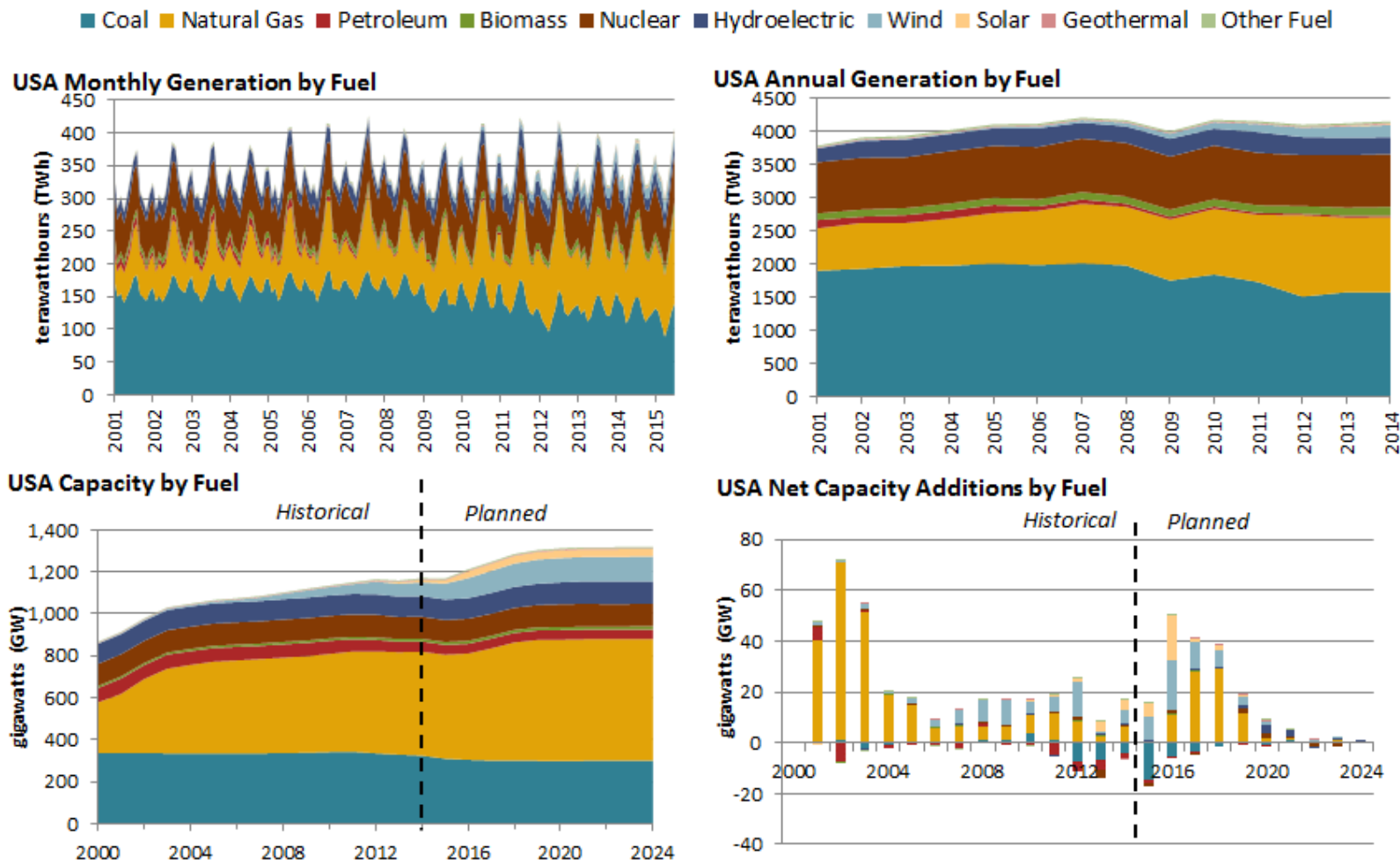
The top two graphics in Figure 4-3 show more recent changes in monthly and annual power generation by fuel source at the national level. As previously noted, total generation peaked in 2007 due primarily to declining demand. Coal- and oil-fired generation declined by over 21 percent and 50 percent, respectively, between 2005 and 2014, while natural gas-fired generation increased by nearly 25 percent. Hydroelectric and nuclear generation remained essentially stable, while non-hydro renewable electricity generation grew by over 160 percent, although starting from a much smaller base.

The bottom left image of Figure 4-3 shows both historical and certain types of planned^{xxvii} cumulative generation capacity, while the bottom right figure illustrates annual capacity changes. Natural gas-fired and wind capacity have seen substantial increases; these technologies as well as solar will likely see continued expansion based on relatively advanced planning for new construction. Coal-fired capacity saw its last notable deployment in 2010 as plants planned before the financial crisis of 2008 came online. Nuclear deployment will also be relatively small out to 2024, with only two plants (four units) currently under construction.

^{xxvi} EIA began publishing estimates of distributed PV in November 2015. Estimates of distributed PV generation are available starting in 2014 and account for approximately 35 percent of total solar PV generation. Data in this figure thus do not include distributed PV.

^{xxvii} SNL data captures plants that are under construction or in the advanced planning and financing stage, or that have announced firm retirement dates. SNL data for these future capacity additions and retirements are considered conservative and not inclusive of all new changes. These data were gathered before the passage of the tax credit extensions in December 2015, so certain renewable energy projects may be less pressured to bring their generators online in order to comply with earlier planned expirations.

Figure 4-3. Monthly and annual generation in the United States (*top*) and historical and planned capacity additions by fuel (*bottom*)

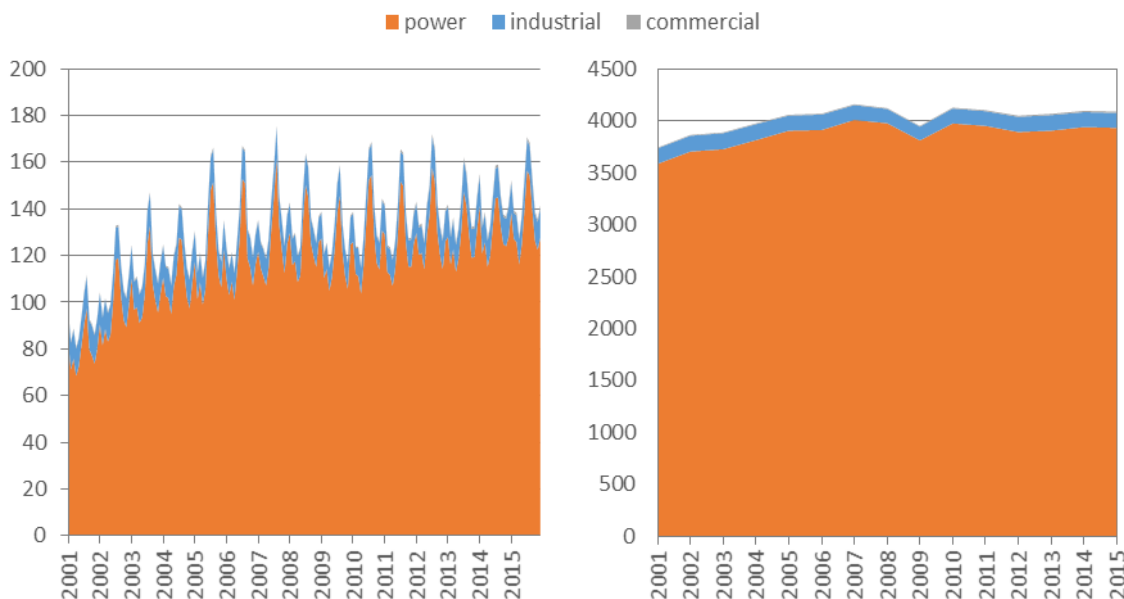


Total generation peaked in 2007 due largely to declining demand. Coal and oil fired generation declined by 33 and 58 percent, respectively, by 2015. The largest capacity additions in recent years have come from natural gas and wind, and this trend is expected to continue out to 2020.

Source: SNL 2015¹³³.

It is also useful to look at the different sectors within the United States that generate power and the fuels that they rely on. The U.S. electric power industry includes all electricity generated in the electric power, industrial, and commercial sectors¹³⁴. The electric power sector is defined by the EIA as an energy-consuming sector that consists of electricity-only and combined-heat-and-power plants whose primary business is to sell electricity, or electricity and heat, to the public and includes both electric utilities and independent power producers¹³⁵. In 2013, 96 percent of all electricity generated in the U.S. was generated in the electric power sector, while 3.7 percent was generated at utility-scale facilities in the industrial sector, with the commercial sector responsible for the remaining 0.3 percent¹³⁶.

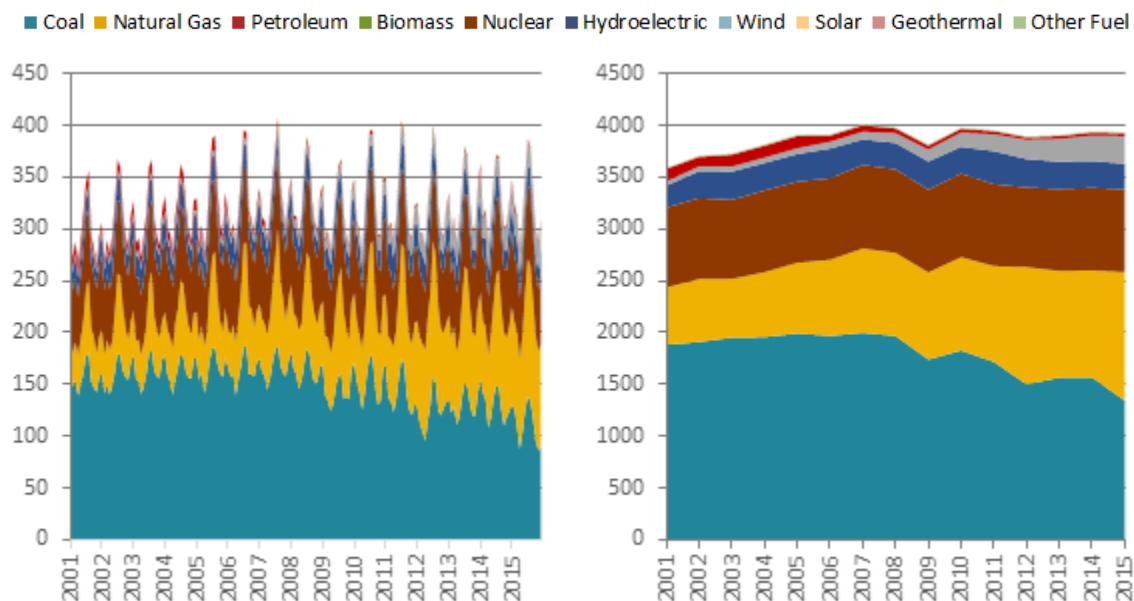
Figure 4-4. U.S. monthly and annual generation (TWh) by sector, 2001–2015



The power sector made up 96 percent of all generation, followed by the industrial sector at 3.7 percent and the commercial sector at 0.3 percent. Source: EIA 2016¹³⁷.

Figure 4-5 shows the generation by fuel from the power sector. Since this sector makes up the largest contribution to the total generation in the United States, the mix generally resembles that of the nation, with coal- and natural gas-fired capacity providing 34 percent and 32 percent of generation, respectively, in 2015.

Figure 4-5. U.S. monthly and annual generation (TWh) from the power sector by fuel, 2001–2015

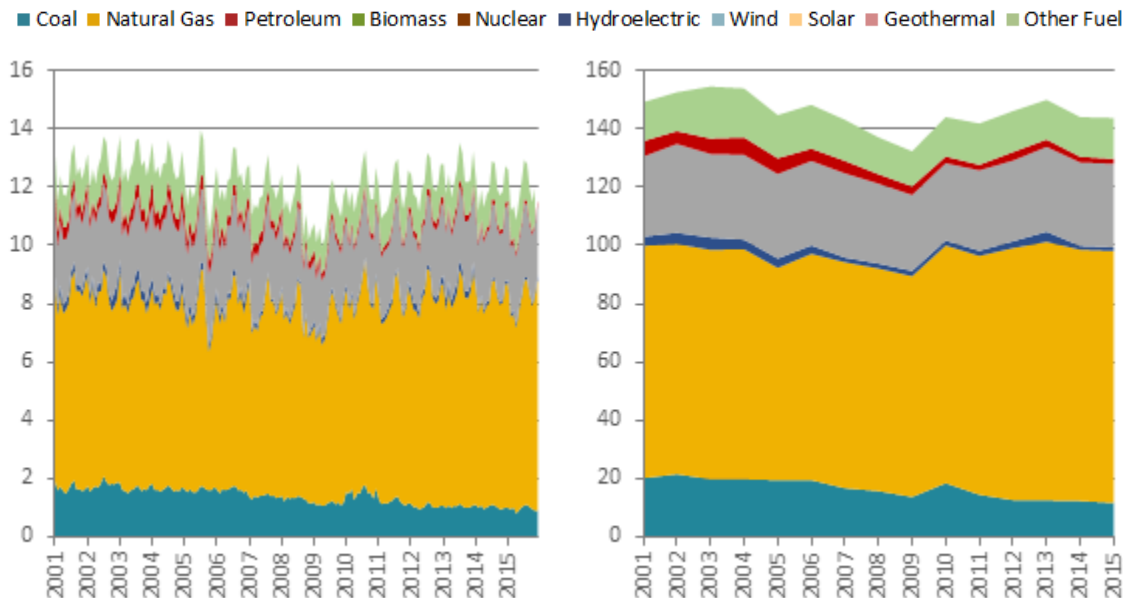


The generation portfolio of the power sector closely resembles that of the entire United States, with 34 percent of generation coming from coal and 32 percent from natural gas in 2015. Source: EIA 2016¹³⁸.

Although the power sector generally resembles the national generation mix, the industrial sector varies significantly and is comprised primarily of natural gas–firing at nearly 60 percent of generation in 2015. The industrial sector also has a much larger contribution from non-hydro renewables than the power sector, at 20 percent of total U.S. generation in 2015. There is currently no contribution from nuclear in this sector (Figure 4-6).

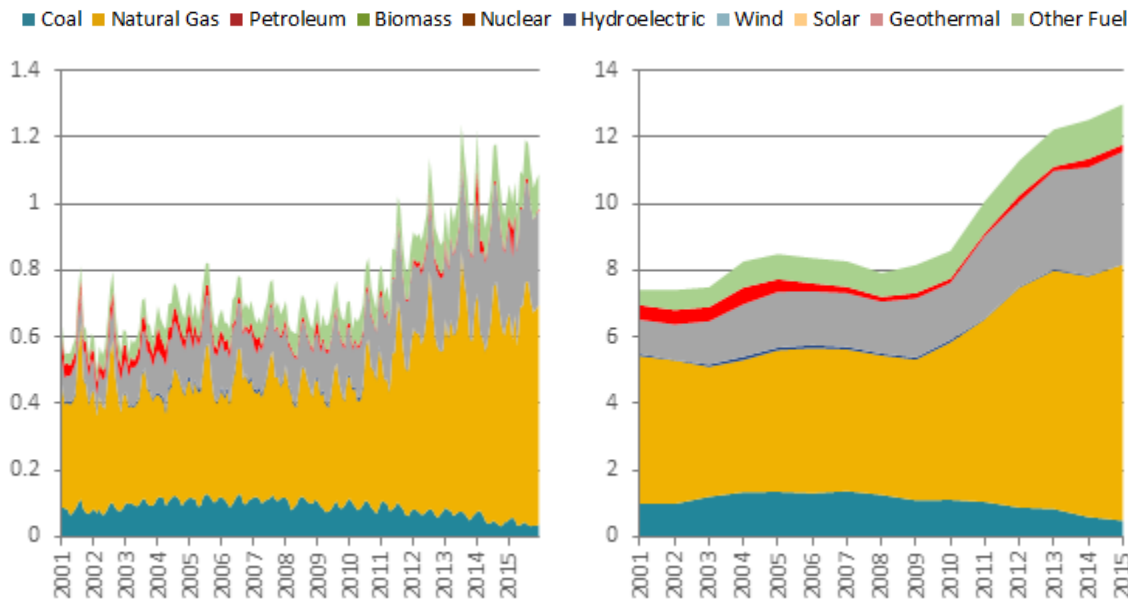
The commercial sector has a similar portfolio to the industrial sector, with 59 percent of generation from natural gas–fired sources and 26 percent from non-hydro renewables in 2015. This sector has seen the largest growth *since* 2001, adding 5.5TWh of generation by 2015 that was predominantly composed of natural gas–firing capacity (Figure 4-7).

Figure 4-6. U.S. monthly and annual generation (TWh) from the industrial sector by fuel, 2001–2015



The generation portfolio of the industrial sector is largely made up of natural gas, followed by non-hydro renewables and coal. Source: EIA 2016¹³⁹.

Figure 4-7. U.S. monthly and annual generation (TWh) from the commercial sector by fuel, 2001–2015



In 2015, the commercial sector had the largest contribution, compared to the other sectors, from renewables at 26 percent, while natural gas made up the majority of generation at 60 percent. Source: EIA 2016¹⁴⁰.

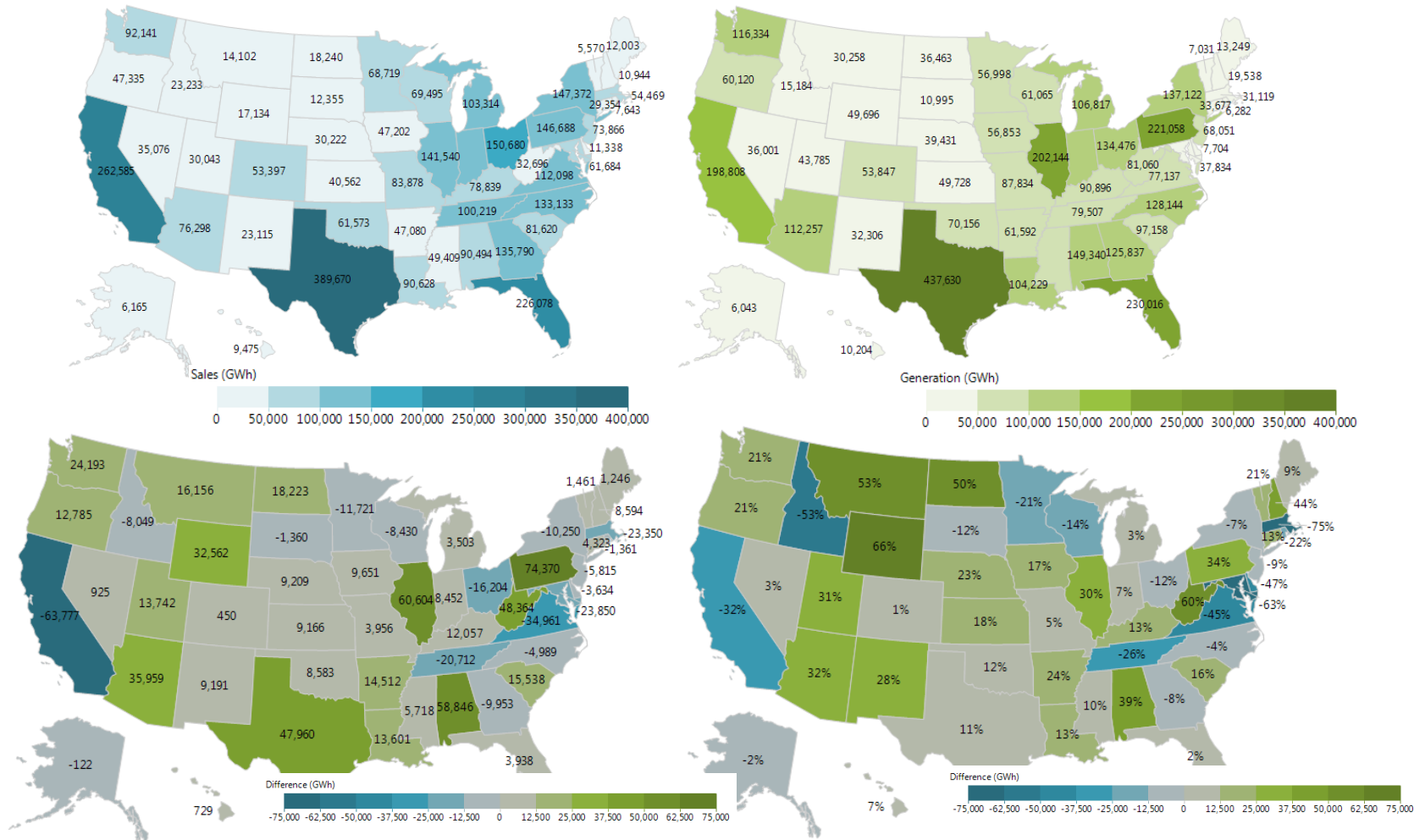
Figure 4-8 shows electricity generation and retail sales from all sectors by state¹⁴¹. Where sales exceed generation, the state runs an electricity deficit and must import power. Several states

stand out as large net importers as measured in GWh: California, Virginia, Massachusetts, Tennessee, and Ohio. Massachusetts is particularly notable for its small size but large amount of net imports. Proportional to its total sales, Massachusetts far exceeds any other state in net imports. Idaho and Delaware, while not large net importers in terms of total energy, import high percentages of their total sales.

The strongest net exporters of electricity are Illinois, Pennsylvania, West Virginia, Alabama, and Texas. Because West Virginia has a low amount of total sales, it is also one of the highest proportional exporters. Lower-consumption states in the western United States, such as Wyoming, Montana, and North Dakota, also are strong exporters on a proportional basis.

While regional patterns are harder to find, generally high net-importing states abut at least one high net-exporting state, with Massachusetts being the notable exception. Extremes in total energy import and export tend to occur in more populous states, though Alabama and several others do not fit this pattern.

Figure 4-8. Sales and generation by U.S. state in 2014. Top: total sales (left) and generation (right) in GWh. Bottom: difference between generation and sales shown in GWh (left) and percent (right).



The largest net importers are California, Virginia, and Massachusetts. Net exporters are Illinois, Pennsylvania, and Alabama. Note that these data are for 2014 only and can vary annually. Sources: EIA 2016¹⁴²

4.2 Regional NERC Trends

The previous section addressed generation trends and metrics at the national level. This section focuses on more granular regional issues in order to illuminate changes that are happening at a less aggregated level. This report represents data at the NERC regional level to appropriately capture regional generation differences.

4.2.1 Regional Categories

The U.S. electricity grid does not always fit neatly within state boundaries. The 48 continental states are comprised of three synchronous interconnections: the Eastern Interconnection, the Western Interconnection (or WECC), and the Electric Reliability Council of Texas (ERCOT).^{xxviii} In addition, Alaska and Hawaii manage and operate their own grid systems. Each of these interconnections and state grids operate at their own level of synchronization, and there is limited capacity to import or export electricity through direct current (DC) interties. The Eastern Interconnection is further broken down into six NERC Regional Entities (Regions):

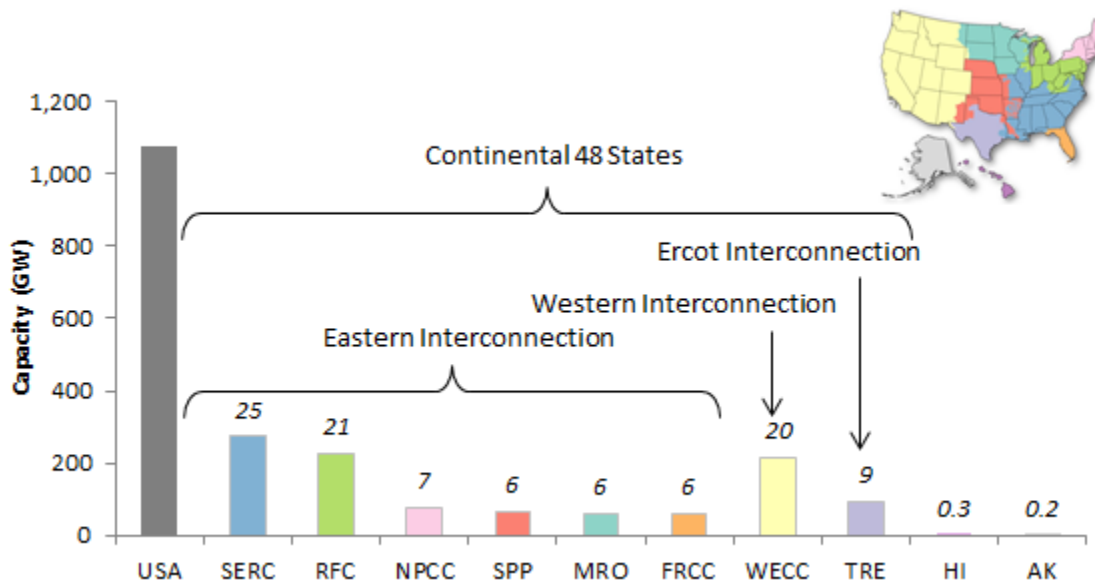
- SERC (formerly Southeastern Electric Reliability Council)
- ReliabilityFirst Corporation (RFC)
- Northeast Power Coordinating Council (NPCC)
- Southwest Power Pool (SPP)
- MRO
- FRCC.

Figure 4-9 shows the total generating capacity in each region, interconnection, and Hawaii and Alaska, as well as the totally generating capacity for the entire country. The boundaries for each NERC region correspond to the bar color in the chart.

Grid operations can vary significantly between regions. Table 4-1 summarizes select generation metrics between 2009 and 2014 at the national level and by NERC region, including Hawaii and Alaska. Note that although several NERC regions include large portions of Canadian territory and a small amount of Mexico, these data only capture U.S. generation characteristics. A larger illustration of the NERC regional boundaries is shown in Figure 4-10.

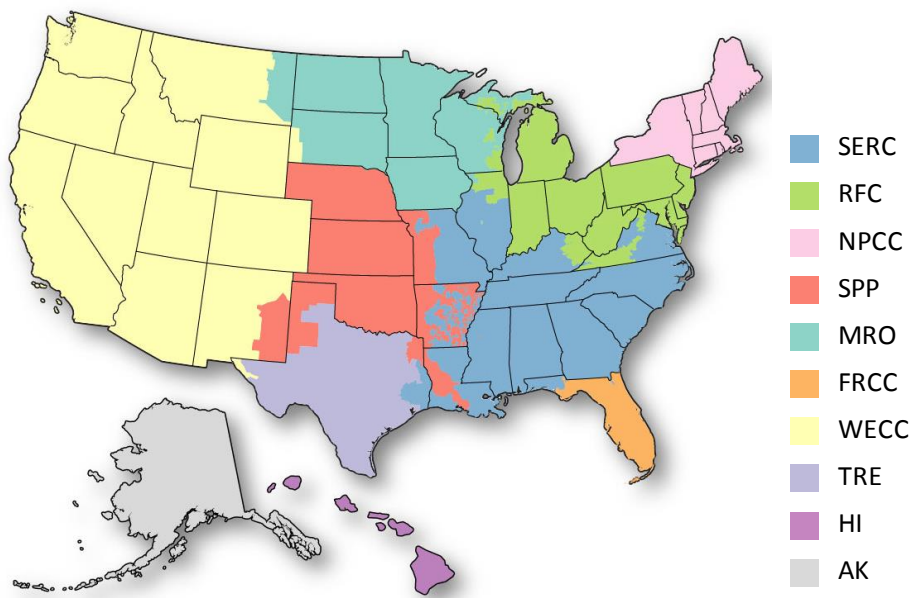
^{xxviii} Both the Eastern and Western Interconnections extend beyond the borders of the United States to include the non-territorial areas of Canada. The Western Interconnection also extends beyond the U.S. southern border to include a portion of Baja California Norte in Mexico. In addition to its asynchronous DC ties to the Eastern Interconnection, ERCOT also maintains 280 MW of asynchronous connection to northern Mexico.

Figure 4-9. Electrical generating capacity in the U.S. by NERC region



The United States (and North America) is divided up into a number of reliability regions of varying size and market structures. Six NERC regions comprise the Eastern Interconnection, with the one region in the West comprising the Western Interconnection, and the one in Texas comprising ERCOT. These interconnections, plus Hawaii and Alaska, operate at their own frequencies and have limited capability to share electricity through DC interties. The percentage of each region’s total capacity is shown above the column. Source: SNL 2015¹⁴³.

Figure 4-10. NERC regions



WECC is the largest reliability region in the continental United States while FRCC is the smallest. Source: NERC 2015¹⁴⁴.

Table 4-1. Change in generation from major fuel types by region, 2009–2014

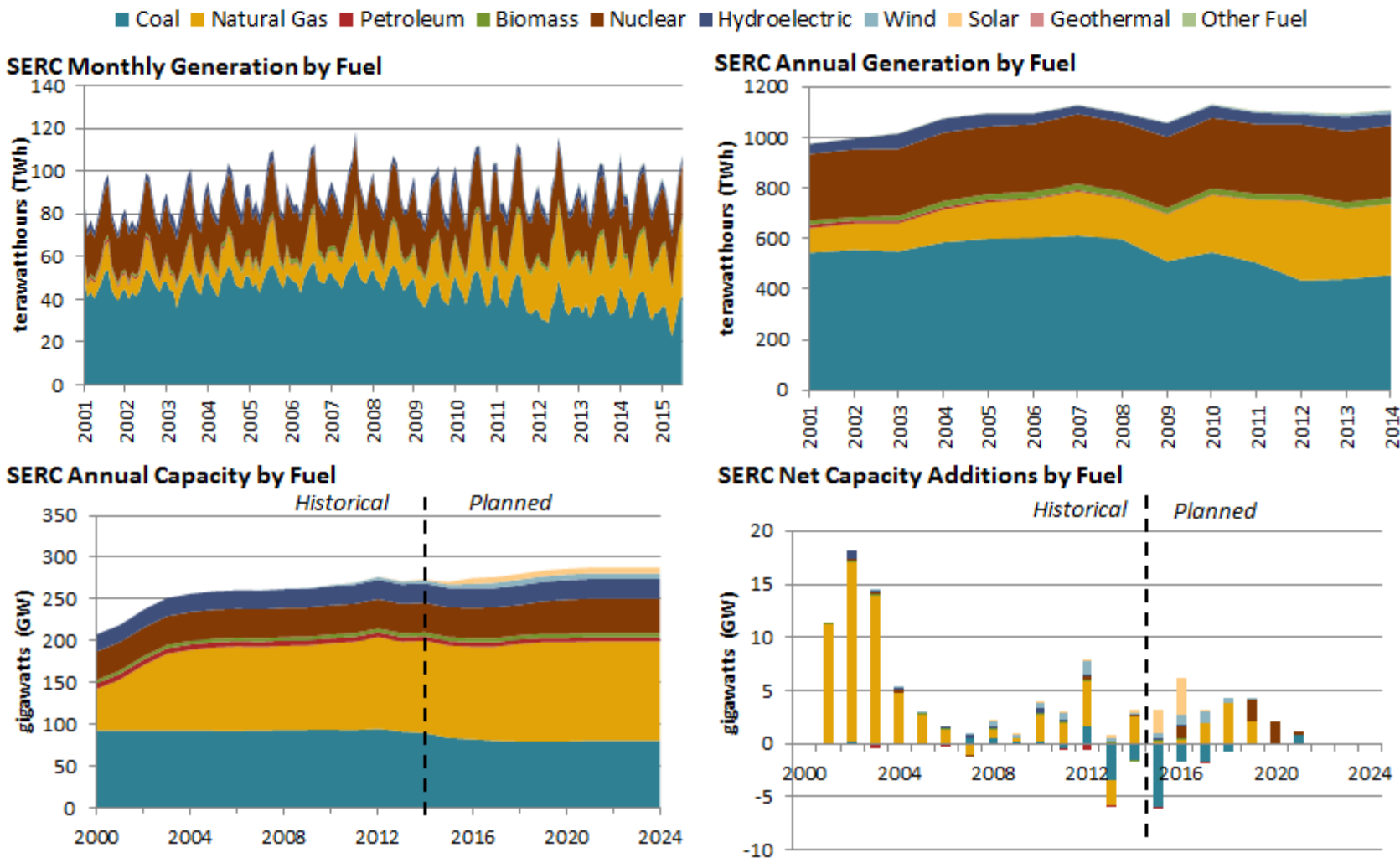
	Coal		Natural Gas		Nuclear		Non-Hydro Renewable		Total	
	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change
US	-171.3	-10	204.6	22	-1.7	0	130.8	85	132.0	3
WECC	-13.8	-6	-4.3	-2	-10.3	-15	43.4	92	11.9	2
SERC	-53.9	-11	94.8	51	3.8	1	12.7	52	49.8	5
RFC	-83.0	-15	65.1	85	12.1	5	17.5	102	13.5	1
NPCC	-17.4	-62	11.8	12	0.2	0	14.5	148	-6.4	-2
SPP	-0.8	-1	-5.7	-10	-0.2	-2	4.0	29	3.4	2
MRO	-9.6	-6	2.7	31	-3.9	-11	19.2	105	12.2	6
FRCC	-4.1	-7	30.6	29	-1.2	-4	0.0	-1	9.7	4
TRE	11.4	10	9.7	6	-2.2	-5	19.4	105	37.8	12
Alaska	-0.1	-11	-0.3	-8	0.0	0	0.2	1484	-0.7	-10
Hawaii	0.0	1	0.0	0	0.0	0	0.5	74	-1.3	-12

The shift from coal to natural gas generation is occurring fastest in the eastern half of the country, where growth in renewables is modest. The opposite behavior is observed in the western part of the country (including Texas). Source: SNL 2015¹⁴⁵.

4.2.2 *SERC*

Electricity in SERC is predominately sourced by coal-fired, natural gas-fired, and nuclear generation (Figure 4-11); SERC saw the largest absolute increase in demand for electricity (and third fastest growth rate) among all NERC regions and other states between 2009 and 2014 (Table 4-1). In 2014, the region had more natural gas-fired capacity than coal-fired (40 percent and 34 percent, respectively), but coal-fired generation exceeded generation from natural gas (41 percent and 25 percent, respectively). The region is undergoing a rapid shift from coal to natural gas, however, and monthly data through the first half of 2015 showed the gap in generation between the two fuel sources narrowing. Non-hydro renewable generation has expanded by nearly 10 percent each year on average since 2009, but is starting from a very low base. Current and near-term changes in capacity are primarily natural gas-fired additions and some coal-fired retirements. The region also had one of the lowest shares of wind capacity and generation at 1.3 percent and 0.9 percent, respectively, in 2014. SERC is also the only region with new nuclear capacity expected to come online in the near term, with over 5 GW expected by roughly 2020. Nuclear generation development is enabled by the “construction work in progress” (CWIP) incentives sometimes offered in the southeastern region, by federal loan guarantees under the Energy Policy Act of 2005, as well as by the vertically integrated market structure.

Figure 4-11. Monthly and annual generation in SERC (*top*) and historical and planned capacity additions by fuel (*bottom*)



SERC has experienced a rapid shift from coal to natural gas generation and is the only region building new nuclear plants. Source: SNL 2015¹⁴⁶.

4.2.3 RFC

Generation in RFC is primarily fueled by coal, which made up 43 percent of the region's capacity and 51 percent of its generation in 2014 (Figure 4-12). The region also has the largest share of nuclear capacity. RFC has seen the greatest absolute reduction in coal-fired generation since 2009 compared to other regions. Natural gas-fired capacity has expanded in recent years, and additional capacity is planned; however, generation from natural gas represented only 14 percent of total generation in 2014. Despite this relatively low level, natural gas-fired generation has nearly doubled since 2009, and this region has experienced the fastest growth in natural gas-fired generation. RFC expects to have the highest share of the nation's recent and future coal-fired retirements. Wind capacity is expected to continue growing based on the reported queue of projects under development (Figure 4-12). Electricity demand has been essentially flat in the RFC for the past 5 years.

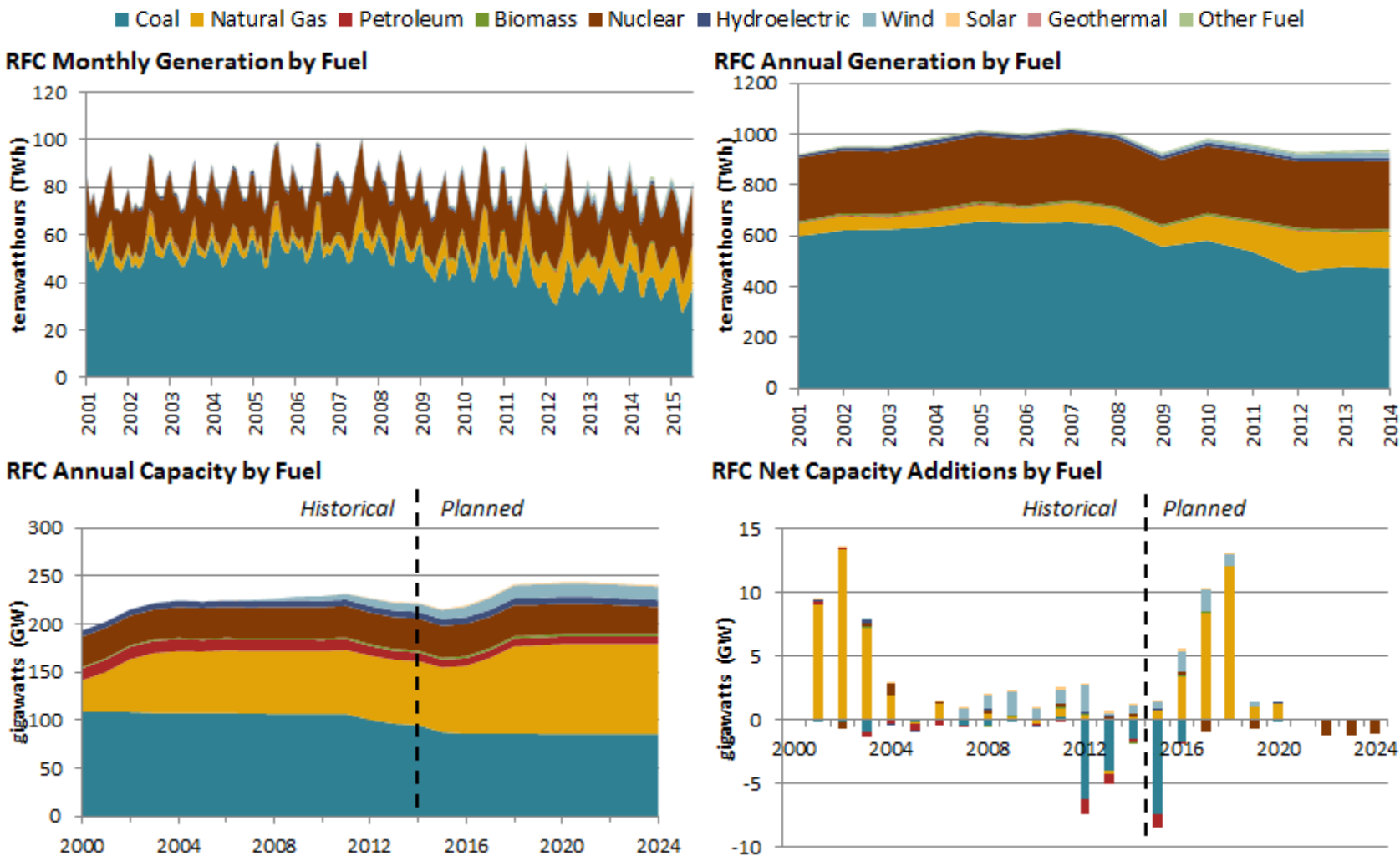
4.2.4 NPCC

NPCC has seen a significant decline in the need for generation since it peaked in 2005. It had the lowest share of coal-fired capacity and generation of all the NERC regions within the 48 continental states, at 6 percent and 5 percent, respectively, in 2014. Conversely, the region had some of the highest shares of nuclear capacity and generation at 13 percent and 32 percent, respectively, and biomass at 3 percent and 4 percent, respectively. Natural gas has become the largest single source of capacity and generation in NPCC, and both are expected to continue growing. In 2014, petroleum-fired capacity was as high as 17 percent of total capacity within the region but only represented 1 percent of generation. Petroleum-fired generation is primarily used to ensure sufficient and reliable power supply in the Northeast during cold winter months, with a significant number of combined-cycle plants able to operate on both petroleum and natural gas. The former can be stored at or near the power generator in significant quantities. The NPCC region has driven much of the concern over lack of coordination between the natural gas and electricity sectors given its limited spare natural gas pipeline capacity. During the Polar Vortex of 2014, the region experienced high electricity prices due to gas shortages, resulting from increased need for gas use for heating. New measures are underway to help alleviate risks of natural gas shortages for electric generators during the coldest winter months (Logan et al. 2015). Looking forward, natural gas, wind, and solar have the most projects in the development queue, while additional coal- and petroleum-fired generation is scheduled to retire in 2016 (Figure 4-13).

4.2.5 SPP

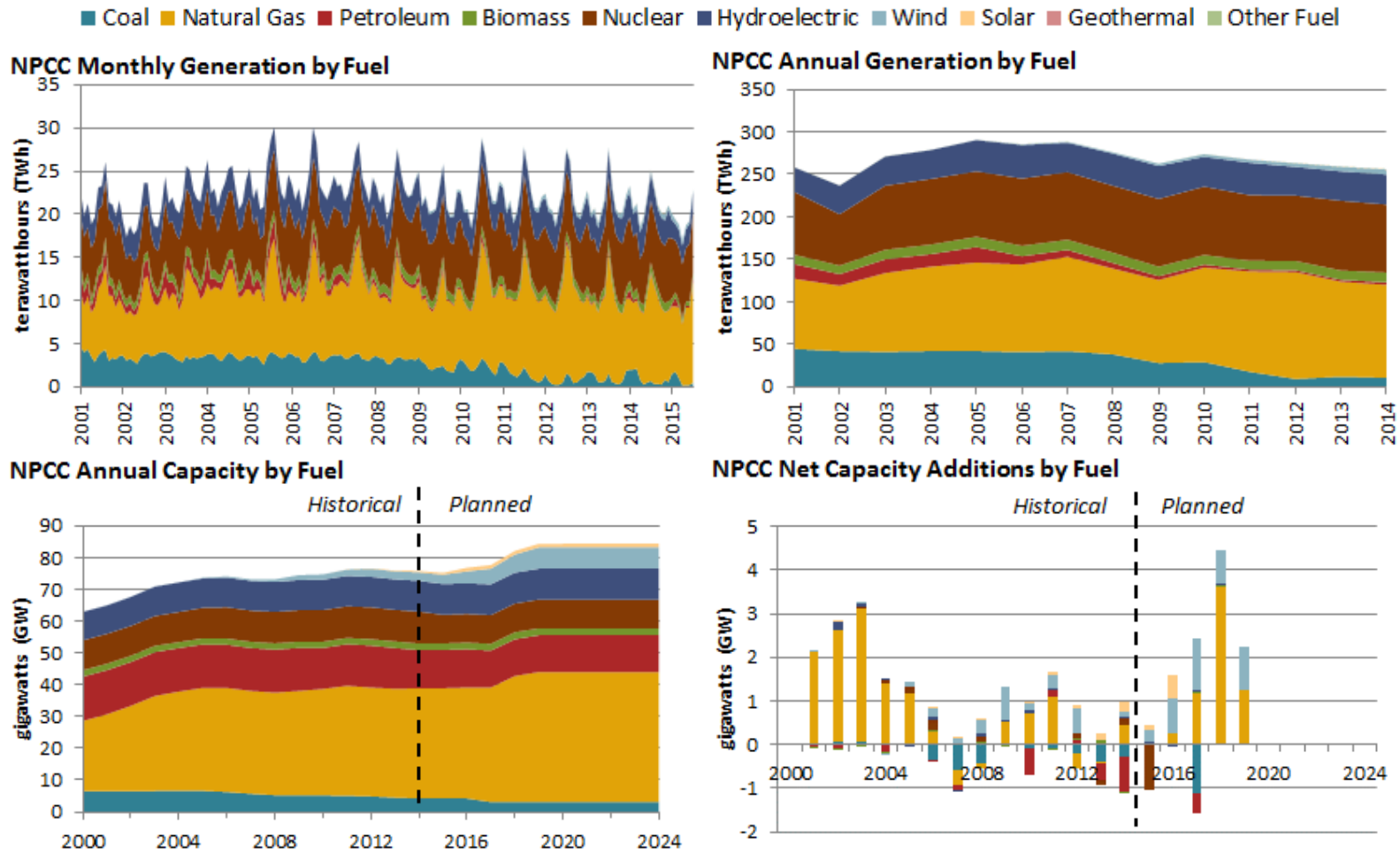
SPP relies primarily on coal and natural gas as generation fuels and has seen modest growth in demand for new electricity generation, as shown in Figure 4-14 and Table 4-1. Natural gas-fired generation has declined in SPP more than any other NERC region since 2009. Capacity and generation shares for coal were 35 percent and 59 percent, respectively, and 48 percent and 25 percent for natural gas in 2014. SPP has only a minor reliance on nuclear power, and hydroelectric generation has declined to a very small share of total generation. Over the next few years, wind projects, which currently dominate the development pipeline, are likely to nearly double available wind capacity (Figure 4-14).

Figure 4-12. Monthly and annual generation in RFC (*top*) and historical and planned capacity additions by fuel (*bottom*)



RFC has seen a sharp drop in coal generation since 2008, with natural gas making up most of the lost generation. Source: SNL 2015¹⁴⁷.

Figure 4-13. Monthly and annual generation in NPCC (*top*) and historical and planned capacity additions by fuel (*bottom*)

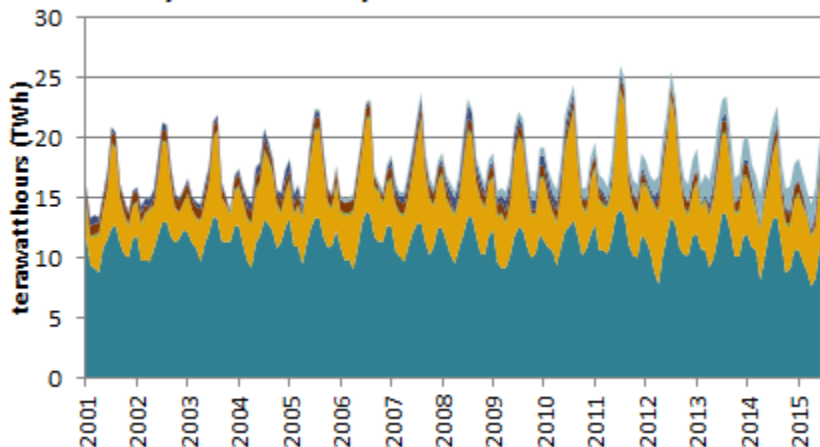


NPCC is heavily reliant on natural gas and nuclear; demand has declined significantly since it peaked around 2005. Source: SNL 2015¹⁴⁸.

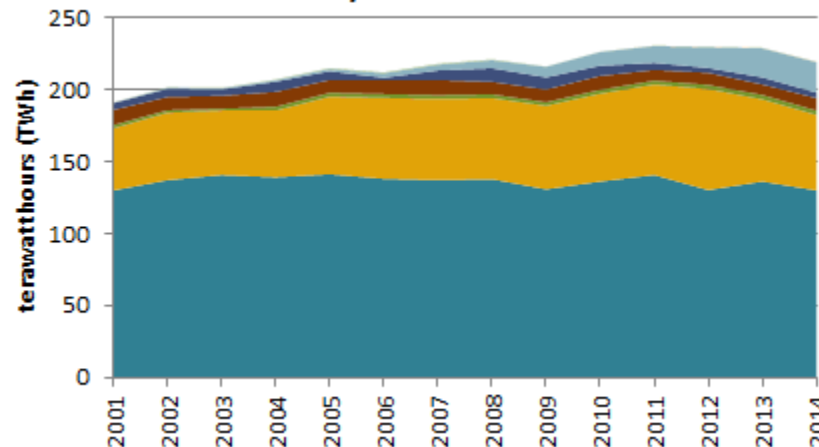
Figure 4-14. Monthly and annual generation in SPP (top) and historical and planned capacity additions by fuel (bottom)

Coal Natural Gas Petroleum Biomass Nuclear Hydroelectric Wind Solar Geothermal Other Fuel

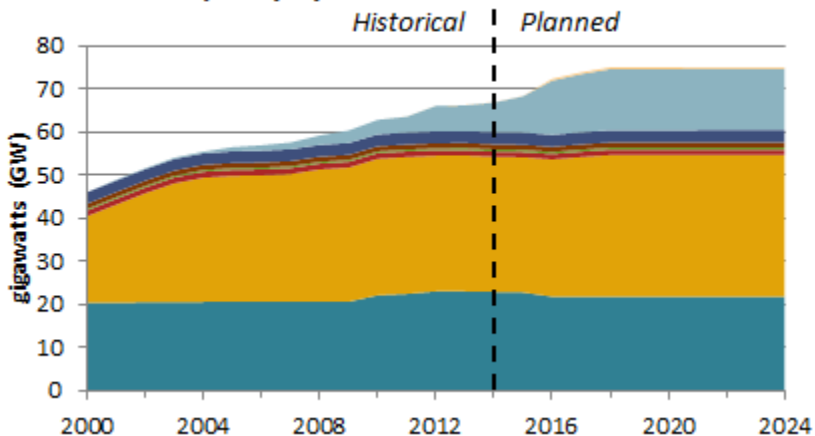
SPP Monthly Generation by Fuel



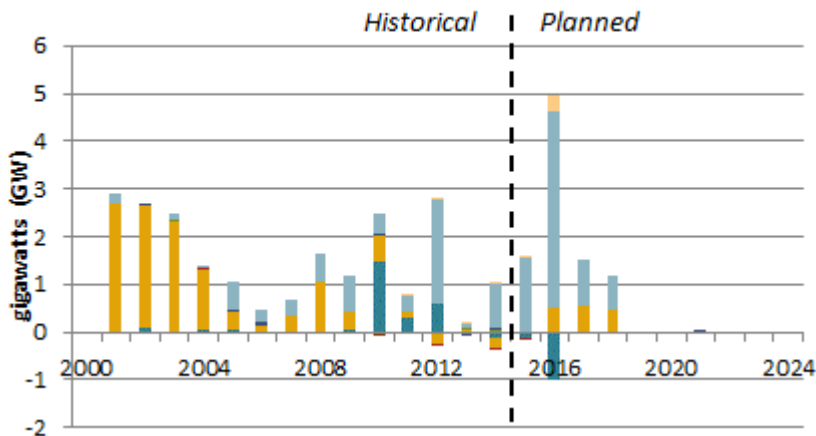
SPP Annual Generation by Fuel



SPP Annual Capacity by Fuel



SPP Net Capacity Additions by Fuel



SPP relies on coal for over half of its generation, while natural gas and wind account for much of the remainder. Source: SNL 2015¹⁴⁹.

4.2.6 *MRO*

MRO had the highest share of coal-fired and wind generation in the United States, with shares at 62 percent and 14 percent, respectively, in 2014. The region had the second-fastest growth in power generation between 2009 and 2014, just behind Texas Reliability Entity (TRE) (Table 4-1). MRO also continues to see expanded growth in wind capacity, with planned generation additions consisting primarily of wind capacity until 2019, when more natural gas comes online (Figure 4-15). High shares of coal and wind have led to less demand for natural gas. The region had the lowest shares of natural gas-fired capacity and generation in 2014 of the NERC regions within the 48 continental states, at 24 percent and 6 percent, respectively.

4.2.7 *FRCC*

FRCC relies heavily on natural gas and had the highest share of both capacity and generation at 62 percent and 60 percent, respectively, of all NERC regions and other states in 2014. Recent capacity additions and planned capacity additions are almost entirely natural gas, as shown in Figure 4-16. Approximately 2 GW of oil- and coal-fired generation is slated to be retired between 2016 and 2018, although these are primarily used as peaking capacity. FRCC has the lowest capacity shares of hydro at 0.1 percent and wind at essentially 0 percent (utility-scale). Like NPCC, FRCC is highly reliant on natural gas-fired generation and is becoming even more so.

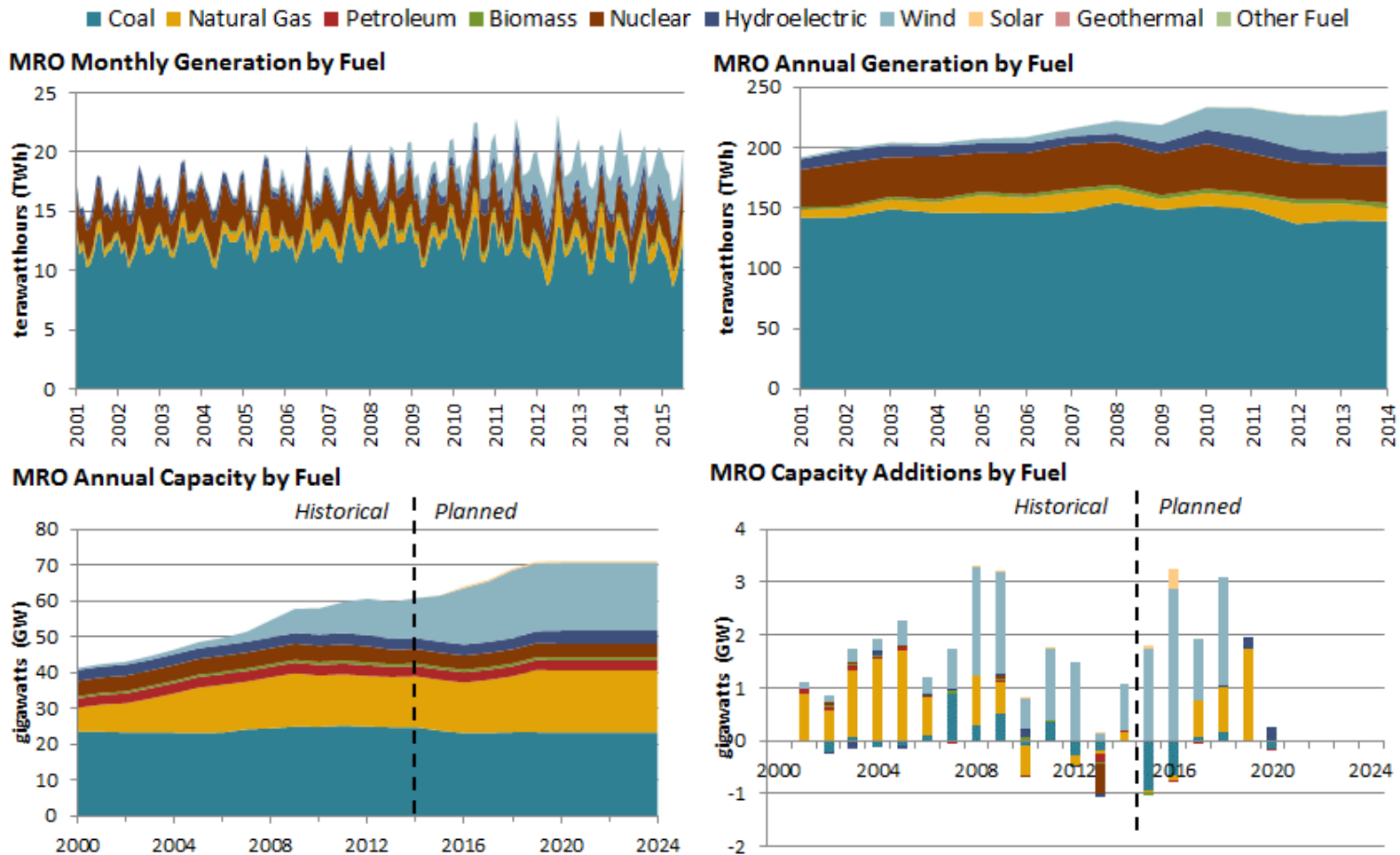
4.2.8 *WECC*

WECC has the highest shares of renewable capacity and generation among NERC regions (Figure 4-17). Capacity for utility-scale solar and hydro stood at 3 percent and 26 percent, respectively, in 2014, while the corresponding generation shares were 1 percent and 22 percent, respectively. Over 10 GW of utility-scale solar capacity is expected to come online in 2016, although the estimate was derived before extension of the ITC in December 2015; as a result, some project developers may feel less rushed to complete their projects on time. All of the geothermal capacity within the continental United States comes from the WECC region, but this accounted for only 2 percent of total generation in the region in 2014. The 2014 shares of generation from coal and natural gas were 27 percent and 30 percent, respectively.

4.2.9 *TRE*

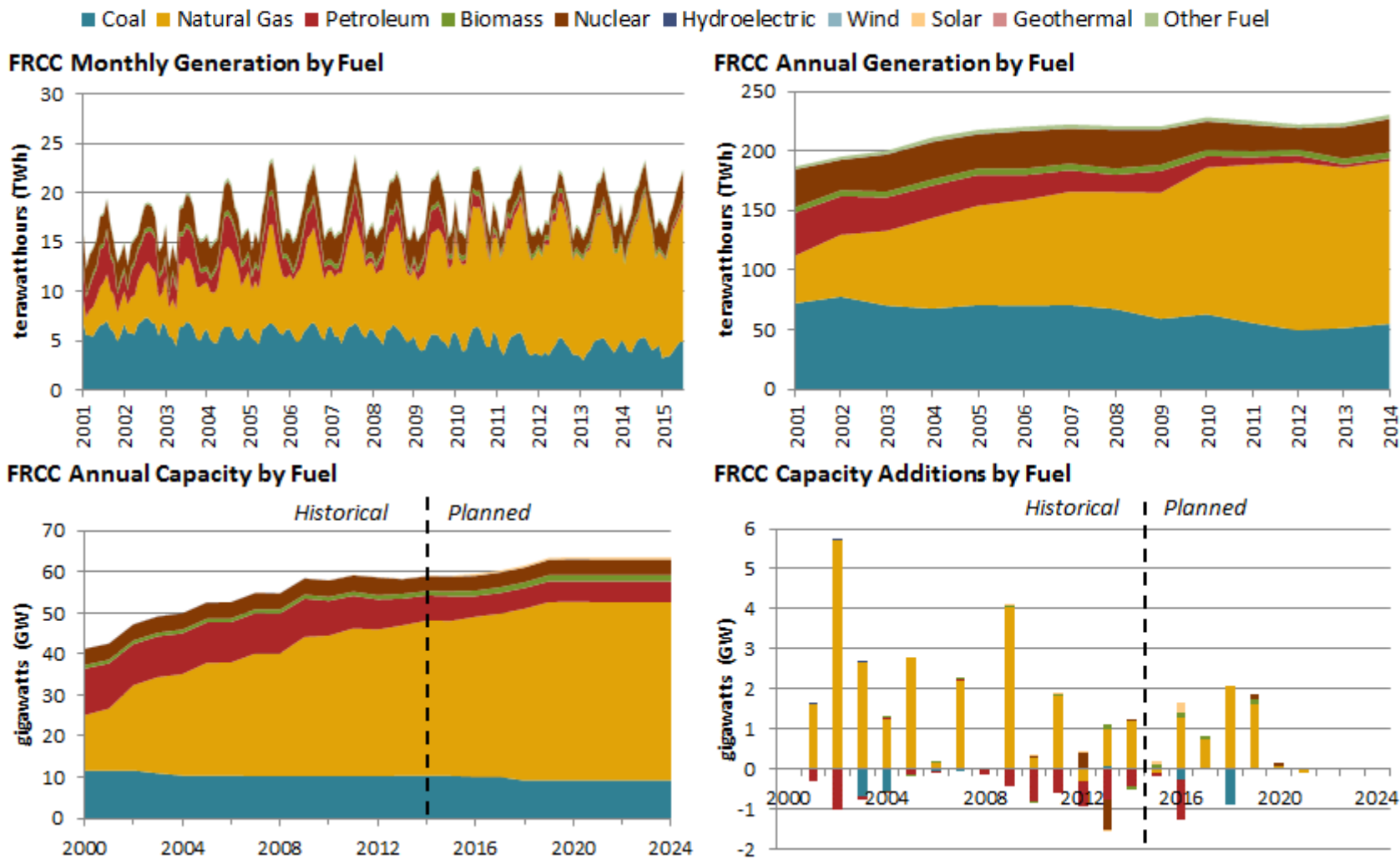
TRE had the fastest growth in electricity generation among all regions between 2009 and 2014 (Table 4-1; Figure 4-18). In 2014, TRE had the second highest share of wind capacity and generation, at 12 percent and 9 percent, respectively. There have been significant additions of new wind capacity in recent years, with more capacity expected to come online through 2016. The region has some of the lowest shares of hydroelectric and biomass generation, at 0.1 percent and 0.2 percent, respectively. The region's primary fuel source is natural gas, which represented 59 percent and 45 percent of capacity and generation in 2014, respectively. TRE also expects a large amount of new natural gas-fired capacity in the next few years.

Figure 4-15. Monthly and annual generation in MRO (top) and historical and planned capacity additions by fuel (bottom)



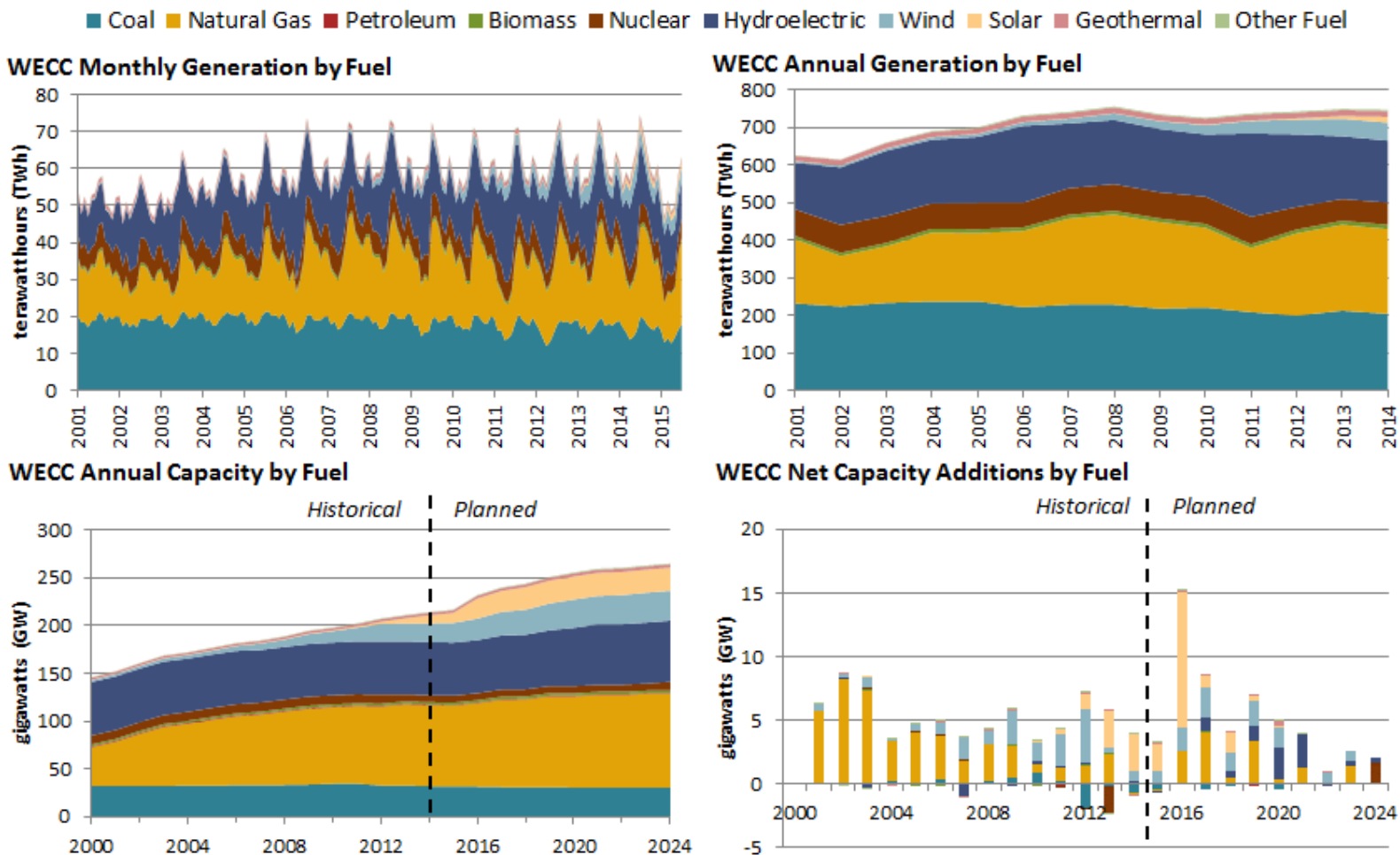
MRO is heavily dependent on coal, although coal generation is down from its peak in the mid-2000s and wind generation is growing rapidly. Source: SNL 2015¹⁵⁰.

Figure 4-16. Monthly and annual generation in FRCC (*top*) and historical and planned capacity additions by fuel (*bottom*)



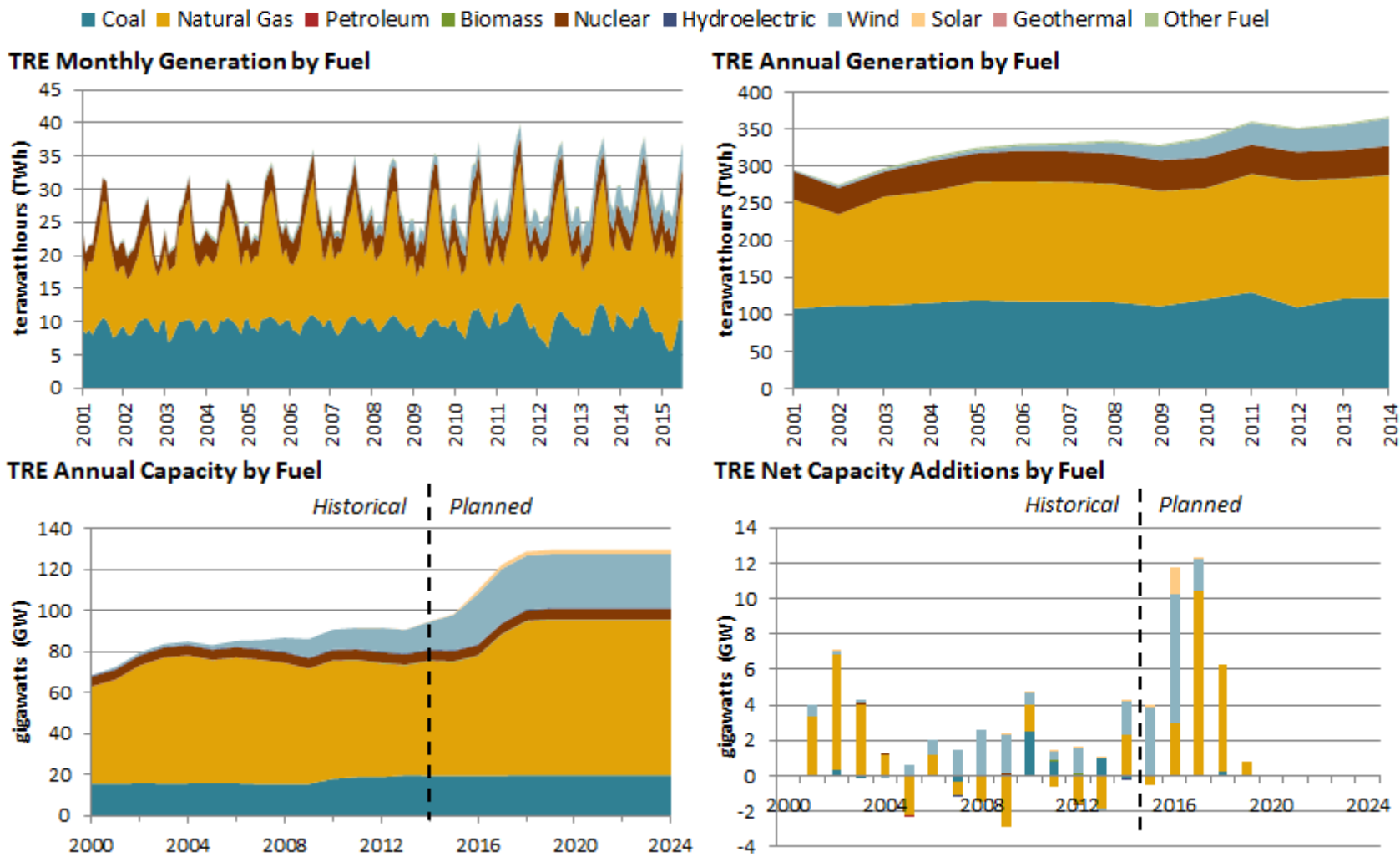
FRCC gets over half of its generation from natural gas and is expected to become even more reliant on the fuel. Source: SNL 2015¹⁵¹.

Figure 4-17. Monthly and annual generation in WECC (top) and historical and planned capacity additions by fuel (bottom)



WECC has a relatively diverse generation portfolio and relies on a combination of coal, natural gas, nuclear, and renewables. Source: SNL 2015¹⁵².

Figure 4-18. Monthly and annual generation in TRE (*top*) and historical and planned capacity additions by fuel (*bottom*)



Texas power generation is dominated by natural gas and wind. Source: SNL 2015¹⁵³.

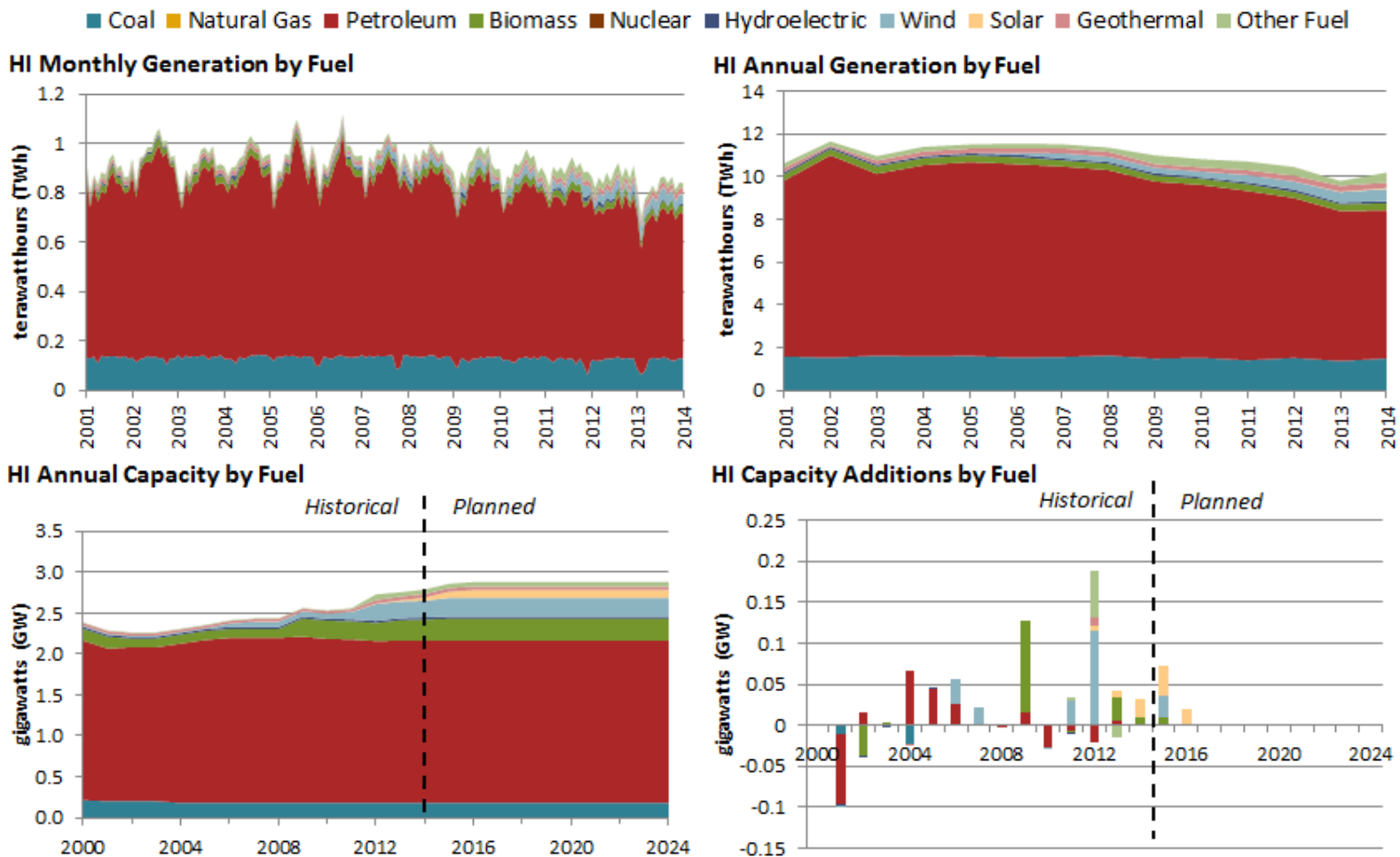
4.2.10 *Hawaii*

Hawaii has a number of operating constraints that make its capacity and generation profile very different than the rest of the country. As indicated in Figure 4-19, Hawaii's primary fuel source is petroleum, which represented 69 percent and 68 percent of capacity and generation shares in 2014. The state has little to no nuclear or natural gas-fired capacity. Coal-fired capacity and generation in 2014 represented 6 percent and 15 percent, respectively, and the remainder was primarily from non-hydro renewable resources such as biomass, wind, geothermal, and solar. The state has an aggressive target for renewable electricity (100 percent RPS by 2045; see DSIRE 2015), and its strong growth in many forms of renewables over the past few years is expected to continue. For example, 12 percent of Hawaii's electricity customers now have solar panels on their roofs, compared to the 0.5 percent average for the United States (Tierney 2016).

4.2.11 *Alaska*

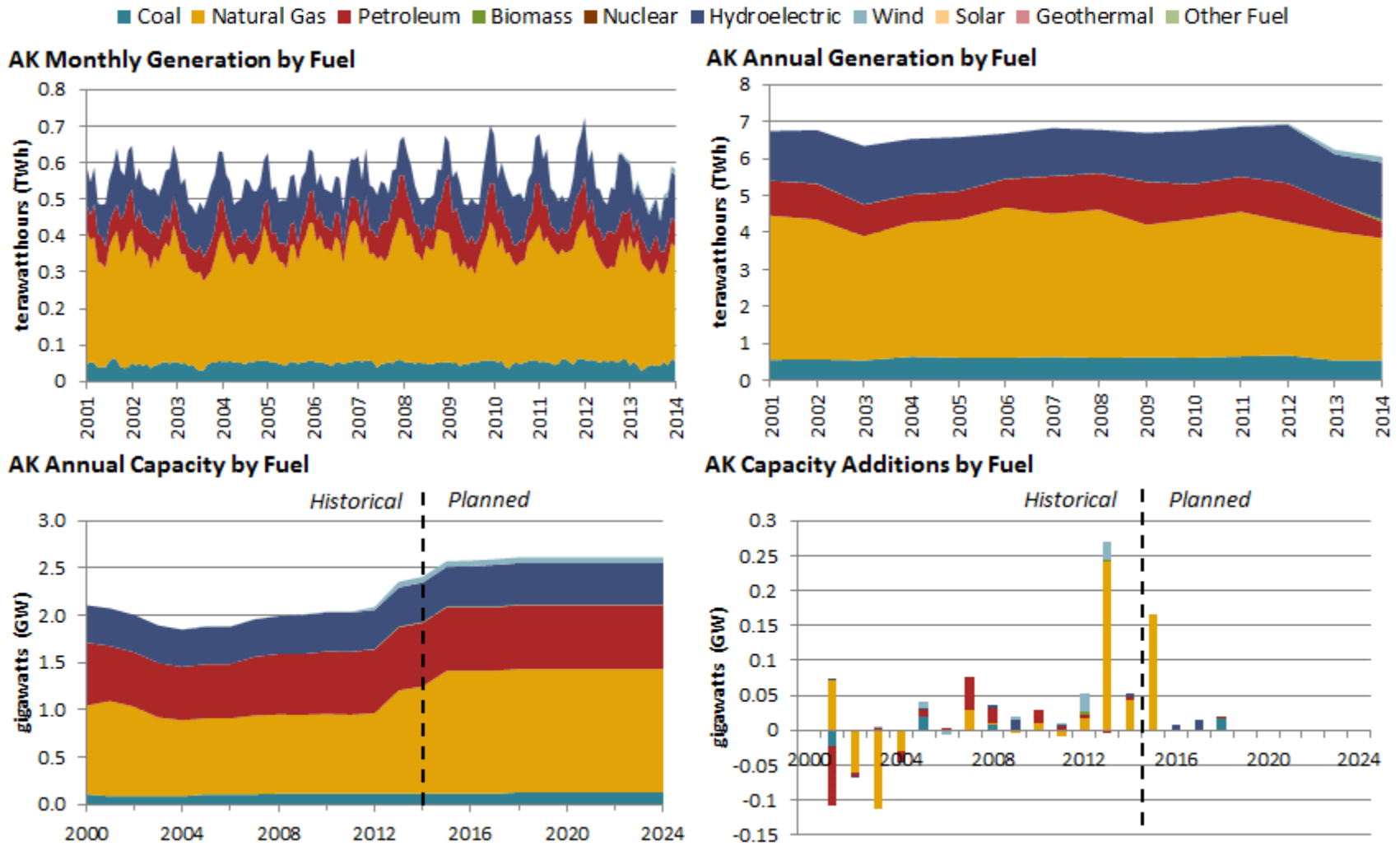
Alaska has little to no generation from nuclear, biomass, solar, or geothermal (Figure 4-20). It also had the lowest 2014 regional capacity shares in coal at 5 percent. Alaska is, however, second in generation shares for a number of fuel types, including natural gas at 56 percent, hydro at 21 percent, and petroleum at 12 percent.

Figure 4-19. Monthly and annual generation in Hawaii (top) and historical and planned capacity additions by fuel (bottom)



Hawaii is heavily dependent on petroleum generation but has ambitious plans to generate 100% of its electricity from renewable resources. Source: SNL 2015¹⁵⁴.

Figure 4-20. Monthly and annual generation in Alaska (top) and historical and planned capacity additions by fuel (bottom)



Alaska relies on natural gas and petroleum for much of its generation. Source: SNL 2015¹⁵⁵.

4.2.12 *Regional Capacity and Generation by Fuel*

Differences in fuel use between NERC regions tend to follow geographic patterns. Figure 4-21 shows regional capacity and generation shares for each fuel. Nuclear capacity and generation are clearly strongest in NPCC, RFC, and SERC, which make up the entire East Coast except for Florida. Solar shares of capacity and generation for WECC, in the West, are several times higher than solar shares in any other region. WECC also significantly leads other regions in hydro, except for Alaska. Geothermal is only present in WECC and Hawaii, and makes up small shares in each. Only Alaska and Hawaii generate more than trivial shares of their electricity from petroleum, though other regions do have significant petroleum-fired capacity. Wind shares are highest in the central part of the country (MRO, TRE, and SPP) and West (WECC). Coal and natural gas do not have as clear-cut regional differences, though the share of coal-fired generation is highest in SPP and MRO in the center of the country.

Relationships between capacity share and generation share for a fuel tend to be similar across regions. Coal makes up a larger percentage of generation than of capacity in every region except for NPCC (which has very little of either). Wind capacity share is larger than generation share for all regions. The largest difference between capacity share and generation share is for nuclear, where shares of generation are roughly double the shares of capacity for every region that has nuclear in its portfolio. This is due to the high capacity factor (~90 percent) for nuclear compared to other fuels. There are, however, several exceptions where regions deviate from the national trend. Hawaii stands out for biomass: its capacity share is much larger than its generation share for this fuel; nationally, however, generation share leads capacity share for biomass, and the two values are closer together. Natural gas does not exhibit a clear pattern across regions.

Figure 4-21. Capacity and generation shares for generation technologies and region

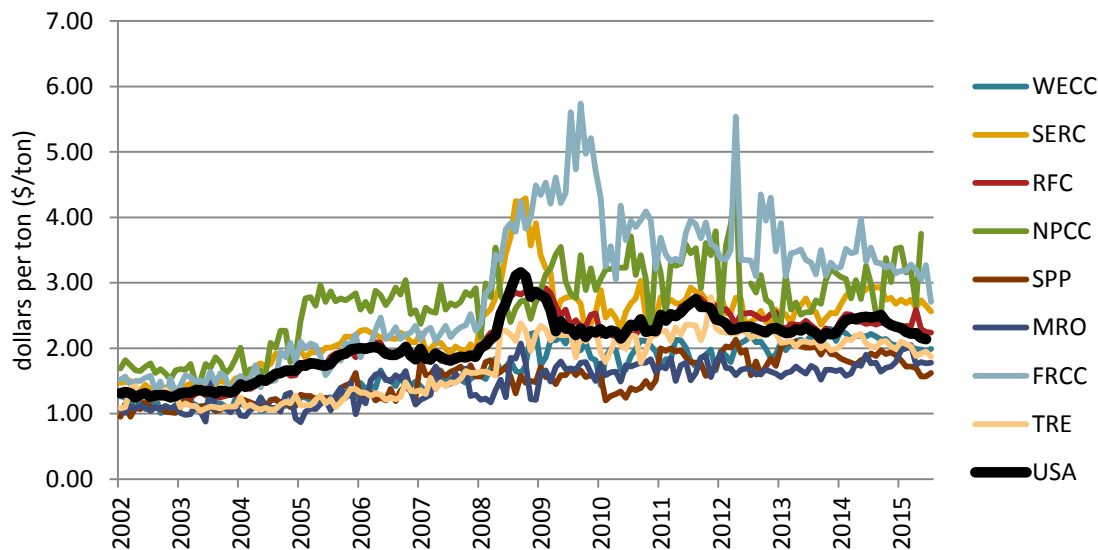


Differences in fuel use between NERC regions tend to follow geographic patterns. Relationships between capacity share and generation share for a fuel tend to be similar across regions. Source: SNL 2015¹⁵⁶.

4.2.13 Regional Fuel Prices

Fuel prices also have changed over time and vary across regions mainly as a function of transportation costs. Coal prices are presented in Figure 4-22 below and show a significant increase through 2008 before the financial crisis, followed by stable behavior since 2009. Coal prices vary by distance from source, with Florida and New England generally experiencing the highest prices.

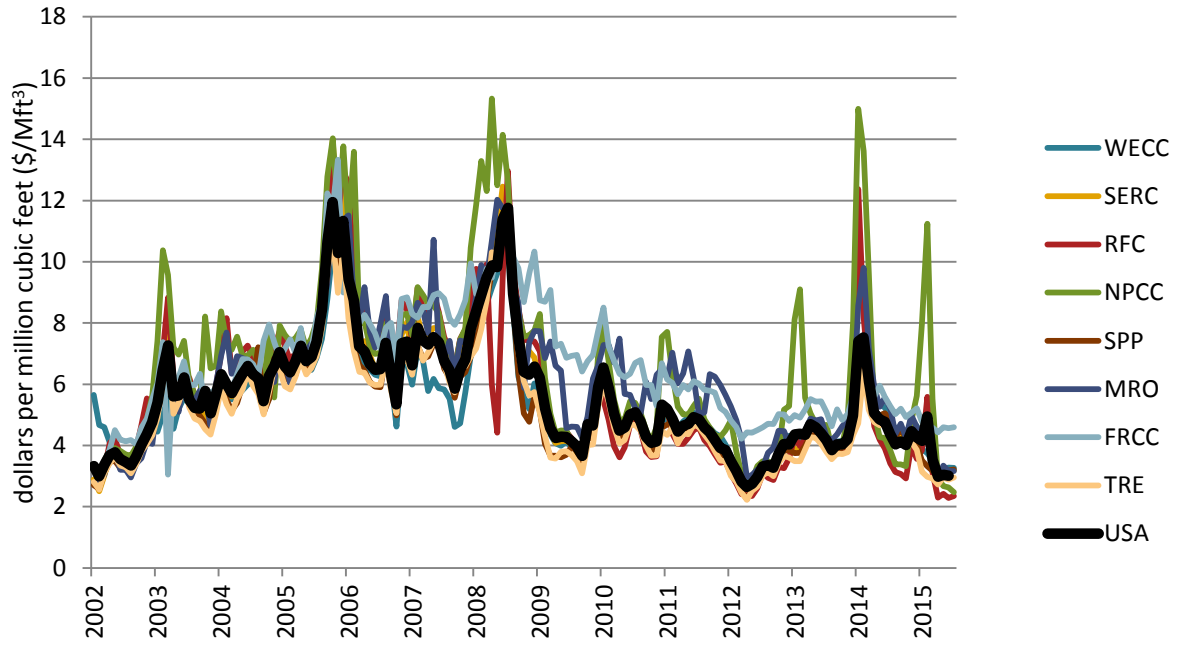
Figure 4-22. Coal monthly spot contractual fuel cost (\$/ton), 2002-2015



Coal prices rose before the recession of 2008 and have remained stable or declined slightly since then.
Source: SNL 2015¹⁵⁷.

Natural gas prices (Figure 4-21) have historically experienced greater volatility than coal. However, the expansion of domestic production over the past 7 years has led to a steadier supply and more stable prices, as well as prices at near historic lows in 2015–2016.

Figure 4-23. Natural gas monthly spot contractual prices (\$/Mft³), 2002-2015



Natural gas prices have been relatively low and less volatile since 2009, although prices have spiked during exceptionally cold winters, especially in New England. Source: SNL 2015¹⁵⁸.

5 Coal

5.1 Technologies

There are three main types of coal plants operating in the United States today: pulverized coal (PC), fluidized bed combustion, and integrated gasification combined cycle (IGCC).^{xxix} The vast majority of existing U.S. coal plants rely on PC configurations. PC plants use a coal-fired boiler to raise steam that is expanded through an ST, which in turn drives an electric power generator. Most existing PC plants use subcritical steam operating conditions, whereas newer, more efficient plants make use of supercritical or ultra-supercritical operating conditions (efficiency increases with higher steam pressure and temperature).

Fluidized bed and IGCC plants make up much smaller portions of the market and have only been considered commercial since the 1980s (at the beginning of 2016, there were only 3 operating IGCC plants in the United States). Fluidized bed boilers use steam in the same manner as PC plants, but the heat is generated by suspending solid fuel particles in the boiler by injecting air, thereby creating a turbulent mixture of the fuel, ash, and air during combustion. This results in more efficient combustion, the ability to fire low-rank coals, lower combustion temperatures (resulting in lower pollutant emissions, such as NO_x), modest plant efficiency improvements, and the ability to remove sulfur by adding limestone to the fluidized bed. IGCC plants first convert coal into a synthesis gas (syngas) rich in hydrogen (H₂) and carbon monoxide (CO) within a coal gasifier, which is then cleaned as desired and combusted in a CT. The exhaust heat resulting from this process is then used to raise steam to power a ST, thus the CC designation (see section 5.2 on natural gas below).

New coal plants in the United States are required to meet a CO₂ emissions limit in order to comply with EPA's Carbon Pollution Standards (EPA 2016a), which were finalized in October 2015. These standards (1,400 lb CO₂/MWh-gross for new coal units and 1,000 lb CO₂/MWh-gross for new gas units) are based upon EPA's designation of supercritical PC plants with partial CCS (approximately 20 percent capture) as the best system of emissions reduction for coal generation.

Using CCS technologies, CO₂ can be captured precombustion (in IGCC plants) or postcombustion from the flue gas using postcombustion technologies (for use with PC or fluidized bed combustion plants) or oxygen combustion (combustion of coal in an oxygen environment, creating a stream of less-dilute CO₂ as a flue gas). Once isolated and captured, the CO₂ is then transported for utilization (i.e., enhanced oil recovery) or geological storage in saline aquifers. These and other advanced technologies are under development by NETL (see section 5.7 and the private sector)¹⁵⁹.

In addition to research on advanced CCS and crosscutting technologies, efforts are underway across the globe to demonstrate CCS technology at scale and “learn by doing” in the field¹⁶⁰. The Carbon Sequestration Leadership Forum is one global network that is sharing best practices, operational experience, and key lessons to advance the deployment of CCS. DOE is playing a substantial role in CCS demonstrations, helping to overcome the technical and economic uncertainties associated with first-of-a-kind demonstrations of new technologies. However, even

^{xxix} PC and fluidized bed combustion plants, which both utilize the Rankine cycle for power generation, are sometimes referred to as conventional coal plants.

with Government support, these projects, by their nature, are ambitious and challenging—some projects will not go forward to completion. See section 5.7 for a more detailed discussion of CCS-related demonstrations.

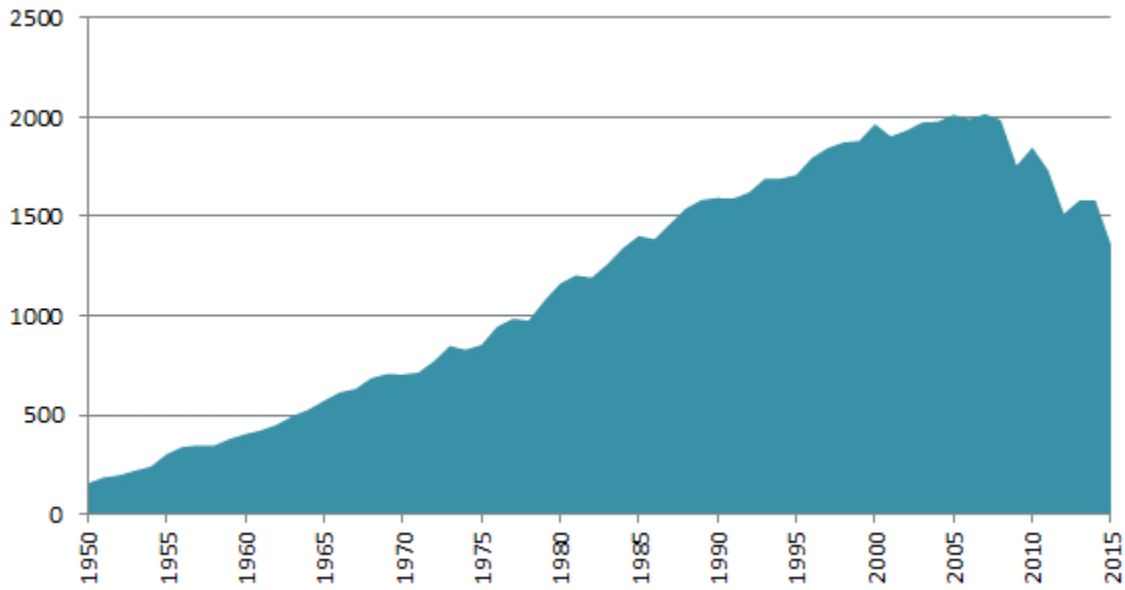
Text Box 1. The Kemper IGCC Plant with CCS

IGCC with CCS is under development, and DOE has an active RDD&D program focused on reducing costs along the entire process chain. The Kemper IGCC plant under construction in Mississippi—the second such commercial U.S. plant using “transport integrated gas” technology—is a 582-MW unit that is expected to capture approximately 65% of its emissions for use in nearby enhanced oil recovery (EOR). It is expected to come online in the second half of 2016. The plant will use locally available lignite fuel, but it will emit fewer air pollutants than traditional coal plants and use fewer water resources, less water for cooling than a conventional coal plant. It will also sell most or all of the captured CO₂ for EOR applications. The original cost estimate for the plant was \$1.8 billion, but it has since risen to \$6.2 billion¹⁶¹. More field experience and “learning by doing” could reduce these costs significantly in the future¹⁶². The only other coal power-based CCS project in North America is the Boundary Dam Plant in Saskatchewan, Canada. It uses postcombustion capture and sells the CO₂ for EOR¹⁶³. A third project, NRG Energy’s Petra Nova project in Parish, Texas, is expected to be operational later in 2016.

5.2 Operational Attributes and Fleet Characteristics

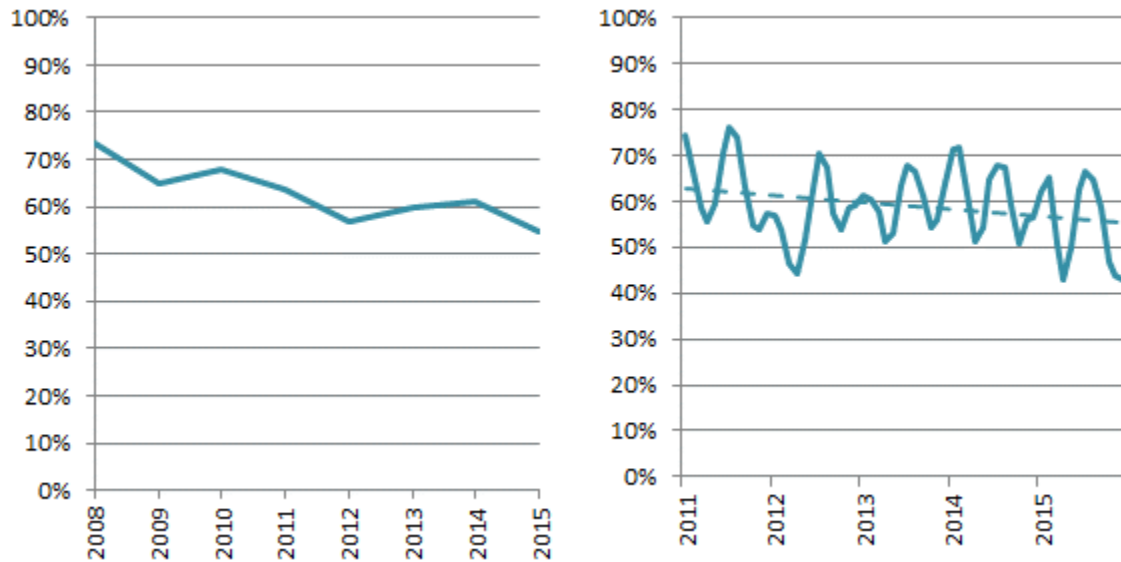
Coal has been the predominant source for electric power in the United States, and generation steadily increased until 2007. In that year, coal generation peaked at 2,016 TWh (49 percent of the nation’s annual generation). By 2015, coal generation had dropped to 1,356 TWh (33 percent of annual generation), a level not seen since 1989 (Figure 5-1). The reduction in coal-fired generation is due to a variety of factors, including low natural gas prices, higher maintenance costs of an aging fleet, growing regulatory pressure with respect to emissions, water consumption constraints, Federal and State incentives for renewable electricity options, and low electricity demand growth. Figure 5-2 shows the decline in coal capacity factor. The maps in Figure 5-3 illustrate capacity (left) and generation (middle) in 2010 and 2014, as well as the corresponding capacity factors (right). With few exceptions, capacity and generation from coal went down across the United States over the illustrated time period. Capacity factors also generally decreased modestly in most of the country, with notable exceptions in New England and the Mid-Atlantic, where many states saw capacity factors from coal decrease by over 50 percent.

Figure 5-1. U.S. coal generation (TWh), 1950–2015



Annual generation from coal peaked in 2007 and has been declining in recent years. Source: EIA 2016¹⁶⁴

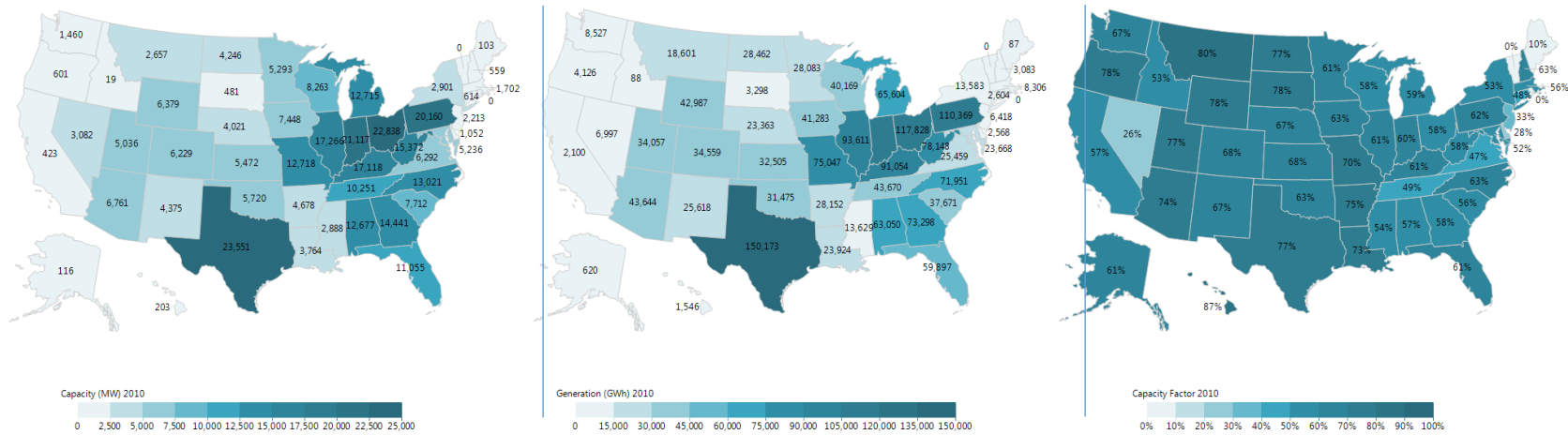
Figure 5-2. Annual and monthly capacity factors for coal generators



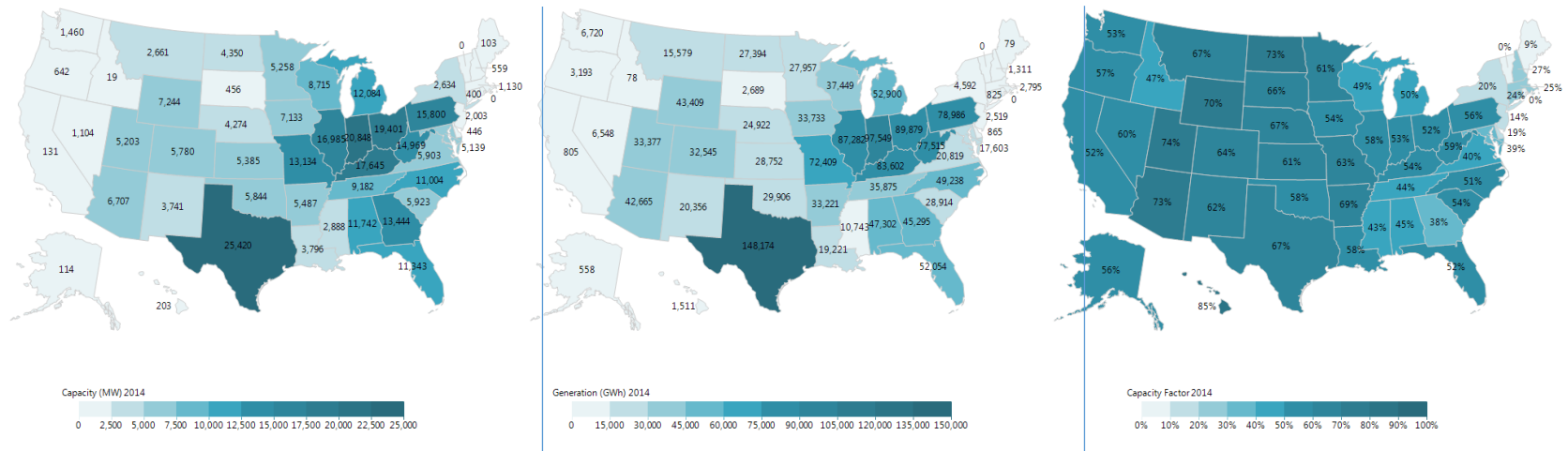
The capacity factor from the U.S. coal generating fleet fell from over 70 percent in 2008 to under 60 percent in 2015. Source: SNL 2015¹⁶⁵.

Figure 5-3. Coal capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



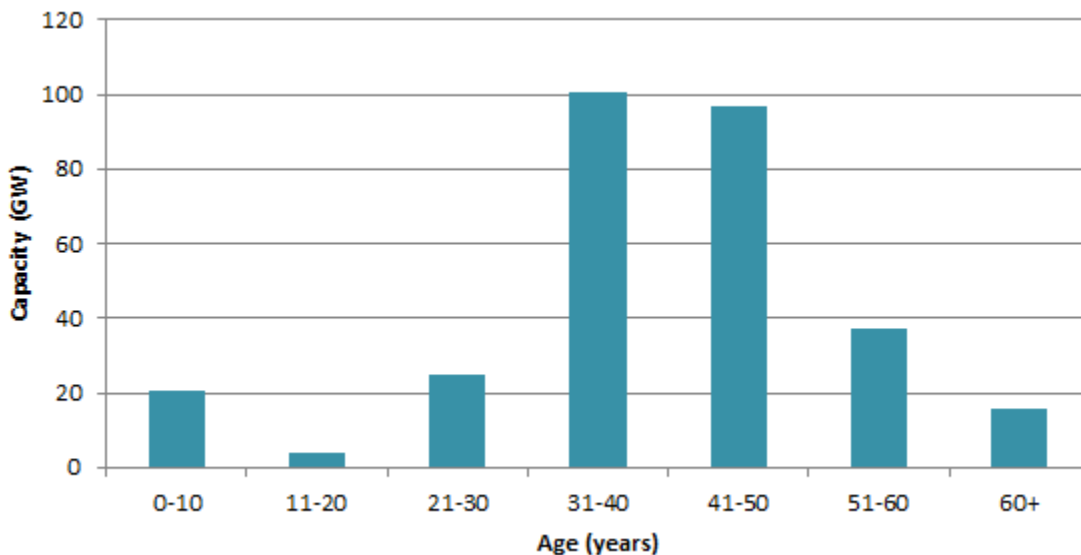
2014



Capacity, generation, and capacity factors for coal generally declined across the United States between 2010 and 2014. Source: EIA 2016¹⁶⁶.

Almost 90 percent of coal plant capacity was built over 30 years ago (Figure 5-4). The result is an aging fleet of plants that average around 40 years in age¹⁶⁷. Life expectancies for coal plants are 55 years for units under 100 MW and 65 years for units over 100 MW¹⁶⁸. The reported age of any power plant might be deceptive as equipment is often upgraded on a regular basis, which can extend plant life beyond the life expectancy.

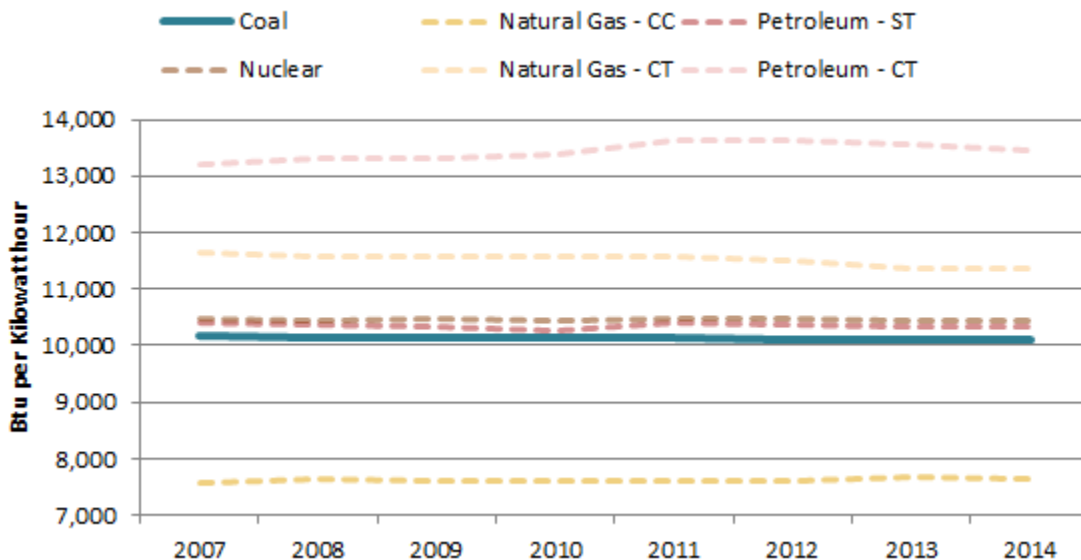
Figure 5-4. Age profile of U.S. coal generation fleet, 2014



A majority of the U.S. coal fleet capacity is between 30 and 50 years old. Source: SNL 2015¹⁶⁹.

The average heat rate for the U.S. fleet of coal-fired ST generators has gradually improved since 2007, mainly due to the retirement of smaller, older, or otherwise less efficient units (Figure 5-5). Heat rate improvement of existing coal plants is one of the building blocks of the best system of emissions reduction under the CPP.

Figure 5-5. Heat rates for coal generators (BTU/kWh) , 2007–2014



The heat rate for coal generators has declined slightly since 2007, meaning that, on average, the U.S. coal fleet is more efficient. Efficiency upgrades and retirements of older, less efficient units have contributed to this increase. Source: EIA 2015¹⁷⁰.

Heat rate estimates for modern, state-of-the-art coal generators are given in table 3 of appendix B; these are the heat rates used in the LCOE calculations presented in this report. While these estimates are representative of the current state-of-the-art technology, actual plant heat rates depend on a number of factors, including coal quality, specific plant design and operating conditions, site-specific factors including atmospheric conditions, and the temperature of available cooling water.

5.3 Technology Costs

The LCOE for new plants is shown in table 5-1 (2013\$). The range of values for the LCOE of PC is slightly lower than for IGCC, and adding CCS (at a 90 percent CO₂ capture rate) significantly increases LCOE for both. Publicly and privately supported research, development, and demonstration programs, including those managed by DOE, are focused on reducing the cost and performance penalties and risks associated with commercial CCS deployment (see section 5.7).

Table 5-1. LCOE for New Coal Generators (2013\$/MWh)

Technology	EIA		NETL		Lazard	
	Low	High	Low	High	Low	High
Coal - PC	54.81	97.53	65.01	91.43	52.53	77.95
Coal - PC - CCS (90 percent) ^a	-	-	108.96	144.66	-	-
Coal - PC - partial CCS (22 percent) ^a	-	-	88.33	110.58	-	-
Coal - IGCC	68.87	125.49	75.68	111.06	69.47	148.99
Coal - IGCC - CCS (90 percent) [*]	105.74	195.68	99.97	147.28	103.80	204.16

Current ranges of coal technology prices using cost assumptions from three sources: EIA 2015I, NETL 2015, and Lazard 2015¹⁷¹. See appendix B for more information on LCOE calculations.

5.4 Fuel/Resource

Coal has been a major fuel for electricity generation for more than a century in the United States. The three main types of coal used for power generation, in order of descending rank, are bituminous, subbituminous, and lignite. In general, higher-rank coals such as bituminous have higher energy content (characterized as the higher heating value, with units of Btu/lb), fixed carbon content, and sulfur, and less ash and moisture than lower rank coals¹⁷². Higher moisture coals have a lower heating value due to the latent heat of vaporization of the water. The mineral matter that comprises the ash content of coal is not combustible; consequently, its presence adversely impacts the energy content of the coal.

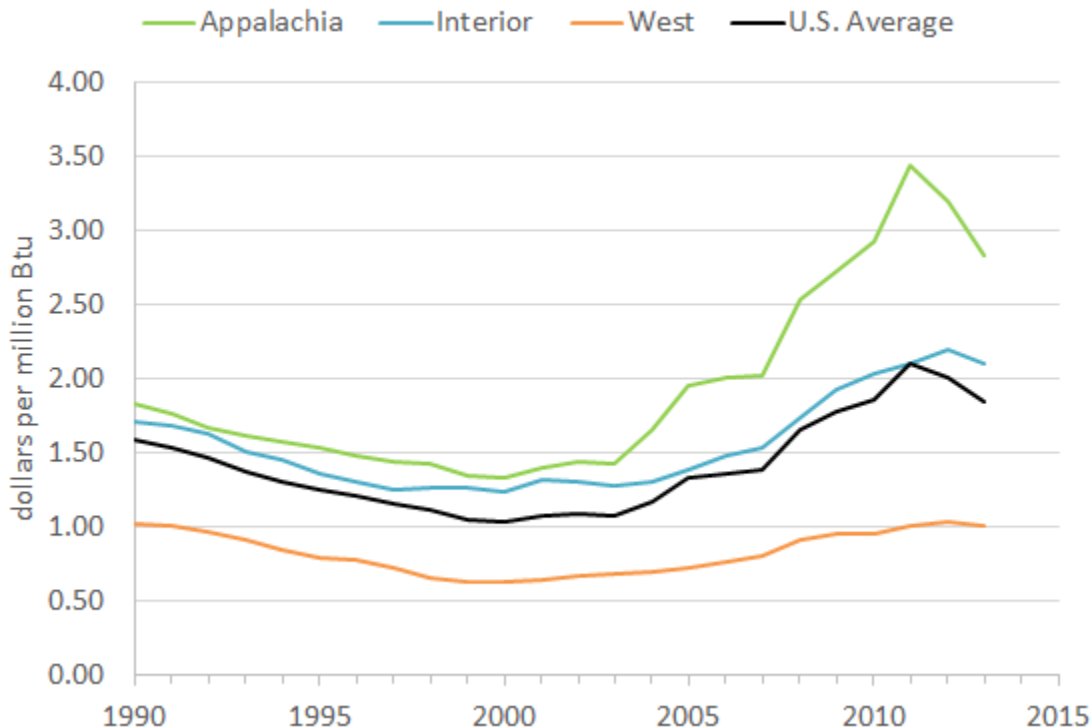
The 345 underground mines in the United States produced 354,704 tons of coal in 2014, or 30 percent of total domestic coal production. Underground mining is more prevalent east of the Mississippi River, where bituminous and anthracite coals are generally found at deeper depths, accounting for 61 percent of coal produced in that region. The 613 surface mines in the United States accounted for almost 70 percent of domestic coal production in 2014. Surface mining is the most prevalent form of coal mining west of the Mississippi, used for over 90 percent of coal production in that region, while it is only used for 29 percent of coal production in the East. Surface mining has declined 21 percent since 2008 due in part to a reduction in demand for coal (total production is down 15 percent over the period)¹⁷³. In 2014, U.S. production of coal consisted of 48 percent bituminous coal, 44 percent subbituminous coal, 8 percent lignite, and less than 1 percent anthracite^{174, xxx}.

5.4.1 Coal Price History

The majority of coal is sold under long-term contracts, with spot market sales making up the remainder of sales. The price of coal varies significantly by the source of coal, the heat content (Btu/lb) in the coal, how much sulfur and ash it contains, and how far the coal is from the point of use. The minemouth price futures for steam coal to the electric sector are shown in Figure 5-6, although there are wide variations in price by type of coal and location.

^{xxx} Totals may not add up to 100 percent due to rounding errors.

Figure 5-6. Average minemouth coal prices (2013\$) by region, 1990–2015

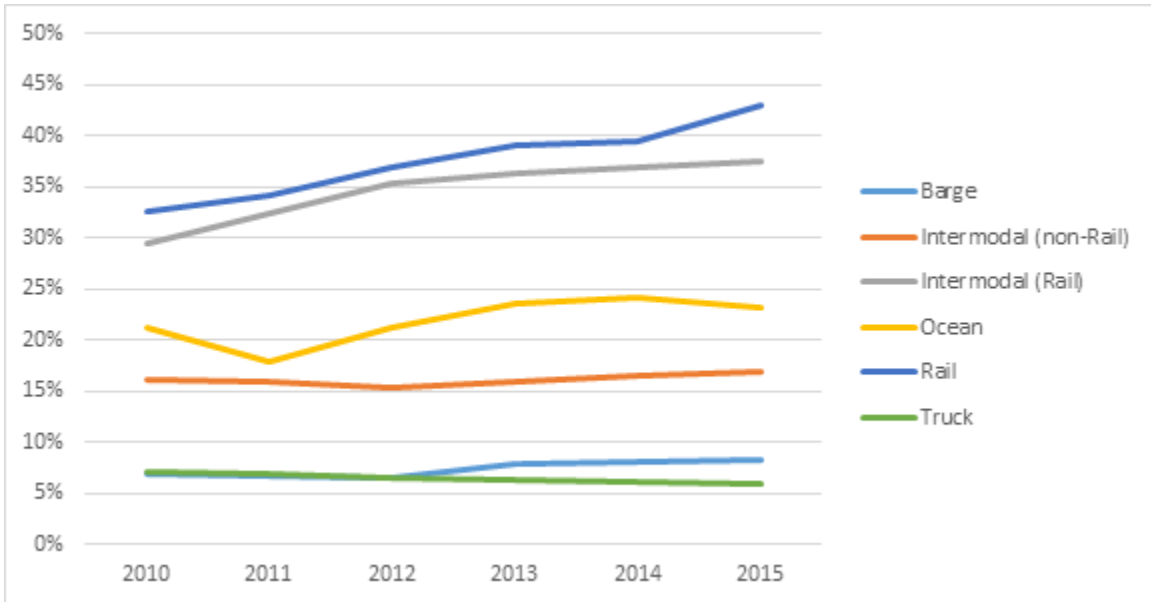


Appalachian minemouth coal prices are the highest in the United States, while minemouth prices are the lowest in the West. Source: EIA 2016¹⁷⁵.

Transportation can make up a significant portion of the delivered cost (the minemouth price plus transportation cost) of coal depending on the transportation method and year as shown in Figure 5-7. This is especially true for coal from the Powder River Basin in Wyoming, as it must be shipped long distances by rail to coal plants and international markets (Figure 5-8)^{176 xxxi}. PRB coal is also produced from open pit or surface mining, which is a much less expensive extraction method than underground mines, which are more prevalent in production of eastern coals.

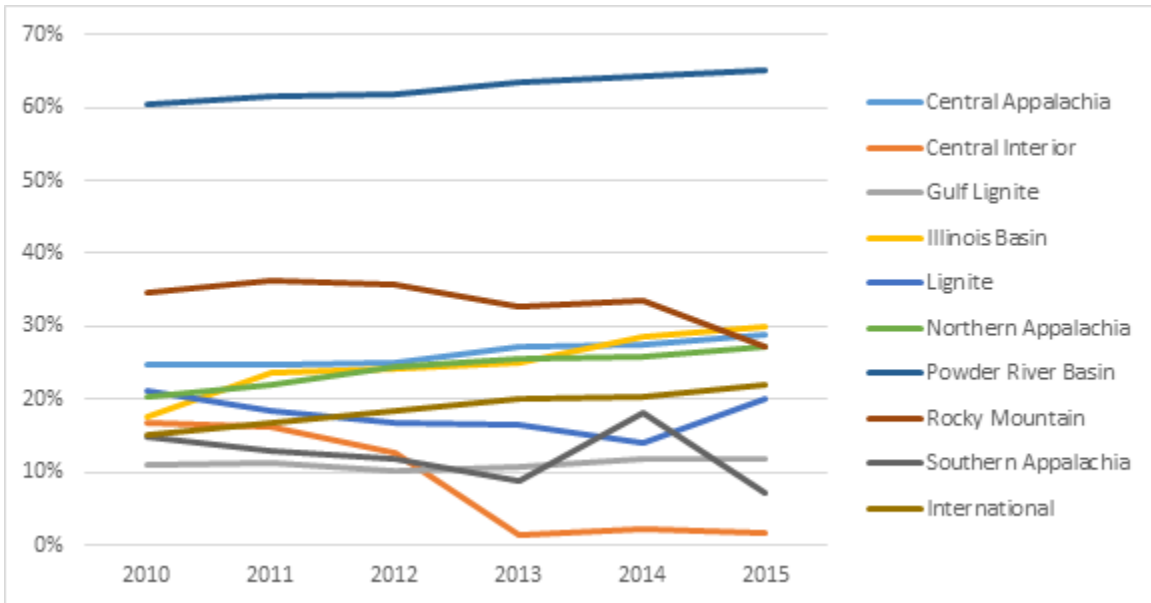
^{xxxii} Even with its high transport cost share of price on a percentage basis, Powder River Basin coal is still significantly lower cost than coal produced in other basins on a dollar per ton-mile basis. From 2010–2015, Powder River Basin coals averaged 3.1 cents per ton-mile delivered while Illinois Basin coals averaged 14.4 cents per ton-mile delivered and Central Appalachian Basin coals averaged 19.9 cents per ton-mile delivered. Over the period, the only coals that were competitive with Powder River Basin on a dollar per ton-mile basis were those imported from Indonesia (0.8 cents per ton-mile delivered) and South America (4.1 cents per ton-mile delivered); however, deliveries of these coals were constrained primarily to coastal power generators.

Figure 5-7. Transportation cost share of delivered coal price, 2010-2015



Transportation costs by railroad make up a much larger percentage of delivered coal prices than waterway or truck. Source: Mintz et al. 2015¹⁷⁷.

Figure 5-8. Rail transportation cost share of delivered coal cost by origin, 2010-2015



Rail transportation costs made up a large portion of the delivered coal price from the Powder River Basin. Source: Mintz et al. 2015¹⁷⁸.

5.5 Environmental Impacts

5.5.1 Upstream

Coal mining is conducted both on the surface and underground. Underground mining involves mining deep into the earth to extract coal in place and generally results in fewer disturbances at the surface, but has the potential to affect groundwater and, in some cases, emit methane, a potent GHG (in the case of gassy coal seams). These impacts, particularly related to the groundwater impacts of mining, can be minimized through best practices and regulations such as the Coal Mining Effluent Guidelines and Standards and others promulgated under the Clean Water Act, which have been enacted and regularly amended to this end.

Legacy environmental impacts exist, particularly from abandoned mines, and some of these impacts are still being felt. The most significant of these is perhaps the problem of acid mine drainage (AMD), which occurs when water flows over sulfur-containing materials¹⁷⁹. AMD is considered one of the largest nonpoint sources of pollution in the Mid-Atlantic region by the EPA; it can contaminate drinking water, disrupt ecosystems for aquatic life and bacteria, and corrode infrastructure such as bridges¹⁸⁰. Most of the mines that have led to AMD problems have been legacy mines that operated before environmental regulations were in place to prevent impacts to the ecosystem.

Surface mining involves removing the top layers of soil or rock to expose shallow coal seams. While surface mining practices vary by state, it is common for the soil to be set aside during coal production and replaced after mining operations have ceased. The Surface Mining Control and Reclamation Act of 1977 requires coal mining areas to be restored to “a condition capable of supporting the uses which is [sic] was capable of supporting prior to any mining, or higher or better uses”¹⁸¹. The interpretation of the Surface Mining Control and Reclamation Act can vary by state, but it is common practice in certain states to remediate the mined area to the original contours of the land, while in other instances the now-cleared area is repurposed for other uses¹⁸². The practice of surface mining has undergone a steeper decline where remediation is difficult, such as in eastern states with varied topography. This is partly a result of increased environmental regulations and permitting constraints¹⁸³.

There is generally no manufacturing needed to produce coal, outside of equipment for mining and cleaning coal. Cleaning coal (beneficiation) removes impurities such as sulfur, ash, and rock in an effort to increase the value of coal. The main environmental concern during cleaning coal is the release of particulate matter to the air created from coal dust¹⁸⁴. Water is used in this process and can be contaminated by this same dust. Wastes from this process include slurry, which is stored in impoundments onsite¹⁸⁵.

5.5.2 Emissions and Environmental Impact

The conversion of coal into electricity produces many emissions, resulting primarily from inorganic materials found in the coal. Waste streams can be minimized or mitigated by choice of conversion technology (e.g., gasification versus combustion), use of environmental control technologies, or maximization of the conversion efficiency of the process.

Airborne emissions from coal generation contain NO_x, SO_x, particulate matter, NMVOCs, mercury, and CO₂, among others. NO_x is a common cause of smog in cities, and SO_x is one of the leading contributors to acid rain and is a precursor to particulate matter. Particulate matter can

affect the health of humans, lead to respiratory issues, and increase premature death rates. CO₂ is one of the leading contributors to anthropogenic climate change. The Clean Air Act of 1970 first regulated these air pollutants and has been successful in driving the development of specific environmental control technologies for emissions reductions, improving the science related to energy conversion, and effecting efficiency improvements.

Combustion controls modify the operating conditions to reduce the production of NO_x during combustion. They include (1) lowering the combustion temperature (2) creating a fuel-rich environment or (3) reducing the time that oxidation can occur¹⁸⁶. Postcombustion technologies, often selective catalytic reduction, use chemicals (ammonia) and a rare-earth element catalyst to convert NO_x to N₂¹⁸⁷.

SO_x emissions are generally controlled through either using low-sulfur fuel or using a limestone scrubber to remove sulfur from the flue gas¹⁸⁸. Emissions are regulated by EPA, and regulations have been largely successful in reducing problems from acid rain. The Cross-State Air Pollution Rule¹⁸⁹, which replaced the Clean Air Interstate Rule regulation on cross-border air pollution transport in 2015¹⁹⁰, was challenged in courts but remains in place. The CSAPR requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.

Particulate matter emissions can be controlled by removing and capturing the fine particles contained in the plant flue gas. Control technologies include electrostatic precipitators, fabric filters, mechanical collectors, and venturi scrubbers¹⁹¹. The Mercury and Air Toxic Standards were implemented in 2012 to control mercury and air toxic (hydrogen chloride, hydrogen fluoride, heavy metals) emissions from coal- and petroleum-based generators¹⁹².

CO₂ emissions for new coal-fired plants are regulated under a Federal program set forth in section 111(b) of the Clean Air Act. EPA promulgated rules for new stationary sources under 111(b) in August 2015 that set the emissions requirements for any new coal-fired plants¹⁹³. New supercritical PC plants emit greater than the allowed CO₂ volume¹⁹⁴, thus requiring at least partial CCS for most new plants. However, certain IGCC configurations (as well as specific coals, site-specific conditions, etc.) may be able to meet this limit without incorporation of CCS equipment¹⁹⁵.

5.5.3 *Downstream*

In addition to these gaseous emissions, burning coal also produces solid coal combustion residues, which can pose additional dangers when released to the environment. The two largest forms of solid combustion wastes are fly ash (accounting for roughly half the combustion waste) and SO_x “scrubber” slurry, which results from emissions reduction efforts at the plant. Bottom ash contains materials that are too large to be carried by the hot gases and therefore settle at the bottom of the boiler. When temperatures are high enough to melt ash, boiler slag can form and collect at the bottom of the boiler and in the exhaust stack filters. About 45 percent of these wastes are reused in other products, such as concrete products and drywall¹⁹⁶.

Waste is often stored onsite in retention ponds. This coal ash-containing water in retention ponds can have impacts on local ecosystems as shown in past leaks and releases. In 2015, EPA’s new Disposal of Combustion Coal Residue rule took effect, which provides for the safe disposal of coal ash¹⁹⁷.

5.6 Constraints^{xxxii}

New coal-fired plants in the United States are required to meet a CO₂ emissions limit in order to comply with EPA's Carbon Pollution Standards¹⁹⁸, finalized in October 2015. While in some instances compliance can be achieved without CCS, the majority will require the capture of CO₂ produced during coal conversion to electricity.

5.7 Technical RDD&D

DOE has active RDD&D programs in place for advanced coal generation and CCS technologies along the entire value chain.^{xxxiii} This value chain includes advanced energy systems R&D; CO₂ capture R&D; CO₂ injection and storage R&D, including utilization of CO₂ (mainly for enhanced oil recovery [EOR]); and monitoring, verification, and accounting of underground storage volumes.

Advanced energy systems R&D focuses on innovative, near-zero-emissions technologies that are integrated with CCS and improved fuel conversion. The R&D portfolio includes advanced combustion, gasification, turbines, and fuel cell energy conversion systems. The research is targeted at improving overall system efficiency, reducing capital and operating costs, and enabling affordable carbon capture.

Advanced combustion systems R&D focuses on the development of high-efficiency oxy-combustion and chemical-looping combustion technologies and novel concepts optimized for coal-fueled power plants with carbon capture. New systems are also being developed that generate power at higher efficiencies while also enabling carbon capture. Advanced combustion system R&D also includes research on gasification systems and advanced turbines (including supercritical CO₂-based cycles).

Carbon capture R&D is focused on the development of postcombustion and precombustion CO₂ capture technologies for new and existing power plants to improve efficiency while minimizing the cost and energy penalty of CO₂ capture.

Postcombustion CO₂ capture offers the greatest near-term potential for reducing power sector CO₂ emissions because it can be retrofitted to existing coal-based power plants. This technology can also be leveraged in other power- and nonpower applications, including carbon capture from natural gas and biomass electricity systems.

Precombustion capture R&D focuses on ways to capture CO₂ before combustion, primarily in IGCC plants. The continued deployment of IGCC systems such as the Kemper plant (text box 1), either domestically or internationally, will continue to bring down capital costs through "learning by doing" and aid in the advancement of this pathway. Precombustion capture is also applicable to certain industrial processes, such as the production of hydrogen through steam methane reforming.

In both pre- and postcombustion cases, R&D is underway to develop solvent-, sorbent-, and membrane-based capture technologies

^{xxxii} The "Constraints" section does not address environmental or RDD&D constraints that are addressed elsewhere in this report.

^{xxxiii} Much of the information in this subsection comes from the DOE RDD&D program for CCS website, available at: <http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research>. NETL (2015c, 2012a) contributes significantly to this effort.

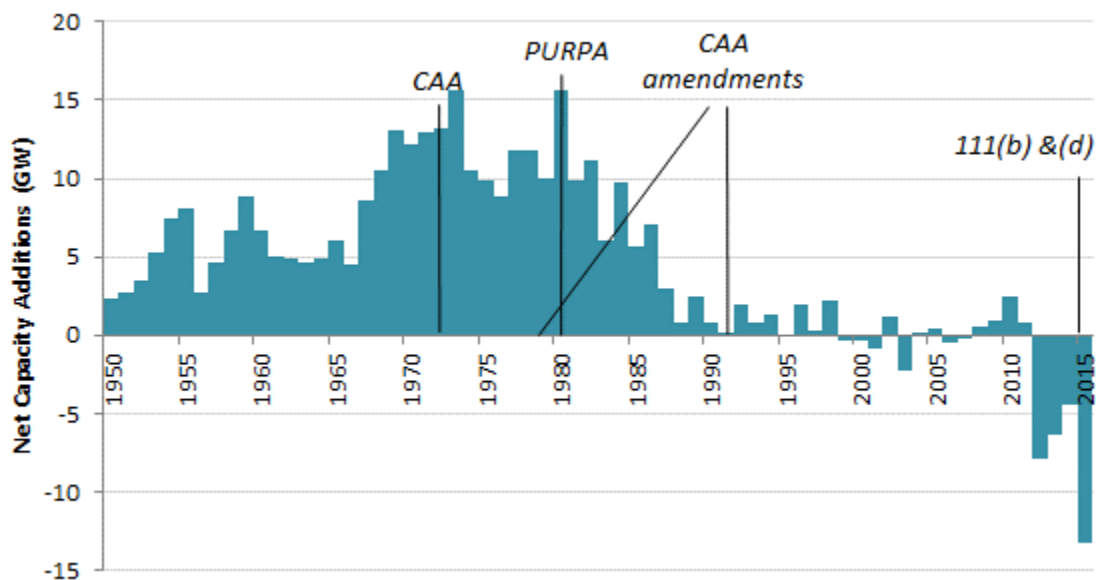
Carbon storage R&D is focused on developing and advancing technologies to enable safe, cost-effective, permanent geologic storage of CO₂. The technologies being developed will benefit both industrial and power sector facilities that will need to mitigate future CO₂ emissions and apply to both land-based and offshore applications, in different depositional environments. The R&D effort also serves to increase understanding of the effectiveness of these advanced technologies in different geologic reservoirs appropriate for CO₂ storage and to improve the ability to understand the behavior of CO₂ in the subsurface. These objectives are key to increasing confidence in future safe, effective, and permanent geologic CO₂ storage. There are several options for geologic CO₂ storage in the subsurface, including saline formations, oil reservoirs, natural gas reservoirs, unmineable coal seams, basalt formations, and organic-rich shale basins.

5.8 Development and Projected Future Deployment

Coal-fired generation technologies achieved continuous improvements in economies-of-scale through approximately 1965. As plant size grew and performance improved (e.g., higher steam temperatures and pressures), utilities could charge less and still remain profitable. As such, the market alone drove deployment without the pressure for strong price regulation. But as technological limits led to a leveling off in economies-of-scale, and growing concern over environmental impacts from coal use began to be felt in the 1970s and 1980s, coal faced growing challenges, especially given strong growth in nuclear power. The energy crisis of the 1970s and early 1980s did result in some new laws that encouraged greater use of domestic coal, but new coal additions began to decline in the mid-1980s and have remained low since, with the possible exception of 2010 when the last large units came online. Regulations associated with section 111(b) of the Clean Air Act now require new coal plants to limit their CO₂ emissions intensity to 1,400 lb CO₂/MWh, which is a level achievable by a supercritical PC unit capturing about 20 percent of its carbon emissions (Figure 5-9)¹⁹⁹.

There were roughly 25 GW of coal retirements from 2012 to 2014 (SNL 2015). In 2015 alone, 13 GW of coal capacity retired, which was over 70 percent of retired capacity. The plants retired in 2015 had an average age of 54 years and an average net summer capacity of 133 MW, much older and smaller in capacity than the coal fleet remaining in operation.

Figure 5-9. Historical annual coal capacity additions and retirements (GW), 1950–2015



Coal capacity grew steadily during the 1950s and 1960s, and accelerated during the 1970s and early 1980s due to global oil turmoil. Growth slowed from the mid-1980s until 2004 or so, when economic growth combined with concerns of natural gas shortages drove new coal investment. The economic recession, shale gas revolution, and new environmental regulations have hampered new coal builds since 2010. Aging coal units have retired in recent years due to the availability of other, less expensive generating resources (natural gas and renewables). Source: EIA 2016²⁰⁰.

Many of the recent coal retirements were the result of market forces and new environmental regulations; some power plant operators decided that retrofitting units to meet the new environmental standards would be cost-prohibitive or too risky (based on market and regulatory uncertainty) and chose to retire these units instead. The drivers for the recent reduction in coal-fired generation include low-cost natural gas generation, environmental regulations, Federal and State policies associated with renewable energy (e.g., PTCs and RPS) and flat electricity demand²⁰¹. Projections vary as to the potential for CCS retrofits on the existing fleet or the construction of new coal-fired plants that meet the CPP. Table 5-2 shows the projected generation from coal under the QER 1.2 Base Case and a Side Case scenario.

Table 5-2. QER 1.2 Base Case generation for U.S. coal in TWh

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Conventional Coal	1,607	868	1278
Coal with CCS	0	5	7

Projected generation from coal under the QER 1.2 Base Case and Side Case. For more details on the analysis methodology, see section 2.8. Source: EPSA 2015²⁰².

In the International Energy Agency’s (IEA’s) *World Energy Outlook* (WEO), global coal-fired generation is projected to grow between 23 percent (New Policies Scenario) and 72 percent (Current Policies Scenario) through 2040, with much of the expansion coming in developing countries (Tables 5-3 and 5-4). Over that time period, coal-fired generation in IEA’s Organization for Economic Co-operation and Development countries is projected to stay mostly flat in the Current Policies Scenario or decline by over one-third in the New Policies Scenario²⁰³. As shown in Table 5-4, the New Policies Scenario results in advanced coal and CCS deployments, with capacity increases expected in supercritical and advanced coal, and a projected 63 GW of coal with CCS by 2040.

Table 5-3. Historical and projected global coal generation by scenario outlook, 2000-2040

			New Policies		Current Policies		450 Scenario	
	2000	2013	2020	2040	2020	2040	2020	2040
Coal-Fired Generation (TWh)	6,001	9,612	10,171	11,868	10,918	16,534	9,185	4,107
Percentage of Global Total	39	41	37	30	39	38	35	12

Source: IEA 2015²⁰⁴.

Table 5-4. Current and projected coal-fired capacity (GW) in the WEO New Policies scenario, 2014 - 2040

	2014					2040				
	OECD	China	India	Rest of world	World	OECD	China	India	Rest of world	World
Total	647	864	174	238	1 922	412	1 175	438	443	2 468
Subcritical	415	529	149	158	1 251	161	476	196	210	1 044
Supercritical	147	205	25	28	405	120	318	222	103	764
Advanced	85	130	0	51	266	98	355	21	123	597
CCS	0.1	-	-	-	0.1	33	25	-	6	63
Subcritical	64%	61%	86%	67%	65%	39%	41%	45%	48%	42%
Supercritical	23%	24%	14%	12%	21%	29%	27%	51%	23%	31%
Advanced	13%	15%	0%	21%	14%	24%	30%	5%	28%	24%
CCS	0%	-	-	-	0%	8%	2%	0%	1%	3%

Global coal deployment is projected to grow modestly through 2040, with much of the expansion coming in developing countries. Much of the coal-fired capacity increase is expected in supercritical and advanced coal technologies. Source: IEA 2015²⁰⁵.

6 Natural Gas

6.1 Technologies

The main technologies for natural gas-fired electricity generation are CTs (commonly referred to as “simple cycles”) and CCs (commonly referred to as “natural gas combined cycles,” or NGCCs), which integrate a CT with an ST bottoming cycle. Both CT and CC units can be and are run on secondary fuels such as fuel oil, distillate, and other fuels, allowing for dual-fired back-up capabilities; however, due to the current low cost of natural gas, this is the fuel of choice for CTs and CCs in the electric sector for most regions of the country. On a total heating value basis, the price of natural gas has fallen below the cost of coal in some regions.

A CT is comprised of three main sections: the compressor, the combustor, and the expander. The compressor compresses incoming air to high pressure and feeds it to the combustor. Then, natural gas (or another fuel) is injected into the combustion chamber and combusted to produce a high-temperature and high-pressure gas stream. This gas stream is then expanded through the expander section that is linked to a generator to produce electricity²⁰⁶.

CC generators use exhaust heat from a CT to generate steam to run a secondary ST generator. After the air has expanded through the primary CT, the combustion gas remains hot (750-930°F) and can generate steam to power a ST. Generally a CC produces two-thirds of its power from the CT and one-third from the ST. Use of a regenerator is another option where the still hot exhaust gas is used to partly preheat the compressed gas before it enters to the combustor. Similarly, advanced ST designs for converting hot gas and steam into kinetic energy are increasing the efficiency of power production. The combination of these advancements has increased the overall efficiency of CC to around 60 percent lower heating value, while older CC generally achieve at least 50–55 percent lower heating value efficiency.

Natural gas is also burned in standard boiler packages, where natural gas is combusted to create steam, which is then passed through a turbine to create rotational energy for the generator. This is often the case for combined heat and power systems, and coal-fired power plants that have been converted to gas-fired units. However, due to competition with CCs, older natural gas STs have recently been retired from service in significant quantities. In some instances, low gas prices have also made gas-fired boilers less expensive to operate than coal-fired boilers.

CCS can also be applied to natural gas-fired generators, although minor differences exist in capturing the CO₂ from the flue gas, primarily due to the lower CO₂ concentrations. These differences go beyond the scope of this report; nevertheless, many of the postcombustion technologies under development by DOE for coal may be applicable to CCS for natural gas-fueled plants.

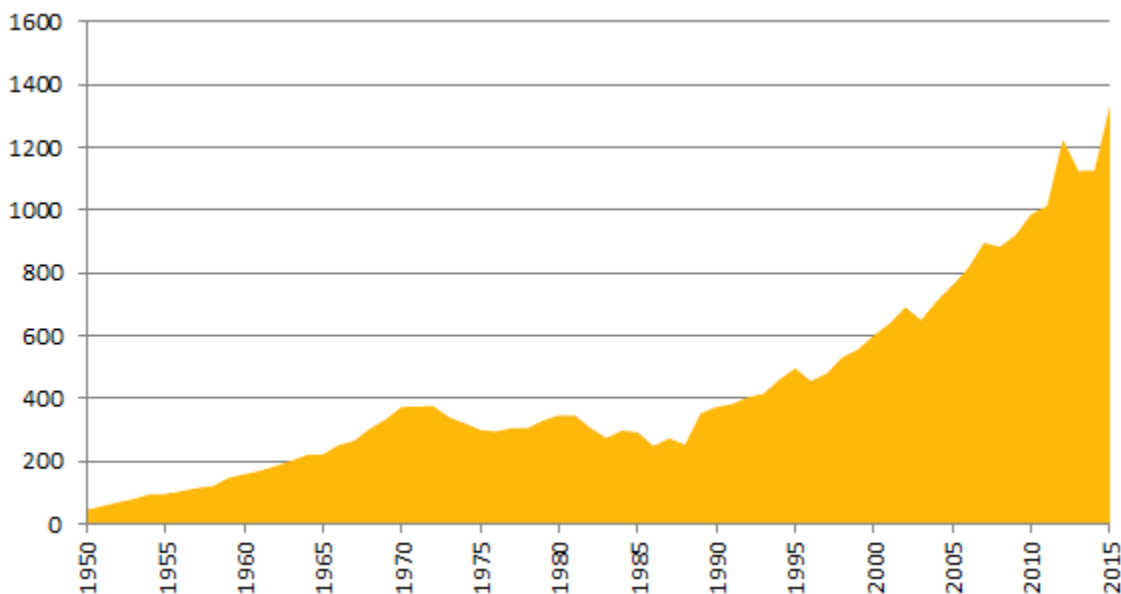
Natural gas can also be used in an internal combustion engine, typically for small-scale applications like residential back-up generation or for support of isolated power grids. These engines can also be linked together to provide significant ancillary services for grid applications, such as the Plains End plant in Jefferson County, Colorado, which helps integrate increasingly large amounts of wind power there. Natural gas may also be used in distributed generation-scale (1 MW+) fuel cells, such as certain solid oxide or molten carbonate fuel cells. A ~59 MW molten carbonate fuel cell plant composed of twenty-one 2.8 MW units began operation in South Korea in 2014²⁰⁷. Finally, natural gas is also one feedstock for hydrogen production by a process

known as methane steam reforming. This hydrogen can be used to generate electricity in proton exchange membrane fuel cells.

6.2 Operational Attributes and Fleet Characteristics

Electricity generation from natural gas has steadily increased from 45 TWh in 1950 (12 percent of total generation) to 1,335 TWh and 33 percent of total generation in 2015 (Figure 6-1). In 2006, natural gas became the second largest source for electricity generation in the United States—surpassing nuclear power—and continued to expand in 2015. Natural gas-fired generation exceeded that of coal for 7 of the 12 months of 2015; this was the first time ever that monthly natural gas-fired generation was greater than coal²⁰⁸. Recent analysis notes that some regions of the country could become overly dependent on natural gas-fired generation and develop insufficiently diverse generation mixes²⁰⁹.

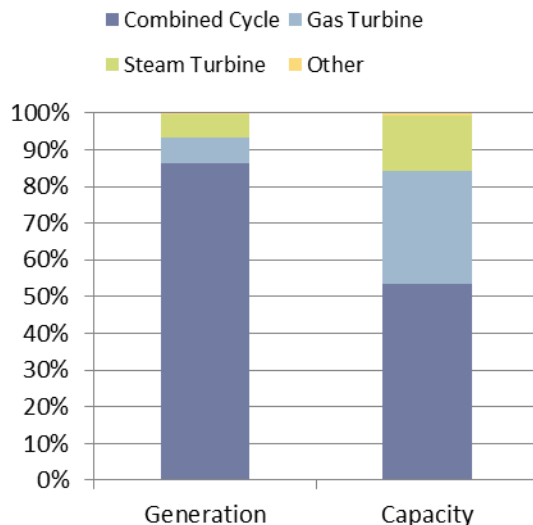
Figure 6-1. U.S natural gas generation (TWh), 1950–2015



Natural gas generation has grown nearly continuously since the late 1980s—well before the shale gas revolution started in the mid-2000s. Source: EIA 2016²¹⁰.

Figure 6-2 shows shares of natural gas installed capacity and generation by technology type. While generation is dominated by CC plants, capacity is more evenly distributed.

Figure 6-2. Share of U.S. operating natural gas–fired capacity and generation by technology type, 2014



While NGCC plants only make up about 55 percent of capacity, they make up about 85 percent of generation, indicating their high dispatch rate. Conversely, gas turbines make up 30 percent of capacity but less than 10 percent of generation because they are used primarily for meeting peak load. Sources: EIA 2016²¹¹.

Natural gas CCs and CTs have significantly different capacity factors, due primarily to operating characteristics and costs, which dictate their roles in dispatch. CTs are less efficient and therefore have higher operating costs and emissions than CC units. However, CTs short startup times and fast ramp rates make them indispensable for maintaining grid reliability, and their low capital costs make them well suited to use at low annual capacity factors. Thus, natural gas CT units contribute primarily to peak load and therefore only need to be operated a few hours out of the year. NGCC plants retain some of the flexible characteristics of NGCTs but operate at a higher efficiency and, therefore, lower cost. Consequently, these units dispatch more frequently than CTs and are often used for baseload power. Until recent sustained low natural gas prices, however, most NGCC units were utilized for intermediate and peak loads, rather than baseload.

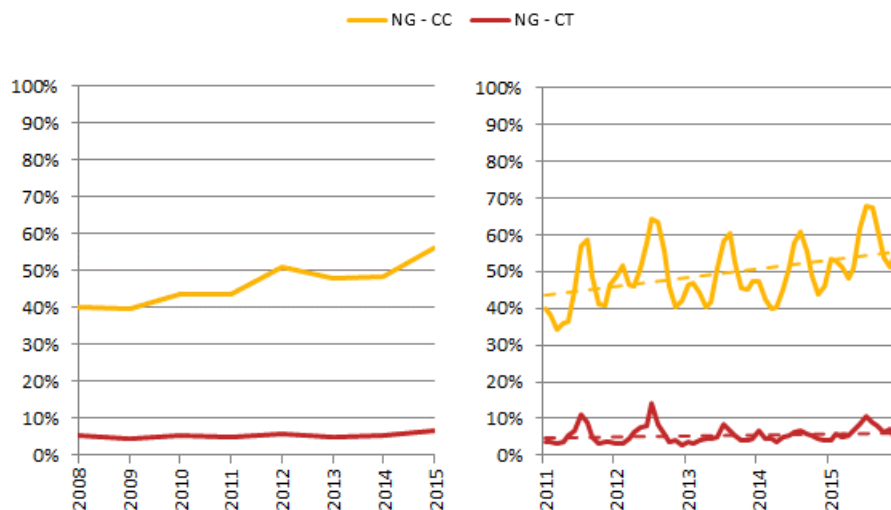
CTs can quickly start up and shut down, as well as ramp their outputs without major reliability or maintenance concerns. This flexibility makes CTs useful in complementing variable generation, such as wind and solar, because it allows for load following. NGCCs retain some of the flexibility characteristics of NGCTs, but flexible operation comes at a cost: reduced efficiency, higher emissions, and increased wear and tear on the equipment, increasing maintenance costs²¹². Vendors now offer NGCC units that are specifically designed for flexible operation, and these can reduce the maintenance impacts (in particular), but these units cost up to 30 percent more than the standard commercial offerings²¹³.

Natural gas single-cycle turbines, in particular, are viewed as important for reliability purposes, with their fast startup times (as little as 7 to 11 minutes from cold startup to 100 percent output), fast ramping capability, and reduced propensity to cycling damage (as they have no steam cycle)²¹⁴. CC turbines also add flexibility to the system because of their easy ramp up and turn down capabilities, but the steam cycle can result in slightly reduced ramp rates and longer startup

times from cold start to full output, depending on the system²¹⁵. Both types of generation are complementary to systems that have high proportions of variable renewable energy generation. In contrast, coal-fired units ramp on the order of hours, and doing so incurs increased O&M costs. It is worth noting that both coal-fired and nuclear generation technologies are also moving in the direction of increasingly flexible operation; however, they are unlikely to achieve the performance of single-cycle turbines without substantial advances. During low-load operation times, simple-cycle gas turbines experience a much more substantial efficiency penalty than coal units.

The capacity factors over time for each technology are shown below in Figure 6-3. The maps in Figures 6-4 and 6-5 also show the increased use of NGCC generators over the 2010–2014 timeframe. The maps also indicate that some states rely on CTs more regularly than other locations, most notably Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island all have CT capacity factors greater than 20 percent.

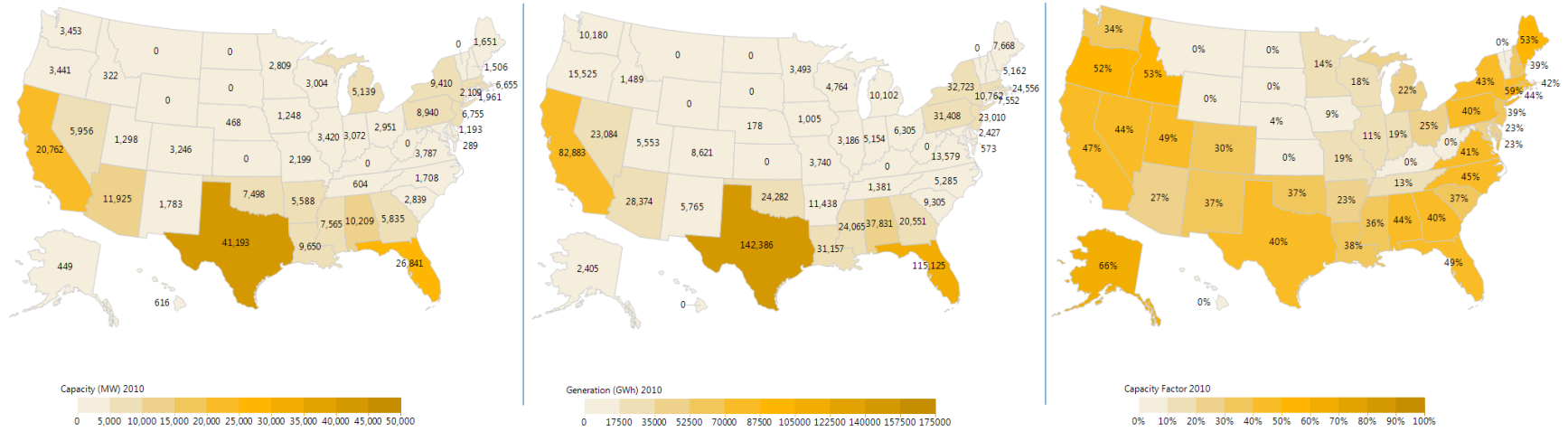
Figure 6-3. U.S. annual and monthly natural gas generator capacity factors



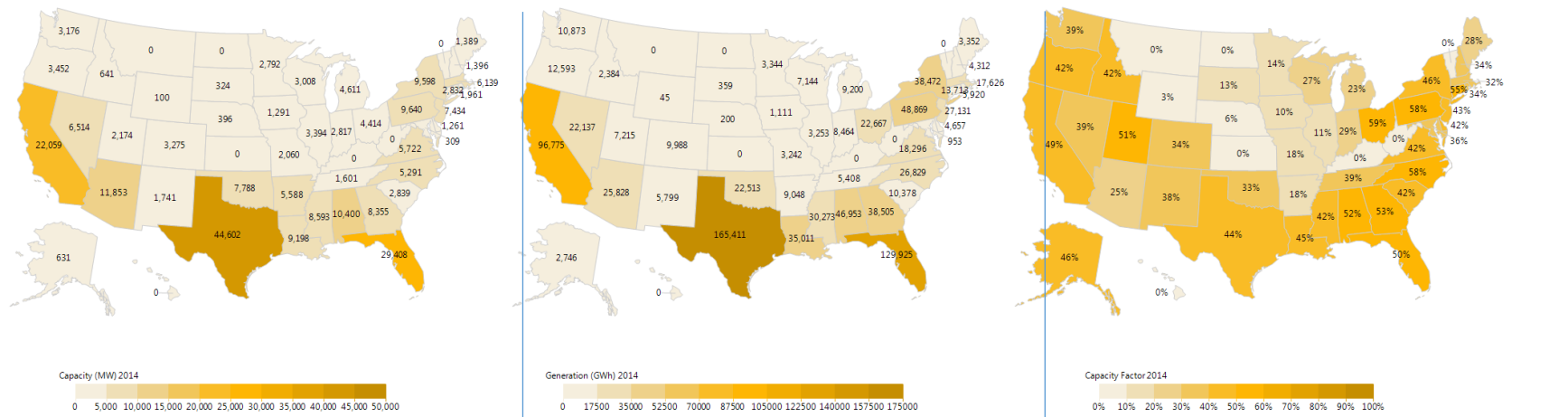
NGCC capacity factors have increased over time due to cheap natural gas and retirements of older coal plants. CTs still provide peaking needs, leading to lower capacity factors. Source: SNL 2015²¹⁶.

Figure 6-4. Natural gas CC capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



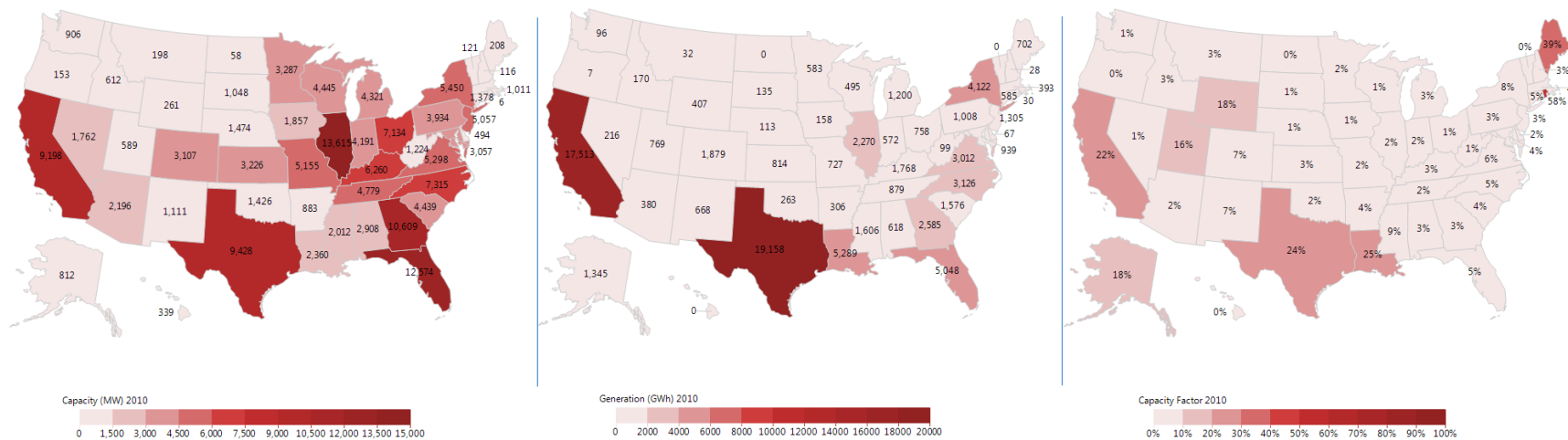
2014



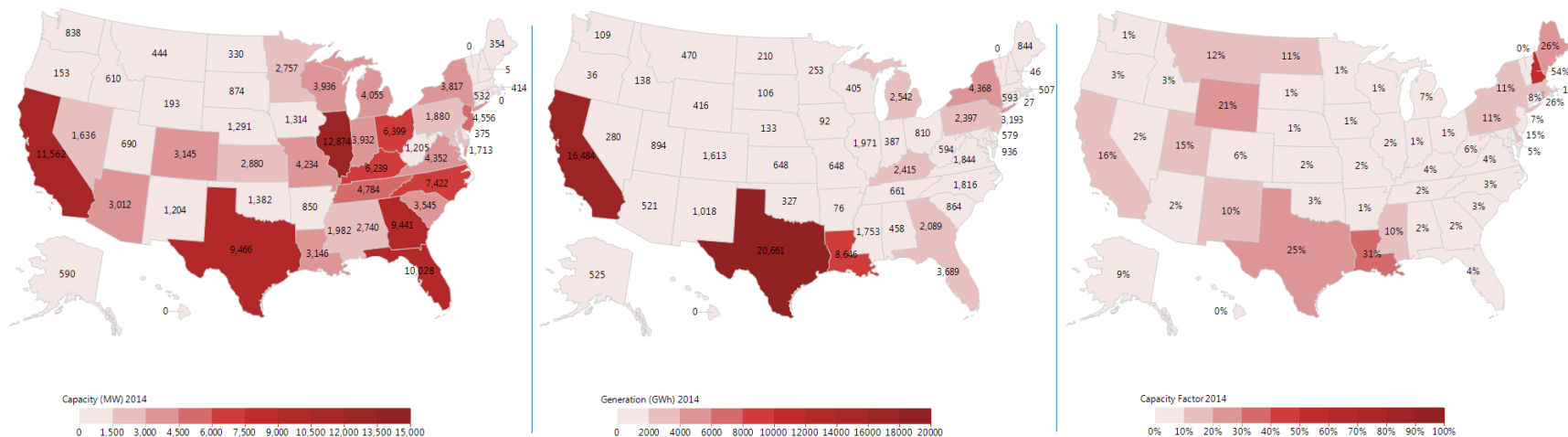
Capacity, generation, and capacity factor from natural gas CCs all generally increased across the U.S, 2010 to 2014. Source: EIA 2016²¹⁷.

Figure 6-5. Natural gas CT capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



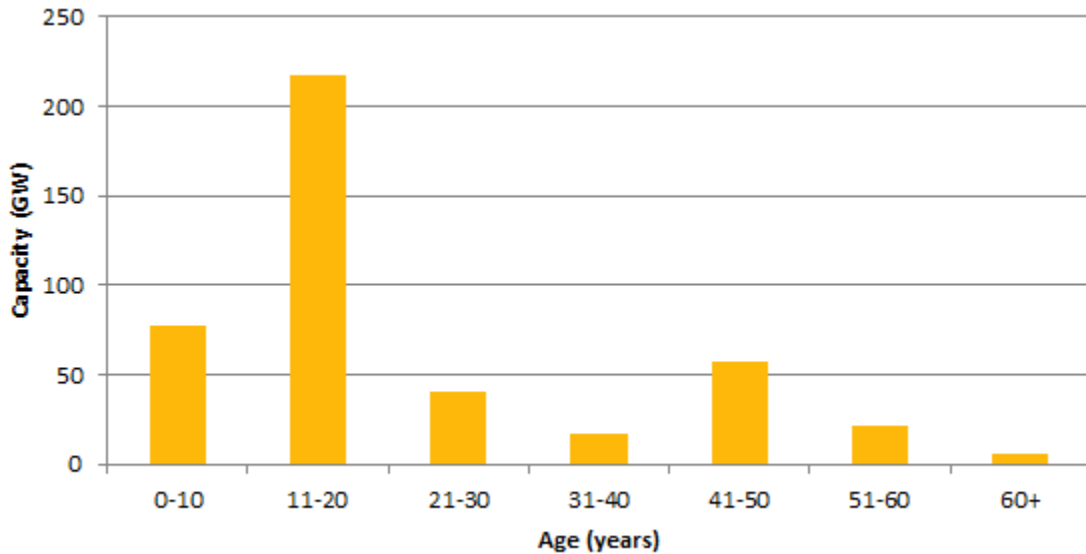
2014



Capacity, generation, and capacity factor from natural gas CTs varied regionally, with a few states—Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island—relying more heavily on this technology (>20% capacity factor) between 2010 to 2014. Source: EIA 2016.

Figure 6-6 shows the range of ages in the entire U.S. natural gas generation fleet. There is not much regional differentiation between these numbers, with the exception of NYISO in which the average age for NGCCs is 28 years²¹⁸. The average expected lifetime for both CTs and NGCCs is 55 years, depending on the modeling source and equipment manufacturer²¹⁹; however, maintenance programs could help extend the life of many plants.

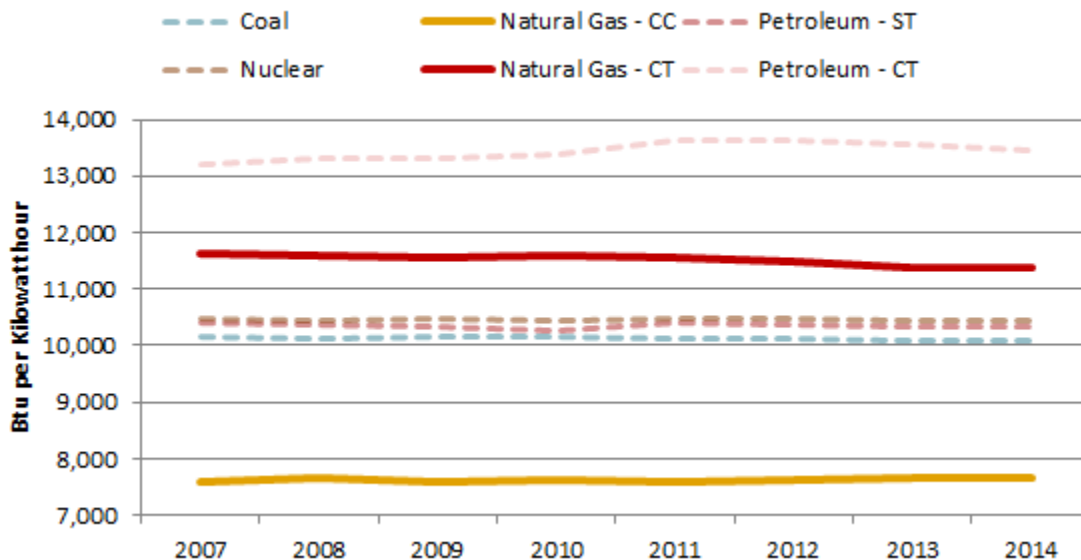
Figure 6-6. Age profile of U.S. natural gas generation fleet, 2014



A majority of natural gas generation capacity has been installed in the past 20 years, so large scale overhauls will not be required over the near to mid-term. Source: SNL 2015²²⁰.

The average heat rate for the fleet of NGCC plants has remained steady since 2007, as shown in Figure 6-7. For gas-fired CTs, heat rate has declined modestly. As a result of increased deployment and higher capacity factors of NGCC plants, the national average heat rate for natural gas plants has declined significantly since 2003 (Figure 6-7).

Figure 6-7. Heat rates for fossil generators (BTU/kWh), 2007–2014



Actual plant heat rates depend on a number of factors, including coal quality; specific plant design and operating conditions; site-specific factors, including atmospheric conditions and the temperature of available cooling water, etc. Source: EIA 2015²²¹.

6.3 Technology Costs

The LCOE for natural gas CT units and for NGCC units with and without CCS are shown in Table 6-1. LCOE for natural gas is highly dependent on fuel costs, which are expected to increase over time. The range of values for the LCOE of NGCCs is lower than for CTs, even when CCS is added to NGCC units. The LCOE of NGCC with CCS is roughly tied with nuclear as a low- or no-carbon dispatchable technology. The LCOE of NGCC generators (without CCS) also overlaps with land-based wind, although it is hard to compare between dispatchable and nondispatchable technologies.

Table 6-1. LCOE Natural Gas Generators (2013\$/MWh)

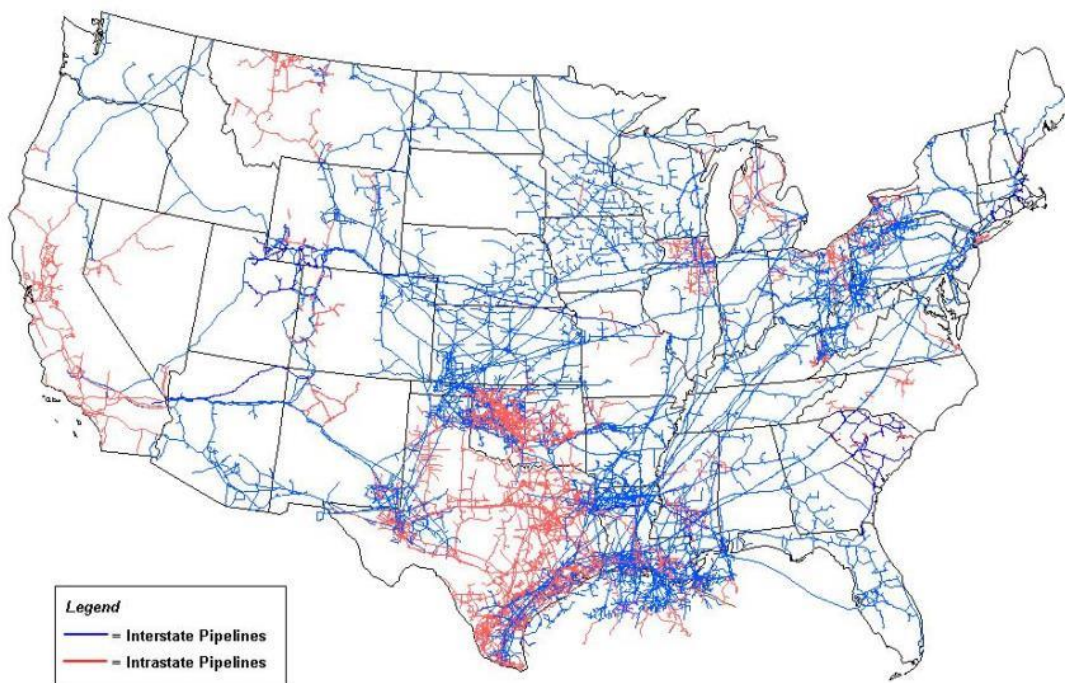
Technology	EIA		NETL		Lazard	
	Low	High	Low	High	Low	High
Gas – CC	36.53	105.54	37.23	74.95	36.77	81.51
Gas – CC – CCS	55.34	171.21	56.74	123.14	-	-
Gas – CT	65.24	238.49	-	-	66.70	219.30

Current ranges of natural gas technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015²²². See appendix B for more information on LCOE calculations.

6.4 Fuel/Resource

Currently, the vast majority of natural gas is transported through pipelines in an extensive network that spans most of the continental United States. Production from a series of wells is transported through a network of pipelines to natural gas processing facilities, where the gas is stripped of contaminants, including waste, and sent to the transmission pipeline system²²³. A map of the intrastate and interstate pipelines is shown in Figure 6-8.

Figure 6-8. U.S. natural gas pipeline network, 2009



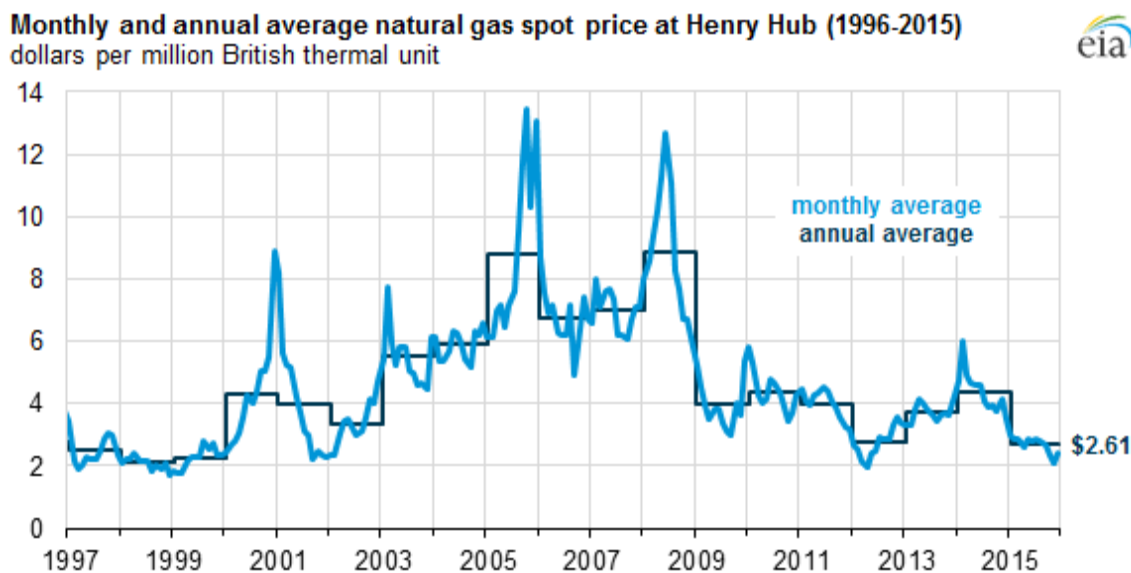
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Natural gas pipelines are required to transport natural gas from production facilities to end-use locations. Pipeline networks are more concentrated in high production areas (e.g., south Texas and Pennsylvania). Source: EIA 2009²²⁴.

6.4.1 Natural Gas Price History

Natural gas prices were generally coupled with oil prices until roughly 2009, as natural gas was generally a byproduct of oil production until then²²⁵. Since then, the price of natural gas has become largely disconnected from oil due to production from gas-only wells. Further, while oil is a global commodity, natural gas is priced locally given the high costs and energy losses involved in shipping natural gas as liquefied natural gas (liquefied natural gas adds a variable cost premium [\$/MMBtu] to the price of local natural gas). The Henry Hub price of natural gas since 1997 is shown in Figure 6-9.

Figure 6-9. Henry Hub natural gas spot price (\$/MMBtu), 1997-2016



Henry Hub natural gas prices were relatively high and volatile through mid-2008, but they have become lower and less volatile since then as unconventional gas output surged. Source: EIA 2016²²⁶.

6.5 Environmental Impacts

6.5.1 Upstream

Natural gas is extracted from underground by drilling wells into subsurface reservoirs. With the shale revolution and widespread use of hydraulic fracturing, there have been public concerns in the United States of environmental degradation and disruption from the production of natural gas. The shale revolution has caused some of these concerns to become exacerbated at a regional level in areas of large shale development; typically, the public is more worried about hydraulic fracturing and natural gas production if they do not have a history of living near production sites²²⁷. These concerns include, but are not limited to²²⁸:

- Water withdrawals for hydraulic fracturing competing with other water uses (agriculture, municipal, etc.)
- Spills, leaks, and explosions from natural gas and produced water
- Produced water spills on the surface during onsite storage, handling, and disposal
- Underground water aquifer contamination by methane or produced water through well-bores
- Methane leakage from the wellhead and at gathering facilities
- Air quality impacts from diesel generators to run drilling rigs and fracturing equipment
- Induced seismicity.

The main source of waste during natural gas production is produced water (a byproduct of production). Produced water generally contains constituents that can be harmful to human health,

if exposed in large enough concentrations. This waste is generally disposed of through injection into Underground Injection Control wells, treatment at a centralized waste facility, beneficial reuse in other industries or for other fracturing jobs, or disposal in evaporation ponds²²⁹. These ponds are normally lined to prevent infiltration of the surrounding ground surface. There are potential concerns from inadequate treatment and disposal of produced water leading to environmental contamination along with induced seismicity from injection into underground injection control wells. Induced earthquakes in Oklahoma, for example, coincide with the injection of saltwater (primarily produced water) into underground formations but not from the hydraulic fracturing process itself²³⁰.

6.5.2 Emissions and Environmental

A new NGCC plant emits roughly 50 to 60 percent less CO₂ compared to a typical coal-fired power plant²³¹. There are four reasons for the lower CO₂ emissions: (1) the specific heat of combustion is higher for natural gas than for coal on a carbon basis (more heat generated per ton of carbon in the fuel, and therefore more heat per ton of CO₂ generated); (2) natural gas has a higher atomic ratio of hydrogen; (3) the efficiency of NGCCs are much greater than coal; and (4) fuel feed systems and off-gas cleanup are simpler and use much less parasitic power. The case for natural gas CTs is less clear because about two-thirds of the thermal energy created by combustion of natural gas is lost with discharge of heat from the CT to its surroundings. CTs can rapidly respond to increasing or decreasing power generation needs when necessary.

There are two measures that can be used to reduce NO_x. The first is a dry low NO_x burner. The second is selective catalytic reduction, which uses ammonia and a catalyst to reduce NO_x emissions, similar to coal plants²³².

Improved understanding of natural gas generator's life-cycle GHG emissions is currently a subject of robust research interest, as methane leakage associated with natural gas production and delivery is not well characterized²³³. This is largely because up to 30 percent of life-cycle emissions are a result of fuel provision, including fugitive emission and gas used to power equipment for gas production and transportation. Liquefying natural gas contributes further emissions, given the energy intensity of the liquefaction process²³⁴. However, most estimates indicate natural gas-fired electricity generation produces lower CO₂-equivalent emissions than other fossil energy sources. The majority of life-cycle analyses conducted to date indicate that natural gas-fired power plants enjoy a roughly 50 percent advantage over coal in life-cycle GHG emissions, though research points to the need for better data sets and new methodologies to determine the real life-cycle emissions from natural gas-fired generation²³⁵.

6.6 Constraints

Nationally, natural gas consumption for power generation has increased over 60 percent since 2005, and CO₂ regulations may further increase its use²³⁶. Natural gas generators provide baseload power as well as ramping resources to meet the needs of the electric system. As variable renewable power is added to the grid, natural gas is well suited to provide backup generation.

Several market and policy challenges also exist for natural gas-fired power plants. First, hydraulic fracturing (fracking) has polarized the public in some regions of the country at the state and local levels²³⁷, drawing opposition to gas-related developments. Both gas production

operations and new gas transportation pipelines have met with public opposition, and the perceived risk associated with natural gas fracking, especially ground water contamination related to the treatment of produced waters at the surface and induced seismicity due to waste water injection, has the potential to derail new development in some regions. A 2015 EPA report cited no “widespread, systemic impacts on drinking water resources in the US,” though the report also admits several key limitations to the study, including lack of baseline data for a majority of wells²³⁸. Oklahoma saw an approximate doubling of wastewater injections into saltwater aquifers between 1997 and 2014, and also experienced a 200-fold increase in magnitude 3 and 4 earthquakes since 2009²³⁹. Researchers from Stanford and Southern Methodist University who study induced seismicity say that a lag between increasing injections and increased seismic activity is expected, as it takes time for pressure to build up at appropriate depths and propagate to nearby faults. Thus a causal relationship between seismicity and natural gas production is possible²⁴⁰. In New York, the governor has banned hydraulic fracturing until environmental concerns are better understood and can be controlled.

Second, some regions of the country could become overly dependent on natural gas-fired generation²⁴¹. Risks associated with gas-fired generation dependence include electric system reliability and/or financial impacts should there be a disruption in natural gas supply or a significant surge in natural gas prices. Reliability risks to the electric system could also occur as a result of a loss or lack of a nearby high deliverability facility such as a pipeline or storage facility, which could lead to load curtailment at existing facilities. The recent leak at the Aliso Canyon gas storage facility provides one example: loss of the facility may lead to disruptions in electric supply during the warm summer months²⁴². Electric system reliability could also be impacted by pipeline congestion, particularly during the heating season. Modeling by the Eastern Interconnection Planning Collaborative indicated that in the winters of 2018 and 2023, over 90 percent of natural gas-fired generation in regions of NYISO and ISO – New England could be affected by gas system constraints, accounting for 27 percent and 29 percent of total anticipated generation, respectively, across the scenarios examined²⁴³. These issues are compounded by some natural gas-fired generators not maintaining firm primary gas transportation contracts with pipeline companies, meaning that they are more likely to see service curtailment in situations of high gas system utilization, such as during periods of cold weather when residential gas demand rises.

Third, as natural gas use in power generation increases, aligning gas and electric market and dispatch schedules will become more important. This issue was highlighted during extended cold weather experienced during the winter of 2013–2014. Pennsylvania, New Jersey, and Maryland Interconnection LLC (PJM) experienced the prolonged cold weather of January 17–29, 2014, and pointed out that the timing differences between the gas and electric markets forced generators to commit to buying gas before knowing whether their units would be scheduled to operate²⁴⁴. Following extensive stakeholder engagement that was ongoing at the time of the previously described situation in PJM, FERC issued Order No. 809 adopting the North American Energy Standards Board’s changed natural gas pipeline nomination schedule that better matched electric dispatch scheduling. The ruling also requires organized electric markets to ensure their day-ahead dispatch schedules better aligned with natural gas pipeline scheduling. While these rules will likely improve reliability for some generators, such as those in the desert Southwest where there is little or no high deliverability storage, the impacts will vary by region, and the

rules do not address issues related to pipeline congestion. The rule went into effect April 1, 2016, so its impact is not yet fully understood²⁴⁵.

Natural gas is dependent on processing facilities to create a standard British thermal unit (Btu) content and to remove contaminants and water. The gas is then compressed and goes into the pipeline transmission network. Processing plant operation is highly dependent on electric power for processing, as well as upstream and downstream constraints. It is also important that capacity at downstream fractionators for the natural gas liquids is available, or the plant will shut down. A dramatic increase in shale gas production and reserves has caused natural gas supply to increase, which is heavily tied to the hydraulic fracturing process. With low natural gas prices, the rate of shale production declined in the second half of 2015²⁴⁶. Also, concerns about the environmental impacts of the fracturing life cycle could potentially impact domestic natural gas supply across the United States.

Several concerns surround making sure pipelines are in place to supply natural gas generation facilities: the time lag in power plant commissioning and pipeline construction, pipeline cost recovery, and size constraints of existing pipelines. There is a time lag of several years from the time a pipeline need is identified to when a new pipeline enters service. By the time a pipeline operator is ready to apply for a certificate from FERC, the demand for additional capacity may already exist. However, it generally takes 1.5 to 3 years for the permitting and construction of a new pipeline after the pipeline operator has decided to move forward with building it. Thus, pipelines may experience constraints before new capacity can be built to meet demand growth. Pipeline operators also may have concerns about capital cost recovery. Most shippers currently only want to commit to 10- to 15-year contracts, which is not a term sufficient, in and of itself, to repay the capital costs of construction; while shippers generally renew their contracts, the pipeline does not start out with assurance of full recovery. In order to receive a permit to build from FERC, a pipeline operator will often prefer to have enough commitments from firm transportation customers to cover the cost of building the pipeline. Moreover, most electric power generators rely on interruptible transmission service, which is more economical than reserving firm capacity, and have not traditionally been among those customers who commit to new pipelines.

Permitting and construction of pipelines can take many years and needs to be considered when deciding where to site a new power plant²⁴⁷. CTs and NGCCs need to be sited in areas that take into consideration gas transmission and water sources. Long gas transmission lines can increase the capital costs of the project and increase overall costs of delivered power. For NGCCs, cooling water is needed for the condenser of the ST bottoming cycle. NGCCs are considered compact and therefore can be sited close to urban demand centers and will generally not experience problems with transmission. Low emissions and minimal requirements for fuel storage (natural gas liquids) lead to minimal impact on siting procedures, although new generator availability penalty and incentive structures in certain ISOs/RTOs may change this by incentivizing onsite fuel storage. Natural gas-fired plants will also need to be sited near pipeline infrastructure to ensure adequate supply for operation.

6.7 Technical RDD&D

Much of the Federal RDD&D being done on advanced energy systems and postcombustion CCS applies to natural gas-fired generation as well as coal-fired generation. Additional fundamental research is supported by DOE focusing on advances in materials, combustion, and simulation

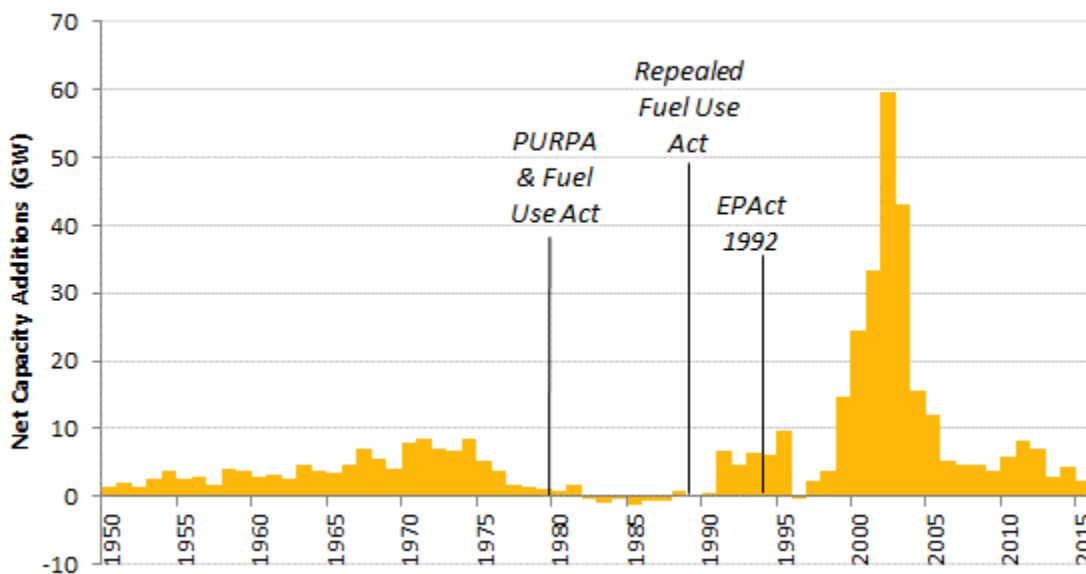
that can lead to continued incremental improvements in gas turbine efficiency²⁴⁸. The private sector (e.g., GE, Siemens, and EPRI) is also conducting significant RDD&D on further improving the operational efficiency of CT and NGCC systems.

6.8 Development and Projected Future Deployment

Natural gas-fired capacity additions were consistently less than those from coal until 1991, at least partially due to the Industrial Power Plant and Fuel Use Act of 1978, which banned construction of new gas-fired generation until its repeal in 1989. Since the repeal, improvements in gas turbine technology, lower natural gas prices, and environmental regulations have led to a massive surge in new CC generating capacity from about 1999 to 2003. Other factors that contributed to this surge were the availability of lower-cost financing, shorter construction lead times, and momentum gained from the experience in construction, which lowered construction costs and lead times to completion (gas plants essentially became ‘cookie cutter projects’).

Although natural gas capacity additions have decreased since their peak, in recent years they have been larger than any other nonrenewable generating source (Figure 6-10).

Figure 6-10. Historical annual natural gas capacity additions and retirements, 1950–2015



Natural gas capacity additions reached a peak in 2002, likely as a result of improved technology, low gas prices, and Clean Air Act amendments impacting coal generation. Source: EIA 1990 and EIA 2016.

The domestic outlook for NGCC generation is generally strong over the short to mid-term, but varies over the longer term, depending on assumptions about how cost and performance will change for other options and what carbon constraints are imposed (Table 6-2). The QER 1.2 Base Case sees a steady decline in NGCC generation throughout the scenario period due to growth of solar and wind generation. The QER 1.2 Base Case sees sustained growth in NGCC generation, which is deployed in this scenario at a higher rate than non-hydro renewables.

Table 6-2. QER 1.2 Base Case generation (TWh) for CC plants, 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Gas CC Generation	1,133	1985	945
Gas CC with CCS	0	0	0

Source: EPSA 2015²⁴⁹.

In both IEA’s New Policies Scenario and Current Policies Scenario, gas generation is projected to nearly double again by 2040, while in the 450 Scenario^{xxxiv}, it is expected to soon peak and then begin declining by 2040 (Table 6-3). The implications of a 450-type scenario on domestic natural gas producers, natural gas generators, and equipment manufacturers would be significantly negative within two decades.

Table 6-3. Historical and projected global natural gas generation by scenario outlook, 2003-2040

			New Policies		Current Policies		450	
	2000	2013	2020	2040	2020	2040	2020	2040
NG Generation (TWh)	2,752	5,079	5,798	9,008	6,006	10,534	5,658	5,465
Percentage of Global Total	18	22	21	23	21	24	22	16

Source: IEA 2015²⁵⁰.

^{xxxiv} IEA’s scenario assumes new policies that bring about emissions reductions to meet the Intergovernmental Panel on Climate Change goal of 2°C global temperature rise, which requires a stabilization of atmospheric GHG concentrations at about 450 parts per million in 2100. For more details on the exact policies used in the scenario see IEA’s WEO 2015.

7 Nuclear

7.1 Technologies

The most common types of existing nuclear reactors, which use uranium as a primary fuel source, are pressurized water reactors (PWRs) and boiling water reactors (BWRs). Both are commonly referred to as light water reactors (LWRs). In PWRs, water is heated by nuclear fission within the reactor, but it is not allowed to boil due to the pressurization of the system. This water is then run through a heat exchanger, which produces steam that drives a turbine with a traditional steam cycle. A BWR, on the other hand, contains only a single closed system, and water in the reactor is heated to form steam, which drives a turbine before being condensed, pressurized, and reheated. PWRs are able to operate at a higher temperature and pressure—leading to higher turbine efficiencies—and are able to separate radiation contamination from the generating equipment. BWRs, on the other hand, are able to achieve higher thermal efficiencies with direct contact, and output is easier to control by adjusting the amount of water entering the reactor.

Another reactor type uses “heavy water” with deuterium atoms, although these are not deployed in the United States. A small number of other reactor types (gas cooled, light water graphite, and fast neutron) are also in operation outside of the United States. Nuclear reactors are called fission^{xxxv} reactors since they rely on capturing energy from the breaking apart of uranium atoms.

Nuclear generators typically serve as baseload providers since they perform best, and are most economic, when operating at full capacity. The fleet of nuclear generators in the United States operates at the highest capacity factor compared to other generators and typically delivers power to the grid about 90 percent of the time²⁵¹. In 2015, the fleet capacity factor was 92.2 percent, the highest since 2008²⁵². LWRs are typically shut down every 18–24 months for refueling. LWRs have some capability to ramp up or down output, and thus follow load, when they are in the early phase of just having been refueled²⁵³. Research is underway to better understand how nuclear plants, sometimes in combination with renewable energy options, might be operated in a more flexible fashion²⁵⁴.

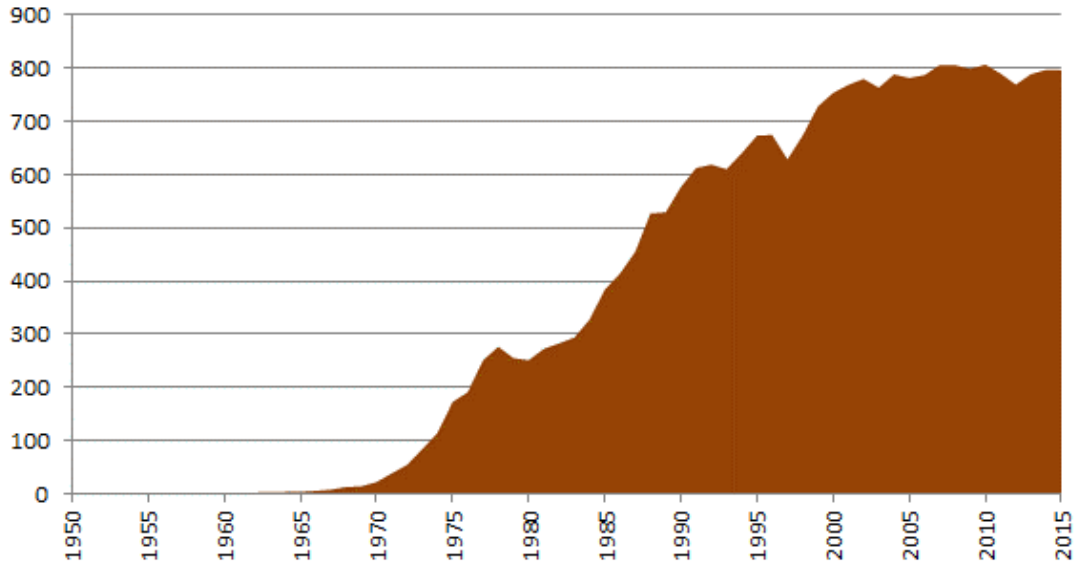
7.2 Operational Attributes and Fleet Characteristics

In 2015, nuclear generation stood at 797 TWh, and its share of total generation was 20 percent, relatively unchanged for the past decade (Figure 7-1).^{xxxvi} In 2015, the fleet-wide capacity factor for nuclear was an estimated 92.2 percent²⁵⁵ with 99 reactors, compared to 91.7 percent in 2014 with 100 reactors (Figure 7-2). Nuclear plants’s availability factor is very close to their capacity factor at 90 percent²⁵⁶. This indicates that nuclear plants generally only shut off for maintenance activities and that forced outages are very rare. While generation and capacity were constant across most of the country between 2010 and 2014, Figure 7-3 shows a dramatic drop in capacity for California due to the closing of the San Onofre 2 & 3 reactors.

^{xxxv} Fusion reactors are an entirely different technology under development that relies on capturing energy from fusing lighter atoms.

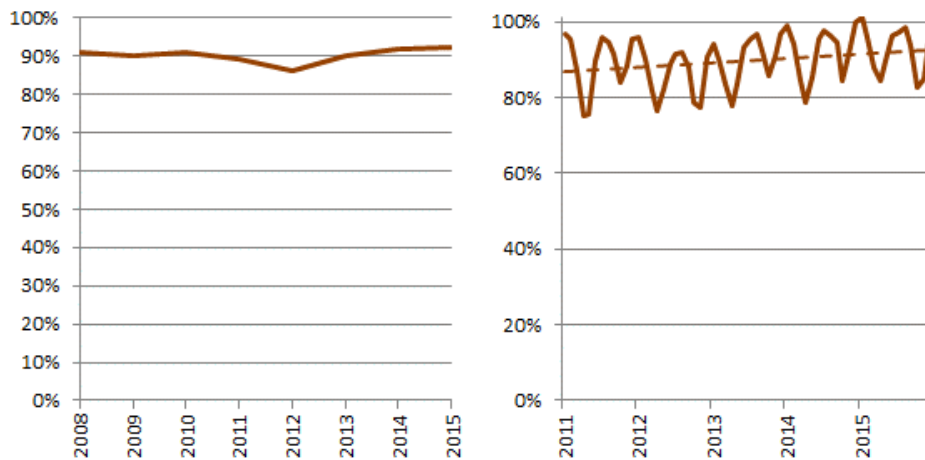
^{xxxvi} The last two nuclear generators to enter service in the United States were units 1 and 2 at TVA’s Watts Bar Nuclear Plant in 1996 and 2016, respectively. Five generating units have been retired since 2013, while four additional units have announced their intentions to retire before 2020, and other units are evaluating the economic viability of continued operation.

Figure 7-1. U.S nuclear generation (TWh), 1950–2015



Source: EIA 2016²⁵⁷.

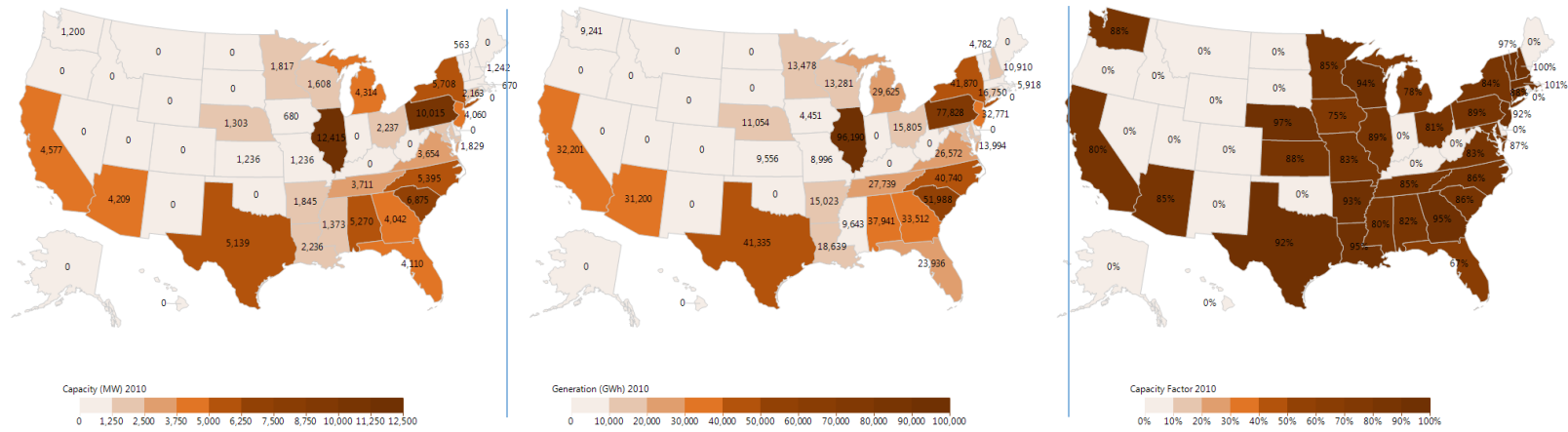
Figure 7-2. U.S. annual and monthly nuclear generator capacity factors



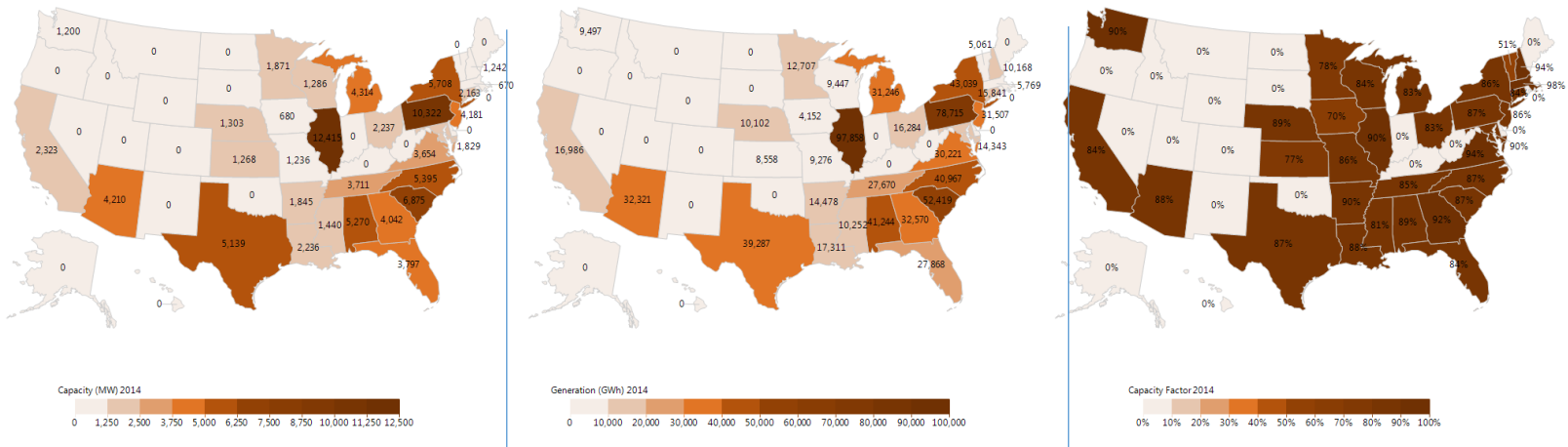
Nuclear capacity factors have remained relatively constant over time due to their ability to operate constantly, except for infrequent refueling operations. Source: SNL 2015^{xxxvii}.

Figure 7-3. Nuclear capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



2014

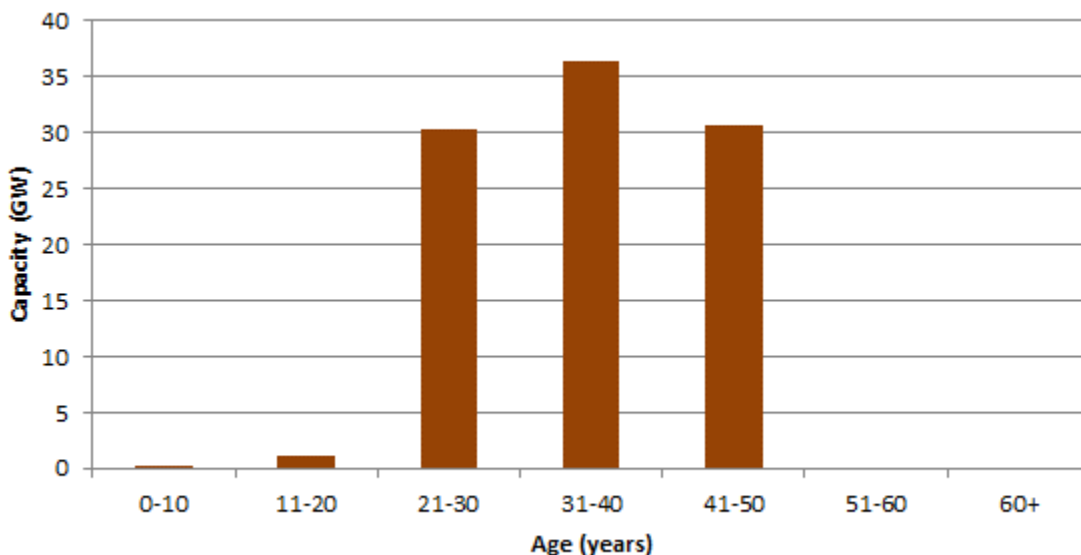


Capacity, generation, and capacity factor from nuclear remained constant across the United States between 2010 and 2014, except in California, which lost significant nuclear capacity when the San Onofre 2 & 3 reactors ceased operation. Source: EIA 2016²⁵⁸.

The average age of the nuclear power fleet is 34 years (Figure 7-4), and plants are given an initial 40-year operating permit. To date, 84 plants have received a 20-year operating license extension, with 12 additional license extension applications pending and 5 more expected to be filed²⁵⁹. Additionally, two plants (Surry Power Station and Peach Bottom Nuclear Generating Station) have announced intentions to seek subsequent life extensions. NRC is expecting these and other applications for license extensions to 80 years of operation and is currently developing the *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*²⁶⁰.

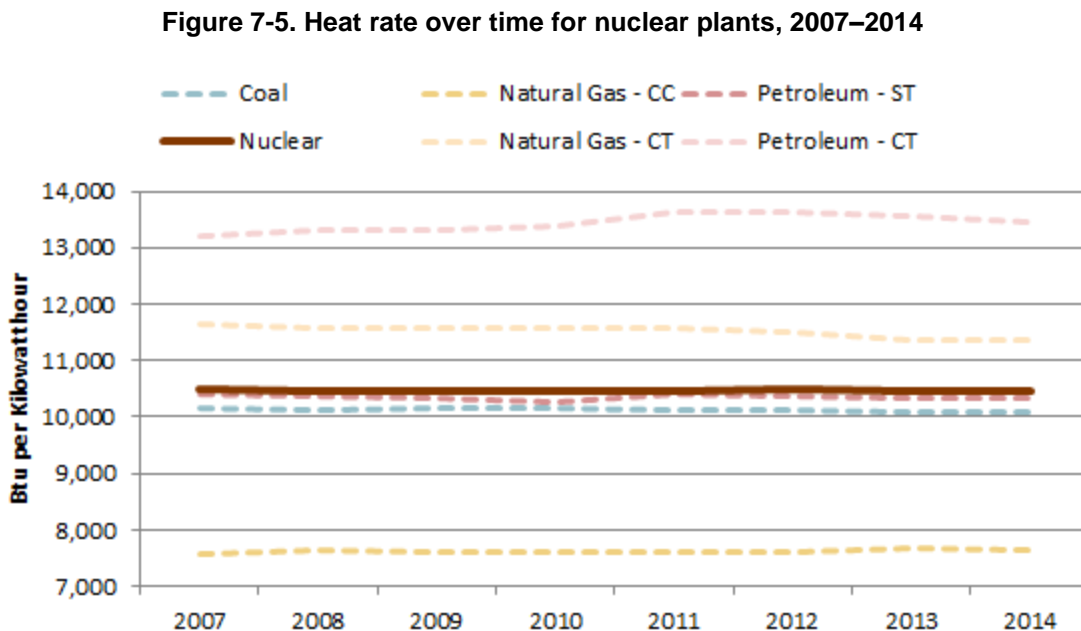
The current nuclear power operating fleet (99 reactors) consists of approximately 54 GW electrical (GWe) of generating capacity in regulated markets, and 45 GWe in restructured electricity markets. In states with restructured electricity markets, nuclear operators have found increasing difficulty competing in a low-energy price environment, arising from flat or declining energy demand, low natural gas prices, increased operating costs, and other factors. Economic pressure on nuclear plants grew during 2015 as average monthly wholesale electricity prices declined from their 2014 levels by approximately 30 percent at most major trading hubs, again due largely to lower natural gas prices²⁶¹. Since a peak of 104 operating reactors, 5 units have already shut down earlier than their licensed lifetime (note: three of these also faced costly repairs). As of June 23, 2016, an additional 9 units have announced intentions to close prematurely, although the decision to close could be reversed for 6 units in Illinois and New York, pending passage of proposed legislation to enact clean energy standards, building on the renewable energy portfolio standards already in existence in 30 states and the District of Columbia. Additionally, as a result of California’s evolving energy policy, Pacific Gas and Electric Company announced that it would not pursue license extension of its 2-unit Diablo Canyon Power Plant.

Figure 7-4. Age profile of U.S. nuclear generation fleet, 2014



Most nuclear plants were built in the 1970s and 1980s, so the average age of the fleet is now 34 years.
 Source: SNL 2015²⁶².

The average heat rate for the fleet of nuclear generators has remained steady since 2007, as shown in Figure 7-5.



Source: EIA 2015²⁶³.

7.3 Technology Costs

The LCOE for nuclear generation is shown in table 7-1. The cost range for nuclear plants is one of the smallest across all three sources, and is roughly on par with NGCC-CCS generators.

Table 7-1. LCOE for nuclear generators (2013\$/MWh)

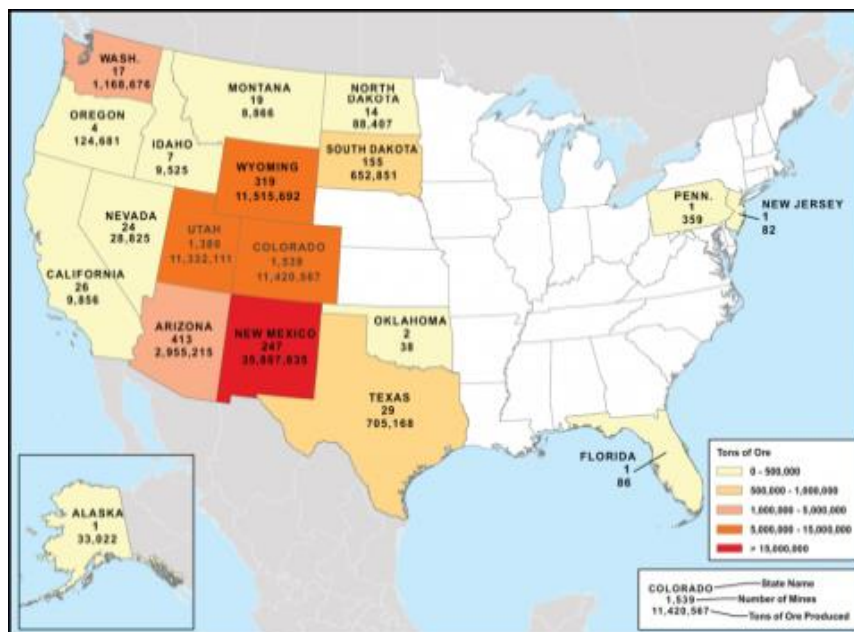
Technology	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Nuclear	81.71	122.62	--	--	76.77	138.67

Current ranges of nuclear technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015²⁶⁴. See appendix B for more information on LCOE calculations.

7.4 Fuel/Resource

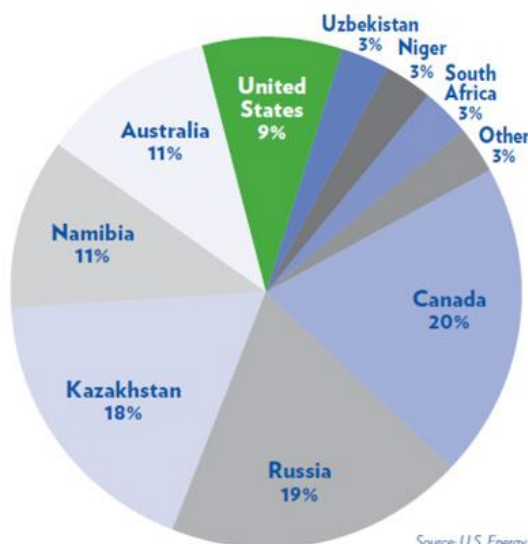
Uranium is mined in several states in the United States, but the majority of uranium today is imported. Uranium mines and production by state is shown in Figure 7-6, and the international makeup of uranium sources is shown in Figure 7-7. As of 2013, the United States had 207,400 tonnes of recoverable uranium²⁶⁵. However, some of these reserves are only economic at high uranium prices.

Figure 7-6. Uranium mines and production by state



A majority of domestic uranium production occurs in the Rocky Mountain western states. Transportation to processing facilities and to the eastern United States (where most nuclear power plants are located) needs to be accounted for. Source: DOE 2014²⁶⁶.

Figure 7-7. Sources of uranium for the U.S.



Source: U.S. Energy Information Administration (2011)

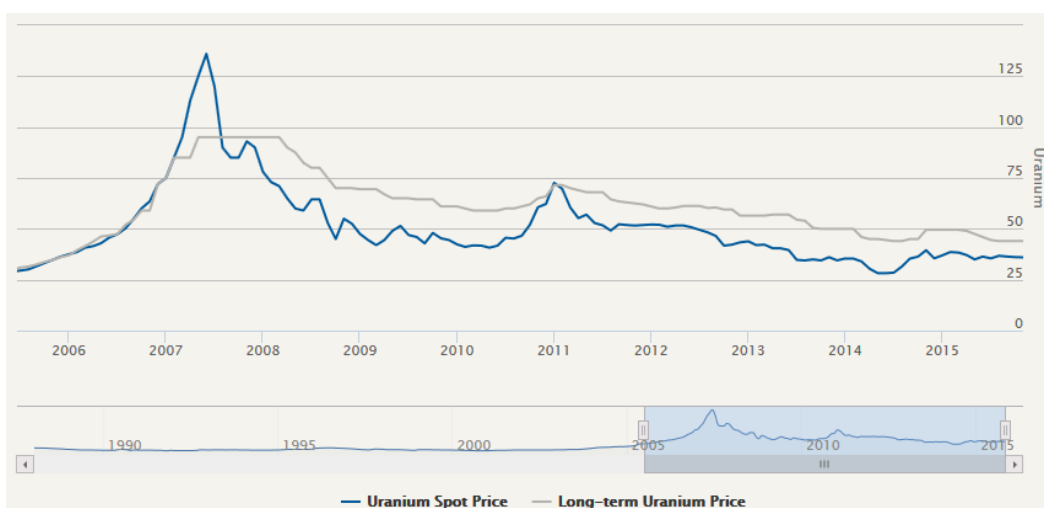
Over 90 percent of uranium used in the United States comes from international sources. There is a potential for global competition for uranium if installed nuclear capacity increases. Source: Virginia Uranium 2012²⁶⁷.

Uranium is shipped via highway, rail, air, or water and is regulated by NRC and the Department of Transportation. There are requirements for packaging and physical protection of materials along with hazard communication.

7.4.1 Uranium Price History

Uranium is not traded on public markets; instead, buyers and sellers negotiate prices privately^{268, xxxviii}. Spot and longer-term prices are illustrated for the past decade in Figure 7-8. Although remaining relatively constant from 1985 to 2005, prices spiked in 2007, possibly due to projected rising demand from China and India and flooding at uranium mines in Australia and Canada, but they have since leveled off.

Figure 7-8. Uranium prices (\$/lb), 2005–2015



Most uranium is sold on long-term contracts, and prices have been relatively flat in the past 4 years. The price spike in 2007 can possibly be attributed to projected rising demand from India and China and uncertainty over production from existing mines. Source: Cameco 2015²⁶⁹.

7.5 Environmental Impacts

7.5.1 Upstream

Mining uranium has potential environmental impacts similar to other metalliferous mining operations (e.g., aluminum, gold, and platinum mining operations)²⁷⁰, which include (but are not limited to) water contamination from acid mine drainage release and heavy metal exposure to the surrounding ecosystems²⁷¹. Airborne exposure from mine tailings is also a concern as they contain uranium and radium²⁷². Radium decays into radon and poses a threat to human health. Because of this, most tailings are covered with water in holding ponds to reduce this risk²⁷³. Water used during mining may contain traces of radium, and most mines adopt a “zero-discharge” policy²⁷⁴.

Because the half-life of uranium-238, the non-fissile primary isotope of uranium, is 4.5 billion years, it has relatively low radioactivity, similar to granite²⁷⁵. Mine workers may potentially be exposed to gamma radiation during the mining process, and dust suppression and ventilation are necessary to maintain safe working conditions²⁷⁶.

Uranium must be enriched to increase the concentration of uranium-235, the fissile isotope used in reactors. The enriching process causes the resulting fuel to be able to sustain fission. Uranium

^{xxxviii} Prices are from independent market consultants Ux Consulting and TradeTech.

is initially mined as one form of uranium oxide (U_3O_8), is converted to uranium hexafluoride (UF_6) due to its low sublimation temperature for enrichment, and is converted again to a different form of uranium oxide (UO_2) for use as nuclear fuel. In the United States, uranium is enriched through gaseous diffusion²⁷⁷; however, this process has been largely replaced by centrifuge processes in the rest of the world²⁷⁸.

7.5.2 Emissions and Environmental Impacts

Nuclear reactors do not produce any CO_2 during generation. However, there are other environmental issues that impact the efficacy of nuclear power, such as concerns about radioactive contamination, waste disposal, and large water withdrawals. As with all generation sources, CO_2 is emitted during the manufacturing and decommissioning phases, and this needs to be accounted for in the life-cycle analysis. The Intergovernmental Panel on Climate Change estimates the life-cycle CO_2 emissions of nuclear power plants at 13 g/kWh (comparable to wind turbines and smaller than any other energy source)²⁷⁹. A single 1 GW nuclear reactor would emit 6 million fewer tons of CO_2 each year than a coal-fired plant that generated the same amount of electricity.

Once the uranium fuel reaches a specific depleted burnup, the reactor must be shut down to replace the fuel rods. Burnup is expressed in gigawatt-days per metric ton uranium in the fuel rods (GWd/MTU). Average burnup was 35 GWd/MTU two decades ago, but it is now over 45 GWd/MTU. The specific burnup allowable is determined through certification by NRC and takes into consideration radioactive fission product buildup, residual heat generation, and NRC specifications for storage of the used fuel rods. Also, materials used for O&M are considered low-grade radioactive waste. These materials need to be properly managed to ensure that radiation does not impact the environment.

7.5.3 Downstream

The U.S. fleet of commercial nuclear power generators produces approximately 2,200 tons of used fuel each year. There is currently no centralized storage or disposition facility for used nuclear fuel in the United States, so it is stored at the nuclear power plants awaiting construction of a permanent waste handling facility²⁸⁰. This used fuel is currently stored first in pools onsite and then moved to concrete casks, if room is needed in the pools.

Other countries recycle used fuel rods to separate the uranium and plutonium for potential reuse, but this process is currently not done in the United States. A commercial mixed oxide fuel facility was under construction in Barnwell, South Carolina, in the late 1970s, but this facility has been put on standby and is unlikely to resume construction given the cost of fuel recycling relative to producing fresh new fuel elements. The DOE Savannah River Site in South Carolina has been developing a mixed oxide fuel facility for noncommercial processing; however, the continued viability of this facility is currently a topic of debate.

7.6 Constraints

Light-water PWR and BWR nuclear power plants are water-cooled, so they need to be located near sources of water. With climate change causing changes in weather patterns and rising temperatures, there is some concern over water availability for cooling nuclear plants. Rising inlet temperatures could reduce the thermal efficiency of the steam cycle and potentially lead to shut downs due to regulatory restrictions. Palo Verde, a nuclear plant in Arizona, uses municipal

effluent for cooling to reduce impacts of water withdrawal in the desert environment²⁸¹. The Diablo Canyon nuclear plant in California operates a reverse osmosis plant to desalinate seawater for plant cooling loads. The reverse osmosis plant is operated during off-peak hours and at times when power generation curtailment might be necessary.

Large-scale environmental events (like Fukushima) have created concerns regarding nuclear power into the future. Siting new nuclear power plants near population centers has been an issue of contention due to the risk of radioactivity if containment is breached. Nuclear plants are designed with numerous safety features to prevent a breach. The perceived fear of a breach may be much larger than the actual chance of it occurring.

However, high capital costs and long construction times are most likely the largest barrier limiting further expansion of nuclear power technology in the United States²⁸². Underestimated costs and construction delays were evident for many nuclear projects during the pre-1990s expansion, and both are still evident in the five units currently under development²⁸³. While loan guarantees and other incentives like “construction work in progress”^{xxxix} provisions can help overcome financing challenges, delays and cost overruns at the Vogtle and Summer projects have caused the Fitch ratings agency, for example, to claim that the efficiencies and cost reductions promised with the new Westinghouse AP1000 “modular construction” scheme have fallen short of expectations²⁸⁴. These two examples could be temporary setbacks that provide important lessons on how to improve the modular construction techniques at future plants should they enter the development pipeline.

Transportation of nuclear material is highly regulated under U.S. Code of Federal Regulations title 10, chapter 1, part 71 by NRC and the Department of Transportation (49 CFR 173.417)²⁸⁵. Because the United States receives most of its uranium from other countries, there is the potential for disruptions to uranium supply due to geopolitical conflicts. There are also some concerns about scarcity and cost increases of uranium supply if nuclear power expansion increases demand, but there have been no shortages yet²⁸⁶. These concerns, however, are mitigated by both the supply of depleted uranium in the United States and the large recoverable reserves of uranium in the United States.

The United States has significant reserves of unmined uranium. Wyoming, for example, as the top supplier of uranium in the country, has the potential to significantly increase production, and the Wyoming Mining Association projects there are 456 million pounds of recoverable uranium in the state²⁸⁷. This is enough uranium to power the U.S. nuclear reactor fleet for 140 years. Additionally, DOE is sponsoring R&D to separate uranium from seawater.

Another issue is the supply chains for heavy construction plants to build high pressure reactor components. There are no forging facilities in the United States that can fabricate large reactor pressure vessels of the nature used at the Vogtle or Summer projects. Capabilities for this size exist globally in France, Japan, South Korea, and now in China. Currently, Westinghouse has the AP1000 reactor vessels manufactured in South Korea by Doosan Industries and shipped to the United States. Domestic forging capabilities exist to manufacture smaller diameter reactor pressure vessels used in small modular reactors (SMRs). The supply chains for building

^{xxxix} Construction work in progress, known as CWIP, allows certain plant owners to begin collecting revenue from rate payers before construction work is complete.

materials (steel, concrete, etc.) can rise during periods of high global economic development and may increase the overall plant cost.

7.7 Technical RDD&D

DOE has active programs on extending the life of existing nuclear power plants, as well as additional work on SMR commercialization, advanced reactors, and fuel cycles. Advanced technologies could allow nuclear power to contribute more readily to a diverse, sustainable, affordable, and reliable electricity system.

To potentially prolong the life of the existing fleet of generation assets beyond their 60-year operating window (assuming an initial 40-year license and one 20-year renewal), DOE has developed the Light Water Reactor Sustainability Program.^{x1} In December 2015, the nuclear industry also launched a major effort to further improve the efficiency and, particularly, the economics of existing units²⁸⁸. Elements of the programs focus on understanding material aging and degradation; advanced instrumentation, information, and control systems technologies; risk-informed safety margin characterization; and advanced LWR nuclear fuels. Efficiency improvements through power upgrades and advanced modeling and simulation tools to better understand safety performance are also part of this effort²⁸⁹.

To address the economic, public safety, waste disposal, and proliferation concerns that have existed over the past decades, DOE is leading the development of new nuclear technology that uses higher temperatures, novel cooling techniques, and more modular sizes. SMRs up to 300 MW in size could overcome many of these barriers by offering smaller capacities that can integrate into power grids of limited size, reducing financial risk and cutting costs through factory manufacturing of key components. There are a number of potential SMRs under development around the world. In the United States, DOE is cost sharing NRC Design Certification of the NuScale Integral PWR and is targeting commercial operation of the first reactor in the mid-2020s.

Other types of advanced nuclear reactors classified as generation IV (Gen IV) technology are under development and offer promise²⁹⁰. Gas-cooled reactors that operate at high temperature and include advanced passive safety features may be closest to deployment. Other technologies, including liquid metal-cooled fast reactors, fluoride and chloride molten salt-cooled high-temperature reactors, and advanced SMRs, are under development²⁹¹. Many advanced nuclear reactors provide benefits beyond electricity production, such as process heat for industrial applications or hydrogen production; this fuel source could be important in transport applications or as an energy storage mechanism.

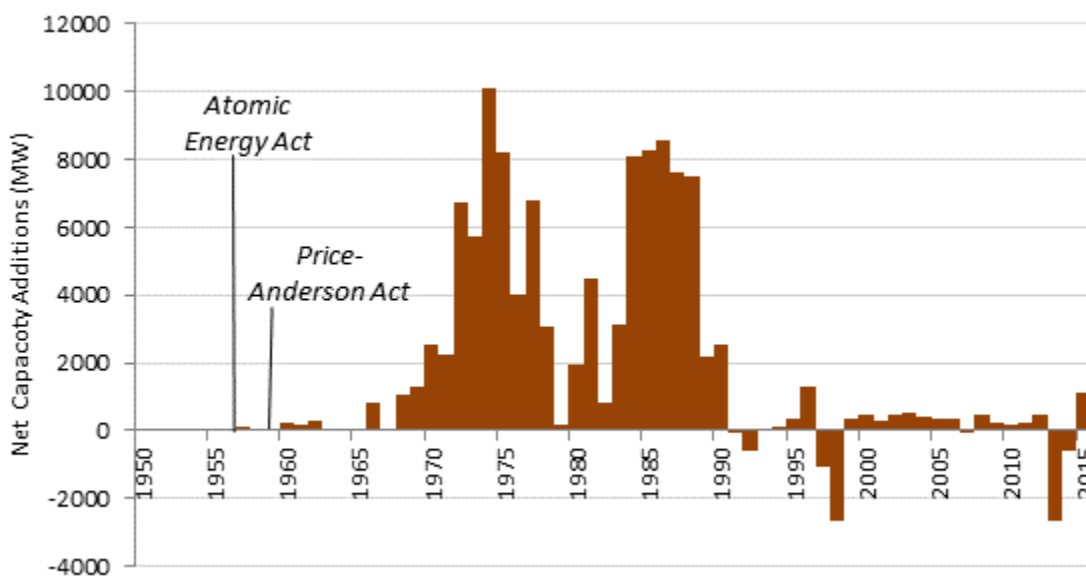
7.8 Development and Projected Future Deployment

Nuclear generation started in 1960 at less than 1 TWh and grew rapidly through the 1970s and 1980s to become the leading source of zero-carbon operational electricity generation in the United States (Figure 7-9). Much of this capacity was enabled by the Atomic Energy Act and the Price-Anderson Act, which established a program for covering public claims in the event of an accident. Most of the U.S. nuclear fleet commenced construction between 1967 and 1990²⁹².

^{x1} More information on DOE's Light Water Reactor Sustainability Program is available here: <http://www.energy.gov/ne/nuclear-reactor-technologies/light-water-reactor-sustainability-lwrs-program>.

More recently, with growing concerns over fuel diversity and GHG emissions, several new nuclear plants have begun construction in the United States, including the 2.2 GW Vogtle project (units 3 and 4) and the 2.2 GW Summer project (units 2 and 3). All four units are based on the Westinghouse AP1000 design, considered a Gen III+ reactor^{xli} that has passive safety features for up to 72 hours of cooling without human or external electricity needs. In addition, the 1.2 GW Watts Bar 2 unit—which began construction in 1973, and then sat unfinished until construction recommenced in 2007—received an operating license in October 2015 and is anticipated to be fully operational by mid-2016. This unit will be the first new nuclear reactor brought online in the United States since 1996, when Watts Bar 1 entered service, and is likely to be the last Gen II reactor built in this country.

Figure 7-9. Historical annual nuclear capacity additions and retirements (MW), 1950–2015



Most of the U.S. nuclear capacity additions occurred between 1967 and 1990, and until 2013, there was a 30-year gap in new construction of plants. Source: EIA 1990 and EIA 2016²⁹³.

The domestic outlook for nuclear energy from two QER 1.2 projections shows modest growth through 2040, with slightly more growth anticipated in the Side Case (table 7-2).

Table 7-2. QER 1.2 Base Case generation for advanced nuclear (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Nuclear Generation	784	808	873

QER 1.2 projections show modest growth through 2040, with slightly more growth in the Side Case. Sources: EPSA 2015²⁹⁴.

^{xli} Gen I technology is the label applied to the very first reactor designs; Gen II includes the vast majority of technologies deployed in the United States through the 1980s and 1990s. Gen III and III+ technology includes standardized design and advanced passive safety features, while Gen IV is the next generation of nuclear technology currently under development.

Globally, nuclear generation has lost a significant share of the global total since 2000 as other forms of generation have expanded more rapidly. Sixty-five reactors are under construction in several countries (China, South Korea, and India, especially), with two in the final stages of startup²⁹⁵, which is likely to reverse the recent decline in global output. In IEA’s 450 Scenario, nuclear output more than doubles by 2040 compared to today’s level (see table 7-3). Whether U.S. manufacturers will engage in this potential will depend on a host of factors, but cost, financing, and perceived safety concerns may discourage future development. As electricity grids across the globe move towards more flexible architectures, smaller nuclear plants may have an advantage.

Table 7-3. Historical and projected global nuclear generation by scenario outlook, 2000-2040

Year	New Policies				Current Policies		450	
	2000	2013	2020	2040	2020	2040	2020	2040
Nuclear Generation (TWh)	2,591	2,478	3,186	4,606	3,174	3,974	3,218	6,243
Percentage of Global Total	17	11	12	12	11	9	12	18

Source: IEA 2015²⁹⁶.

8 Water Power

8.1 Technologies

Hydropower is one of the oldest and most established forms of power generation, with much of the large, existing capacity developed and managed by Federal agencies and greater numbers of smaller plants operated by the private sector. Hydroelectric plants capture the energy in moving water to spin a turbine and generate electricity. Plants can consist of impoundments, where a dam blocks the entire flow of a waterway, or diversions, where water is diverted from a waterway to flow through a turbine. Impoundments may include water storage, which allows for greater flexibility in electricity generation. Plants can include dams (impoundments) upstream of the generating equipment to ensure more reliable production, or be simple “run of the river” systems, which, like diversions, may only be available during certain months of the year when water flows are sufficient to support generation.

Hydropower is often divided in two categories: conventional hydroelectric power and pumped storage hydro (PSH). Conventional hydroelectric power historically uses impounded water (dams) to control gravitational potential (head) or diversions to better control electricity dispatch. While the era of building large new dams came to an end in the 1970s when the current regulatory paradigm was put into place based on environmental and ecosystem concerns, many of the large Federal dams built prior to this time continue to comprise the majority of hydropower capacity. PSH uses electricity when both price and demand are low to pump water uphill into a storage compound (often at night) and releases the water through a turbine during times of higher demand and higher prices (usually in the day). PSH was traditionally installed to help balance baseload generators like nuclear, but it is increasingly used to help integrate variable renewable generators²⁹⁷. There are far fewer PSH plants than conventional hydropower plants in the United States.

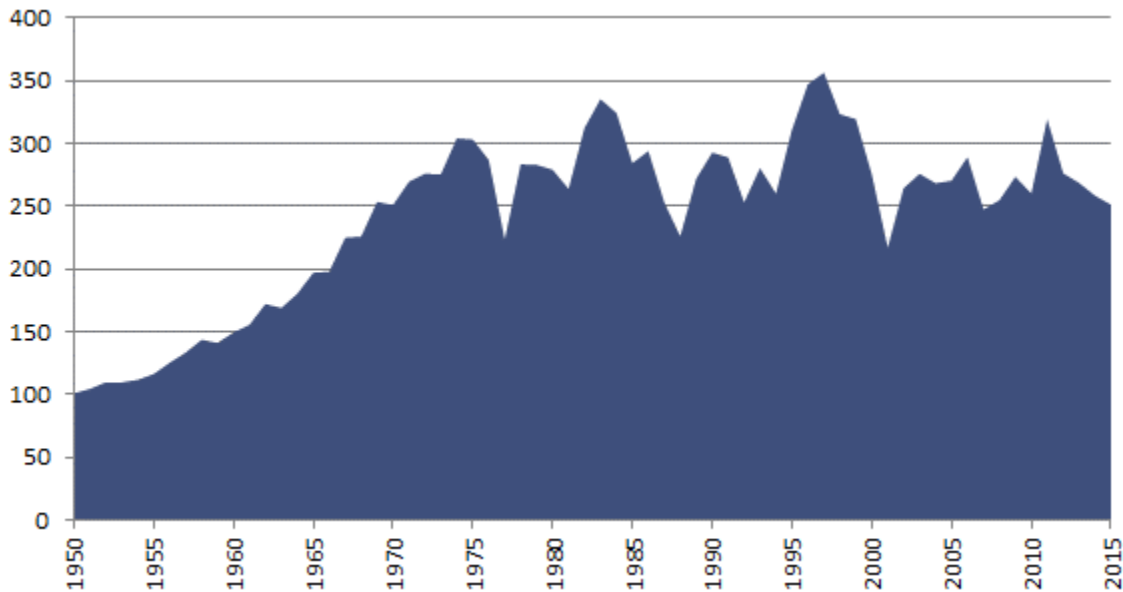
Hydropower is often used as baseload in the U.S. power system due to low variable fuel costs and low operational costs. It is often dispatched early due to low prices, but some operating conditions affect its dispatch schedule. Projected reservoir levels, environmental controls, and balancing for variable generators can lead to complicated dispatch schedules²⁹⁸. Conventional hydropower generators, and especially PSH, can be used in peaking and balancing applications to maintain grid reliability.

There have been several U.S. deployments of marine hydrokinetic (MHK) energy devices, which convert the energy of waves, tides, and river and ocean currents into electricity. Their historical contribution to U.S. electricity generation is negligible, but these technologies and future prospects are discussed in section 8.7.

8.2 Operational Attributes and Fleet Characteristics

Conventional hydroelectric power contributed 6.3 percent of the electricity generated in the United States in 2015²⁹⁹. While conventional hydropower generation has been relatively stable (Figure 8-1), its share of total generation has declined from 30 percent in 1950 as generation from other sources has increased over time with higher electricity demand. PSH is not a net-positive generation source as it net loses energy due to efficiency losses from charging versus discharging. If those losses are included, then conventional hydro and PSH would be slightly reduced to 6.2 percent.

Figure 8-1. U.S. hydropower generation (TWh), 1950–2015

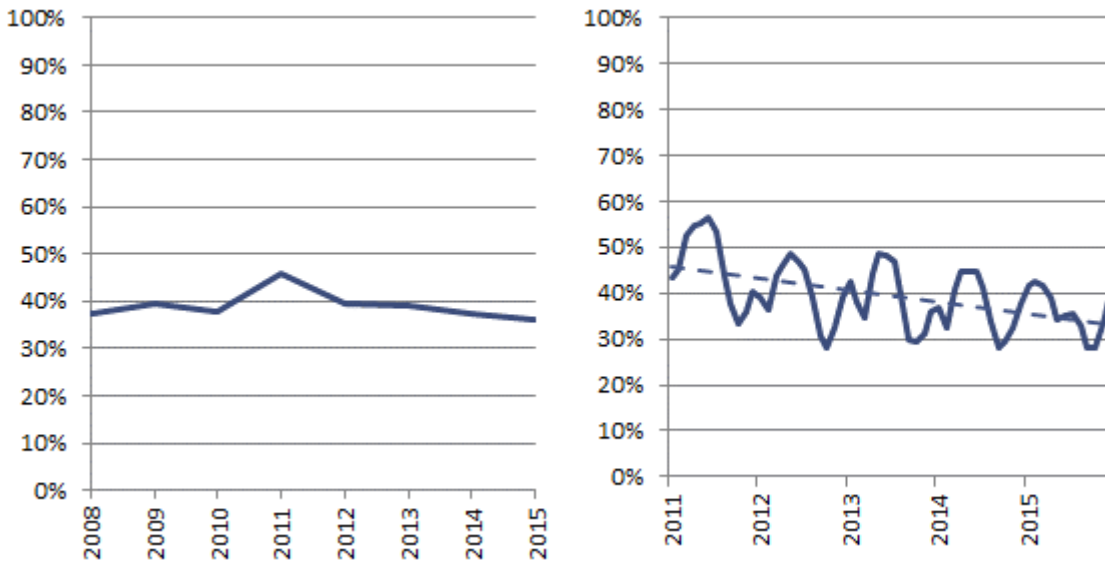


Source: EIA 2016³⁰⁰.

Note: This chart only includes net generation from conventional hydropower generators and does not include subtractions from PSH.

In 2014, there were 79.6 GW of installed hydropower capacity from conventional facilities and 21.6 GW from PSH. The average capacity factor of conventional hydroelectric generators was 40 percent (Figure 8-2). Hydropower output can fluctuate from year to year based on natural variability of the water cycle such as the level of rainfall or snowpack. In addition, unlike impoundment hydroelectric, run-of-river facilities have little to no ability to control generation and are more sensitive to long- and short-term natural variability of water flows. Because the majority of hydropower facilities support multiple purposes, such as recreation, flood management, irrigation, navigation, and water supply, requirements for uses other than power generation (e.g., reservoir elevation rules upstream, dissolved oxygen, or flow requirements downstream) can also impact when the plant is able to release or store water³⁰¹. Figure 8-3 shows that between 2010 and 2014, certain states experienced a significant decrease in generation and capacity factor, including California and several states in the Midwest and Southwest, likely due to decreased water supply from drought conditions.

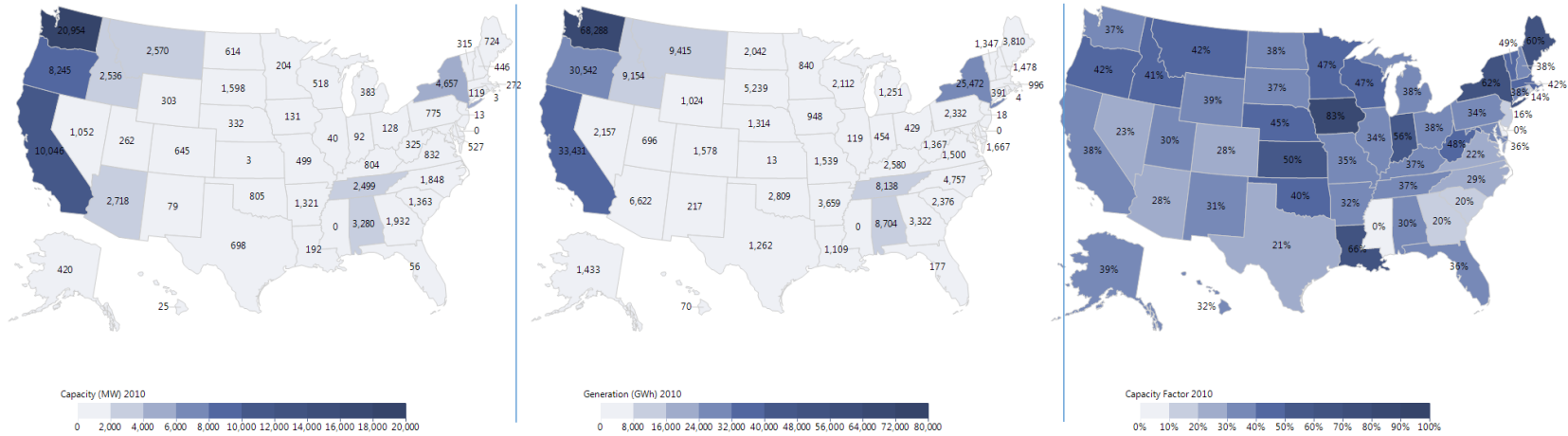
Figure 8-2. U.S. annual and monthly hydropower generator capacity factors



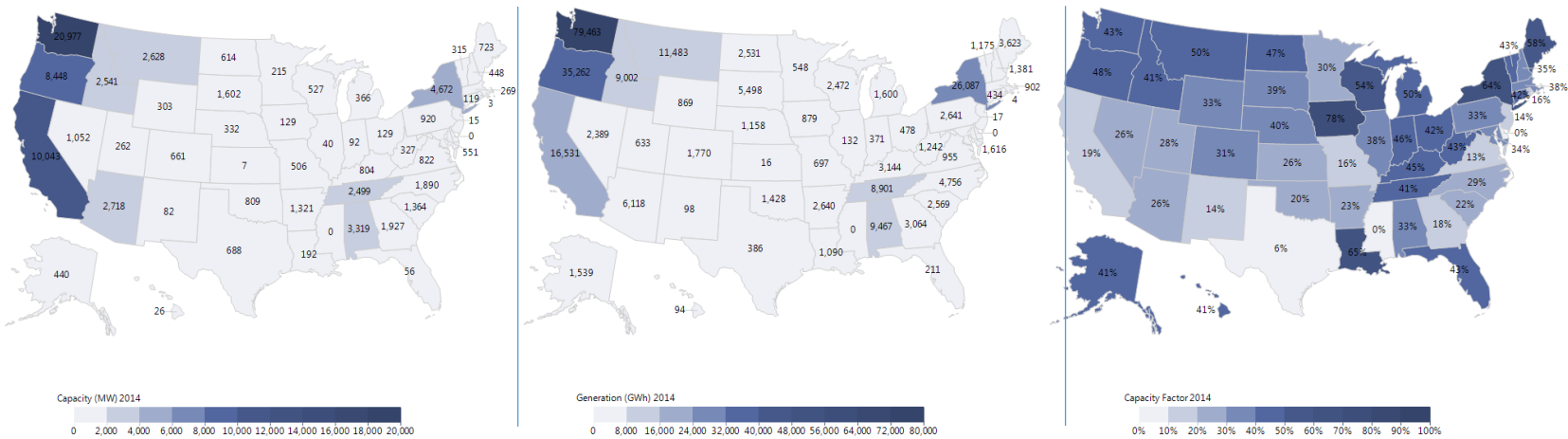
Conventional hydropower capacity factors have hovered around 40 percent, with fluctuations primarily due to yearly water availability fluctuations. Source: SNL 2015³⁰².

Figure 8-3. Hydropower capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



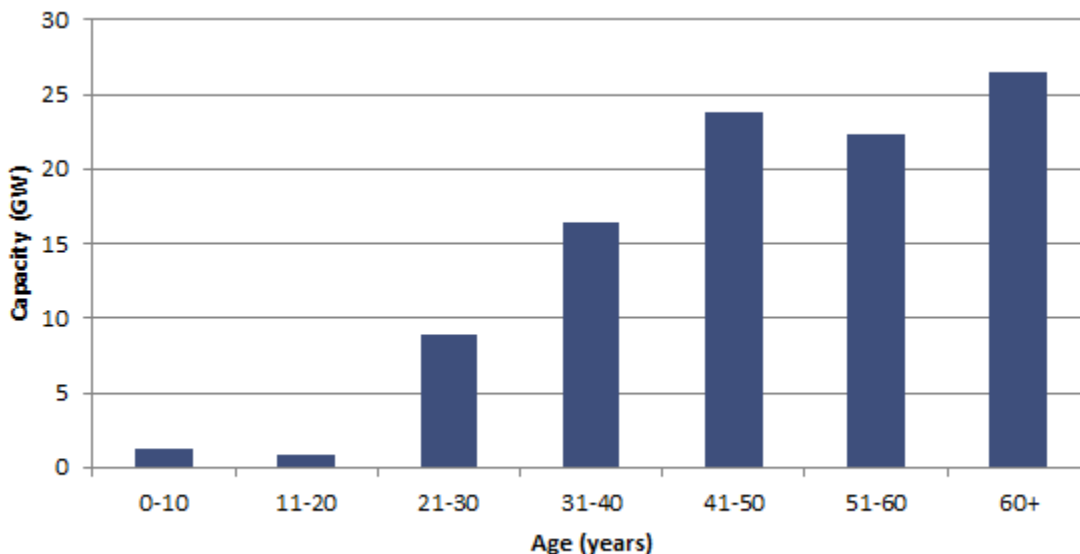
2014



Capacity from hydropower remained relatively constant across the United States between 2010 and 2014; however, generation and capacity factor decreased in several states, including California and Midwest and Southwest states (Kansas, Oklahoma, Missouri, Texas, New Mexico). Note: This chart only includes net generation from conventional hydropower and does not include subtractions from PSH. Source: EIA 2016³⁰³.

About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s (Figure 8-4)³⁰⁴. However, with routine maintenance and refurbishment of turbines and electrical equipment, the expected life of hydropower facilities is likely to be 100 years or more.

Figure 8-4. Age profile of U.S. hydropower generation fleet, 2014



About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s. Source: SNL 2015³⁰⁵.

Hydropower provides a variety of ancillary services that are beneficial to the electricity system. One example is regulation and frequency response (including inertia), in which hydropower generators can quickly respond to sudden changes in system frequency. Other ancillary services include spinning and supplemental reserves enabled by high ramping capability, reactive power and voltage support, and black start capability. There has been a renewed interest in the flexibility benefits that many hydropower projects can offer the grid, given the growth in variable renewable sources like wind and solar. A recent report notes that about half of all installed hydropower capacity (39 GW) has high flexibility potential and could play an important role in low-cost integration of variable renewable generators³⁰⁶. PSH can also be used in peaking and balancing applications to maintain grid reliability and can play a balancing role in areas with high penetrations of VERRs.

8.3 Technology Costs

The LCOE for hydropower generation is shown in Table 8-1. Costs for MHK technologies are not shown, but they are assumed to be much higher due to lower technology maturity. Hydropower has the potential to be very competitive with other forms of generation, but the costs of different hydropower installations vary significantly.

Table 8-1. LCOE for new hydropower generation (2013\$/MWh)

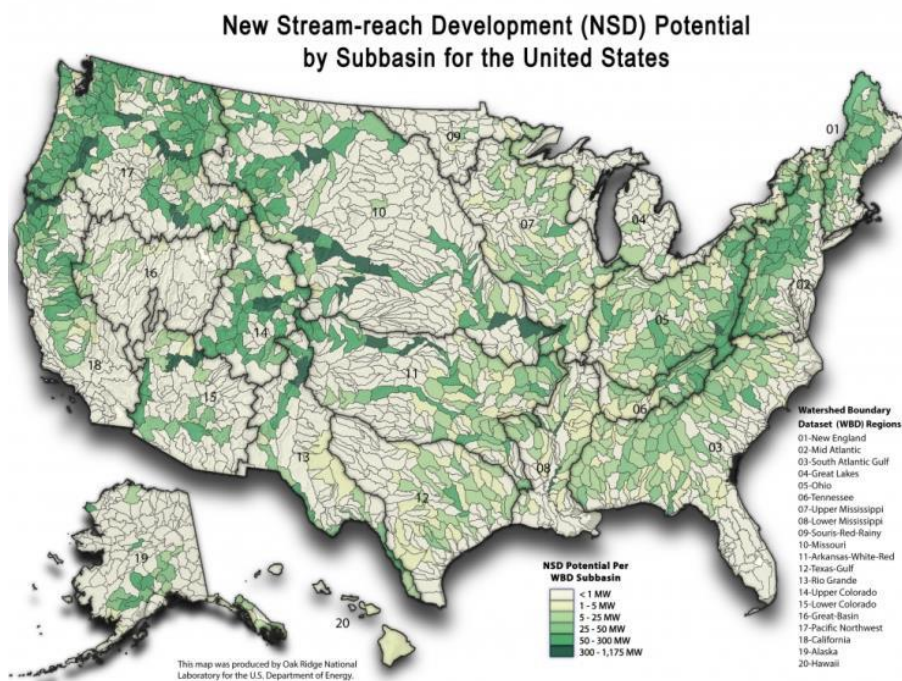
	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Hydropower	47.22	78.83	25.31	245.68	N/A	N/A

Current ranges of hydropower technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015³⁰⁷. See appendix B for more information on LCOE calculations.

8.4 Fuel/Resource

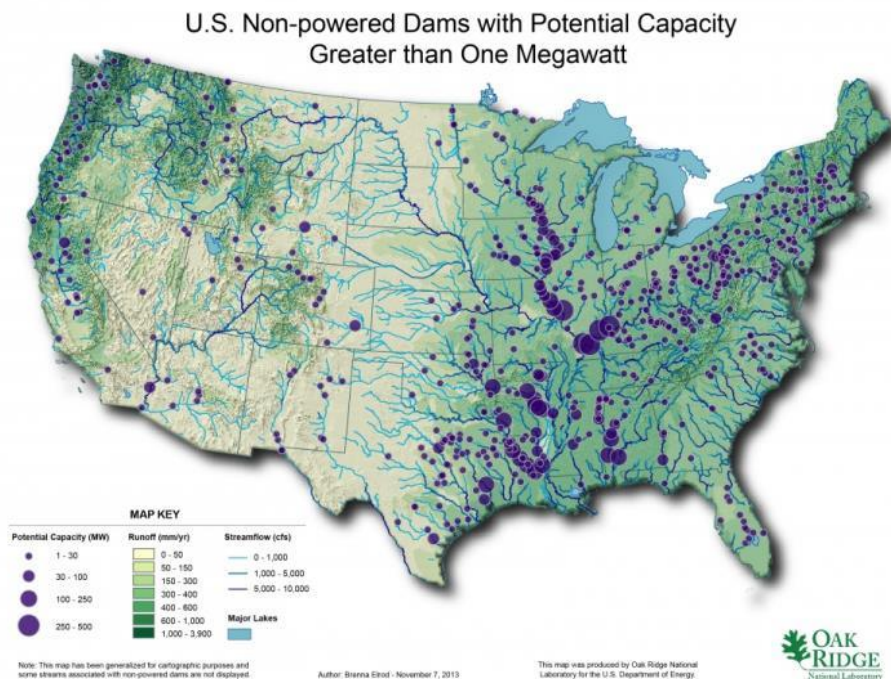
A report prepared by ORNL for DOE detailed the new stream-reach hydropower development available in the United States. This report found that the technical resource potential for new hydropower development was 65.5 GW of capacity, when excluding federally protected lands (Figure 8-5). Another ORNL report found a technical resource potential of over 12 GW capacity at the over 50,000 existing non-powered dams in the United States (Figure 8-6).

Figure 8-5. U.S. new stream-reach hydropower technical resource development potential



The technical resource potential for new hydropower developments is 65.5 GW, focused largely in the Pacific Northwest and Rocky Mountain West. Source: Kao et al. 2014³⁰⁸.

Figure 8-6. U.S. non-powered dam hydropower technical resource potential



The technical resource potential for powering non-powered dams is 12 GW, focused mainly on the Mississippi River and its major tributaries such as the Ohio and Red Rivers. Source: Hadjerioua, Kao, and Wei 2012³⁰⁹.

8.5 Environmental Impacts

8.5.1 Upstream

In the creation of hydroelectric reservoirs, large swaths of land may need to be flooded, which can allocate land away from other uses and can have an impact on aquatic life both in the reservoir and downstream of the facility³¹⁰. Reservoirs can also lead to stagnant water conditions that can lead to the spread of water-borne diseases. In addition, dams can alter water quality in a variety of different ways, from reductions in dissolved oxygen to the degradation of other water quality attributes. Stagnant water and reservoirs can also lead to silt and nutrient buildup up- and downstream of the dam that can affect aquatic ecosystems. Also, large reservoirs of water can lead to temperature changes in water, which can affect all stages of aquatic life. In addition, dams can block and disrupt access to fish spawning or rearing habitats and directly kill fish by turbine entrainment. Furthermore, dams can alter instream flows, which impact habitat for fish and other aquatic organisms. Some fish and organisms can be impacted if drawn into turbine blades, so mitigation measures need to be taken to protect aquatic life. These mitigation measures include fish passage devices such as ladders or elevators and intake screens to prevent fish from entering turbine runs³¹¹.

Run-of-river and diversion projects can impact aquatic life in many of the same ways as hydroelectric dams, but their environmental impacts are less in comparison due to the typically smaller size of any impoundments used and significant reductions in flooded areas.

8.5.2 *Emissions and Environmental Impact*

Hydropower is a renewable energy source that does not consume fossil fuel and therefore does not produce CO₂ during generation. However, the damming of rivers causes significant disruptions to the local environment to construct the dam and to the resulting land area that is submerged when the reservoir is filled.

8.5.3 *Downstream*

Downstream, the hydroelectric dam causes environmental disruptions by restricting the flow of water and nutrients, thus affecting plants and animals living along and in the stream. Diversion projects divert water from the main stream reach through a channel to the hydroelectric facility; this can allow fish to continue through the main stream reach without a fish passage device.

8.6 **Constraints**

New large-scale hydroelectric dams are unlikely to be built due to environmental and siting concerns; in fact, some dams are now being removed to return rivers to free-flowing conditions. The licensing and relicensing of hydropower projects often takes so much time that it acts as an impediment to new projects and existing projects. Over the next 10 years, existing FERC licenses will expire for nearly 250 hydropower projects, totaling more than 16,000 MW of installed capacity. On average, it takes 8 to 10 years to relicense an existing hydro project, with at least 5 years of pre-filing activity and then at least another 3 years after the application is filed. However, only 2,198 dams are currently used for hydroelectricity—3 percent of the nation’s total dams. (Other uses for dams include navigation, flood control, irrigation, and recreation.) Adding hydroelectricity to these preexisting dams may not be subject to as many siting constraints because some of the environmental impacts from dam construction have already been incurred; this, combined with the ability to leverage existing infrastructure at nonpowered dams, can reduce costs. New development of smaller projects, including diversions or conduits, may also face fewer siting constraints due to lower expected environmental impacts, but these projects may face economic constraints due to their smaller size and potentially less water and greater seasonal variability.

Since MHK technologies encompass a large array of archetypes and the technologies are relatively new, there are still many unknowns when it comes to their environmental impacts. This has led to permitting and regulatory agencies taking a very conservative approach and has hampered the deployment of many demonstration-scale projects. Some common environmental concerns that are raised include the acoustic impacts of operational devices, the impacts of electromagnetic fields from subsea cables, and the collision of marine animals with tidal turbine blades³¹².

New proposed PSH development could occur on existing dams or be built entirely off-stream, leading to different implications for siting. PSH development at an existing dam would require the construction of an upper reservoir separate from the river system, but the dam would still have one reservoir on a naturally flowing water body and therefore be considered “open loop.” An example of this is the recently considered Iowa Hill project by the Sacramento Municipal Utility District. A PSH facility built entirely off-stream is considered “closed-loop” and would not face the same environmental concerns because it is not connected to a river system. An

example of this is the Eagle Mountain project (also recently licensed), where both upper and lower reservoirs would be in abandoned open-pit mines³¹³.

Hydroelectric power is impacted by the water cycle (i.e., snowpack and rainfall), which varies regionally, seasonally, and annually. The regional and seasonal trends have historically been somewhat predictable, although there are many factors that can influence water flow and power production. For example, hydroelectric generation typically is lowest in the fall and peaks in the spring when snowpack melts; this peak is more notable in the mountainous West³¹⁴. Climate change, however, could impact the seasonal availability of water and its management, potentially creating challenges and opportunities for hydropower going forward³¹⁵. Many existing hydropower facilities are considered multi-use and offer flood control, recreation, and navigation. These additional uses for the facility may be higher priority than energy production, resulting in uncertainty regarding power generation.

Large-scale hydropower projects are often difficult to finance due to high capital costs, lengthy permitting periods, and environmental concerns. While the prospects for building very large new dams are low, there are other opportunities for hydropower to expand in the U.S. generation portfolio. Upgrading equipment at existing sites to expand capacity is likely to continue, and projects at currently nonpowered dam sites could continue to advance. New low-impact, environmentally sustainable developments could also occur. Still, the amount of new hydropower capacity that is expected to come online over the near to mid-term is relatively modest when compared to wind and solar.

8.7 Technical RDD&D

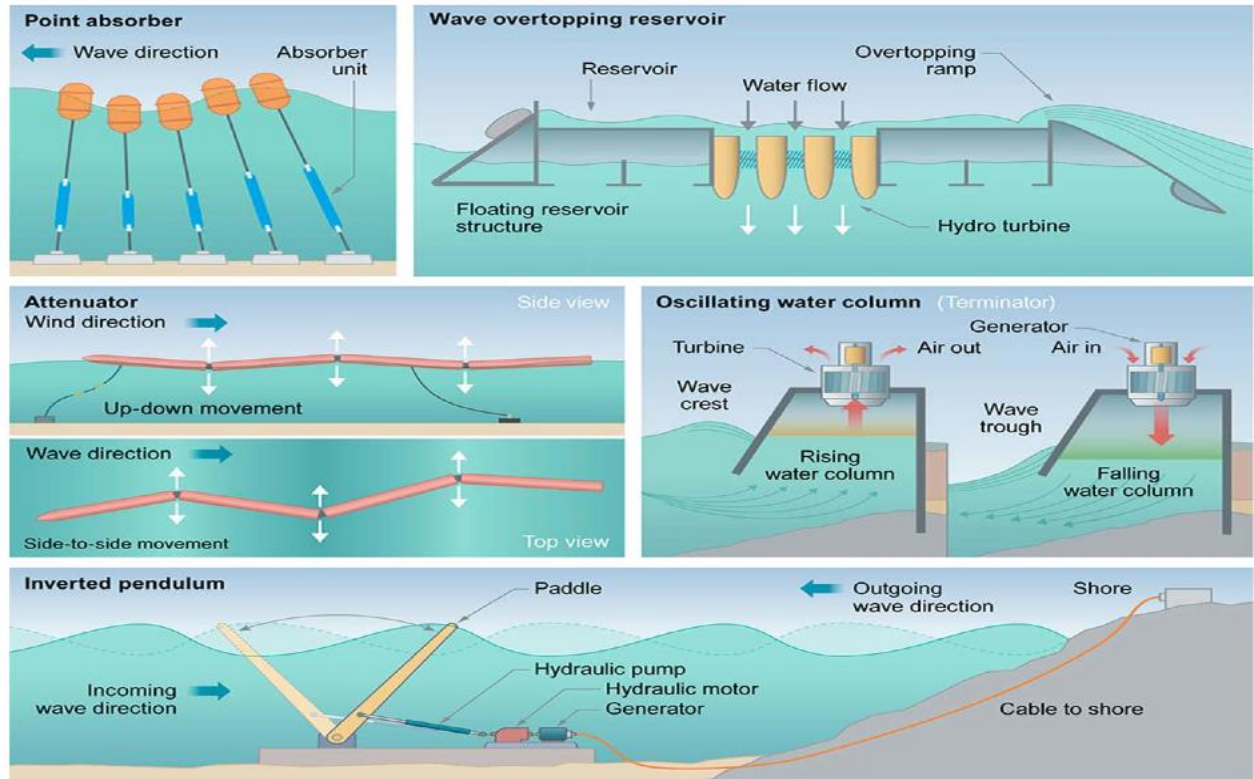
Large-scale hydropower technologies are mature and well understood; however, smaller, low-impact projects present an opportunity to develop low-head and modular technologies optimized for these new applications. Low-head sites generally have a change in elevation ranging from approximately 2 to 30 meters and can be applied to existing nonpowered dams, canals, and conduits across the United States.

DOE-funded hydropower RDD&D focuses on developing technologies for low-head hydropower, materials and manufacturing, improved turbines, and system evaluation metrics.^{xlii} Through its national laboratories, DOE also supports the development of specialized design and evaluation tools that will enable new turbine designs to meet power production goals while minimizing environmental effects. Researchers are also focusing on ways to lower the environmental impact during the construction and operation of new and existing dams, although recent history indicates a limited opportunity to build new hydropower facilities with dams.

New MHK technologies are also an area of active RDD&D³¹⁶. Most MHK technologies capture kinetic energy in waves, tides, or currents, although others also focus on capturing energy from temperature and salinity gradients. There are dozens of MHK technologies under development, with a select group illustrated in Figure 8-7 that focus on capturing energy from waves. While electricity production from MHK is variable, tides are predictable over the long term, and waves are forecastable over the short term³¹⁷.

^{xlii} More information on DOE's hydropower program is available here: <http://energy.gov/eere/water/hydropower-technology-development>.

Figure 8-7. Selected wave energy conversion devices



A wide spectrum of MHK power generation technologies is under development, with most MHK technologies at an early stage of testing and pilot-scale demonstration. Wave and tidal energy conversion devices, among others, have the potential to supply coastal populations with significant quantities of renewable electricity. Source: Augustine et al. 2012³¹⁸.

MHK technologies are currently in the R&D phase, with some pilot-scale technology demonstrations.^{xliii} Challenges and opportunities for MHK technologies are summarized in Table 8-2. High costs are probably the single largest barrier to greater deployment, although overcoming engineering challenges of operating in harsh conditions and concerns over potential environmental impacts are also important. With continued technology development and subsequent cost reductions, MHK applications could power remote locations or provide a substantial amount of renewable electricity for coastal load centers where electricity prices are highest³¹⁹. For example, the first U.S. MHK demonstrations have occurred in Maine, Alaska, and Hawaii.

^{xliii} More information on the DOE portfolio of MHK technology RDD&D is available here: <http://energy.gov/eere/water/marine-and-hydrokinetic-energy-research-development>.

Table 8-2. Challenges and opportunities for MHK technologies

Issue	Challenge	Opportunity
Resource Assessment and Characterization	Today's national resource assessments are at a low resolution, making industry decisions on technology development and deployment high risk.	Higher resolution regional assessments for MHK will support resource classification schemes and provide more detailed information. These will reduce risk for investment opportunities in technology development and deployment.
Technology Maturity	The marine and hydrokinetic energy sector is currently represented by a great diversity of technology solutions and there are limited data available to identify low-cost, high-performance solutions with high reliability, so investments are spread across all of the technology types rather than focused on the most promising technology development pathways.	There are many new players taking interest in development of what could be winning solutions in this sector, and a national effort could with entrepreneurs could develop solutions with high potential to be cost competitive and environmentally responsible. Identifying winning solutions would establish the United States as a global leader for domestic and international markets.
Cost Reduction	Significant innovation is still needed to bring costs down by more than 50% to achieve cost competitiveness of MHK devices. Devices need to capture more energy and reduce both capital and operating costs.	Innovation mechanisms and a large body of knowledge to draw from other scientific and industrial sectors are available today to accelerate the cost-reduction profile.
Demonstration	Developers who are ready to test full-scale prototypes lack access to test facilities and permitted demonstration sites. This impedes the developer's ability to validate device performance in its intended resource; test and iterate installation, operation, and maintenance logistics; and monitor device-to-environment interactions.	Access to world-class test facilities and other demonstration opportunities and associated instrumentation have the potential to accelerate technology evolution while substantially reducing technology development and demonstration costs to the industry. Specifically, early-adopter markets may present demonstration opportunities.
Deployment	The process for permitting device deployments can be expensive and time consuming, leaving fewer resources for R&D and increasing project development costs. The lack of scientific information, for example baseline environmental data, and high monitoring costs can drive environmental and regulatory expenses to 30%–50% of total early-stage MHK project cost.	By assessing and addressing potential environmental impacts now through scientific research, developing new instruments, and validating them with initial device demonstrations, this sector can avoid serious deployment barriers. National support for environmental monitoring can help reduce the monitoring cost burden for developers, allowing them to focus funds on technology development to approach cost competitiveness and facilitate more widespread deployments.

Source: DOE 2015³²⁰.

DOE sponsors an active research program to explore the potential for MHK, which includes research along the entire supply chain—from resource characterization and technology development to simulations and multi-metric environmental impact studies. According to technical resource assessments,^{xliv} MHK technologies harnessing energy from waves, tides, and currents have the technical ability to produce 538–757 TWh^{xlv} per year in the continental United

^{xliv} There are three levels of resource assessments: (1) Theoretical potential is the annual average amount of physical energy that is hypothetically available. (2) Technical resource potential is the portion of a theoretical resource that can be captured and converted into electricity using a specific technology. (3) Practical resource potential is the portion of the technical resource that is available when other siting considerations and constraints—including economic, environmental, and regulatory—are factored in.

^{xlv} Of this total, 378–472 TWh/year is from wave energy; 15–22 TWh/year is from tidal current energy; 45–163 TWh/year is from ocean current energy; and 100 TWh/year is from river current energy.

States, and 1,285–1,846 TWh per year in the total United States (including Alaska and Hawaii)³²¹.

8.8 Development and Projected Future Deployment

Forty-nine percent of U.S. hydroelectric capacity (8 percent of total plants) is federally owned by the Army Corps of Engineers, the Bureau of Reclamation, and TVA³²², and these agencies accounted for much of the hydropower expansion through the 1960s. Additionally, billions of dollars in investments from public power, municipal, and private entities have made extensive use of Clean Renewable Energy Bonds, Build America Bonds, Qualified Energy Conservation Bonds, and other federally subsidized bond mechanisms to install hydroelectric dams, accounting for the other 51 percent of capacity and 92 percent of total plants.

The environment for construction of new or expanded hydropower capacity changed in the 1960s and 1970s with the passage of new environmental legislation such as the Clean Water Act, the National Environmental Policy Act, the Wild and Scenic Rivers Act, and the Endangered Species Act, which altered the way hydropower facilities were licensed by FERC (previously called the Federal Power Commission until 1977); the environment for construction of new or expanded hydropower capacity was also affected by changes in electricity markets that introduced wholesale generation competition³²³. The main focus of current hydropower expansion is a combination of equipment upgrades at existing plants; new lower-impact, run-of-river modular component or small-scale plants; “conduits,” where energy is captured from the flow of water through existing water conveyance infrastructure such as irrigation pipes; and conversion of existing nonpowered dams to include generation³²⁴. However, only about 1.4 GW of net capacity was added between 2005 and 2013, and the vast majority of added capacity was associated with upgrades to or powering of existing dams. Capacity additions to existing powered dams, from investments in generator upgrades, accounted for the largest capacity increase, with additions to nonpowered dams coming in second. Conduit and new facilities accounted for a very small portion of new generation.

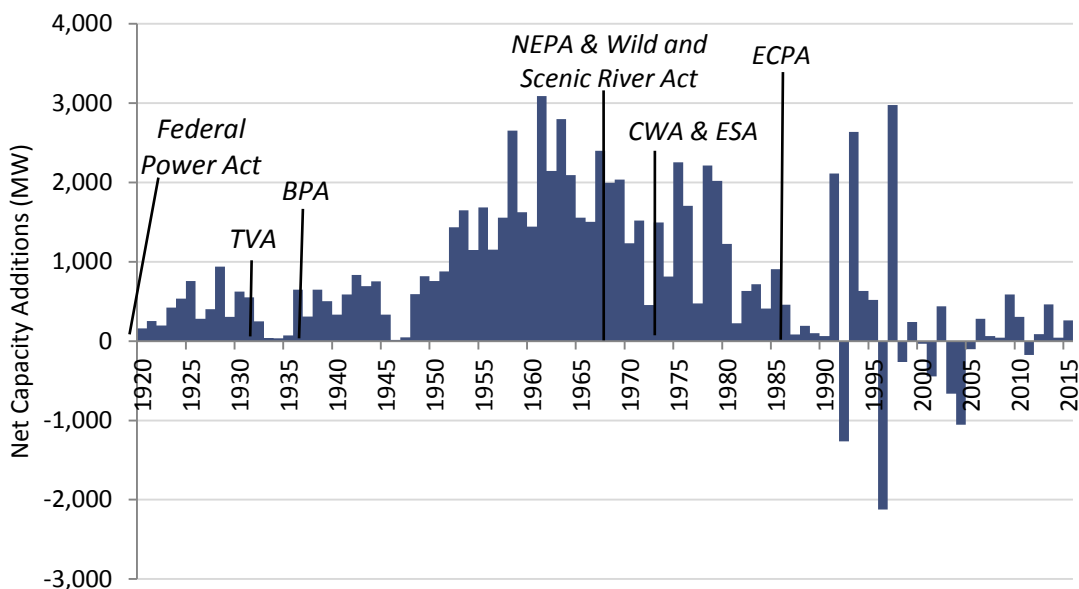
Private developments of hydroelectric dams have taken advantage of Federal tax credits, but these credits have not spurred development to the same level as other renewable generating technologies. The PTC is available to hydropower developers at \$0.012/MWh, which is half the rate of the PTC for wind and geothermal generators. Also, hydropower is only eligible for expanding and upgrading existing facilities and powering of existing dams. New stream-reach developments are currently ineligible. Most State RPS programs include hydropower as a qualified source for RPS compliance, but with some limitations such as project size (e.g., up to 30 MW) or a specification that no new impoundments be built³²⁵. The U.S. Congress passed legislation in 2013 that streamlined the approval process for small hydropower (less than 10 MW)^{xlvi} and is considering additional legislation to reform the licensing process for hydroelectric generators³²⁶. Multiple factors, largely the environmental concerns surrounding large dams, are moving the industry away from larger plants and toward smaller plants (Figures 8-8 and 8-9).

FERC maintains a current list of PSH projects that have submitted applications for licenses and is experimenting with a new, expedited 2-year licensing process for certain hydroelectric

^{xlvi} See the Hydropower Regulatory Efficiency Act (HR 267, S 6162) and the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act (HR 678, S 6257).

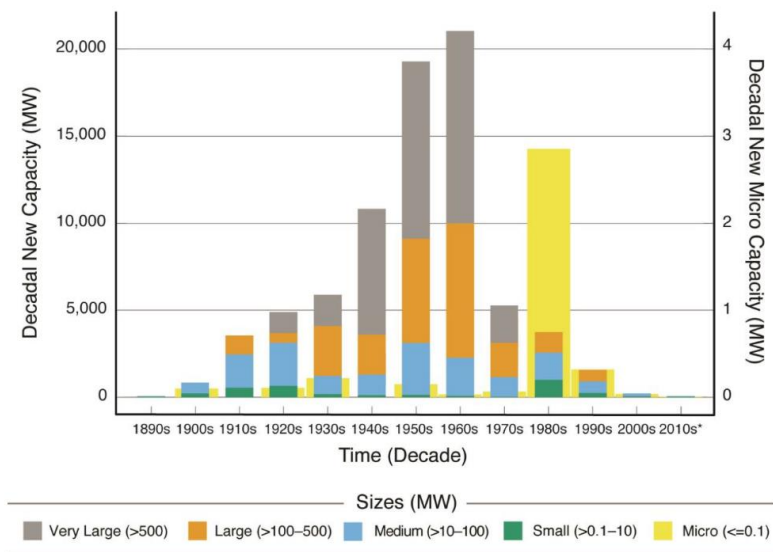
plants³²⁷. As of April 2016, approximately 2.03 GW of new PSH capacity had applied for licensing with FERC³²⁸.

Figure 8-8. Historical annual hydropower capacity additions and retirements (MW), 1920–2015



Following policy in the 1960s and 1970s that altered FERC licensing for dams, as well as changes to market structures, the buildout of hydropower capacity has slowed^{xlvii}. Source: EIA 1990 and EIA 2016³²⁹.

Figure 8-9. Timeline for hydropower capacity additions in the U.S. (MW), 1890-2015



*Data for the 2010s only cover 2010-2013.

The buildout of large and very large hydropower facilities peaked in the 1950s and 1960s, and has diminished since. Source: Uria-Martinez et al. 2015³³⁰.

^{xlvii} Note: NEPA means National Environmental Protection Act, ECPA means Electronic Communications Privacy Act, CWA is the Clean Water Act, and ESA is the Endangered Species Act.

Table 8-3 presents estimates of hydropower generation in 2040 from the QER 1.2 Base Case and the Side Case. Both show modest increases in hydropower generation, with the Base Case deploying slightly more hydropower resources. While generation increases in both scenarios, however, hydropower capacity is essentially flat. Potential MHK generation is not included in these projections.

Table 8-3. QER 1.2 Base Case generation for hydropower (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Hydropower	255	290	298

The QER1.2 Base Case and Side Case both show modest deployment of hydropower. Source: EPSA 2015³³¹

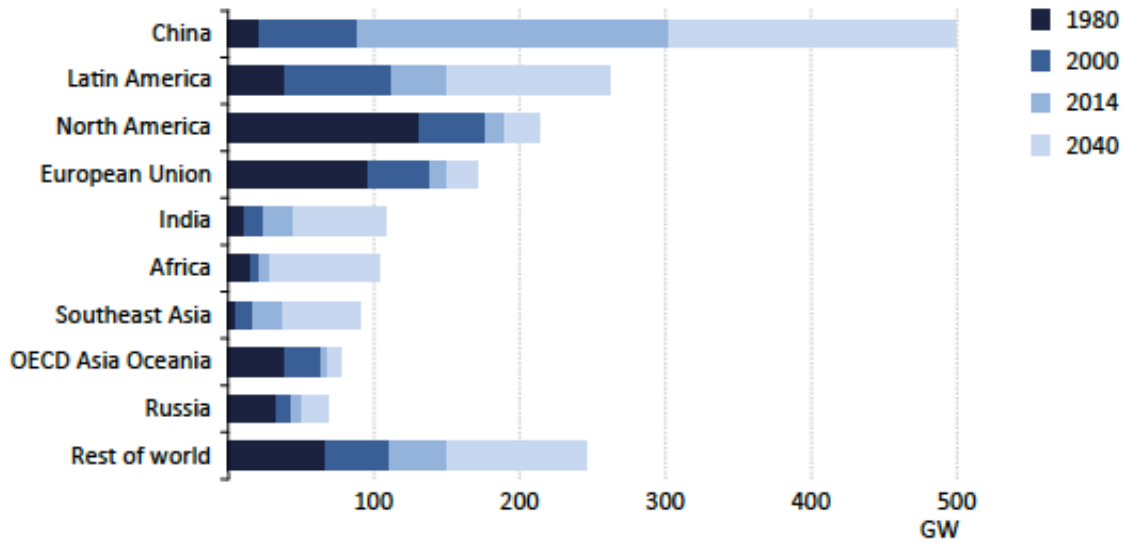
Global growth of hydroelectric generation is expected to be fairly robust in nearly all of the IEA scenarios (Table 8-4). Generation is expected to increase by nearly 60 percent by 2040 in the Current and New Policies scenarios, and by nearly 80 percent in the 450 Scenario. Much of the new capacity is expected to be installed in China, Latin America, Africa, and India (Figure 8-10).

Table 8-4. Historical and projected global hydroelectric generation by scenario outlook

			New Policies		Current Policies		450	
	2000	2013	2020	2040	2020	2040	2020	2040
Hydro Generation (TWh)	2,620	3,789	4,456	6,180	4,423	5,902	4,464	6,836
Percentage of Global Total	17	16	16	16	16	14	17	20

Source: IEA 2015³³².

Figure 8-10. Installed hydropower capacity (GW) in the IEA New Policies scenario



Much of the new hydropower capacity is expected to be installed in China, Latin America, Africa, and India. Source: IEA 2015³³³.

9 Wind

9.1 Technologies

Wind turbines utilize the kinetic energy of wind to turn a rotor. While there are several possible configurations for wind turbines, most have three blades mounted on a horizontal axis at the top of a tower. The blades turn a rotor that is connected to a shaft, which spins a generator to produce electricity. Most turbines maintain an upwind orientation, meaning they use a weather vane and yaw drive/motor to keep the blades facing into the wind.

In the United States, all operating capacity currently comes from land-based wind turbines. While there has been significant deployment of offshore wind in Europe, to date, there has been no offshore wind deployment domestically. However, in July 2015, Deepwater Wind began construction of what is expected to be the first offshore wind farm in the United States.^{xlviii} Over the past 30 years, utility-scale wind turbine technology has made notable advances, including higher hub heights, longer rotor blades, and more sophisticated electronics³³⁴. These improvements allow for access to faster and more consistent wind speeds, which increases the capacity factor, resulting in lower LCOE.

Wind turbines are generally available to produce power around 95 percent of the time. However, wind power is variable and depends on the local weather conditions and cannot be fully dispatched on demand. Further, the wind speed must be great enough to turn the turbine, which is a limiting factor for generating availability. Wind turbines generally have a cut-in and cut-out wind speed so that they are only spinning in a range of wind conditions where they can operate efficiently and safely.^{xlix} The ability to forecast wind, and thus anticipate its dispatch availability, has also improved in recent years and is critical to the future viability of wind power.

The generating capacity of a single wind turbine can range anywhere from 2 kW to 8 MW, depending on application, hub height, and blade length. Wind turbines can be utility-scale—in which multiple turbines are usually grouped together or along a ridgeline to form a “wind farm” or wind plant—or they can be used in distributed applications. Variable generator output of the rotating blades is converted by power control equipment at the base of each tower to match power output with the frequency of the electrical grid. Over time, turbines have increased in nameplate capacity, and hub heights and blade lengths have grown to increase the total energy captured by each turbine; however, even with these improvements, which have led to greater energy extraction, wind turbine technologies remain constrained by the Betz limit of 59.3 percent maximum efficiency³³⁵. Higher hub heights allow for access to faster and more consistent wind speeds, which can lower the life-cycle cost of electricity and increase the capacity factor for wind turbines³³⁶. Turbines originally designed for lower wind speeds have also rapidly gained market share in recent years, enabling wind deployment for a wider variety of wind resources³³⁷.

9.2 Operational Attributes and Fleet Characteristics

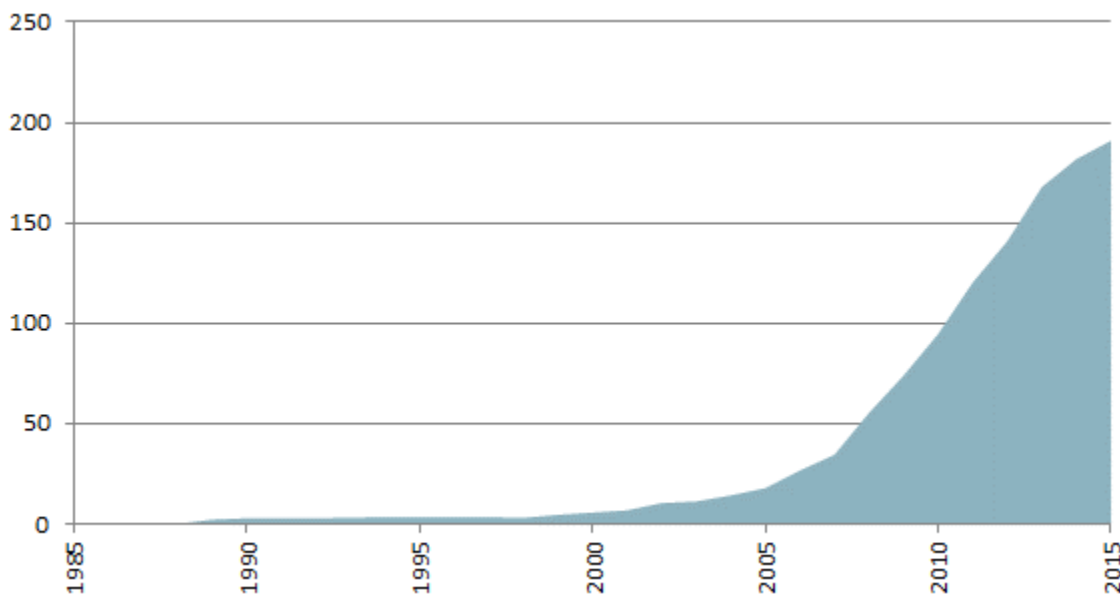
Power generation from wind has grown rapidly over the past decade (Figure 9-1) and by 2015, contributed nearly 5 percent of the total electricity generation (191 TWh) in the United States³³⁸.

^{xlviii} Offshore wind is more developed in Europe, where offshore wind technology has 25-year performance record and now accounts for 11 GW of generation capacity on the continent (Cusick 2016).

^{xlix} Utility-scale wind turbines generally require an average wind speed of 9 miles per hour minimum to achieve cut-in. The typical cut-out speed, for safety reasons, is normally around 55 miles per hour for utility-scale turbines (Duke Energy 2012).

According to the American Wind Energy Association (AWEA), installed wind capacity was more than 74 GW in 2015³³⁹. Wind capacity has grown significantly in the last decade, starting from a base of less than 9 GW installed nationally in 2005 and slowing only in the last few years³⁴⁰. A small portion of total wind generating capacity is classified as distributed, and this accounted for approximately 1 GW in 2014³⁴¹,¹.

Figure 9-1. U.S wind generation (TWh), 1985–2015



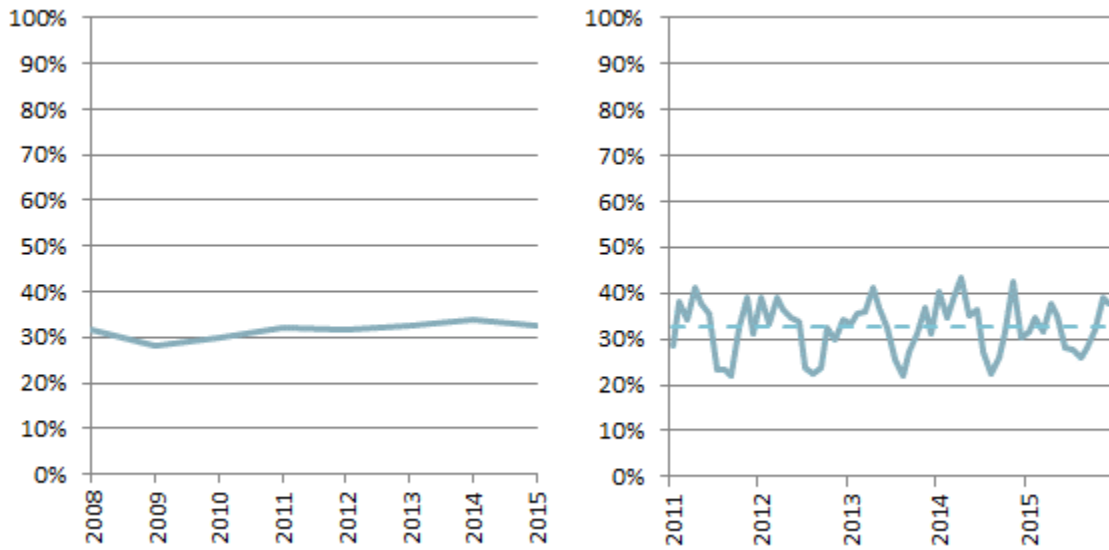
Source: EIA 2016³⁴².

In 2015, the average capacity factor for the existing fleet of wind turbines was around 35 percent (Figure 9-2). Capacity factors of wind are highly dependent on the resource, and higher hub heights and longer blades can increase the capacity factor in areas with high wind shear and low turbulence.

Figure 9-3 shows that Texas has the largest installed wind capacity and generation of all the states, with California and Iowa coming in second for capacity and generation, respectively. Notably, several states in the southeastern United States do not have any installed utility-scale wind capacity, due in part to relatively lower wind speeds (Figure 9-3).

¹ Distributed wind systems are connected on the customer side of the meter to meet the onsite load or are connected directly to distribution or microgrids to support grid operations or offset large loads nearby. Distributed wind systems are defined by technology application, not technology size, and are typically smaller than 20 MW (DOE 2015f).

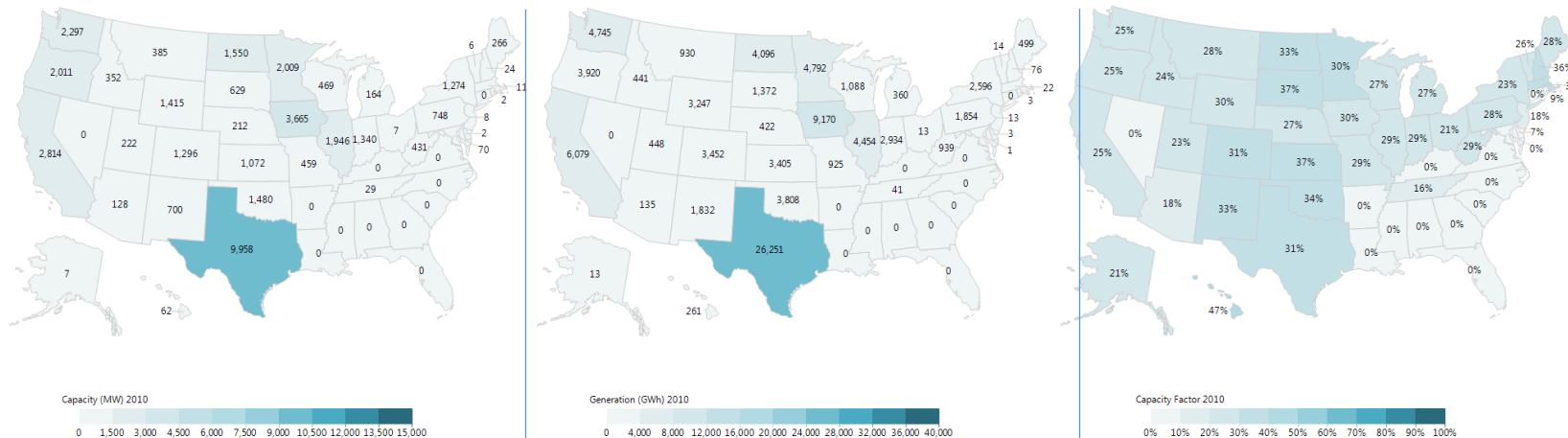
Figure 9-2. U.S. annual and monthly wind generator capacity factors



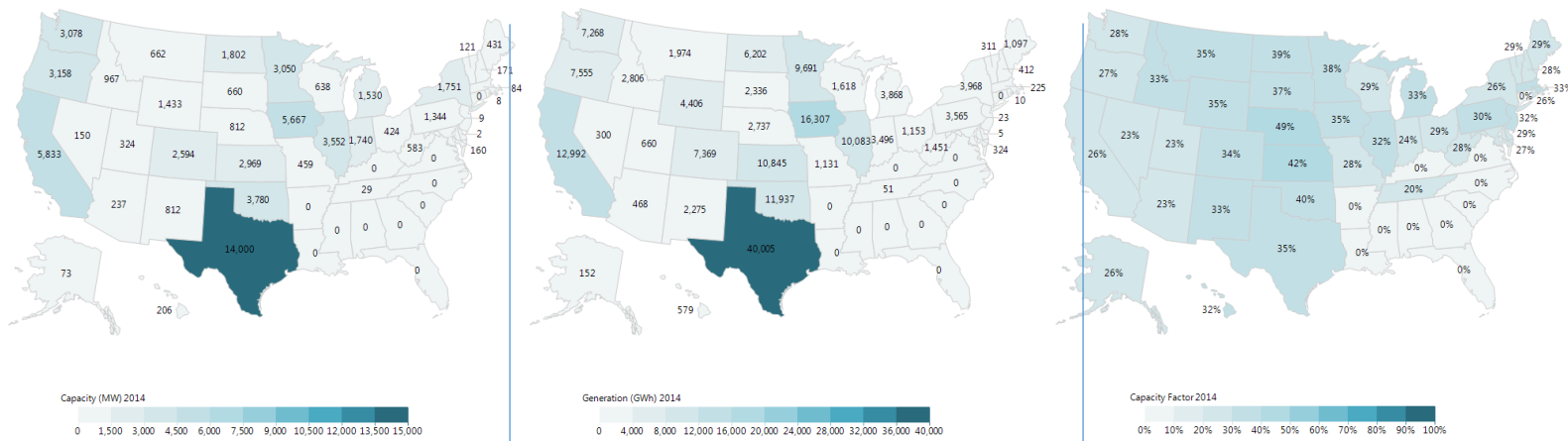
Wind capacity factors have increased slightly from a low in 2009. Generating availability is based on local weather conditions, but advances in turbine design could contribute to future increases in capacity factors. Sources: SNL 2015³⁴³.

Figure 9-3. Wind capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



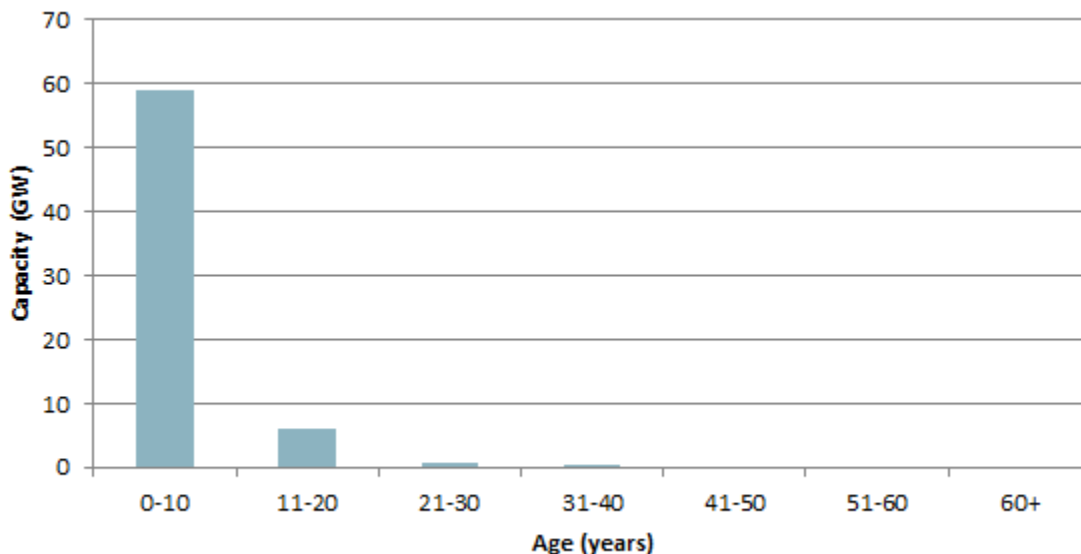
2014



Installed wind capacity increased by over 60 percent from 2010 to 2014. Texas had the largest capacity and generation, with California and Iowa competing for second over the 5-year period. The southeastern United States has a notable dearth of wind installations. Source: EIA 2016³⁴⁴.

A majority of wind capacity was installed in the last 10 years³⁴⁵. Wind turbines are modeled to last between 20 and 30 years³⁴⁶. At the end of life, turbines can be replaced with newer, more efficient turbines, utilizing the existing power system infrastructure. This process is referred to as repowering.

Figure 9-4. Age profile of U.S. wind generation fleet, 2014



The majority of wind capacity is less than 10 years old. Source: SNL 2015³⁴⁷.

9.3 Technology Costs

The LCOE for land-based and offshore wind power generation is shown in Table 9-1. The LCOE of land-based wind is comparable with other forms of generation such as NGCC, although as discussed further in section 3.4.1, it is difficult to directly compare dispatchable and nondispatchable technologies. The LCOE of offshore wind is higher than land-based wind due to lower technology maturity and the difficulty of operating in the marine environment, which increases balance of plant (foundations, transmission cables, etc.), installation, and O&M costs.

Table 9-1. LCOE for new wind generation (2013\$/MWh)

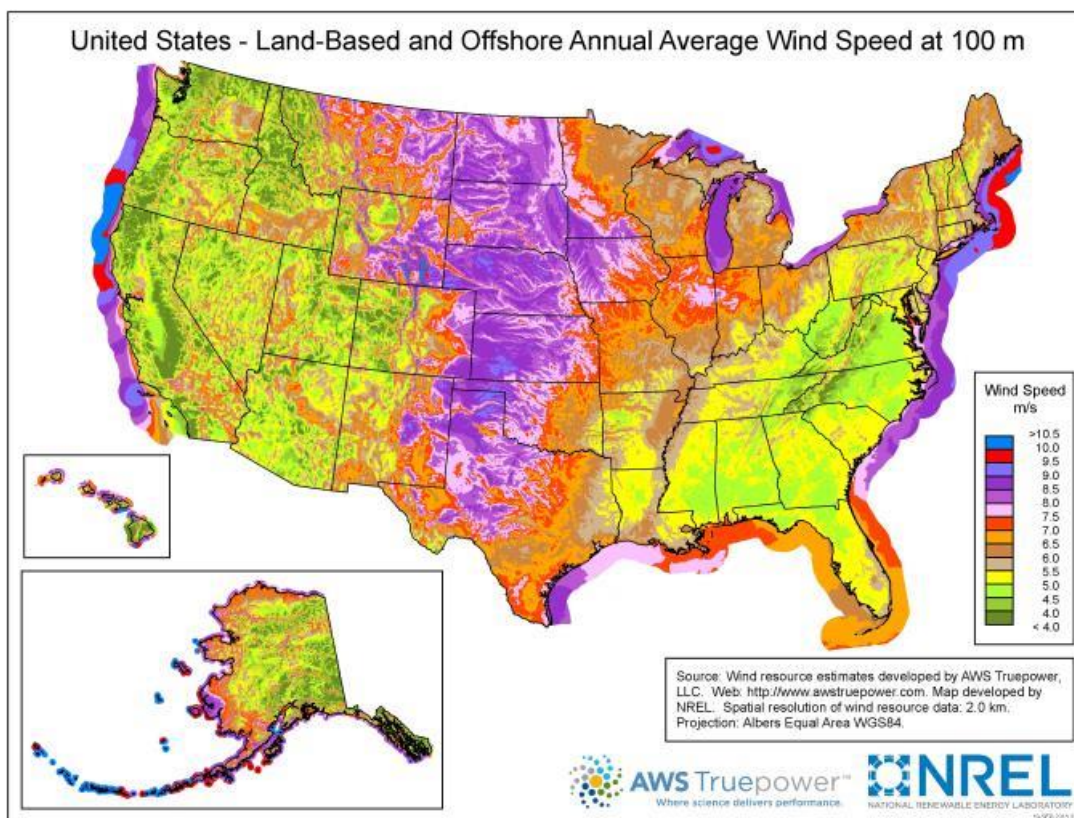
	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Wind, Land-Based	37.09	117.76	35.36	88.87	26.30	81.86
Wind, Offshore	117.22	279.25	114.75	241.09	81.27	218.10

Current ranges of wind technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015³⁴⁸. Calculation does not include the PTC. See appendix B for more information on LCOE calculations.

9.4 Fuel/Resource

Wind resources in the United States vary from state to state, but, in general, the largest resources are located in the Midwest and offshore from the coast. Currently, only land-based wind resources are developed, but offshore resources hold great potential for future development. Wind speeds at 100 meters above the surface for land-based and offshore applications are shown in Figure 9-5. Wind speeds tend to be higher and steadier at higher altitudes and in off-shore locations.

Figure 9-5. Land-based and offshore wind speeds at 100 m



In general, the largest U.S wind resources are located in the Midwest and offshore from the coasts. Source: NREL 2014³⁴⁹.

9.5 Environmental Impacts

9.5.1 Upstream

Wind turbines often rely on magnets made of rare earth elements to generate electricity. Some environmental concerns with mining rare earth metals are potential radioactivity, acidification, eutrophication, toxicity, and large energy footprint for extraction³⁵⁰. These impacts will vary by mining method. There is also some concern over supply chains for some of these materials, as most of the U.S. supply is imported from China³⁵¹. Rare earth elements are only a small portion of the total materials needed to build a turbine, however. Fiberglass is another major component

of turbines that is used in the blades, and its main ingredient is sand, which must also be mined³⁵². Two of the most important materials for construction are steel and copper, but these materials are not unique to wind turbines.

The effects of noise associated with pile-driving and other construction activities on marine mammals are a significant concern for offshore wind.

9.5.2 Emissions and Environmental Impact

Except for construction and decommissioning, wind turbines do not have any emissions associated with power generation. The life-cycle carbon emissions per kWh of wind are estimated at about 50 times less than that of coal-fired power plants³⁵³.

Birds and bats occasionally collide with wind turbines; on land, these impacts are generally more significant for bats than for most birds. Impacts to protected species such as Bald and Golden Eagles are of particular concern. Wind development may also displace some ground-nesting birds from key habitats. Potential impacts to human communities and land use include concerns about noise and visual impacts on communities if sited too close to residences, as well as interference with air traffic control, surveillance, and weather radar systems.

Bird collisions and habitat displacement impacts are an issue for offshore wind as well, though these impacts are likely to be smaller because bird abundance declines as a function of distance from shore.

9.6 Constraints

One of the main challenges to utilizing wind energy is integrating it into the electrical grid because of the variability and uncertainty of the resource³⁵⁴. Wind speed is highly dependent on weather patterns, which can lead to variability in power production (wind power is proportional to the cube of wind speed). Improvements in wind forecasting technologies have the potential to further reduce integration costs and increase wind dispatchability. Connected to variability is uncertainty in wind resource forecasting. In order to bid accurately into power markets, day-ahead forecasts of wind resources are needed to determine production. Forecast systems generally follow the same steps: prediction of wind or solar patterns based on weather forecasts and onsite observations, simulation of power generation, and regional power forecast³⁵⁵.

For example, ERCOT and MISO, which coordinate, control, and monitor the electricity transmission grid in Texas and the Midwest, respectively, and contain a significant amount of the nation's installed wind capacity, both operate day-ahead and real-time energy markets, which allow for grid operators to balance uncertainty and variability from wind production³⁵⁶. The European electricity system further includes intraday markets, which aid in wind integration³⁵⁷. Also, operating a large balancing area reduces the variability of wind power production by compiling multiple generators³⁵⁸.

Long-distance, high-voltage transmission lines are required to connect wind plants in high-resource areas (such as the Great Plains) to highly populated urban centers on the East and West Coasts. However, planning, obtaining regulatory approval, and building high-voltage transmission lines can take more than a decade³⁵⁹. Legal challenges can add additional delay³⁶⁰. Barriers to transmission infrastructure expansion include regulatory hurdles, multiple layers of overlapping jurisdictions, and public opposition. Not all wind plants need new transmission lines, and plant retirements may open additional transmission corridors.

Transmission congestion may also be a barrier to incorporating large amounts of wind energy. In Texas, significant transmission congestion in the northern part of the state was causing wind curtailments and negative wholesale electricity prices. As a result, the Public Utility Commission of Texas created Competitive Renewable Energy Zones with high wind resource potential and authorized transmission expansion to these areas. The result was a significant build out of wind resources and a reduction in congestion that limited wind curtailments³⁶¹.

In addition to transmission congestion, curtailment of wind generation can occur when wind generation occurs during off-peak or nighttime hours when electricity demand is low. If other generators on the system with minimum generation requirements, such as nuclear or fossil units, cannot have generation further reduced, then the wind generation is curtailed.

Beyond integration and transmission issues, opportunities to increase deployment and generation from wind energy include the following: increasing wind plant performance through better understanding of the physics of intraplant flows and turbine-turbine interactions to inform plant level control strategies; reducing costs for offshore wind, particularly in floating applications; overcoming logistical limits (e.g., highway overpasses, turning radius) associated with taller towers and larger rotors; and alleviating siting challenges associated with wildlife.

Wind power development might continue to face challenges of siting opposition and transmission constraints³⁶². Siting wind plants can sometimes be contentious due to concerns over wildlife, radar interference, and nearby residences, where noise and flicker^{li} can be an issue if homes are too close to turbines. Wind turbines are generally impacted by zoning ordinances if sited within urban and rural inhabited spaces. Bird and bat mortality due to collision with wind turbines remains an important consideration in siting and operating wind plants nationwide, although changes in wind technology may have reduced some of the earlier concerns.^{liii} Concerns about endangered bat mortality have made siting more challenging in the East, and concerns about impacts to Bald and Golden Eagles and about habitat displacement of ground-nesting birds like Greater Sage-Grouse are significant issues in the West.^{liiii} There is substantial research underway to minimize the impacts of wind on wildlife³⁶³.

Wind turbines can interfere with civilian and military radar, causing ‘clutter’ (i.e., false targets) if sited in certain locations³⁶⁴. The Federal Aviation Administration has jurisdiction over structures sited over 200 ft (current blade tip heights are approaching 500 ft), and siting concerns about radar are covered in the permitting process³⁶⁵. If wind farm siting is found to potentially impact radar systems, there are a variety of software and hardware solutions available, and more modern solutions are in development. For cases of severe impacts or where an individual radar is affected by multiple facilities, software and hardware mitigation measures are being developed³⁶⁶.

With the increasing size of rotors and towers, transportation of turbine pieces is presenting challenges. Trucks and rail cars need to be specially designed to carry longer turbine blades across the country³⁶⁷. Some manufacturing constraints have been seen in the manufacturing process for pieces that make up the motor in the nacelle, potentially leading to project delays³⁶⁸.

^{li} Flicker refers to the changing projections of shadow and light that can occur when turbines are located between the sun (when it is low on the horizon) and residences. Flicker has been reported to create disturbances for residents near wind plants, but these can be obviated by siting plants a minimum distance from residential neighborhoods.

^{liii} For example, early wind turbines spun at 60–80 rotations per minute and were mounted on lattice towers at 60–80 feet above the ground. Today’s turbines rotate at 11–28 rotations per minute and are mounted nearly 300 feet above the ground. For more, see NWCC 2010.

^{liiii} For more, see NWCC 2010.

Rare earth metals used for magnets in the generator may be a limiting factor, depending on the mining supply and the rate of wind development.

9.7 Technical RDD&D

Wind plants now have the ability to provide important grid services, including synthetic inertia, governor response, and regulation³⁶⁹; however, they are not currently required to do so.^{liv} Power converters can provide several services to assist in the integration of wind, such as frequency and voltage disturbance ride-through, voltage and ramping control, and reactive power control³⁷⁰. Converters can also allow wind power plants to provide a controlled inertial response³⁷¹. Still, increasing amounts of variable generation like wind introduce uncertainty that grid operators must understand and manage.

Technological improvements can reduce LCOE by decreasing capital costs or improving performance and capacity factors. Taller towers, for example, improve turbine performance and can increase capacity factor in areas with high wind shear, as well as support the use of larger rotors that sweep larger areas and utilize more of the available wind resource³⁷². In addition, larger rotor-swept areas combined with turbine technologies designed for lower wind speeds can boost capacity factors in lower wind resource areas, increasing the potential areas that are viable for wind deployment³⁷³.

With technologies considered ‘near future,’ wind turbines could approach the capacity factor of coal-fired power plants (average of 60 percent) at 140 m hub heights³⁷⁴.

Developing advanced materials for wind components and tower structures can make turbines lighter, more resistant to wear and tear, and more responsive to sudden shifts in wind speeds³⁷⁵. New blade designs and materials can enable larger rotor diameters and facilitate fabrication, transportation, and assembly³⁷⁶.

A current priority area for wind research is plant optimization. DOE is targeting significant LCOE reductions through systems-level research on the complex physics governing electricity generation from wind plants, leveraging high-fidelity modeling and high-performance computing platforms. For example, systems-level controls can monitor how wind turbines interact with air inflow and with one another, and use active wake control to mitigate energy and performance losses³⁷⁷.

Offshore wind generally offers stronger, more consistent winds and higher capacity factors than land-based wind in many parts of the country. With technical innovations in offshore wind platforms and turbine materials, offshore wind could achieve lower LCOE by siting plants in locations that allow developers to utilize more energetic wind resources. These sites are usually farther from shore or in deeper waters, which increases capital and O&M costs. More than 60 percent of the offshore wind resources within 50 miles of U.S. coasts are located in deep water, where traditional bottom-fixed foundations such as those already developed and deployed in Europe cannot be used³⁷⁸. DOE has supported research into several different types of floating

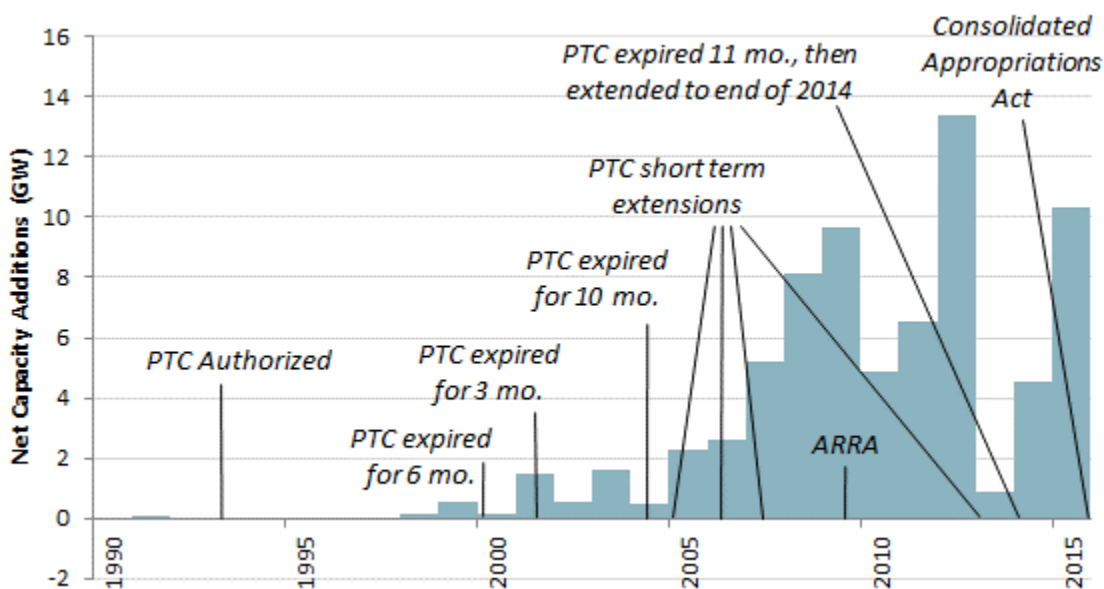
^{liv} In December 2015, NERC issued five general recommendations as part of its *Essential Reliability Services Task Force Measures Framework Report* that focus on the incorporation of these services into the design of variable generating resources in the future (NERC 2015c). Shortly thereafter, on February 18, 2016, FERC issued a Notice of Inquiry, Docket RM16-6000, seeking comment on the need for market reforms to support the provision of essential reliability services by all generators (FERC 2016).

foundations, which could have lower materials and installation costs than fixed-bottom foundations.

9.8 Development and Projected Future Deployment

Wind deployment has been sensitive to the availability of the PTC, and new builds declined significantly as recently as 2013 when the PTC temporarily expired (Figure 9-6). In December 2015, Congress included an extension of the PTC in its omnibus spending bill. The PTC currently offers qualified wind projects a \$.023/kWh tax credit and is now available until December 31, 2019, with a phase-down commencing construction clause for projects beginning after December 31, 2016³⁷⁹.

Figure 9-6. Historical annual wind capacity additions (GW), 1990–2015



Wind development has been sensitive to the availability of the PTC, with significant drops in buildout observed following expirations of the credit. Source: EIA 1990 and EIA 2016³⁸⁰.

State RPS policies are a driver of wind deployment, as wind energy is a cost-effective way for regulated utilities to achieve compliance. Roughly 54 percent of wind capacity built from 1998 to 2014 serves an entity with RPS mandates³⁸¹.

Because wind sales are generally contracted at a fixed price over 20 years in the form of a PPA, wind can also be used to provide a “hedge” against rising or uncertain natural gas prices³⁸². The continued decline in average levelized wind PPA prices, along with a continued rebound in wholesale power prices, left average wind PPA prices signed in 2014 (including the PTC) below the bottom of the range of nationwide wholesale power prices at approximately \$23.50/MWh. Wind PPA prices are most competitive with wholesale power prices in the interior region. The average price stream of wind PPAs executed in 2014 also compares favorably to a range of projections of the fuel costs of natural gas-fired generation extending out through 2040³⁸³.

Advances in wind power technologies are opening new markets. Higher towers allow developers to access higher quality resources or to expand wind development to new regions like the Southeast that typically have low-wind resources³⁸⁴.

The 5-year extension of the PTC for wind that occurred in late 2015 could help smooth out the construction glut expected for 2016, relieving pressure on supply chains, and could increase the expected cumulative installations between 2016 and 2021 by 76 percent, from 25 GW to 44 GW³⁸⁵. After the expiration of the PTC in 2019, the CPP’s Clean Energy Incentive Program could further boost wind installations, depending on how states draft their compliance plans. Additionally, RPS mandates, low LCOE, and the CPP will promote increased wind installations in the United States.

In the QER 1.2 Base Case, the outlook for wind generation is strong while the tax credits are available. Between 2017 and 2024, wind generation nearly doubles. In the QER 1.2 HOGH scenario, the 2017–2024 period of relatively strong development is increased due to higher natural gas price assumptions in this scenario (Table 9-2).

Table 9-2. QER 1.2 Base Case generation for wind (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Wind Generation (Land-Based)	178	433	592

Source: EPSA 2015³⁸⁶

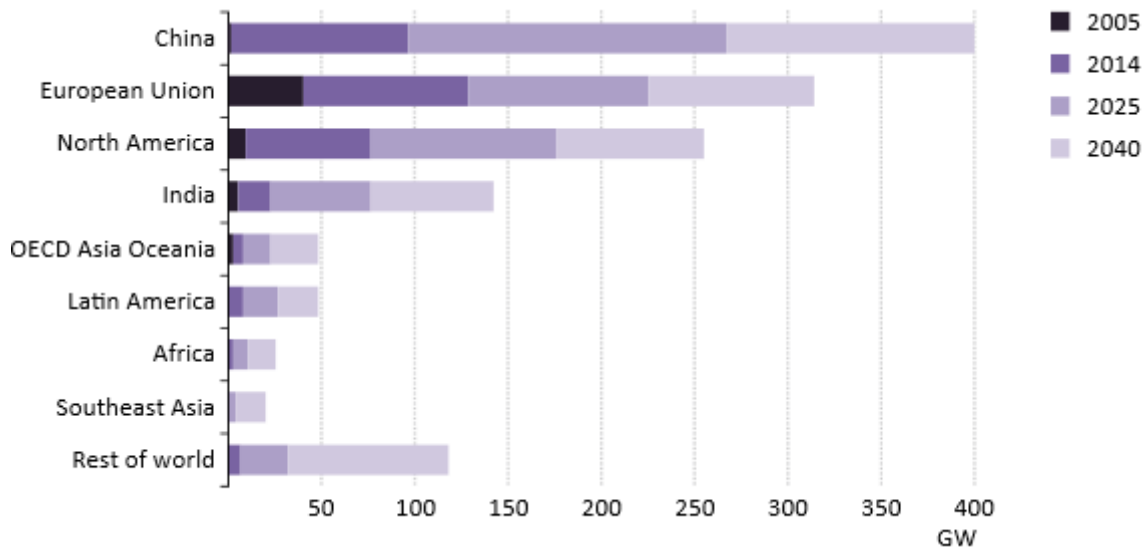
The climate agreement at COP21 in Paris will be a driver of wind and other clean energy installation worldwide if countries are to meet the goals set forth. To reach the goals of the 450 Scenario, nearly twice as much wind generation will be needed than the current policies will incent (Table 9-3). Between 2015 and 2024, China, the EU, and North America are expected to be the countries with the highest demand for wind installation (Figure 9-7).

Table 9-3. Global wind generation projections

	2013	New Policies		Current Policies		450	
		2020	2040	2020	2040	2020	2040
Wind Generation (TWh)	635	1,407	3,568	1,319	2,778	1,507	5,101
Percentage of Global Total	2.7	5.2	9	4.7	6.4	5.8	15

The 450 Scenario results in nearly twice as much wind generation as the Current Policies Scenario. Source: IEA 2015³⁸⁷.

Figure 9-7. Global wind power capacity installed (GW) by region in the New Policies Scenario



By 2025, China is projected to be the leader in installed wind capacity, followed by the EU and North America. Source: IEA 2015³⁸⁸.

10 Biopower

10.1 Technologies

There are three primary processes for producing electricity from biomass. Direct-fired plants typically combust biomass fuel in a boiler that turns a generator. Co-fired plants mix a portion of biomass fuel (typically up to 10 percent heat content) with a conventional fossil fuel (usually coal); they then produce electricity in a traditional plant—usually an ST/generator combination—that has been slightly modified to accept the biomass contribution. Gasification plants first heat biomass fuels without combustion in a special environment to create a syngas that is later combusted in a gas turbine or boiler. While some biomass gasification technologies have reached commercial use, there is still significant opportunity for further development of these technologies to reach higher levels of deployment³⁸⁹.

Biomass fuels include a broad range of sources, including wood and wood-derived fuels, black liquor (primarily pulp residuals in the paper production process), municipal solid waste (MSW), landfill gas (LFG), and others. Biopower plants are typically fully dispatchable and are generally dispatched as baseload generation if variable and fuel costs are low enough. Biopower plants can also be used for ancillary services to provide frequency regulation, contingency, and other reserves³⁹⁰. Depending on the technology, biopower can be a dispatchable and distributed resource³⁹¹.

Biopower plants that rely on direct combustion are often small so that they can be sited close to an appropriate fuel supply³⁹². They can also be used in combined heat and power applications depending on the need for auxiliary heating or cooling. Biomass fuel production can be an important engine of rural economic development, but there are also concerns about how to measure the life-cycle environmental impacts of different biomass fuel options. Currently, biopower plants are typically considered by State and Federal regulators to be “carbon neutral,” although some use conflicting definitions³⁹³. Efforts are underway to develop more nuanced classifications depending on how the fuel is grown, processed, and combusted, and on what consequential impacts result from its production³⁹⁴.

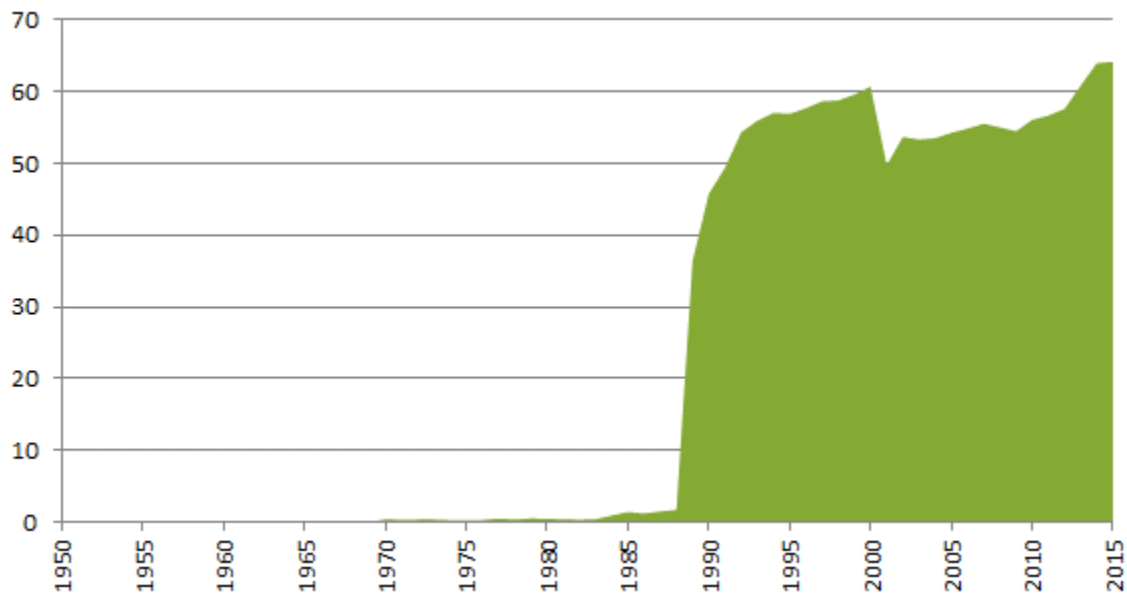
Biopower plants can use CCS processes^{lv} to limit GHG impacts, and they are the only power-generation option that can result in negative GHG emissions³⁹⁵. If CCS technologies used in the fossil-generation fleet are able to achieve cost and performance improvements, the biopower industry will also likely benefit³⁹⁶.

10.2 Operational Attributes and Fleet Characteristics

In 2015, dedicated biopower generation reached 64 TWh (Figure 10-1), which was 1.6 percent of total annual U.S. generation³⁹⁷. Operating plant capacity in 2014 for dedicated biopower plants consisted of 44 percent wood and wood derived fuels, 28 percent black liquor, 12 percent MSW, and 11 percent landfill gas, with the remaining 4 percent consisting of other types of biomass in solid, liquid, and gas forms, as shown in Table 10-1. Co-fired generation was 35 TWh in 2014. Currently, biopower makes up 12 percent of U.S. renewable generation³⁹⁸.

^{lv} CCS is a process that can be used on biopower and all fossil fuel power plants. We describe CCS technology under section 5.1 (in the chapter on coal) and in appendix A. There are some differences in how CCS applies to biomass, coal, or natural gas combustion but we limit our analysis here to the generic level as the differences go beyond the scope of this report.

Figure 10-1. U.S. biopower generation (TWh), 1950–2015



Source: EIA 2016³⁹⁹.

Table 10-1. Share of U.S. operating biomass capacity by subfuel type, 2014

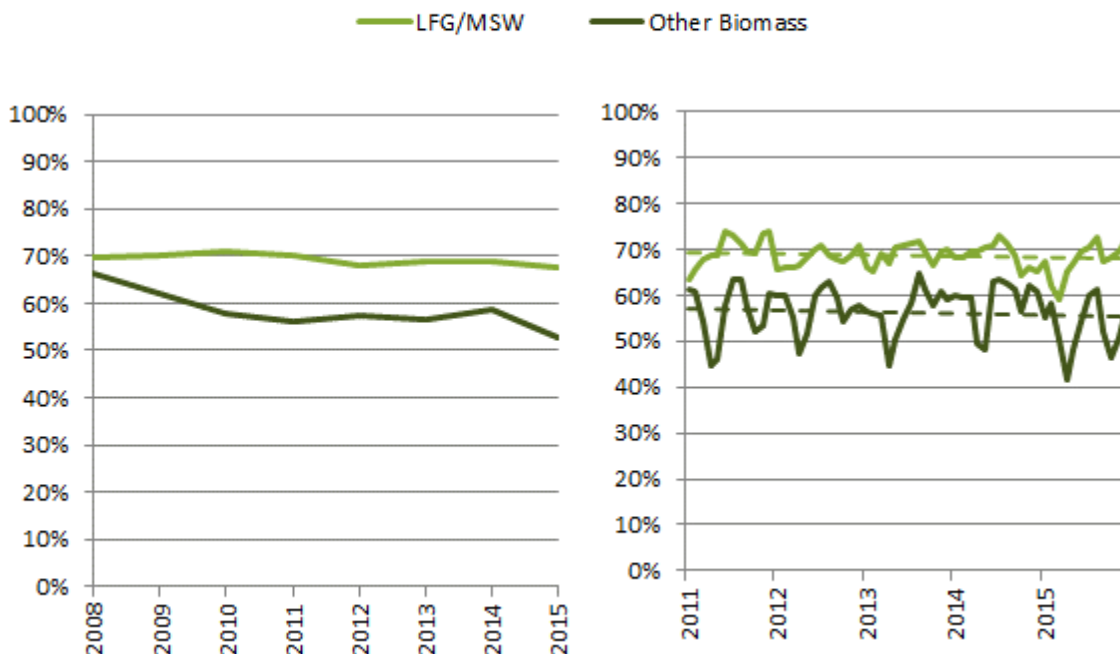
Biomass Category	Prime Mover	Number of Facilities (2012)	Name Plate Capacity (GW)	Annual Net Production (TWh)
EIA Tracked Feedstocks				
Wood and Wood-Derived Fuels	STG	186	8.3	43.1
Landfill Gas	ICE	275	2.1	11.0
Biogenic Municipal Solid Waste	STG	74	2.2	7.4
Other Waste Biomass	STG	37	0.8	2.9
Sub-Total from EIA Tracked Feedstocks		572	13.4	64.3
Other Biomass Feedstocks				
Black Liquor	STG	111	5.3	26.3
Co-Fired with Coal	STG	45	~ 5.0	35.0
Co-Fired with Fuel Oil	STG	13	< 0.1	0.2
Sub-Total from Other Biomass Feedstocks		169	10.3	61.5
Total		741	23.7	125.8

A variety of biomass fuels provide energy for biopower plants. Some of these feedstocks, like black liquor and landfill gas, would otherwise be considered waste^{lvi}. Source: DOE 2015⁴⁰⁰.

^{lvi} Note: STG refers to steam turbine generator, and ICE refers to internal combustion engine.

In the 2011–2015 time frame, the average monthly capacity factor of MSW and landfill gas plants was around 70 percent, while other biopower plants were lower, with a 55 percent average monthly capacity factor (Figure 10-2)⁴⁰¹. The availability factor of biopower plants is around that of coal-fired power plants in that they are available roughly 80-85 percent of the time⁴⁰². Reliability of biopower plants, especially those using gasification, can sometimes be a challenge. On a state-by-state basis, California had the highest installed capacity and generation from biomass in 2010 and 2014, followed by Florida (Figure 10-3).

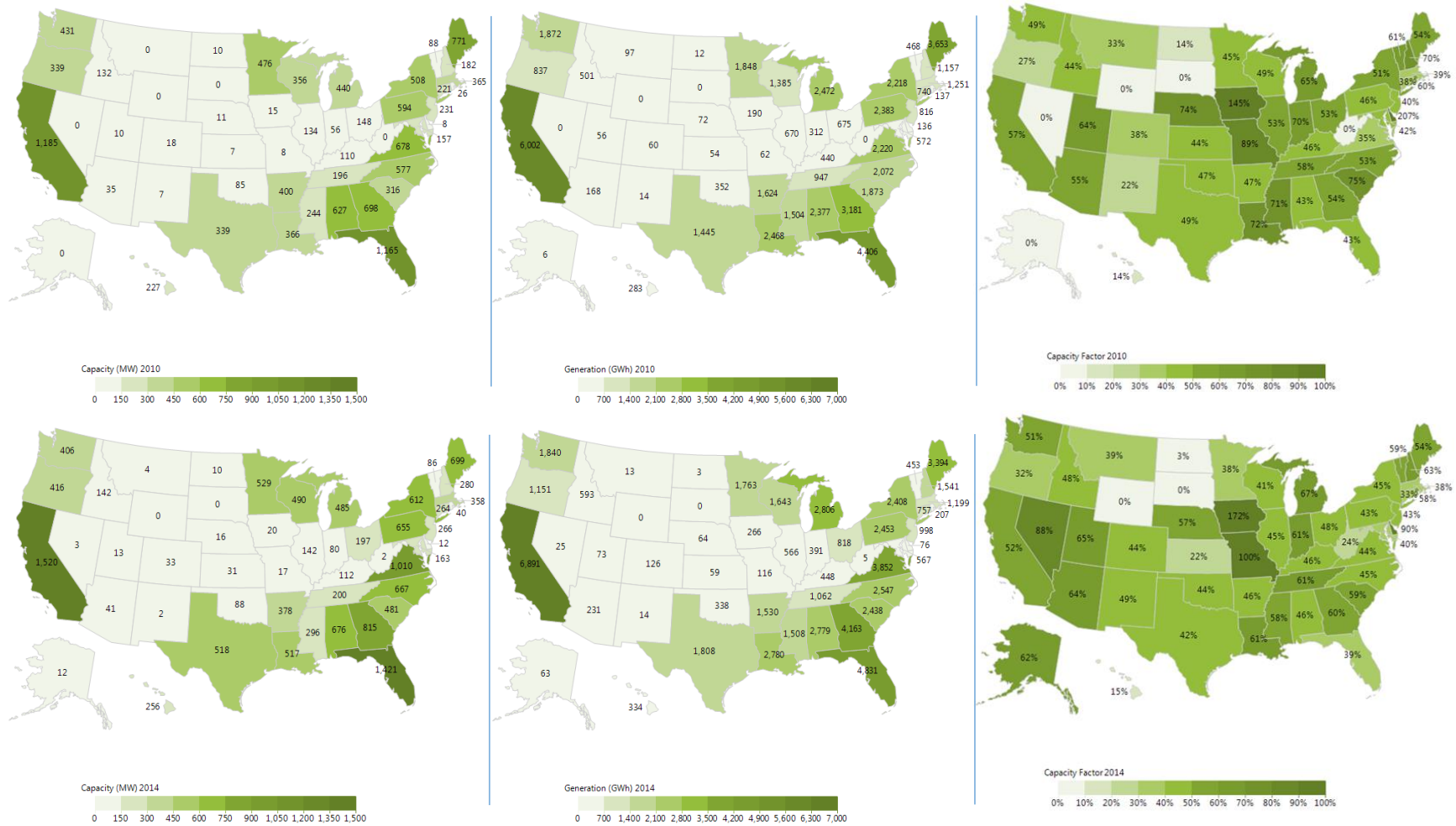
Figure 10-2. U.S. annual and monthly biopower generator capacity factors



The average monthly capacity factor of MSW and landfill gas plants was around 70 percent, while other biopower plants were lower with 55 percent average monthly capacity factor^{lvii}. Source: SNL 2015⁴⁰³.

^{lvii} Note: LFG refers to landfill gas.

Figure 10-3. Biomass capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

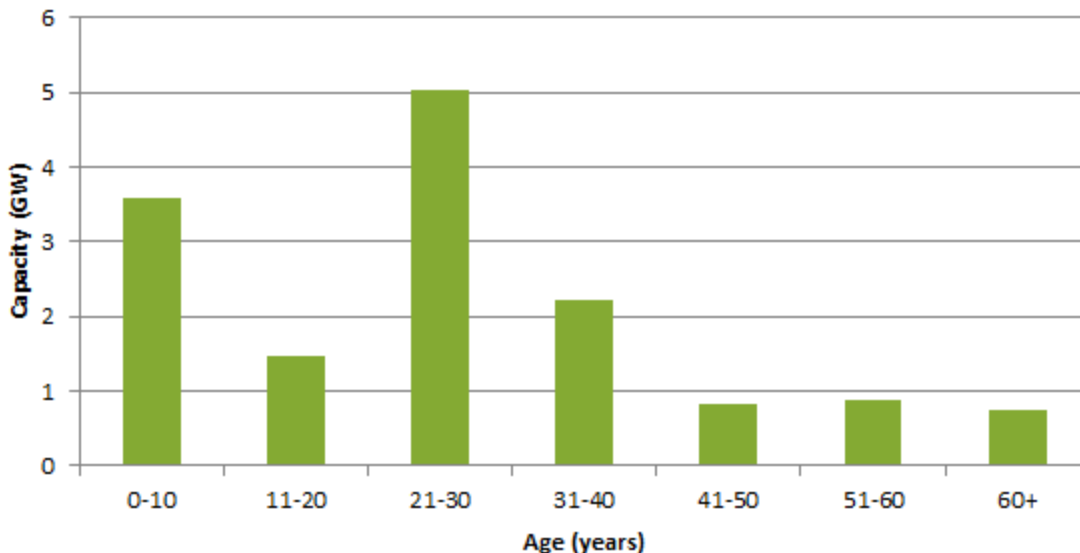


On a state-by-state basis, California had the highest installed capacity and generation from biomass in 2010 and 2014, followed by Florida^{lviii}. Source: EIA 2016⁴⁰⁴.

^{lviii} Note: Co-fired biomass is included in generation, but not capacity, so some capacity factors may be distorted. There is no way to separate the data to remove this distortion.

Direct and co-fired biopower are relatively young when compared to the rest of the U.S. thermal generation fleet and are thought to have the same operating life of 45 years (Figure 10-4)⁴⁰⁵. Roughly 70 percent of generators are less than 30 years old⁴⁰⁶.

Figure 10-4. Age profile of U.S. biopower generation fleet, 2014



About 70 percent of the U.S. biopower fleet is less than 30 years old with an expected lifetime of 45 years. Source: SNL 2015⁴⁰⁷.

10.3 Technology Costs

The LCOE for direct biomass generation is shown in Table 10-2. The LCOE for biomass is about on par with that for nuclear, but the expected range of prices is much wider.

Table 10-2. LCOE for new direct biomass generation (2013\$/MWh)

	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Biomass Direct	65.42	188.34	71.09	158.61	68.03	162.16

Current ranges of biopower technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015⁴⁰⁸. See appendix B for more information on LCOE calculations.

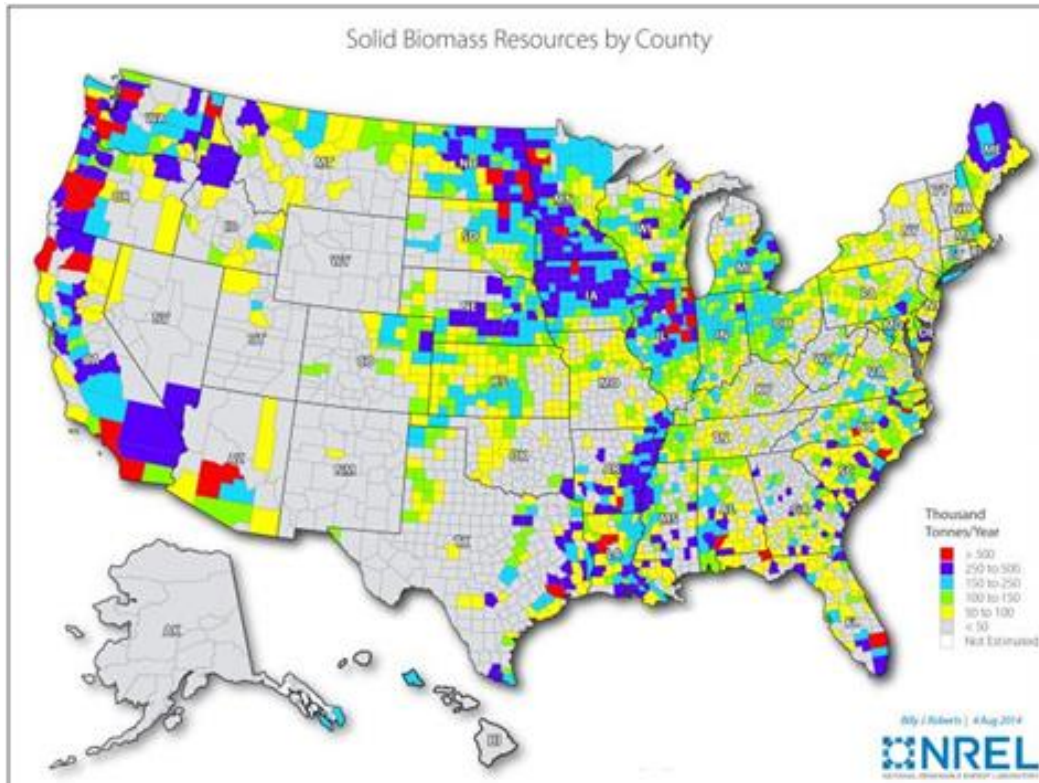
10.4 Fuel/Resource

The United States has a diverse range of solid biomass resources (Figure 10-5). The top fuels used for biopower generation in the United States are black liquor, wood waste, MSW, and landfill gas⁴⁰⁹. This section will focus primarily on these fuel types along with methane creation from waste water treatment plants (WWTPs). Use of biomass to create biofuels is outside the scope of this section as they contribute a negligible portion of the generation mix.

Black liquor is produced during the Kraft process in paper production⁴¹⁰. It is primarily made up of pulping residues and inorganic chemicals used during the process. It was considered a waste until the invention of recovery boilers, and now it is used to create steam for electricity

production⁴¹¹. Wood waste includes, but is not limited to, urban wood waste (tree trimming, construction wastes, wood chips, and pallets), mill residues, forest residues, and crop residues.

Figure 10-5. Solid biomass resources by county map



Solid biomass resources by county in the United States. Analysis includes the following feedstock categories: crop residues (2012), forest and primary mill residues (2012), secondary mill residues (2012), and urban wood waste (2012). Source: NREL 2015⁴¹².

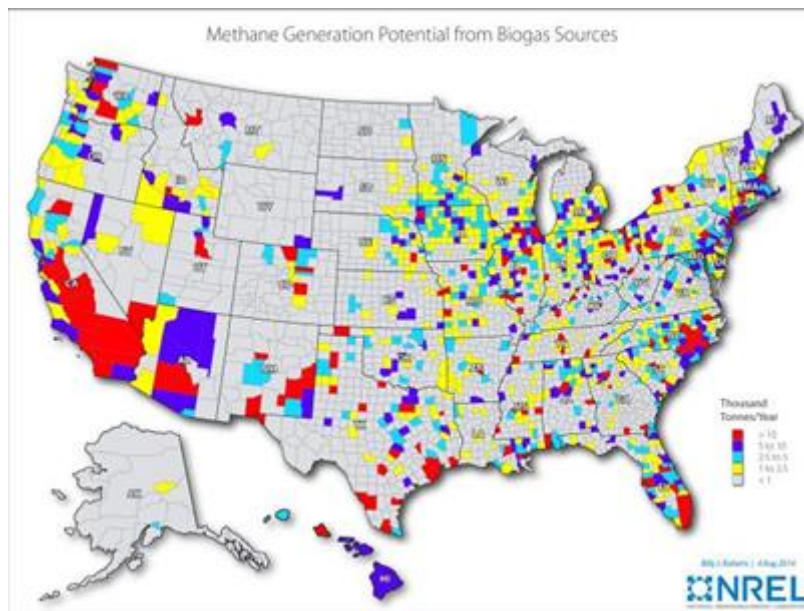
MSW involves the incineration of solid, biogenic wastes to produce energy. Many MSW plants sort waste before incineration to remove recyclable products, but some do not⁴¹³. About 13 percent of all collected municipal waste is burned at landfills to produce electricity and steam⁴¹⁴. Burning MSW can reduce the amount of material sent to the landfill by 87 percent; residual combustion products and ash are still sent to the landfill⁴¹⁵. MSW plants are often called waste-to-electricity plants.

Landfill gas is created during the anaerobic decomposition of organic materials in the MSW deposited in landfills and is made up of roughly 50 to 55 percent methane^{lix} and 45 to 50 percent CO₂⁴¹⁶. This landfill gas can be captured, treated to remove moisture and impurities, and burned to produce electricity and/or heat⁴¹⁷. Roughly 70 percent of landfill gas is burned in internal combustion engines to produce electricity, with the remainder being burned in CTs (generally for larger projects)⁴¹⁸. As of March 2015, there are 854 landfill gas facilities in operation, producing 2,765 million cubic feet per day of landfill gas⁴¹⁹.

^{lix} Roughly 1 million tons of MSW produces 0.43 million cubic feet of methane per day and will produce for 20–30 years. For reference, in 2012, 135 million tons of MSW were landfilled in the United States (EPA 2014a).

Another source of biogas is through processing of municipal wastes at WWTPs. Organic compounds in municipal waste are decomposed in an anaerobic digester to produce methane. As of 2015, 1,270 WWTPs in the United States use anaerobic digesters to produce biogas⁴²⁰.

Figure 10-6. Methane generation potential from biogas sources



This map of methane production potential includes the following biogas sources: landfills; animal manure; wastewater treatment; and industrial, institutional, and commercial organic waste. Source: NREL 2015⁴²¹.

Currently, there are not any domestic, large-scale dedicated feedstock (i.e., biomass that is grown specifically for power production) biopower plants, but there is some potential in the future for large-scale development, especially when combined with CCS.

Transporting biomass for electricity production can be a large part of the per-unit fuel price, especially due to the low energy content of biomass⁴²². Biomass is mostly transported via trucks, making short hauls for urban wastes. In some cases, like pulp and paper mills, there is no transportation required as the biomass fuel is consumed onsite. MSW is transported during the waste collection process and is generally consumed on or near a landfill. Likewise, landfill gas and biogas from WWTPs are transported short distances within landfill boundaries to be used either onsite or injected into pipelines for use elsewhere.

Biomass fuel prices are dependent on the moisture content contained in the biomass, the amount of processing required, transportation costs, and acquisition costs⁴²³. Fuel prices are also dependent on source, with agricultural wastes generally the least expensive and dedicated feedstocks the most expensive⁴²⁴. Some biomass stocks (such as MSW) have zero cost as they are waste streams.

10.5 Environmental Impacts

10.5.1 Upstream Extraction/Manufacturing

A majority of biopower fuels currently used in the U.S. electricity system are derived from wastes. Black liquor, wood waste, MSW, landfill gas, and waste water methane all are derived from a material that is either disposed of or emitted to the environment. Processing and cleaning wood waste may use some energy and water to remove any impurities. For fuels derived from the waste feedstocks mentioned above, the land-use impacts are assumed to be zero because the land use is associated with the primary production activity and not with the biomass feedstock production.

10.5.2 Emissions and Environmental Impact

Biopower generation offers lower SO_x, NO_x, and CO₂ emissions when compared to coal-fired generation⁴²⁵. In co-fired systems, substituting biomass for coal can reduce SO_x emissions of coal plants. However, particulate matter and heavy metal emissions can rise depending on the feedstock and fuel processing method⁴²⁶. Particulate matter emissions can be controlled by a mechanical collector and a baghouse or electrical precipitator⁴²⁷. With co-fired plants, the addition of biomass may affect the quality of the fly ash that is produced from normal coal combustion and impede its sale in the cement and drywall production process⁴²⁸.

There is controversy about whether biopower should be classified as a carbon-neutral energy source. Carbon neutrality for biomass is dependent on the feedstock type, the management and procurement of feedstock, the feedstock transportation method, the generating technology, and the time frame in which the feedstock needs to be replenished⁴²⁹. Sustainable production of biomass is important in determining if biopower is carbon neutral⁴³⁰. See the QER 1.2 Environment Baseline Vol. 1 – *Greenhouse Gas Emissions from the U.S. Power Sector: Baseline and Outlook to 2040* GHG baseline document for further analysis and discussion of this topic.

In the case of landfill gas, the combustion of methane gas creates CO₂, but the atmospheric warming potential of methane is greater than CO₂, leading to reduced amounts of overall GHG emissions compared to releasing methane into the atmosphere. Bioenergy with CCS can reduce atmospheric CO₂⁴³¹. It is one of the only energy sources currently available that can have negative CO₂ emissions with CCS over a lifetime of generation.

10.6 Constraints

One of the main challenges in utilizing biopower is securing a sufficient supply of feedstocks that have acceptable impacts on the environment, food supply, and other ecosystem considerations. Biomass availability for power production can be limited by geographic availability constraints, competing uses (e.g., liquid fuel production), and the increasing severity of droughts⁴³². The biopower industry also faces uncertainty from an evolving life-cycle GHG methodology that could jeopardize its current classification as a carbon-neutral or carbon-negative source of electricity, particularly when including direct and indirect land-use change effects⁴³³. Fundamental biopower technology breakthroughs—including more productive and acceptable feedstock sources, more efficient generators and cost-competitive CCS—are needed to catalyze the deployment of biopower to a level that competes with other sustainable, reliable, and economic power generation options.

For combined heat and power applications, integration challenges could depend on the demand profile for heat and the ratio of heat-to-power it was designed to deliver. Also for biopower combined heat and power applications, securing demand for steady heat supply, especially when sited in remote locations close to feedstock supply, can sometimes be challenging.

For expanded development of biopower, competition may emerge with biofuels for land, water, and feedstock use. Some argue that feedstock use for biofuels will be more profitable for feedstock producers, leading to less biomass supply dedicated to electricity production⁴³⁴.

Siting impacts of biopower plants are similar to coal and natural gas power plants, but plants are generally distributed geographically close to feedstocks to cut down on transportation costs⁴³⁵. With increased particulate matter production, there are concerns about siting biopower plants close to population centers.

10.7 Technical RDD&D

Biopower generation technologies have the unique potential of being carbon-negative depending on design of the generator, type and management of the feedstock, and other operational considerations⁴³⁶. This could become a very valuable capability depending on how global carbon mitigation policies unfold. Other benefits of biopower include being dispatchable, serving as an engine for rural economic development in feedstock production, diverting organic waste from landfills, and assisting regular forest maintenance⁴³⁷.

One core area of research for biopower is advancing feedstocks that have high yields and energy content while reducing environmental impact. This research is focused on foundational biogenetics, soil chemistry, and pretreatment of biomass, but there are also opportunities to improve techno-economic models to characterize the supply chain and system sustainability⁴³⁸.

Direct biopower technology is fairly mature, although some engineering problems, such as corrosion and cost-effective emissions control, remain as barriers⁴³⁹. Ongoing RDD&D in materials chemistry may help address these barriers.

Biomass gasification fluidization reactors are a well-known technology, although there are technical challenges (e.g., filtering contaminants and enriching syngas quality). In the short to medium terms, fluidization appears to be one of the gasification processes with the most techno-economic potential⁴⁴⁰. Some current gasification systems have relatively high capital costs due to nonstandardized plant designs. Efforts are needed to lower O&M and balance-of-plant costs while improving durability. These issues depend on the type of feedstock and the specific technology employed⁴⁴¹.

10.8 Development and Projected Future Deployment

The biopower industry expanded significantly during the 1990s following the passage of PURPA in 1978, which required utilities to purchase generation from “qualifying facilities” like biopower at their avoided cost^{lx} (Figure 10-7). More recently, biopower generation growth since 2005 has primarily occurred due to new capacity additions or conversion of coal plants to

^{lx} Avoided cost is the expense that utilities would have incurred to generate additional electricity. During the 1980s, avoided costs were relatively high, so this sent a signal for more qualifying facilities to emerge.

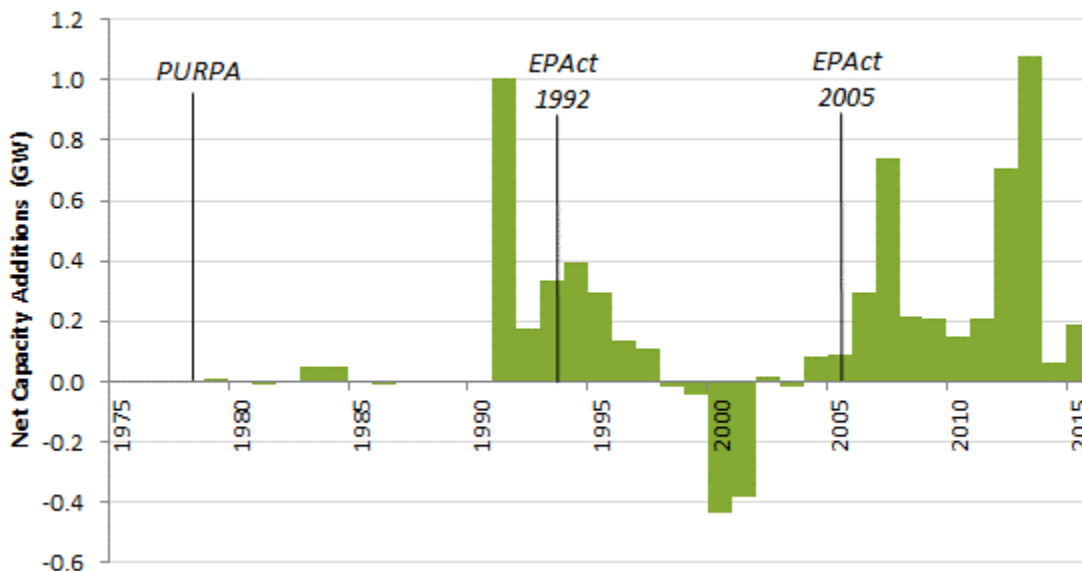
biomass in the southeastern parts of the country in order to meet voluntary or required renewable generation goals or to improve resource diversity⁴⁴².

Biopower plants are currently eligible for “renewable energy attributes” and the associated renewable energy credits and tax incentives in most states⁴⁴³. Some states, however, have specific requirements for carbon neutrality of biopower plants to qualify for these tax credits. EPA is in the process of reevaluating its framework for biogenic carbon accounting. “Qualifying biomass” is allowed to be included in state compliance plans in the CPP, but it remains unclear what forms of biomass will be deemed acceptable⁴⁴⁴.

Closed-loop biomass, defined as “any organic material from a plant which has been grown exclusively for bioenergy use,” is eligible for the full value of the renewable electricity PTC, currently \$23/MWh⁴⁴⁵. Open-loop systems (which are all other forms of biomass) are eligible for the PTC at half that level, currently \$11/MWh. The December 2015 omnibus budget bill passed by Congress extends the PTC for qualified generators for projects that commence construction before 2017⁴⁴⁶.

Biopower is currently dependent on incentives to lower the cost of generation. Policies such as tax incentives, clean renewable energy bonds, RPS, and the CPP may drive more biopower installation. Competitive financing is often dependent on biopower facilities’s ability to provide combined heat and power, which may impact the siting of power plants (plants need to be close to heating needs).

Figure 10-7. Historical annual biopower capacity additions and retirements (GW), 1975–2015



Biopower capacity additions grew modestly in the early 1990s, and then again since 2006. Source: EIA 1990 and EIA 2016⁴⁴⁷.

Note: EPAAct means Energy Policy Act; PURPA means Public Utility Regulatory Policies Act.

Depending on the overall emission impacts of biopower and the reduction of CO₂ entailed in the CPP, biopower may be utilized to comply with regulations. In the QER’s Side Case, more biopower is deployed than in the QER1.2 Base Case (Table 10-3).

Table 10-3. QER 1.2 Base Case Generation for Biopower (TWh), 2014-2040

	2014 (Base Case)	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
MSW	23	24	23
Wood & Other Biopower	40	62	80

Source: EPSA 2015⁴⁴⁸

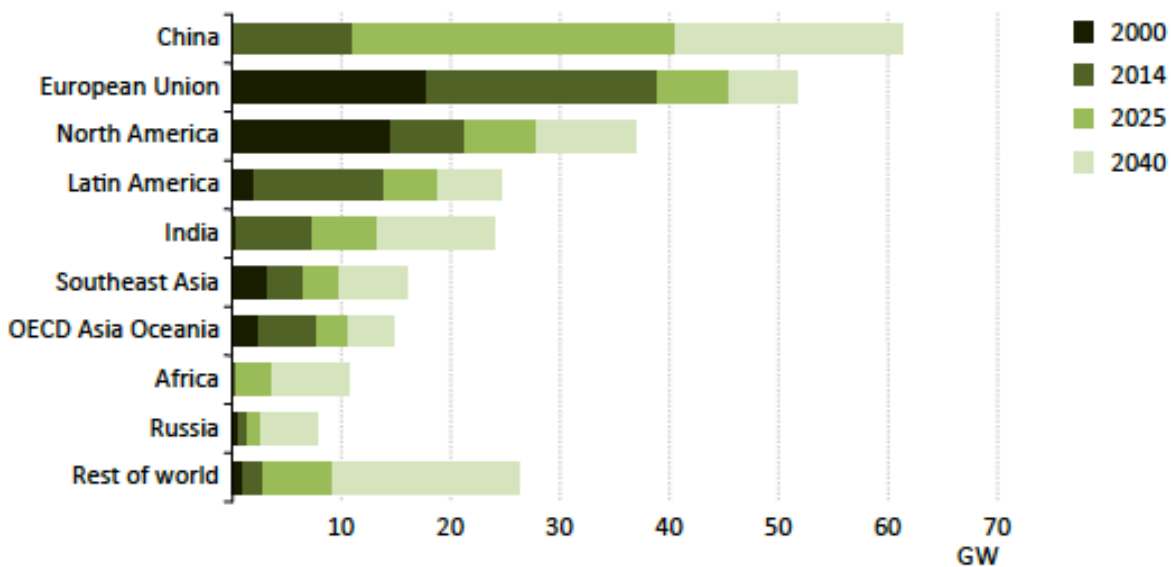
Global growth of biopower is expected to be modest compared to other technologies according to IEA’s WEO 2015 (Table 10-4, Figure 10-8).

Table 10-4. Global bioenergy generation projections, 2013-2040

	2013	New Policies		Current Policies		450	
		2020	2040	2020	2040	2020	2040
Bioenergy Generation (TWh)	464	728	1,454	717	1258	732	2077
Percentage of Global Total	2	3	4	3	3	3	6

The 450 Scenario could lead to twice as much bioenergy compared to current policies, but the overall contribution of bioenergy is expected to be very small. Source: IEA 2015⁴⁴⁹.

Figure 10-8. Projected biopower capacity additions (GW) in the New Policies Scenario of the WEO



In the 2014–2025 timeframe, China will have the largest buildout of biopower, surpassing the EU. Source: IEA 2015⁴⁵⁰.

11 Solar

11.1 Technologies

There are two primary types of solar generation technology: PV and CSP. PV modules use semiconductors to convert sunlight directly to electricity, as described further in appendix A. A variety of silicon, thin film, and more novel PV technologies exist and are under development. Modules can either be fixed, track along a single axis, or track along two axes. Sun-tracking increases the power output of modules but also requires increased capital and O&M costs. PV plants can range in size from a few kW (distributed) to hundreds of MW (utility-scale).^{lxi}

CSP uses an array of mirrors to concentrate solar heat at a liquid medium to capture thermal energy from the sun's radiation. This thermal energy is used to create steam to drive a turbine. There are two main designs currently used for CSP (solar troughs and power towers), but other options also exist. CSP plants can include thermal storage, which allows them to provide power even after the sun goes down and add flexibility to the grid. CSP plants are generally large in size in order to create enough steam to power a turbine. Plant capacities are generally 10–300 MW.

Solar PV is considered a variable generation technology and can only produce power during daylight hours. Output from modules is dependent on the time of year and weather conditions. Transient clouds may impact production as well. Maximum PV production occurs for a few hours before and after solar noon, which typically coincides with periods of high electricity demand during the day (especially in the summer with high cooling needs). However, increased solar installations can change the net load shape for utilities and change how other sources of electricity are dispatched⁴⁵¹. Geographically diverse solar projects can also be used to lessen the impacts of production variation for PV projects. CSP also produces power at peak periods, and thermal storage can allow for load smoothing and production after the sun goes down.

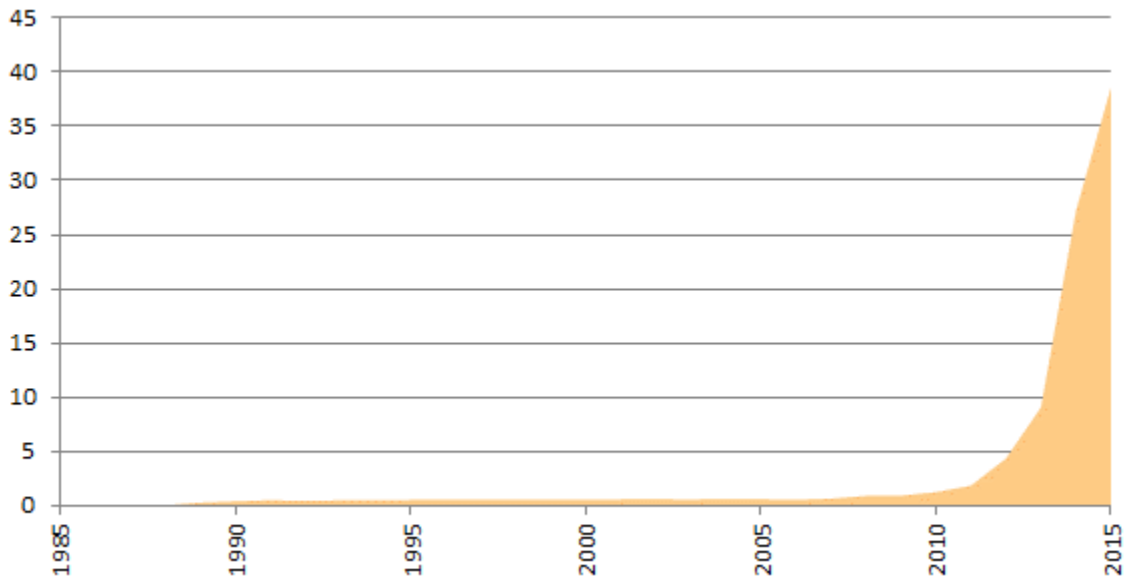
11.2 Operational Attributes and Fleet Characteristics^{lxii}

Solar power currently contributes less than 1 percent to the total U.S. generation of electricity (EIA 2015q). Solar generation is growing rapidly in the United States but from a very small base. Utility-scale solar (PV and CSP) generation grew from less than 0.5 TWh in 2010 to 26 TWh in 2015 (Figure 11-1). The capacity and generation values discussed in this section focus primarily on utility-scale solar (defined as having 1 MW or greater capacity); data on distributed PV generation only became available through EIA beginning in November 2015 and starts from the year 2014⁴⁵². Distributed solar PV has also experienced significant growth in recent years (Figure 11-2). As shown in Figure 11-3, distributed solar accounted for 32 percent of total solar generation, and also represented 42 percent of total solar capacity, as of June 2016. Still, distributed PV accounted for only 0.3 percent of total net generation, about 12 TWh, in 2015⁴⁵³.

^{lxi} Distributed PV installations are defined by EIA as those that have a capacity of less than 1 MW and that are on the customer side of the meter (EIA 2015g).

^{lxii} All generation and capacity numbers for solar PV included in this section are in units of alternating current (AC) generation or capacity.

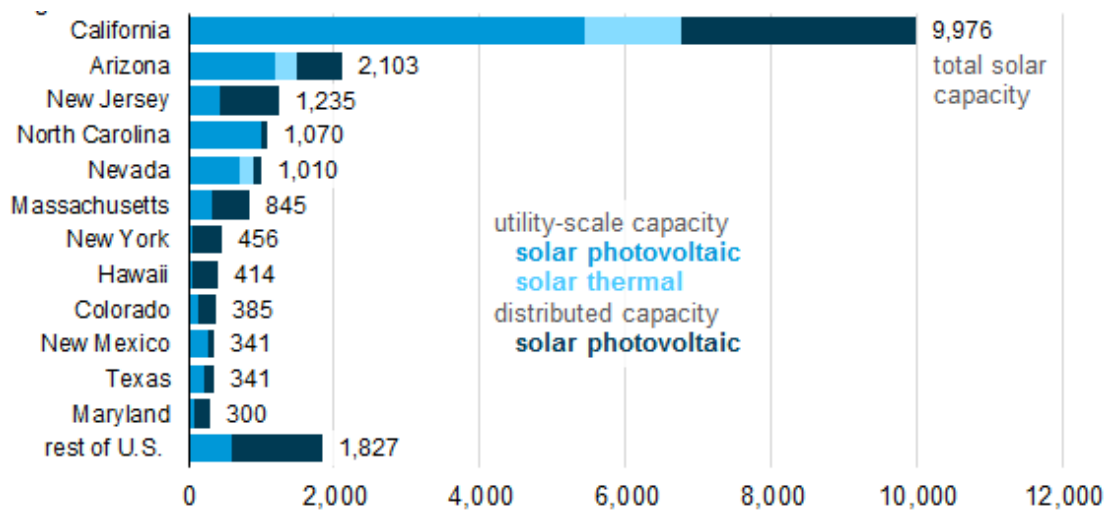
Figure 11-1. U.S. solar generation (TWh), 1985–2015



Source: EIA 2016⁴⁵⁴.

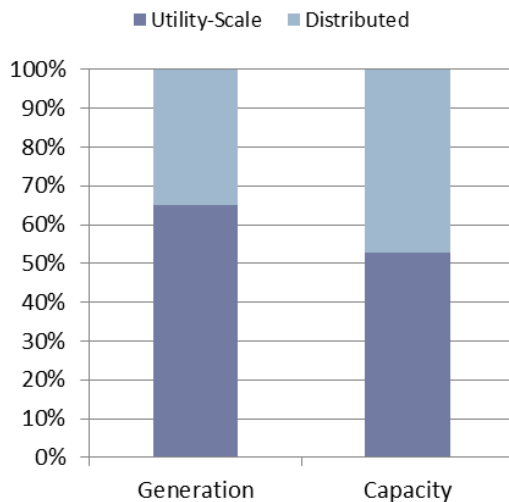
Note: This includes both utility-scale and distributed solar starting in 2014.

Figure 11-2. Solar electricity generating capacity (MW), November 2015



Source: EIA 2016⁴⁵⁵.

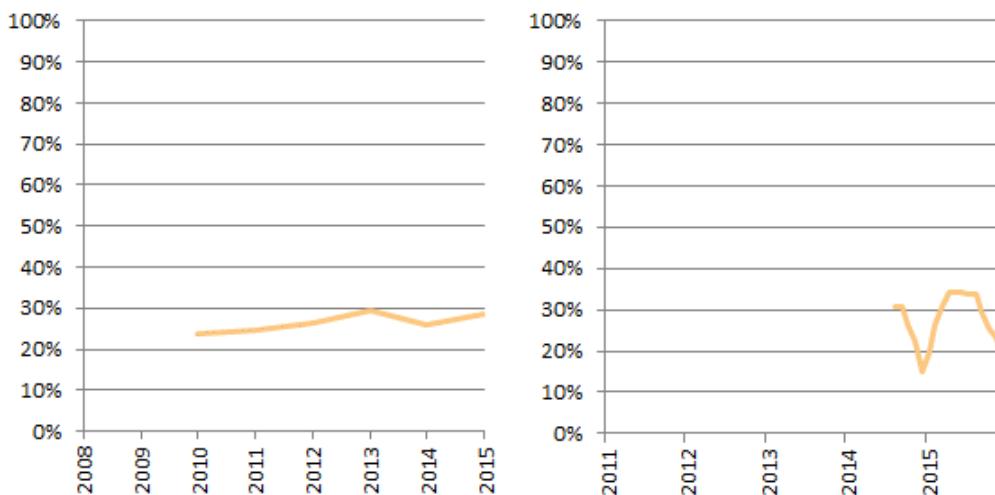
Figure 11-3. Share of U.S. operating solar capacity and generation by utility-scale vs. distributed, 2014



Solar generation includes utility-scale PV, distributed PV, and CSP. Total solar generation reached 18 TWh in 2014, accounting for 0.7 percent of the nation’s total. Distributed PV generation accounted for 0.2 percent of the total, but was much higher in some regions of the country. Sources: EIA 2016a; EIA 2016⁴⁵⁶.

The average annual capacity factor for utility-scale PV solar as of 2015 is around 27 percent, but this can change (15 to 34 percent) with the season (Figure 11-4)⁴⁵⁷. Solar PV and CSP production can be impacted by dirt accumulating on panels and can potentially lead to a 10 percent reduction in power production. PV modules generally have a power degradation rate of 0.5 percent per year, but this degradation eventually tapers down over the life of the module⁴⁵⁸.

Figure 11-4. U.S. annual and monthly utility solar PV generator capacity factors

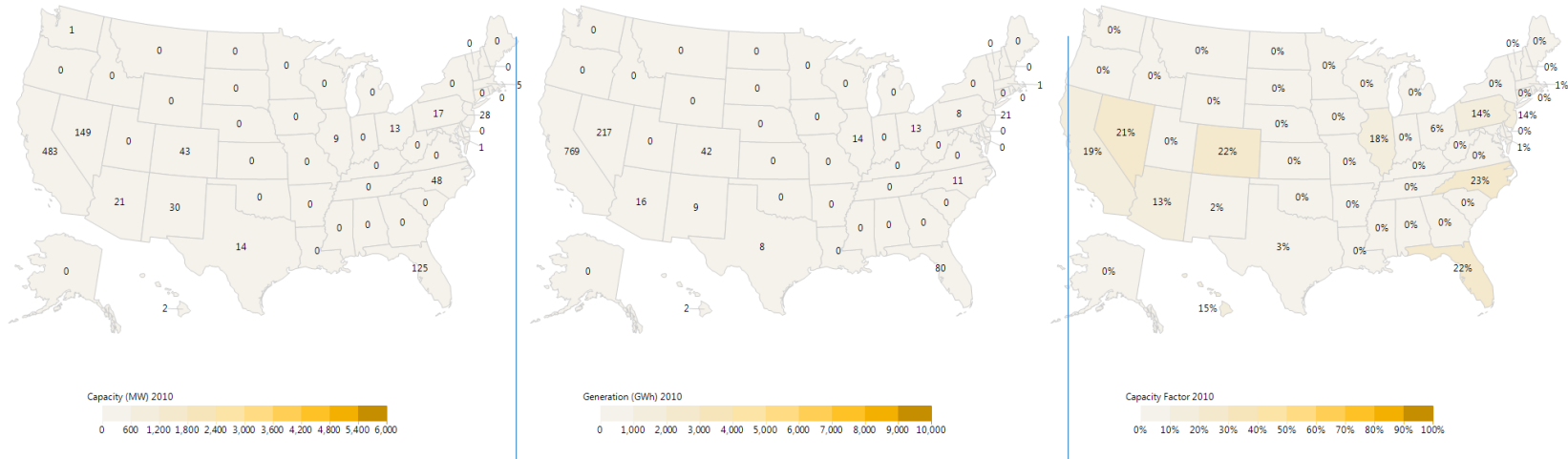


The average annual capacity factor for solar increased by about 20 percent between 2010 and 2015. The capacity factor can change significantly (15 to 34 percent) with the season. Sources: SNL 2015⁴⁵⁹.

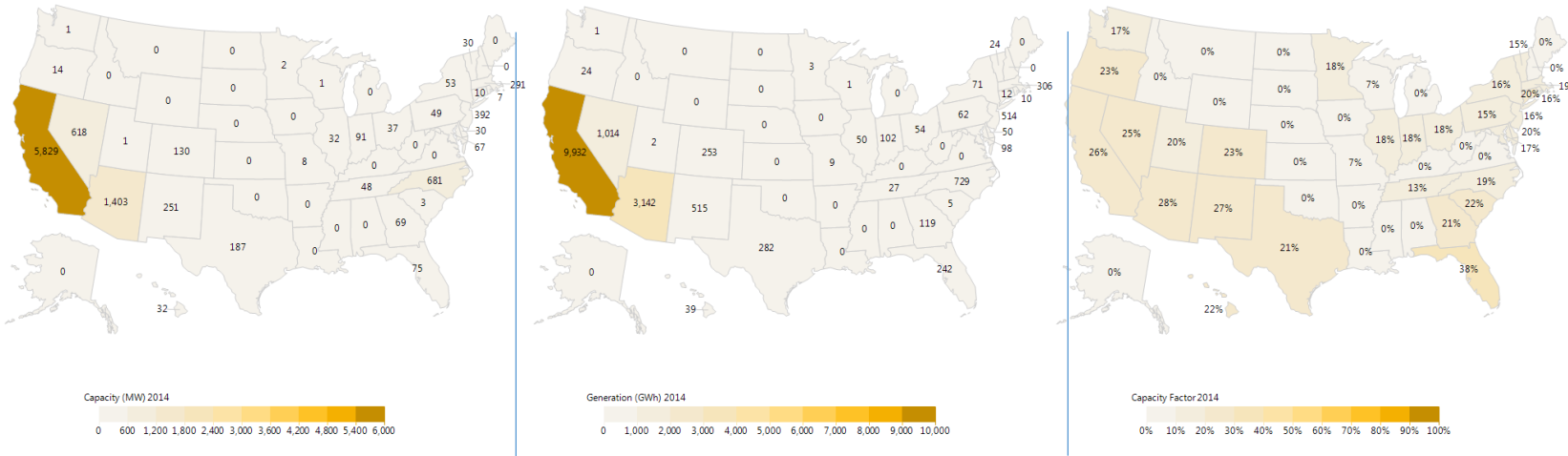
Between 2010 and 2014, 1.3 GW of CSP capacity was installed in the United States. Of this total, 71 percent was installed in California and 61 percent was installed in 2014, the largest year for CSP deployment to date. As of 2014, there were still many states without any installed utility-scale solar capacity, which are generally located throughout the central and southeastern United States. California had the highest installed utility-scale solar capacity and generation in 2014, followed by Arizona, Nevada, and North Carolina (Figure 11-5). Many states had a rapid growth in capacity between 2010 and 2014.

Figure 11-5. Utility-scale solar capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom, 2014.

2010



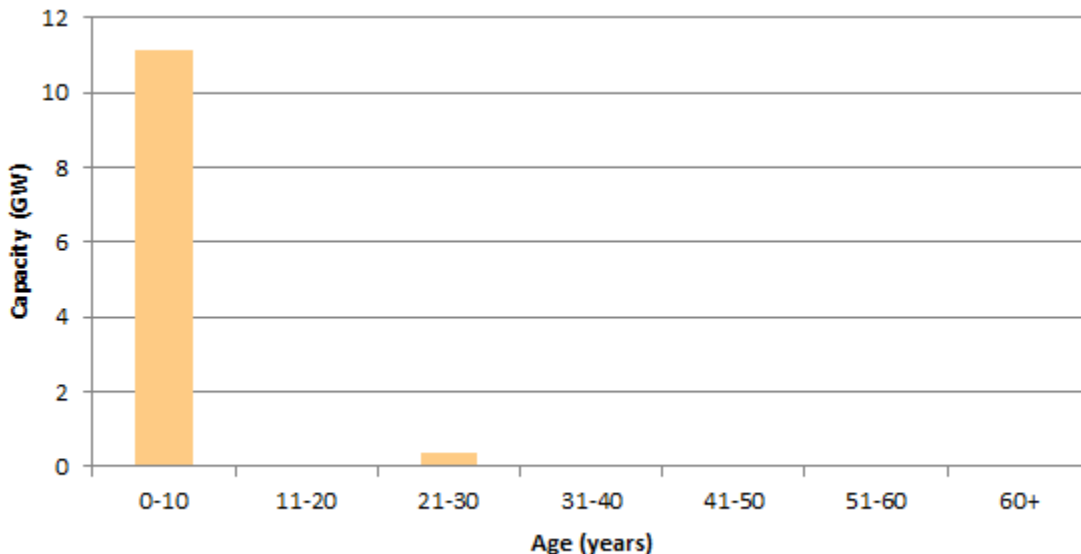
2014



California had the highest installed capacity and generation from utility-scale solar in 2014, followed by Arizona, Nevada, and North Carolina. Many states had a rapid growth in capacity between 2010 and 2014. Source: EIA 2016⁴⁶⁰.

PV modules come with a 25- to 30-year lifespan, while the inverters typically have a 10- to 2-year lifespan⁴⁶¹. However, a majority of solar installations have been constructed within the past 2 years, so there is little data on long-term lifespan and performance (Figure 11-6)⁴⁶². CSP plants are modeled to have a 30-year life⁴⁶³. However, this assumption is simply a parameter for projecting economic pro forma, and such plants can conceivably be operated indefinitely with regular maintenance and equipment replacement.

Figure 11-6. Age profile of U.S. solar generation fleet, 2014



The majority of solar generators are less than 10 years old. Source: SNL 2015⁴⁶⁴.
 Note: This includes only utility-scale capacity, which is defined as 1 MW or greater.

11.3 Technology Costs

The LCOE for solar generation from utility PV and from CSP is shown in Table 11-1. The range of values for the LCOE of utility PV is lower than for CSP, although both types of solar generation can experience a wide range in LCOE. The range for solar PV is within the LCOE range for land-based wind, although probably higher on average. Solar CSP is closer in LCOE to offshore wind.

Lazard’s cost ranges for utility-scale solar directly correlate to improved capacity factors. Lazard’s utility PV capital costs are higher for the low LCOE estimate because they assume that the higher cost pays for improvements in the capacity factor (e.g., fixed-tilt vs. single-axis tracking), while NREL’s and EIA’s values only represent single-axis tracking, and wider ranges are due to variations in regional resources. The result is a tighter range for Lazard for utility-scale solar.

Table 11-1. LCOE for new solar generation (2013\$/MWh)

	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Utility PV	80.00	430.52	54.94	171.03	46.06	132.61
CSP*	140.20	1,271.89	82.61	207.35	104.44	249.46

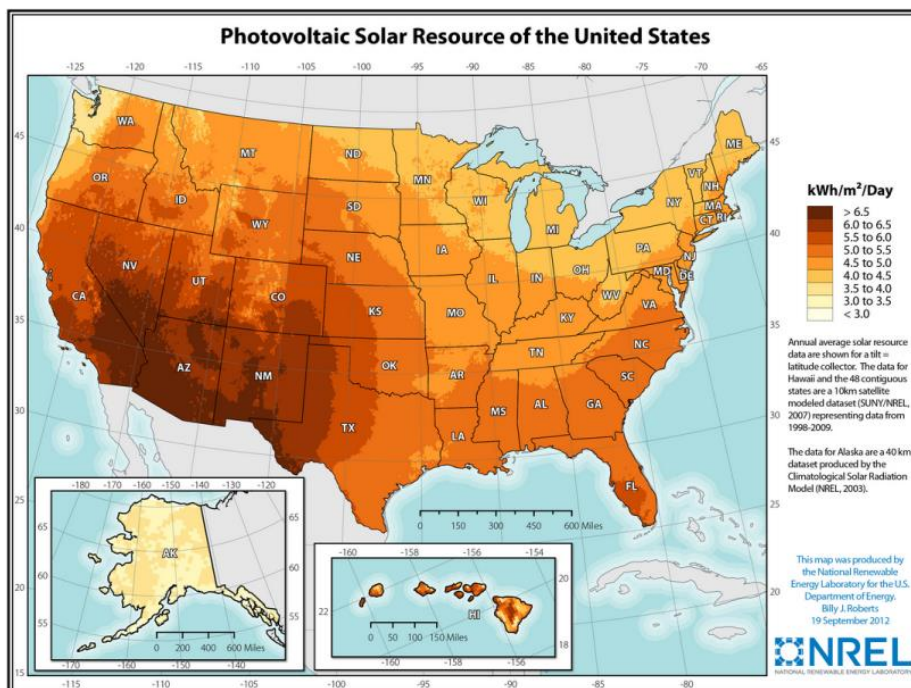
Current ranges of solar technology prices using cost assumptions from three sources: *EIA 2015, no storage; NREL 2015 and Lazard 2015, with storage⁴⁶⁵. See appendix B for more information on LCOE calculations.

Please refer to section 3.4.1 for further discussion on the methodologies and assumptions used to calculate these LCOE values.

11.4 Fuel/Resource

Figures 11-7 and 11-8 detail the solar resource in the United States for both PV and CSP applications. Generally, the southwestern United States has the best solar resources for both PV and CSP technologies; this is especially true for CSP, which relies on direct radiation, whereas PV can use both direct and diffuse radiation. The estimated PV resource is dependent on tilt and tracking technology. The solar resource varies greatly by location, and both latitude and longitude matter. At any given location, the incident radiation from the sun changes substantially by season and year to year depending on weather patterns.^{lxiii}

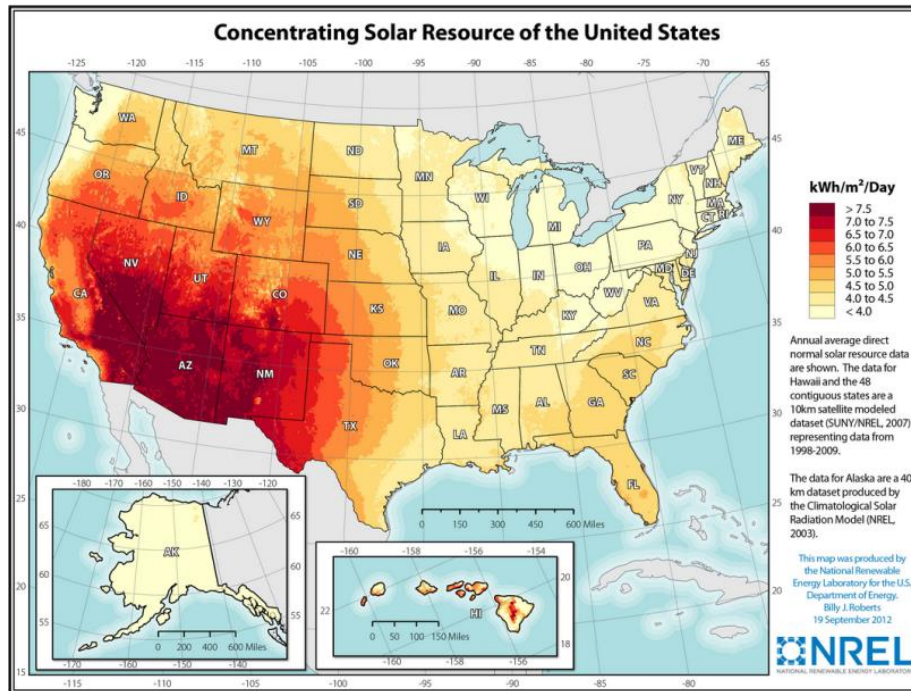
Figure 11-7. PV solar resource of the U.S.



The solar PV resource is best in the southwestern United States, with good resources spanning most of the southern states. Source: NREL 2015⁴⁶⁶.

^{lxiii} The solar irradiance varies roughly ± 10 percent about the average irradiance for each state, although this also varies from state to state based on geographic location.

Figure 11-8. Concentrating solar resource of the U.S.



The best CSP resource is located in the southwestern United States, centered around Arizona. Source: NREL 2015⁴⁶⁷.

11.5 Environmental Impacts

11.5.1 Upstream

Different solar PV cell technologies use different types of materials, which have varying environmental concerns. See appendix A for further discussion of the PV technologies. Materials for solar cell production need to be mined, and environmental impacts will be similar to ferrous mining operations. Some solar cell materials for certain thin-film PV technologies (such as cadmium and telluride) are toxic and need to be handled safely to prevent contamination of workers and the environment. The toxic nature of these materials needs to be considered when disposing modules at the end of life as well. During production of certain solar cells, many hazardous chemicals are needed to refine, polish, and dope the material, and 50 percent of material is lost during the sawing process⁴⁶⁸.

Manufacturing of solar cells is energy intensive and is often the largest source of GHG emissions during life-cycle analysis. PV module manufacturing, production, and installation result in emissions of, on average, 40 lb of CO₂/MWh⁴⁶⁹.

11.5.2 Emissions and Environmental Impact

After manufacturing and installation, PV and CSP plants do not produce any CO₂ and have zero marginal fuel costs. Life-cycle CO₂ emissions on a per kWh basis from PV and CSP plants are roughly an order of magnitude less than CO₂ emissions from natural gas plants⁴⁷⁰.

Utility-scale projects can also be located in the desert environments of the southwestern United States and could have impacts on desert habitats and endangered desert species. Utility-scale developers in these areas must complete environmental review procedures to assess their impact on desert environments.

11.6 Constraints

Certain non-silicon based thin-film solar cell materials, such as tellurium and indium, are rare earth elements. While material availability will likely not be a limiting factor of total PV deployment, PV production of certain technologies could be affected by global supply⁴⁷¹. Rare earth elements are simply less abundant in the earth's crust. Since they are a potential byproduct of minerals processing (such as phosphorous and soda-ash), it simply comes down to economics. Presently, China is producing rare earth elements for lower cost than is possible in the United States. Silicon solar cells have an advantage in this respect, as silicon is abundant in the earth's crust. Also, balance-of-system materials are dependent on global material supply chains and prices.

PV for residential scale can be installed on the rooftop of the home without requiring any additional land area. Commercial-scale PV is often installed on the rooftop of the building and may require only a small land area for the inverter adjacent to the building. Utility-scale projects are located in desert environments in the United States, and there has been concern about destroying desert habitat and impacting endangered desert species⁴⁷².

CSP plants often require large amounts of land, generally in desert climates. A source of water for cooling and steam production is needed and can be an issue for large-scale development in arid regions. There have also been concerns over power towers resulting in bird deaths, as birds can fly through the heliostat field and be burned; however, proper procedures can reduce these mortalities⁴⁷³.

As PV modules produce DC power, inverters are needed to convert output to AC so that it can be incorporated into the grid. Smart inverters can provide several services to assist in the integration of PV generation. Such services include frequency and voltage disturbance ride-through, voltage and ramping control, and reactive power control⁴⁷⁴. Inverters can also limit their active (i.e., real) power output and control their power ramping to maintain system stability. Voltage and ramping controls can be programmed as a function of grid voltage or frequency or can be triggered remotely. Ramping can also be set as a maximum rate. Inverters can provide reactive power injection or absorption. This function, when coupled with an algorithm that can rapidly respond to grid conditions, can provide stability for the distribution grid⁴⁷⁵.

Frequency and voltage disturbance ride-through allows PV systems to continue to operate for a limited time during events when the grid's voltage or frequency operates outside of predetermined ranges. The grid may be able to recover if the disturbance is small or short. However, if inverters are not programmed to operate during disturbances, a large number of PV systems could disconnect simultaneously, triggering a sharp reduction in voltage and leading to a large-scale grid failure in high-penetration scenarios⁴⁷⁶. This issue has prompted Germany to spend considerable resources retrofitting more than 400,000 installed PV inverters⁴⁷⁷. German regulators have redefined inverter output levels as a function of frequency during over-frequency periods.

At high penetration rates, there is concern with peak demand shifting to later in the afternoon, resulting in a need for large thermal generators to ramp up when the sun starts to set. For thermal generators designed to operate at a consistent output, more frequent output cycling can result in increased maintenance costs and reduced life⁴⁷⁸. This phenomenon is referred to as the “duck-curve,” as published by CAISO in 2013. However, by increasing overall system flexibility through responsive demand and energy storage technologies, more flexible thermal generators, and enhanced operations, this issue can be managed⁴⁷⁹.

Increased installations of utility-scale solar projects may lead to further investments in transmission as these projects are generally located away from demand centers. Distributed solar resources may potentially delay transmission and distribution upgrades in the short term by curbing demand, but high penetration rates may require grid modernization to provide for widespread solar installation in the long term.

Like wind, solar energy is variable and nondispatchable. As the levels of VERs increase, their value to the grid decreases, both because VER integration costs increase and because VERs reduce the marginal cost of electricity due to their negligible costs of operation. This will be a future challenge for solar PV as penetration levels increase. Soft costs are both an opportunity and a threat, as it remains to be seen whether their contribution to total cost in the United States can be reduced significantly.

Distributed PV has benefited from net energy metering, financing innovations, and specific RPS requirements for distributed solar. The potential for future PV deployment in the distribution network is high because of the ITC extension and future reductions in installed costs. However, the increased expansion of distributed PV is causing a number of states to reevaluate their net energy metering policies to address cost allocation and rate designs⁴⁸⁰.

11.7 Technical RDD&D

RDD&D for PV technologies is outlined in the DOE’s SunShot 2020 goals. The SunShot goals call for the reduction of unsubsidized, utility-scale solar LCOE to \$.06/kWh (estimates for current LCOE range from \$0.05 to \$0.43/kWh, according to Table 11-1). In order to achieve this SunShot goal, DOE has funded R&D projects aimed at lowering manufacturing costs, increasing efficiency and performance, and improving reliability of PV⁴⁸¹.

For a review of PV technologies and different materials, please see appendix A. DOE lists the following manufacturing and technical improvements for the various cell technologies⁴⁸²:

- *C-Si*: Reduce raw materials requirements, reduce material waste during sawing, and optimize crystal growth process
- *Thin films*: Increase cell efficiencies through increased crystal quality, improve doping control, increase minority carrier lifetime, and reuse/recycling of toxic cell materials
- *Multi-junction*: Decrease cost of manufacturing and materials (substrates, absorbers, etc.), increase cell efficiency, and extend multi-junction concept to other cell materials
- *Perovskite*: Increase cell stability, identify degradation mechanisms, and improve durability.

Increasing the efficiency of silicon cell manufacturing can be achieved by reducing wasted material. Inefficient ingot casting and sawing can result in a waste of 50 percent of purified and crystalized silicon. Companies have reduced wafer costs by 60 percent by eliminating the need for sawing machines and are working on achieving competitive module efficiencies and further reducing manufacturing costs⁴⁸³.

Increasing module efficiency could also help reduce panel costs. The average efficiency of commercially available solar PV modules has been rising for decades. Some scientists believe 50 percent efficiency could be possible with newer approaches and materials⁴⁸⁴. Higher module efficiencies could also reduce installation and maintenance costs by reducing the size of PV plants.

Perovskite cells (see appendix A for details about cell types) are still far from commercialization. Hurdles that need to be overcome include the rapid pace at which cells degrade and safety concerns over the quantity of lead used in cell manufacturing⁴⁸⁵.

DOE SunShot initiatives are also aimed at reducing soft costs of solar installation. These costs can account for up to 64 percent of the PV system⁴⁸⁶. R&D funding is aimed at increasing market transparency, training the solar workforce, developing and communicating process improvements, and focusing on local solutions for PV installation⁴⁸⁷.

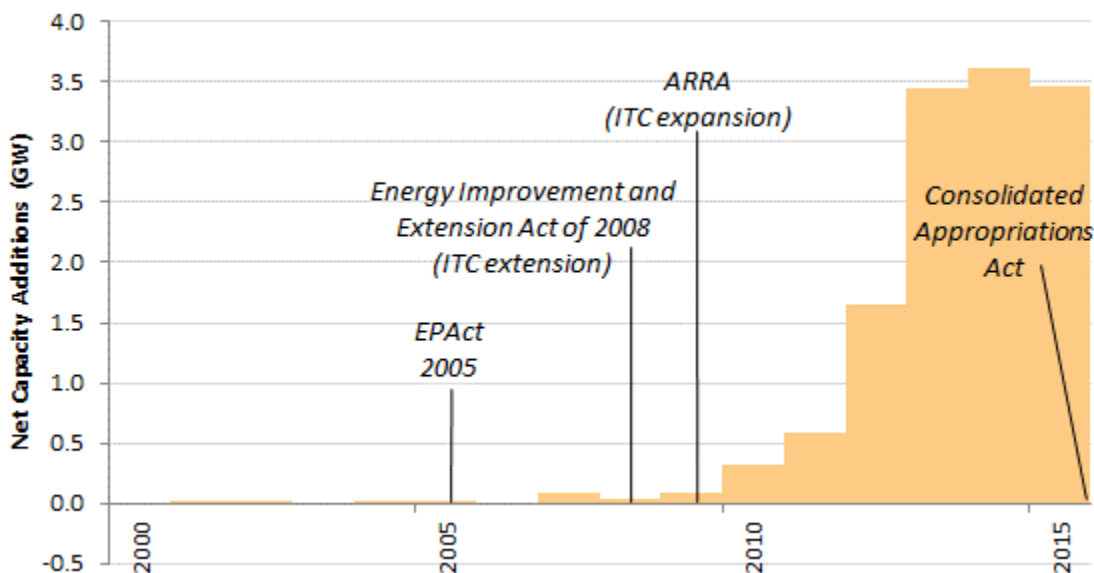
Other DOE SunShot funding is allocated to the system integration of PV. System integration includes programs for grid performance and reliability, dispatchability, power electronics (smart inverters), and communications⁴⁸⁸.

CSP RDD&D is sponsored under the SunShot initiative at DOE and is focused on reducing costs, increasing efficiencies, and increasing operating reliability. Demonstration projects include different materials for collectors, receivers, thermal storage equipment, working fluids, and power-cycle equipment⁴⁸⁹.

11.8 Development and Projected Future Deployment

Utility-scale solar PV capacity in the United States has been growing steadily since 2009 (Figure 11-9)⁴⁹⁰. Tax credits at the Federal level, RPS policies, and significant cost reductions have been the main drivers for utility-scale PV growth. RPS policies have expanded the market for renewable energy technologies in 29 states and the District of Columbia. Carve-outs for distributed generation (included in the RPS of 16 states), net metering, financing innovations, and system resiliency planning are some of the drivers for the continuing expansion of distributed generation installed capacity.

Figure 11-9. Historical annual utility-scale solar capacity additions (GW), 2000–2015



Solar development has been incentivized by the ITC, state RPS policies, net metering, and significant reductions in cost. Only federal policies are shown. Capacity is reported in GW-AC. Source: EIA 1990 and EIA 2016⁴⁹¹.

Solar resource abundance, declining costs, increasing module efficiencies, and supportive policies at the Federal and State levels could sustain the growth in PV capacity additions seen in the United States over the last 10 years. The new legislation extending and then phasing out the ITC for projects that begin construction before 2022^{lxiv} and the CPP’s Clean Energy Incentive Program aim to provide the solar industry with longer-term policy certainty. The ITC extension could spur a 50 percent increase in cumulative installed capacity between 2016 and 2020 over the no-extension scenario⁴⁹². Lawrence Berkeley National Laboratory (LBNL) estimates that RPS policies will require renewable generation to double from 215 TWh in 2015 to 431 TWh in 2030 for compliance for the entire United States⁴⁹³. Specifically, LBNL estimates solar carve-outs (including distributed PV) mean that an additional 2 GW of capacity will be needed by 2020 and 5 GW by 2030 relative to current amounts.

While, 1.3 GW of CSP capacity has been installed in the United States in the last 5 years, no CSP projects are projected for 2016⁴⁹⁴. The QER 1.2 Base Case predicts over 300 TWh of solar generation coming online by 2040. In the Side Case, about 180 TWh more of solar generation is projected.

Table 11-2. QER 1.2 Base Case projections for solar generation (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Solar Generation	45	320	498

In the Side Case, about 180 TWh more solar generation is projected in 2040. Source: EPSA 2015⁴⁹⁵.

^{lxiv} Commercial projects placed in service after 2023 qualify for a 10 percent ITC.

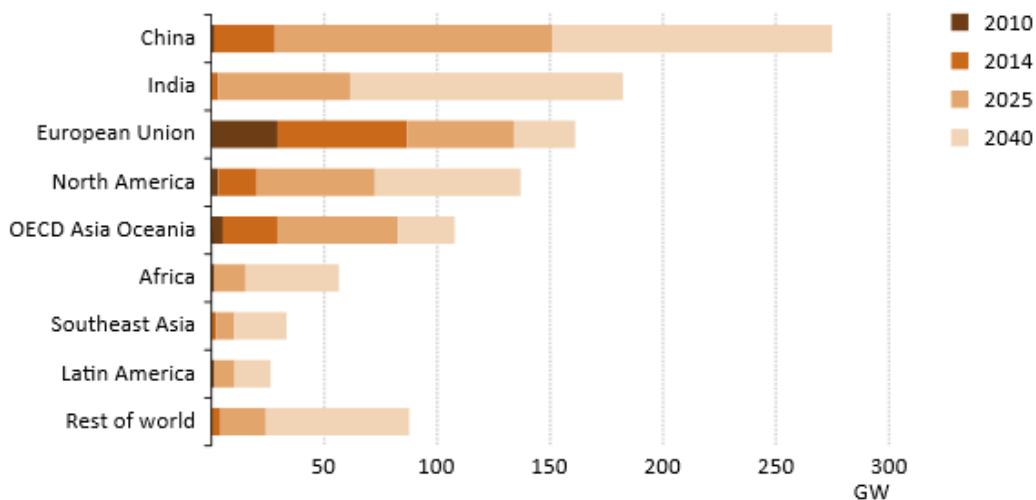
In their 450 Scenario, IEA projects that, globally, more than twice the amount of solar PV generation and over six times the amount of solar CSP generation will come online compared to the Current Policies Scenario (Table 11-3). In the 2025 time horizon, China and India will lead global solar demand (Figure 11-10).

Table 11-3. Global solar generation projections, 2013-2040

	2013	New Policies		Current Policies		450	
		2020	2040	2020	2040	2020	2040
PV Generation (TWh)	139	494	1,521	446	1,066	529	2,232
CSP Generation (TWh)	5	27	262	25	147	32	937
Percentage of Global Total	0.6	1.9	4.5	1.7	2.8	2.1	9.3

In the 450 Scenario, more than twice the amount of solar PV generation and three times the amount of solar CSP generation will come online compared to the Current Policies Scenario. Source: IEA 2015⁴⁹⁶.
 Note: Solar PV includes both utility-scale and distributed capacity.

Figure 11-10. Solar PV installed capacity by region in the New Policies scenario



In the 2025 time horizon, China and India will lead global solar demand. Source: IEA (2015)⁴⁹⁷.
 Note: Includes both utility-scale and distributed solar PV capacity.

12 Geothermal

12.1 Technologies

Geothermal power plants utilize turbine technology in a process similar to that used in fossil fuel and nuclear power plants, but geothermal plants capture heat from below the earth's surface to create steam or vapor. There are currently three main types of geothermal generation technology in the United States: dry steam plants, flash steam plants, and binary -cycle power plants. A fourth, enhanced geothermal systems (EGS), is not a generation technology per se, but a process to engineer the underground heat source so that it can provide usable energy⁴⁹⁸. To date, EGS is not commercially available.

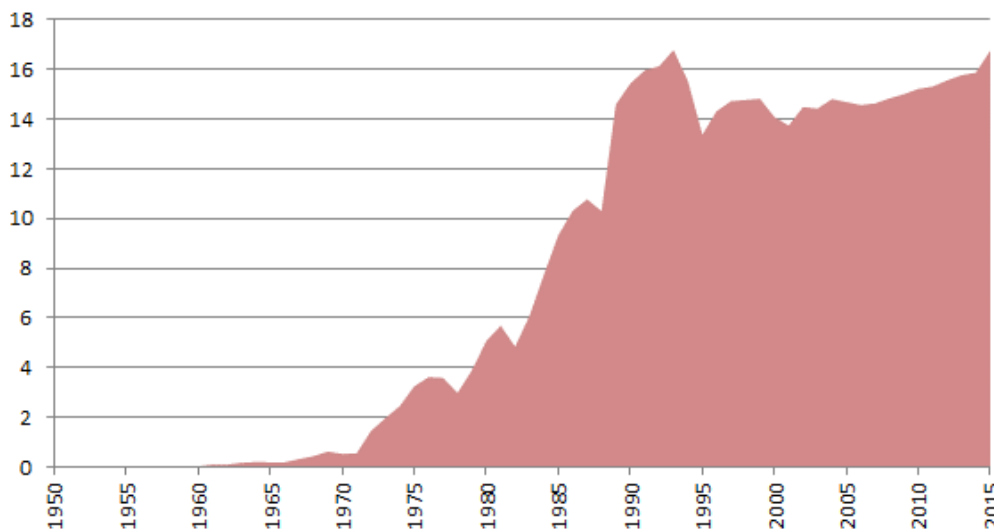
Dry steam plants use steam piped directly from a geothermal reservoir to turn a generator. Flash steam plants use high-pressure, hot brine from deep reservoirs and convert it to steam to drive generator turbines. Binary cycle power plants transfer the heat from geothermal brine to a secondary working fluid with a lower boiling point, which is converted to vapor, again driving a turbine. Finally, EGS is a subsurface technology under development that could significantly expand the geothermal resource base as it relies on hot rock, but not necessarily the water content or permeability required in traditional hydrothermal resource sites⁴⁹⁹. It aims to engineer the subsurface to optimize the reservoir for sustained heat exchange. EGS can use any of the surface technologies noted above to generate electricity in an ST.

Geothermal plants range in size depending on the size of the geothermal reservoir that is available. Large-scale geothermal plants in the United States range from as small as 2 MW up to 100MW, but other geothermal plants can be smaller size and distributed for certain applications⁵⁰⁰. Geothermal plants are often composed of one or more generating units. One benefit of geothermal energy is that it can be easily ramped up and down through control systems. Geothermal power plants offer dispatchability, high physical inertia, and firming capabilities, attributes that are unique among renewables⁵⁰¹. Other geothermal power generation benefits include low life-cycle GHG emissions, baseload applications, and dispatchability.

12.2 Operational Attributes and Fleet Characteristics

Geothermal power generation currently comprises less than 1 percent of the total electricity generation portfolio (17 TWh in 2015, Figure 12-1), with roughly 3.7 GW installed capacity⁵⁰².

Figure 12-1. U.S. geothermal generation (TWh), 1950–2015

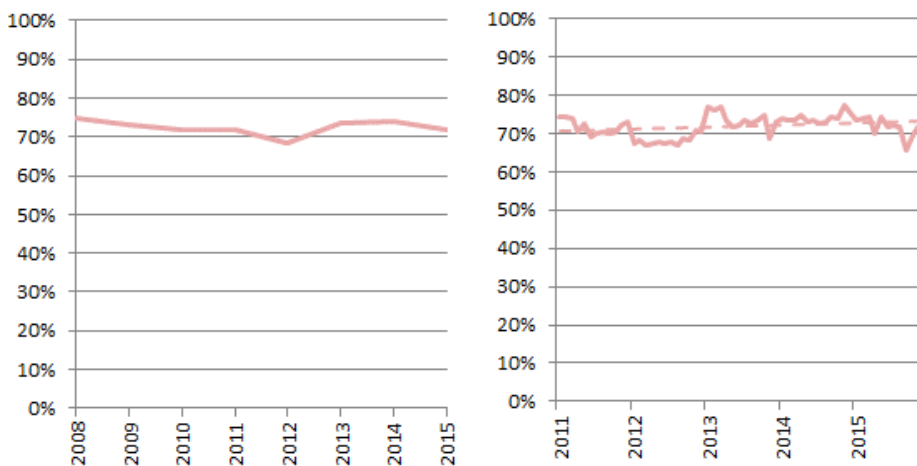


Geothermal generation expanded rapidly during the 1980s but has remained relatively constant since then. Source: EIA 2016⁵⁰³.

The capacity factor for geothermal plants was roughly 70 percent (based on installed nameplate capacity) between 2011 and 2015 (Figure 12-2)⁵⁰⁴. Plants require little downtime for maintenance, so the availability factor is in the range of 90 to 95 percent⁵⁰⁵. However, over time there may be a reduction in availability as reservoirs decline in quality from ongoing extraction.

The majority of geothermal capacity and generation came from California in the 2010–2014 timeframe, followed by Nevada (Figure 12-3). Because of limited resource availability, geothermal generation is confined to only a few additional states: Oregon, Idaho, Utah, New Mexico, and Hawaii.

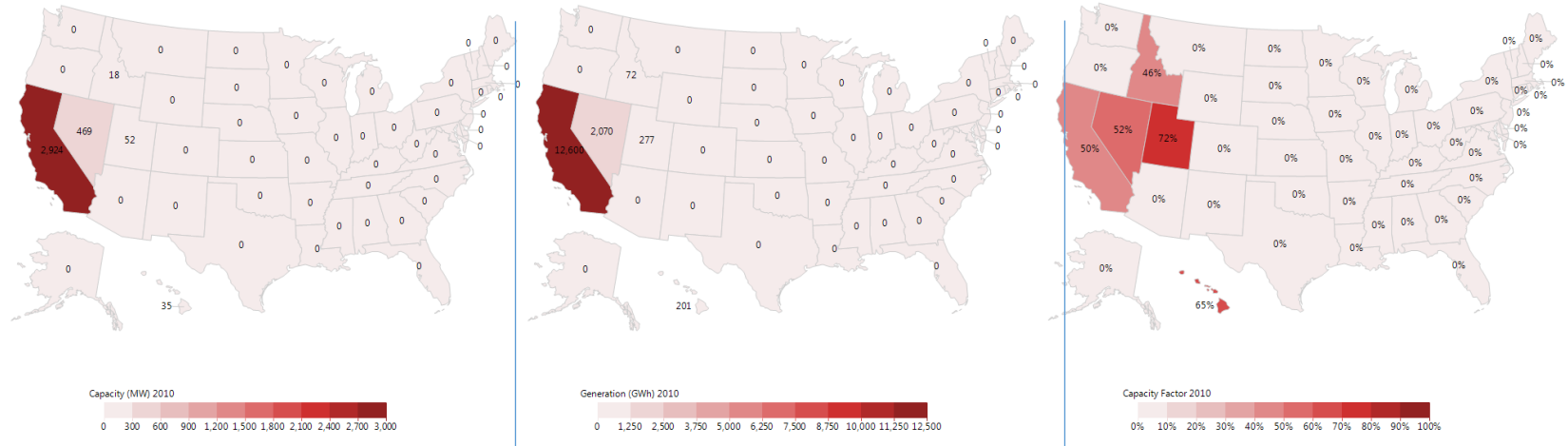
Figure 12-2. U.S. annual and monthly geothermal generator capacity factors



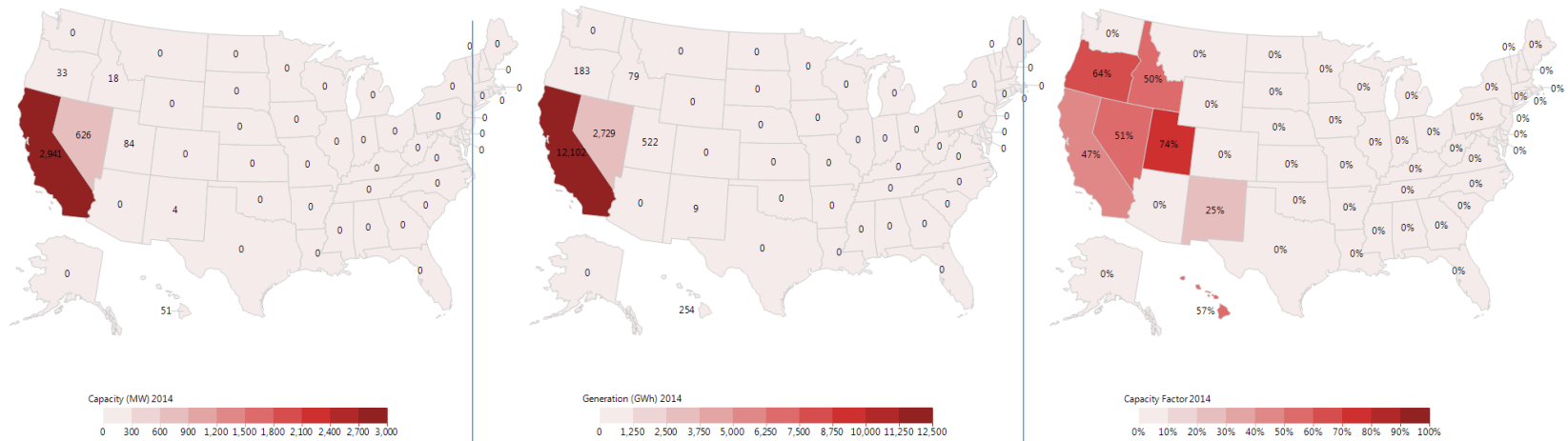
Annual capacity factors have declined slightly since 2008, likely due to reduced availability from declining reservoir quality. Sources: SNL 2015⁵⁰⁶.

Figure 12-3. Geothermal capacity (left), generation (middle), and capacity factor (right) by state. Top: 2010; bottom: 2014.

2010



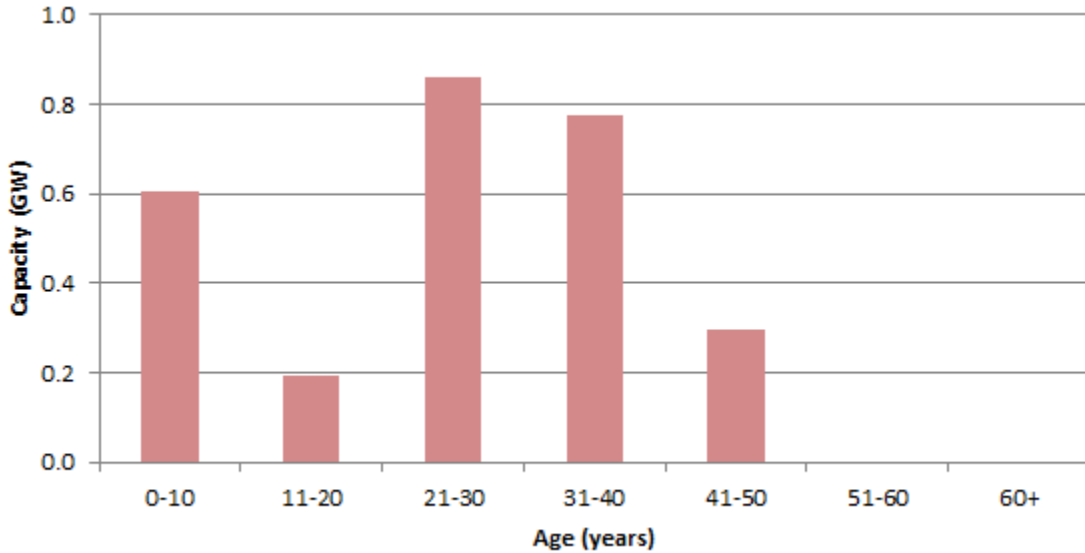
2014



The majority of geothermal capacity and generation came from California in the 2010–2014 timeframe, followed by Nevada. Geothermal generation is limited to only a few additional states: Oregon, Idaho, Utah, New Mexico, and Hawaii. Source: EIA 2016⁵⁰⁷.

Geothermal systems vary in age, but roughly 70 percent of the existing generating capacity is over 20 years old⁵⁰⁸.

Figure 12-4. Age profile of U.S. geothermal generation fleet, 2014



Geothermal systems vary in age, but roughly 70 percent of the existing generating capacity is over 20 years old Source: SNL 2015⁵⁰⁹.

12.3 Technology Costs

The LCOE for geothermal generation is shown in Table 12-1. Looking at mean LCOE across sources, geothermal could provide low-LCOE, low-carbon baseload generation; however, the ranges of LCOEs is wide and depends on cost assumptions. For example, the high range given by NREL is due to the inclusion of near-field EGS resources in the cost assumptions, which are more expensive to develop than traditional hydrothermal resources. EIA and Lazard do not include EGS in their calculations. Similarly, the low end of the range for EIA represents expansion of an existing facility and is not representative of development of a new facility.

Table 12-1. LCOE for new geothermal generation (2013\$/MWh)

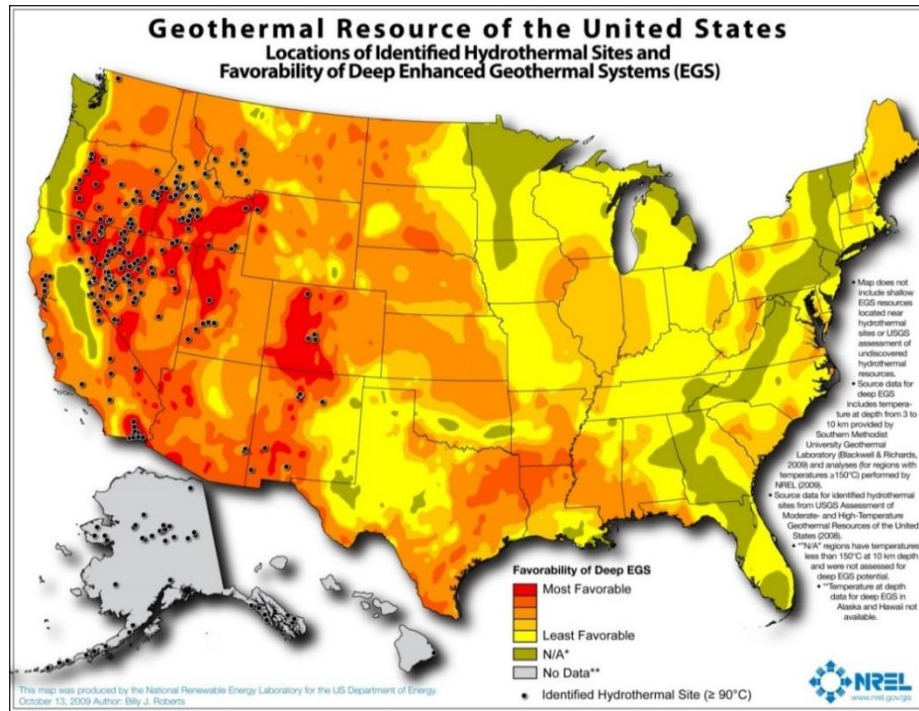
	EIA		NREL		Lazard	
	Low	High	Low	High	Low	High
Geothermal	37.44	54.10	24.08	453.26	66.25	124.88

Current ranges of geothermal technology prices using cost assumptions from three sources: NREL 2015; EIA 2015; Lazard 2015⁵¹⁰. See appendix B for more information on LCOE calculations.

12.4 Fuel/Resource

Most of the conventional U.S. geothermal resources are located in the western United States, although EGS could significantly expand the footprint, as shown in Figure 12-5. The United States Geological Survey estimates there are approximately 39 GW of identified and undiscovered geothermal resources and 517 GW of mean estimated EGS resources⁵¹¹.

Figure 12-5. Geothermal resource of the U.S.



Most existing geothermal plants are located in the far western United States as the underground resource is best there. EGS have the potential to significantly expand the resource footprint for geothermal technologies. Source: Roberts 2009⁵¹².

12.5 Environmental Impacts

12.5.1 Upstream

Geothermal well drilling has similar environmental concerns to well drilling in the oil and gas industry. Drilling mud, used in the drilling process, and solid tailings must be disposed of properly to prevent contamination of the environment. There are also emissions from the diesel generators during the drilling process.

12.5.2 Emissions and Environmental Impact

Although geothermal plants emit no CO_2 associated with combustion of a fuel, most plants release a small amount of CO_2 that comes from dissolved gases found in the hot reservoir fluids, and this amount varies by technology⁵¹³. These CO_2 emissions total less than 1 percent of the amount generated by an equivalent size fossil fuel-powered plant, roughly $0.1 \text{ lb CO}_2/\text{kWh}$ ⁵¹⁴. Some reservoirs may contain hydrogen sulfide, sodium chloride, and mercury in the water. These are extracted using scrubbing technology and emissions controls, which produce small amounts

of solid waste. Open-loop systems can introduce hydrogen sulfide, CO₂, ammonia, methane, and boron into the atmosphere⁵¹⁵. Systems can use a closed-loop design to prevent produced water from contaminating the environment.

12.6 Constraints

Geothermal plant construction is similar to the supply chain for other steam power generation technologies such as coal, natural gas, and nuclear. Increased demand for metals and aggregates from other industries may adversely affect the construction cost and lead times since geothermal turbines are customized to the resource. Similarly, the cost and availability of drilling rigs may be a factor in the exploration phase of the construction.

Geothermal power siting is determined to a large extent by the location of available geothermal reservoirs. Since the plant sits near the reservoir, there are few options for alternative locations once a reservoir is identified. While some land is disrupted to construct the power plant facility and to drill the production wells, most of the surface area remains undisturbed.

There are some concerns about induced seismicity near new or expanded geothermal plants, as they are often located near fault lines, and water is being removed and reinjected into the earth for the purposes of enhancing the permeability or fluid content of an underground reservoir. However, induced seismicity is an issue that has been successfully managed in many different sectors, and it has been concluded that with proper protocol induced seismicity does not pose a threat to long-term geothermal development⁵¹⁶.

Geothermal generators are baseload plants capable of providing valuable services to the grid, such as generation flexibility. As more VERs are integrated to the electric system, the flexibility of baseload capacity will grow in importance. The services a geothermal plant can provide include regulation, load following, spinning reserve, nonspinning reserve, and replacement or supplemental reserve⁵¹⁷. However, current ancillary service compensation models in areas with the most geothermal development do not provide sufficient revenue to warrant the increased operational and control retrofitting expenses⁵¹⁸. Similarly, the dispatchability and baseload capabilities and characteristics may not be fully valued by utilities⁵¹⁹.

Deployment barriers include multijurisdictional permitting requirements, long development lead times, limited geographic availability (which increases grid interconnection costs), and a high-risk development profile. In 2015, 1,049 MW of geothermal capacity under development was stalled due to financing barriers, with 484 MW stalled specifically due to the lack of funding for further exploration⁵²⁰. The National Geothermal Data System and the Regulatory and Permitting Information Desktop Toolkit (RAPID) address exploration data availability and permitting barriers, which could lower the cost of development and shorten lead times.

Geothermal resources are often found in remote locations, requiring the construction of transmission infrastructure. The process of siting transmission lines can be costly and lengthy. Transmission costs are not necessarily proportional to plant capacity and can render projects economically unfeasible. Transmission costs include land use and rights-of-way fees. Additionally, visual impact mitigation requirements and local opposition can further increase costs and delay transmission construction⁵²¹.

12.7 Technical RDD&D

Developing EGS offers the potential to expand the geographic availability and capacity potential of geothermal resources for power production. EGS could expand the geothermal power potential more than tenfold compared with hydrothermal resources. Approximately 90 percent of the geothermal power potential in the United States is available only with EGS⁵²².

EGS differs from conventional geothermal systems in that suitable reservoir conditions must be created by increasing the permeability of a reservoir that contains enough heat to support sustained power production and by injecting fluid to convey the heat to a power plant located on the surface. Usually, EGS systems require drilling deeper—down to a depth of 2 to 6 kilometers—in harder rock than conventional geothermal development⁵²³. This deeper drilling increases the costs and risks of developing EGS plants, but it also increases access to otherwise unavailable geothermal resources.

The highest potential areas for reducing cost and lead time of geothermal plants are accurate resource characterizations and advances in well development. Improving characterizations of the subsurface is critical to reduce development risks, secure financing, and lower development costs⁵²⁴. Advances in well drilling hydrothermal reservoirs can reduce the large up-front capital costs that are currently a barrier for geothermal exploration.

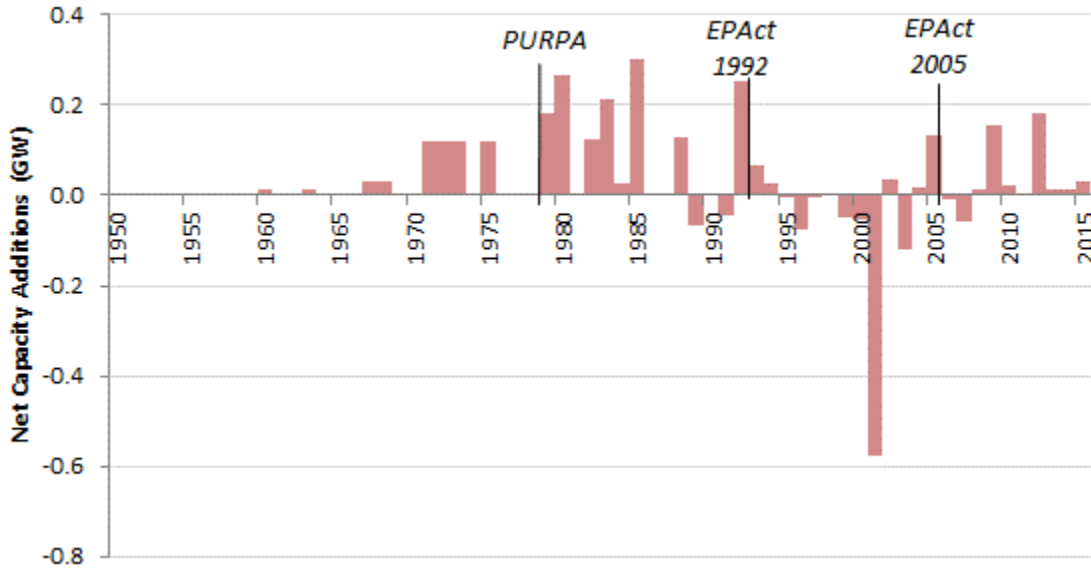
The Frontier Observatory for Research in Geothermal Energy (FORGE) is a DOE-led initiative where the geothermal community will be able to test improved EGS technologies and techniques with the goal of accelerating the commercial deployment of EGS. FORGE focuses on methods to characterize, create, and sustain an EGS system⁵²⁵.

Other technologies that expand the capacity potential and geographic availability of geothermal resources include low-temperature power production and coproduction (with oil and gas) systems, hybrid systems (e.g., geothermal with solar), and the development of blind geothermal resources (i.e., geothermal resources that have no visible surface expressions).

12.8 Development and Projected Future Deployment

Prior to 1980, geothermal generation in the United States remained below 5 TWh annually. Then, between 1980 and 1989, generation tripled to 15 TWh as new facilities came online. Much of the early growth in geothermal power was driven by PURPA incentives, although this driving force has declined over time as the avoided costs of utility generation have fallen (Figure 12-6). Challenges in exploring new “blind” hydrothermal resources and long drilling times for production wells have led to increased uncertainty for investors in large geothermal projects. Additionally, expiration of tax credit horizons that do not allow enough time for project development (i.e., commence construction clauses that do not take into account the long lead time of geothermal project development), the scarcity of PPA opportunities, the need for transmission infrastructure, and low natural gas prices have likely contributed to modest growth in recent years. In 2012, about 180 MW of capacity was added to the U.S. geothermal fleet, which was the greatest annual growth in the last decade. In 2013 and 2014, 15 MW or less of geothermal capacity was added, and in 2015, 32 MW of geothermal capacity came online. Even with modest development in recent years, the United States is still the world leader in installed geothermal capacity.

Figure 12-6. Historical annual geothermal capacity additions and retirements (GW), 1950–2015



The greatest growth for geothermal additions occurred in the 1980s. Many factors have contributed to geothermal’s slowed growth since then, including challenges in exploring new ‘blind’ hydrothermal resources and long drilling times for production. Source: EIA 1990 and EIA 2016⁵²⁶.
 Note: The large number of retirements in 2001 is due to a change in EIA’s reporting; thus, total net capacity does not match actual installed capacity.

The 2015 omnibus spending bill extended PTC eligibility to geothermal projects beginning construction before 2017 and included the option to elect a 30 percent ITC instead⁵²⁷. The 1-year extension and change in requirements—from “placed in service” to “begun construction”—may help geothermal projects that have at least completed the exploration phase but are unlikely to spur greenfield development. RPS policies (especially the 50 percent target in California, where there is a large proven geothermal resource) could also spur geothermal development.

Incentives from the CPP starting in 2022, technological advances and other improvements that remove deployment barriers, and the commercialization of near-field EGS could further improve the outlook for geothermal. The QER1.2 Base Case projects U.S. geothermal generation to grow from 16 TWh in 2014 to 57 TWh in 2040. The growth is slightly more in the Side Case scenario at 68 TWh in 2040 (Table 12-2).

Table 12-2. QER 1.2 Base Case generation for geothermal (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Geothermal Generation	16	57	68

The QER scenarios project that between 10 and 18 TWh of geothermal generation could come online by 2040 Source: EPSA 2015⁵²⁸.

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Globally, geothermal has been growing more consistently, at a 4 to 5 percent annual rate⁵²⁹. IEA anticipates that by 2040, 299 TWh of generation will be online under current policies, with 541 TWh operating by 2040 under a 450 Scenario (Table 12-3).

Table 12-3. Global geothermal generation projections

		New Policies		Current Policies		450	
	2013	2020	2040	2020	2040	2020	2040
Geothermal Generation (TWh)	72	116	392	110	299	119	541
Percentage of Global Total	0.3	0.4	1	0.4	0.7	0.5	1.6

IEA anticipates that by 2040, 299 TWh of generation will be online under current policies, with 541 TWh operating by 2040 under a 450 Scenario. Source: IEA 2015⁵³⁰.

13 Petroleum

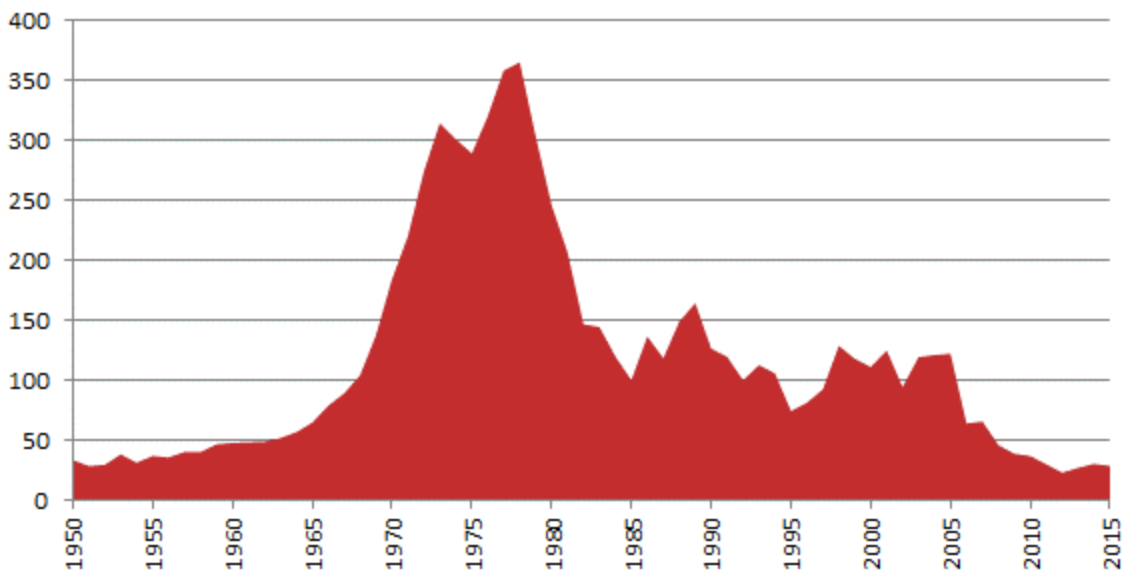
13.1 Technologies

Petroleum is often combusted in STs, but a refined product can also be used in gas turbines or CC units. Chapters 5 and 6, as well as appendix A, discuss these technologies more in depth. Diesel generators, often using internal combustion or reciprocating engines, are used for off-grid or emergency power, and can usually be classified as distributed generation. Despite petroleum’s significant decline as a generation fuel, from 17 percent of generation in 1978 to less than 1 percent in 2015, it remains an important fuel in some ISO/RTO markets, especially New England, during cold winter months (Figure 13-1). Many of the natural gas-fired CTs and CCs in these regions have dual fuel capability, meaning they can run on either natural gas or petroleum products with minor modifications. This is an important reliability option in New England, given that petroleum products are often easier to store at or near the generator, which can help alleviate issues that arise from gas supply disruptions.

13.2 Operational Attributes and Fleet Characteristics

In 2015, petroleum products generated approximately 28 TWh of electricity, or less than 1 percent of the nation’s total. This is down from a peak of 365 TWh in 1978, when it accounted for 17 percent of all U.S. generation (Figure 13-1).

Figure 13-1. U.S petroleum generation (TWh), 1950–2015

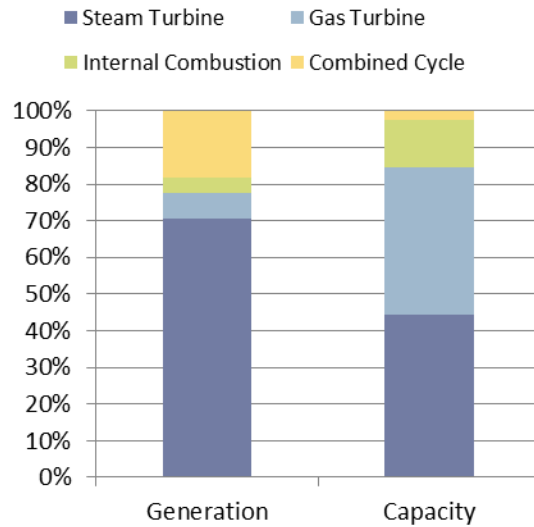


Source: EIA 2016⁵³¹.

Figure 13-2 shows that petroleum capacity by technology type was 44 percent ST, 40 percent CT, 13 percent internal combustion engine, and 4 percent CC in 2014. Due to their use in meeting peak demand, petroleum STs are dispatched first and therefore make up a larger percentage of generation at 71 percent. Petroleum-fired CC generators accounted for 18 percent

of generation, while CT and internal combustion engine technologies accounted for 7 percent and 4 percent of generation, respectively, in 2014.

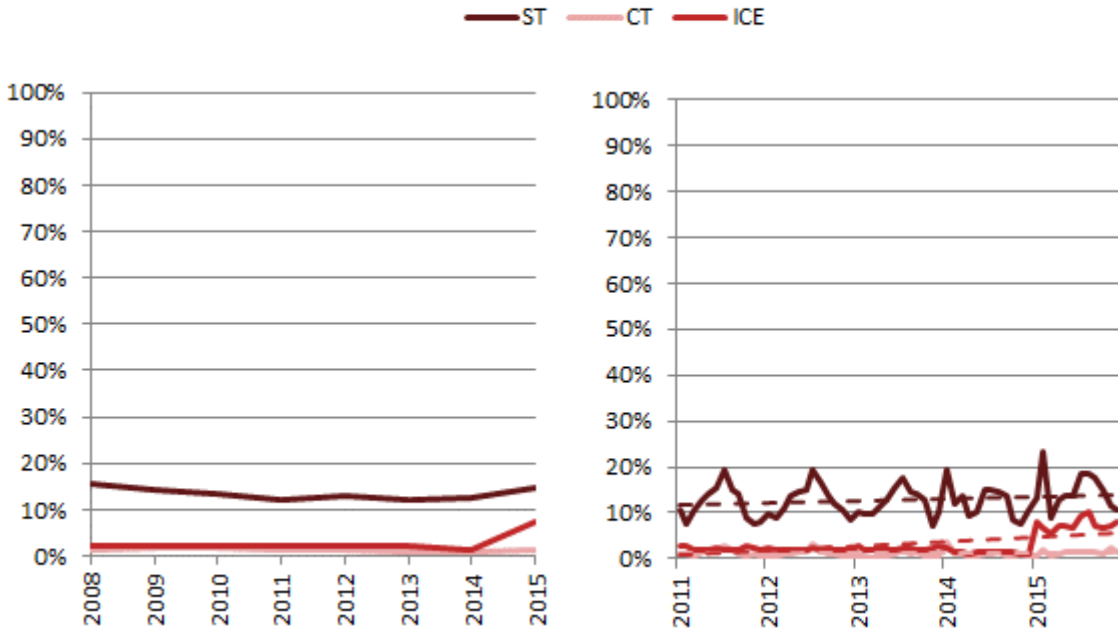
Figure 13-2. Share of U.S. operating petroleum capacity and generation by technology type, 2014



Source: EIA 2016⁵³².

Due to their use primarily in meeting peak loads, capacity factors for petroleum generators are very low. As they are dispatched more frequently, petroleum STs have the highest capacity factor of any petroleum generator. The increased use of petroleum-fired STs in New England as back-up power during the Polar Vortex of 2014 and in 2015 is apparent in the second peak that appears at the beginning of those years in the monthly data below (Figure 13-3, right). Generation from internal combustion engines has also increased since 2014, but capacity factors still remain below 10 percent.

Figure 13-3. U.S. annual and monthly petroleum generator capacity factors

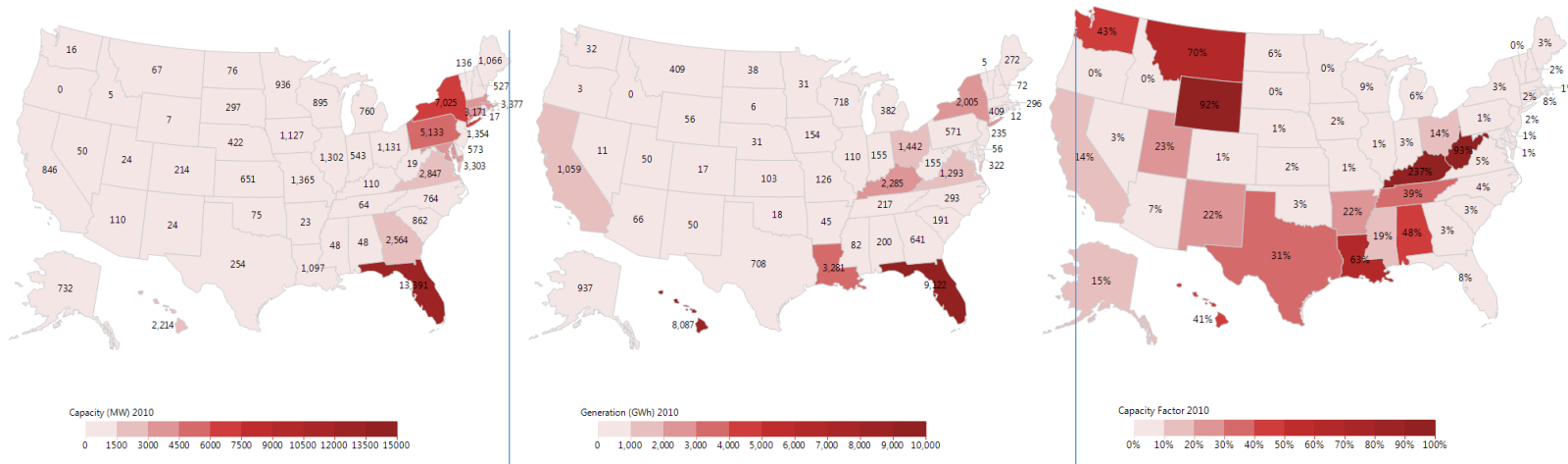


Annual capacity factors have remained constant for STs and CTs, but jumped in 2013 for internal combustion engines (ICEs). Monthly capacity factors show the use of petroleum for meeting winter needs during shortages of other fuels (2014 and 2015). Sources: EIA 2016⁵³³.

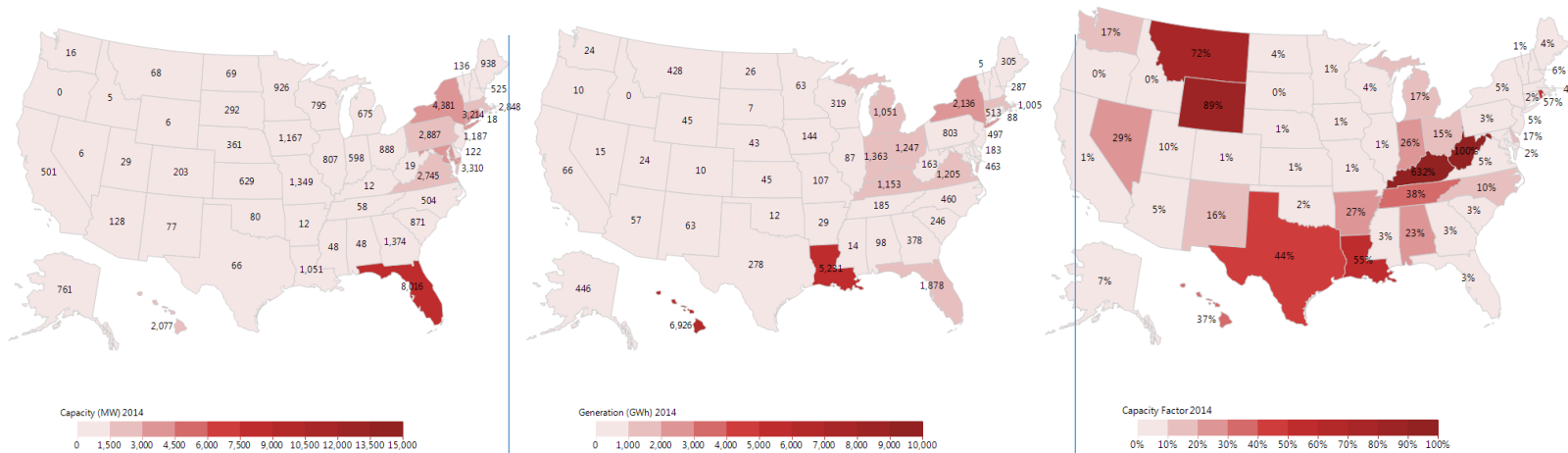
The majority of petroleum generation comes from only a few states and has generally been decreasing, as has capacity. Florida and New York lost the most petroleum-fired capacity in the 2010–2014 timeframe at 5,375 MW and 2,644 MW taken offline, respectively. Although most of the United States relies very little on petroleum generators with capacity factors for these plants at less than 10 percent, there are a few states that use these plants more frequently, such as Montana, Wyoming, and Louisiana⁵³⁴.

Figure 13-4. Petroleum capacity (*left*), generation (*middle*), and capacity factor (*right*) by state. Top: 2010; bottom: 2014.

2010



2014

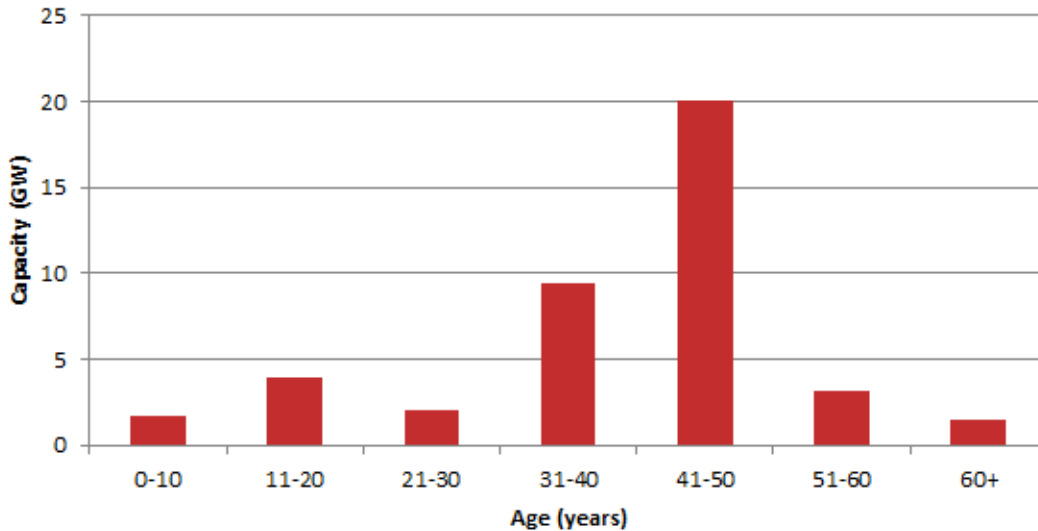


Significant amounts of petroleum capacity came offline between 2010 and 2014, with Florida and New York losing the most at 5,375 MW and 2,644 MW, respectively. Most states generate very little electricity from petroleum, with state capacity factors less than 10 percent; however, a few states rely more heavily on their oil generators, such as Montana, Wyoming, and Louisiana. Source: EIA (2016f) ⁵³⁵.
 Note: Some capacity factors may be distorted. There is no way to separate the data to remove this distortion.

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Over half of the U.S. petroleum generation fleet is greater than 40 years old, corresponding to the sharp drop-off in new capacity additions following the oil crisis in the 1970s. With few capacity additions or retirements announced beyond 2016, the average fleet age will likely continue to increase (Figure 13-5).

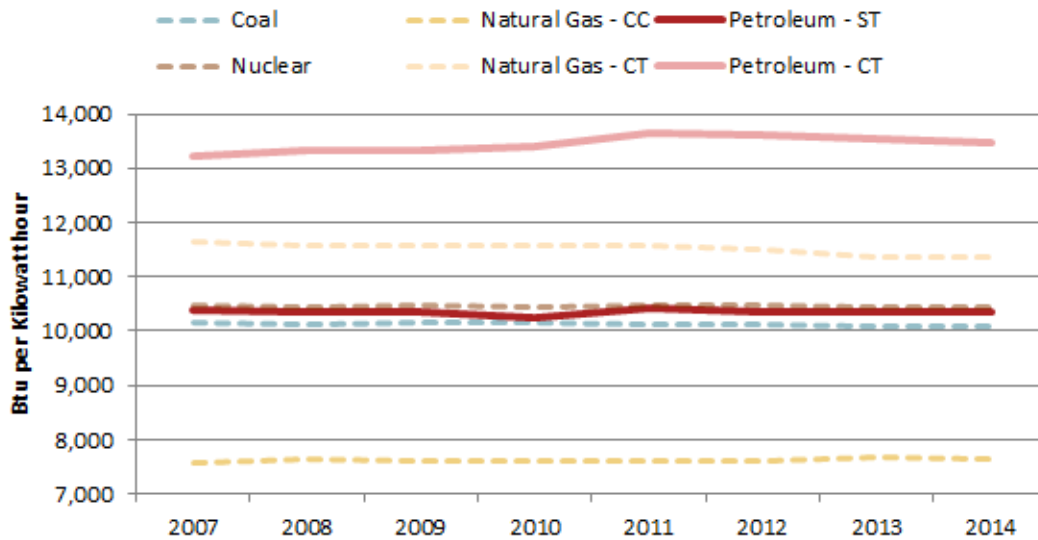
Figure 13-5. Age profile of U.S. petroleum generation fleet, 2014



Over half of the petroleum generating capacity is greater than 40 years old, corresponding to the sharp drop-off in new capacity additions in the 1970s. Source: SNL 2015⁵³⁶.

Heat rates for the U.S. fleet of petroleum-fired generators, both STs and CTs, have remained relatively constant since 2007 (Figure 13-6). In comparing different fossil fuel and nuclear plants, petroleum CTs are the least efficient plant type. Without new additions to the petroleum fleet, it is unlikely that these heat rates will change significantly.

Figure 13-6. Heat rates for petroleum generators (BTU/kWh), 2007–2014



The heat rate for petroleum generators has remained relatively constant since 2007. Source: EIA 2015a⁵³⁷.

13.3 Technology Costs

No LCOE was estimated for petroleum, as cost is not expected to play a significant role in the decision to build future petroleum-fired generation. Any future buildout will be made on a reliability basis, not a cost basis.

13.4 Fuel

U.S. oil production has increased due to the increased use of hydraulic fracturing and is currently about equal to the peak in production experienced in 1970⁵³⁸. The low crude oil pricing environment, however, may cause production to diminish in the short term. Onshore rig counts in the United States dropped from their peak in October 2014 at 1,596 rigs to 857 rigs in March 2015⁵³⁹.

In 2015, about 24 percent of the petroleum consumed by the United States was imported from foreign countries, the lowest level since 1970⁵⁴⁰,^{lxv}. This translates to about 4.6 million barrels per day of petroleum from about 82 countries.^{lxvi} This decrease in imports is in part due to the increase in U.S. production resulting from the widespread adoption of hydraulic fracturing, as well as the decrease in demand observed since 2007⁵⁴¹.

Petroleum is transported across the country in a complex network of pipelines, as well as by rail and by barge (Figure 13-7). In 2014, the U.S. liquid fuels system produced 8.7 million barrels of crude oil and imported 7.3 million barrels⁵⁴². Petroleum offers an advantage as a generation fuel because it can be stored onsite, which is not an option for natural gas.

Figure 13-7. Pipelines in the U.S. and Canada that transport petroleum products



^{lxv} This figure is based on net petroleum imports, where petroleum includes crude oil, natural gas plant liquids, liquefied refinery gases, refined petroleum products such as gasoline and diesel fuel, and biofuels including ethanol and biodiesel.

^{lxvi} This is the difference between the 9.4 million barrels per day of petroleum imported minus the 4.8 million barrels per day of petroleum exported.

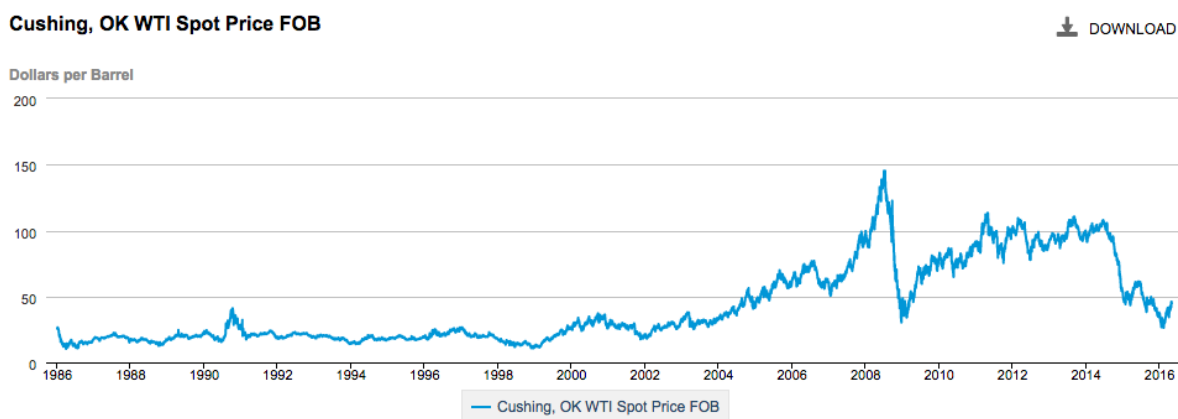
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The solid orange lines show the crude oil pipelines in the lower 48 states of the United States and Canada. The dashed orange and black lines show the pipelines for petroleum products. The blue lines denote hydrocarbon liquids pipelines, which are byproducts of both petroleum and gas production and refining. Source: EIA 2016⁵⁴³.

13.4.1 Oil Price History

Oil is traded on a global market, which makes its pricing particularly sensitive to external factors and, therefore, volatile. Increased U.S. production and decreased global demand for petroleum led to a sharp drop in prices in 2014, which have remained significantly lower than the 5-year average (Figure 13-8). It is likely that price volatility will be a continuing trait in oil prices, which makes reliance on oil as a generation fuel particularly risky.

Figure 13-8. Spot prices of West Texas Intermediate crude oil at the Cushing, Oklahoma hub (\$/bbl), 1986-2016



Source: EIA 2016⁵⁴⁴.

13.5 Environmental Impacts

13.5.1 Upstream

Similar to natural gas, petroleum is extracted from underground by drilling wells into subsurface reservoirs, which are often then hydraulically fractured to allow the oil to flow. These processes, especially hydraulic fracturing, have raised many public concerns, which are outlined in chapter 5.

Once the oil has been extracted, it must be refined before use. Pollutants that result from the refining process include particulate matter, volatile organic compounds, NO_x and SO_x, as well as wastewater. These hazards are regulated under statutes such as the Clean Air Act, the Clean Water Act, and the Safe Drinking Water Act, among many others⁵⁴⁵. The EPA recently issued their final rule adding more controls to prevent toxic air emissions⁵⁴⁶; the agency is currently considering whether there is a need to update their regulations regarding wastewater disposal at refineries⁵⁴⁷.

13.5.2 Emissions

In 2015, petroleum-fired generation only accounted for about 1 percent of total CO₂ emissions in the U.S. electric power sector⁵⁴⁸. At around 70 kg of CO₂ emitted per MMBtu, petroleum falls between coal and natural gas in terms of its emission coefficient⁵⁴⁹. Other air pollutants are a concern with petroleum, such as SO_x, NO_x, and NMVOCs, which can be greater than coal in some cases⁵⁵⁰.

13.6 Constraints

The petroleum infrastructure system is currently undergoing changes to accommodate the increase in U.S. production. Crude oil flow has generally reversed from the historical south-to-north that took imported oil to inland refineries, resulting in pipeline reversals and new pipeline additions. There has also been an increase in the use of rail, barges, and trucks to move oil across the Nation. QER 1.1 addressed these changes in oil infrastructure in depth⁵⁵¹.

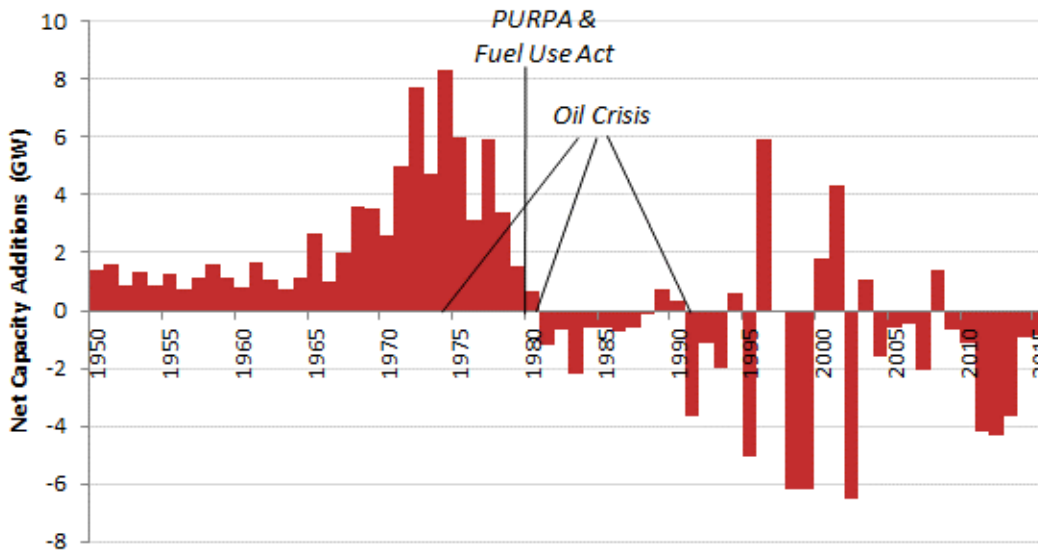
13.7 Technical RDD&D

Very little technical RDD&D is underway in regard to petroleum generation due to the high price per kWh. The DOE programs regarding oil are focused on production, including enhanced oil recovery (EOR) and offshore drilling technologies⁵⁵². EOR via gas injection is a process in which compressed gas, frequently CO₂, is injected into an oil reservoir to push out more oil than could be captured by traditional pumps or injection techniques⁵⁵³. This form of EOR is particularly interesting to understand and harness as CO₂ gathered from CCS technologies could be used in the process, with the oil well acting as a final storage place for the captured CO₂. In 2010, DOE funded seven “next generation” EOR projects involving CO₂⁵⁵⁴.

13.8 Development and Projected Future Deployment

Buildout of petroleum capacity peaked in 1974 and has steadily declined since then due to the oil crises of the 1970s, which caused oil price spikes and concerns over dependency on foreign supplies. Additionally, the Fuel Use Act restricted construction of new power plants using oil or natural gas between 1978 and 1987⁵⁵⁵. Since 1981, net retirements of oil plants have been much greater than deployments.

Figure 13-9. Historical annual petroleum capacity additions and retirements (GW), 1950–2015



Buildout of petroleum capacity peaked in 1974 and has steadily declined since then due to due to the oil crises of the 1970s. Source: EIA 1990 and EIA 2016⁵⁵⁶.

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In the QER 1.2 Base Case, petroleum generation will continue to decline out to 2040. In both the Base Case and the Side Case scenario, petroleum generation halves by about 2020 and remains at steady levels out to 2040 (Table 13-1).

Table 13-1. QER 1.2 Base Case projections for petroleum (TWh), 2014-2040

	2014 Actual	QER 1.2 Base Case (2040)	QER 1.2 Side Case (2040)
Petroleum Generation	30	12	14

Source: EPSA 2015⁵⁵⁷.

IEA’s projections in the WEO all show petroleum declining as a generation fuel. In every scenario, petroleum generation is at about 1 percent of total world generation by 2040 (Table 13-2).

Table 13-2. Global petroleum generation projections, 2013-2040

	2013	New Policies		Current Policies		450	
		2020	2040	2020	2040	2020	2040
Petroleum Generation (TWh)	1,044	836	533	849	590	760	279
Percentage of Global Total	4	3	1	3	1	3	1

In all scenarios, petroleum generation makes up only 1 percent of total world generation by 2040. Source: IEA 2015⁵⁵⁸.

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