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Electric Power System, Markets and Reliability Study

Interim Draft Report

July 2017

Prepared by U.S. Department of Energy

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1 Introduction

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157 Secretary Rick Perry issued a memorandum on April 14, 2017, directing preparation of a study that
158 examines whether recent problems associated with baseload power plants may be putting the nation's
159 energy security and reliability at risk.^a The memo notes that many baseload plants have retired, and
160 asks whether these retirements are premature and whether they reduce grid resilience. It asks why so
161 many baseload plants have closed, whether wholesale energy and capacity markets are adequately
162 compensating important resilience and reliability attributes, how electric markets have evolved, and
163 whether regulatory burdens, subsidies and mandates have forced premature retirements. The
164 Secretary directs the Department to conduct rigorous analysis to answer these questions and to
165 recommend sound policies to protect the nation's electric grid.

166 The Secretary's memo articulates several goals for the study and the power system as a whole:
167 American families and businesses deserve a power system that is affordable, supports national security
168 through fuel diversity and fuel assurance, and is technologically advanced, resilient, reliable and second
169 to none. These goals will be discussed further below.

170 The memo raises important and timely questions about the electric grid. Those questions can only be
171 answered by recognizing that generators and the grid are part of a larger electric power system,
172 viewing the retirements story not just as a battle between generators, transmission owners and fuel
173 sources, but also including customers and their options and preferences along with the supply side.
174 Many of the technologies that we use to produce and consume electricity and energy have changed
175 extensively over the past twenty years. These changes have caused great disruptions to the legacy
176 resources and assumptions that formed the bulk power system we operate today. The questions here
177 are as much about how to deal with and manage broad technological and economic change for a
178 critical national infrastructure as they are about whether the erosion of baseload power plants
179 threatens grid reliability.

180 The problems affecting baseload resources today reflect the broader challenge of how the energy
181 industry can constructively manage change as technologies and economic relationships evolve.

182 Because the above goals may conflict and require delicate balancing by policymakers – for instance,
183 high levels of reliability can become expensive, which works against affordability. Given growing levels
184 of uncertainty and volatility from technology, finance, world threats, environment, etc., it is prudent to
185 compile diverse portfolios that can provide a variety of important attributes. Secretary Perry's memo
186 essentially asks how we should go about building such portfolios, and directs us to understand the
187 consequences for the nation's electric resource portfolio options as significant amounts of coal and
188 nuclear resources become unavailable to serve in current and future portfolios.

189 The stakes are high around these issues because electricity is so crucial to modern society and
190 economic activity, and because of the magnitude of the industry and its capital and revenues. The
191 United States has around 7,700 operating power plants¹ that generate electricity from a variety of
192 primary energy sources; 707,000 miles of high-voltage transmission lines;² more than 1 million rooftop
193 solar installations;³ 55,800 substations;⁴ 6.5 million miles of local distribution lines;⁵ and 3,354

^a The Secretary's memo is attached in Appendix A.

194 distribution utilities⁶ delivering electricity to 148.6 million customers.^{b7} The total amount of money
195 paid by end users for electricity in 2015 was about \$400 billion.⁸ This drives an \$18.6 trillion U.S. gross
196 domestic product and significantly influences global economic activity totaling roughly \$80 trillion.⁹

197 1.1 Study Outline

198 Chapters 1 through 0 of this study provide the analytical framework, relevant data about the power
199 system and generation retirements, and lay out the research and findings about baseload power,
200 reliability, resilience and renewables.

201 Secretary Perry asked for specific recommendations for how to address and resolve these issues. Since
202 there are many paths that could be taken from here, for many actors besides the federal government,
203 Chapter 0 offers a comprehensive catalog of actions that could be undertaken. This section is intended
204 to inform and motivate further discussion and action within and across the electric stakeholder
205 community.

206 Outline here

207 Chapter 0 recommends specific actions and measures that can be undertaken immediately to address
208 the most pressing issues identified in this study. Some of these actions fall within the scope and
209 authority of the Department of Energy. However, some recommendations point to broader solutions
210 that the Department cannot enact alone.

211 The Appendices contain the following information:

- 212 • Appendix A contains Secretary Perry's April 14 memorandum, which initiated this study.
- 213 • Appendix B lists all of the power plants in the Energy Information Agency's database that have
214 retired in the United States since 2000.
- 215 • Appendix C lists all of the major U.S. statutes and regulations that have affected electricity
216 supply and demand.
- 217 • Appendix D contains an extensive set of tables and graphics that support the information
218 provided in the body of this report.
- 219 • Appendix E lists all of the technical reports and studies that the Department of Energy and its
220 national laboratories have prepared since 2012 on topics relating to the issues addressed in this
221 study.
- 222 • Appendix F offers a set of technical references for those who wish to learn more about the
223 topics addressed in this study.
- 224

^b A "customer" is defined as an entity that is consuming electricity at one electric meter. Thus, a customer may be a large factory, a commercial establishment, or a residence. A rough rule of thumb is that each residential electric meter serves 2.5 people. Of the Nation's 147 million customers, 13 million now purchase electricity from non-utility retail service providers, comprising 20 percent of all U.S. retail electric sales (megawatt-hours) and delivered mostly by investor-owned distribution utilities, in the 19 states and District of Columbia that allow retail competition.

Excluded from this study

Several topics are not addressed in this study, for the reasons explained here.

Cyber-security is the common potential failure mode that affects every part of the American power system – every power plant, every transmission and distribution system, every user and many end use devices are at risk from existing and emerging cyber-security threats. Because the cyber-security problem is ubiquitous, this study does not address cyber-security because it does not have any unique relevance or impact on baseload power plant retirements, renewables, and power system reliability.

Alaska & Hawaii -- The analyses that follow do not directly address the oil, coal and gas plants in Hawaii and Alaska. Those plants are small plants that fall below the size screens used in this study, and the Hawaii and Alaska power systems are remote, vertically integrated systems with special needs and issues. While the broad trends discussed in this study apply in Hawaii and Alaska as well as on the mainland United States, many of this study's economic observations do not directly apply to the specific situations in the Hawaii and Alaska power systems.

Geothermal, oil and biomass steam generation – Geothermal, oil and biomass power plants are often operated as baseload plants, operating at a relatively stable level over a long period of time. Since these types plants are not as prevalent or widespread as gas, coal and nuclear plants, such units are not examined in this study.

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1.2 Findings of this study

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Based on an extensive review of electric power system evolution and events over the past thirty years, and analysis of DOE and other data sources using basic supply and demand principles, this study concludes that:

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- Functionality, not technology -- Baseload power plants should be defined in terms of functionality rather than fuel or technology. Baseload plants are those dispatched to serve customers' base (minimum) load. These plants are operated within a relatively fixed operational zone over an extended period of time (days or weeks), with limited cycling or ramping capability. The generating technology types that meet this definition include coal, nuclear, gas-fired steam and combined cycle plants. (See Section 2)

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- Many baseload plant retirements are not premature. Since 2002, most baseload power plant retirements have been the victims of overcapacity and relatively high operating costs that often reflect the advanced age of the retiring plants. Many of these retired plants had already complied with some of the environmental regulations implemented under statutes enacted between 1970 and 2001, but had not yet complied with the later requirements imposed by these regulations. Furthermore, the first tranche of fossil plant retirements occurred before the explosive growth of renewable generation over the past five years. Many of the on-going stream of plant retirements have been driven by the combination of low natural gas price-based electricity prices, low electric demand, environmental regulations, state policies, and competition from renewables. In other words, many retirements are consistent with observed market forces. (See Section 3)

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- Some baseload plant retirements have been premature relative to their design life and operational efficiency. Costly environmental regulations and subsidized renewable generation

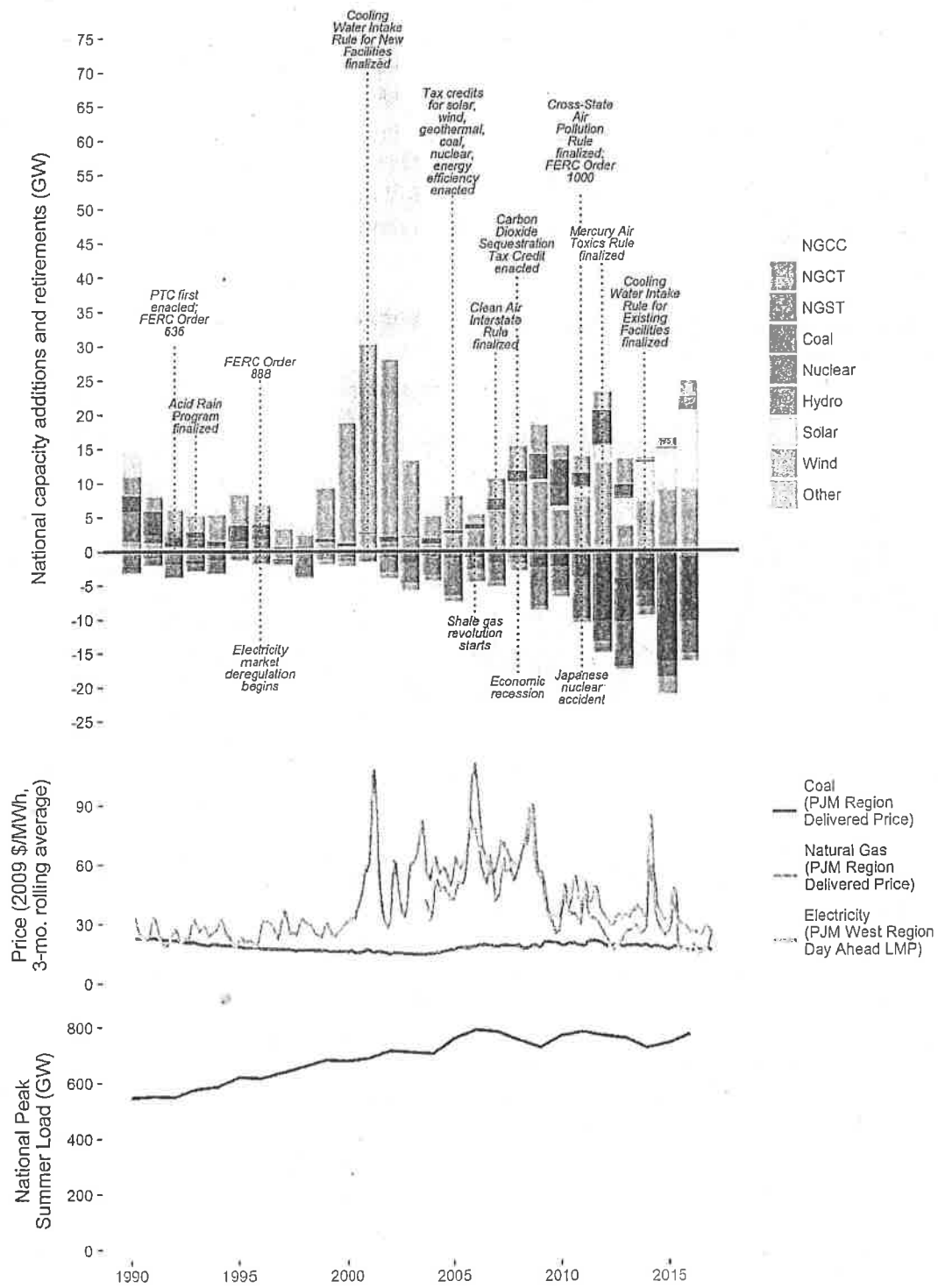
249 have exacerbated and accelerated baseload power plant retirements. However, those factors
250 played minor roles compared to the long-standing drop in electricity demand relative to
251 previous expectations and years of low electric prices driven by high natural gas availability.
252 (See Section 3.12)

- 253 • Baseload history -- Most baseload plants were built between the 1950s and 1990s under cost-of-
254 service regulation, where regulators approved the construction and on-going cost-pass-through
255 for "prudent" utility-recommended plants. Vertically integrated utilities built increasingly larger
256 coal and nuclear plants using contemporaneous technologies to capture economies of scale and
257 efficiency, and marketed any excess power to their neighbors. After Congress committed the
258 nation to allow new third-party generator entrants (PURPA, 1978) and to mandate open access
259 to the transmission system (EPACT, 1992), FERC implemented regulations encouraging the
260 formation of centrally-organized wholesale markets. Many of the older baseload plants were
261 forced to compete in these open markets against lower-priced generators. While the owners of
262 these assets enjoyed profits associated with high wholesale prices for several years, by 2005
263 many of the older baseload plants had been sold to independent power producers and lost the
264 protection of rate-based status and the opportunity to earn a specified rate of return. Many
265 inefficient plants retired in those years. Even those plants still owned by integrated utilities are
266 having to compete against third-party and market opportunities as state regulators and
267 abundant low-cost power opportunities push utilities to acquire more cost-effective power
268 portfolios. (See Section x)
- 269 • Retirement history -- The retirement of baseload power plants has accelerated since 2009.
270 (Figure 1.2) Baseload retirements correlate closely to the fall in natural gas prices and the
271 flattening of customer peak demand.

272 Add labels in graph in high white space above X axis (Capacity additions) and low below
273 (capacity retirements)

274 Modify graphic to shrink middle right legend so main graphic gets more real estate

275 Figure 1.1. Timeline of Electric Generating Capacity Additions and Retirements, Tax Incentives,
 276 Orders and Regulations, Regional Market Prices, and Load^{c10}



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^c (Top) Implemented federal legislation and regulations are shown on a timeline with national changes in electric generating capacity and compared against (Middle) Regional market prices for the PJM region, and (Bottom) Summer peak electric demand. The type and quantity of capacity additions and retirements have changed notably

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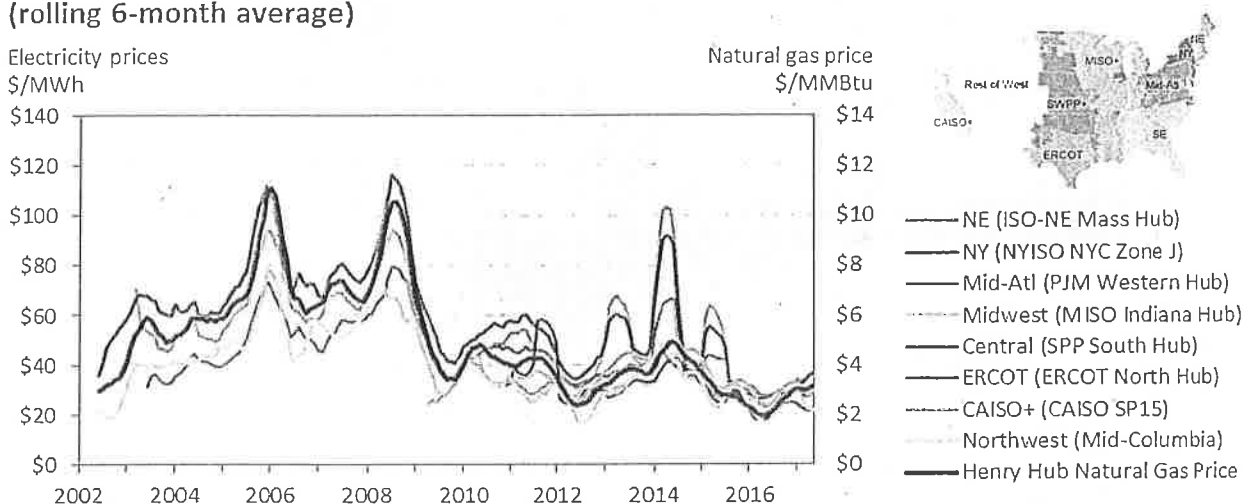
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- Growth of natural gas-fired generation -- While coal and nuclear power plants used to provide the bulk of America's electricity, wholesale electricity prices have closely tracked natural gas prices for the past 15 years. (Figure 1.2) The fact that new, high-efficiency natural gas plants and the pipelines that serve them can be built quickly helped to grow gas-fired generation relative to coal and nuclear power. After unconventional production techniques for oil and gas entered the scene in 2007, natural gas prices began falling and have stayed low. As a result, newer, more flexible gas-fired plants began driving down market-clearing electric prices in 2009, under-cutting the higher production costs of older coal and nuclear generators. (See Section x)

Figure 1.2. Electricity prices track natural gas prices¹¹

Regional wholesale day-ahead electricity prices vs. Henry Hub natural gas price (rolling 6-month average)



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- Renewables didn't cause retirements, but they've exacerbated the problem – Baseload plant retirements due to age, inefficiency, and inability to compete began appearing in the early 2000s, well before any significant levels of wind and solar generation in any region of the country. But starting around 2007, variable renewable generation (VRE) – particularly wind and solar – have grown quickly, accelerated by the favorable effects of state Renewable Portfolio Standards (RPS) and the subsidizing effects of federal tax credits. Because VREs are neither fully controllable nor predictable, but very low-cost, they have displaced other generation and forced a change in the way operators manage the grid. Current levels of wind and solar penetration are reducing the level of net baseload generation and requiring affected regions to demand that all power plants operate with greater flexibility and provide essential reliability services such as frequency response, cycling and ramping. While baseload plants provide valuable inertia that helps with frequency regulation, most coal and nuclear plants are not capable of flexible ramping and cycling and cannot beak even operating at lower capacity factors.

over the past decades. Technology costs (not shown), fuel prices, tax incentives for various generating technologies, market deregulation, environmental regulations mainly to protect air quality, but also water quality, weather and economic events, efficiency and age of the generating fleet (shown elsewhere), and flattening of electricity demand have all contributed to the change in electric generating capacity. Note: this graphic does not quantify the impact of various market effects and policies on electric generating capacity.

- 303 • Each retirement decision is unique to a particular situation. But every retirement decision
304 reflects the owner's assessment of whether that plant will be produce enough energy, paid at
305 high enough prices, to recover the costs of its fuel, operations and capital requirements,
306 including potential new capital investments. Over the past decade, many power plant owners
307 have concluded that plants with higher heat rates, limited ability to operate flexibly, and that
308 need capital improvements to meet environmental regulations, will not be able to earn
309 adequate revenues in wholesale electric markets that select and dispatch resources based
310 principally on short-run marginal costs. Many of the coal retirements in 2015 in particular were
311 prompted by decisions about whether the costs of investing in a plant to comply with MATS
312 regulations would ever be recovered given market prospects for continuing low demand and
313 low prices, or close the plant to avoid that investment. Similarly, the timing of some nuclear
314 retirement decisions appears to be related to nuclear relicensing and regulatory compliance
315 schedules. Environmental regulatory requirements may have been the straw that broke a
316 baseload camel's back -- particularly for coal plants -- but it appears that most baseload plants
317 were already burdened by the effects of low natural gas prices, eroding customer demand, and
318 lower capacity factors before the incremental burden of new regulations tipped the balance
319 over to retirement. (See Section 3)
- 320 • Regional factors drive retirements – Coal and nuclear assets tend to be concentrated in a few
321 regions of the country, as are wind and solar development. (Figure 1.3) Baseload plant
322 retirements tend to be concentrated in areas that moved to wholesale and retail electric
323 competition earlier, and came later to regions that remained under vertical integration and full
324 cost-of-service regulation. Therefore, the retirements challenge is concentrated in the
325 Northeast and the Mid-Atlantic rather than nationwide, while the challenge of managing high
326 penetrations of renewable generation is concentrated in Texas, California, the Southwest and
327 Midwest.

328 **Figure 1.3 Baseload plant retirements vary by region^{12 13 d}**

^d Generator units larger than 50 MW of net summer capacity. The Other category includes a combined 936 MW of biomass, wind, petroleum coke, and syngas from petroleum coke. Retirements reflect regional fuel use and historic concentrations of power plants.

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2 Assessing baseload resources

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The electric industry refers to baseload generation as the power plants that are used to meet base load – the minimum level of electricity that customers demand around the clock, as shown in Figure 2.1.

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Baseload plants have high capital and operating costs but – until recently – have low fuel costs and good fuel efficiency. Although the output level of these plants can be changed, they are most economical when operated at near-full capacity at all times. Large baseload units have longer start-up and shut-down times (cycling) and must move slowly between production levels (cycling) to avoid damaging plant components with thermal stress or metal fatigue.

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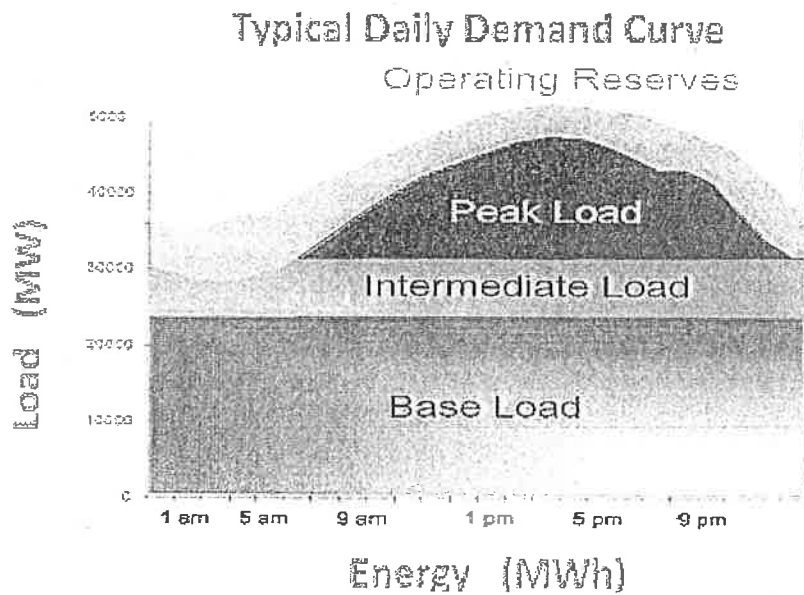
Large nuclear, coal-fired, natural gas-fired steam and run-of-river hydroelectric plants have historically been used for baseload generation. With the recent drop in natural gas prices, it has become more economical to use natural gas-fired combined cycle plants as baseload generation.

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Figure 2.1. Schematic of customer daily load curve showing base load¹⁶



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Intermediate or mid-merit plants are used to follow load, meeting daily variations in demand. Natural gas combined cycle plants have traditionally been used for load-following. Peaking generators (mostly gas turbines which are low-cost to build but have high heat rates) and customer-provided demand response are dispatched infrequently to meet extreme spikes in demand. Appendix D contains D-1, a description of the types of power plants, and D.2, a description of how generators are selected (dispatched) to produce electricity.

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For this study, DOE defines baseload generators as plants that are operated in the pattern of baseload generation described above – they were operated for many years to run at high, sustained output levels and high capacity factors with minimal cycling or ramping. While this definition includes most nuclear, coal and gas-fired steam generators, it is not a given that every nuclear, coal-fired or gas-fired steam generator is a baseload plant.

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693 NERC draws a distinction between baseload generation and the characteristics of generation
694 providing reliable baseload power¹⁷:

695 Coal and nuclear resources, by design, are designed for low cost O&M and continuous
696 operation. However, it is not the economics nor the fuel type that make these resources
697 attractive from a reliability perspective. Rather, these conventional steam-driven
698 generation resources have low forced and maintenance outage hours traditionally and
699 have low exposure to fuel supply chain issues. Therefore, "baseload" generation is not a
700 requirement; however, having a portion of a resource fleet with high reliability
701 characteristics, such as low forced and maintenance outage rates and low exposure to
702 fuel supply chain issues, is one of the most fundamental necessities of a reliable [bulk
703 power system].

704 Power plant cycling

705 With increased variable renewable energy generation and lower electricity demand, all power plants
706 have had less ability to run in a baseload generation pattern and have been asked to cycle and ramp
707 more often. Plants that can't cycle or ramp will operate less, earning less revenue and possibly
708 becoming unprofitable. GE, a major power plant manufacturer, reports that cycling costs are one to
709 seven percent of overall fossil plant construction cost and that the average fossil-fueled plant sees an
710 O&M cost increase of \$0.47 to \$1.28 per MWh produced. GE observes that:

- 711 • Wear-and-tear cycling costs can increase with the changing power portfolio or fuel prices.
- 712 • These costs are generator-specific. They can impact financial viability of generators.
- 713 • Incorporating cycling costs into commitment and dispatch decisions can change these decisions.
- 714 • Solar and wind have different impacts on cycling.¹⁸
- 715 • Operational and/or physical changes to coal/gas plants can increase flexibility. Retrofits have
716 the potential to increase overall profitability.¹⁹

717 The cycling issues described above have similar impacts on gas-fired steam and older combined
718 cycle generators. [also nuclear?]

719 **2.1 Applying the baseload generation** 720 **definition**

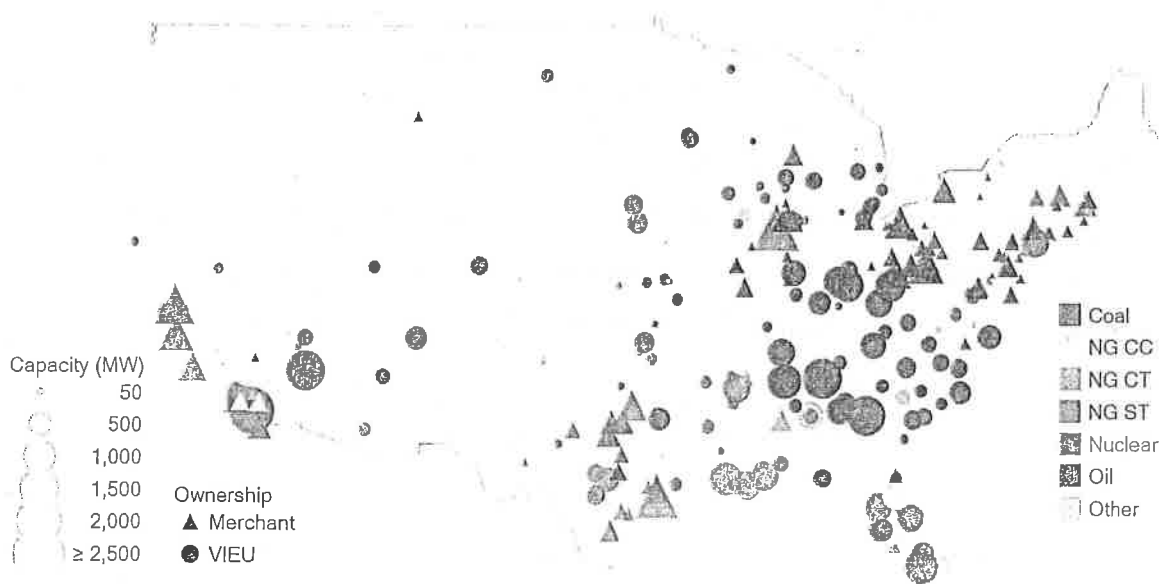
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723 **2.2 Baseload generation – looking** 724 **forward and next steps**

3 Baseload plant retirements – what retired and why

As Figure 3.1 shows, the baseload retirements issue is essentially a regional issue – types of plants and capabilities vary by region, as do the magnitude and timing of retirements. This section opens with an overview of power plant retirements nationwide, then looks at the reasons why baseload plants are retiring – the causes are a stew of market-affecting factors including low natural gas prices, wholesale competition, the flattening of customer demand, cost increases relating to regulation, the growth of renewable generation devaluing baseload generation in favor of greater flexibility, and the decision-forcing effects of regulatory deadlines.

Figure 3.1. Map of baseload (coal, nuclear, gas thermal, hydro) retirements

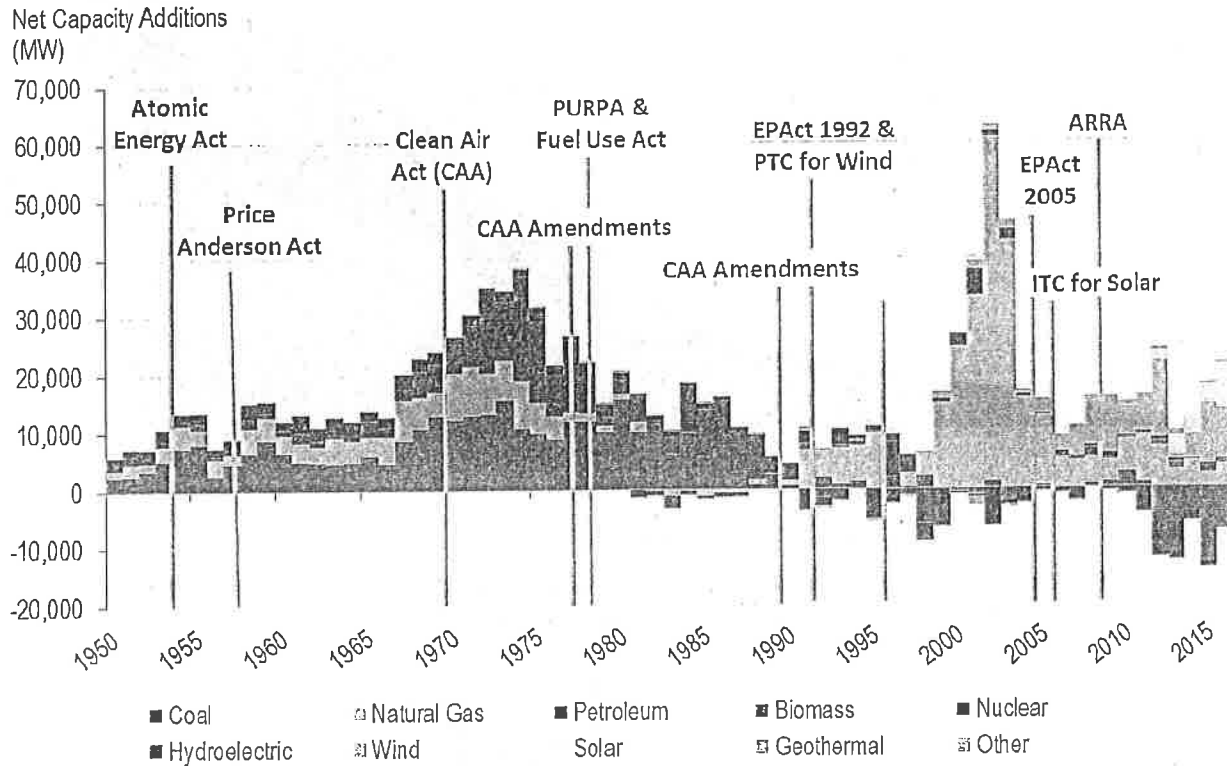


Location of Coal, Natural Gas, Nuclear, Petroleum, and Other Generating Plant Retirements by Ownership and Fuel Types, January 2002 – March 2017^{20 21}

3.1 Overview -- power plant retirements since 2000

Capacity additions of different generation technologies came in waves that were largely influenced by policy, fuel costs, and technology development. The 1930s and 1940s fostered the development of hydropower; nuclear power was widely deployed in the 1970s after nuclear research for peaceful uses was allowed; natural gas additions peaked in the 2000s; and non-hydro renewables are quickly growing in the 21st century. Note that the deployment of these generation technologies followed Federal policies and technology development—e.g., nuclear power reactors and natural gas combined-cycle turbines—by several decades. Acronyms: Clean Air Act (CAA), Energy Policy Act of 1992 (EPAct 1992), Energy Policy Act of 2005 (EPAct 2005), Investment Tax Credit (ITC), Production Tax Credit (PTC).

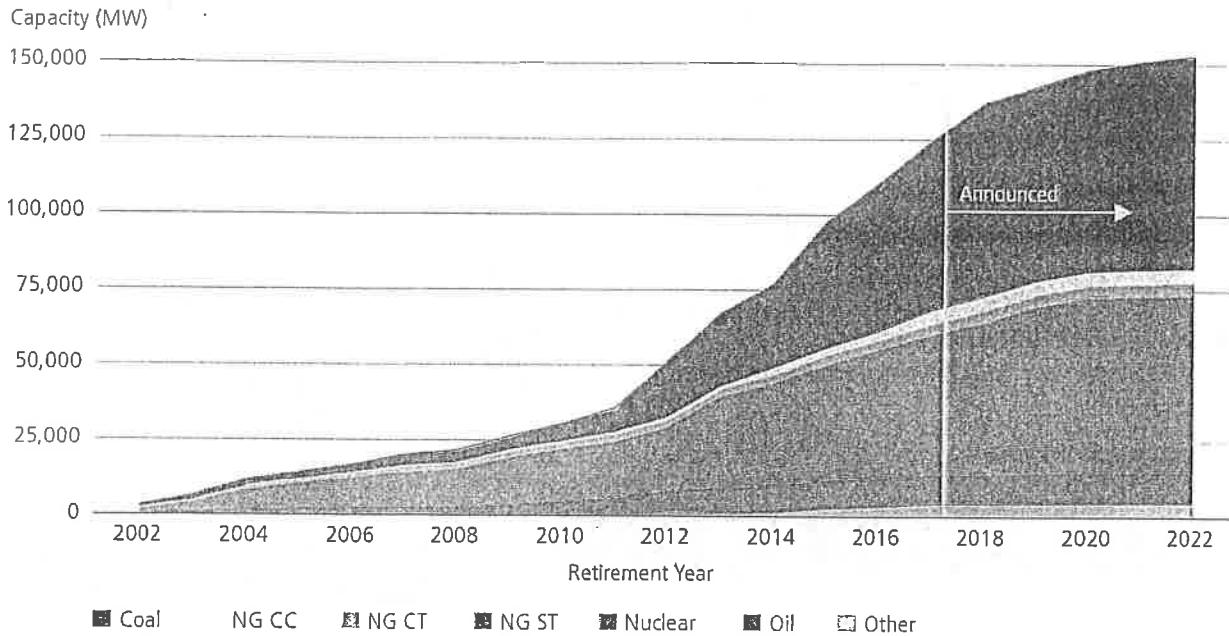
748 **Figure 3.2. Net Generation Capacity Additions and Retirements.**²² (Source: QER Updated Figure
 749 1-1)



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 751 Similar policies and developments that drove waves of power plant construction similarly drove
 752 retirements over the last two decades, with power plant age and technology vintage an important factor
 753 in plant retirement patterns.

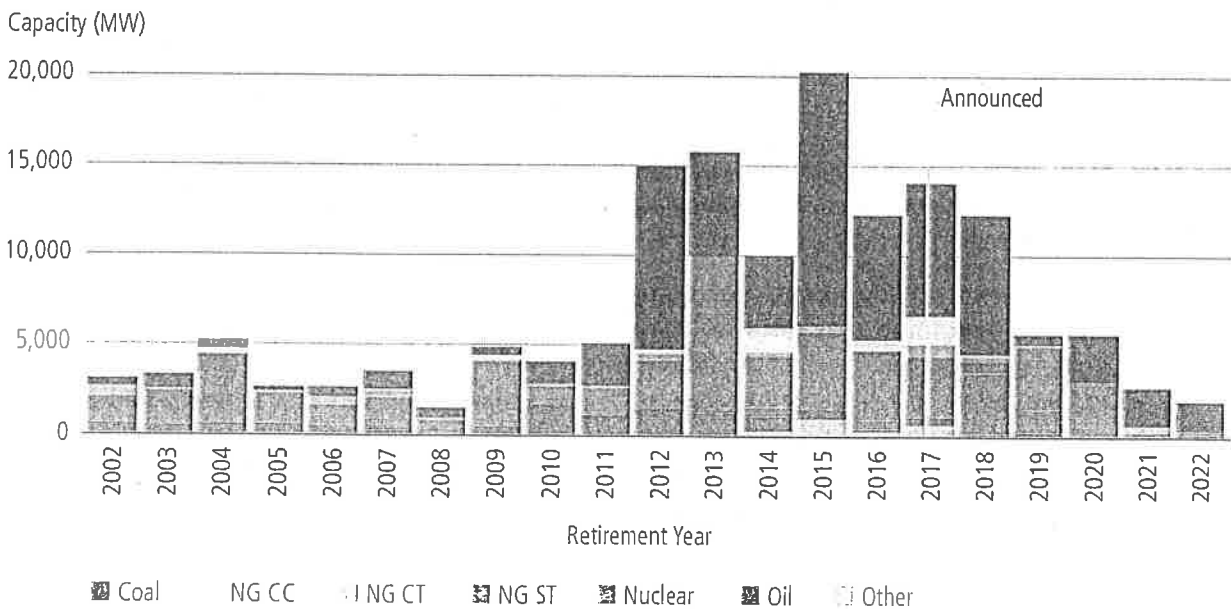
754 Power plant retirements are nothing new – significant generation retirements in the current age began
 755 in 2002, and have accelerated since, as shown in Figures 3.3 and 3.4. Retirements have been due
 756 primarily to flattened demand and low electric prices and the inability to compete successfully due to
 757 plant age, inefficiency and capital needs rather than regulatory burdens. Retirements of baseload plants
 758 (gas thermal, coal, hydro and nuclear) have been going on for at least 15 years.

759 **Figure 3.3. Cumulative Retirements of Utility-Scale Electricity Generation Capacity January 2002**
 760 **– March 2017, and Announced Retirements April 2017 – December 2022**^{23 24}



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Figure 3.4. Historic and Announced Annual Retirements of Coal, Natural Gas, Nuclear, Petroleum, and Other Generating Units, January 2002 through December 2022^{25 26}



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766 Why plants retire

767 A power plant owner decides whether to retire a plant based on rational expectations of whether the
768 owner can recover sufficient revenues to justify continued operation.

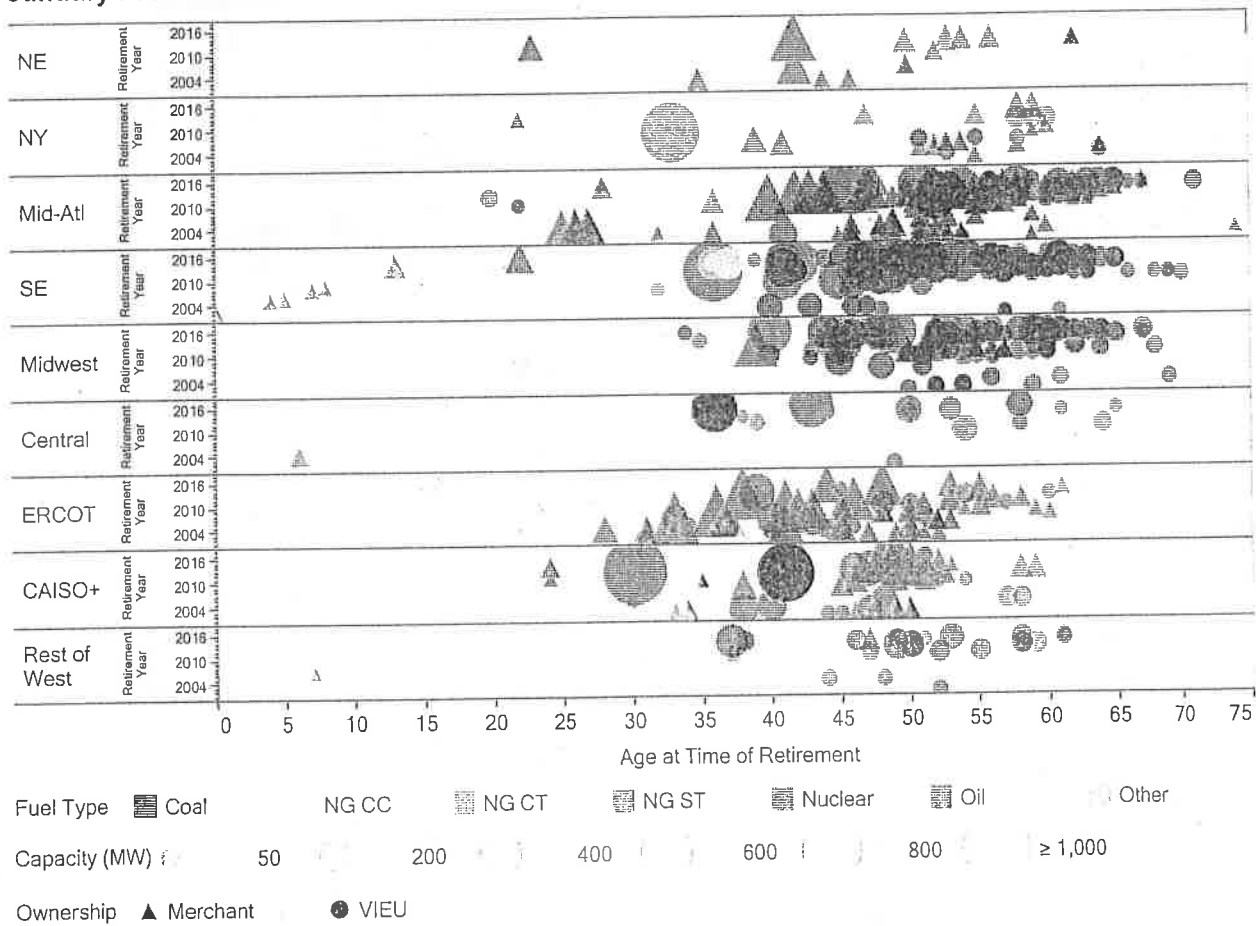
769 Add explanation of the elements of a decision whether to close a power plant – forward-looking,
770 how many years time horizon, whether there’s expected demand, anticipated prices, expected
771 capital, operating, fuel costs, your competitiveness against other resources. How long does it
772 take to execute a retirement decision? Forcing effect of a regulatory deadline (hydro

773 relicensing, nuclear relicensing, environmental compliance deadline) on when you start the
 774 analysis, when you make the decision and how long you keep running the plant.

775 Regulators imposing IRP and pushing for least-cost resource portfolios (Midwest and some other
 776 vertically integrated states, Hawaii) have been the cause of some recent VIEU abandonments for
 777 portfolio restructuring.

778 A review of coal, nuclear and natural gas retirements to date (2002 through May 2017) shows that
 779 baseload plant retirements are a regional issue, reflecting regional patterns of generation development,
 780 affecting different regions in very different ways. Statement about region with most MW retired.
 781 Most of the power plants retired were 40 years old or older by their retirement date. And most
 782 retirements are concentrated in the East where more plants were built earlier, to serve larger
 783 populations (Figure 3.5).

784 **Figure 3.5. Generating Unit Retirements by Region, Unit Age, Ownership, and Retirement Year,**
 785 **January 2002 – March 2017^{27 28}**

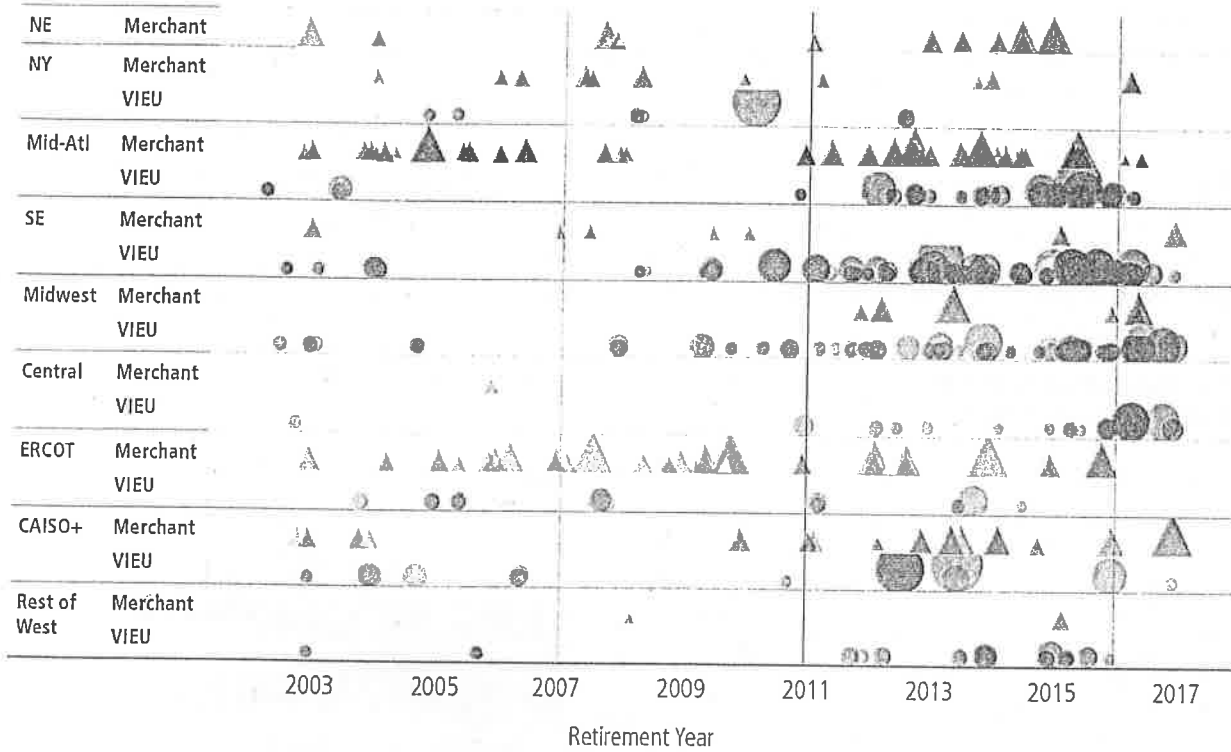


786 Ownership ▲ Merchant ● VIEU

787 Figure 3.6 focuses on the year of power plant retirement. This is important because a variety of
 788 economic trends and regulatory events occurred in different periods over the 2002 through 2016
 789 period. This figure shows that merchant plants made up the majority of the baseload plants that
 790 retired in the 2002 through 2011 period, because those plants were more directly exposed to
 791 competitive wholesale market prices and more likely to exit the market quickly if a plant was losing
 792 money. Generators that have long-term bilateral PPAs or are utility-owned self-supply (same LT PPA
 793 contract) gets exposed to true market prices much later than merchant plants competing for only short-
 794 term bilateral contracts or in spot market.

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Figure 3.6: Generating Unit Retirements by Region, Ownership, Capacity, and Fuel Type, January 2002 – March 2017^{29 30}



Fuel Type

■ Coal NG CC ▨ NG CT ■ NG ST ■ Nuclear ■ Oil □ Other

Capacity (MW)

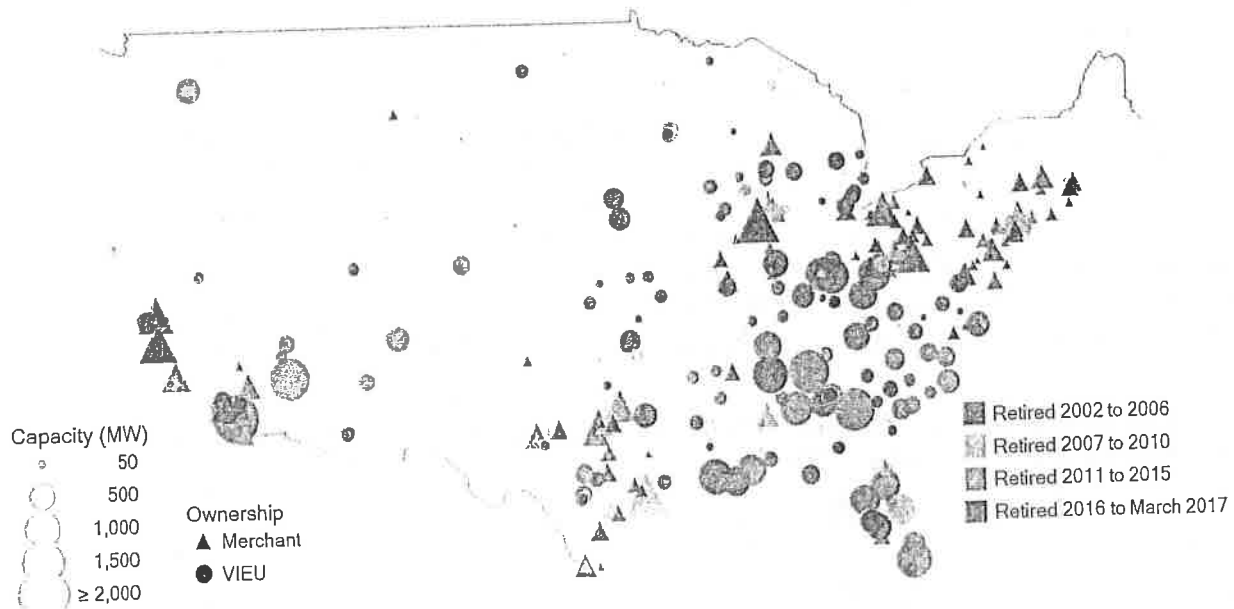
○ 50 ○ 200 ○ 400 ○ 600 ○ 800 ○ ≥1,000

Ownership

▲ Merchant ● VIEU

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Figure 3.7: Power Plant Retirements by Retirement Period, January 2002 through March 2017^{31 32}



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802 Figure 3.7 shows:

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- The 2002 through 2005 period was when the wholesale competition initiated in the late 1990s got underway, with forced utility (called Vertically Integrated on these charts) power plant divestiture moving a number of power plants into merchant ownership in California, Texas, and the mid-Atlantic states in particular. Most of the retirements that occurred in this period were of smaller, older merchant power plants that were inefficient and borderline uneconomic before a utility owner sold it to the new merchant owner. Most of these retirements occurred in centrally-organized markets, particularly PJM and ERCOT.

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- The period from 2006 through 2011 saw some early environmental regulations begin to affect the coal fleet, the early growth of utility-scale wind generation, the economic recession from 2008 through 2011, and the start of the shale gas boom in 2008 with natural gas prices starting a downward trend a decade ago. Old, inefficient natural gas-fired plants retired early in this period, but the fall in natural gas prices starting in 2009 began to force the shut-down of smaller, older coal plants and older oil plants in 2009 through 2012. At the same time it became clear that a portion of the customer electricity demand lost from the recession was not going to reappear, which meant that higher demands would not absorb more costly electric production at higher levels on the energy supply curve.

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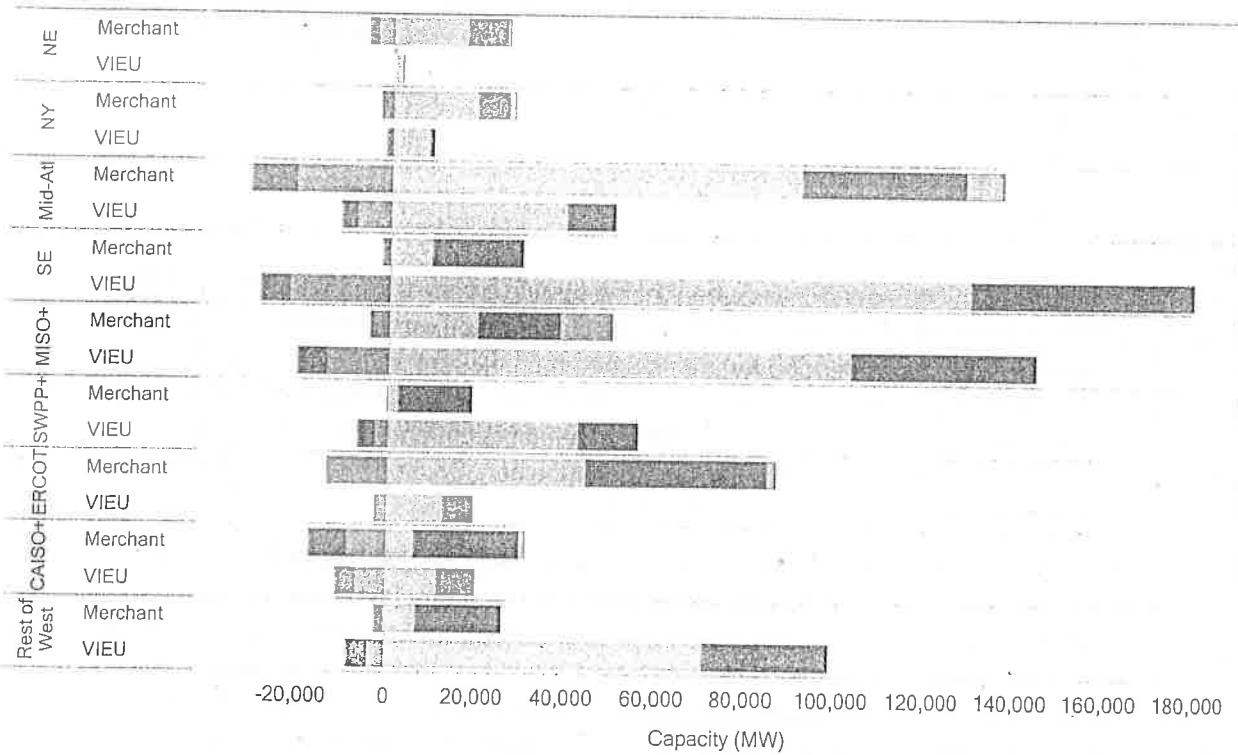
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- In the period from 2012 through 2015, it became clear that low natural gas prices were probably a long-lasting trend rather than a short-term phenomenon. And this was the period when the compliance deadlines for a number of environmental regulations, initiated under several different statutes, all converged. This is the period with the most baseload plant retirements, with a marked increase in California, the mid-Atlantic, Midwest and Southeast. Most of these plants were rendered uneconomic and uncompetitive low-priced natural gas-fired generation, in a significantly flattened supply curve meeting a lower demand curve. The 2015 MATS compliance deadline was the last of these deadlines, so many of the retirements in this period were of plants whose owners chose to shut down a plant rather than invest in one or multiple costly environmental remediation measures. (See Section 3.6 on regulation)

- In 2016 and 2017, going forward, on-going power plant retirements are those that have been rendered uneconomic by sustained low electric prices.

Figure 3.8 illustrates merchant and VIEU retirements from 2002 through 2016, announced retirements through 2022, generation capacity that was operational prior to 2002 and is still in operation, capacity that was added between 2002 and 2016, and demand response in 2016. Figure 3.8 shows generation capacity, additions, retirements, announced retirements, and demand response as a percentage of 2002 total installed capacity in each region. These graphics show that in every region, the proportion of retirements (in orange) is less than 20 percent of total capacity available, and that in those regions with a larger share of merchant generation, much more merchant capacity retired than vertically-owned utility plants.

Figure 3.8: Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region, January 2002 – December 2022^{33 34}



Retired Between 2002 to 2016
 Operating 2002 to Present
 Demand Response as of 2016
 Planned for Retirement Before 2022
 Added Between 2002 to 2016

Other regional conclusions can be drawn from the above data:

- New England has not seen a high proportion of retirements. Their reliability concerns focus principally on gas-electric interdependence challenges rather than on a shortfall of baseload generation.
- ERCOT has experienced continued churn of its natural gas-fired generation fleet due to the combination of fierce wholesale competition, rock-bottom natural gas prices, and easy entry and exit to the generation market. Texas has experienced strong growth of renewable generation (principally wind), with enough new transmission built to remove the transmission constraint that protected most of the region’s generation from the low and negative price levels set by wind and gas-fired generation in West Texas.

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- Baseload retirements occurred later in the Southeast, Central, Midwest and West than they did in other regions. This is because those regions are dominated by vertically integrated utilities under traditional regulation, so the utilities could recover costs and capital returns on less economic plants for a longer period than merchant generators without ratebase protection and captive ratepayers. Regulators in many of these states also have utility-specific resource adequacy or reserve margin requirements, which would justify retaining a plant longer than its short-term economics might otherwise support.

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860 **3.2 Big picture – multiple causes**

861 **compounded to force power plant**

862 **retirements, changing the supply curve**

863 **for electricity**

864 There have been three statistical studies of the causes of baseload power plant retirements.

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- The Columbia University Center on Global Energy Policy Study, “Can Coal Make a Comeback,” (April 2017) found that 49% of the collapse of the domestic coal industry has been due to increased competition from high volumes of low-cost natural gas, 26% from lower-than-expected electricity demand, and 18% due to the growth of renewable energy.³⁵
 - The draft Lawrence Berkeley National Lab study, “Power Plant Retirements: Trends and Possible Drivers,” (June 2017), found the strongest correlations to coal, nuclear and natural gas-fired plants lie with the diminishing load growth, high summer planning reserve margins (i.e., over-capacity), coal plants using high SO₂ emissions rates (i.e., they needed more costly environmental upgrades), low natural gas prices, and advancing generator age.
 - The Analysis Group study, “Markets, Reliability and the Evolving U.S. Power System,” (June 2017), looked at the decrease in prices per MWh in the PJM market (since that decrease would go straight to a coal plant’s bottom line) and concluded that of an almost \$30/MWh price drop, \$28.00 of the price decline was due to the decrease in natural gas prices, \$1.00 was due to the drop in electric demand growth, and \$0.39 would be due to new wind generation operating at full capacity.

880 More broadly, the data reviewed below indicate that retirements of nuclear, coal and natural gas

881 power plants have occurred for several reasons, but have been driven principally by the effects of

882 supply and demand upon old, inefficient power plants:

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- Reduction of demand growth (peak and energy) since late 1990s and flattening of demand since 2008 have reduced the room for less competitive plants to make sales.
 - The coal and most of the natural gas baseload plants that have retired are old and inefficient units that were not recovering their operations and fuel costs, much less capital cost recovery. Retirement decisions are based upon forward-looking expectations about whether a plant will be able to recover its costs and make a profit; since electric prices have been low for years, and are going lower, many coal and nuclear plant owners see little likelihood of earning full cost recovery from power market revenues alone.

- 891 • Merchant generators began retiring noticeable quantities of old, inefficient natural gas thermal
892 and coal plants (baseload capacity) in the early 2000s. Vertically integrated electric utilities
893 (VIEUs) began retiring more of these units after 2010, and the number of plants and MW
894 retired has accelerated over recent years. Most of the retirements before 2013 were owned by
895 merchant generators rather than vertically integrated electric utilities, and most of those
896 retired plants were gas-fired. Merchant plants that are directly exposed to market prices
897 without the protection of long-term self-supply arrangements or captive customers covering
898 capital and operating costs, would be the first to close if they were not competitive against
899 other sources.
- 900 • Electric energy prices across North America have been dictated by natural gas prices for over a
901 decade. After domestic and international natural gas prices began falling with the success of
902 shale gas and unconventional drilling, increased low-cost natural gas-fired generation began
903 displacing inefficient coal and gas-thermal generation.
- 904 • A significant number of coal plant retirements occurred in 2015, the last year that a coal or
905 plant needing to add pollution control equipment for MATS compliance could operate without
906 investing in the required pollution control equipment.
- 907 • The growth in variable renewable generation after 2007 (earlier inside ERCOT) has exacerbated
908 but did not cause the baseload retirements problem. (This is obvious from the fact that the
909 Southeast has seen significant retirements in recent years, but has almost no renewable
910 generation.) As shown in the ERCOT supply curve discussion, the low marginal cost of
911 renewable production lowers the supply curve and thereby the market-clearing price available
912 to all suppliers. At the same time, the variable output levels of renewable generators and the
913 fact that they reduce night-time minimum load and change daytime peak and ramping
914 requirements have reduced the opportunities for baseload plants to operate at sustained, high
915 output levels. This leads to reduced dispatch of baseload units at lower prices, higher operating
916 costs, and ultimately lower revenues insufficient to cover costs.
- 917

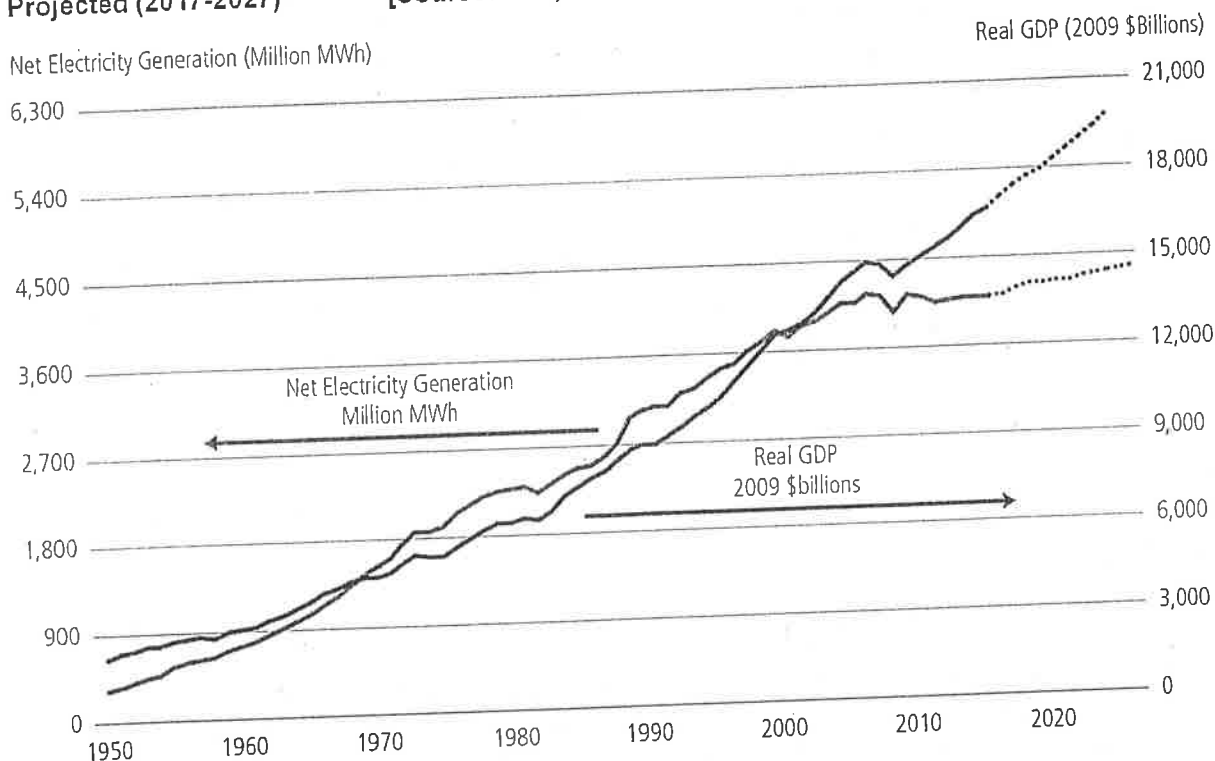
18 3.3 Cause -- electricity demand is lower 19 than projected

20 Between 1970 and 2005, total U.S. electricity generation grew steadily at a compound annual growth
21 rate (CAGR) of 2.7%. But since 2005, generation growth has stalled with a CAGR of only 0.05% from
22 2005 to 2015, even as the nation's gross domestic product grew by 1.3% per year over the same period.
23 [EIA].¹ As Figure 3.9 shows, although electricity demand used to rise in parallel with economic growth
24 (as measured by Real Gross Domestic Product), demand and GDP began decoupling around the year
25 2000. EIA attributes this fall in demand to a variety of factors including the impact of years of energy
26 efficiency standards improving building and appliances and technology improvements in lighting and
27 other end equipment, and broader economic factors such as a shift toward less electricity-intensive
28 industries and slower population growth. [EIA AEO 2017] The factors affecting the slowdown in energy
29 demand are shown in Figure 3.10. The dip in both GDP and electricity use in 2008-09 reflects the U.S.

¹ Note that this projected demand growth was not unique to EIA or the Annual Energy Outlook. Virtually every prominent projection of electricity demand included steady electricity demand growth.

930 recession, which lowered electricity usage enough to affect power plant economics and prompt some
 931 plant closures.

932 **Figure 3.9. Gross Domestic Product and Net Electricity Production, Historical (1950-2016) and**
 933 **Projected (2017-2027)**^{36 37 38 39} [Source: EIA, QER 1-28 updated]¹



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 936 **Figure 3.10. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy**
 937 **Efficiency, 1980 to 2016.**^{40 41}

938 [figure]
 939 It is difficult to forecast customer electric usage accurately. As shown in Figure 3.11, the recent history
 940 of the EIA's Annual Energy Outlook customer electric use projections show that DOE's expert
 941 forecasters – as most other energy experts – have consistently over-estimated actual U.S. electricity
 942 usage (see the blacked dotted line at the bottom of this figure). EIA and many other forecasters have
 943 consistently over-estimated peak demand as well as energy over recent years.^{k 1}

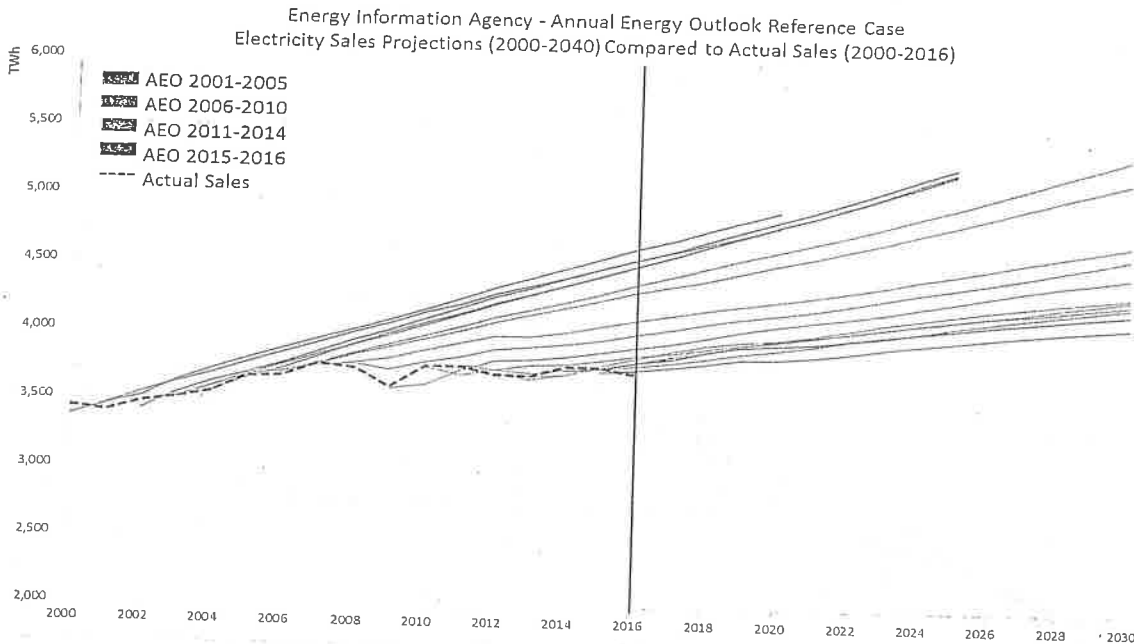
¹ Historically, from the 1950's to 1990's, electricity consumption and economic growth (measured here by real gross domestic product) have risen in parallel. Beginning in the 2000's, economic growth became decoupled from electricity consumption, as a result of continued progress in improved energy productivity across all economic sectors

^k For instance, MJ Bradley & Associates' "Load Forecast Analysis" (August 24, 2016) reviewed a number of electricity demand forecasts over time and concluded that most forecasts overshoot actual demand from 3 years out or farther, but improved in recent years and as the horizon between forecast and actual use year shortened. (http://www.mjbradley.com/sites/default/files/MJBA_LoadForecastAnalysis_FINAL_0.pdf)

¹ Over-estimating customer demand can have significant market impacts. During the 2000-2001 California electricity crisis, the electric utilities consistently overstated the amount of electricity that they wanted to purchase from the California Power Exchange, and then under-consumed from willing sellers the following day. More recently,

Figure 3.11. EIA annual electricity sales 2000-2016 (terawatts) and AEO reference case electricity sales projections 2017-2030^{m 42}

Bold up actual usage line and projections and axis numbers, cut off at 2025



Currently, about 90 percent of U.S. residential electricity, 60 percent of commercial, and 30 percent of industrial electricity consumption is used in appliances and equipment that are subject to Federal minimum efficiency standards implemented—and periodically updated by—the Department of Energy (DOE). Between 2009 and 2030, these cost-effective standards are projected to save consumers more than \$545 billion in utility costs, reduce energy consumption by 40.8 quadrillion British thermal units, and reduce carbon dioxide (CO₂) emissions by over 2.26 billion metric tons.

There are two significant impacts of the growth in energy efficiency. First, the unexpected flattening of energy and peak demand has changed suppliers' expectations and behavior relative to reasonable expectations when competitive energy markets began. In the 2000 to 2005 timeframe, investors and

merchant developer Panda Energy has filed suit against ERCOT (the Texas grid operator), claiming that ERCOT's consistently high demand forecasts fraudulently overstated the region's future electric requirements, predicting resource scarcity that never materialized. Panda claims that it built a 785 MW, \$2.2 billion gas plant on the basis of those "false and misleading" forecasts (as did other merchant developers) and when the high demands never materialized, ERCOT had overcapacity that drove down electricity prices and drove the Panda plant into bankruptcy only X years after it went on-line. See, for instance, "PE Firm Puts Plant Into Ch. 11, Blames Texas Grid Regulator," Law 360, Keith Goldberg, Law360, April 18, 2017, and "Power company sues grid operator over demand, supply projections," Jordan Blum, Houston Chronicle, March 26, 2016.

^m This figure demonstrates how changes in economic, market, and technological trends and in policies affecting energy use in the U.S. can affect total electricity sales. The AEO Reference Case is a business-as-usual trend estimate that assumes that laws and regulations in effect at the time are 'frozen' and continue throughout the timeframe of the projection. Its goal is to project what might happen in the future if no new policies are enacted—it does not attempt to forecast what will happen. Federal and state policies, market forces, and broader economic factors have had the net effect of lowering electricity consumption compared to what was expected to occur in absence of any change, as shown by the comparison of historical AEO Reference Case projections to actual U.S. electricity sales.

957 plant operators would have reasonably expected that growing customer demand for electricity would
 958 have assured that new generation capacity could be sold profitably.

959

3.4 Cause -- falling natural gas prices have reduced wholesale electricity prices

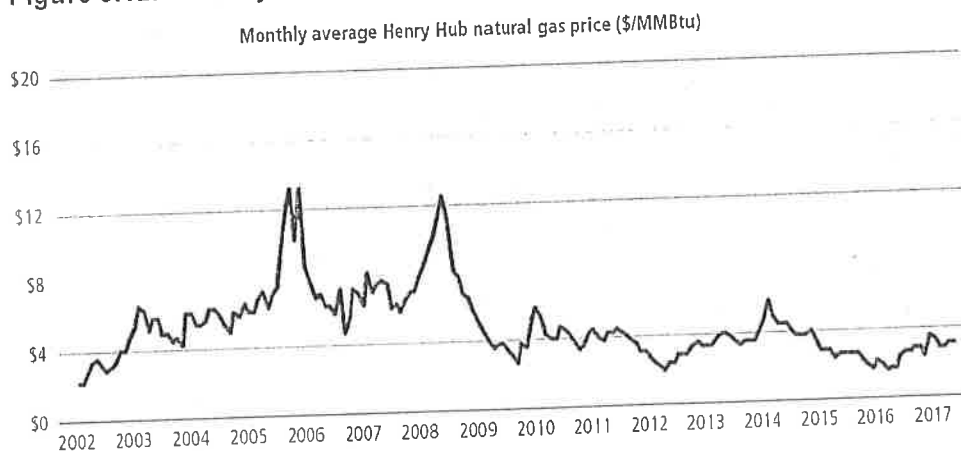
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963 Unconventional natural gas development, increasing in productivity between 2007 and 2009, has
 964 significantly expanded the availability of natural gas and lowered its cost across the U.S. and the world.
 965 Before the widespread use of unconventional drilling techniques in the past decade, natural gas prices
 966 in the U.S. approached \$14/mmBtu in several periods (including in 2005 after Hurricanes Katrina and
 967 Rita reduced production and delivery from Gulf of Mexico sources). As fracking practices spread and
 968 made previously inaccessible gas sources economic, natural gas prices dropped to below one-third of
 969 their former levels (See Figure 3.12).

970 **Figure 3.12: Monthly average Henry Hub natural gas price (\$/mmBtu)⁴³**



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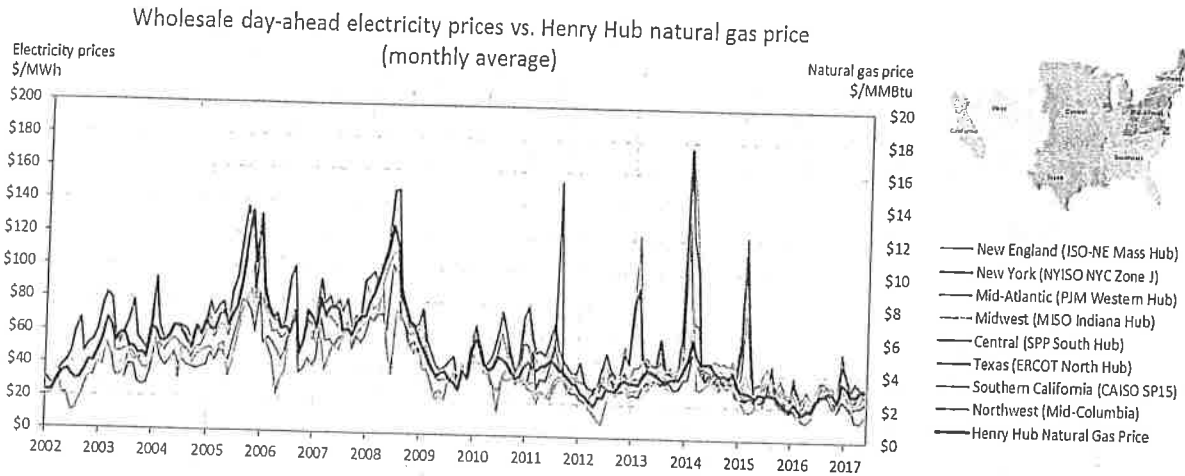
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973 Although coal and nuclear generation produced more energy per year than gas-fired generation,
 974 electricity prices have tracked natural gas prices for more than 15 years, as shown in Figure 3.13. This is
 975 because gas-fired mid-merit and peaker power plants have been the marginal generators following load
 976 in many hours of the day (as discussed in Section --), and their short-run marginal costs are driven by
 977 natural gas prices. Thus natural gas plants and gas prices have driven spot market electricity prices.
 978 Since spot market prices are used as a marker for setting prices for bilateral electric contracts, natural
 979 gas prices also drive the price for most of the wholesale electricity sold across the nation.ⁿ

ⁿ Although wholesale prices closely follow natural gas prices and are now at historically low levels, retail electric prices remain relatively flat and have not sunk as low as wholesale prices. This occurs for several reasons, including the need for retail rates to collect the utility's capital, operating and administrative costs for transmission and distribution, retail sales, and many other programs. Utility retail rates in vertically integrated states include return of and on capital investments in utility-owned power plants (which is not a protection available to merchant generation) and the costs of the total energy acquisition portfolio. State legislators and regulators also impose a variety of program requirements that may raise retail electricity costs.

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Figure 3.13. Wholesale day-ahead electricity prices vs. Henry Hub natural gas price (monthly average)⁴⁴



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Although natural gas is being blamed as the cause for major havoc within the power sector, the nation has realized extraordinary economic benefit from the fracking revolution. Since gas prices starting falling in 2009, the increased supply and lowered cost of natural gas has delivered effective benefits of \$ trillions to the American economy...

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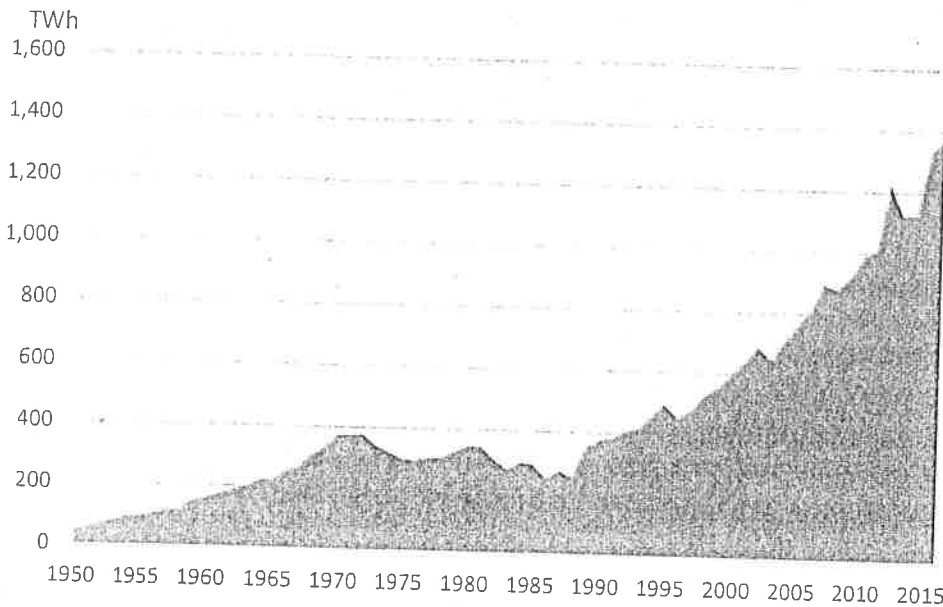
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Natural gas-fired generation has grown nearly continuously since the late 1980s. These plants have low capital costs and gas pipelines can be built more quickly than electric transmission lines, so it was often easier for a plant developer to build a new gas-fired plant near a large electric load than to build a higher-cost coal plant farther away and ship the coal by wire to large load centers.

Figure 3.14. U.S. Natural Gas Generation, 1950-2016. [Page 3-14]



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NGCC generators are very efficient, have unused capacity, and have significantly higher capacity factors than natural gas combustion turbines (CTs), which contribute primarily to peak load and may only operate for a few hours a year. Until recently, most NGCC units were utilized for intermediate and peak loads, rather than baseload. Because natural gas prices have been low for a sustained period, and

997 because NGCC plants retain some of the flexible characteristics of CTs and operate at a higher efficiency
998 and lower cost, these units are now often used for baseload power.

999 A CT's short start-up times and fast ramp rates makes it essential for maintaining grid reliability, absent
1000 affordable grid-scale storage, given today's resource mix. Capacity factors for CTs are quite low
1001 (generally below 10 percent), but when operating, they can be significant contributors to conventional
1002 air pollutants.⁴⁵ Single-cycle natural gas turbines can go from cold start-up to 100 percent output in 7–
1003 11 minutes; in contrast, coal-fired units ramp on the order of hours, and doing so incurs increased
1004 operations and maintenance costs.⁴⁶ NGCC ramp rates fall somewhere in between, and some NGCC
1005 units can ramp to full rated power in less than 30 minutes.⁴⁷ This flexibility makes CTs useful in
1006 complementing variable generation, especially for solar, because this flexibility complements the high
1007 peaks associated with solar generation and allows for load following. Some states rely on CTs more
1008 regularly than other locations; most notably, Texas, Louisiana, Wyoming, New Hampshire, Maine, and
1009 Rhode Island all have CT capacity factors greater than 20 percent.⁴⁸

1010 3.5 Cause – subsidies

1011 A subsidy is a transfer payment of funds from one group of people to another – federal or state
1012 taxpayers to nuclear plant owners, a utility's electric ratepayers to its energy efficiency users, federal
1013 taxpayers to renewable energy producers, and so on – to lower the effective cost of the benefiting
1014 technology or fuel source. Subsidies are created to perform different functions and serve varying public
1015 policy goals, including developing technology, advancing reliability, supporting an infant industry,
1016 creating or preserving local jobs, creating competitive international business advantage, or reducing
1017 power system pollution and emissions. All subsidies distort markets, but each affects different markets
1018 in different ways.

1019 Every form of energy and energy source present in modern electricity and energy service provision is
1020 subsidized or incented in one form or another, and most have been subsidized for many decades. The
1021 forms of subsidies and incentives in place today for energy resources include:

- 1022 • Tax policy (accelerated depreciation, depletion allowances, production tax credits, investment
1023 tax credits, etc.),
- 1024 • Regulatory requirements (safety and environmental requirements, renewable portfolio
1025 standards, ethanol use requirements, procurement mandates, efficiency standards),
- 1026 • R&D funding (research, development and demonstration), market purchases (particularly for
1027 federally-owned hydropower and transmission systems),
- 1028 • Government services (information and marketing, technology transfer, federal land and
1029 resource leases, provision of highways, ports and waterways) (the Congressional Budget Office
1030 estimates annual lost revenues due to low royalty rates for on-shore and off-shore oil, gas &
1031 coal resources at \$2 billion/year.
- 1032 • Disbursements (direct grants and subsidies, as for oil tankers, nuclear insurance guarantees, or
1033 ARRA grants)⁴⁹
- 1034 • Not charging for externalities such as pollution or increased need for grid integration services.

1035 The MIS study, prepared for the Nuclear Energy Institute, [MIS 2016] shows over the past two decades
1036 the largest energy subsidy beneficiaries have been coal and renewables and that tax incentives have
1037 been the means for the largest subsidies. MIS estimates that, "the federal government's primary

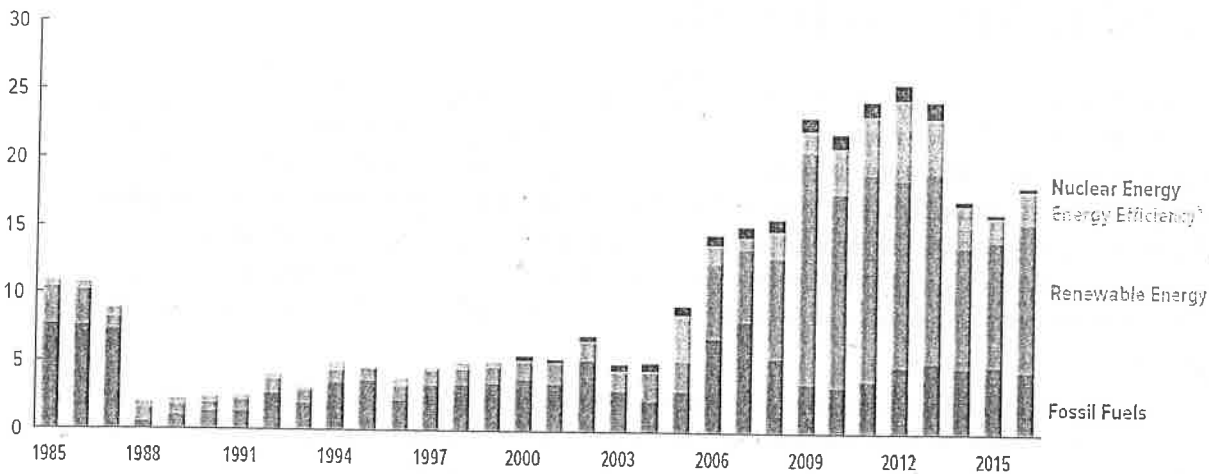
1038 support for nuclear energy development has been in the form of research and development (R&D)
 1039 programs, one of the more visible types of incentives identified. For the last 20 years, federal spending
 1040 on R&D for coal and for renewables has exceeded spending on nuclear energy R&D. Over the past six
 1041 years, 2011 through 2016, renewable energy received more than three times as much help in federal
 1042 incentives as oil, natural gas, coal, and nuclear combined, and 27 times as much as nuclear energy.”

1043 The Congressional Budget Office has estimated the costs of energy-related tax preferences – a limited
 1044 set of subsidies for a more limited period of time – over the period 1985 through 2016. As noted
 1045 above, tax preferences include depletion allowances (oil and gas, geothermal), investment tax
 1046 preferences (solar PV) and production tax credits (wind).

1047 **Figure 3.15: Costs of Energy-Related Tax Preferences, by Type of Fuel or Technology, 1985 to**
 1048 **2016**

Costs of Energy-Related Tax Preferences, by Type of Fuel or Technology, 1985 to 2016

Billions of 2016 Dollars



Source: Congressional Budget Office, using data from Molly F. Sherlock, *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures*, Report for Congress R41227 (Congressional Research Service, May 2, 2011), p. 26, and updated data from the Congressional Research Service; Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2016–2020*, JCX-3-17 (January 30, 2017), pp. 29–30, <http://go.usa.gov/xXBA6>; staff of the Joint Committee on Taxation, "Estimated Budget Effects of Division Q of Amendment #2 to the Senate Amendment to H.R. 2029 (Rules Committee Print 114-40), The 'Protecting Americans From Tax Hikes Act of 2015,'" JCX-143-15 (December 16, 2015), <http://go.usa.gov/xXKNZ>; Department of the Treasury, *Combined Statement of Receipts, Outlays, and Balances* (December 2016), <http://go.usa.gov/xXKN9>; and Office of Management and Budget, *Budget of the U.S. Government, Fiscal Year 2017: Appendix* (February 2016), p. 1025, <http://go.usa.gov/xXKNR>.

149 Several states have established or are considering creation of subsidies such as New York’s Zero
 150 Emissions Credit to flow additional funds to nuclear power plants that are no longer cost-competitive.⁹
 151

152 Subsidies, in the form of federal R&D and federal tax credits, encouraged the development and spread
 153 of wind and solar generation -- just as, in earlier decades, federal R&D and subsidies enabled the
 154 development and commercialization of civilian nuclear energy and the natural gas combustion turbine
 155 and the realization of hydraulic fracking techniques for oil and gas development. Clearly all of those
 156 subsidies contributed to the current baseload problem, but no one can be blamed for it.

⁹ The current bill before the New York Legislature to enact the Zero Emissions Credit provision would fund the credit using monies collected from New York taxpayers for the operation of the NY Energy Research & Demonstration Agency. If enacted in its current form, this bill would essentially pay for the subsidies required to keep New York’s nuclear power plants in operation, producing zero-carbon electricity, by supplementing electricity customers’ energy and capacity payments with taxpayer funds.

1057 If the goal is to eliminate subsidies to avoid picking winners and losers, or to avoid favoring one fuel or
1058 technology over another across electricity markets, the only way to do that would be to attempt to
1059 eradicate all forms of subsidies for all forms of electricity sources (including wind and solar ITC and PTC,
1060 low-cost coal leases, oil and gas depreciation allowances, nuclear loan guarantees, all energy R&D
1061 expenditures, all ethanol purchase requirements, energy efficiency funding, and so on). Since most of
1062 these subsidies were created by statute and have deep political support, thorough and universal repeal
1063 of all energy-related subsidies would be difficult.

1064

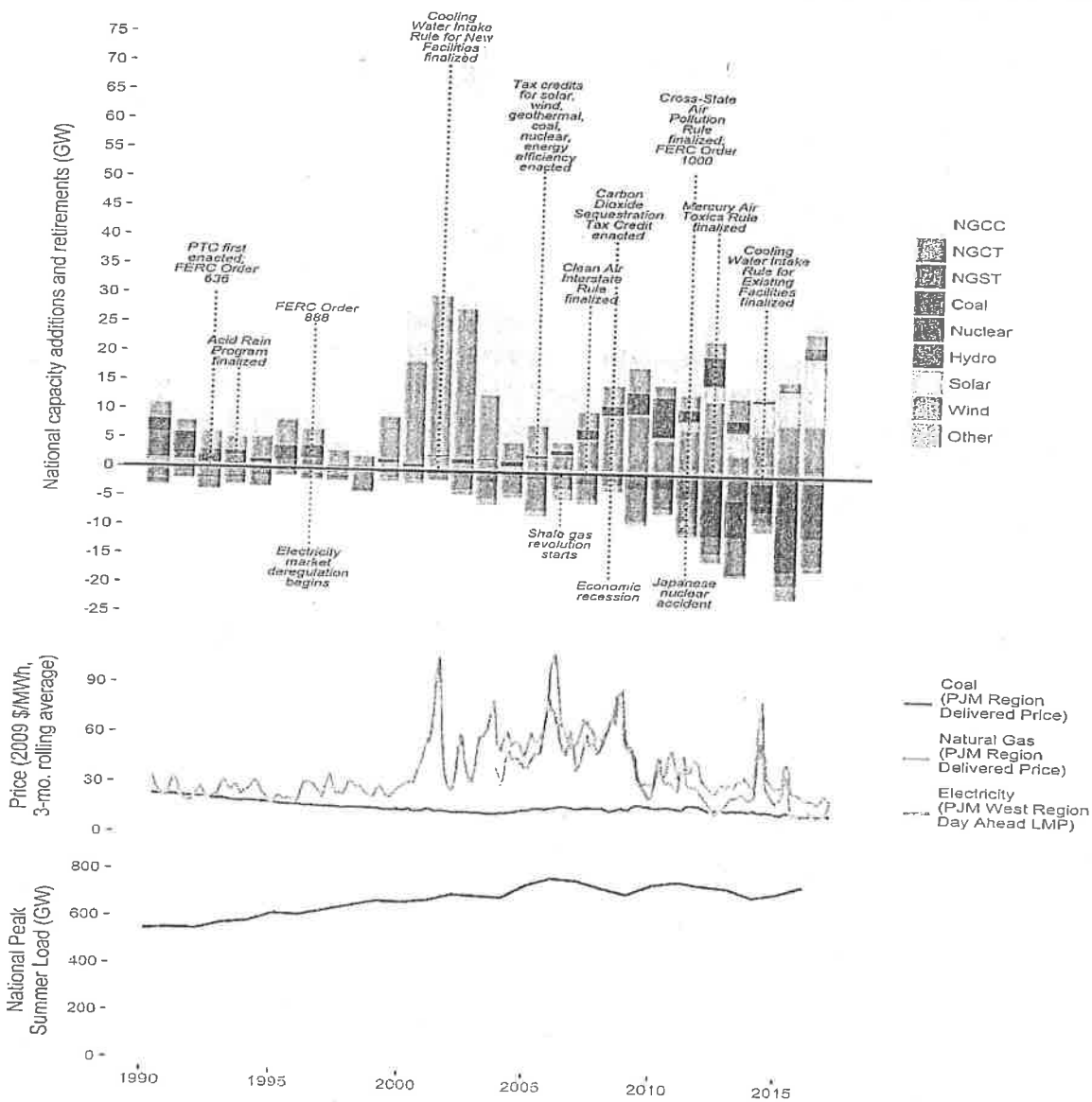
1065

3.6 Cause – regulations

1066 Figure 3.16 shows electric capacity additions and retirements between 2002 and 2017, along with key
1067 regulations affecting electric generation, the price curves for natural gas and coal, and customer
1068 demand levels over that period. The graphs show a strong correlation between falling natural gas prices
1069 and baseload retirements as well as flattening electric demand and retirements. It also shows many
1070 coal plants retiring in 2015 to avoid having to make new capital investments for environmental
1071 remediation in a time of low electricity prices.

1072 Figure 3.16. Big picture of retirements and contributing factors^{P 50}

1073 [narrow price graph legend to make narrower so we can make charts wider; pop hairlines more]



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'7
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Timeline of Electric Generating Capacity Additions and Retirements, Tax Incentives, Orders and Regulations, Regional Market Prices, and Load
cost estimates for regulatory impact – check EIA, EEI, NEI, EPSA, NERC, trade press, EPA, utility 10ks and presentations – correlate to timing of impact and deadlines and inability of these

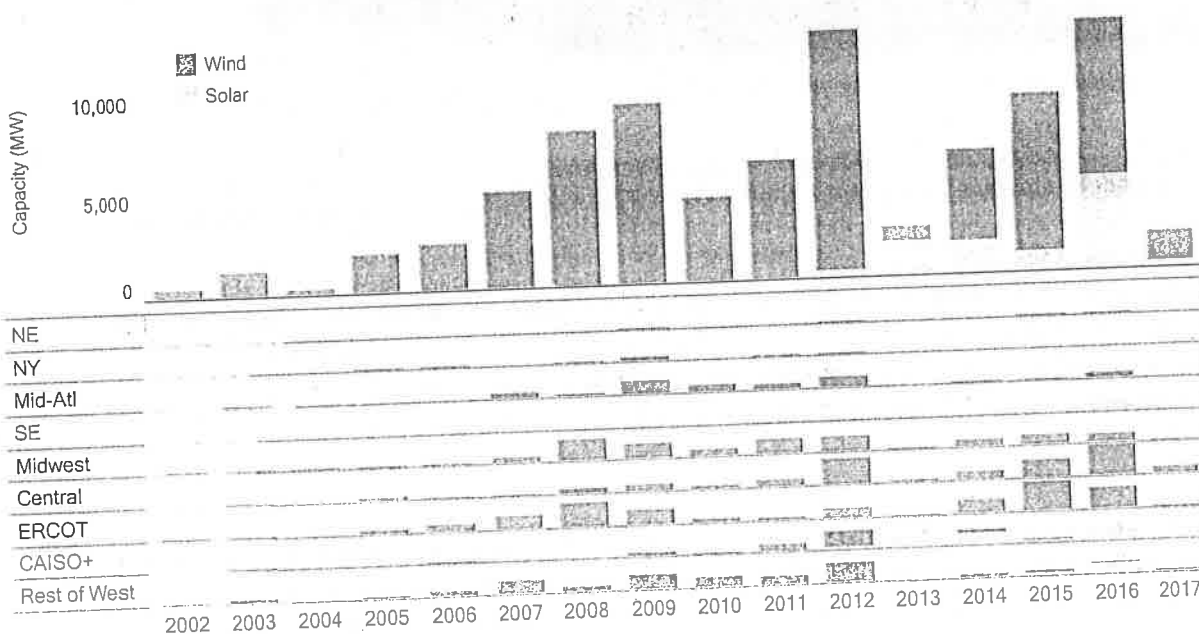
^P Wholesale day-ahead electricity market prices are for the PJM West Region. Delivered coal and natural prices are aggregated monthly PJM regional fuel costs derived from FERC-423 and EIA 923 data files. In addition to the 7 states in PJM, EIA included power plant fuel costs for Commonwealth Edison, East Kentucky Power Cooperative, Dominion Power in North Carolina, and Indiana-Michigan Power. EIA weighted the fuel receipts by total quantity of fuel delivered to calculate a weighted average monthly cost. We converted the fuel prices from MMBtu to MWh to account for different efficiencies of power plants using an average heat rate of 10000 Btu/kWh for coal and 7200 Btu/kWh for natural gas.

1079 plants to recover short-term operating costs much less capital cost recovery w/o additional
 1080 environmental capital charges

1081 **3.7 Cause – renewables**

1082 Figure 3.17 shows the annual installations of wind and solar generation across the nation from 2002
 1083 through 2017 (to date). Figure 3.x shows the growth in monthly net electricity generated from wind and
 1084 solar sources since 2007. These graphs show that there was relatively little wind installed before 2007,
 1085 and minimal solar capacity before 2013. Since over – GW of coal and __ of natural gas generating
 1086 capacity retired between 2002 and 2007, and another – MW retired between 2008 and 2012, renewable
 1087 generation could not have been the sole cause for these baseload retirements.

1088 **Figure 3.17. Annual Generation Capacity of Wind and Solar, Total and by Region, January 2002**
 1089 **through March 2017^a**

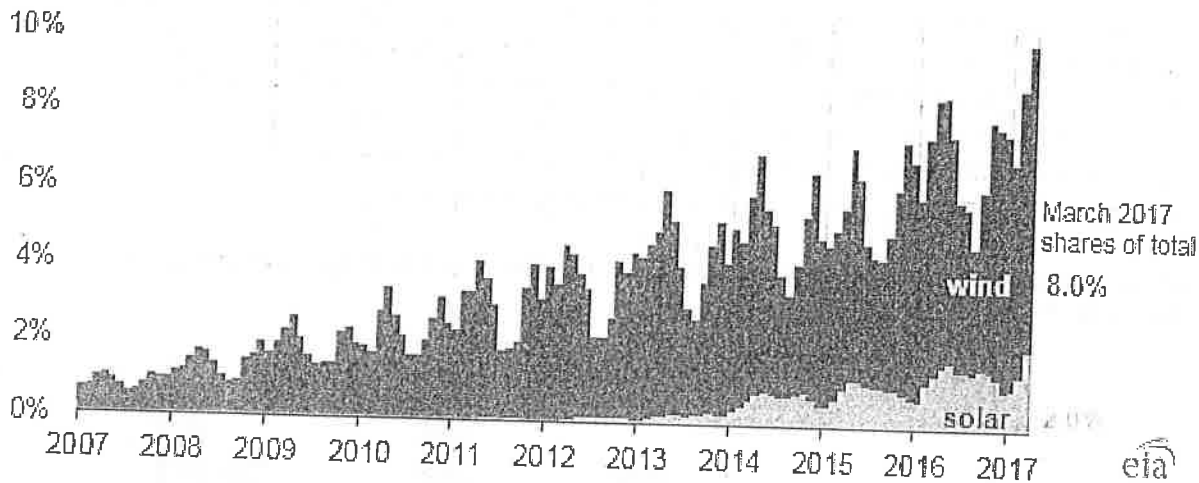


1091

^a Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, <https://www.eia.gov/electricity/data/eia860m/>

1092 Figure 3.18. Monthly growth in net wind and solar energy

Monthly net electricity generation from selected fuels (Jan 2007 - Mar 2017)
share of total electricity generation



93

94
95
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(Source: EIA, "Today in Energy, Wind and solar in March accounted for 10% of U.S. electricity generation for the first time," June 14, 2017; note that EOA did not collect small-scale PV data before 2012)

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Wind and solar generation combined reach their highest levels in spring and fall, when customer energy demand is lower. This exacerbates the problem for baseload plants, in that since customer loads are already lower in spring and fall, having renewable energy peak in those seasons further erodes the size of the customer low load slice willing to buy coal, nuclear or natural gas-fired power.

1

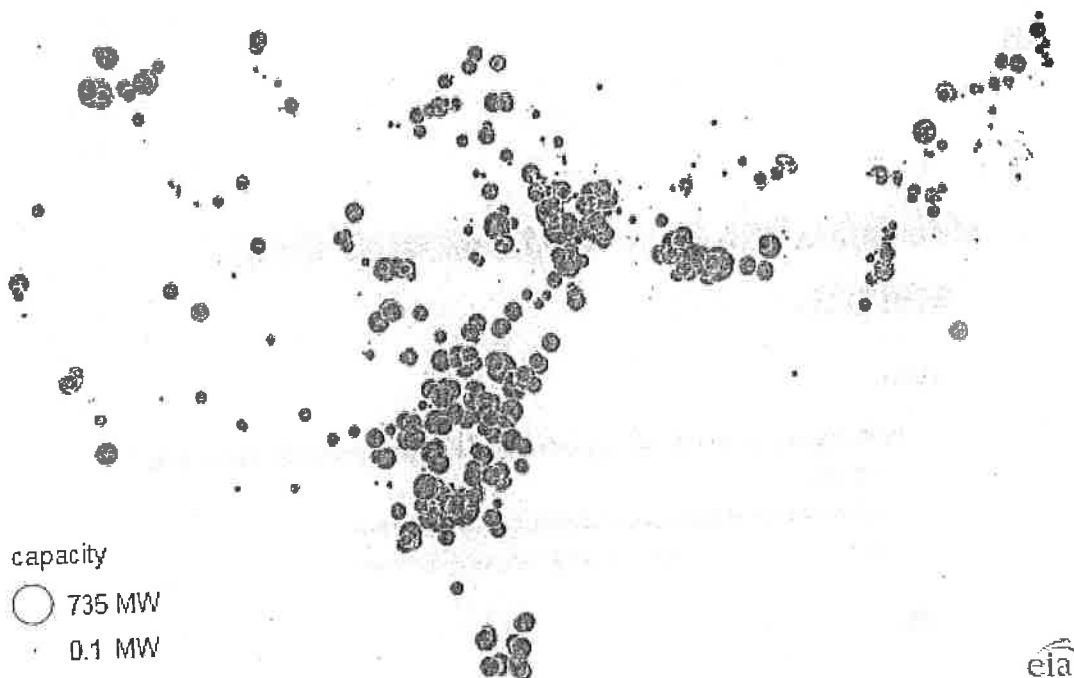
Wind

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Wind turbines have contributed more than one-third of the nearly 200 GW of utility-scale generating capacity added since 2007, reflecting a combination of improved wind turbine technology and lower costs, increased access to transmission capacity, state-level RPS, and federal production tax credits and grants. More than half of U.S. wind capacity is located in five states: Texas, Iowa, Oklahoma, California and Kansas. (Figure x) In particularly windy hours, wind output has contributed as much as 50% of the electricity generation mix. [add cites for SPP, ERCOT]

1108

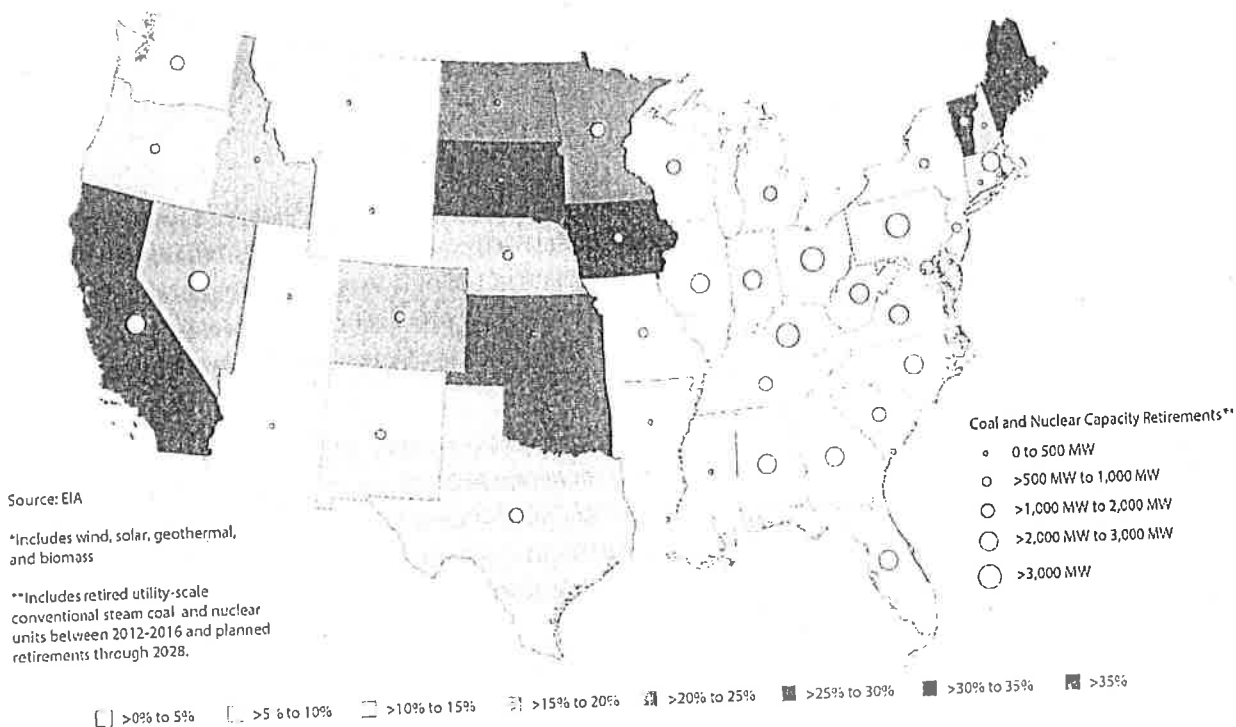
Figure 3.19. Wind generation growing⁵¹
 Distribution of wind power plants in the Lower 48 states (as of December 2016)



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 1110

Figure 3.20. Renewable penetration not correlated with coal and nuclear plant retirements⁵²

Recent and Planned Coal and Nuclear Retirements
 and 2016 U.S. Renewable Energy* Share of Electricity Generation, by State



1111
 1112

1113 DUCK CURVE – explain impact. This a regional impact that needs to be managed on a
1114 regional basis (see next chapter on reliability)

1115
1116 GREATER NEED for cycling and ramping

119 3.8 Consequence -- nuclear plant 120 retirements

121 A recent report observes that:

- 122 • There is an industrywide systemic economic and financial challenge to operating nuclear power
123 plants in deregulated markets;
- 124 • Given the confluence of market factors in combination with market structure in deregulated
125 markets, a significant number of operating nuclear plants have negative cash flow positions
126 today;
- 127 • Given current trends, these market factors are unlikely to change significantly over the next 5
128 years;
- 129 • Early retirement of nuclear plants is primarily caused by lower revenue problem^r rather than
130 higher operating costs, as wholesale electricity prices have precipitously fallen over the last
131 several years;
- 132 • ... The magnitude of the gap [between operating revenues and operating costs] is ... in the
133 range of \$5 to 15 per MWh. For a 1,000 MW nuclear unit, approximately every \$5 per MW of
134 gap represents about \$40 million in annual negative cash flow;
- 135 • ... Without action to enhance revenue (e.g., New York ZEC payments), more nuclear plants face
136 premature retirements in the future.⁵³

137 Overview of the U.S. nuclear fleet

138 FROM QER: The current operating nuclear power fleet consists of approximately 54 GW of generating
139 capacity in regulated markets and 45 GW in restructured electricity markets.⁵⁴ In total, this represents
140 9% of total U.S. 2017 utility-scale generation capacity, producing 20% of U.S. electric production in 2016.
141 EIA reports that nuclear plants have higher capacity factors than any other electric generation
142 technology, averaging 90% (nearly full capacity full-time) over the past five years. The plants refuel
143 every 18 to 24 months.⁵⁵

144 The first of these units went on-line in 1969; the average age of the nuclear fleet is 37 years old
145 (capacity-weighted).⁵⁶ Almost all of the operating plants have received approval to conduct at least one
146 capacity uprate; through 2016, these uprates to the existing fleet have contributed more than 7 GW of
147 additional nuclear capacity.⁵⁷ In addition to capital investments for capacity uprates, nuclear owners
148 make significant plant component investments to replace aging components to qualify for license

^r The report, "Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet," from the Idaho National Laboratory and the Center for Advanced Energy Studies (September 2016), attributes low electricity market prices to "low natural gas prices, low demand growth, increased penetration of renewable generation, and negative electricity market prices"

1149 renewal, plus a suite of new safety investments to comply with new regulations following the Fukushima
1150 reactor problem in 2011.

1151 The United States has the world's largest nuclear reactor fleet. These plants deliver grid stability and
1152 reliability, price stability, fuel security, and provide reliable and resilient power, especially
1153 during extreme weather events such as the 2014 Polar Vortex. Nuclear power plants contribute
1154 about 20% of the nation's electricity and about 60% of total U.S. emissions-free generation. The 99
1155 active nuclear reactors (located in 61 power plants) provide almost half a million jobs and contribute
1156 over \$60 billion to the U.S. gross domestic product.⁵⁸

1157 Many view nuclear energy as a key strategic asset for the United States. They argue that nuclear power
1158 is an essential strategic asset and that the nation has a strategic imperative to maintain and enhance
1159 American leadership and influence in global nuclear markets, including in the export of commercial
1160 nuclear technologies and systems.

1161 Of these 99 units, 53 are owned by traditional utilities (private and publicly-owned) which rely on
1162 regulated cost-of-service ratemaking. This form of ratemaking provides a reliable source of cost
1163 recovery assuming reasonably prudent operation and management by the utility. These units'
1164 continued operation depends on decisions by their ratemaking authorities: state regulators, state
1165 governments, city councils, and cooperative boards state regulatory bodies, plus two federal agencies,
1166 the Tennessee Valley Authority (which operates 7 nuclear units) and the Bonneville Power
1167 Administration (which operates 1 unit). Authorities may decide to close nuclear units on grounds other
1168 than economics or even system reliability – for example, New York State seeks to close the Indian Point
1169 plant due to its proximity to the New York City metropolitan area.

1170 Twenty-eight nuclear units are merchant plants that were spun off to affiliates by vertically integrated
1171 utilities under state competitive restructuring efforts in the early 2000s. All these merchant nuclear
1172 units operate in ISO/RTO systems. Many of the units went merchant to exploit high locational marginal
1173 prices (LMPs) in ISO/RTO energy markets in the days of high natural gas prices; profits from high LMP
1174 prices are not available to utility cost-of-service regulated units because their revenues are set by state
1175 regulators to recover of operating costs and provide a target return on invested capital. Most of the
1176 merchant plant conversions involved spinning the merchant plant off as an affiliate of the original
1177 vertically integrated utility owner, with a power purchase agreement between the affiliated merchant
1178 and the regulated utility specifying pricing provisions and durations. Once the initial power purchase
1179 agreement expires, the merchant plant must compete with other generators for contracts or spot sales
1180 in the organized power markets. The Kewaunee nuclear plant in MISO (WI) retired in 2013 after its
1181 purchase power agreement expired and the owners were unable to find a new purchaser for the power
1182 or the unit due to expectations of continued low natural gas prices and electric prices.

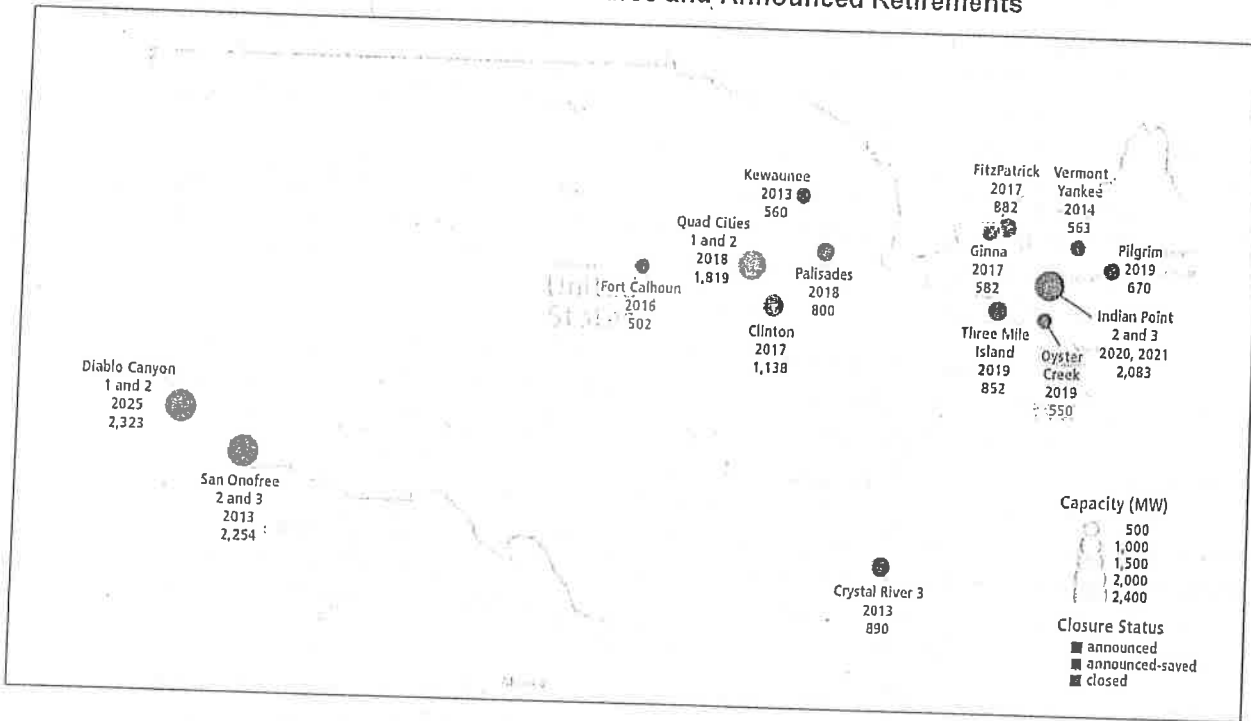
1183 Twenty nuclear units were spun off to entities other than affiliates of the original vertically integrated
1184 utility. Many of the independent nuclear owners are affiliates of vertically integrated utility holding
1185 companies (Exelon, Entergy, NextEra, Dominion). Exelon Nuclear and Exelon Generating Co. own 29
1186 (half) of all 48 merchant nuclear units.

1187 Nuclear plant retirements

1188 Nuclear plant retirements are a recent phenomenon, with the first post-Three Mile Island retirement
1189 announcement occurring in 2012. Figure 3.21 shows the nuclear reactors that have announced
1190 retirements (including those whose closure has been averted by state action). To date, 4,666 MW of
1191 nuclear plant capacity has retired – 5% of the U.S. nuclear capacity and less than one percent of total
1192 U.S. generating capacity. As noted above, another – plants representing – MW of nuclear capacity (–%)

of the U.S. nuclear capacity and --% of total U.S. generating capacity) has announced retirement plans (not counting the five plants that changed their plans after their host states offered subsidy payments for each plant to remain open).

Figure 3.21: Map of Nuclear Power Plant Closures and Announced Retirements



Reasons for nuclear plant retirements

Table 1 lists the nuclear plants that have announced retirement, illustrating the range of operating costs for these plants.

Table 3.1: Nuclear plant retirements and announced closures

Reactor	Retired/ Announced Closure Year	Relicense Application Received[i]	Relicense Granted?[ii]	Entered Extended operation[iii]	State	Average Operating Cost (year)[iv]	Capacity Factor 2014-2016[v]	Reason for Closure
Crystal River 3	2013	12/18/08	Withdrawn 2/6/13	--	FL	40.25 (2012 fleet avg)	--	failed steam generator replacement
Kewaunee	2013	8/14/08	2/24/11	--	WI	40.25 (2012 fleet avg)	--	market conditions
San Onofre 2 and 3	2013	--	--	--	CA	40.25 (2012 fleet avg)	--	failed steam generator replacement
Vermont Yankee	2014	1/27/06	3/21/11	3/21/12	VT	36.81 (2014 fleet avg)	89.8 (2013- 2014)[1]	market conditions
Fort Calhoun	2016	1/11/02	11/4/03	8/9/13	NE	36.13 (2015 fleet avg)	61.8 (2013- 2015)a	market conditions
Fitzpatrick[2]	2017	7/1/06	9/8/08	10/17/14	NY	40.97 (2016, single)	85.8	market conditions
Clinton ^b	2017	Notice of intent to apply in 2021	--	--	IL	40.97 (2016, single)	95.1	market conditions
Ginna ^b	2017	8/1/02	5/19/04	9/18/09	NY	40.97 (2016, single)	95	market conditions
Quad Cities 1 and 2 ^b	2018	3/3/03	10/28/04	12/14/12	IL	31.85 (2016, double)	99.6, 95.2	market conditions
Palisades	2018	3/31/05	1/17/07	9/8/10	MI	40.97 (2016, single)	93.2	market conditions (despite being under PPA through 2022)
Pilgrim	2019	1/27/06	5/29/12	6/8/12	MA	2015?	90.5	market conditions
Oyster Creek	2019	7/22/05	4/8/09	4/9/09	NJ	40.97 (2016, single)	91.5	avoid large capital costs associated with building a cooling tower
Three Mile Island 1	2019	1/8/08	10/22/09	4/19/14	PA	40.97 (2016, single)	99.4	market conditions
Indian Point 2 and 3	2020, 2021	4/30/07	--	--	NY	31.85 (2016, double)	86.3, 93.8	state policy disputes
Diablo Canyon 1 and 2	2024/2025	11/24/09	--	--	CA	31.85 (2016, double)	92.4, 92.2	market conditions and state policy concerns

1203
1204

Two plants (three reactors) have closed in the face of costly repair requirements.

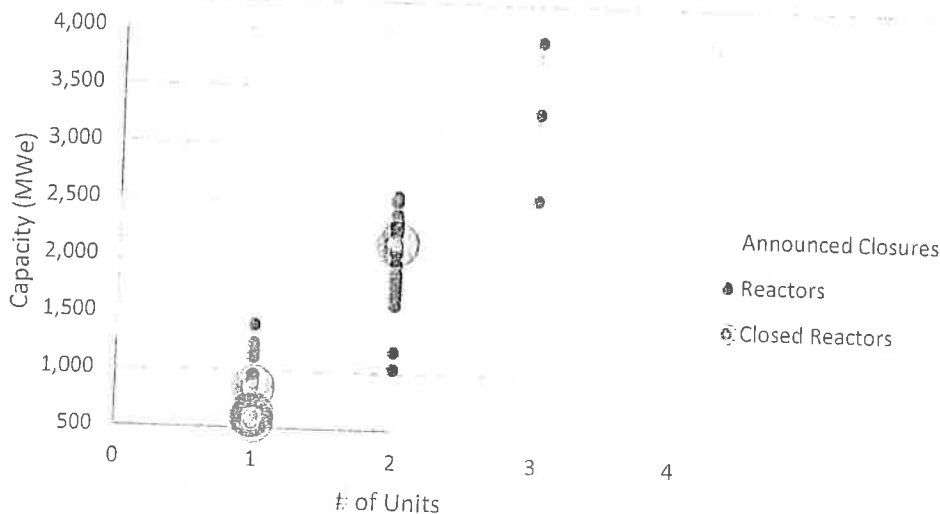
- Problems with a steam generator replacement project led to the permanent shutdown of Southern California Edison’s San Onofre Nuclear plant (SONGS) units 1 and 2 in 2012. After replacing the steam generators at both units, one of the new steam generators experienced internal leakage about a year later; inspections showed vibration-related damage to all the new steam generators, later attributed by SCE to design flaws.⁶² After considering repair and replacement options, SCE announced in June 2013 that it would retire San Onofre 2 and 3. The company cited uncertainty about whether and when the units would be allowed to restart at lower power by NRC, pending steam generator replacement or repair, as a major factor in the shutdown decision. Other considerations were the projected price of replacement power while repairs were being implemented and uncertainty about renewal of the two reactors’ operating licenses in 2022, according to SCE.⁶³
- At Progress Energy’s Crystal River nuclear plant (subsequently part of the Duke Energy acquisition of Progress), which went on-line in 1976, the plant’s concrete containment structure was damaged in 2012 during an effort to replace the plant’s steam generators. Facing a potential repair bill from \$1.5 to 3.4 billion,⁶⁴ Duke Energy announced in 2013 that, “it decided to close the plant because of unacceptable uncertainty about the scope, cost, and duration of repairing or replacing the damaged containment structure.”²³

Five of the six nuclear reactors that have shut down since 2012 were small single unit plants. Of the 11 nuclear power plants (15 reactors) that have announced intentions to close, four are dual-unit plants and seven are single-unit plants, as illustrated in Figure 3.22. This graph indicates that the bulk of nuclear plants heading for retirement are (were) smaller and/or single-unit plants with higher production costs per MWh. Table 3.2 confirms that nuclear economies to scale are significant -- smaller units have notably higher costs than larger units, and higher costs than multi-unit plants.

Nuclear plant costs and revenues

There are clear patterns in nuclear reactor operating costs – specifically, because these plants have such large capital and operating costs, economies to scale have a great impact on plant economics. Figure 3.22 illustrates where the retiring nuclear plants stand with respect to reactor size and the number of units.

Figure 3.22. Retiring nuclear plants and nuclear plant economies to scale⁶⁵



1236 Announced nuclear plant closures arrayed by number of reactors (units) and plant size (including the six
 1237 New York and Illinois units that are no longer expected to retire due to state decisions to subsidize plant
 1238 operation.

1239 Table 3.2 shows the range of nuclear plant average costs in 2016, in \$/MWh. The table indicates that
 1240 single unit plants are more costly than multi-unit plants, and that operators that own only one nuclear
 1241 plant have higher costs than those which own a fleet of plants. Because some operating costs, such as
 1242 security, do not scale linearly with plant size, single-unit plants are more expensive to operate and as a
 1243 result they are more likely to be retired before the end of their license terms.

1244 Table 3.2 Average nuclear costs by reactor type, 2016⁶⁶

2016 Cost Summary (\$/MWh)

Category	Number of Plants / Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generating (Fuel + Capital + Operating)
All U.S.	60*	6.76	6.82	20.42	27.17	34.00
Plant Size						
Single-Unit	25	6.77	8.37	25.83	32.60	40.97
Multi-Unit	35	6.75	6.34	18.75	25.50	31.85
Operator						
Single	12	7.18	8.51	21.05	28.23	36.74
Fleet	48	6.63	6.33	20.24	26.87	33.20

* Costs exclude shutdown plants
 Source: Electric Utility Cost Group (EUCG)

1245 As shown in the nuclear plant closure table above, eleven of the 15 plant closure announcements refer
 1246 to "unfavorable market conditions" as the driver for plant retirement. The most unfavorable condition
 1247 is that the marginal cost of generation for many nuclear plants is higher than the cost of most other
 1248 generators in the market:⁶⁷

- 1250 • Wind marginal cost near \$0/MWh, mostly at night
- 1251 • Solar marginal cost \$0/MWh, daytime
- 1252 • Natural gas CC marginal cost at 7,000 Btu/kWh \$25/MWh (\$3.00/MMBtu for fuel)
- 1253 • Coal marginal cost at 10,000 Btu/kWh \$29/MWh (\$2.50 MMBtu for fuel)
- 1254 • Nuclear marginal cost \$27 to 32/MWh
- 1255 • Natural gas CT marginal cost at 10,000 Btu/kWh \$49/MWh (\$3.00 MMBtu for fuel)

1256 Since U.S. nuclear generators are run flat out without cycling or ramping, they need to produce around
 1257 the clock; in combination with low-priced wind, solar and coal generation and natural gas steam plants
 1258 in night-time minimum load hours (and increasingly, some peak daytime hours in areas with high PV
 1259 penetration and transmission constraints), the over-supply of generation from all sources drives down
 1260 market-clearing energy prices and energy revenues for all producers.

1261 A nuclear plant fully exposed to wholesale market competition can earn additional revenues in three
 1262 other ways – it may receive capacity payments if it is located in an organized market with a capacity
 1263 payment scheme (New York, New England and PJM), it can earn revenues for providing reliability

1264 products such as frequency response, or it may receive Zero Energy Credits or similar subsidy payments
1265 from its host state. But those revenues may not be enough to cover the plant's full costs, including
1266 capital recovery. A recent study of the three Illinois nuclear plants estimated that the Quad Cities plant
1267 lost between \$150 and \$300 million each year between 2011 and 2016, the Byron plant lost between
1268 \$70 and 240 million per year in four of those five years, and the Clinton plant lost between \$52 and 98
269 million in each of the five years. If a nuclear plant is owned by a vertically integrated electric utility, its
270 regulators may allow it to continue collecting capital recovery from its ratepayers even though the
271 utility is effectively paying more to run the nuclear unit than it would cost to buy the same energy and
272 capacity under a bilateral contract or spot market purchases. But as long as natural gas prices stay
273 down and there is an over-supply of energy in many hours of the day and year, the typical nuclear plant
274 will lose money on every kWh produced, and not be able to make it up on volume. Bloomberg New
275 Energy Finance estimates that 34 of the nation's 61 nuclear plants are out of the money, including
276 many of Exelon's merchant nuclear units.⁶⁸

277 Not all nuclear power plants close due to unfavorable economics alone. The Diablo Canyon two-unit
278 plant in California is an example of a plant that is closing because changes in state policy (specifically,
279 moving to a 50% RPS by 2040) will render the plant wholly uneconomic if it invests in replacement of its
280 once-through cooling system, at a cost of \$8 to 12 billion, to satisfy environmental regulations. This led
81 the plant's owner to negotiate closure terms with the state to assure a smooth transition, rather than
82 closing abruptly.

Reasons behind Diablo Canyon nuclear shutdown

Source: David R. Baker, San Francisco Chronicle, "Diablo Canyon closure shows California's power grid is changing fast," July 2, 2016

Pacific Gas and Electric Co.'s surprise decision to shut down Diablo Canyon, the last nuclear plant in California, came after the company squinted at the future and realized that the massive facility would be an awkward fit.

When Diablo opened in 1985, big plants produced large amounts of electricity and fed it to a grid where power basically flowed one way, from generator to customer. Think of water pouring through a network of pipes to numerous taps: Utilities controlled the whole flow, from source to sink.

Now, many businesses and homeowners produce their own energy. A solar array is installed in PG&E's territory every six minutes. Many generate more electricity than they need during the day, feeding the excess back onto the grid.

Huge amounts of solar power flood the grid at midday, falling off sharply in late afternoon. Wind power surges at night. Power flows fluctuate with the weather.

And a fast-growing number of cities and counties — including San Francisco, PG&E's hometown — are buying electricity on behalf of their citizens through a system called community choice aggregation, partially bypassing the utilities.

Nuclear plants of Diablo's generation were designed to ramp up to full throttle and stay there day and night, providing "baseload" power for the grid. But that, increasingly, is not what California needs."

"We're transitioning, clearly, to a distributed system where you rely less and less on those big resources and more on distributed resources," said Stephen Berberich, CEO of the California Independent System Operator, which manages the grid.

"You need a flexible fleet that can start and stop quickly," he said. "The way California is headed, big, baseload power isn't as valuable as it was."

1283 The Nuclear Regulatory Commission's nuclear relicensing program is another factor affecting the timing
 1284 of power plant retirement decisions. The NRC issues initial operating licenses cover a 40-year operating
 1285 term. Those licenses can be extended for up to two additional 20-year terms. Of the 99 operating
 1286 nuclear reactors in the United States, so far, 80 have been approved to (and plan to) operate for 60
 1287 years, while another 9 currently have applications under review by the Nuclear Regulatory Commission
 1288 (NRC).^{5, 69} The timeline for these units to reach the end of their 60-year license is as follows: 6 units
 1289 between 2029 and 2030; 27 units between 2031 and 2035; 15 units between 2036 and 2040; 20 units
 1290 between 2041 and 2045; and 12 units between 2046 and 2050.⁷⁰ Forty-eight units will reach the end of
 1291 their licensed lifetime by 2040. EIA reports that the capital investment required to operate a plant
 1292 safely past 60 years is currently unknown.⁷¹

1293 NRC staff estimate that domestic nuclear plant owners decide to pursue a license extension as far as 15
 1294 years before the initial license expires; some have applied as early as 22 years ahead (in order to extend
 1295 two units' licenses in tandem for greater process efficiency). DOE staff estimate that it presently costs a
 1296 nuclear plant owner approximately \$25 million per unit, from application drafting through NRC
 1297 approval; this includes \$4 to 6 million in NRC fees.

1298 Nuclear relicensing often entails major capital upgrades of plant equipment. The two biggest capital
 1299 investments that have been cited as outweighing continued operation are steam generator
 1300 replacements and cooling system upgrades. According to DOE's Light Water Reactor Sustainability
 1301 Program, the required capital costs for equipment upgrades drive the total cost for extension; these
 1302 costs vary by plant. DOE estimates that it probably requires from \$500 million to \$1 billion per plant of
 1303 additional capital expenditures to operate a plant for an additional 20 years.

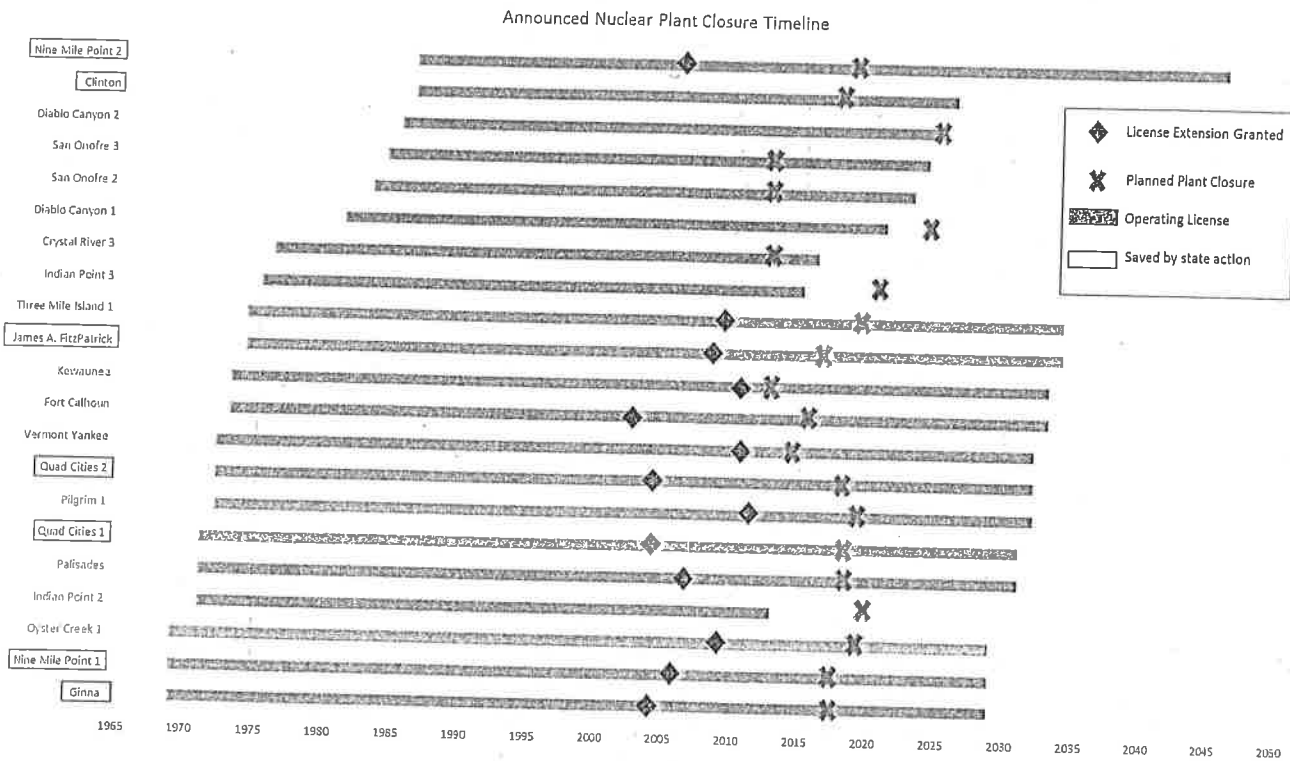
1304 As with other power plants, a nuclear plant owner must assess whether its prospects for future
 1305 revenues will repay continuing operations costs and capital investments. The fact of an approaching
 1306 NRC relicensing application deadline forces a nuclear owner to look closely at expected costs – capital
 1307 costs for equipment replacements and required upgrades,[†] continuing O&M costs, and relicensing costs
 1308 – and compare those to the likely revenue stream in a market environment that may require less
 1309 baseload operation and more cycling at low gas-based energy prices. More than one nuclear owner has
 1310 decided that future revenue prospects don't justify further investments in the plant for long-term plant
 1311 upgrades and environmental regulatory compliance, and therefore chose to retire the plant in advance
 1312 of its license expiration. Other plant owners (indicated by the plant name in a box below) were able to
 1313 avert closure by negotiating with the host state to receive subsidy payments for continuing operation.

1314 **Figure 3.23. Nuclear plant retirements compared to NRC plant operating license terms⁷²**

1315 Enlarge and bold up plant names and years

⁵ Diablo Canyon 1 and 2 license renewal applications are under NRC review, but Pacific Gas & Electric Company has announced it will withdraw the application.

[†] Some nuclear plants, like Diablo Canyon, are located on oceans and subject to the EPA's Once-through-cooling requirements, which would require costly modifications to the plant's cooling systems. Most nuclear plants have to replace their steam generators after 20 to 30 years of service, at a cost of several hundred million dollars per reactor. For example, replacement of the two steam generators at the Waterford 3 reactor in Louisiana was estimated by the plant's owner at \$550 million. (See Entergy Corporation, "Entergy Louisiana Seeks Approval to Replace Waterford 3 Steam Generators," news release, June 27, 2008, http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=1203).



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Cooling system updates at Oyster Creek

Source: Dolley, Steven, "Exelon, New Jersey Agree to Shut Down Oyster Creek by 2019," Nucleonics Week, December 13, 2010

Exelon's single-unit Oyster Creek plant in New Jersey, the nation's longest-operating power reactor, is ... scheduled to be retired in 2019. When the plant's initial 40-year NRC license was renewed for 20 years in 2009, the State of New Jersey required it to comply with water discharge requirements by building closed-circulation cooling towers to reduce warm water discharges into Barnegat Bay. Exelon said the cooling towers would have cost \$700-\$800 million and that it would retire the plant if required to build them. Exelon and the New Jersey Department of Environmental Protection reached an agreement in 2010 to close Oyster Creek in 2019, a decade before its license expiration, without building the closed-circulation cooling system.

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In these nuclear retirements, each plant owner made the decision to retire the plant because their expectations of future income (based on current and anticipated electric market conditions) from continued operation would not exceed the costs of continuing to operate the plant (including compliance with long-standing operating, safety and environmental regulations).

Benefits of nuclear power

(Source: "Utility CEOs to DOE: Hands off state energy policies, grid planning," Gavin Bade, "Utility Dive," June 15, 2017)

"[There's a] need for a diverse, resilient portfolio in the country and part of that is baseload generation that's being squeezed out of the market right now," said Chris Crane, CEO of Exelon, the nation's largest nuclear operator. "[Nuclear] provides more benefits than just megawatts. The resiliency, fuel diversity — it's important that is factored into price formation."

But Crane said recognizing those benefits could largely be left up to the states. Exelon won financial support for its nuclear plants last year in Illinois and New York, where the generators were under pressure from low natural gas prices, stagnant demand and subsidized renewables. The company is currently pushing for similar subsidies in Pennsylvania, while other utilities seek supports in Ohio, Connecticut and New Jersey.

"Allowing the states to recognize the environmental benefits of nuclear are important at the federal level," Crane said. "All of the incentives for [renewable] generating sources will phase out over time and it will create a more competitive platform. It's just not increasing them at this point."

1322 Subsidies for nuclear plants are being positioned as a payment to assure the retention of the power
 1323 plant within the host state, to help meet the state's reliability goals (as proposed in Ohio), protect local
 1324 jobs, or retain zero-emissions generation to support attainment of the state's greenhouse gas-limiting
 1325 goals (New York and Illinois). But others view these subsidies as unfair advantages — Dynegy's CEO says
 1326 that company will have to close 1,835 MW of coal-fired generation in Illinois because Exelon's
 1327 subsidized nuclear plants can bid lower in the MISO capacity auction, setting capacity prices so low that
 1328 Dynegy's coal plants can't recover their costs.⁷³

1329 For all the reasons outlined above, the EIA AEO estimates that another --- MW of nuclear generation is
 1330 at risk of closure by 20xx.

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3.9 Consequence -- coal plant retirements

There were -- coal-fired power plants in the U.S. at the start of 2002 and --- at the end of 2016. EIA reports that:

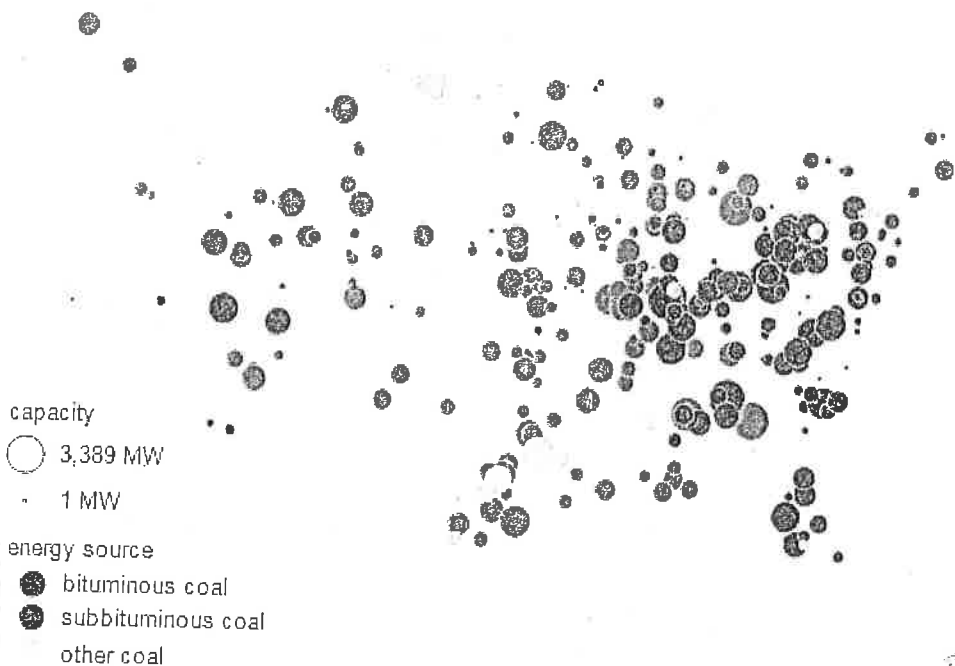
Coal-fired electricity generators accounted for 25% of operating electricity generating capacity in the United States and generated about 30% of U.S. electricity in 2016. Most coal-fired capacity (88%) was built between 1950 and 1990, and the capacity-weighted average age of operating coal facilities is 39 years.

About half of the coal capacity operating in 2016 use bituminous coal as their main energy source, a type of coal that comes from Appalachian states such as West Virginia, Kentucky, and Pennsylvania. Bituminous coal is the most abundant in the U.S. and is more commonly produced in eastern and midwestern states. Bituminous coal has a greater range of sulfur content. The other half of coal plants use subbituminous coal, which is mostly produced in western states such as Wyoming and generally has a lower sulfur content than most bituminous coals. Less than 5% of operating coal capacity uses lignite [principally in Texas] or other coal types.

Most coal-fired generation is located in the east, as shown in Figure x. Nearly all coal consumed in the U.S. is used for power generation. Coal energy production peaked in 2007 and has been declining since. No new coal plants have been built for domestic utility electricity production since 2013 because new coal plants are more expensive to build and operate per kW and kWh than natural gas-fired plants. [need EIA cite]

Figure 3.24. Location of coal plant retirements

Distribution of coal plants in the Lower 48 states



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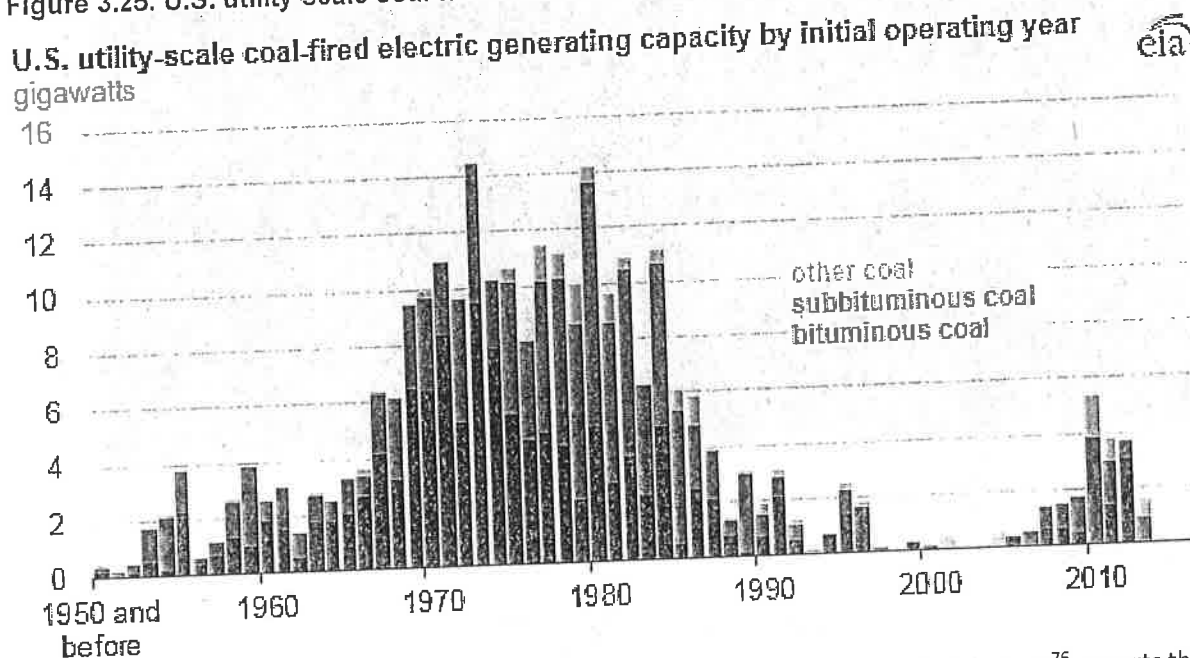
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As shown in Figure 3.25, almost all coal plants were built before 1990⁷⁴/ The service life of coal-fired generators reportedly, "average between 35 and 50 years, and varies according to boiler type, maintenance practices, and the type of coal burned, among other factors."⁷⁵

Figure 3.25. U.S. utility-scale coal-fired electric generating capacity by initial operating year



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A review of the literature about coal plant cycling by the Argonne National Laboratory⁷⁶ reports that coal plant heat rates (fuel use per kWh of generation, expressed in Btu/kWh) increase with plant age, while plant availability decreases. Cycling and load-following exacerbate the effects of plant aging and reduce component life. These operational patterns impose higher maintenance costs as well as higher fuel costs.

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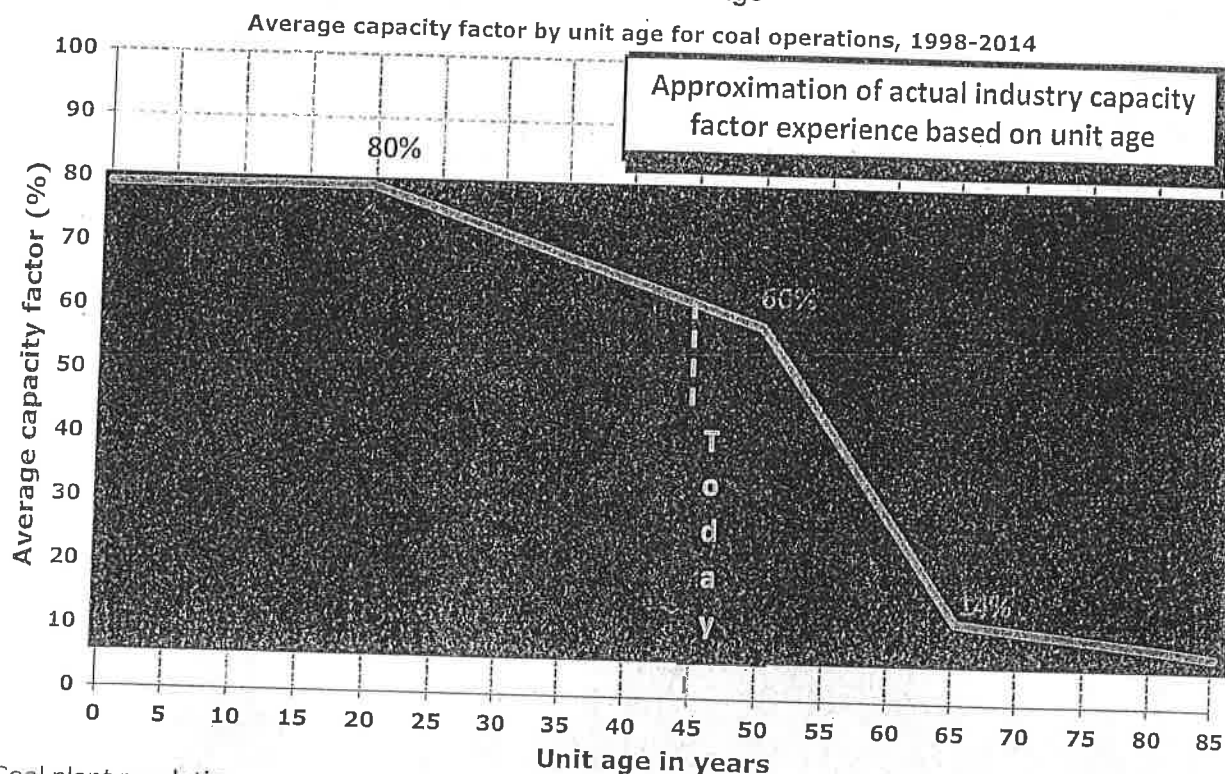
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A NETL report⁷⁷ indicates that younger coal plants have much higher capacity factors than older coal plants – likely because they have better fuel efficiency and produce electricity at a lower price per kWh. (See Figure 3.26) That report also finds that plant damage from cycling increases and accelerates over time with continued cycling, and that forced outage rates are more than double for plants that cycle than plants that run in steady baseload operation. Most of the coal plants retiring over the past few years were load-following in 2008-2014 (probably because the operators planned to run them hard without major reinvestment until the retirement date).

1374 Figure 3.26. Coal unit capacity factors decline as units age^{7a}



75
76 Coal plant regulation

77 Coal plants have been the focus of more environmental regulation than any other type of generation.
78 Ten environmental regulations adopted by the Obama administration implemented environmental
79 statutes adopted as far back as 1970:

- 80 • Cross-State Air Pollution Rule (CSAPR) to reduce SO₂ and NO_x emissions (finalized June 6, 2011,
81 updated September 7, 2016)
- 82 • Mercury and Air Toxics Standards to limit mercury, acid gases and other toxic pollution from
83 power plants (adopted February 16, 2012)
- 84 • National Ambient Air Quality Standards (NAAQS) to strengthen emission reductions for
85 particulate matter, a major source of respiratory illness (adopted January 15, 2013)
- 86 • Cooling Water Intake, standards on discharges of cooling water intake systems from electric
87 plants and other industrial facilities, to protect aquatic species (adopted August 15, 2014)
- 88 • Coal Combustion Residuals limiting coal ash disposal (adopted April 17, 2015)
- 89 • Carbon Pollution Standards for New Plants, requiring all new, modified or reconstructed coal-
90 fired plants to be equipped with carbon capture and sequestration technology (CCS) (Adopted
91 August 3, 2015)
- 92 • Effluent Guidelines limiting the levels of toxic metals in wastewater that can be discharged from
93 power plants (adopted September 30, 2015)
- 94 • Clean Power Plan to limit carbon dioxide emissions from existing power plants, scheduled to
95 take effect in 2022 (finalized October 23, 2015 and stayed by the Supreme Court on February 9,
96 2016)
- 97 • NAAQS for ground-level Ozone (adopted October 26, 2015)
- 98 • Stream Protection Rule to address water pollution from underground and surface mining
99 (finalized December 20, 2016 and disapproved by President Trump on February 16, 2017).

1400 Only four of these regulations would have taken effect before 2016, but the prospect of having to meet
 1401 all of them (particularly MATS, widely regarded as requiring the most costly capital investments of all
 1402 the regulations) caused many coal generation owners to reevaluate whether it would be cost-effective
 1403 to keep operating or retire their assets.

1404 Coal plant retirements

1405 Between 2002 and 2016, -- coal plants representing 53,604 MW of generation capacity had retired from
 1406 the U.S. generation fleet; 33% of coal production disappeared between 2011 and 2016. Figure x shows
 1407 that those coal plant retirements are concentrated in the eastern U.S. It has been claimed that,
 1408 "industry practices, under positive economic conditions, is to replace the baseload asset base before
 1409 [each power plant] reach[es] age 60."⁷⁹ EIA reported that coal-fired power plants made up more than
 1410 80% of the 18 GW of electric generating capacity retired in 2015, and that the retiring units, "tended to
 1411 be older and smaller in capacity than the coal generation fleet that continues to operate."⁸⁰

1412 **Figure 3.27: Location of Coal Retirements, January 2002 to March 2017^{81 82}**



1413 An analysis of plants that have retired and those that have announced retirements indicates a few
 1414 important trends and attributes. First, about 70% of the plants that have retired between 2010 and
 1415 2016 had a capacity factor of less than 50% in the year prior to retirement, and about half of the future
 1416 planned retirements operated below a 50% capacity factor in 2016. Coal unit capacity factors
 1417 consistently declined with plant age, reflecting the fact that younger coal plants use more modern
 1418 technology with better heat rates and thus lower per kWh production costs. (See Figure 3.27) Second,
 1419 while none of the retired units between 2010 and 2016 had significant SO₂ control equipment installed,
 1420 more than half of the future announced retirements have SO₂ control. The average size of planned
 1421 retirements (380 MW) exceeds the average size of recent retirements (218 MW), indicating that future
 1422 retirements are in general larger than plants that have already retired.

1424 The conclusion to be drawn from these points (as verified in the map above) is that until quite recently,
 1425 the coal plants that have retired have been those that were smaller, older, had higher heat rates and
 1426 therefore were dispatched less often and ran at lower capacity factors. Most of the earliest coal
 1427 retirements were merchant-owned units in the Northeast and Midwest – these plants were fully

1428 exposed to competition from other generators and fuel types, while investor-owned plants in the
1429 southeast and elsewhere enjoyed a longer period of protection from low market prices.

1430 Factors affecting coal plant retirements

1431 The Navajo coal plant is a good example of the problem facing coal plants. Built in --, the 2.25 GW plant,
1432 located in the Navajo Nation and fed by a mine-mouth coal plant, is owned by four utilities that serve
1433 Arizona and Nevada; one quarter of the plant is owned by the federal government, which uses the
1434 energy to power pumps at the Central Irrigation Project. In 2017 the utilities announced an agreement
1435 with the Navajo Nation to retire the plant at the end of 2019, "based on the rapidly changing economics
1436 of the energy industry, which has seen natural gas prices sink to record lows and become a viable long-
1437 term and economical alternative to coal power."⁸³ This decision preceded two future cost increases that
1438 would affect the Navajo plants: one due to begin after 2019 once a new site lease with the Navajo
1439 Nation was to take effect, and a pollution control upgrade that the Environmental Protection Agency
1440 had allowed the utilities to defer to 2028-2030.⁸⁴ The cost of energy production at the Navajo
1441 Generating Station (NGS) was clearly rising – NREL estimated production costs at \$32/MWh in 2015,
1442 \$38/MWh in 2016, \$41/MWh in 2019 after the new coal lease terms take effect, and \$51/MWh after
1443 the emissions standards take effect.⁸⁵ Generation share had been shifting gradually from coal to natural
1444 gas and non-hydro renewables for almost two decades in the Southwest and the rest of the Western
1445 Interconnection. The region is over-supplied with coal, natural gas-fired, wind and solar generation, and
1446 with low gas prices the utilities could buy natural gas-fired electricity at the Mead.Hub for only
1447 \$25/MWh in 2016, well below the cost of energy from the NGS. In 2016, replacing NGS power with
1448 market-priced resources would have saved CAP water customers about \$38.5 million.⁸⁶ On the other
1449 hand, closing NGS would result in the loss of about 548 permanent jobs at the plant, and potentially
1450 about 422 jobs at the nearby coal mine which supplies NGS. Native Americans -- mostly Navajo and Hopi
1451 -- make up between 80% and 90% of the workforce.⁸⁷

52 Several other large coal plants built after 1970 with capacities greater than 1,000 MW that have
53 announced plans to retire in the next few years. These plants have already made the capital
54 investments to comply with the MATS environmental regulations, so that deadline is not a forcing
55 factor in the retirement decision. Although these plants too were designed to operate around the
56 clock, low wholesale electric prices tied to natural gas are causing those plants to be operated at lower
57 capacity factors, dropping their cash flow into the red. One observer comments, "The wider market
58 dynamics are more concerning for coal.... For a power plant to make money today, it must be able to
59 ramp up and down to coincide with the variable levels of renewable generation coming online. That
60 makes combined cycle natural gas plants profitable, even at lower prices. [But] coal plants have
61 relatively high and fixed operating costs and are relatively inflexible. They make their money by
62 running full-out."⁸⁸

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Coal plant retirements caused by low natural gas prices and low demand

Source: "Can Coal Make a Comeback?", Trevor Houser, Jason Bordoff & Peter Marsters, Columbia University, Center on Global Energy Policy, April 2017

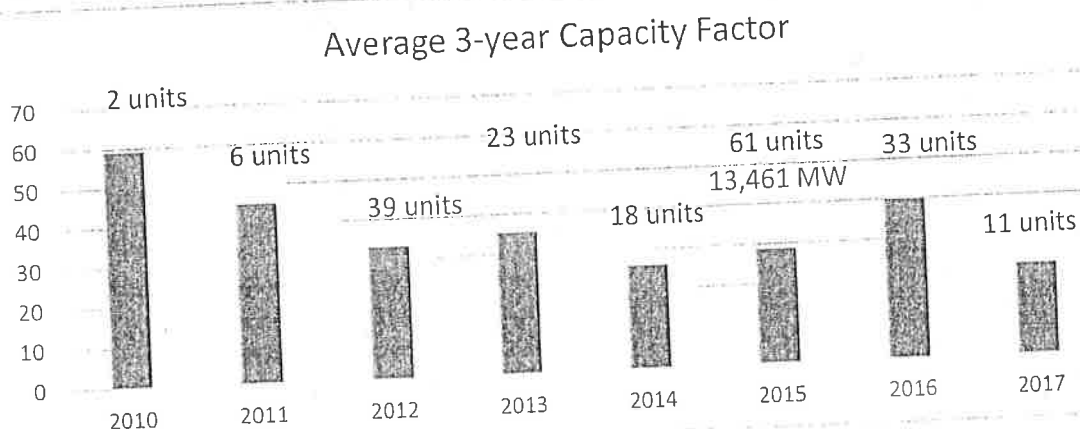
This paper offers an empirical diagnosis of what caused the coal collapse...

U.S. electricity demand contracted in the wake of the Great Recession, and has yet to recover due to energy efficiency improvements in buildings, lighting and appliances. A surge in U.S. natural gas production due to the shale revolution has driven down prices and made coal increasingly uncompetitive in U.S. electricity markets. Coal has also faced growing competition from renewable energy, with solar costs falling 85% between 2008 and 2016 and wind costs falling 36%.

Increased competition from cheap natural gas is responsible for 49% of the decline in U.S. coal consumption. Lower than expected demand is responsible for 26%, and the growth in renewable energy is responsible for 18%. Environmental regulations have played a role in the switch from coal to natural gas and renewables in U.S. electricity supply by accelerating coal plant retirements, but were a significantly smaller factor than recent natural gas and renewable energy cost reductions.

1464 Like fossil units, many coal plants have retired or are at risk of retirement because their marginal cost of
 1465 production is greater than prevailing electric market prices. As early as 2012, coal plant owners were
 1466 warning EIA that they expected to retire almost 27 GW of capacity from 175 coal-fired generators
 1467 between 2012 and 2016.⁸⁹ The coal units that retired between 2009 and 2011 were small, with an
 1468 average size of only 59 MW and a low fuel conversion efficiency (heat rate); the units that have retired
 1469 since are younger and more fuel-efficient, but today they are being dispatched less often (see Figure x)
 1470 because they are more costly than alternate energy sources.

1471 **Figure 3.28. The coal plants that retired had low capacity factors⁹⁰**



1472 Average three-year capacity factor for the coal plants retiring in each of the listed years

1473 Coal's high cost challenge is evident even in coal country. In West Virginia, the leading utility has closed
 1474 three coal-fired plants and converted two others to gas, lowering its coal dependence from 74% in 2012
 1475 to 61% last year, and the Kentucky Public Service Commission encourages its utilities to offer business
 1476 customers renewable energy packages.⁹¹ And the Kentucky Coal Museum has installed 80 solar panels
 1477

1478 on its roof to save money to save between \$8,000 and \$10,000 per year on electric bills that have been
1479 running about \$2,100 every month.⁹²

Coal plant closure considerations

Source: "Coal Power Plant Post-retirement options," O'Malley, Power, 9/1/16

The primary recent drivers of retirement announcements have been low natural gas prices and new environmental regulations—especially the Mercury and Air Toxics Standards (MATS), Clean Water Act Section 316(b), and the Coal Combustion Residuals rule. Other contributing factors have included more competitive markets and a variety of regional and state-level policies involving renewables and carbon pricing.

Most of the power plants being closed today were built in the 1940s to 1960s, before the Clean Air Act was passed in 1970. Many have minimal air pollution controls, use once-through cooling water, and sluice wet coal ash to ponds. Scrubbers, closed-loop cooling, and dry ash handling are current requirements or will be phased in over the next few years. Because much of the older capacity tends to be smaller units under 300 MW, which are not economical to retrofit, they are therefore retired. Many closures coincided with the MATS deadlines in 2015 and 2016, at a time when natural gas prices were at historic lows.

Now that MATS deadlines have passed, additional closures are being announced by companies including Dynegy (5,000 MW) and DTE Energy (2,100 MW). Economics, renewable energy mandates, and reduced demand for electricity are driving these additional closures.

Power plant closure activity began on the East and West Coasts in oil-fired plants, because of the high cost of fuel. Closures are now occurring in the coal belts, the Upper Midwest, and the Southeast. There are even some coal-fired plant closures in western states (Table 1)

Power plant decommissioning and redevelopment projects are all about risk, money, and who pays. When a power plant shuts down, revenue ceases but costs do not. Some owners quantify their costs, which may be allocated over many cost centers. Best-in-class companies also determine real estate valuations and exit strategy costs so they can make informed decisions about whether to redevelop, hold, or sell.

"Who pays" has emerged as a very interesting question. In states that are still regulated, decommissioning costs could be passed through to ratepayers, subject to public service commission approval. In deregulated states, shareholders would pay for decommissioning, subject to management approval.

... As a Genco, if you are in a Regional Greenhouse Gas Initiative state where you can recover the cost of closing plants through the rate base, it is often wise to do so. In deregulated states, conversely, shareholders have to pay for those costs up-front, and more case-making must typically be done to secure board approval for the \$10 million to \$20 million price tag.

3.10 Consequence – natural gas-fired power plant retirements

EIA reports on the U.S. gas-fired generator fleet:⁹³

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In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. Natural gas provided 34% of total electricity generation in 2016, surpassing coal to become the leading generation source. The increase in natural gas generation since 2005 is primarily a result of the continued cost-competitiveness of natural gas relative to coal.

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Natural gas-fired combined-cycle units accounted for 53% of the 449 gigawatts (GW) of total U.S. natural gas-powered generator capacity in 2016. Combined-cycle generators have been a popular technology choice since the 1990s and made up a large share of the capacity added between 2000 and 2005. Under current natural gas and coal market conditions in many regions of the country, combined-cycle generating units are often used as baseload generation, which operate throughout the day.

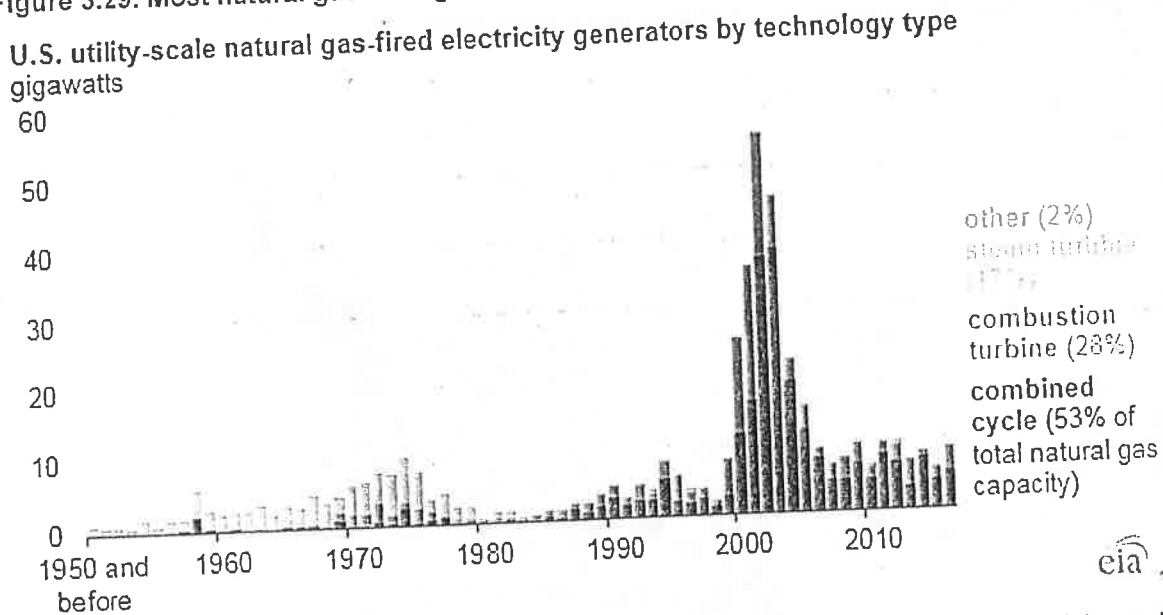
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Other types of natural gas-fired technology, such as combustion turbines (about 28% of total natural gas-powered generator capacity) and steam turbines (17%), generally only run during hours when electricity demand is high. The capacity-weighted average age of U.S. natural gas power plants is 22 years, which is less than hydro (64 years), coal (39), and nuclear (36).

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Figure 3.29 shows the on-line dates for the three types of natural gas-fired power plants.

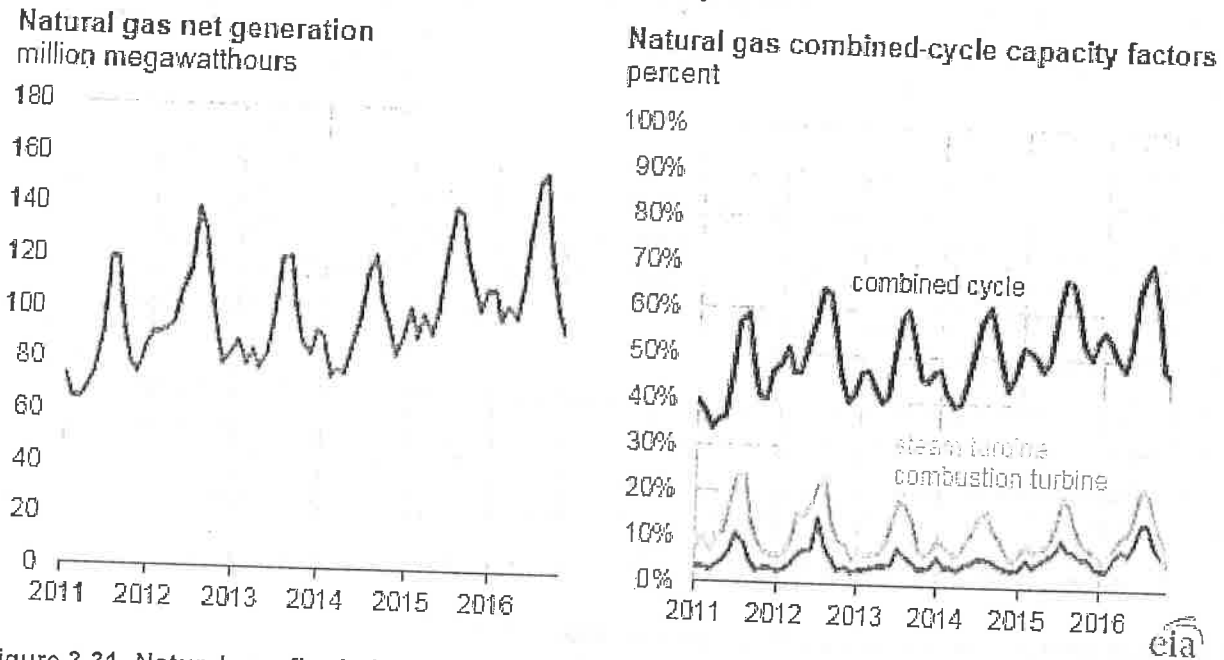
Figure 3.29. Most natural gas-fired generation built after 2000⁹⁴



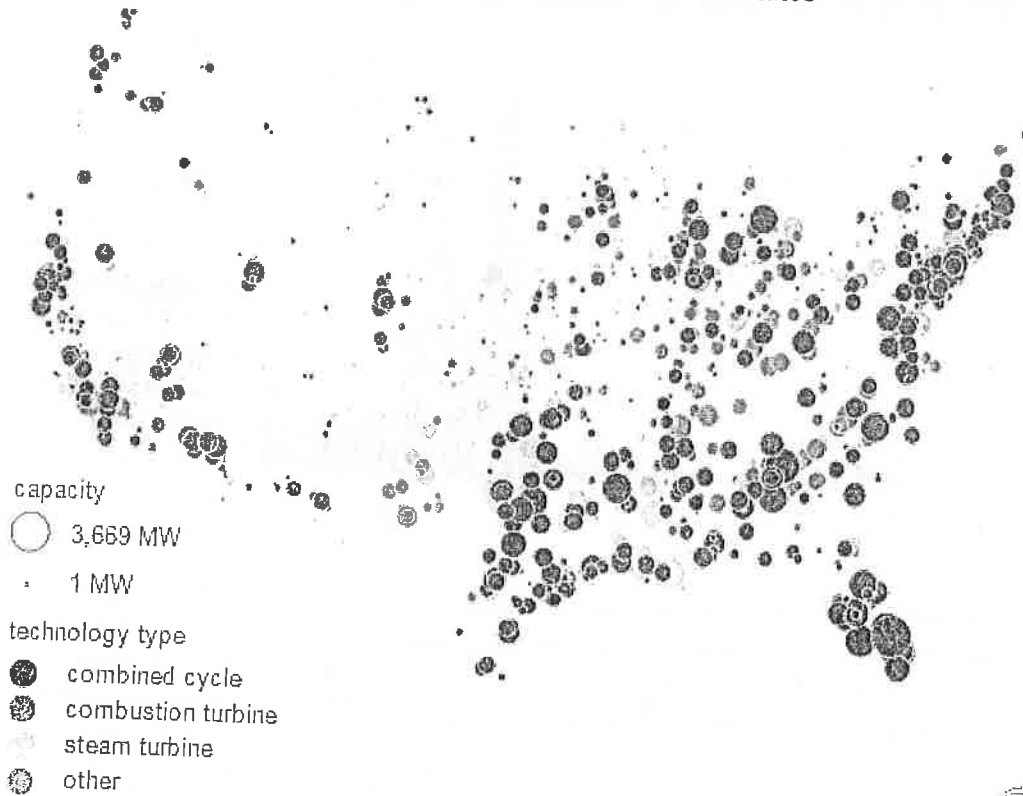
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Figure 3.30 shows total natural gas-fired net generation and how the capacity factors of these plants vary by technology over the years 2011 through 2016. Although steam turbines were originally built principally for relatively stable baseload use, those plants are being displaced in the dispatch merit order by more efficient combined cycle plants and combustion turbines, both of which are designed for greater flexibility and are often located closer to loads than the large steam plants. This is shown in Figure 3.Z. The states of California, Texas, New York and Florida all had more than 20,000 MW of natural gas-fired capacity at the end of 2016. NREL reports that the due to the flexibility, efficiency and cost-competitiveness of natural gas combined cycle power plants, grid operators have been dispatching NGCC plants more frequently as baseload generators. In consequence, the capacity factor for all NGCC plants has grown from about 40% in 2008 to roughly 56% in 2016, surpassing that of coal.⁹⁵

1514 Figure 3.30. Natural gas fleet net generation and capacity factors⁹⁶



15
16 Figure 3.31. Natural gas-fired plants serve most of the Lower 48 states⁹⁷



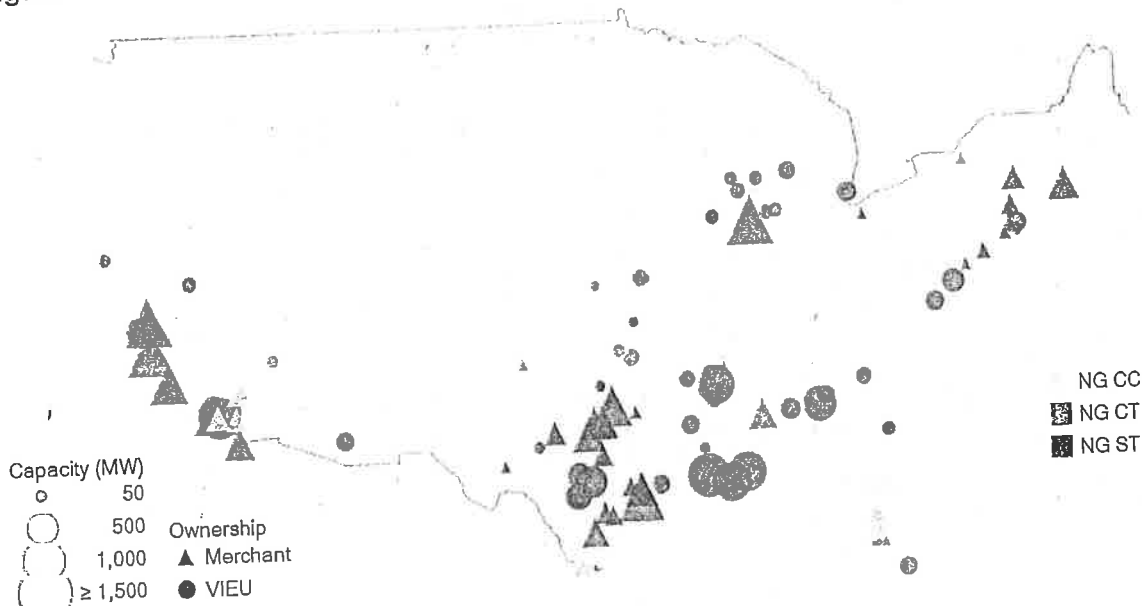
Natural gas plant retirements

As noted above, Texas has been an inhospitable environment for merchant gas plants. So has California, where merchants bought the utilities' old gas plants during the early days of asset

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divestitures and discovered that some of the gas-fired plants were better off retired. More broadly, because it's relatively easy to build a natural gas-fired power plant in most regions, volatile commodity prices along with an excess of gas capacity contributed to significant retirements of the older, less efficient generators. EIA reported in 2011 that between 2000 and 2010, 33 GW of net summer capacity natural gas-fired generation retired (72% steam turbines), with an average age of 48 years. In 2010, the average steam turbine operated at a heat rate of 2,000 Btu/kWh more than the average combined cycle plant.⁹⁸

Figure 3.32: Location of Natural Gas Retirements, January 2002 to March 2017



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Not all plant retirements are caused by the invisible hand of the electric market weeding out old, inefficient power plants to improve system efficiency and costs for everyone. Sometimes there is a regulatory or state policy forcing the retirement.

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“Californians are paying billions for power they don’t need”

Source: Ivan Penn & Ryan Menezes, LA Times, February x, 2017)

At its 2001 launch, the Sutter Energy Center was hailed as the nation's cleanest power plant. It generated electricity while using less water and natural gas than older designs.

A year ago, however, the \$300-million plant closed indefinitely, just 15 years into an expected 30- to 40-year lifespan. The power it produces is no longer needed — in large part because state regulators approved the construction of a plant just 40 miles away in Colusa that opened in 2010.

Two other large and efficient power plants in California also are facing closure decades ahead of schedule. Like Sutter, there is little need for their electricity.

California has a big — and growing — glut of power, an investigation by the Los Angeles Times has found. The state's power plants are on track to be able to produce at least 21% more electricity than it needs by 2020, based on official estimates. And that doesn't even count the soaring production of electricity by rooftop solar panels that has added to the surplus.

To cover the expense of new plants whose power isn't needed — Colusa, for example, has operated far below capacity since opening — Californians are paying a higher premium to switch on lights or turn on electric stoves. In recent years, the gap between what Californians pay versus the rest of the country has nearly doubled to about 50%.

This translates into a staggering bill. Although California uses 2.6% less electricity annually from the power grid now than in 2008, residential and business customers together pay \$6.8 billion more for power than they did then. The added cost to customers will total many billions of dollars over the next two decades, because regulators have approved higher rates for years to come so utilities can recoup the expense of building and maintaining the new plants, transmission lines and related equipment, even if their power isn't needed.

How this came about is a tale of what critics call misguided and inept decision-making by state utility regulators, who have ignored repeated warnings going back a decade about a looming power glut.

... California regulators have for years allowed power companies to go on a building spree, vastly expanding the potential electricity supply in the state. Indeed, even as electricity demand has fallen since 2008, California's new plants have boosted its capacity enough to power all of the homes in a city the size of Los Angeles — six times over. Additional plants approved by regulators will begin producing more electricity in the next few years.

The missteps of regulators have been compounded by the self-interest of California utilities.... Utilities are typically guaranteed a rate of return of about 10.5% for the cost of each new plant regardless of need. This creates a major incentive to keep construction going: Utilities can make more money building new plants than by buying and reselling readily available electricity from existing plants run by competitors.

... Sutter was built in 2001 by Houston-based Calpine, which owns 81 power plants in 18 states. Independents like Calpine don't have a captive audience of residential customers like regulated utilities do. Instead, they sell their electricity under contract or into the electricity market, and make money only if they can find customers for their power.

... [The CEO of Calpine says,] Independent plants are closing early ... because regulators favor utility companies over other power plants.

... So that California utilities can foot the bill for these plants, the amount they are allowed by regulators to charge ratepayers has increased to \$40 billion annually from \$33.5 billion, according to data from the U.S. Energy Information Administration. This has tacked on an additional \$60 per year to the average residential power bill, adjusted for inflation. ... The average cost of electricity in the state [California] is now 15.42 cents a kilowatt hour versus 10.41 cents for users in the rest of the U.S. The rate in California, adjusted for inflation, has increased 12% since 2008, while prices have declined nearly 3% elsewhere in the country.

“Gas Apocalypse’ Looms Amid Power Plant Construction Boom”

Source: Naureen Malik, Bloomberg News, May 23, 2017)

<https://www.bloomberg.com/news/articles/2017-05-23/-gas-apocalypse-looms-amid-power-plant-construction-boom>

The glut of cheap natural gas from a single, gigantic, shale basin that straddles the Northeast, mid-Atlantic and Midwest has sparked a massive construction boom of power plants. Dozens have been built in the past two years alone.

There's just one problem: There isn't nearly enough electricity demand to support all the new capacity. And as wholesale electricity prices plunge, industry experts are anticipating a fire sale of scores of plants in the region. Many, in fact, have already been sold along the PJM Interconnection LLC grid, the nation's largest, encompassing 13 states from Virginia to Illinois.

"Everything in fossil fuels is for sale," said Ted Brandt, chief executive officer at Marathon Capital LLC, a mergers-and-acquisitions adviser in Chicago. "People are bleeding."

... Drawing from abundant, cheap and nearby natural gas in the country's most prolific shale field, the new plants are adding a gigantic amount of power generation -- more than 20 gigawatts -- to a region that arguably has more than it needs. The new gas-fired plants are also coming online at a time of market turmoil, buffeted by Obama administration efficiency policies that have helped tamp down demand and by the Trump administration's determination to keep old coal-fired plants going.

Spot wholesale prices at PJM's benchmark Western hub slumped to an average of \$28.79 per megawatt-hour last year, falling by more than half since 2008 as the shale boom took hold. Many players are exiting the market.

Calpine Corp. -- the highly leveraged Houston-based independent power producer with a more than \$4 billion market value and 17 plants in the PJM grid -- is exploring a sale of its facilities. The company has attracted interest from private-equity firms, Bloomberg reported this month. And FirstEnergy Corp. and American Electric Power Co. took more than a combined \$11 billion in 2016 charges for plants. They're exiting production to focus on buying and distributing electricity. Dynegy Inc. has also been reported as a takeover target.

"It's a gas-driven apocalypse in the power market," said Toby Shea, a New York-based analyst at Moody's Investors Service.

3.11 Not a consequence – hydropower retirements

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The EIA reports that conventional hydroelectric generation accounts for 79.6 GW or 7% of the nation's operating electricity generating capacity and 6-7% of its energy production each year.¹⁰¹ Half of U.S. hydro capacity is located in Washington, California and Oregon. About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s;¹⁰² the average hydroelectric facility has been operating for 64 years.¹⁰³ However, with routine maintenance and refurbishment of turbines and electrical equipment, the expected life of a hydropower facility is likely to be 100 years or more.

Hydroelectric plant operation is constrained by factors such as whether the plant has a storage reservoir or is run-of-river, the availability of streamflow (which is in turn affected by seasonal rainfall and snowpack), and the water usage requirements of irrigation, navigation, recreation and fisheries

547 protection needs. A hydro plant's operation may vary widely between seasons -- the average capacity
548 factor of conventional hydroelectric generators was 40 percent.¹⁰⁴

549 Hydro facilities can help to balance the output from variable generating resources, which they do in
550 CAISO through local resources and the Energy Imbalance Market. Hydro provides primary frequency
551 response, especially in the Western interconnection. Hydro facilities are often black-start facilities,
552 which energize the grid after a blackout. Finally, hydro facilities may provide ramping and reactive
553 power support. The degree to which any given facility can provide these services depends on a range of
554 engineering, environmental, and economic factors. Pumped storage projects in particular can assist in
555 the integration of renewable resources into the electrical grid by pumping water into storage during
556 high renewable output periods and generating electricity in the hours when the renewable resource is
557 unavailable.

558 FERC regulates over 1,600 non-federal hydropower projects at over 2,500 dams, half of the U.S.
559 hydropower capacity. Many hydro facilities are licensed by FERC for up to 50-year terms. It takes an
60 average of 5 to 8 years to relicense an existing hydro project, with at least 3 years of pre-filing activity
61 and then at least another 2 years after the application is filed. New (extension) licenses can be for terms
62 between 30 and 50 years. Most of the hydro plants that are not regulated by FERC are owned by federal
63 or state agencies such as BPA and the Federal Bureau of Reclamation.

64 A few plants have not sought relicensing due to concerns over the cost of meeting mandatory
55 environmental requirements imposed by federal and state resource agencies. Capital upgrade
56 requirements can include capacity upgrades (initiated by the plant owner rather than a regulator), dam
57 safety upgrades, or environmental improvements. FERC reports that most hydro plants are relicensed.

58 There has been some concern over whether some of these aging hydro plants are retiring. EIA public
59 reports indicate that 1,376 MW (of the total 79.6 GW of U.S. hydroelectric capacity) retired between
60 2002 and 2017. The EIA looked into the question whether these hydro plants have actually retired in
61 recent years. The agency found that most of the plants recorded as retired had not ceased operation,
62 but rather have been modified with measures such as turbine replacement, creating a misleading
63 classification. Only 52 real hydroelectric plants retired, representing 273 MW of generation capacity, in
64 the sense that they have been decommissioned or wholly removed from the host site.¹⁰⁵

5 3.12 Premature retirements – what's 6 premature?

7 Many of the retired and retiring plants are unable to provide the services that are needed to maintain
8 reliability on a more fast-moving, high-variability bulk power system. Even if they could provide more
9 ramping and cycling services without high cost to the plant, most of these legacy plants cost more per
10 MWh than other market sources.

11 While some of the nuclear units now closing are doing so because of either state policy pressure (as
12 with California's Diablo Canyon and New York's Indian Point), and some have damages that are too
13 costly to fix, most are closing or threatening closure because nuclear power has become unable to
14 compete against low-cost gas-fired generation and renewables with low electric demand. The case can
15 be made that well-functioning nuclear plants which have made appropriate investments to upgrade
16 and refresh their facilities, received license extensions, and complied with all environmental regulations
17 -- but are now being forced to retire anyway because market prices are so low -- face premature
18 retirement. It is clear that nuclear energy offers benefits, particularly as a zero-emission energy source;

1589 but as gas prices stay flat, renewables grow and demand stays flat, it is not clear yet whether the
 1590 subsidies that some states are willing to pay to keep these plants in operation will be sufficient to
 1591 support a total revenue stream that covers each plant's full cost over time.

1592 The early coal plant retirements were smaller, inefficient units that retired because they could not
 1593 compete against lower-priced coal, natural gas and nuclear generation. More recently, many older coal
 1594 plants became uneconomic as market electric prices declined; they were being dispatched less
 1595 frequently and could not earn enough revenues to recover operating costs, much less recover sunk
 1596 capital costs or the prospective capital and operating costs required to comply with increasing
 1597 environmental regulations. Many of these now-retired plants would have already have been retired or
 1598 scheduled for retirement or upgrades before now had natural gas prices not sunk, to drop effective gas
 1599 prices per MWh below coal prices. Only a few cases, like the new, highly efficient Navajo plant, appear
 1600 to merit a claim that the plant is being forced to retire prematurely, while it still has value to contribute
 1601 to the grid.

1602 There is no good definition yet for the term, "premature retirement." When used with respect to
 1603 legacy power plants, the term "premature retirement" often means, it had to retire before the owner
 1604 or advocate was ready to retire it.... A more analytical consideration of the term would involve looking
 1605 into questions such as:

- 1606 • Has the plant already operated past its design lifetime (possibly with modifications and
- 1607 upgrades)?
- 1608 • Had the owner of the plant already achieved full rate recovery for its capital costs (particularly
- 1609 for VIEU-owned, ratebased plants)?
- 1610 • What's the cost of keeping an old plant going? If the plant is out of the money relative to other
- 1611 energy sources, how much additional investment will it take to make it efficient and
- 1612 competitive? Will or can that investment be recovered?
- 1613 • What are the opportunity costs of keeping an uneconomic generator from retiring? How much
- 1614 less would an electric utility's energy portfolio cost if it no longer had to support and buy energy
- 1615 from an out-of-the-money generator?⁴
- 1616 • What are the societal costs and benefits of retirement v. non-retirement? What are the non-
- 1617 monetary costs of keeping a plant open (e.g., on-site nuclear storage absent a federal nuclear
- 1618 waste repository, or pollution affecting communities near the plant)? What are the non-
- 1619 monetary benefits of keeping it open (e.g., local voltage support, inertia for grid-stabilizing
- 1620 frequency response, or zero-emissions pollution)?
- 1621 • If you think a legacy plant should be forced to stay open rather than retire, is it appropriate to
- 1622 burden its shareholders by trying to keep the plant open through multiple years of losses?
- 1623 • If you think a legacy plant should be subsidized to stay open rather than retire, will the
- 1624 magnitude of the subsidy contemplated be sufficient to overcome the revenue shortfall for
- 1625 long? Will the benefits realized from keeping the plant open outweigh the societal costs of the
- 1626 transfer payment from a large group of taxpayers or electric customers to the power plant
- 1627 owners?
- 1628 • Is there a more effective way to attain the benefits sought from preventing power plant
- 1629 retirement than actually paying to keep it open? If the goal sought is clean energy, is there a
- 1630 cheaper way to get it than nuclear generation? If the goal is to protect grid inertia, are there
- 1631 other ways to maintain or improve inertia? If the goal is to protect community jobs, can

⁴ State regulators and utility executives wrestle with this question constantly through Integrated Resource Planning processes and utility rate cases, and they are the ones initiating many recent legacy plant retirements.

community economic development, job training programs and community development grants provide an effective community transition as effectively and cost-effectively as keeping a power plant open?

3.13 Baseload retirements – looking forward and next steps

The role of baseload resources continues to evolve, and the financial strains on baseload coal, nuclear and natural gas plants are real and significant. If current retirement trends continue, many more coal and nuclear plants could retire over the coming decade. It is certain that more natural gas and renewable generation capacity can come on-line quickly (although much less certain that we have sufficient transmission to serve new remote generation). And it is probable that our grid managers have sufficient tools and resources to manage this change without a loss of grid reliability.

In most other industries, the problem of over-supply and brutally low prices would be solved by the market pendulum swinging from over-capacity to under-capacity as sustained low market-clearing prices drive all of the inefficient competitors out of business. In such a circumstance, scarcity would create high prices, which would eventually lure more competitors back into the market, and the cycle would continue.

But this is electricity, not a commodity market, and our society cannot afford to risk grid reliability and affordability. Unlike commodity markets, electric utilities cannot react quickly – in part because their regulatory institutions don't allow them to do so. Thus, as the Secretary directs, we should look for ways to manage this difficult transition to assure that we protect grid reliability and cushion the communities and customers affected by these changes.

Several issues relating to baseload retirements deserve further research:

- What is the value of retaining nuclear power plants to maintain some minimum level of system inertia and emissions-free energy?
- Nuclear plants in the French fleet routinely cycle, while U.S. nuclear plants don't. Are there modifications we can make to U.S. plants to make them more flexible?
- Are there ways to lower the marginal operating costs of nuclear and coal plants without compromising sustainability and safety goals?

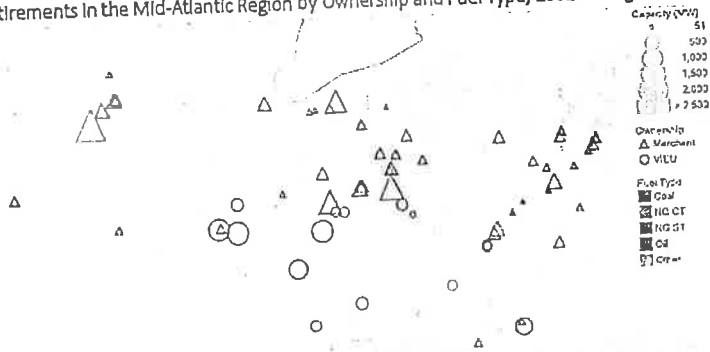
3.14 Regional Profiles

This section will contain nine regional profiles with information on retirements, diversity, and more, with commentary on the trends and conditions particular to each region.

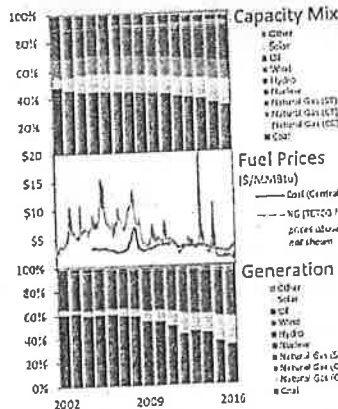
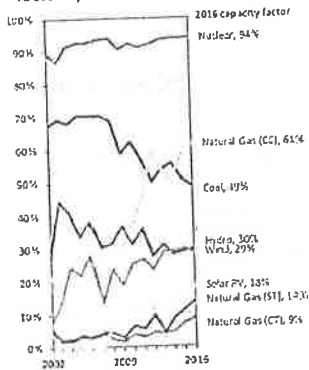
The page that follows is an example of the information coming in each regional profile.

Mid-Atlantic Regional Profile

Retirements in the Mid-Atlantic Region by Ownership and Fuel Type, 2002 through 2017.



Mid-Atlantic capacity-weighted average capacity factor by technology type, 2002-2016



Regional Statistics

	2002	2016
Utility-scale capacity (MW)	172,931	188,746
Utility-scale generation (MWh)	829,790,355	810,903,642

Retirements by Energy Source, 2002-2017*

*2017: Q1 actual, Q2-4 announced	# of Plants	MW
Coal	65	23,526
Natural Gas	41	6,923
Nuclear	0	0
Oil	60	5,326
Hydro	2	3
Biomass	5	168
Wind	1	10
Solar	0	0
Other	41	159

NERC Reserve Margin for 2016

Target %	xx%
Current %	xx%

Direct Resources, 2016

	Capacity (MW)	Growth Rate?
Coal	63,147	?
Natural Gas	67,157	?
Nuclear	33,830	?
Oil	7,197	?
Hydro	3,331	?
Wind	7,484	?
Solar	1,476	?
Other	3,124	?

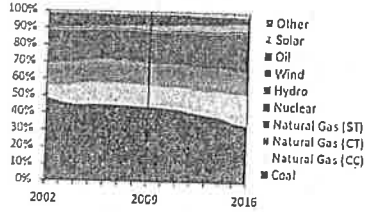
Ownership Trends

	VIEU	Merchant
% of Retired Capacity 2002-2017	24	76
% of Current Capacity	28	72

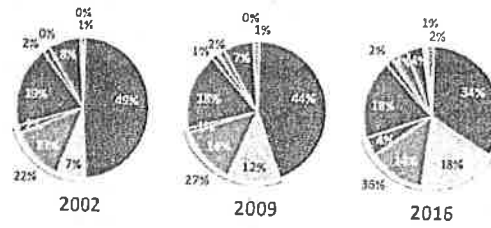
1665

1666

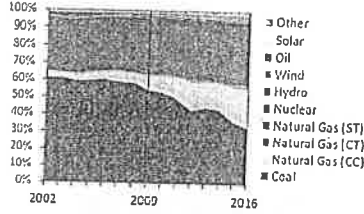
Mid-Atl utility-scale generating capacity (percent of total)



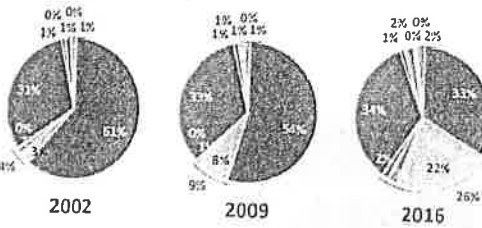
Mid-Atl utility-scale capacity mix



Mid-Atl utility-scale electrical energy (percent of total)



Mid-Atl utility-scale generation mix



Mid-Atl utility-scale generating capacity, 2002 vs. 2016

Technology	2002		2016	
	MW	Percent of Total	MW	Percent of Total
Coal	84,568	49%	63,147	34%
Natural Gas (all)	37,420	22%	67,157	36%
Natural Gas (CC)	12,053	7%	33,635	18%
Natural Gas (CT)	22,347	13%	25,375	14%
Natural Gas (ST)	3,020	2%	8,147	4%
Nuclear	32,620	19%	33,830	18%
Hydro	2,854	2%	3,331	2%
Wind	100	0%	7,484	4%
Oil	13,326	8%	7,197	4%
Solar		0%	1,476	1%
Other	2,042	1%	3,124	2%
Total	172,931		186,746	

Mid-Atl utility-scale electrical energy, 2002 vs. 2016

Technology	2002		2016	
	MWh	Percent of Total	MWh	Percent of Total
Coal	502,102,794	61%	271,601,367	33%
Natural Gas (all)	34,567,856	4%	212,945,249	26%
Natural Gas (CC)	22,509,779	3%	181,069,575	22%
Natural Gas (CT)	9,025,060	1%	19,427,882	2%
Natural Gas (ST)	3,033,017	0%	12,447,792	2%
Nuclear	255,924,849	31%	278,804,277	34%
Hydro	6,809,664	1%	8,660,684	1%
Wind	66,791	0%	18,897,716	2%
Oil	11,229,487	1%	2,742,624	0%
Solar		0%	2,529,970	0%
Other	10,088,914	1%	14,721,754	2%
Total	820,790,355		810,903,642	

1668 4 Reliability and resiliency

1669 [UNDER CONSTRUCTION]

1670 Most of the common metrics for grid reliability suggest that the grid is in good shape despite the
 1671 retirement of many baseload power plants. Table 4.1 compares NERC-calculated reserve margins for
 1672 2011 and 2016 for all of the NERC regions, and shows that in most cases, reserve margins are still
 1673 comfortably above each region’s target margin.

1674 **Table 4.1. NERC region reserve margins for 2011 and 2016^v**

Assessment Area	2011-Y1	2016-Y1
FRCC	24.2%	24.3%
MISO	23.1%	18.7%
NPCC-New England	16.9%	20.4%
NPCC-New York	33.1%	23.2%
PJM	23.8%	28.9%
SERC-E	25.8%	18.9%
SERC-N	29.3%	18.7%
SERC-SE	22.7%	32.6%
SPP	26.7%	27.2%
TRE-ERCOT	16.9%	14.5%
WECC	39.7%	26.8%

1675
 1676 These reserve margin estimates reflect 2016 conditions and forecasts of peak loads, generation,
 1677 demand-side and transmission-enabled imported resources available at peak, and other factors. In
 1678 every region but ERCOT, reserve margins remain (as of the 2016 calculation) comfortably or
 1679 significantly higher than the levels which would raise a resource adequacy flag or signal potential
 1680 reliability problems. However, even if the reserve margin is within a couple points of the target, having
 1681 those resources does not guarantee reliability. Problems occur (hot weather, wind, drought, attacks),
 1682 so the grid is always at risk. Since power plant retirements continue — as do additions of new capacity
 1683 from natural gas and renewable plants and energy efficiency and demand response — the 2016 figures
 1684 do not accurately describe 2017 conditions. We also don’t know conditions five years out, although we
 1685 can be confident that older, inefficient power plants will continue to retire. There is also a risk that
 1686 planned power plants will not be built or will be delayed. NERC and North America’s reliability
 1687 coordinators conduct on-going analyses to assess resource adequacy as system conditions change over
 1688 time.

1689 NERC’s 2016 Long-Term Reliability Assessment and the 2017 State of Reliability Report offer some
 1690 common, positive findings:

- 1691 • There were no severe grid events on the bulk power system in 2016.

^v These are NERC planning reserve margins, which reflect a set of capacity-based region-specific forecasts and planning assumptions that are becoming less relevant as technology and economics and the growth of variable renewable energy move us toward a more energy-based system.

- Significant causes of system problems, including protection system mis-operations, are declining and have been declining for four years.
- Frequency response has been improving across all four interconnections, but still needs attention to assure that frequency is stabilized during system disturbances.
- Transmission outages aren't getting any worse.
- System resiliency to severe weather continues to improve.
- The gas-electric interface and our growing dependence on natural gas with the potential for a single point of extensive disruption remain a cause for concern.¹⁰⁶

According to the North American Electric Reliability Corporation, current bulk power system reliability is an issue of risk management. In testimony to FERC on June 22, 2017, NERC CEO Gerry Cauley touched on both reliability and resiliency, commenting:

[I]t is essential to continually identify and address emerging risks and their potential to significantly impact BPS reliability. Risk Policy and regulatory developments occurring with respect to renewable energy development, storage, conservation, demand response, and micro-grids have the potential to significantly affect BPS reliability. Market structures and developments also are impacting fuel supply, generation and transmission infrastructure planning, operations, and investment decisions. Given the rapidly changing generation resource mix, and related new technologies, it is critical to understand impacts on essential reliability services (ERS) – specifically frequency response, voltage support, and ramping capability. It is also important to appreciate the operating characteristics of new technology at the interface of the BPS. ...

Substantial progress has been made in the last five years to improve coordination between natural gas pipelines, gas distribution companies, and electric industries. ... NERC [has] recommended incorporating fuel availability into national and regional assessments.

Until recently, natural gas interdependency challenges were more often experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, the recent outage of an operationally-critical natural gas storage facility in Southern California — Aliso Canyon — demonstrates the potential risks to BPS reliability of increased reliance on natural gas without increased coordination between the two industries.

A recent DOE paper summarized the standards and regulations pertaining to power system reliability into four rules:

1. Power generation and transmission capacity must be sufficient to meet peak demand for electricity
2. Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources
3. Power systems must be able to maintain steady frequency
4. Power systems must be able to maintain voltage within an acceptable range.¹⁰⁷

1733 NERC on reliability

1734 NERC data on regional reserve margins indicates that [fill in from NERC 2016 LTRA]

4.1 Reliability and current reliability performance

1737 [UNDER CONSTRUCTION]

- 1738 • Baseload plants deliver capacity and energy, but capacity and energy alone don't incent and
- 1739 deliver the essential reliability services necessary for
- 1740 • Define products more appropriate to essential reliability services
- 1741 • Use markets to improve reliability
- 1742 • NERC reliability metrics show improvement
- 1743 • Check SAIDI & SAIFI where available
- 1744 • Reserve margins

1745 *Yes and no -- Baseload power is not as necessary as it used to be. Baseload power was useful to a well-*

1746 *functioning grid over the decades from 1960 to 1990, when these plants were initially built. But with*

1747 *technology and market changes, the bulk power system has changed markedly and high-value market*

1748 *and reliability require different services and capabilities to attain high reliability and resilience.*

1749 *Therefore, baseload capacity erosion is not yet a problem for grid reliability and resilience – but further*

1750 *study is needed to determine how much more baseload capacity can be lost before grid reliability might*

1751 *be harmed.*

1752 *Natural gas thermal, coal and hydro baseload plants have been retiring for two decades. The first wave*

1753 *of retirements began in the early 2000s well before significant renewables development began. It*

1754 *occurred primarily within the merchant generation fleet after new gas plant construction across much*

1755 *of the nation produced new, low-cost electricity at prices well below the cost capabilities of the older,*

1756 *smaller fossil plants that independent power producers bought from vertically integrated utilities during*

1757 *the early stages of wholesale market restructuring.*

4.2 Essential reliability services and baseload power plants

1760 [UNDER CONSTRUCTION]

- 1761 NERC on essential reliability services
- 1762 EPSA sources on essential reliability services
- 1763 PJM analysis on portfolio building
- 1764 Sandia paper on grid reliability
- 1765 RAP paper on capability reserves
- 1766 NERC IVGTF and recent LTRA assessments
- 1767

1768 Need to balance reliability and resiliency against societal costs and societal preferences (all the
1769 state and customer requirements detailed above)

1770

1771 Cautionary illustrations from Hawaii, Germany, maybe Australia for what happens if you bring on too
1772 much VRE w/o adequate analysis, planning

773

774 Related questions & topics

- 775 • Impacts of VRE on the grid
- 776 • Is there a minimum level of rotating mass needed on the grid? [needs more study]
- 777 • Role of customer load in providing inertia
- 778 • Is synthetic inertia from wind plants equivalent to large turbine generation (and how is it not)?
- 779 • Using DR and EE to modify customer side instead of putting all the burden of system balancing
- 780 on supply-side resources
- 781 • Role of modern grid technologies to manage the system (both demand and supply sides) better

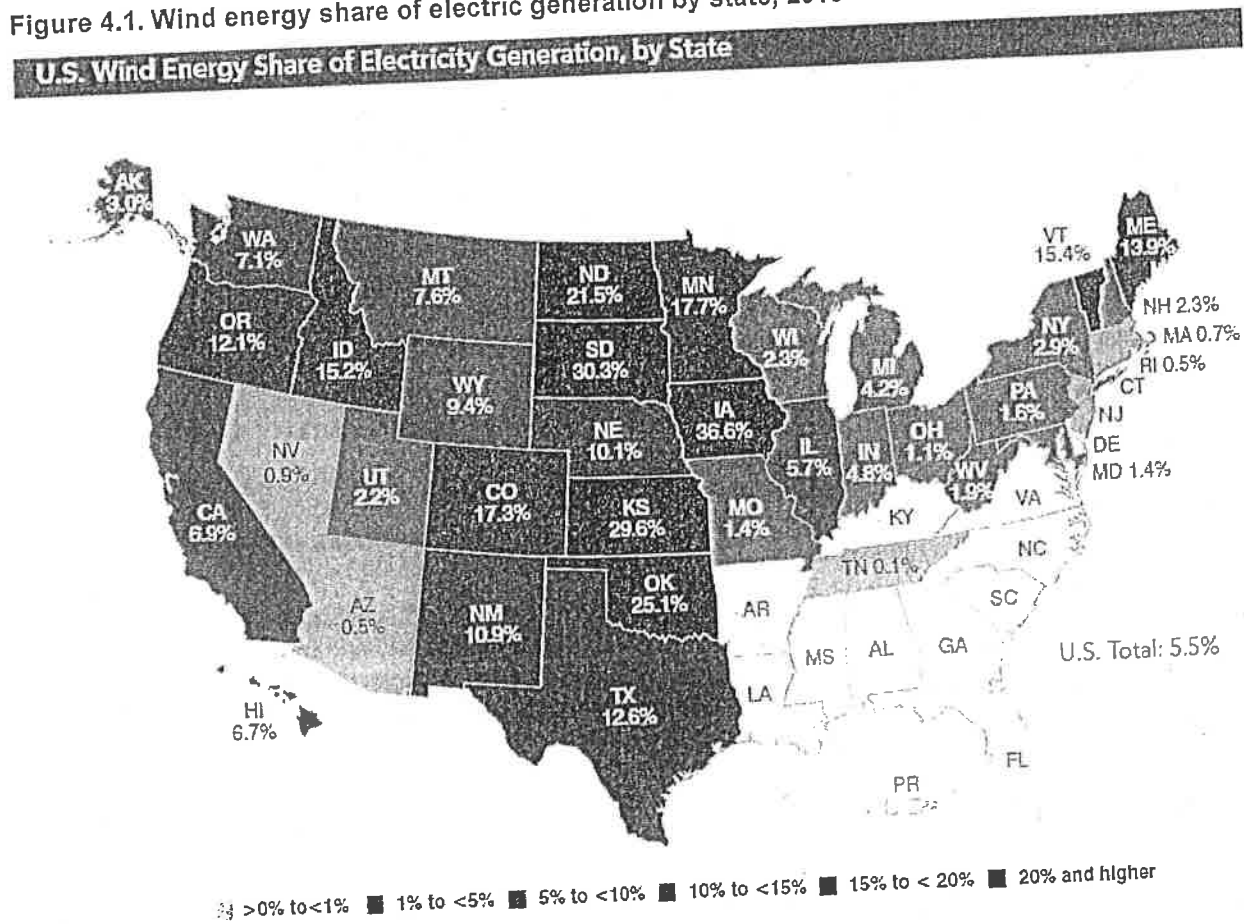
782 **4.3 Effects of high levels of renewable** 783 **penetration on the grid**

784 [UNDER CONSTRUCTION]

85 Current levels of electricity production from wind are increasing rapidly (see Figure 4.1).

1786

Figure 4.1. Wind energy share of electric generation by state, 2016¹⁰⁸



1787

Potential Grid Integration Challenges

In many power systems, sufficient flexibility exists to integrate additional variability, but this flexibility may not be fully accessible without changes to power system operations or other institutional factors (e.g., increased ramping of generation and improved coordination across markets and balancing areas) (Lew et al. 2013).

Integration of advanced renewable supply forecasting into dispatch and market operations has reduced uncertainties, improved scheduling of other resources to reduce reserves and fuel consumption, and enabled variable RE to participate as dispatchable

Competitive Renewable Energy Zones (CREZ) in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW wind and 3,600 miles completed nine years after CREZ legislation was signed), to access wind resources in remote parts of the state.

Grids are evolving in response to technological advances and anticipation of high RE penetration levels. For example, ERCOT, which is a small interconnection and more vulnerable to frequency excursions, now requires wind generators to provide inertial response, which helps keep a system stable in the initial moments after a disturbance (Bird, Cochran, and Wang 2014).

Capacity payments or markets, potentially tied to flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, and can occur whenever generation with lower marginal costs is added to the system. For example, low natural gas prices have reduced the market competitiveness of nuclear plants, contributing to recent retirements (Wernau and Richards 2014).

Maintaining reliability with variable renewables

Legacy power plant owners are justified in questioning how high levels of variable renewable energy (VRE, wind and solar resources) could affect grid operations and the prospects for individual power plants. Figure x shows the most challenging week of operation modeled in the Western Wind & Solar Integration Study, Phase 1, which shows both huge displacement of legacy coal, nuclear and coal power plants by wind energy and dramatically different operational requirements (more cycling on and off and ramping up and down) for those plants.

1795 **Figure 4.2. High VRE levels means big changes for conventional gas, coal and nuclear plants¹⁰⁹**

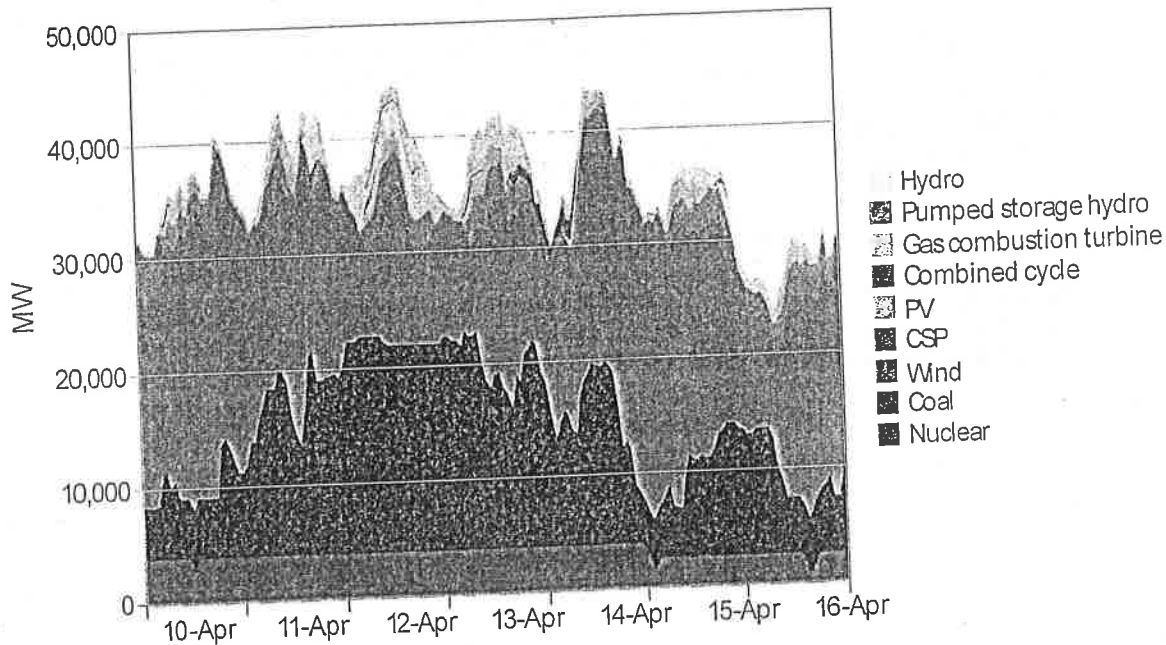


Figure ES-1. WWSIS-1 dispatch for the most challenging week of 3 years of data analyzed
 Notes: PV, photovoltaic; CSP, concentrating solar power

1796

1797 One of the greatest challenges lies in how to manage the effects of fast-moving solar and load
 1798 net of solar generation.

1799 **Table 4.2. Characteristics of VRE power, grid integration challenges and mitigation options¹¹⁰**

Wind & solar characteristics	Potential grid integration challenges	Mitigation options
Variability	Generator output can vary as underlying resource fluctuates	In many power systems, sufficient flexibility exists to integrate additional variability, but this flexibility may not be fully accessible without changes to power system operations or other institutional factors (e.g., increased ramping of generation and improved coordination across markets and balancing areas) (Lew et al. 2013).
Uncertainty	Generation cannot be predicted with perfect accuracy (day-ahead, day of).	Integration of advanced renewable supply forecasting into dispatch and market operations has reduced uncertainties, improved scheduling of other resources to reduce reserves and fuel consumption, and enabled variable RE to participate as dispatchable resources (IEA 2014; Lew et al. 2011). Examples: Xcel Energy, U.S. RTOs/ISOs (Porter et al. 2012)
Location-specificity	Generation is more economical where highest quality resources are available	Competitive Renewable Energy Zones (CREZ) in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW 3,600 miles completed nine years after

		CREZ legislation was signed), to access wind resources in remote parts of the state.
Non-synchronous generation	Generators provide voltage support and frequency control in a different manner than traditional resources	Grid code ^w requirements are evolving in response to technological advances and anticipation of high RE penetration levels. For example, ERCOT, which is a small interconnection and more vulnerable to frequency excursions, now requires wind generators to provide inertial response, which helps keep a system stable in the initial moments after a disturbance (Bird, Cochran, and Wang 2014).
Low capacity factor	Availability of the underlying energy resource limits the run-time of the plant	Capacity payments or markets, potentially tied to flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, and can occur whenever generation with lower marginal costs is added to the system. For example, low natural gas prices have reduced the market competitiveness of nuclear plants, contributing to recent retirements (Wernau and Richards 2014).

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Balancing generation with electricity load requires more flexibility.

System operators could need additional reserves and/or an improved ability to dispatch generation.

More transmission and more advanced planning could be needed.

Numerous technical studies for most regions of the nation indicate that significantly higher levels of renewable energy can be integrated without any compromise of system reliability (Table 4.3).

Table 4.3. Renewable energy penetration levels achievable by region, per recent technical studies

Region	Minimum level of renewable energy penetration (energy, not capacity) and technical source
New England	24%
PJM	30%
Midwest (MISO and SPP)	25%
ERCOT	

^w Capacity payments or markets, potentially tied to flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, and can occur whenever generation with lower marginal costs is added to the system. For example, low natural gas prices have reduced the market competitiveness of nuclear plants, contributing to recent retirements (Wernau and Richards 2014).

California	50% RPS – “Investigating a higher renewables portfolio standard in California,” E3, ECCO International & DNV KEMA, January 2014
Eastern US	30%
Western US	33% wind and solar energy penetration – “The Western Wind and Solar Integration Study Phase 2,” NREL, Intertek-APTECH, GE Energy, September 2013 40% renewable penetration – “WECC Flexibility Assessment,” NREL and E3, December 2015
Hawaii	100% RPS by 2045 – “Hawaiian Electric Company Power Supply Improvement Plan,” E3 for Hawaiian Electric Company, December 2016
National	50%

1807
1808
1809 There are four principal ways to maintain and enhance bulk power system reliability: technology, rules and standards, business practices, and using high (and expensive) levels of transmission and generation.

Using technology advances to provide essential reliability services

Source: Jacquelin Cochran, Paul Denholm et al., National Renewable Energy Laboratory, April 2015

Technology advancements now enable wind plants to provide the full spectrum of balancing services (synthetic inertial control, primary frequency control, and automatic generation control), an increasingly common requirement for systems with high levels of RE generation (Ela et al. 2014). For example, ERCOT requires wind turbines to provide an autonomous response to changes in power grid frequency, and the Colorado utility Xcel Energy requires many turbines to be on automatic generation control, which allows the computerized control system to directly control wind generation output (Bird, Cochran, and Wang 2014). PV plants are also starting to implement similar grid requirements (Morjaria et al. 2014).

Modern turbines and solar plants can also provide voltage support. Distributed solar PV systems can be configured with smart inverters that monitor local grid conditions and autonomously provide system grid services. The California Public Utility Commission, for example, is updating interconnection requirements for distributed PV to include smart inverters that provide local voltage support, meet ramp rate requirements after an outage, and ride through frequency and voltage events (CPUC 2014).

Revising grid codes early allows hardware and procurement agreements to be designed in advance of high variable RE penetration levels and reduces the financial burden associated with implementing such requirements retroactively. Germany’s requirements for installed solar photovoltaic (PV) to provide grid services were applied retroactively, at considerable cost (Cochran et al. 2012).

1810 FERC, NERC and the RTOs and ISOs have undertaken several initiatives to use rules, standards and grid
1811 codes to modify requirements for both interconnecting renewables and legacy power plants to improve
1812 grid reliability. These initiatives include early work to develop Low Voltage Ride-Through requirements
1813 for interconnecting wind and solar generation and NERC’s recent Lessons Learned warning that ...

1814

1815 The Bonneville Power Administration offers a good example of how to integrate wind energy effectively
1816 using operational and business practices rather than bringing on more reserves. Wind generation
1817 capacity in BPA's balancing authority area grew from 250 MW up to 4,782 MW in June 2016, driven by
818 state RPS requirements and federal and state tax credits. Much of the wind generation is located along
819 the Columbia River Gorge, connecting to the high voltage transmission system serving BPA's Columbia
820 River hydroelectric plants, so the wind fleet had little output diversity and could swing output as much
821 as 1,000 MW within an hour. BPA dealt with the reliability risk by limiting the amount of transmission
822 capacity BPA would provide the wind fleet (establishing control and curtailment on wind production),
823 began charging for using hydropower to balance the wind generation (also called a balancing capacity
824 rate, since adopted by FERC for other regions), and setting a penalty rate to encourage accurate wind
825 production scheduling. Wind forecasting and scheduling practices and tools have improved significantly
326 since. As generation over-supply has created more hours when negative energy pricing occurs, BPA has
327 worked with its stakeholders to create the Oversupply Management Protocol to assure that BPA can run
328 its federal hydrogeneration when necessary to serve endangered fish and other obligations,
329 compensating other generators for production curtailed to facilitate the federal hydropower.¹¹¹

31 PJM on how markets advance reliability

32
33 Will high penetrations of renewables impact affordability? [Capture direct impacts on electricity prices
34 as well as increased tax burden.]

Utility Dive, "Los Angeles muni to join Western EIM in 2019,"

6/2/17 and CAISO Western EIM Benefits Report, Fourth Quarter 2016.

"Participating utilities balance their loads in real time, and the market has saved more than \$170 million since launching in November 2014."

Matching demand with renewable megawatts is an important function of the market. The California ISO curtailed about 80,000 MWh in March—up from 47,000 MWh in the same month in 2016. However, a recent report concluded that the EIM is helping to minimize curtailments. Members have also saved \$173 million since the wholesale market was launched in November 2014.

1836

1837

NERC graphic, Hawaii or CAISO or CEC graphics

1838

1839

4.4 Fuel diversity and resource portfolios

1840

[UNDER CONSTRUCTION]

1841

1842 Hartman on diversity index

1843

how has fuel diversity changed over the past 15 years? More or less diverse? Diversity is another

1844

aspect of how to deliver valuable reliability and resiliency services, not a goal in itself.

1845

1846

Looking ahead: Risks of a gas-heavy generation system, including common modes of failure. Ways to

1847

mitigate this through markets, rules, technology, operations?

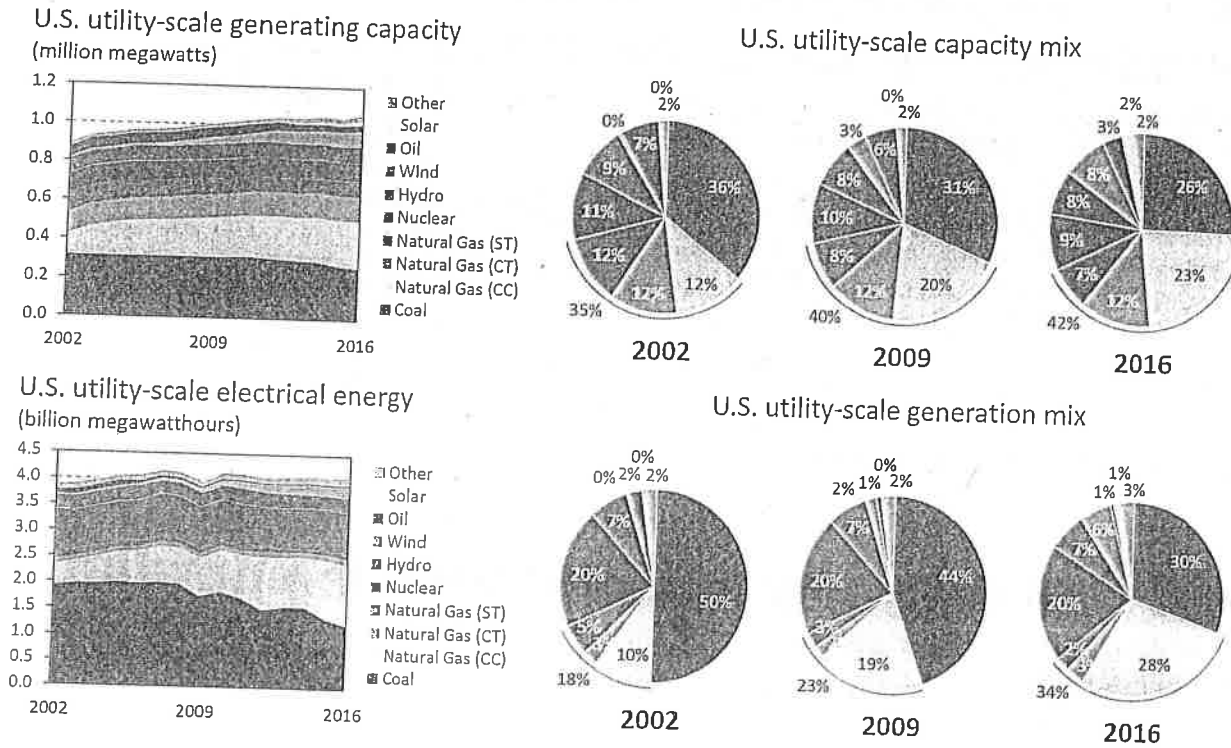
1848

1849

EPSA work on diversity, including NERC resources and PJM paper & appendix

1850

1851 **Figure 4.3. Fuel Diversity^{x112}**



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53
54
55 **Table 4.4. U.S. utility-scale generating capacity, 2002 vs. 2016**

U.S. utility-scale generating capacity, 2002 vs. 2016

Technology	2002		2016	
	MW	Percent of Total	MW	Percent of Total
Coal	315,655	36%	270,058	26%
Natural Gas (all)	313,277	35%	446,958	42%
Natural Gas (CC)	106,109	12%	239,519	23%
Natural Gas (CT)	104,170	12%	131,012	12%
Natural Gas (ST)	102,998	12%	76,426	7%
Nuclear	100,324	11%	99,316	9%
Hydro	79,356	9%	79,985	8%
Wind	4,417	0%	81,312	8%
Oil	59,651	7%	36,398	3%
Solar	397	0%	21,528	2%
Other	14,590	2%	21,155	2%
Total	887,666		1,056,710	

^x Notes: Natural gas technologies: ST = steam turbine, CT = combustion turbine, CC = combined cycle

- 1857 ORNL paper
- 1858 NERC and PJM
- 1859 Has the diversity of the electric system diminished? If yes, is this a problem for baseload power?
- 1860
- 1861 No -- the electric system is more diverse today than it was 20 years ago. This diversity is a problem for
- 1862 baseload power, but it enhances bulk power system reliability and resilience rather than compromising
- 1863 it.
- 1864
- 1865 Relate diversity to performance and operational characteristics and what the BPS and electric
- 1866 wholesale markets should be valuing and compensating
- 1867 Diversity and national security
- 1868
- 1869 Diversity alone does not guarantee reliability. Reliability is attained through the characteristics and
- 1870 capabilities of a portfolio of supply and demand-side resources that must be structured and incented to
- 1871 deliver reliability, not merely through the fact of diversity in itself.
- 1872

1873

IHS – Makovich et al – “The Value of U.S. Power Supply Diversity,” July 2014

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs— including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply [in 2013] lowers the cost of generating electricity by more than \$93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power.

... The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

... Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

4.5 Grid resiliency, fuel assurance and on-site fuel storage

[UNDER CONSTRUCTION]

Waiting for data on how coal and nuclear plants performed in actual emergency situations (polar vortex, Hurricane Sandy) – do they have black-start capability? Did they freeze up or remain operational? Has anything changed in their capabilities?

Performance of different types of generators during recent system emergencies (Hurricane Sandy, polar vortex, hurricanes) – what failed and why? Any lessons?

- 1883 NERC on polar vortex, SW outage, other plant performance issues
- 1884 FERC black-start rates
- 1885 Again, regional issue, not national, given different failure modes (other than common cyber issue)
- 1886 affecting different types of prevailing resources
- 1887
- 1888 PJM evolving resource characteristics paper, Fig 6
- 1889 EPRI report on flexibility
- 1890
- 1891 Need for flexibility on the grid – ERCOT example, where existing baseload and intermediate plants
- 1892 didn't meet the need – use utility dive story, not lab example.
- 1893

4.6 Diversity, reliability and resource portfolios

1894

1895

1896 [UNDER CONSTRUCTION]

1897 EXPLAIN – whether wholesale energy and capacity markets are adequately compensating attributes

1898 such as on-site fuel supply and other factors that support grid resilience, and could this affect reliability

1899 and resilience in the future?

- 1900
- 1901 • Why capacity and energy products aren't enough
 - 1902 • Essential reliability services, ancillary service markets, and need to define new electricity
 - 1903 products
 - 1904 • On-site fuel availability is only fuel assurance at a super-local, plant-specific level; role of this for
 - 1905 system resilience. Whether plants with on-site fuel have actually proven resilient in recent
 - 1906 system emergencies
 - 1907 • Fuel assurance and national security

1908

1909 NERC on essential reliability services, IVGTF findings

- 1910 • Increased speed of supply variability from wind and solar ramps
- 1911 • Illustration -- NYT, "Coal Country's Power Plants Turning away from Coal," 5/26/17

1912

4.7 Reliability and resiliency – looking forward and next steps

1913

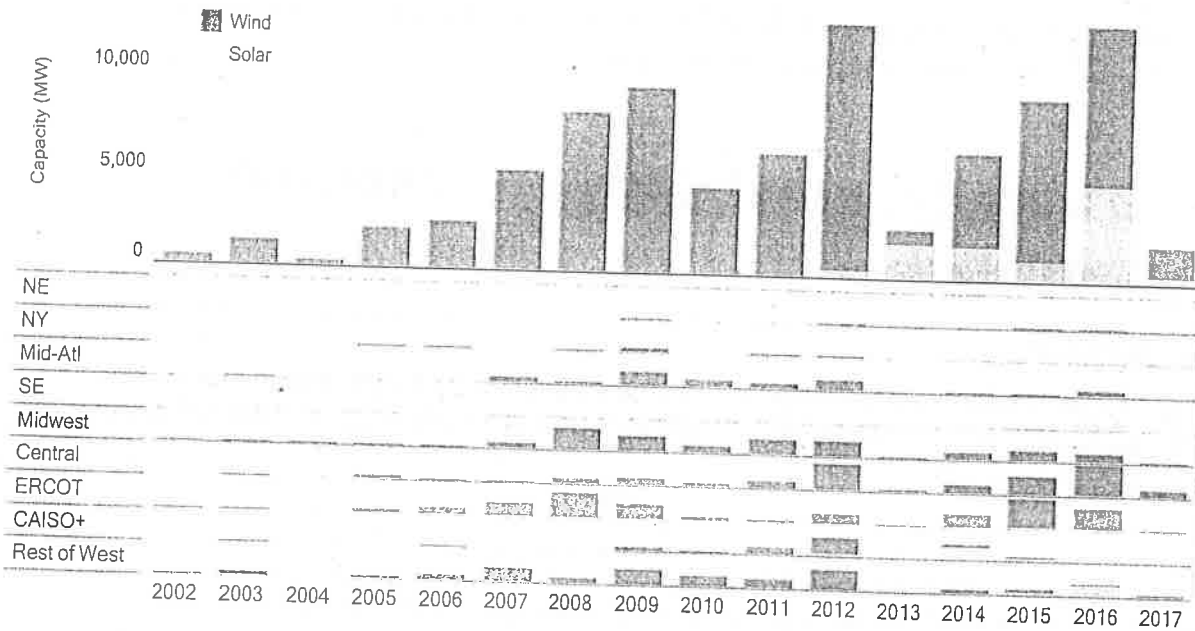
1914

1915 [UNDER CONSTRUCTION]

5 Renewable energy growth, reliability impacts and prospects

[UNDER CONSTRUCTION]

Figure 5.1: Annual Generation Capacity of Wind and Solar, Total and by Region, January 2002 through March 2017¹¹³



5.1 Growth in renewable energy penetration

[UNDER CONSTRUCTION]

Incentives and subsidies

Growth patterns

5.2 Impacts of renewable energy on grid operations

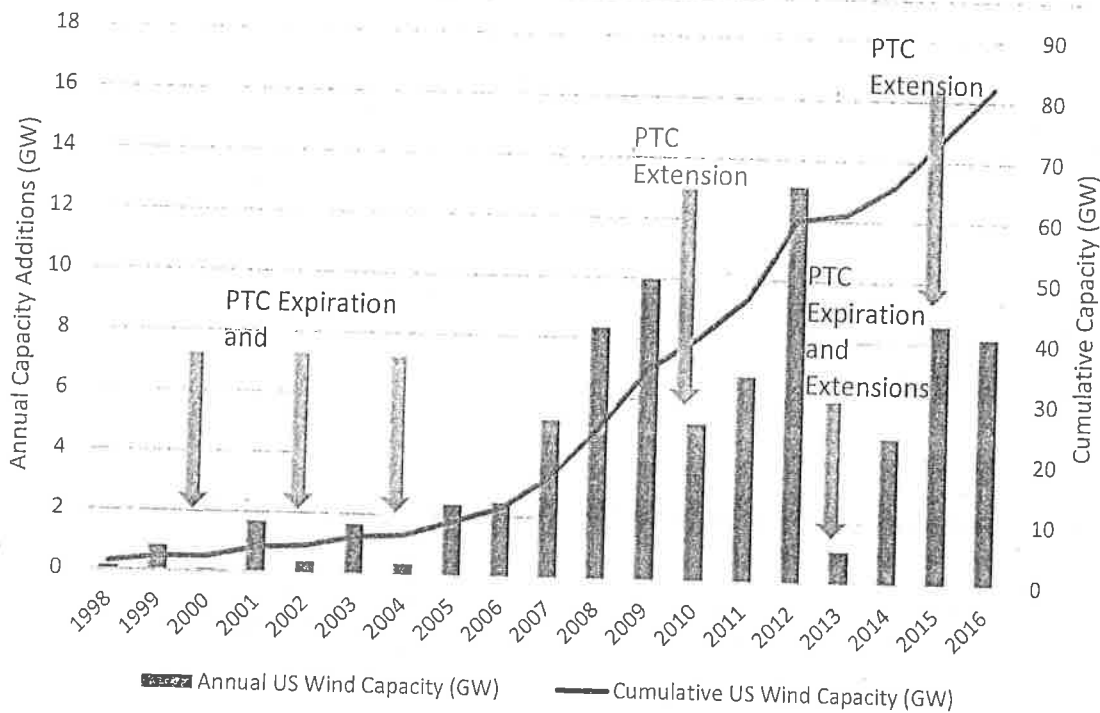
[UNDER CONSTRUCTION]

Duck curve

Moving the peak

1969
1970
1971
1972
1973

Figure 5.x – Federal tax policy has had a significant effect on wind capacity development
(Source: Updated QER Figure 3-4. Relationship between the Production Tax Credit and Annual Wind Capacity Additions¹¹⁵)



1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984

State energy policies affecting at least two-thirds of the nation’s electricity users have already made a long-term commitment to encourage renewable energy use. These state measures include establishing renewable portfolio standards (see Figure 5.x), establishing state subsidies (investment or production tax credits, setting up a renewable energy credit program to make renewable energy more fungible, or setting up greenhouse gas programs (emissions targets, carbon pricing and carbon credit trading) that favor low-emissions renewable generation. [DSIRE 2017, C2ES 2016]. Several states have policies to use public benefit funds for energy efficiency and renewable energy acquisitions. [C2ES, Public Benefit Funds]

1934 Lower CF contribution

1935

5.3 Integrating renewable energy to maintain reliability

1936

1937

1938 [UNDER CONSTRUCTION]

1939 LBNL, NERC IVGTF, etc

1940 Ability of VREs to provide ERS

1941

5.4 Renewable energy growth will continue

1942

1943

1944 [UNDER CONSTRUCTION]

1945 Will removing renewables subsidies and RPS make renewable generation go away (and presumably put
1946 less pressure on coal and nuclear plants)? No.

- 1947 • Current federal PTC for wind ends soon, federal ITCs for solar PV and energy efficiency ended in
1948 _____. Forty percent of current wind capacity does not receive PTC. [Rob Gramlich]
- 1949 • Cost and price forecasts for domestic and global nat gas and renewables production prices all
1950 show continuing long-term downward trends

1951

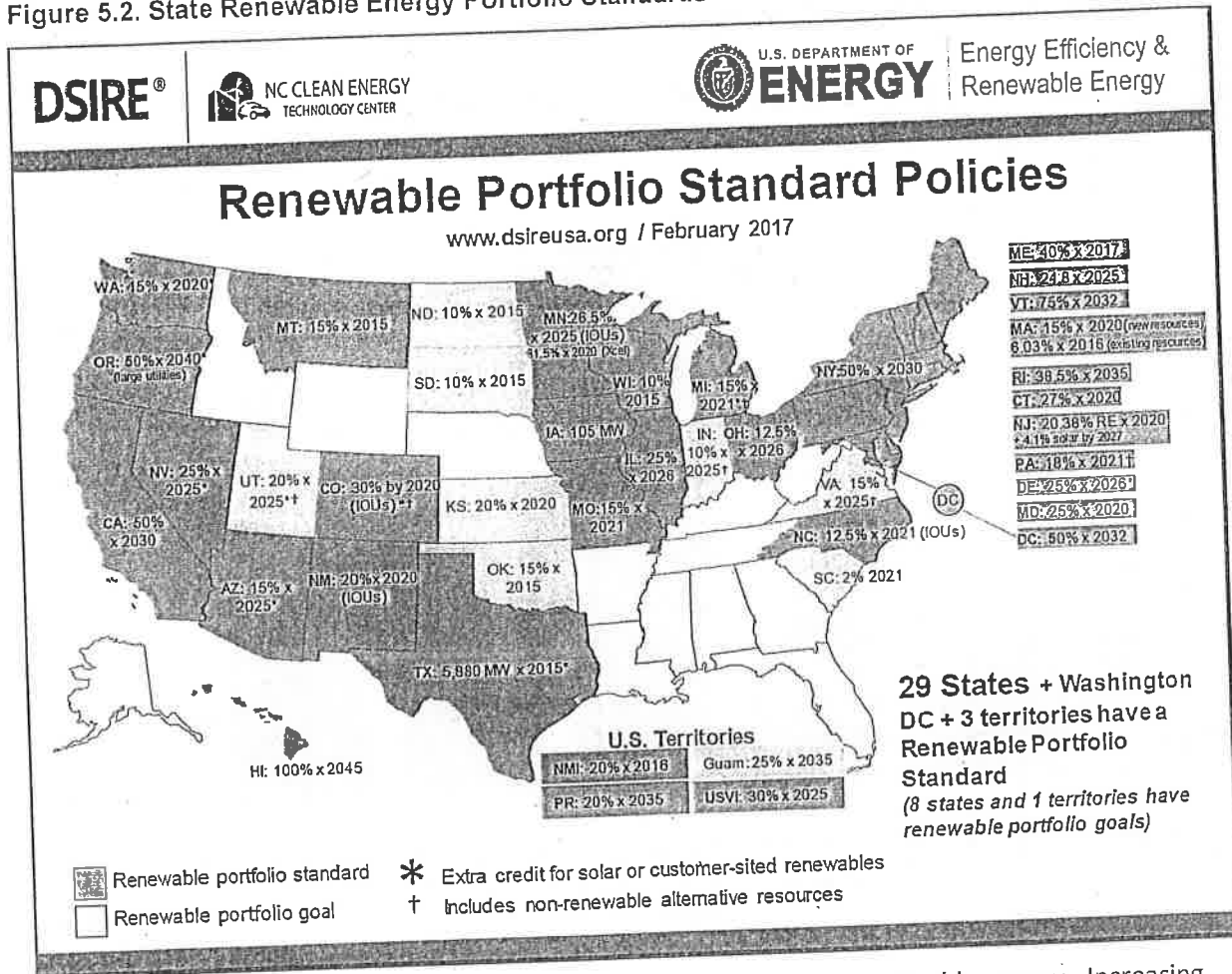
1952 QER: Declining costs for wind and solar have been spurred by industry innovation as well as a variety of
1953 Federal and state policies that accelerate deployment. Technology improvements in wind turbines—
1954 including taller turbines, longer blades, and advanced turbine designs — have enabled substantial cost
1955 reductions for wind power. Power purchase agreements for wind have fallen from rates as high as 7
1956 cents/kWh in 2009 to around 2 cents/kWh inclusive of the Production Tax Credit (PTC) in 2015, driven
1957 by wind deployment in excellent resource locations in the interior regions of the country.¹¹⁴ Regulatory
1958 policies accelerating wind development include the renewable energy tax credits at the Federal level
1959 and the renewable portfolio standards (RPSs) at the state level.

1960 At the Federal level, the Investment Tax Credit (ITC) and PTC established under the Energy Policy Act of
1961 1992 are two key Federal tax incentives that have been instrumental in accelerating the construction of
1962 renewable electricity projects. (See Figure 5.x) Both of these incentives are designed for use by entities
1963 that pay Federal taxes and are subject to strict treatment under both the Internal Revenue Code and
1964 generally accepted accounting principles. These attributes have major implications for who utilizes the
1965 incentives and how projects are developed. The federal Production Tax Credit (PTC), enacted first in
1966 ____, directly affected wind project deployment -- between 2000 and 2013, cumulative wind capacity
1967 grew from under 5 GW to over 60 GW, directly tracking the PTC expiration and extension schedule.

1968

1985

Figure 5.2. State Renewable Energy Portfolio Standards¹¹⁶



1986
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1995

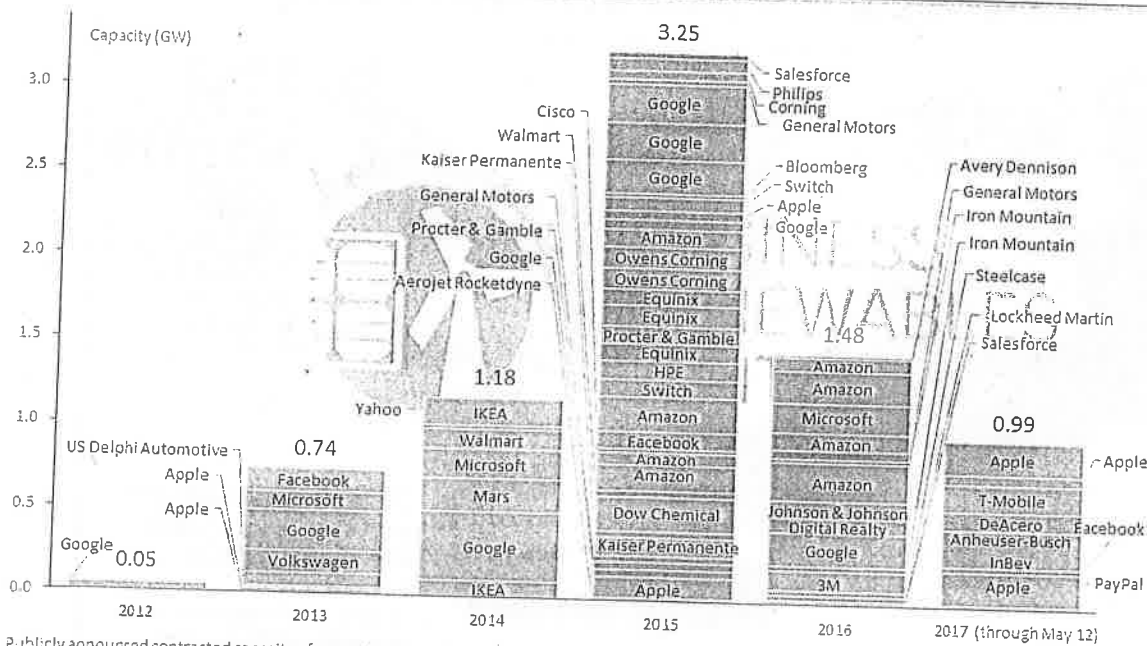
Some electricity customers have established a strong preference for renewable energy. Increasing numbers of businesses have made commitments to use renewable energy, either through direct investments in its production (as by Walmart, Amazon and Google) or by buying renewable energy through utility or third-party retail electric provider green tariffs or through direct contracts with renewables producers. [World Resources Institute 5/2017, WRI 2 5/17, Bloomberg New Energy Finance 10/25/16, Corporate Eco Forum & WWF, 10/16] (See Figure 5.x) As of late 2016, corporate purchases of power purchase agreements directly with renewable energy producers have been doubling every year since 2012, both to execute their sustainability commitments and by the benefits of reducing and stabilizing energy costs with predictable, flat renewable energy purchases.¹¹⁷

996

Figure 5.3. Corporate purchases of renewable energy¹¹⁸



Corporate Renewable Deals 2012 – 2017



Publicly announced contracted capacity of corporate Power Purchase Agreements, Green Power Purchases, Green Tariffs, and Outright Project Ownership in the US and Mexico, 2012-2017. Excludes on-site generation (e.g., rooftop solar PV) and deals with operating plants. Last updated: May 12, 2017.

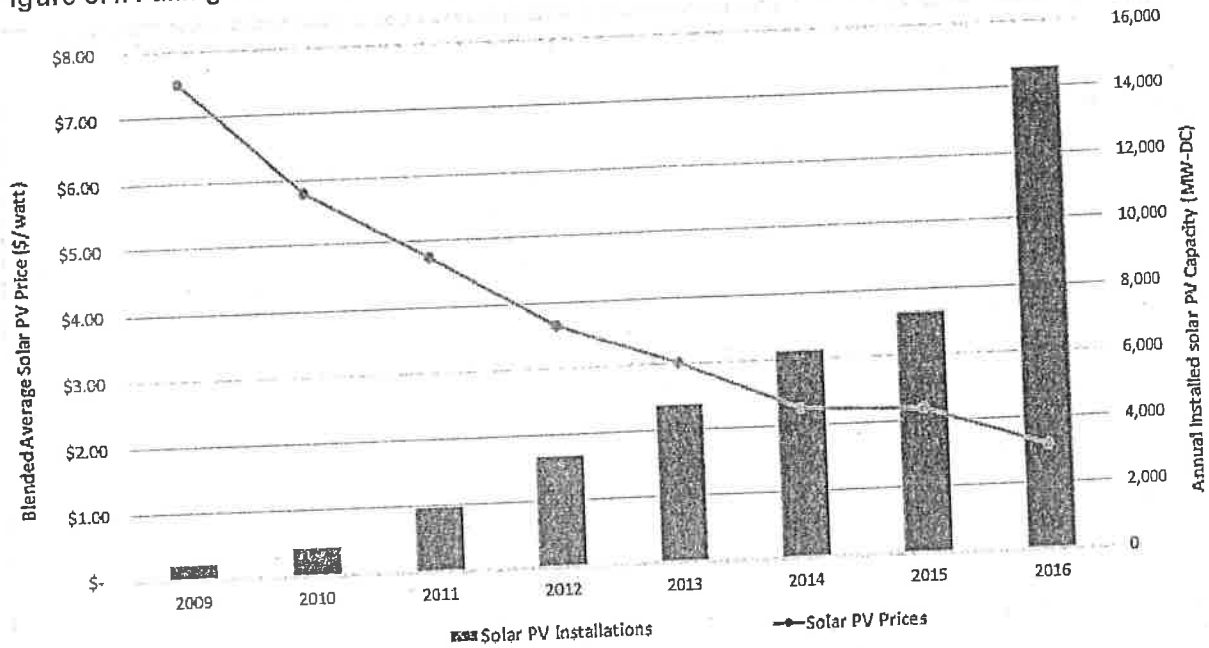
Copyright 2015 by Rocky Mountain Institute
For more information, please visit <http://www.businessrenewables.org/> or contact BRCC@rmi.org

At the residential level, x% of customers are buying renewable energy through some sort of green tariff and customer surveys indicate a strong preference for solar, wind and natural gas-fueled power. [SolarCity 3/15] And the number of customers installing solar photovoltaics is growing every year – at the end of 2016, there were --,000 residential rooftop PV installations representing –MW, with that growth rate increasing by --% every year as PV prices drop. [get these numbers and a good graphic from SEIA website]

Solar photovoltaics prices continue to fall (Figure 5.4), and therefore pose a continuing threat to the level of customer energy and peak usage available for supply-side generation to serve. The Solar Energy Industry Association reports that solar prices have dropped 67% since 2011, and that solar developers are now signing power purchase agreements for utility-scale plants at prices between \$0.03 to \$0.05 per kWh. [need someone to call SEIA to find out whether this is before or after ITC] Although PV generation is variable and subject to the availability of sunshine, these prices are so low that most power purchasers view PV at these rates as a valuable component of an electricity portfolio.

2012

Figure 5.4. Falling Solar PV prices and rising installed capacity¹¹⁹



2013

2014

2015

2016

2017

2018

Utility-scale PV installed capacity is distributed unevenly across the United States. As Figure 5.5 shows, California comprises over 40 percent of the installed utility-scale PV capacity in the country, followed by North Carolina, and the Southwest of the United States with Arizona, Nevada, and Utah.

Figure 5.5. Location of Utility-Scale Solar Generating Units, 2016¹²⁰



2019

¹¹⁹ Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, <https://www.eia.gov/electricity/data/eia860m/>

2020 Utilities are also restructuring their purchase patterns and resource portfolios to acquire or own much
 2021 more renewable energy. At the June 2017 Edison Electric Industry conference, two utility CEOs
 2022 explained their moves to increase renewables:

2023 DTE Energy CEO Gerry Anderson said his utility's move away from coal and toward
 2024 cleaner sources of power was guided largely by economics. When the Michigan utility
 2025 began preparing for the Clean Power Plan — an Obama-era emissions rule — officials
 2026 found they "could deeply decarbonize DTE Energy and we could do it in a way that's
 2027 affordable."

028 That perspective is one shared by both the broader industry and PNM, said [Pat] Vincent-
 029 Collawn [incoming EEI Chair and PNM Resources CEO]. "If you look at where we are with
 030 natural gas prices, renewables prices, it's changed dramatically," she said. "So those
 031 market forces lead us to different conclusions because we do want to produce power at
 032 the lowest possible cost."¹²⁰

033
 034 Lazard Freres 2016 projections for continued downward prices for new utility-scale solar and
 035 wind capacity (use NREL instead?)

036 Illustration – Utility Dive, "Updated: Tucson Electric Power signs solar + storage PPA for 'less
 037 than 4.5c/kWh", 5/23/17 – competitive with peaker plant prices

AEP, largest coal user in the East, sees cleaner energy demand

Source: USA Today, interview with AEP CEO, 6/3/17

Nick Akins, the CEO of American Electric Power, one of the largest utilities in the U.S., says the preference for gas, renewables and energy efficiency, will only grow in response to increasing demands from shareholders and customers for cleaner energy, regardless of changes in national energy policy.

With 5.4 million customers in 11 states, AEP plans to spend \$1.5 billion on renewable energy from 2017 through 2019, and \$13 billion on transmission and distribution improvements, including new "smart" technologies that will make the grid more resilient and efficient, AEP says."¹²¹

"You don't see coal making a comeback at AEP or other utilities?" No, I don't think so. ... You wouldn't make a decision (to build a coal power plant) at this point because it's heavily capital-intensive, and involves a longer-term process and risk to build. And, of course, you can add renewables that are very efficient and natural gas that's efficient and much less expensive and risky, in terms of construction and operation.

Do you plan to close any more coal-powered plants soon? I suspect we'll see some more retirements in the future, and as we progress towards that cleaner energy economy, and consider the expectations of our customers and shareholders for us to mitigate risk, you'll continue to see that happen.

But on the other hand, I want to make sure there's an understanding that coal will remain a part of the portfolio, but it will be of a lesser degree because of these other resources that are available to us now that weren't available to us just a few years ago.

The availability of new transmission to interconnect utility-scale renewables to the grid has been essential for the accelerated development of VREs in resource-rich regions. Starting with Texas' example in the early 2000s, many states identified renewable energy development as an economic development and job creation opportunity, and encouraged grid planners and transmission utilities to build new transmission to open up those areas. FERC fostered this effort with the addition of wind-

2043 specific provisions for the Open Access Transmission Tariff [cite] in 2003 and the end to pancaked
 2044 transmission rates in 200x. Several years later, FERC adopted Order 1000, requiring regional system
 2045 planning and coordination, which facilitated development of more backbone transmission for increased
 2046 trade and deliverability.

Battery storage role

Source: "Battery storage: The next disruptive technology in the power sector,"

David Frankel & Amy Wagner, McKinsey & Co. blog, June -, 2017

Storage prices are dropping much faster than anyone expected, due to the growing market for consumer electronics and demand for electric vehicles (EVs). Major players in Asia, Europe, and the United States are all scaling up lithium-ion manufacturing to serve EV and other power applications. No surprise, then, that battery-pack costs are down to less than \$230 per kilowatt-hour in 2016, compared with almost \$1,000 per kilowatt-hour in 2010.

McKinsey research has found that storage is already economical for many commercial customers to reduce their peak consumption levels. At today's lower prices, storage is starting to play a broader role in energy markets, moving from niche uses such as grid balancing to broader ones such as replacing conventional power generators for reliability, providing power-quality services, and supporting renewables integration.

Further, given regulatory changes to pare back incentives for solar in many markets, the idea of combining solar with storage to enable households to make and consume their own power on demand, instead of exporting power to the grid, is beginning to be an attractive opportunity for customers (sometimes referred to as partial grid defection). We believe these markets will continue to expand, creating a significant challenge for utilities faced with flat or declining customer demand. Eventually, combining solar with storage and a small electrical generator (known as full grid defection) will make economic sense—in a matter of years, not decades, for some customers in high-cost markets.

2047
 2048
 2049
 2050
 2051

5.5 Reliability and resilience

[UNDER CONSTRUCTION]

from QER:

The reliability of the electricity system underpins virtually every sector of the modern U.S. economy. Reliability of the grid is a growing and essential component of national security. Standard definitions of reliability have focused on the frequency, duration, and extent of power outages. With the advent of more two-way flows of information and electricity, communication across the entire system from generation to end use, controllable loads, more variable generation, and new technologies such as storage and advanced meters, reliability needs are changing, and reliability definitions and metrics must evolve accordingly.

Increased computing power and more sophisticated telecommunication and metering equipment has pushed the time scale for balancing electric systems to shift from daily to hourly, minute to minute, second to second, or millisecond to millisecond at the distribution end of the supply chain, with events at the distribution level potentially affecting system frequency and transmission conditions. The demands of the modern electricity system have required, and will increasingly require, innovation in technologies (e.g., inverters), markets (e.g., capacity markets), and system operations (e.g., balancing authorities).

Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions); both in terms of the duration and frequency of outages; this is largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.

The leading cause of power outages in the United States is extreme weather, including heat waves, blizzards, thunderstorms, and hurricanes. Events with severe consequences are becoming more frequent and intense, due to climate change, and have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States.

Grid owners and operators are required to manage risks from a broad and growing range of threats. These threats can impact almost any part of the grid (e.g., physical attacks), but some vary by geographic location and time of year. Near-term and long-term risk management is increasingly critical to the ongoing reliability of the electricity system.

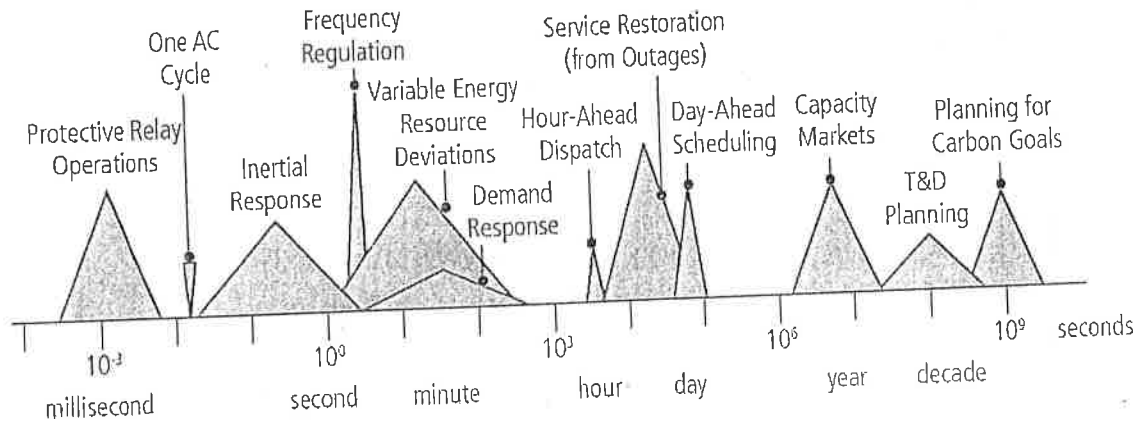
Demand response (DR) technologies and programs offer a particularly flexible grid resource that is capable of improving system reliability, reducing the need for capital investments to meet peak demand, reducing electricity market prices, and improving the integration of variable renewable energy resources. DR can be used for load reduction, load shaping, and management of consumption to help grid operators mitigate the impact of variable and distributed generation on the T&D systems.

Maintaining power system reliability involves working to coordinate assets and ideas at multiple time scales, from long-term planning over decades down to operations occurring in real time at fractions of a second.

Capacity markets, day-ahead scheduling, and hour-ahead dispatch are well-understood tools for managing supply variability (mid-right axis). Beyond capacity contracts, traditional transmission and distribution (T&D) system long-term planning methods work to map and price investment requirements to ensure grid reliability (right end of axis). However, the widespread integration of variable energy

2094 resources significantly expands the time dimensions in which grid operators must function, ranging from
 2095 hourly to minute to second intervals (mid-left axis). And, in a world of sub-second decision making (i.e.,
 2096 inertial response, one alternating current (AC) cycle, and protective relay operations), dispatch
 2097 effectiveness will require the integration of automated grid management (left end of axis).

2098 **Figure 5.6. System Reliability Depends on Managing Multiple Event Speeds¹²¹ Note, BCS to**
 2099 **remove Planning for Carbon Goals**



2100
 2101
 2102 Supply variability is an important part of system operations, where balancing authorities must ensure
 2103 that risks of unexpected loss or variability of supplies are hedged by having some power plants
 2104 immediately available (spinning reserves) and other plants able to supply power with short-term
 2105 notifications of need (non-spinning reserves).

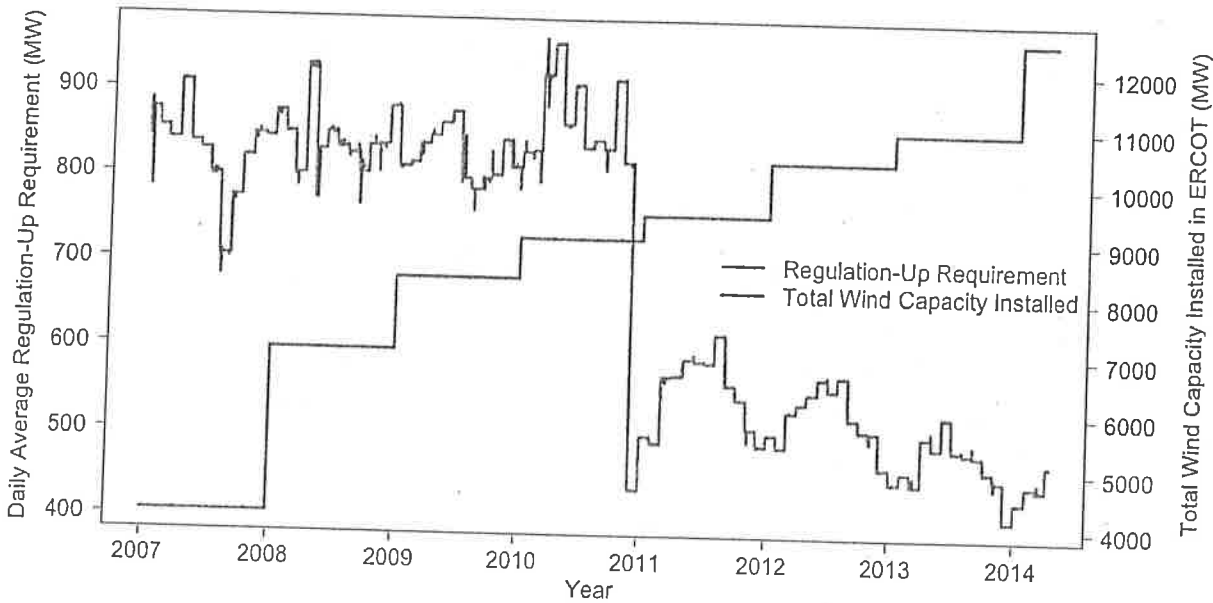
2106 5.6 High levels of wind penetration can 2107 be integrated into the grid without 2108 harming reliability

2109 [UNDER CONSTRUCTION]

2110 Wind integration costs don't always go higher

2111 Within ERCOT, as wind generating capacity grew from xx to xx MW and the share of energy rose from
 2112 xx to y% per year, they have found that the amount of fast-acting frequency regulation reserve has
 2113 fallen rather than grown, as shown in Figure 5.7. This is in part because ERCOT no longer has to provide
 2114 contingency reserves to replace the sudden loss of the interconnection's largest generator (a nuclear
 2115 power plant). Within ERCOT, contingency reserves cost about \$0.76/monthly electric bill in the 2007 to
 2116 2011 period; after the ISO revised its contingency reserves to reflect the higher renewables
 2117 penetration, the increased cost was only \$0.04 cents/bill more.¹²²

Figure 5.7. Daily average regulation up requirement has fallen as wind capacity grows in ERCOT¹²³



Western Wind and Solar Integration Study Phase 3

- “With good system planning, sound engineering practices, and commercially available technologies, the Western Interconnection can withstand the crucial first minute after severe grid disturbances with high penetrations of wind and solar on the grid.”
- “Adequate frequency response in the Western Interconnection was maintained for the conditions studied.”
- “Selected nontraditional frequency-responsive controls on wind and solar power plants and energy storage were examined and could improve frequency response.”
- “The transient stability of the system is not fundamentally changed by high wind and solar generation. This does not mean that the system behaves identically. There is, however, nothing to indicate that the system dynamics have changed so fundamentally that radically different means to ensure stability are required.”

NREL Role of Wind Power in Primary Frequency Response (2016)

“The ability of wind power plants to provide PFR [primary frequency response]—and a combination of synthetic inertial response and PFR—significantly improved the frequency response performance of the system.”

Powering into the Future: Renewables and Grid Reliability (MJ Bradley, 2017)

“Renewable generators also can provide frequency control. Many new wind and solar facilities have components called ‘active power controls,’ which allow their output to be increased or decreased to help maintain reliability. These controls allow renewable generators to provide primary frequency response that is similar to that of the automatic governors on conventional power plants. Using these

2142 components, they can quickly and automatically adjust their output to help stabilize grid frequency.”

2143 “These technologies can respond to automatic generation control signals every few seconds to rapidly
 2144 increase or decrease output to help balance the system. They can also follow detailed, five-minute
 2145 schedules that are shared with the central grid operator ahead of time, meaning that the dispatcher can
 2146 count on a certain level of output on a short-term basis.”

2147 Powering into the Future: Renewables and Grid Reliability (MJ Bradley, 2017)

2148 “MISO needed almost no additional fast-acting power reserves to back up 10,000-plus MW of wind
 2149 power on the system.”

2150 “ERCOT needs only about 50 MW on average of fast-acting stand-by reserves to reliably integrate
 2151 10,000 MW of wind into the grid.”

2152 “PJM found that a 30 percent regional variable renewable penetration level— adding over 100,000 MW
 2153 of renewable power—requires no additions in operating reserves, and only 1,500 MW (or 1.5 percent of
 2154 renewable capacity) of quick-ramping regulation generators such as flexible natural gas generation.”

2155 “Large geographic size also helps to improve the collective capacity value of renewable generators (and
 2156 reduces the need for other balancing services).”

2157 Update to Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements (2013)

2158 “Although additional regulation is necessary with increasing wind penetration, the main driver is still
 2159 load variance rather than wind variance.”

2160 **5.7 Reliability and resiliency – looking**
 2161 **forward and next steps**

2162 [UNDER CONSTRUCTION]

2163

6 Power markets

[UNDER CONSTRUCTION]

6.1 Wholesale Electricity Markets

This section has two subsections:

- 1) A review of the factors and events that have shaped the evolution of wholesale electricity markets; and
- 2) A discussion of the major issues in these markets today.

6.2 Evolution of U.S. Wholesale Electricity Markets

In the latter 1970s and '80s, the U.S. electricity industry was in a baseload capacity building boom. However, high inflation became particularly troublesome for utilities' high capital cost projects. Many large utilities were building nuclear plants, and all too frequently these projects became subject to major construction delays and cost overruns. Similar difficulties, although at a smaller scale, occurred at times with the construction of large new coal-fired plants. Many state officials, and eventually a majority of the U.S. Congress, concluded that if new generation capacity was needed in a given area, non-utility companies might well be able to provide that capacity at lower cost than investor-owned utilities, to the benefit of electricity consumers.

In 1978, Congress passed the Public Utilities Regulatory Policies Act (PURPA), which was an effort to curb the electricity industry's reliance on (at that time) high-cost natural gas and oil.² PURPA provided for "increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers," as well as the development of new generation resources—specifically renewable energy and cogeneration facilities.¹²⁴ PURPA is significant because it introduced a form of competition to the investor-owned utility model and set the stage for later regulatory reform of the electricity industry.

The Energy Policy Act of 1992 included provisions authorizing FERC to approve "exempt wholesale generators," allowing any company, using any fuel and any generation technology, to go into the generation business and sell electricity at competitive prices. The act also gave FERC the authority under section 722 to order transmission owners to provide transmission service as required by transmission customers.

² Also in 1978, the Power Plant and Industrial Fuel Use Act prohibited "(1) the use of natural gas or petroleum as a[n] energy source in any new electric powerplant; and (2) construction of any new electric powerplant without the capability to use coal or any alternate fuel as a primary energy source." Source: <https://www.congress.gov/bill/95th-congress/house-bill/5146>
PPIFUA was repealed in 1987, which "set the stage for a dramatic increase in the use of natural gas for electric generation and industrial processing." Source: https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

2193 In 1996, FERC used this transmission authority to mandate that public utilities^{aa} provide open access
 2194 transmission to the interstate transmission grid, through its landmark Order No. 888. FERC required
 2195 public utilities under its jurisdiction to make non-discriminatory transmission service available to all
 2196 parties, meaning charging all parties the same rate that the public utility would charge itself for the use
 2197 of its transmission facilities. This action by FERC greatly assisted the development of competition
 2198 among wholesale power producers because it meant that utilities would find it difficult to limit access
 2199 to their transmission facilities as a means of protecting their generation assets from competitors.

2200 Electricity restructuring took hold in both the wholesale and retail sectors. It “allowed both non-utility
 2201 generators to sell electricity to utilities – displacing the utility generation function – and/or “retail
 2202 service providers” to buy electricity from generators and sell to end-use customers – displacing the
 2203 utility procurement and billing functions.”^{125bb} Between 1998 and 2006, 23 states sought to bolster
 2204 competition among bulk power suppliers by requiring their vertically integrated investor-owned electric
 2205 utilities to divest some or all of their generating assets. Divestiture was pursued most aggressively by
 2206 the states with high retail electricity prices (most of New England, New York, the Mid-Atlantic states,
 2207 and California).^{cc} Generating units that had been operating under cost-of-service regulation were sold
 2208 to independent power producers (IPPs) or transferred to non-regulated investor-owned utility affiliates.

2209 However, the wave of restructuring did not sweep over the entire nation. In large areas—particularly
 2210 the Southeastern states and the West apart from California—the industry still consists of vertically-
 2211 integrated utilities under cost-of-service regulation by state commissions or local regulatory bodies.^{dd}
 2212 As a result, two broad organizational structures exist at the wholesale level in the U.S. today:

- 2213 • Traditional or bilateral markets -- These feature regional bilateral trading, primarily between
 2214 vertically integrated utilities and utilities with independent generators. The Southeastern
 2215 states and the non-California West do not have organized markets and so trade principally
 2216 through bilateral contracts. However, many utilities in Western states already participate in—
 2217 or plan to join—the Energy Imbalance Market (EIM) set up by the California Independent
 2218 System Operator (CAISO).^{ee126} Within the organized market areas, a large amount of the
 2219 energy traded moves under bilateral contracts and self-supply, with these arrangements often
 2220 benchmarked to organized market prices. And
- 2221 • Organized or centralized markets -- These feature regional and multilateral bid-based
 2222 optimization. Organized markets run by the independent system operators (ISOs) and regional
 2223 transmission organizations (RTOs) are located in New England, New York, the Mid-Atlantic

^{aa} The Federal Power Act defines a “public utility” as “[utility definition (non-ERCOT lower 48 IOUs and coops with no RUS debt.). For example, non-ERCOT investor-owned utilities are “public utilities” under the FPA. Somewhat confusingly, publicly-owned electric utilities such as municipally-owned entities, also called public power, are not “public utilities” under the FPA.

^{bb} Because the bulk power system is the focus of this report, we do not address retail restructuring in detail

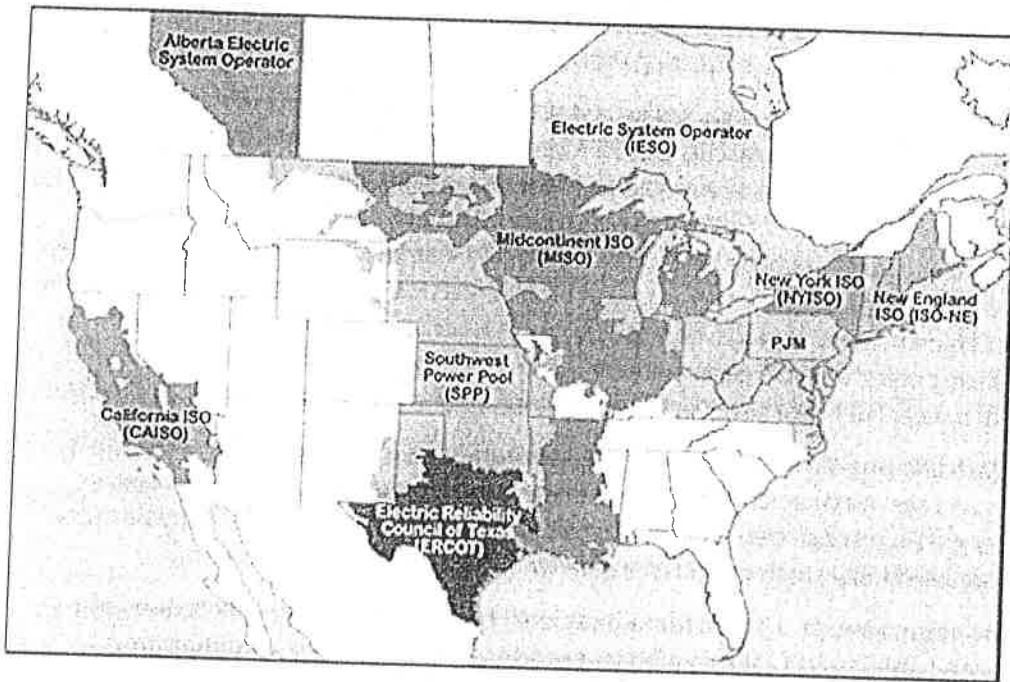
^{cc} In most of these states, there was strong interest in making both wholesale and retail electricity markets competitive as a way to bring down high retail electricity rates, and 18 states embraced retail competition to some degree. California tried it and then retreated after lack of adequate infrastructure combined with major flaws in their market design led to blackouts and market abuse.

^{dd} There also exist many publicly-owned utilities, the majority of which are not vertically-integrated, though some are. Cooperatively-owned utilities also exist, none of which are vertically-integrated. Both types are regulated by local elected or appointed governing boards, though a state public utility commission may have some jurisdiction in some states.

^{ee} These utilities are not full members of CAISO but can participate in and benefit from its real-time wholesale energy market nonetheless. Notably, the EIM allows for greater flexibility in accommodating high levels of renewable energy integration.

2224 states, parts of the Midwest and Southwest, California, and Texas. In these areas (Figure 6.1),
 2225 the RTOs and ISOs perform short-term unit commitment and economic dispatch based on bids
 2226 from suppliers and load-serving entities.^{ff}

2227 **Figure 6.1. The seven RTOs or ISOs in the U.S.**¹²⁷



28
 29
 30 Spectrum of Wholesale Power Markets

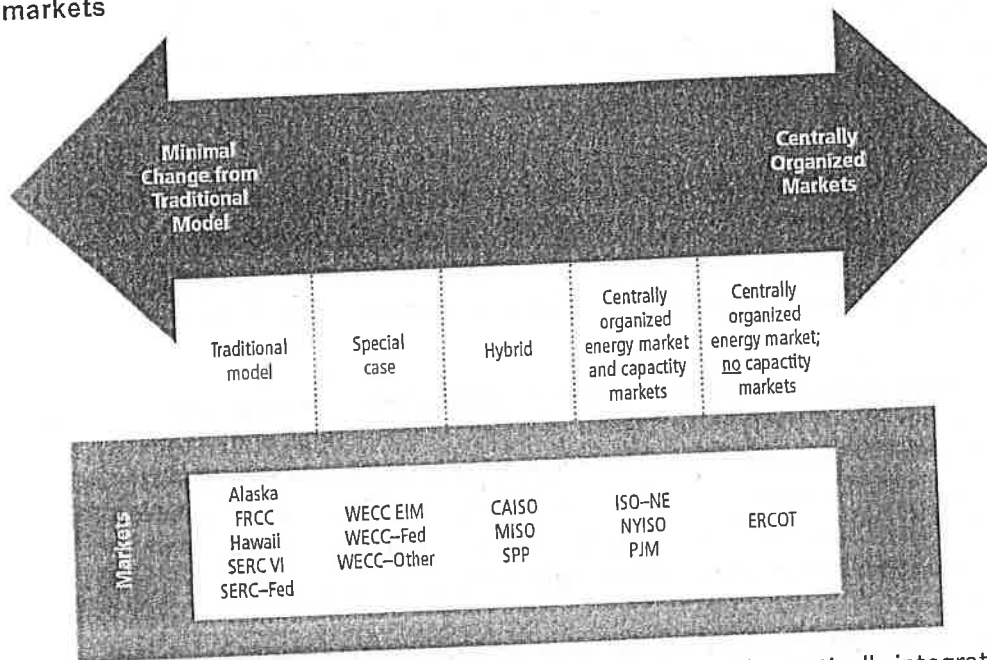
31 It is useful to look at the spectrum of wholesale power markets through the perspective of where each
 32 market region stands along the path from fully vertically integrated electric utilities with minimal
 33 market organization to fully restructured, using an extensive centralized wholesale market for pricing
 34 and dispatch. (Figure 6.2) Other issues include the degree of centralized planning and mechanisms for
 35 resource adequacy, as well as the degree of retail competition in a market. The two attributes of
 36 degree of restructuring and types of resource adequacy constructs used form a useful framework for
 37 analyzing market differences and underscore the diversity of approaches to electricity policy amongst
 38 the states.

39 Bold up text in graphic, label what middle horizontal section's about. Replace "Hybrid" with, both
 40 vertically integrated utilities and centralized market. Fix graphic so it uses market region terms we
 41 don't have to explain Why would WECC Fed & WECC other be special cases? Move them under
 42 traditional with a * for Not state-regulated.

^{ff} Although organized markets offer participants real-time and day-ahead markets for trading, a significant amount of energy traded even in these regions is under long-term contracts for purposes of price stability, hedging, etc. [would be nice to have an estimate here of the percentage, but I understand we don't have a good figure on this. Is that true? So far, yes]

2243
2244

Figure 6.2. States and regions along the spectrum from traditional to fully restructured electric markets



2245
2246
2247
2248
2249
2250

“Traditional” markets such as the Southeast are dominated by vertically integrated IOUs that operate under a regulated cost-of-service model, serving customers in a defined franchise area. Public power and rural cooperative utilities also have a significant presence in some regions, and their utility asset ownership models can vary from vertically integrated to distribution-only. IPPs operate within these regions, but the majority of power is produced and delivered by the integrated utilities.

2251 Power purchases between these various entities are generally limited to bilateral trades. These can be
2252 made to take advantage of price discrepancies or cover shortfalls in supply. These bilateral transactions
2253 represent a small portion of the total generation in traditional markets and are typically in the form of
2254 long-term power purchase agreements rather than short-term trades. For example, in 2015 FERC
2255 estimated that short-term trades, called spot transactions, in the Southeast region accounted for less
2256 than one percent of overall supply.¹²⁸

2257 In centrally organized wholesale energy markets, generators bid on a day-ahead basis the price they
2258 are willing to produce power at, based on an assessment of their operating costs, fuel costs and return
2259 expectations. The market and system operator (the local RTO or ISO) then pools these bids into a single
2260 supply curve or bid stack and determines a clearing price that matches supply to predicted demand,
2261 and congestion forecasts for the day or hour ahead. This yields a set of market-clearing prices for each
2262 hour and location or geographic/electrical zone in the region and market time horizon. Each generator
2263 that bid at or below that market clearing price in that time period will be paid that price for generation
2264 delivered in that period, even if their bid prices were significantly lower than the market price. Most of
2265 the markets maintain price caps that limit what can be charged in any particular hour, to stem potential
2266 market manipulation.

2267 In ERCOT and New York, which moved to full retail and wholesale competition, state restructuring
2268 policy required the utilities to sell their power generation assets and keep only the “wires” component
2269 of the business. All non-nuclear generation assets were sold to IPPs which manage and build new
2270 generation based on expected market earnings. The IPP owners seek to sell power under bilateral
2271 contracts to utilities or other off-takers, such as industrial users, or if contracts aren’t available, sell
2272 their power into daily and day-ahead wholesale energy markets.

Hybrid centrally organized markets (e.g. California ISO and the Southwest Power Pool) combine elements of centrally organized energy markets and traditional resource adequacy mechanisms. In fact, several of these markets had moved toward more of a pure restructured model before moving back to elements of the more traditional regulated approach.

Mechanisms for Resource Adequacy

Resource adequacy is “the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.” Planning for adequate investment in generation and transmission capacity to ensure resource adequacy is a critical component of ensuring a reliable electricity system.

Traditional, vertically integrated regions and some utilities in hybrid markets conduct an integrated resource planning process to plan for necessary transmission and capacity investments (both for new generation and demand response). Some centrally organized markets have implemented capacity markets as a mechanism for ensuring future resource adequacy. In these markets, the system operator conducts an auction process, and retail service providers procure resources (including generation, energy efficiency, demand response, and transmission-enabled imports resources) to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and ISO New England); voluntary, where utilities can choose to operate under an integrated resource planning process (Midcontinent ISO); or voluntary backstopped by a mandatory process (New York ISO). Other regions (California ISO and the Southwest Power Pool) have capacity obligations where market operators require utilities to procure necessary generation reserves, either through ownership or through contracts with third-party providers. California and other states have intervened to require utilities to build or subsidize specific power plants outside the competitive capacity market processes, using the rationale that the intervention is necessary to assure resource adequacy.

ERCOT uses an energy-only market and does not have formal requirements or markets for capacity. In this approach, market scarcity pricing (relatively high energy prices during high-demand periods reflecting the lack of ample additional resources), provides necessary financial incentives for investment in generation capacity.

All of the RTOs and ISOs perform five basic functions⁶⁸:

- 1) Real-time management (dispatch for secure operation) of the transmission system within its footprint;
- 2) Ensuring non-discriminatory access to the area’s transmission system by wholesale buyers and sellers;
- 3) Dispatch of generation assets in its footprint to keep supply and demand in balance, and to operate the generation fleet as economically as possible while observing security constraints;
- 4) Managing regional planning to meet future requirements for generation and transmission capacity; and

⁶⁸ See <https://www.e-education.psu.edu/eme801/node/535>, p. 1, and PJM’s Evolving Resource Mix and System Reliability, March 30, 2017, p. 16.

2311 5) Coordinating provision of essential reliability services (ERSs) such as frequency response,
 2312 voltage control, ramp capabilities, etc.

2313 All of the market operators operate two markets for bulk electric energy to ensure that enough
 2314 generation capacity will be on line to meet the energy demand expected over the next 24 hours. The
 2315 “day-ahead” market determines, on the basis of resource bids, which generators will operate during
 2316 each hour of the following day and at what level of output. In the “hour-ahead” or “real-time” market,
 2317 the RTO makes any needed adjustments to resources’ operating schedules to accommodate
 2318 unexpected changes in demand or the availability of individual generation units.^{hh}

2319 Wholesale electricity prices in the RTO areas are “locational marginal prices” (LMPs) which reflect the
 2320 value of electric energy at different locations, taking into account the shifting patterns of load,
 2321 generation supply, and the physical limits of the transmission system (transmission “congestion”).ⁱⁱ The
 2322 LMPs are recalculated every five minutes to reflect changing market conditions. Generators and other
 2323 resources (such as storage, demand response and out-of-region imports) are selected in merit order
 2324 starting with the least-cost resource and then adding the next lowest-cost resource until supply meets
 2325 demand. All generators designated to run at a given time are paid the uniform market-clearing price—
 2326 the LMP at that moment—regardless of their respective bids, which often vary widely among different
 2327 technology types as shown in Figure YY.

2328 Figure YY: Representative supply stack and merit order with clearing price “LMP*
 2329 [add graph.]

2330 RTOs and ISOs consistently deliver efficiency benefits and savings that far exceed their costs.^{jj}

2331 For example, in 2015, MISO estimated its benefits at between \$2.4 and \$3.3 billion,
 2332 compared to \$267 million in costs.²⁷ Such estimates likely understate benefits
 2333 considerably, as they do not fully account for outages and extreme system conditions.²⁸
 2334 Strong net benefits accrue in MISO as well as CAISO and SPP, despite being comprised
 2335 predominantly of regulated utilities. Regulated utilities generally pass their organized
 2336 market revenues and operating costs through to ratepayers, and their resource
 2337 investments must be approved by state regulators to receive cost recovery. This
 2338 removes the incentive to follow market signals, closely manage risk and costs, and to
 2339 innovate.

2340 Favorable value propositions have helped forge RTO/ISO expansion, as the trend of
 2341 utilities joining RTO/ISOs has increased since the 2000s. In 2013, MISO integrated
 2342 utilities spanning most of Arkansas, Louisiana, Mississippi and some of Texas. CAISO
 2343 expanded outside of California in 2014, while SPP has also grown recently. A recent
 2344 study of CAISO’s full transformation into a multistate entity estimated the benefits to
 2345 California ratepayers alone will be \$55 million a year in 2020, escalating to \$1 to \$1.5
 2346 billion per year by 2030.

^{hh} <https://www.e-education.psu.edu/eme801/node/535>, p. 3.

ⁱⁱ See <https://www.iso-ne.com/participate/support/faq/lmp>.

^{jj} Hartman: <http://www.rstreet.org/wp-content/uploads/2016/08/67.pdf>

1347 [Further highlight benefits to consumers generally.]

1348 The shift to "centralized" wholesale markets in the RTO/ISO regions has had far-reaching implications
 1349 for the owners of generating capacity serving these regions. When divestiture occurred, the divested
 1350 units lost the important cost recovery protections afforded by cost-of-service (COS) regulation. COS
 1351 regulation sets up-side limits on the revenues an owner can receive, through administratively-
 1352 determined rates designed to allow utilities to earn an authorized return on investment. However, COS
 1353 regulation also provides high assurance that the variable and long-run fixed costs of a generating unit
 1354 will be recovered (unless the utility was found to have acted imprudently, in which case associated costs
 1355 may be disallowed).

1356 The shift to competitive wholesale markets created major risks for the affected generation owners. The
 1357 new financial arrangements put in place as part of the divestiture of nuclear and other generating units
 1358 sometimes provided special cost recovery mechanisms for a limited period of time, particularly for units
 1359 considered "stranded assets" that would have difficulty succeeding in a competitive market. Many of
 1360 the newly independent generating units, including coal and nuclear plants, were highly profitable for a
 1361 time in the new competitive markets (particularly those which were receiving a stranded cost recovery
 1362 subsidy for their capital costs, which meant they could succeed by recovering only marginal costs).
 1363 Between 2005 and 2008, variable renewable generation had barely begun to penetrate the bulk power
 1364 system, and national natural gas prices were over \$8 per MMBtu, helping to drive LMPs to high levels
 1355 and obscuring the fact that ISO/RTO markets were not designed to guarantee cost recovery.

1356 "Missing Money," Reliability Standards, and Capacity Market Formation

1357 In the mid-2000s, the inability of many generation owners to recover sufficient fixed costs through the
 1358 RTOs' energy-only markets became known as the "missing money problem." One of the earliest uses of
 1359 the term "missing money" in the power generation business, primarily in the merchant-owned sector,
 1360 was in 2005,^{kk} when it became clear that prices to merchant generators consistently fell below the
 1361 average total cost of power supply.^{ll}

1362 Missing money is still a problem. Merchant plant owners have:

1363 ... used the term for more than a decade to refer to the fact that wholesale electricity
 1364 markets have price caps (mostly between \$1,000 and \$10,000 per MWh) that constrain
 1365 how much sellers can make when supply is tight. Without that [extra] income,
 1366 generators argue, it may not be profitable to build new capacity, or extend the life of
 1367 existing capacity, that is needed to meet demand.

1368 More recently, the [label] of missing money has been expanded to include the price
 1369 impacts of subsidized or [state renewable portfolio standard] mandated renewables
 1370 generation. In California, New York and many other states, wind and solar are pushing
 1371 down wholesale prices and making continued operation of some nuclear and fossil fuel
 1372 generation unprofitable.^{mmm}

^{kk} William W. Hogan, Harvard University, "'Energy Only' Electricity Market Design for Resource Adequacy," September 23, 2005, https://www.hks.harvard.edu/hepg/Papers/Hogan_Energy_Only_092305.pdf

^{ll} Makovich, Martin, and Marks, p. 4, "Missing Money in Competitive Power Generator Cash Flows," IHS Energy, November 2014.

^{mmm} Severin Borenstein, "Electricity Markets and Missing Money", blog post, The Energy Collective, April 4, 2017, <http://www.theenergycollective.com/severinborenstein/2401671/electricity-markets-missing-money>.

2383 Due to the “missing money” issue, merchant generation owners, particularly in the eastern centrally-
 2384 organized markets, saw the problem as a threat to the economic viability of their investments in existing
 2385 generating capacity as well as a barrier to the financing of new generation. The RTO/ISOs were
 2386 concerned about resource adequacy and the need to ensure that generators would invest in upgrades of
 2387 existing plants or in new plants when needed to assure reliability. They acted on these concerns to
 2388 create pseudo-markets for electric capacity, using a forecast of future demand that assumes customers’
 2389 willingness to pay for electric reliability in a way that closely parallels a vertically integrated utility
 2390 world’s assumed reliability reserve requirement.

2391 Capacity markets operate in parallel with energy-only markets. The basic premise of a capacity market
 2392 is that an owner of generating capacity or a demand-side resource should be compensated for making a
 2393 commitment that it will build or maintain a given amount of capacity available in a specific location for a
 2394 specified future period as a source of reliable wholesale electricity, regardless of the extent to which
 2395 that capacity is tapped to serve the energy-only market. Four RTO/ISOs operate capacity markets,ⁿⁿ
 2396 using annual auctions in which bidders compete by submitting offers (in terms of \$/MWh) at which they
 2397 are prepared to make capacity commitments. PJM and ISO-NE hold mandatory annual capacity auctions
 2398 for three-year advance commitments; NYISO (mandatory in some zones) and MISO’s hold annual
 2399 voluntary capacity auctions for one-year commitments.

2400 Capacity markets are very controversial. Some analysts assert that the missing money problem results
 2401 largely from the unwillingness of regulators and the RTO managers to allow real-time energy prices to
 2402 rise to their natural levels in periods when generation capacity is in short supply, because regulators
 2403 don’t want to expose retail customers to the risk of extreme price spikes. Scarcity pricing advocates
 2404 believe that without scarcity pricing, the energy market is inefficient and that inefficiency creates the
 2405 need for the capacity market.^{oo} Scarcity pricing is needed, in this view, to allow owners of existing
 2406 capacity to recover their fixed costs, and to provide signals to resource providers when it would be
 2407 economically rational to invest in additional capacity. ERCOT, for example, considered but rejected
 2408 creation of a capacity market; instead, its real-time energy prices are allowed to rise to a limit of
 2409 \$9,000/MWh, as compared to price caps in PJM and ISO-NE of \$2,000/MWh. Critics argue that formal
 2410 capacity markets are an inadequate substitute for scarcity pricing because they are administrative
 2411 constructs with predetermined capacity demand curves and short time horizons.

2412 The PJM and ISO-NE capacity markets have also been attacked by state regulators and consumer groups
 2413 as expensive handouts to existing generation owners – that is, they have not led to the construction of
 2414 new capacity in areas that are generation-short, nor to desired performance in times of system stress.

ⁿⁿ ERCOT has recently modified its energy prices to include a “real time reserve price” adder, linked to an administratively-determined “operating reserve demand curve” (ORDC). Arguably, this amounts to building an explicit capacity component into its energy market, making ERCOT’s resource adequacy approach similar to that of PJM and ISO-NE.

^{oo} William W. Hogan, Harvard University, oral remarks, p. 454, transcript of FERC Technical Conference to Discuss State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000) (Washington, DC, May 1-2, 2017), <https://www.ferc.gov/CalendarFiles/20170530122053-Transcript,%20May%202,%202017.pdf>

2415 And these capacity markets do not incorporate necessary non-market considerations that matter to state
2416 policy-makers.^{pp, qq}

2417 ..a shift towards more merchant generation and reliance solely on market revenues may indicate
2418 a movement away from planning and policy decisions that take into account critical factors such
2419 as fuel diversity, environmental policies, and economic development[emphasis added]. This is not
2420 a desirable trend nor is it an indicator of successful markets.^{rr}

421 The variety of problems that arose during the “polar vortex” severe cold-weather events in January 2014
422 (e.g., frozen coal piles, equipment malfunctions, and the unavailability of significant amounts of
423 generation capacity due to gas-delivery curtailments)^{ss} caused PJM and ISO-NE to amend their capacity
424 markets by establishing strong penalties for non-performance by generators that are receiving capacity
425 payments.

426 Capacity markets as a market method for achieving resource adequacy remain works in progress. After
427 several years of experience, merchant and now VIEU generators are not earning enough income from
428 market-based energy and capacity revenues to consistently cover their average production costs, much
429 less recover capital investment and profits. RTO/ISOs, regulators, market participants and others
430 continue to debate new ideas for both improving the functionality of the markets and producing
431 additional revenues for the generation owners. Note, for example, the recent attention given to using
432 the capacity markets as mechanisms for procuring and ensuring the delivery of “essential reliability
433 services” (ERSs), such as the provision of voltage support, frequency response, and ramp capability.^{tt}
434 ADD A DIRECT QUOTE TO BACK THIS LAST STATEMENT UP

35 6.3 Challenges in Today's Electricity 36 Markets

7 [UNDER CONSTRUCTION]

8 In more recent years, the economic challenges faced by many existing generation units – especially in
9 restructured areas and to a lesser extent in cost-of-service areas – have become much more apparent
0 for several reasons, including:

- 1 1) Lower demand than expected. Electricity demand growth has stalled due to the economic
2 downturn, increased efficiency in household and business use, as well as growth in self-
3 generation from distributed resources.
- 4 2) Increased nuclear costs. The nuclear accident at Fukushima in 2011 – induced by earthquakes
5 and tsunamis, not operational errors – revealed that an inability to deliver the power needed

^{pp} See written statements and oral discussion of state regulators at FERC May 1-2, 2017 Technical Conference.

^{qq} American Public Power Association, various documents at Electric Markets,
<http://www.publicpower.org/Programs/interiordetail2col.cfm?ItemNumber=38695&navItemNumber=38586>.

^{rr} Caplan, Elise, Is increase in merchant generation capacity a positive?, blog, American Public Power Association, February
2017, <http://blog.publicpower.org/sme/?p=1179>

^{ss} See *Polar Vortex Review*, NERC, September 2014.

^{tt} FERC, May 1-2 Technical Conference, op cit

2446 onsite for effective reactor cooling could have devastating impacts. This has led to the stationing
 2447 of additional backup equipment and other precautionary measures at many U.S. nuclear plants,
 2448 thus increasing their costs.^{uu}

- 2449 3) Increased coal costs. Owners of coal-fired plants have had to either make major investments at
 2450 many plants or retire them in order to comply with new environmental requirements such as
 2451 those initially set forth in 2011 by EPA in its Mercury and Air Toxics (MATS) rule.
- 2452 4) Inexpensive natural gas. New technology for the development of shale gas resources has led to a
 2453 major expansion in the availability of natural gas at very low prices. As a result, natural gas-fired
 2454 plants now set the market-clearing prices during many hours in the RTO markets, and LMPs have
 2455 drifted lower and lower.
- 2456 5) Growth in wind and solar power. The wide adoption of state-level renewable portfolio standards
 2457 (RPSs) created an administrative demand for wind, solar, and other renewable energy. In
 2458 addition to the support provided by the RPSs, developers of wind and solar generation resources
 2459 have been aided by two kinds of federal subsidies, a production tax credit (PTC) for wind
 2460 generation^{vv} and an investment tax credit (ITC) for solar. Further, over the last decade, the
 2461 capacity costs for onshore wind and utility-scale solar have dropped by large percentages [to xx%
 2462 of their costs in 2007]. The combined impact of favorable policies and falling costs has been
 2463 rapid growth in wind and solar generation.

2464 These economic challenges have driven many coal, nuclear, and even some gas-fired generation plants
 2465 into retirement, and the economic viability of many baseload plants still operating appears
 2466 questionable. The growth of wind and solar generation has contributed to erosion of the revenues
 2467 earned by existing baseload plants because the owners of the wind and solar facilities are able to
 2468 operate at near-zero variable cost. RTO/ISO energy markets dispatch units based on incremental
 2469 operating costs. As a result, bidders with near-zero operating cost can under-bid those using other
 2470 technologies. Wind and solar owners frequently offer *zero or negative bids*; these bids will almost
 2471 always be accepted by the RTOs whenever these units are able to produce electricity. At the same time,
 2472 because LMPs are being set in many hours by gas-fired plants, these owners know that they will
 2473 probably earn enough overall to cover their relatively high fixed costs. Some wind generators are able
 2474 to earn a return even when LMPs go negative, as long as the negative price is less than the per-MWh
 2475 value of the PTC and other benefits.

2476 PJM notes the effects of tax preferences on its market:

2477 Tax and subsidy policies have had an impact on the economics of certain types of generation.
 2478 Specifically, the wind and solar production tax credits have had the most significant impact on
 2479 nuclear generation. Nuclear and wind generation are competing to clear in the market during
 2480 off-peak hours when wind resources are the strongest and load is reduced. In those off-peak
 2481 hours, the production tax credit has created an incentive for renewable resources to bid negative
 2482 prices as they must run in order to receive their payment from the federal treasury.^{www} Since

^{uu} See <https://www.nei.org/Issues-Policy/Safety-and-Security/Fukushima-Response>.

^{vv} Wind developers had the option under the American Recovery and Reinvestment Act of 2009 to choose between a PTC and an equivalent ITC.

^{www} As a result of recent federal legislation, the production tax credit has been converted into a direct payment of cash option to reflect that the market for tax credits has been reduced in recent years.

2483 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours
 2484 representing 14.3% of all off-peak hours.^{xx} (Source of the block quote is PJM's May 9th letter to
 2485 the Secretary regarding his memo.)

2486 Among the existing, unretired plants now serving baseload needs, nuclear units seem to have been hit
 2487 especially hard in recent years. According to one recent analysis,^{yy} 34 of the nation's 61 nuclear plants
 2488 are losing money, and this group includes almost all of the remaining merchant nuclear capacity. The
 2489 report says that these plants receive \$20-\$30/MWh for electricity that costs an average of \$35/MWh to
 2490 produce, and are losing an estimated \$2.9 billion per year. Coal-based generation is also at risk.
 2491 Possible changes in environmental regulations may slow but will not arrest this trend, absent a
 2492 substantial increase in the price of natural gas and a reversal of trends across many states to increase
 2493 their commitment to renewable energy.

2494 The prospects of the loss of large amounts of nuclear capacity, the continued growth of gas-fired
 2495 capacity, and environmental and employment concerns have caused a number of states to consider or
 2496 adopt "out-of-market" measures, such as the laws recently enacted in New York and Illinois to grant
 2497 "zero emission credits" (ZECs) to the owners of certain threatened nuclear units. Massachusetts has
 2498 issued a solicitation for Canadian hydro and offshore wind as required by a new state law.^{zz} (Several
 2499 other states are now considering similar legislation.) Owners of merchant non-nuclear baseload
 2500 capacity have reacted strongly, arguing that subsidies aimed at specific large facilities amount to gross
 2501 interventions in federally-regulated wholesale power markets, and that FERC should reject them
 2502 summarily as being inconsistent with the "just and reasonable" requirements of the Federal Power
 2503 Act.^{aaa}

2504 Some commenters have noted that "subsidies beget subsidies" and point out that if the ZECs approach
 2505 is allowed to stand, many of the non-nuclear capacity owners who are also under heavy economic stress
 2506 will seek relief from all possible sources. The cumulative result, they continue, could be major damage
 2507 to the credibility of the wholesale markets, higher capital costs for many new grid-related investments,
 2508 and higher costs for consumers.

2509 The recent trends in these markets have highlighted a condition that has long been characteristic of the
 2510 electricity industry – that is, the dominant generation technologies have had high capital costs and low
 2511 operating costs. According to one recent analysis (Gifford et al.^{bbb}) this condition has been particularly
 2512 problematic in the merchant generation sector, where it has induced periodic boom-bust cycles that
 2513 have driven many merchant companies into bankruptcy. Now, they say, it is threatening to do so again.
 2514 Recently the CEO of one merchant firm (NRG) announced that his firm had lost almost \$900 million in

^{xx} The Independent Market Monitor for PJM has outlined its own views on the harmful impact of subsidies. Its analysis can be found at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec1.pdf

^{yy} "More Than Half of America's Nuclear Reactors Are Losing Money," Bloomberg New Energy Finance, June 2017. Note: The full BNEF report is available only to Bloomberg subscribers. A digest of the report has been published by Utility Dive, <http://www.utilitydive.com/news/bnef-more-than-half-of-us-nuclear-plants-losing-money/445195/>.

^{zz} Citation to the state of Mass RFP website

^{aaa} Get quotation from NRG's Silverstein from FERC May 2 transcript or written statement.

^{bbb} Gifford, Raymond L., et al., "The Breakdown of the Merchant Generation Business Model," Power Research Group, June 2017.

2515 2016, and added that "... the competitive power sector is in a period of unprecedented disruption. I
 2516 believe the IPP model is now obsolete and unable to create value over the long term."^{ccc}

2517 Further, Gifford et al. argue that the problem goes beyond the viability of the existing merchant gas-
 2518 fired units:

2519 ... the construction of a new merchant CCGT does not pencil out to cover fixed costs of these
 2520 generators. Policy makers should pause when markets count on planned merchant generation
 2521 that cannot recover their fixed costs under current market conditions. The stark economics
 2522 facing these plants makes it seem that either these planned additions will not be able to attract
 2523 the capital to be built, or that the developers are betting on sustained and significant increases in
 2524 prices to attract capital. Policy makers, regulators and customers lose under either scenario.^{ddd}

2525 In contrast, the 2016 PJM Market Monitor's report paints a less ominous picture. It finds that RTO
 2526 markets can provide adequate revenue to support some existing capacity, but the outlook varies widely
 2527 by technology, fuel choice, time interval, and location:

2528 Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three
 2529 representative locations shows that units that entered the PJM markets in 2007 have not
 2530 covered their total costs, including the return on and of capital, on a cumulative basis through
 2531 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM
 2532 markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE
 2533 zones but have not covered total costs in the western ComEd Zone. Energy market revenues
 2534 were not sufficient to cover total costs in any scenario except the new entrant CC unit that went
 2535 into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in
 2536 covering total costs.^{eee}

2537 The MMU's 2016 report also says that sufficient net revenues are provided by capacity, energy and
 2538 ancillary services markets to support new entry for CTs and CCGTs in some but not all PJM zones:

- 2539 • In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13
 2540 of the 20 zones. The zones in which a new CT would not have recovered levelized costs were
 2541 western zones in which lower capacity prices were not offset by changes in energy net revenues.
- 2542 • In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in
 2543 nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones.
- 2544 • In 2016, a new [coal plant] would not have received sufficient net revenue to cover levelized
 2545 total costs in any zone.

2546 Results in the PJM footprint for new wind and solar resources in 2016 were heavily dependent on
 2547 revenues from state renewable energy credits:

- 2548 • In 2016, net revenues covered more than 33 percent of the annual levelized total costs of a new
 2549 entrant wind installation in ComEd, 49 percent of the annual levelized total costs of a new

^{ccc} See "NRG CEO: Independent power producer model 'obsolete,'" *Utility Dive*, March 1, 2017, <http://www.utilitydive.com/news/nrg-ceo-independent-power-producer-model-obsolete/437150/>.

^{ddd} Gifford, p. 6.

^{eee} 2016 *State of the Market Report for PJM*, pages 279-280. "As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CF), diesel (DS), nuclear (NU), solar, and wind generating units."

2550 entrant wind installation in PENELEC and 198 percent of the annual levelized total costs of a new
2551 entrant solar installation in PSEG. Renewable energy credits accounted for three percent of the
2552 total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a
2553 wind installation in PENELEC. Renewable energy credits accounted for 83 percent of the total net
2554 revenue of a solar installation in PSEG.

2555 Similarly, the market monitor's levelized cost analyses indicate that revenues from PJM markets are
2556 sufficient to support most existing resources, but that substantial amounts of existing coal and CT
2557 capacity is at risk of retirement:

- 2558 • In 2016, most units did not achieve full recovery of avoidable costs through net revenue from
2559 energy markets alone, illustrating the critical role of the PJM Capacity Market in providing
2560 incentives for continued operation and investment. In 2016, RPM capacity revenues were
2561 sufficient to cover the shortfall between energy revenues and avoidable costs for most units and
2562 technology types in PJM, with the exception of some coal units.
- 2563 • The actual net revenue results show that 96 units with 14,500 MW of capacity in PJM are at risk
2564 of retirement in addition to the units that are currently planning to retire. Of the 96 units, 55 are
2565 CTs and account for 1,408 MW and 25 are coal units and account for 11,282 MW.^{fff}

2566 More generally,

2567 Figure 6.3 below shows that capacity reserve margins in most of the nation's regions as defined by NERC
2568 are more than adequate to reliably serve load. A sustained pattern of additional retirements could
2569 significantly change this picture, but note: A wave of merchant bankruptcies, if it occurs, would not
2570 necessarily translate into a wave of plant retirements. A portion of the capacity owned by the bankrupt
2571 firms, particularly newer units, would presumably be sold to new owners at a discount, this reducing the
2572 buyers' fixed costs and better enabling them to operate the plants at a profit. Thus it appears that
2573 reliability *per se* may not be the problem ahead – rather, the greater concern may be to ensure that the
2574 portfolio of resources in each region remains a balanced portfolio with which to efficiently meet the
2575 range of public policy goals and customer expectations.

^{fff} MMU report, p. xx.

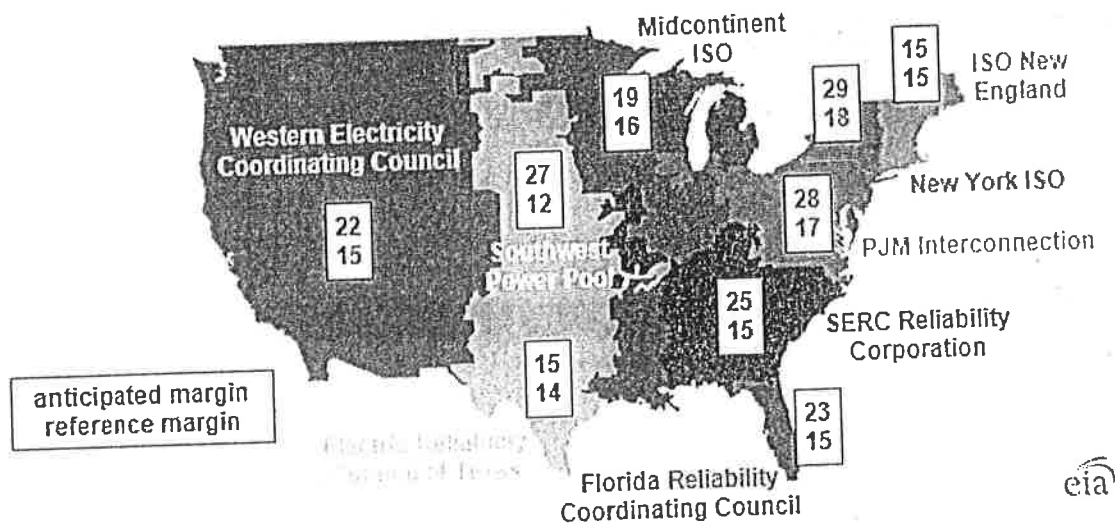
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Figure 6.3. Reference margins and anticipated reserve margins in select NERC regions, summer 2017

Reference margins and anticipated reserve margins in select NERC regions, summer 2017



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Source: U.S. Energy Information Administration, based on North American Electric Reliability Corporation, 2017 Summer Reliability Assessment.

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The end result is that there are pressures for major changes in the wholesale markets, particularly the three eastern RTOs and California, with generators seeking more predictable revenue streams from all sources (capacity, ancillary services and energy) with fewer interventions by the RTOs in those markets to adjust prices through bid mitigation and uplift charges. Recent discussions have centered on price formation in energy markets [cite Trade Association Principles and May 1-2 FERC transcript]. FERC has also undertaken a series of inquiries and rulemakings to

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6.4 Negative pricing

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2590 [UNDER CONSTRUCTION]

2591 Negative pricing from renewables harming baseload plants is not yet a huge issue

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- In most areas and cases, there's a low % of time when negative bids occur, so they don't pose major loss burden on baseload plants (which need high average prices and high peak prices more than they need non-negative off-peak prices)
- baseload plants have bid negative to protect min load operation long before wind or PV drove over-generation
- in all hours when wind is doing "over-generation", hydro, coal and nuclear were hitting min load production, so it was their inflexible generation pattern that forced wind to bid negative
- many utility baseload plants do not bid into organized spot markets but are self-scheduled by VIEU, so they aren't taking MCP in hours when $MCP \leq \$0$.

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2602 LBNL paper

2603 Wilson research with market monitors
2604 logic
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606 **6.5 Market distortions, price formation**
607 **and price suppression**

608 [UNDER CONSTRUCTION]
509 Everything distorts markets

510 **6.6 Markets – looking forward and next**
511 **steps**

512 [UNDER CONSTRUCTION]

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7 Affordability

2614 [UNDER CONSTRUCTION]

2615 Secretary Perry's memo asks whether the loss of coal, natural gas, nuclear and hydroelectric baseload
 2616 power making the grid less affordable. As discussed in Section 3, coal and nuclear power have become
 2617 more costly while natural gas has become much less so. Wind and solar generation have high capital
 2618 costs but their marginal cost is nearly zero (ignoring the value of the PTC). Efforts to retain many of the
 2619 high-cost baseload plants that are now retiring may end up raising rather than lowering the average
 2620 cost of wholesale electricity for many customers. It is not yet clear what impact all of the recent
 2621 baseload plant retirements will have on customer bills, nor how the continuing trend of retirements will
 2622 affect grid costs and bills.

2623 Although many people have a sense of what the term "affordable" means, there is no formal metric for
 2624 an "affordable" grid or an "affordable" electric bill. The meaning of "affordable" is often contextual,
 2625 dependent upon the size of one's budget and how much one values the good sought – the perceived
 2626 value of electricity is much lower to a comfortably housed family on a spring day than it is to a senior
 2627 citizen living in a high-rise apartment in Chicago on an August afternoon.

2628 There have been several studies of the impacts of RPS growth on regions of the country. A LBNL study
 2629 summarizes those and concludes that the overall effect of a state-level RPS can affect customer rates
 2630 from a decrease of 4% up to an increase of 1-2%.

2631 One of the benefits of renewable energy is that it can serve as a hedge for more volatile fossil-fueled
 2632 generation. Many customers seek a steady bill payment because it's easier to budget for and manage
 2633 than bill that varies by month. To the degree that renewable energy stabilizes the cost of an overall
 2634 energy portfolio (or even just a customer's bill), that affects perceived affordability.

2635 7.1 Affordability -- Looking forward and 2636 next steps

- 2637 • Develop a clear understanding of what electric affordability means
- 2638 • Determine the costs of current power plant retirement levels
- 2639 • Determine the impact of renewable energy on grid-connected customer bills.
- 2640 • Determine the costs of likely on-going retirements for grid customers.

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8 Values and extra-market considerations

[UNDER CONSTRUCTION]

Looking forward and next steps

Coal power plant brings good jobs

Source: "America's biggest greenhouse-gas polluter, and the place that relies on it," Elizabeth Hernandez & Eric Chaney, The Center for Public Integrity, June 5, 2017

https://www.publicintegrity.org/2017/06/05/20897/americas-biggest-greenhouse-gas-polluter-and-place-relies-it?utm_source=Sailthru&utm_medium=email&utm_campaign=Newsletter%20Weekly%20Roundup:%20Utility%20Dive%2006-10-2017&utm_term=Utility%20Dive%20Weekender

The James H. Miller Electric Generating Plant ... is one of Alabama Power's coal-burning workhorses, putting out enough electricity to power about a million homes. It never stops running – and never stops producing carbon dioxide and other greenhouse gasses.

... Miller is a source of good-paying jobs, a means to raise a family in an area where economic opportunities are thin..... According to Alabama Power, salaries at the plant range from around \$36,000 to about \$120,000 a year, or about \$74,000 on average. ... Miller employs around 365 people but can have as many as 1,500 contractors on site during planned maintenance outages. The plant pays about \$12 million a year in property taxes.

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9 Solution Options

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There are a number of solutions that could be pursued to address the issues presented in this report. This section presents an extensive and varied list of possible solutions that is not exhaustive or ordered by priority but reflects the views of many stakeholders. This list of solutions does present options that are conflicting, which is necessary for a thorough catalogue. Inclusion in this list does not indicate an official U.S. Department of Energy position with respect to any of these solutions.

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Below are some important core criteria that readers and decision-makers should consider when evaluating solution options:

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1. *Reliability including Flexibility*: The system, including the customer, has sufficient capacity to balance generation with demand over operational, planning and investment timelines. The system has sufficient flexibility to match changes in next load over all operation time-scales, as well as changes in available generation due to outages.
2. *Resilience and Security*: The grid can survive and recover from disruptive events at sufficient speeds to prevent interruptions to critical services and minimize disruptions to the nation and its critical infrastructures.
3. *Affordability*: All customers have access to service at a reasonable cost, inclusive of all customer expenditures, enabling downstream job creation and growth of GDP. Service providers within the system receive revenues sufficient to incentivize adequate investment to meet reliability and resilience needs.
4. *Environmental Considerations and Public Health*: The costs associated with operations of the system reflect the existence and impacts of public health and environmental quality externalities, such as air pollution emissions, land use, and water quality.
5. *Competition*: Sufficient competitive conditions exist within the system, such as low barriers to entry, dispersed market power, and accurate and timely information, so that grid services and infrastructure can be obtained through market and non-market structures that support a variety of business models. These market structures properly balance short-run efficiency with long-term private and public sector investment, while fulfilling the criteria above.
6. *Innovation*: The entire system, including the grid, markets and institutions, is designed to welcome new technologies or practices that enhance the above criteria.
7. *Customer Options*: Customers, states, and other entities have the ability to obtain desired attributes not included in the criteria above.

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#	Solution Option
1.	<p>Facilitate flexible energy storage projects across the grid.</p> <ul style="list-style-type: none"> • Allow long-term contracts for energy storage services. • Allow storage to be compensated for all the reliability services it provides. • Remove restrictive storage regulatory asset classifications. • Enable distribution-level power reliability through power electronics, smart inverters, and integrated building controls. • Pursue R&D on flexible energy solutions and corresponding power electronics capabilities

2.	<p>Allow power plants to improve efficiency and reliability without triggering new regulatory approvals.</p> <ul style="list-style-type: none"> • Implement R&D portfolio targeting efficiency improvements across the generation fleet • Provide regulatory certainty for units who wish to reduce fuel consumption or improve performance • Accelerate improved efficiency of transmission and distribution system to improve reliability and affordability.
3.	<p>Accelerate investment and deployment in power systems to address reliability and affordability concerns through:</p> <ul style="list-style-type: none"> • Streamlining transmission investment and deployment process to reduce generation and transmission constraints • reforming energy infrastructure siting and permitting to expedite development • Updating transmission backstop siting authority • Simplifying loan guarantees for large scale energy projects • Modifying resource adequacy standards to have a longer time horizon
4.	<p>Accelerate licensing and relicensing and reduce costs of nuclear, hydro, geothermal, and new generation technologies.</p>
5.	<p>Acknowledge state energy generation policy preferences in federal and regional rates and pricing decisions.</p> <ul style="list-style-type: none"> • Research and encourage ways to implement policy preferences that least distort competitive markets, including through non-technology specific incentives • Clarifying Federal and State jurisdictions in the electricity sector
6.	<p>Adopt carbon tax or pricing scheme as an economically efficient way to recognize low-carbon resources</p>
7.	<p>Redesign energy and ancillary service markets to:</p> <ul style="list-style-type: none"> • Remove restrictions that limit technology participation • Better reward performance • Incentivize needed capacity • Support long-term capital investment • Build balanced, forward-looking resource portfolios • Ensure essential reliability services are included and valued appropriately • Enforce against out-of-market measures • Adjust markets to bring state policies into them
8.	<p>Redesign wholesale energy markets to reduce the impacts of potentially inefficient or preferential features:</p> <ul style="list-style-type: none"> • Negative pricing and production tax credits and market clearing price setting • Price caps • Scarcity mechanisms • Role of storage and customer-side resources (efficiency, demand response, microgrids, solar photovoltaic, electric vehicles, combined heat and power) • Ex-ante price readjustments • Develop both comprehensive and user friendly analytic tools supporting energy market redesign and decision-making • Address uplift
9.	<p>Incorporate additional zero or lower-emission power sources in portfolio standards.</p>
10.	<p>Support utility, grid operator, and consumer efforts to enhance reliability and resiliency:</p>

	<ul style="list-style-type: none"> • Improve analytical tools for system planning and portfolio analysis • Strengthen capabilities for state and federal support for reliability and resiliency measures and activities • Facilitate distributed and grid-edge technologies to support system stability, reliability, and resiliency
11.	Coordinate electricity and natural gas systems when dealing with capacity expansion, market rules and products, operational concerns, and regional needs.
12.	<p>Develop mechanisms to compensate or require essential energy services (e.g., reliability, resilience, security) that are necessary to operate the grid and reflect product attributes desired by consumers (e.g., low-emissions, clean, flexible).</p> <ul style="list-style-type: none"> • Assess potentially under-recognized contributions from baseload plants • Develop new methods (market mechanisms, interconnection requirements, contracts, technology) that enhance reliability and resilience • Mitigate fuel availability concerns through a full suite of operational, contractual, and technology alternatives • Expand the use of power purchase agreements as a way to stabilize markets and reliability mechanisms • Ensure new bulk power and distributed resources have capability and incentive to provide essential energy and reliability services Enable utility participation in developing customer-side resources (efficiency, demand response, microgrids, solar photovoltaic, electric vehicles, combined heat and power) to enhance customer options and reduce integration challenges
13.	<p>Expand use of innovative and flexible resources--such as energy storage, demand response, energy efficiency and fast ramping generation- to contribute to grid stability, resilience, and reliability within the bulk power and distribution systems.</p> <ul style="list-style-type: none"> • Remove market restrictions • Redefine reliability products and compensation schemes • Continue RD&D on storage and other technologies that contribute to improve flexibility and reliability • Develop technologies to improve flexibility of existing thermal generators
14.	<p>Expand regional market and operations boundaries to achieve more effective integration of reliability services and assets</p> <ul style="list-style-type: none"> • Market implications of regional integration • Strengthen the connections within and between transmission systems • Mitigate market and operational seams between organized and bilateral market regions.
15.	<p>Build portfolios of diverse resources that balance and improve reliability, resilience, affordability while respecting state and societal preferences</p> <ul style="list-style-type: none"> • Continue RD&D on technologies and methods to meet broader societal and state preferences
16.	Eliminate all subsidies, incentives, payments, tax benefits to truly level the playing field for all energy sources
17.	<p>Compensate demand-side resources to meet customer needs in ways that support the grid</p> <ul style="list-style-type: none"> • Update net metering policies to reflect total grid system costs and maturing nature of DER technologies. • Manage DER (including curtailments) to support the broader stability, security, and reliability of the power grid.

18.	Utilize existing federal authorities under the Federal Power Act (202c) to direct emergency out-of-market operations for baseload and other grid assets to ensure the reliability of the power system.
19.	Accelerate pace and final resolution of regulatory and policy agency decisions on infrastructure, markets, reliability and other policy issues
20.	Develop safeguards, training, and direct assistance to protect workers, jobs, and communities from the devastating impacts of energy market shifts.
21.	<p>Expand electrification of multiple end-uses (vehicles, industrial processes, heating) to better match electric generation variability and needs and provide reliability services</p> <ul style="list-style-type: none"> • Fast-tracking electric vehicle charging station deployment at national highway rest stops • Encouraging industrial process electrification • Conducting early-stage R&D to increase industry options
22.	<p>Encourage adoption of outcome-based regulations at the state and federal levels, wherever allowed by statute</p> <ul style="list-style-type: none"> • Reduce use of prescriptive regulations where markets can be enabled • Avoid picking winners and losers • Use market incentives and/or penalties for non-performance, not regulations • Reserve use of prescriptive regulations for public safety and emergency conditions or where specific performance is required for reliability and equipment protection

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2686 **10 Recommendations**

2687 TBD

Glossary of Key Terms and Concepts

Affordability:

Ancillary services:

Balancing authority: The responsible entity that integrated resource plans ahead of time, maintains load-interchange-generation balance within a balancing area, and supports interconnection frequency in real time. Currently 66 BAs manage the bulk power system in the lower 48 states.

Base load or minimum load: In a given geographic area, the minimum amount of electric power (MW) typically required by consumers over a given period at a constant rate.

Baseload power plant: Baseload generation has historically been power plants that run almost continuously to serve a base level of demand that is typically present on the system due to everyday needs. Most often, nuclear plants, large thermal units, or hydroelectric plants are considered base-load generation. This type of generation is usually large with respect to size and output, and operates within a steady range of production. Baseload units have low operating costs and have been operated to maximize the plant's mechanical and thermal efficiency and minimize system operating costs.

Bilateral contract: Bilateral transactions for electricity occur between two parties without going through an RTO's organized market. They can be arranged through a negotiated long-term contract or for a short-term exchange (hourly or monthly) through a voice broker or an electronic brokerage platform. Bilateral contract prices are often linked to the prices set in centrally organized markets.

Bulk power system, or BPS: Statutory definition from EPCA 2005, "(1) The term 'bulk-power system' means— "(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and "(B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." More broadly, the BPS is used to include utility-scale generation and storage as well as transmission and system control and communications facilities.

Capacity: A measurement of the maximum output that generating equipment can supply to a system load, commonly expressed in megawatts. Differs from the term "generation," which measures the actual electricity produced, allowing for equipment down time.

Capacity factor: The ratio of the electrical energy produced by a generating unit over a given period of time, relative to the electrical energy that could have been produced at continuous full-power operation over the same time period. For example, a 10 MW generating unit running continuously would produce: $365 \text{ days} \times 24 \text{ hours} \times 10 \text{ MW} = 87,600 \text{ megawatt-hours}$ of electricity.

Centrally organized markets: Regional Transmission Operators and Independent System Operators manage centrally organized electricity markets serving two-thirds of the nation. All of these markets offer day-ahead markets, which schedule electricity production and consumption before the operating day, while the real-time (or balancing) market reconciles differences between the day-ahead market schedule and real-time load subject to factors such as reliability, asset outages and transmission limits. These energy markets match sellers' bids with buyers' offers to set market-clearing prices (also called Locational Marginal

- 2726 Prices) that are paid to all sellers for all electricity consumed as often as every five minutes. Most RTOs and ISOs
 2727 also run markets for ancillary services and some run capacity markets.
- 2728 *Demand*: the rate at which electric energy is delivered to or by a system or part of a system, generally expressed
 2729 in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.
- 2730 *Economic carrying capacity*: the idea that limits to renewable energy penetration are limited by economics
 2731 rather than engineering, driven by factors that include transmission and the flexibility of the power grid
 2732 to balance supply and demand. Economic carrying capacity is the point at which variable renewable
 2733 energy is no longer economically competitive or desirable to the grid or society.
- 2734 *Economic dispatch*: The practice by balancing authorities of operating their area's generation fleet and
 2735 demand response resources so that the lowest-cost resources are used first, followed when needed by
 2736 more expensive resources and bids. In practice, economic dispatch is modified to reflect system
 2737 reliability requirements and transmission operating limits, so it becomes security-constrained economic
 2738 dispatch.
- 2739 *Essential reliability services (ERSs)*: Services that must be available to grid operators when needed to
 2740 enable the reliable transfer of electricity from generation sites to consumers. They include frequency
 2741 response (including regulation, contingency reserve and load following), reactive power and voltage
 2742 support, and ramping capability. ERSs were formerly known as "ancillary services," but have been
 2743 renamed to more fully recognize their functional importance. Various ERSs may be provided by
 2744 generation, storage and demand-side resources.
- 2745 *Facility*: a set of electrical equipment that operates as a single element (e.g., a line, a generator, a shunt
 2746 compensator, transformer, etc.)
- 2747 *Flexibility*: The ability of a resource—whether it is a component or a collection of components of the
 2748 power system—to respond to the scheduled or unscheduled changes of power system conditions at
 2749 various operational timescales.
- 2750 *Frequency response*: the ability of a system or elements of the system to react or respond to a change in
 2751 system frequency. In North America, system frequency is maintained at or very close to 60 cycles per
 2752 second.
- 2753 *Fuel security*: In a given area, the extent to which, in a given area, the BPS depends on fuels or fuel
 2754 sources that are readily accessible and sufficient to enable operation in the event of a fuel supply
 2755 disruption
- 2756 *Generation/fuel diversity*: The extent to which, in a given area, customer electricity is generated from
 2757 diverse fuels and technologies. Generation diversity is enhanced by energy efficiency, which reduces
 2758 customers' need for generation.
- 2759 *Independent System Operator*:
- 2760 *Interconnection*: a geographic area in which the operation of bulk power system components is
 2761 synchronized such that the failure of one or more of such components may adversely affect the ability of
 2762 the operators of other components within the system to maintain reliable operation of the facilities
 2763 within their control.
- 2764 *Load*: An end-use device or customer that receives power from the electric system. Collectively, load
 2765 refers to all customers' electricity use, whether for energy (MWh) or capacity (MW).

2766 *Peaking capacity:* Generation units that are normally used only during the hours of highest daily,
2767 weekly, or seasonal loads. These units are designed to be turned on or off at short notice as needed and
2768 typically have relatively low capital costs and high operating costs.

2769 *Ramping:* the ability of a generator to increase or decrease real power (megawatts) in response to
2770 changes in system load, interchange schedules or generator output, in order to maintain grid reliability
2771 and compliance with applicable NERC standards

2772 *Reactive Power:* the portion of electricity that establishes and sustains the electric and magnetic fields
2773 of alternating current equipment.

2774 *Regional Transmission Operator (RTO):*

2775 *Reliability Standard:* A requirement approved by FERC to provide for reliable operation of the bulk
2776 power system. The term includes requirements for operating existing bulk power system facilities and
2777 for planning or modifying facilities to assure the reliable operation of the bulk power system. Reliability
2778 standards include cyber-security and physical security requirements, but they not include any
2779 requirement to enlarge or build new transmission or generation capacity.

2780 *Reliability:* The ability of the system to continue operation while some lines or generators are out of
2781 service. To be reliable, the BPS must satisfy two fundamental requirements simultaneously:

- 2782 1) Adequacy – the system must have the physical capacity (i.e., generation, transmission, and
2783 related assets) to supply the aggregate electric power and energy requirements of electricity
2784 consumers at all times, taking into account scheduled and reasonably expected unscheduled
2785 outages of system components; and
- 2786 2) Operations – the ability of the BPS to remain functional despite sudden disturbances to
2787 system stability or unanticipated loss of system components.

2788 *Reliable operation:* operating the elements of the bulk-power system within equipment and electric
2789 system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading
2790 failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity
2791 incident, or unanticipated failure of system elements.

2792 *Resilience:*

2793 *Resource adequacy:* The ability to provide adequate supply during peak load and generation outage
2794 conditions, which includes both supply-side and demand-side resources as contributors to meeting
2795 aggregate electrical demand (including losses)¹²⁹ while accounting for “scheduled and reasonably
2796 expected unscheduled outages of system elements.”¹³⁰

2797 *Security:*

2798 *Sustainability:*

2799 *Variable renewable energy (VRE):* Renewable energy generated from variable sources such as wind and
2800 solar (as distinct from renewable sources such as geothermal or biomass, which have relatively
2801 predictable availability). VRE, especially at relatively high penetrations in a grid, can pose several
2802 challenges to the grid, including variability, uncertainty, location-specificity, non-synchronous
2803 generation, and low capacity factors; most or all of these challenges can be mitigated.

2804 *Voltage Control:*

Appendix A: Memo from Secretary Perry

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2808 April 14, 2017

2809 MEMORANDUM TO THE CHIEF OF STAFF

2810 FROM: Rick Perry

2811 SECRETARY OF ENERGY

2812 SUBJECT: STUDY EXAMINING ELECTRICITY MARKETS AND RELIABILITY

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2814 At the most recent G7 Energy Ministerial, my colleagues discussed the need for an energy transition
2815 utilizing greater efficiency and fuel diversity. There was also notable concern about how certain policies
2816 are affecting, and potentially putting at risk, energy security and reliability. It impressed upon me that
2817 the United States should take heed of the policy choices our allies have made, and take stock of their
2818 consequences.

2819 A reliable and resilient electric system is essential to protecting public health and fostering economic
2820 growth and job creation. The U.S. electric system is the most sophisticated and technologically
2821 advanced in the world. Consumers utilize heating, air conditioning, computers, and appliances with few
2822 disruptions. Nonetheless, there are significant changes occurring within the electric system that could
2823 profoundly affect the economy and even national security, and as such, these changes require further
2824 study and investigation.

2825 Baseload power is necessary to a well-functioning electric grid. We are blessed as a nation to have an
2826 abundance of domestic energy resources, such as coal, natural gas, nuclear, and hydroelectric, all of
2827 which provide affordable base load power and contribute to a stable, reliable, and resilient grid. Over
2828 the last few years, however, grid experts have expressed concerns about the erosion of critical
2829 baseload resources.

2830 Specifically, many have questioned the manner in which baseload power is dispatched and
2831 compensated. Still others have highlighted the diminishing diversity of our nation's electric generation
2832 mix, and what that could mean for baseload power and grid resilience. This has resulted in part from
2833 regulatory burdens introduced by previous administrations that were designed to decrease coal-fired
2834 power generation. Such policies have destroyed jobs and economic growth, and they threaten to
2835 undercut the performance of the grid well into the future. Finally, analysts have thoroughly
2836 documented the market-distorting effects of federal subsidies that boost one form of energy at the
2837 expense of others. Those subsidies create acute and chronic problems for maintaining adequate
2838 baseload generation and have impacted reliable generators of all types.

2839 Each of these and other related issues must be rigorously studied and analyzed, and the Department of
2840 Energy is uniquely qualified for the task. The results of this analysis will help the federal government
2841 formulate sound policies to protect the nation's electric grid. In establishing these policies, the Trump
2842 Administration will be guided by the principles of reliability, resiliency, affordability, and fuel assurance-
2843 principles that underpin a thriving economy.

2844 I am directing you today to initiate a study to explore critical issues central to protecting the long-term
2845 reliability of the electric grid, using the full resources and relationships available to the Department. By
2846 Wednesday, April 19, 2017, present to me an implementation plan to complete this study 60-days from
2847 that date, that will explore the following issues:

- 2848 • The evolution of wholesale electricity markets, including the extent to which federal policy
2849 interventions and the changing nature of the electricity fuel mix are challenging the original
2850 policy assumptions that shaped the creation of those markets;
- 2851 • Whether wholesale energy and capacity markets are adequately compensating attributes such
2852 as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to
2853 which this could affect grid reliability and resilience in the future; and
- 2854 • The extent to which continued regulatory burdens, as well as mandates and tax and subsidy
2855 policies, are responsible for forcing the premature retirement of baseload power plants.

356 I have committed to the President that this report will not only analyze problems but also provide
357 concrete policy recommendations and solutions. I also committed to the President that I will do
358 everything within my legal authority to ensure that we provide American families and businesses an
359 electric power system that is technologically advanced, resilient, reliable, and second to none.
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Table X. Key Laws Related to Electricity Generation

Name	Year Enacted	Major Provisions
Federal Power Act	1920; amended 1935, 1978, 1980, 1986, 1992, 2005	<ul style="list-style-type: none"> Established the Federal Power Commission (now the Federal Energy Regulatory Commission) to regulate the interstate activities of the electric power and natural gas industries, and to coordinate national hydropower activities Amendments in 1935 expanded the Commission's jurisdiction to include all interstate electricity transmission and wholesale electricity sales
Atomic Energy Act	1954	<ul style="list-style-type: none"> Established Federal regulatory authority over civilian uses of nuclear materials and facilities exercised through the Nuclear Regulatory Commission Delineated Federal/state jurisdiction for nuclear material and facilities: licensing of nuclear plant construction and operation as well as waste disposal are exclusively in the Federal domain. States retain oversight of generation planning by vertically integrated utilities (e.g., questions of whether or not to construct nuclear facilities in the first place).
Price Anderson Act	1957	<ul style="list-style-type: none"> 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 providing a ceiling on the total amount of liability for nuclear accidents.
Clean Air Act Amendments	1970, 1977, and 1990	<ul style="list-style-type: none"> Authorized comprehensive Federal and state regulation of stationary pollution sources, including power plants¹³¹ Created the National Ambient Air Quality Standards (NAAQS), State Implementation Plans (SIPs), New Source Performance Standards (NSPS, and National Emission Standards for Hazardous Air Pollutants (NESHAP).^{132 133} Requires states to decide what pollution reductions will be required from particular sources and to submit a State Implementation Plan.¹³⁴ The 1990 CAA Amendments direct the creation of an acid rain program (ARP)¹³⁵ and created new regulatory authorities, including an emissions cap-and-trade system to reduce air pollution.¹³⁶ The 1990 CAA Amendments also require EPA to regulate 189 specified hazardous air pollutants¹³⁷ and set up specific procedures to determine whether the air pollution regulations would apply to power plants that run on fossil fuels¹³⁸
National Environmental Policy Act	1970	<ul style="list-style-type: none"> Requires Federal agencies to review the environmental consequences of a proposed project before granting approval. Agencies prepare statements on the environmental impact of a proposed project (Environmental Impact Statement or Environmental Assessment), considering the views of the public and of other Federal, state, and local agencies, and make the report publicly available.¹³⁹

Clean Water Act	1972 ^{§§§}	<ul style="list-style-type: none"> • Authorized regulation for pollutant discharge through the creation of the National Pollutant Discharge Elimination System (NPDES) program, which requires polluting sources to obtain a permit authorizing pollution up to a specified limit. • Regulated pollutants include thermal pollution (heat), conventional pollutants (e.g., dissolved solids and bacteria), and toxic pollutants¹⁴⁰ • Regulated wastewater discharges from the power sector include cooling water, wastewater from coal ash handling, wastewater from pollution control equipment, and other wastewater streams
Energy Policy and Conservation Act (EPCA)	1975	<ul style="list-style-type: none"> • Set test procedures, conservation targets (followed by standards if targets are not set) and appliance labeling requirements • Authorized establishment of Strategic Petroleum Reserve
Resource Conservation and Recovery Act (RCRA)	1976, amended 1984, 1986	<ul style="list-style-type: none"> • Provides EPA with the authority to regulate hazardous waste,¹⁴¹ including management of power sector waste, such as coal ash • Directs the EPA to study promising techniques of energy recovery from solid waste and solid waste from mining¹⁴²
National Energy Act	1978	<ul style="list-style-type: none"> • Passed in response to oil shortages in the 1970s and the increased reliance on imported oil, which was seen as a threat to national security¹⁴³ • Legislation included five statutes: <ol style="list-style-type: none"> 1) Natural Gas Policy Act of 1978—granted FERC authority over intrastate and interstate natural gas production; set rules for natural gas price ceilings, how to allocate costs, and emergency supply authority. 2) Public Utility Regulatory Policies Act (PURPA)—left to states to implement; promoted renewable energy, encouraged energy conservation, ended practice of customers paying less for electricity with increasing usage, allowed some deregulation 3) Energy Tax Act—enacted tax credit for some distributed renewable generation 4) Powerplant and Industrial Fuel Use Act—restricted use of oil and natural gas for power generation, promoted coal, nuclear, and other alternative fuels; repealed in 1987 5) National Energy Conservation Policy Act—made energy efficiency targets into mandatory standards and extended or enacted additional energy conservation measures
National Appliance Energy Conservation Act (NAECA)	1987, amended in 1988	<ul style="list-style-type: none"> • Set standards and schedule for DOE to conduct rulemakings • Amended in 1988 to add fluorescent ballasts
Energy Policy Act	1992	<ul style="list-style-type: none"> • Provided FERC greater authority to provide transmission access for wholesale buyers in procuring wholesale electricity • Included a wide variety of energy efficiency measures, including building energy efficiency standards, equipment energy efficiency standards (including motor standards), measures that encourage and support industrial energy efficiency improvements, and mandates and funding for Federal agencies to improve their energy efficiency • Included the first renewable electricity production tax credit for wind, biomass, landfill gas, and other renewable sources.

^{§§§} The Clean Water Act was significantly amended in 1972. Parts of the legislation have been changed many times since. <https://www.epa.gov/laws-regulations/history-clean-water-act>

		<ul style="list-style-type: none"> • Amended EPCA to expand coverage to certain commercial and industrial equipment • Amended the Federal Power Act to expand FERC's jurisdiction to include electricity system reliability and certain power plant sales • Directed DOE to conduct a five-year program on technologies to increase the recoverability of domestic oil resources through R&D on oil shale extraction and conversion, and expansion of the recoverable natural gas resource base • Directed EPA to promulgate public health and safety standards governing releases from radioactive materials in the Yucca Mountain repository, and directed DOE to developed a five-year civilian nuclear program, and to conduct a five-year technical and financial assistance program to encourage the development and submission for certification of advanced light water reactor designs
Energy Policy Act	2005	<ul style="list-style-type: none"> • Gave FERC responsibility for mandatory reliability standards and allowed the agency to certify an electric reliability organization to develop and enforce those standards. FERC then designated the North American electric Reliability Corporation (NERC) as the designated electric reliability organization. • Established an investment tax credit for solar energy and advanced coal electricity generating systems, a production tax credit for hydropower and advanced nuclear power systems, and energy efficiency tax credits • Removed regulations on natural gas produced by hydraulic fracturing under the Safe Drinking Water Act • Set standards and schedule for DOE to conduct appliance standard rulemakings • Amended PURPA to require electric utilities to make net metering and smart metering available upon consumer request, and to terminate mandatory purchase and sale requirements pertaining to cogeneration and small power production utilities • Modified federal leasing and royalty rules to facilitate and encourage the development of coal deposits on federal lands • Provided incentives for the natural gas industry, such as reduced royalty rates for select natural gas producers, accelerated depreciation for natural gas distribution and gathering lines, and preferential tax treatment for natural gas production
Energy Independence and Security Act (EISA)	2007	<ul style="list-style-type: none"> • Set appliance, lighting, and industrial electric motor efficiency standards, and added stand-by power and 6-year-look back provision • Added Section 1705 to the loan guarantee program, allowing subsidized loans to commercial facilities • Called for coordination to develop a framework for smart grid interoperability standards • Increased funding for the R&D and large-scale demonstration projects of carbon capture and storage systems
American Recovery and Reinvestment Act (ARRA)	2009	<ul style="list-style-type: none"> • Provided \$31 billion in funding for DOE's energy efficiency, renewable energy, fossil energy, and electricity delivery and energy reliability program offices, as well as Title XVII loan guarantees for innovative clean energy technologies; investments in energy infrastructure, including transmission and smart grid technologies; and other major investments in energy administered by DOE.¹⁴⁴ • Established a temporary program for the rapid deployment of renewable energy and electric power transmission projects.
American Energy	2012	<ul style="list-style-type: none"> • Added appliance standards coverage for other types of motors and 6-year look-back for certain products¹⁴⁵

Manufacturing and Technical Corrections Act (AEMTCA)		
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Table Y. Key Regulations and Orders^{hhh} Related to Electricity Generation

Name	Year Finalized ⁱⁱⁱ	Year (s) Implemented	Authorizing Statute ⁱⁱⁱ	Key Provisions Related to Electricity Generation Major Provisions
National Ambient Air Quality Standards (NAAQS)	First NAAQS set in 1971 Most recent revisions in 2010 (SO ₂ & NO ₂), 2013 (PM), and 2015 (ozone)	Attainment schedule depends on severity of non-attainment Attainment of 2015 ozone NAAQS by 2020-2037	Clean Air Act (1970)	<ul style="list-style-type: none"> Established primary and secondary NAAQS^{kkk} for six common "criteria" air pollutants. Power plants are sources of four of these pollutants: sulfur dioxide (SO₂), nitrogen dioxide (NO₂), particulate matter (PM), and ozone (O₃). Clean Air Act (CAA) directs EPA to review the NAAQS every 5 years. NAAQS first established in 1971.^{146 147} SO₂ NAAQS were revised in 1996 and 2010;^{148 149} PM NAAQS were revised in 1985, 1996, and 2010;^{151 152} O₃ NAAQS were revised in 1979, 1997, 2008, and 2015; PM NAAQS were revised in 1997, 2006, and 2013.
Steam Electric Effluent Limitations Guidelines (ELG)¹⁵³	1974, updates in 1977, 1978, 1980, 1982, 2015	2015 limits are stayed while EPA reviews rule	40 CFR 423	<ul style="list-style-type: none"> Established limitations on the discharge of toxic and other chemical pollutants and thermal discharges from existing and new steam electric power plants, as well as pretreatment standards. 2015 update sets first federal limits on levels of toxic metals that can be discharged
New Source Performance Standards for Coal-Fired Power Plants	1979	1979	Clean Air Act (1977)	<ul style="list-style-type: none"> EPA rule governing sulfur dioxide emissions from coal power plants¹⁵⁴ Effectively required flue gas desulfurization on new coal plants.

^{hhh} Research and development tax incentives are not included

ⁱⁱⁱ Dates shown here reflect the date of publication in the *Federal Register*.

ⁱⁱⁱ For Regulations Only

^{kkk} Primary standards are set at levels "requisite to protect the public health." Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. The secondary standard carries no deadline for attainment and has never been the subject of penalties or sanctions for areas that failed to meet it. For this reason, only primary standards are included in this table.

FERC Order 636 – Restructuring of Pipeline Services¹⁵⁵	1992	1992		<ul style="list-style-type: none"> • Required pipeline companies to provide open-access transportation services that are equal in quality whether the gas is purchased directly from the pipeline company or elsewhere • Included provisions designed to increase access increase the quality of transportation services and provisions to promote competition among gas suppliers
Acid Rain Program	1993	Phase 1 Implementation: 1995-2000 Phase 2 Implementation: 2000-2010	Clean Air Act (1990)	<ul style="list-style-type: none"> • Created the world’s first large-scale emission cap and-trade system to reduce air pollution. Effectively superseded by Cross-State Air Pollution Rule • Established a tightening annual SO₂ emissions cap for power plants fired by coal, oil and gas. • Applies individual NO_x emission rates on certain coal-fired boilers.
FERC Order 888¹⁵⁶ - Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities	1996	1996		<ul style="list-style-type: none"> • Mandates non-discriminatory open access electricity transmission grid. • Allows utilities that own transmission services to recoup costs • Allowed Independent System Operators to form and facilitated economic dispatch of electricity across a larger geographic area
NO_x Budget Trading Program	1998	2003; Program ended: 2008	Clean Air Act	<ul style="list-style-type: none"> • Established a market-based cap and trade program to reduce NO_x emissions from power plants and other sources to help states meet the 1997 ozone NAAQS. • Trading program applied to 20 states plus Washington, D.C.
Regional Haze Rule	1999	2001-2018 ¹⁵⁷	Clean Air Act	<ul style="list-style-type: none"> • Requires States to develop long-term strategies including enforceable measures to improve visibility in 156 national parks and wilderness areas. • Aims at returning visibility to natural conditions within 60 years.
Cooling Water Intake Rule¹⁵⁸	2001 (phase 1), 2003 (revised phase 1) 2014 (phase II)	Phase I: 2001, revision began 2003	Clean Water Act	<ul style="list-style-type: none"> • Promulgated under 316(b) of the Clean Water Act. New sources regulated under Phase II existing sources regulated under Phase I • Promulgated to reduce mortality to fish and other aquatic organisms.
Clean Air Interstate Rule (CAIR)	2007	NO _x program began in 2009 and SO _x program	Clean Air Act	<ul style="list-style-type: none"> • Required 27 eastern states + Washington to limit power sector emissions of nitrogen oxides and sulfur dioxide to address regional haze

		in 2010. Rule superseded in 2014.		<p>transport that contributes to the formation of fine particulate matter and ozone.</p> <ul style="list-style-type: none"> The NOx program replaced the NOx Budget Trading Program, and the SO2 program was designed to continue reductions below the ARP permanent cap. Both programs used a cap-and-trade systems. Ended January 1, 2015.
Cross-State Air Pollution Rule (CSAPR) and CSAPR Update	2011	Phase 1: 2015 Phase 2: 2017	Clean Air Act	<ul style="list-style-type: none"> The Cross-State Air Pollution Rule replaced the Clean Air Interstate Rule starting on January 1, 2015, and requires states to reduce power plant emissions of SO₂ and NOx that contribute to ozone emissions and fine particulate pollution in other states.¹⁵⁹ Aligns compliance with the July 2018 attainment date for the 2008 ozone NAAQS Moderate area attainment date.
FERC Order 1000¹⁶⁰ - Transmission Planning and Cost Allocation	2011	2011		<ul style="list-style-type: none"> Requires regional and interregional transmission planning; mandates that the planning process consider transmission needs driven by public policy requirements Requires regional and interregional cost allocation methods that satisfy six allocation principles Eliminates the Federal right of first refusal in FERC jurisdictional tariffs and agreements.¹
Mercury and Air Toxics Standards¹⁶²	2012	2015-2016	Clean Air Act (1990)	<ul style="list-style-type: none"> Establishes emissions limits for mercury, arsenic, acid gases, and other toxic pollutants from coal- and oil-fired power plants.¹⁶³ Utilities had until April 2015 to comply with the standards—through the deployment of wide available and economically feasible technologies, practices, and strategies—with many plants receiving a one-year extension
Coal Combustion Residuals (CCR) Rule¹⁶¹	2015	Not yet implemented	Resource Conservation and Recovery Act (1976)	<ul style="list-style-type: none"> Addresses groundwater contamination risks from CCR (i.e., “coal ash”) disposal in unlined landfills and surface impoundments. Establishes national standards for new and existing CCR landfills and new and existing CCR surface impoundments.
Carbon Pollution Standards and Clean Power Plan¹⁶⁴	2015	Under review	Clean Air Act	<ul style="list-style-type: none"> Carbon Pollution Standards established carbon dioxide emission standards for new fossil fuel-fired generators under Clean Air Act, section 111(b). The Clean Power Plan, promulgated under section 111(d) of the CAA, establishes

¹⁶¹ 80 FR 21302

				greenhouse gas emissions standards for existing power plants.
FERC Order^{mmmm} No. 825 Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators	2016	2016		<ul style="list-style-type: none"> Established settlement interval and shortage pricing requirements. Makes final reforms in these two areas proposed in a September 2015 Notice of Proposed Rulemaking. FERC stated that "[t]hese requirements will help ensure that rates for energy and operating reserves are just and reasonable and will align prices with resource dispatch instructions and operating needs, provide appropriate incentives for resource performance and maintain reliability."¹⁶⁵
FERC Order No. 827 Reactive Power Requirements for Non-Synchronous Generation	2016	2016		<ul style="list-style-type: none"> All newly interconnecting non-synchronous generators will be required to provide react power at the high-side of the generator substation as a condition of interconnection set forth in their Large Generator Interconnection Agreement (LGIA) or Small Generator Interconnection Agreement (SGIA) as of the effective date of the Final Rule.
FERC Order No. 828 Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities	2016	2016		<ul style="list-style-type: none"> Requirements for Frequency and Voltage Through Capability of Small Generating Facilities, issued July 21, 2016. The Commission revised the SGIA to require generators no larger than 20 MW to have voltage and frequency ride through capabilities.
FERC Order No. 831 Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators	2016	2016		<ul style="list-style-type: none"> Retained an existing \$1,000/MWh price cap on energy offered in day-ahead and real-time markets. Also allows prices, for the purpose of calculating locational marginal prices, to exceed \$2,000/MWh, provided offers are based on verified costs. FERC stated that it found that "during the 2013-14 "Polar Vortex" led to a significant increase in the price of natural gas that may have caused some resources with must-run requirements to operate at a loss because their short-run marginal costs exceeded the \$1,000/MWh offer cap in place at the time."

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* National Ambient Air Quality Standards do not directly impact power plants or impose any compliance costs on power plants. Instead, NAAQS establish national air quality standards, and states are responsible for developing State Implementation Plans (SIPs) for meeting air quality standards. NAAQS for NO₂, SO₂, and O₃ are included here because power plants are major sources of NO₂ and SO₂

^{mmmm} There are many more FERC dockets related to this study for specific companies or regional operators. The broader non-utility specific orders relevant to this study are listed above.

emissions, and because NO_2 reacts in the atmosphere to form O_3 . The installation of pollution control systems on power plants is one possible compliance tool that states may choose to achieve the NAAQS.

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Appendix C. Key Environmental Regulations and Statutesⁿⁿⁿ

Key Provisions Related to Electricity Generation				
Name	Year Enacted	Date of Expiration if Exists	Initial Authorizing Statute	Major Provisions
Intangible Drilling Expenses	1916, amended 1954		Internal Revenue Code of 1954	<ul style="list-style-type: none"> Taxpayers may elect to currently deduct intangible drilling costs (IDCs) paid or incurred with respect to the development of an oil or gas property located in the United States. IDCs include wages, machinery used for grading and drilling, and unsalvageable materials used in developing wells.
Depletion Allowance	1926, amended 1932, 1954, 1969, 1975, 1978 & 2005		Energy Tax of 1978	<ul style="list-style-type: none"> Currently, percentage depletion is allowed for independent producers at a rate of 15% for oil and gas and 10% for coal. Percentage depletion is allowed on production up to 1,000 barrels of average daily production of oil (or its equivalent for natural gas). The depletion allowance cannot exceed 100% of taxable income from the property (50% for coal) or 65% of the producers taxable income from all sources. Percentage Depletion for Geothermal was authorized in 1978.¹⁶⁷
Characterizing Royalty Payments as Capital Gains	1954, amended 1986		Internal Revenue Code 1954	<ul style="list-style-type: none"> Income from the sale of coal under a royalty contract may be treated as a capital gain rather than ordinary income.
Oil & Gas: Royalty Relief	1978, amended 1995, 2005		Outer Continental Shelf Lands Act 1978	<ul style="list-style-type: none"> Relief from oil and gas royalty obligations may be granted to increase production or to encourage development on certain producing or non-producing leases.
Tax-Exempt Interest on Industrial Development Bonds	1980		Windfall Profit Tax Act of 1980	<ul style="list-style-type: none"> State and local electric utilities can issue tax-exempt bonds for the development of facilities producing fuel from solid waste.¹⁶⁸
Section 29 Tax Credits for Production from Unconventional Fuels	1980	2002	Windfall Profit Tax Act of 1980	<ul style="list-style-type: none"> Provided tax credit for production of nonconventional fuels including, coal seams, coal-based synthetic fuels nonconventional gas and gas from biomass.^{169 170}

ⁿⁿⁿ Research and development tax incentives are not included

<p>Certain publicly traded partnerships treated as corporations for tax purposes (Secs. 7704 & 851)</p>	<p>1987</p>		<p>Omnibus Budget Reconciliation Act of 1987</p>	<ul style="list-style-type: none"> • General rule that a publicly traded partnership is taxed as a corporation is not applicable if 90% of gross income is interest, dividends, real property rents, or certain other types of qualifying income; Other types of qualifying income includes income and gains from certain activities with respect to natural resources.
<p>Renewable Electricity Production Tax Credit (PTC)</p>	<p>1992, amended 2005, 2009, and 2016</p>	<p>Varies by technology</p>	<p>EPAAct 1992,</p>	<ul style="list-style-type: none"> • The PTC is a per kilowatt-hour tax credit for electricity generated by qualified energy resources, lasting for 10 years from the date the facility is placed in service. • 2.3¢/kWh for electricity generated from wind, geothermal, closed-loop biomass, and solar facilities (not claiming the ITC) that commenced construction prior to 2017. • 1.2¢/kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic energy resources that commenced construction prior to 2017. • The PTC is currently only available to new wind facilities, and the value of the credit will step down annually before being phased out completely in 2020 (i.e. new facilities will still receive 10 years of tax credit if placed in service before 2020).
<p>Accelerated Depreciation for Pollution Control Equipment</p>	<p>2005</p>		<p>EPAAct 2005</p>	<ul style="list-style-type: none"> • Provides amortization allowance for certain certified air pollution control facilities used in connection with an electric generation plant that is primarily coal fired and that was placed in service after 1975.
<p>Investment Tax Credit (ITC)</p>	<p>2005, amended in 2008, 2009, and 2015</p>	<p>Varies by technology</p>	<p>EPAAct 2005</p>	<ul style="list-style-type: none"> • A tax credit that reduces the initial investment for select systems that generate electricity at a residence, commercial building, or utility scale. The expiration date and value of the ITC varies by technology. • A 30% tax credit is currently available for residential solar electric and heating installations, with the value of the credit stepping down annually before expiring in 2022. The credit was previously available for residential fuel cells, geothermal heat pumps, and small wind-energy systems prior to 2017. • For commercial installations, a 10% tax credit is available for geothermal electric systems, with no stated expiration date; a 24% credit is currently available for large wind systems, with the value of the credit stepping down annually before expiring

				<p>in 2020; and a 30% credit is currently available for a variety of solar electric and heating technologies, with the value of the credit stepping down annually to 10% in 2022 and thereafter.</p> <ul style="list-style-type: none"> • A 20% tax credit is available for power generation projects that use integrated gasification combined cycle (IGCC) or certain other advanced coal-based electricity generation technologies
Advanced Nuclear Production Tax Credit	2005	2020	EPAAct 2005	<ul style="list-style-type: none"> • Production tax credit of 1.8 cents per kilowatt-hour of electricity produced by new nuclear power plants. Limited to 6,000MW and the first 8 years the plant is in service. Plants must be in service before 12/31/2000.
Residential and Commercial Energy Efficiency Tax Credits	2005, amended 2008 (for residential only)	2016	EPAAct 2005	<ul style="list-style-type: none"> • A residential tax credit is available for energy improvements to existing homes. • A tax deduction is available for certain qualifying systems and energy-efficient commercial buildings
Amortization of geological and geophysical expenditures	2005		EPAAct 2005	<ul style="list-style-type: none"> • Oil and gas companies can amortize expenses related to geological and geophysical surveys over two years (independent producers) or seven years (large integrated producers (rather than over the lifetime of the project).
Carbon Dioxide Sequestration Credit 45Q	2008	After 75,000,000 metric tons of qualified carbon dioxide have captured in accordance with the statute.	Improvement and Extension Act of 2008	<ul style="list-style-type: none"> • Credit for the sequestration of industrial source carbon dioxide produced at qualified U.S. facilities which may include coal and gas plants. Captured carbon dioxide can be re-injected as part of enhanced oil and natural gas recovery process.

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Appendix F: External Technical References

(Draft as of June 26, 2017)

Reliability and Essential Reliability Services

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