



POWER | RESET

OPTIMIZING THE EXISTING COAL FLEET TO
ENSURE A RELIABLE AND RESILIENT GRID

ASSESS | SUPPORT | REFORM | RENEW



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Power Reset:

Optimizing the Existing U.S. Coal Fleet to Ensure a Reliable and Resilient Power Grid

The National Coal Council is a Federal Advisory Committee established under the authority of the U.S. Department of Energy. Members from a diverse set of backgrounds and organizations are appointed to serve on the NCC by the Secretary of Energy to provide advice and guidance on general policy matters relating to coal and the coal industry. The findings and recommendations from this report reflect a consensus of the NCC membership, but do not necessarily represent the views of each NCC member individually or their respective organizations.

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Power Reset
**Optimizing the Existing U.S. Coal Fleet
to Ensure a Reliable and Resilient Power Grid**

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NCC Overview - 1984 | 2018

In the fall of 1984, Secretary of Energy Don Hodel announced the establishment of the National Coal Council (NCC). In creating the NCC, Secretary Hodel noted that “The Reagan Administration believes the time has come to give coal – our most abundant fossil fuel – the same voice within the federal government that has existed for petroleum for nearly four decades.”

The Council was tasked to assist government and industry in determining ways to improve cooperation in areas of coal research, production, transportation, marketing and use. On that day in 1984, the Secretary named 23 individuals to serve on the Council, noting that these initial appointments indicate that “the Department intends to have a diverse spectrum of the highest caliber of individuals who are committed to improving the role coal can lay in both our Nation’s and the world’s energy future.”

Throughout its nearly 35-year history, the NCC has maintained its focus on providing guidance to the Secretary of Energy on various aspects of the coal industry. NCC has retained its original charge to represent a diversity of perspectives through its varied membership and continues to welcome members with extensive experience and expertise related to coal.

In 1985, the NCC was incorporated as a 501c6 non-profit organization in the State of Virginia. Serving as an umbrella organization, NCC, Inc. manages the business aspects of running the Council. The leadership of the NCC serves as officers of NCC Inc. and members of the Council serve as NCC Inc. shareholders. The Executive Director of the Council is NCC Inc.’s Executive Vice President and Chief Operating Officer.

Today, the NCC continues to serve as an advisory group to the Secretary of Energy, chartered under the Federal Advisory Committee Act (FACA). The NCC provides advice and recommendations to the Secretary of Energy on general policy matters relating to coal and the coal industry.

The Council activities include providing the Secretary with advice on:

- Federal policy that directly or indirectly affects the production, marketing and use of coal;
- Plans, priorities and strategies to address more effectively the technological, regulatory and social impact of issues relating to coal production and use;
- The appropriate balance between various elements of Federal coal-related programs;
- Scientific and engineering aspects of coal technologies, including emerging coal conversion, utilization or environmental control concepts; and
- The progress of coal research and development.

The principal activity of the NCC is to prepare reports for the Secretary of Energy. The NCC’s Coal Policy Committee develops prospective topics for the Secretary’s consideration as potential subjects for NCC studies. During its nearly 35-year history, the NCC has prepared more than 35 studies for the Secretary, at no cost to the Department of Energy. All NCC studies are publicly available on the NCC website.

The NCC is a totally self-sustaining organization; it receives no funds from the Federal government. The activities and operations of the NCC are funded solely from member contributions, the investment of Council reserves and generous sponsors.



NCC REPORT ACCEPTANCE LETTER

May 24, 2018

The Honorable Rick Perry
U.S. Secretary of Energy
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Mr. Secretary:

Thank you for your letter of April 7th, 2018 requesting that the National Coal Council (NCC) prepare a report assessing opportunities to optimize the existing U.S. coal generation fleet to ensure a reliable and resilient electricity system.

On behalf of the members of the NCC, we are pleased to accept your request. Activity has already begun on preparing the report which will address the following key questions:

- What actions can be taken to optimize the U.S. coal-fueled power plant fleet so it can continue to provide reliable, resilient, affordable power as part of a diverse electric generation mix?
- What unique benefits does coal provide?

Glenn Kellow, President & CEO for Peabody, **Paul Sukut**, CEO and General Manager for Basin Electric Power Cooperative, and **Matt Rose**, Executive Chairman for Burlington Northern Santa Fe will serve as co-chairs for this report. We will have the report completed by the requested completion date of September 30th, 2018.

Thank you for your support of the National Coal Council. We welcome the opportunity to support your and President Trump's vision for our nation's energy future.

Sincerely,

A handwritten signature in black ink that reads "Deck A. Slone".

Deck Slone
National Coal Council Chair

A handwritten signature in black ink that reads "Greg Workman".

Greg Workman
National Coal Council Immediate Past Chair



Report Request from Energy Secretary Rick Perry



The Secretary of Energy
Washington, DC 20585

April 07, 2018

Mr. Greg Workman
Chairman, National Coal Council
Dominion Generation
120 Tredegar Street, DC3
Richmond, Virginia 23219

Dear Mr. Workman:

I am writing today to charge the National Coal Council (NCC) to develop a white paper assessing opportunities to optimize the existing U.S. coal-fueled power plant fleet to ensure a reliable and resilient electricity system.

The white paper should focus on drivers governing the evolution of the existing fleet and its attributes; outlooks on the future U.S. generation mix considering regional drivers, anticipated capacity additions, and retirements; characteristics of a reliable and resilient electricity system; and opportunities for the existing coal-fueled fleet to enhance the said characteristics. The white paper should examine policy, market, and technological aspects influencing the ability of coal-fueled plants to uniquely enable a reliable and resilient electricity system. The key questions for this white paper to address are "*What actions can be taken to optimize the U.S. coal-fueled power plant fleet so it can continue to provide reliable, resilient, affordable power as part of a diverse electric generation mix, and what unique benefits does coal provide?*"

I ask that the white paper be completed no later than September 30, 2018.

Upon receiving this request and establishing your internal working groups, please advise me of your schedule for completing the white paper. The Department looks forward to working with you on this effort.

Sincerely,

A handwritten signature in black ink that reads "Rick Perry".

Rick Perry





Power Reset

Optimizing the Existing U.S. Coal Fleet to Ensure a Reliable and Resilient Power Grid

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ACRONYMS

The U.S. ton is a short ton - 2000 pounds; the metric tonne is approximately 2,204.6 pounds. In this report, tonnages are not standardized. "Tons" refer to short tons and "tonnes" refers to metric tonnes.

ACCCE	American Coalition of Clean Coal Electricity
ACEEE	American Council for Energy Efficient Economy
AEP	American Electric Power
ASC	Advanced Super Critical
AUSC	Advanced Ultra-Super Critical
Bbl	Barrel (oil)
BLM	Bureau of Land Management
BNSF	Burlington Northern Santa Fe Railway
BPS	Bulk Power System
CAISO	California Independent System Operator
CBM	Coal Bed Methane
CCR	Coal Combustion Residuals
CCUS	Carbon Capture Use/Utilization & Storage
CEQ	White House Council on Environmental Quality
CO ₂	Carbon Dioxide
CPP	Clean Power Plan
CRS	Congressional Research Service
CSP	Concentrated Solar Power
CT	Combustion Turbine
CURC	Carbon Utilization Research Council
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
DSIRE	Database of States Incentives for Renewables & Efficiency
EERS	Energy Efficiency Resource Standards
EIA	U.S. Energy Information Administration
ELG	Effluent Limitation Guidelines
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERS	Electric Reliability Services
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
HELE	High Efficiency Low Emissions
HG	Mercury
HILF	High Impact Low Frequency
IGCC	Integrated Gasification Combined Cycle
IOU	Investor Owned Utility

IRE	Intermittent Renewable Energy
ISO	Independent System Operator
ITC	Investment Tax Credit
LCOE	Levelized Cost of Electricity
MATS	Mercury & Air Toxics Standards
MISO	Midwest Independent System Operator
MLA	Mineral Leasing Act
MLP	Master Limited Partnership
MOPR	Minimum Offer Price Rule
MSHA	Mine Safety & Health Administration
MW	Megawatt
NAM	National Association of Manufacturers
NARUC	National Association of Regulatory Utility Commissioners
NCC	National Coal Council
NCSL	National Council of State Legislators
NEPA	National Environmental Policy Act
NERC	North American Energy Regulatory Commission
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NPDES	National Pollutant Discharge Elimination System
NRC	National Research Council
NSR	New Source Review
NYISO	New York Independent System Operator
O&M	Operations & Maintenance
OPEC	Organization of Petroleum Exporting Countries
PAB	Private Activity Bonds
PJM	Pennsylvania Jersey Maryland Interconnection
PM	Particulate Matter
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PURPA	Public Utilities Regulatory Policies Act of 1978
RCRA	Resource Conservation and Recovery Act
REE	Rare Earth Elements
ROW	Rights of Way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SO ₂	Sulfur Dioxide
SPP	Southwest Power Pool
USGS	U.S. Geological Survey

Executive Summary

[PLACEHOLDER]

Chapter 1: Coal's Unique Role in the U.S. Energy Portfolio

Key Findings – Chapter 1

- **The existing U.S. coal fleet provides a reliable and resilient foundation in support of the nation's need for a stable, diversified energy portfolio.**
- **The coal fleet's ability to dispatch power when needed provides flexibility in meeting fluctuations in demand not met by intermittent renewable energy resources.**
- **U.S. national and economic security interests are supported by the abundance of domestic coal resources and the coal fleet's ability to provide affordable, reliable electricity for residential and industrial consumers. Low-cost electricity enhances the nation's competitiveness in international markets.**
- **Approximately 24% of U.S. coal-fired generating capacity retired between 2005 and 2017.**
- **To ensure the U.S. continues to reap the benefits from its coal-fired generation assets, we must ASSESS the value of the coal fleet, SUPPORT efforts to retain continued operation of the existing coal fleet, REFORM the regulatory environment and RENEW investment in coal generation.**

Introduction

The nation's abundant, affordable and diverse domestic energy resources underpin its economic prosperity. The existing fleet of U.S. coal power plants is a critical component of the nation's energy portfolio, providing a foundation of reliable and resilient electricity in today's dynamic and rapidly evolving energy system.

The historic stability of the nation's energy system is, however, subject to disruptions arising from market distortions, regulation and regulatory uncertainty, which can increase the cost of electricity, threaten the reliability and resilience of the electric grid and hamper economic growth. These factors have most significantly and disproportionately impacted the nation's coal plants. As of August 12, 2018, more than 115,000 MW of coal generating capacity has retired, converted to another fuel or been slated for retirement by 2030. This represents nearly 40% of the U.S. coal fleet that was operating in 2010.ⁱ

It's time for the U.S. to hit the "Power Reset" button to assess, support, reform and renew the role of the existing coal fleet in the U.S. power sector. ASSESS the value of the coal fleet. SUPPORT efforts to retain continued operation of the existing coal fleet. REFORM the regulatory environment. RENEW investment in coal generation.

The National Coal Council's *Power Reset* report has been undertaken at Secretary Perry's request to identify measures that can be employed to optimize the U.S. coal generation fleet so it can continue to provide reliable, resilient, affordable power as part of a diverse electric mix. This chapter of the report details the unique benefits coal provides in fulfillment of these objectives.

Hallmarks of Reliable and Resilient Energy Resources

The U.S. power system benefits from an electric grid that is not only reliable, but resilient. There are many definitions of “reliable” and “resilient” (see Appendix 1A). In general, a reliable electric system minimizes the likelihood of disruptive electricity outages, while a resilient system is designed with the understanding that outages will occur, is prepared to deal with them, is able to restore service quickly and draws lessons from the experience to improve performance in the future.ⁱⁱ

A recent report noted that “A variety of attributes are required to maintain a reliable and resilient grid – no one technology can do it all.”ⁱⁱⁱ PJM has also examined various attributes that provide Essential Reliability Services (ERS), fuel assurance and flexibility as well as other associated characteristics (see Table 1).^{iv} (See Appendix 1B for list and definition of reliable and resilient attributes.)

Table 1. Reliability and Resilience Attributes^v

Qualitative Comparison of Grid Reliability and Resilience Attributes by Fuel Type					
Attribute	Coal	Natural Gas	Wind/Solar	Nuclear	Demand Response
Dispatchability	✓	✓		✓	
Inertia	✓	✓	✓(wind)	✓	
Frequency Response	✓	✓	✓ ³		
Contingency Reserves	✓	✓			✓
Reactive Power	✓	✓		✓	
Ramp Capability	✓	✓			✓
Black Start		✓			
Resource Availability	✓	✓		✓	
On-Site Fuel Supply	✓			✓	✓
Reduced Exposure to Single Point of Disruption	✓		✓	✓	✓
Price Stability	✓		✓	✓	✓

These assessments demonstrate that a diverse generation portfolio is critical to maintaining a reliable and resilient grid. Among the attributes in which coal plants excel are fuel security/assurance, resource availability, on-site fuel supply, price stability and dispatchability. The ability to store fuel onsite and keep generation online is invaluable, especially during regional storms or other disturbances. It is also valuable in supporting rapid recovery following power outages. In December 2017, the average coal power plant burning subbituminous coal had a stockpile that represented 94 days of burn; plants burning bituminous coal had a stockpile representing 87 days of burn (see Figure 1).^{vi}

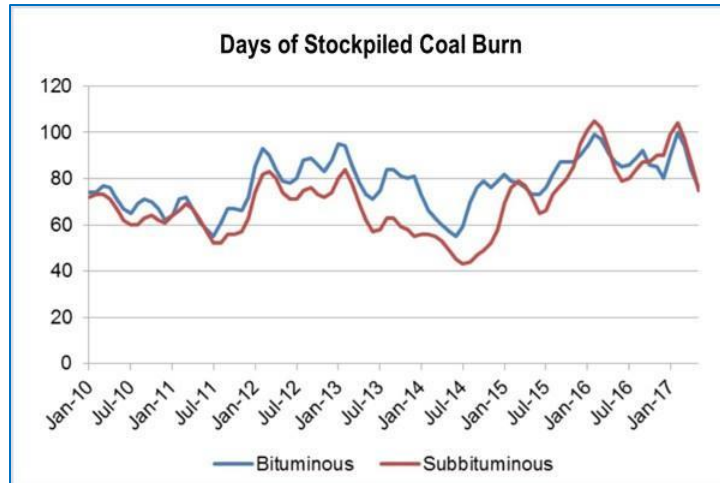


Figure 1. Average Days of Stockpiled Coal Burn

Resource availability is a concept that acknowledges the value associated with abundant fuel sources that are widely and readily accessible. Coal is used to generate electricity in 48 states; it provides at least half the electricity in 13 states and at least one quarter of the electricity in 24 states.^{vii} Unlike natural gas, the vast majority of coal consumed in the U.S. — 86% in 2017^{viii} — is for power generation; thus, coal plants do not compete with higher priority uses such as residential consumers, critical operations (schools/hospitals) and industrial uses.

Coal is mined in 25 states; 60% of coal is produced west of the Mississippi River and 40% is produced in the east.^{ix} Coal can be shipped via a variety of transportation modes, including rail, truck and barge. Diversity in transportation methods makes coal supply less vulnerable to single points of disruption. In addition, there are many electric generating facilities that operate under a “mine-mouth” model with a dedicated coal mine adjacent to the power plant. Because of these factors, coal generation has low exposure to fuel supply chain issues.

Price stability acknowledges the value of a resource that has maintained steady, non-volatile pricing over time and can be secured on a guaranteed basis. The majority of coal is purchased through multi-year contracts for both the commodity and transportation.

The Value of Dispatchability and Flexibility

Dispatchability is a key component of a reliable and resilient power system. Power from baseload plants can be scheduled in advance to meet predicted load and their dispatch can be adjusted to increase or decrease output as required, providing flexibility in meeting fluctuations in demand.^x Unlike dispatchable plants, wind and solar generation are intermittent power sources and do not mitigate the need for added dispatchable generation (i.e., reserve power) in order to reliably maintain grid supply-demand balances, depending on the time of day and year and weather conditions.^{xi}

Issues associated with intermittent renewable energy (IRE) resources and their implications for fuel assurance and price stability were very apparent in the recent wind drought experienced in the United Kingdom. The UK *Daily Mail*^{xii} reported that in early June 2018, Britain was “becalmed” when wind turbines across the nation were at a standstill as the wind “disappeared” for over a week causing a two-year low in electricity production. The lack of wind resulted in turbines generating less than 2% of the country’s power, just after having produced 25% five days earlier. Bloomberg reported that the wind drought had increased day-ahead power prices to their highest level for that time of year for at least a decade.^{xiii} This exemplifies the value of diversity, and the importance of maintaining dispatchable energy resources even as IREs are added to the grid.

However, there are also challenges associated with a diverse grid. For example, as more IREs are incorporated, many indirect system costs are passed on to dispatchable resources. (See Appendix 1C for a list of IRE indirect costs.) One of these cost elements is the “imposed costs” associated with using dispatchable generators to backstop non-dispatchable generators.^{xiv} Dispatchable generators often cycle their output to match net load resulting from demand changes and shifts from non-dispatchable generators. Cycling coal-fueled units creates three major impacts:

- Lower net generation, resulting in a lower capacity factor and, generally, less revenue
- Lower total fuel consumption, but higher heat rate (i.e., lower efficiency), during lower power production periods, and
- Reduced plant life; in its work on this issue, EPRI has noted that “When operational cycling is introduced on a former baseload unit, the residual life can be greatly reduced to between 40% and 60% of the original design life because of the combined effects of creep and fatigue.”^{xv}

While the incremental costs involved in serving as an IRE-backstop are tangible and measurable, they are not currently compensated in most markets and, thus, can affect operators’ decisions to prematurely retire a power plant and similarly reduce investment in plants’ maintenance and longevity. As cycling increases, economic damage escalates, leading to premature retirement of dispatchable units (see Appendix 1D for a detailed assessment of renewable energy and dispatch). As discussed in Chapter 3, there are some technology improvements that would improve the ability of the existing coal fleet to support intermittent sources, while subjecting these coal plants to less damage and reducing incremental costs.

The Role of a Diversity in a Resilient and Cost-Effective Energy Portfolio

Resource diversity is critical to maintain a reliable and resilient grid, especially in the event of high impact-low frequency (HILF) events. Diversity helps maintain system reliability and the resiliency required to recover from HILF events.

In testimony in January 2018 before the U.S. Senate Energy & Natural Resources Committee^{xvi} at a hearing on the performance of the grid under extreme weather conditions, the North American Electric Reliability Council (NERC) highlighted concerns with over-reliance on any one energy resource, noting reliance on a single fuel increases vulnerabilities (see Appendix 1E). More recently, in its 2018 Summer Reliability Assessment^{xvii}, NERC noted that “...the growing reliance on natural gas continues to raise BPS [Bulk Power System] reliability concerns.” Texas ERCOT, for example, anticipates a Reserve Margin shortfall of 2,000 MW (13.75% Reference Margin Level vs. Anticipated Reserve Margin of 10.9%). One of the principal contributing factors in this shortfall is the largely premature retirement of 4,273 MW of coal capacity in January/February 2018.

In 2017, PJM released “PJM’s Evolving Resource Mix and System Reliability,” in which it concluded that PJM needs significant coal-fueled generation capacity to ensure a resilient grid, especially when encountering a HILF event.^{xviii}

As U.S. Department of Energy (DOE) staff has noted, “Maintaining fuel diversity and security provides the best assurance for resilience. Premature retirements of fuel secure baseload generating stations reduces resilience to fuel supply disruptions.”^{xix}

The economic impacts of a less diversified energy portfolio were assessed by IHS Markit in its report on “Ensuring Resilient and Efficient Electricity Generation.”^{xx} Their analysis compared the existing U.S. electric supply portfolio in 2014–2016¹ with a projected less diverse supply portfolio², yielding the following conclusions:

- The current diversified portfolio lowers the cost of electricity production by about \$114 billion/year and lowers the average retail price of electricity by 27% versus the less diversified portfolio. A 27% increase in retail power prices results in a decline of real U.S. GDP of 0.8%, equal to \$158 billion (2016 chain-weighted dollars).
- The current diversified portfolio reduces the variability of monthly consumer electricity bills by about 22% versus the less diverse portfolio.
- A more diverse portfolio mitigates an additional economic cost of \$75 billion/hour associated with more frequent power supply outages.
- Less efficient diversity involves a reduction of *one million jobs*.
- A less efficient diversity portfolio reduces real disposable income per household by about \$845 (2016 dollars) annually.

¹ See Chapter 1, “Today’s Coal Fleet” for a description of the current energy portfolio.

² See Chapter 2 for a discussion on future generation.

Coal’s Unique Energy, Economic and National Security Benefits

“Energy security is a roadmap to economic prosperity.”

Secretary Rick Perry – CERA Week 2018

Electricity drives the U.S. economy. Low electricity prices fuel the nation’s commercial and manufacturing sectors and provide affordable power for all U.S. residents, including those with lower-incomes. U.S. power costs are partly driven by affordable fuel. In its 2018 Annual Energy Outlook, EIA projects that natural gas prices for electric power generation will increase by 34% in real terms between 2018 and 2040; coal prices are projected to increase 9% over the same period.^{xxi}

Long-term national security is supported through continued use of domestic fuels. The remaining recoverable coal reserves in the U.S. are estimated to last more than 300 years at current usage rates. Furthermore, U.S. coal reserves are larger than remaining natural gas and oil resources based on energy content.^{xxii}

To retain its competitive position in international markets and bolster a thriving economy at home, the U.S. needs to support policies and market approaches that ensure low electricity prices. In an assessment of the Levelized Cost of Electricity from Existing Generation Resources^{xxiii}, the Institute for Energy Research (IER) noted that “The lowest possible electricity rates will only be achieved by keeping existing generating resources in operation until their product becomes uneconomic – not relative to suppressed wholesale markets clearing prices but rather *relative to the levelized cost of electricity from new sources that would replace them.*” See Figure 2 for a comparison of the levelized cost of electricity of different electricity sources.^{xxiv}

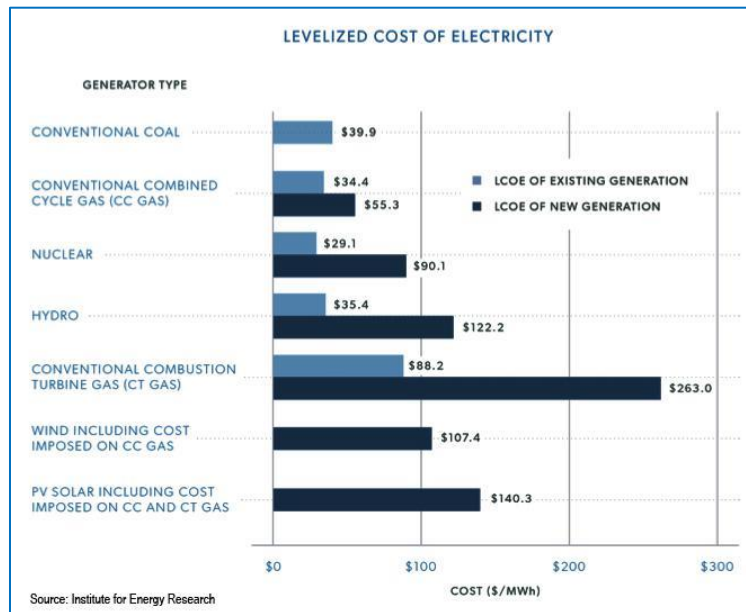


Figure 2. Levelized Cost of Electricity

IER also points out that environmental regulations as well as subsidies and mandates for renewables are driving most new generating capacity construction, not new electricity demand (see Appendix 1F for additional information on subsidies). “FERC Form 1 and EIA 860 show that, in the absence of mandates, subsidies and regulatory compliance costs, the cost of electricity from almost all existing generation resources will remain less than the cost of electricity from their likely replacements for at least the next 10 to 20 years ... When electricity from an existing electric generating plant costs less to produce than the electricity from the new plant technology expected to be constructed to replace it – and yet we retire and replace the existing plant despite the higher future costs – ratepayers must expect the cost of future electricity to rise faster than it would have if we had instead kept the existing power plants in service.”^{xxv}

The net effect of adding capacity without an appropriate demand signal marginalizes the return on existing generation assets. This increasingly relegates coal assets to standby capacity in markets that clearly need, but do not appropriately value, this standby capacity.

Coal’s Role in Enhancing the Global Competitiveness of the U.S.

Maintaining a diversified, dispatchable energy portfolio allows the U.S. to maintain low electricity rates which, in turn, enhance the nation’s competitiveness in international markets and provides lower rates for the residential sector.

The average U.S. residential consumer pays significantly less than its European counterpart, about one-half of the rate for the EU-28 countries and a third of that in the most expensive countries (see Figure 3A).^{xxvi,xxvii} The composition of the residential European prices is broken out by the base price (without taxes and fees), other taxes and fees and VAT. The U.S. price is the composite price including all taxes and fees. In the two countries with the highest residential electricity prices, Germany and Denmark, over half of the cost to the consumer consists of taxes designed to subsidize renewable energy resources and meet other energy policy objectives.

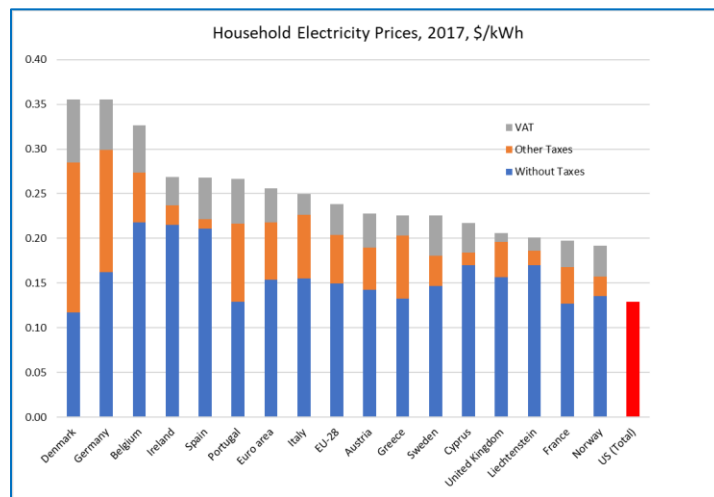


Figure 3A. Residential Electricity Rates

The U.S. non-residential rate (commercial and industrial) is about 30% less than the EU-28 aggregate, and about half that of the highest price countries (Germany and Italy), for which 40–50% of the total rate consists of taxes and other levies (see Figure 3B).^{xxviii,xxix}

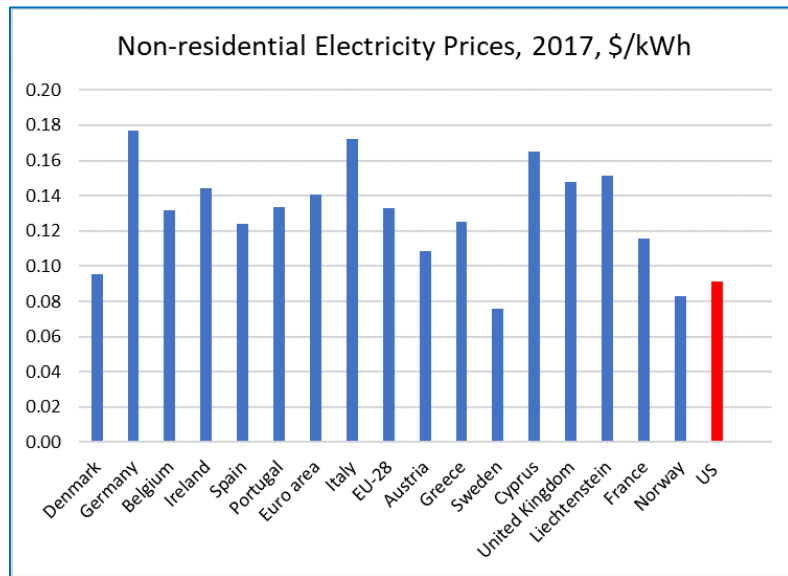


Figure 3B. Non-residential Electricity Rates

It is instructive to examine the lessons learned from other nations that have undertaken efforts to transition away from baseload power in pursuit of aggressively deploying renewable energy sources (see sidebar article on International Lessons Learned on page 19). The repercussions of these policies have been significant for both citizens and businesses operating in these countries.

In a comparison of U.S. and European Union (EU) approaches to energy policy, Robert Bryce with the Manhattan Institute^{xxx} notes that as a result of “policy differences, electricity prices in Europe are far higher than in the U.S. for both residential and commercial consumers ... The average U.S. household pays about a third of what the same electricity costs in Germany and European steelmakers now pay twice as much for their electricity as do U.S. manufacturers.”

Bryce estimates the net effect of the U.S. adopting a renewable energy goal akin to that of the EU would increase our nation’s monthly residential bills by about 29%. He concludes that “For decades, the U.S. economy has prospered thanks to cheap, abundant, reliable supplies of energy. Domestic policymakers should focus on ensuring that this remains the case. Therefore, they should not follow the EU’s lead. Instead, they should eliminate renewable-energy subsidies and remove excessive restrictions on coal-fired electricity generation plants.”

The impact on electricity cost of varying U.S. state energy policy can also be observed. For example, comparing the state-specific price paid for electricity with the fraction of coal-fired generation reveals that states that generate little or no coal-fired electricity pay the highest electricity prices, with the exception of Oregon and Idaho where hydroelectric represents more than 60% of generation. Thirteen (13) states generate more than 50% coal-fired electricity, and nine (9) states generate less than 2% coal-fired electricity. The average price paid for electricity in these states are compared in Figure 4. On average, the low coal generation states pay 160% of the price of electricity compared to the high coal generation states.

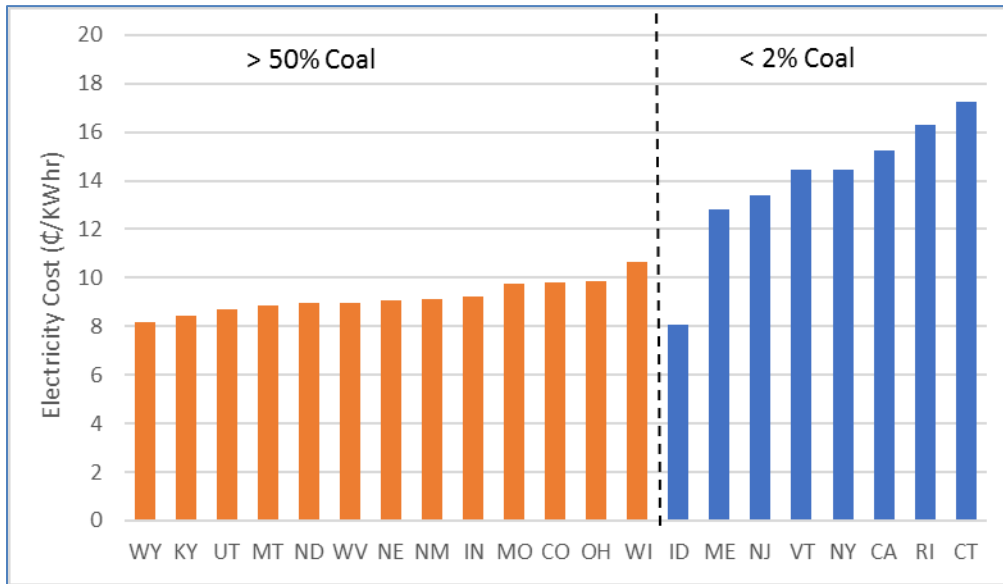


Figure 4. Comparison of Electricity Costs for States in the Contiguous U.S. Using the Highest and Lowest Fractions of Coal-fired Electricity

States that rely heavily on coal for electricity generation also produce more goods as a fraction of overall state GDP. Figure 5 compares the fraction of state GDP for goods or services for states who generate 50% or more electricity from coal, and those that generate less than 10% of electricity from coal.^{xxxix} As shown, the GDP in high coal-generation states is more than twice as reliant on goods produced compared to low coal generation states. In the low coal generation states, services are a more important component of state GDP, representing over 70% of state GDP.

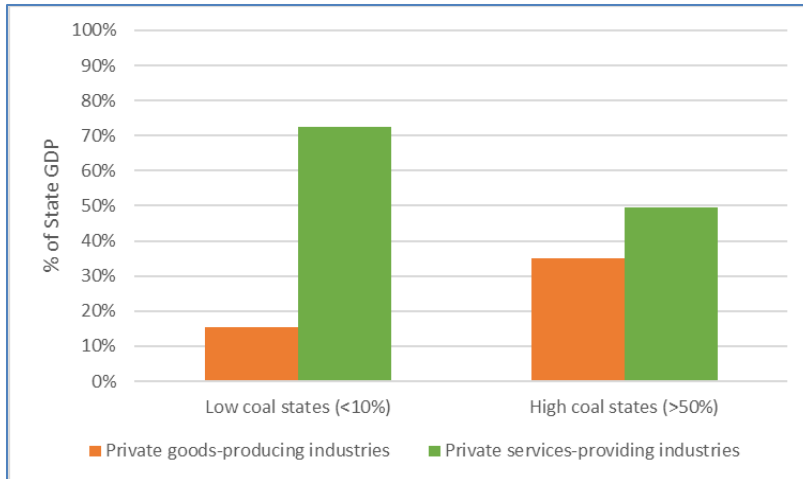


Figure 5. State GDP Distribution for High and Low Coal Generation States

Today's U.S. Coal Fleet

At the end of 2017, the U.S. existing coal fleet that provides the many outlined benefits was made up of approximately 253 GW of generating capacity, with a 2017 net generation of 1,184,681,507 MWh, representing nominally 53% of the available generating capacity. The capacity-weighted average age of these plants was 40 years. The age distribution by generating capacity and average operating capacity factor, or MWh produced compared to the total possible MWh based on plant generating capacity, for plants operating in 2017 is shown in Figure 6.^{xxxii} The capacity factor for the newest plants is over 70%, compared to 50% or less for plants more than 46 years old indicating that, in general, newer plants operate more often than older plants.

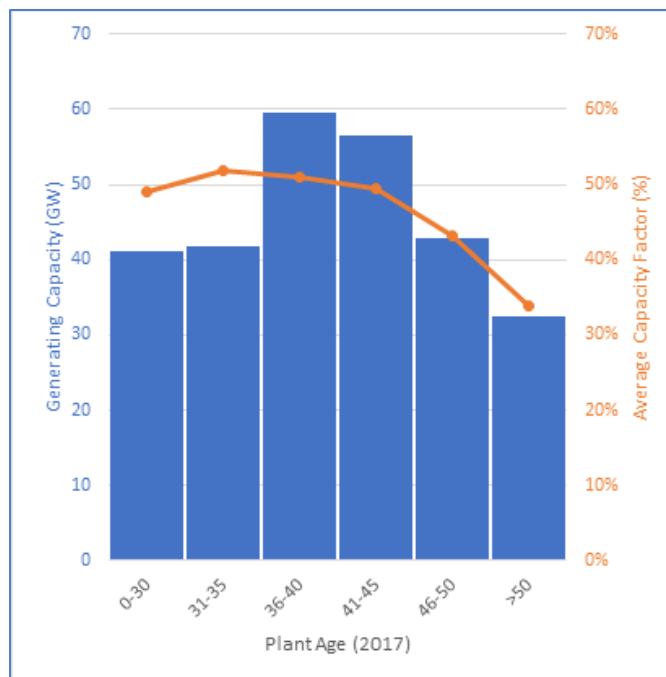


Figure 6. U.S. Coal-fired Fleet Age in 2017 and Respective Average Generating Capacity Factor

In 2005, approximately 325 GW of coal-fired generating capacity was in operation in the U.S. Based on EIA data, 51% of these plants had retired by 2017, representing approximately 79 GW, or 24% of the 2005 generating capacity. The average size of a unit in the U.S. fleet was 231 MW in 2005 and the average size of the units retired since then was 109 MW. Since 2005, 27 GW of new coal-fired generation has been added – although no additional plants are being built or planned today – and the average size of operating units in 2017 was 364 MW. Thus, from 2005 to 2017, many smaller and older plants retired, as shown in Figure 7.^{xxxiii} Information on the location and size of coal-fired power plants in operation in the contiguous U.S. at the beginning of 2018 is included in Appendix 1G.

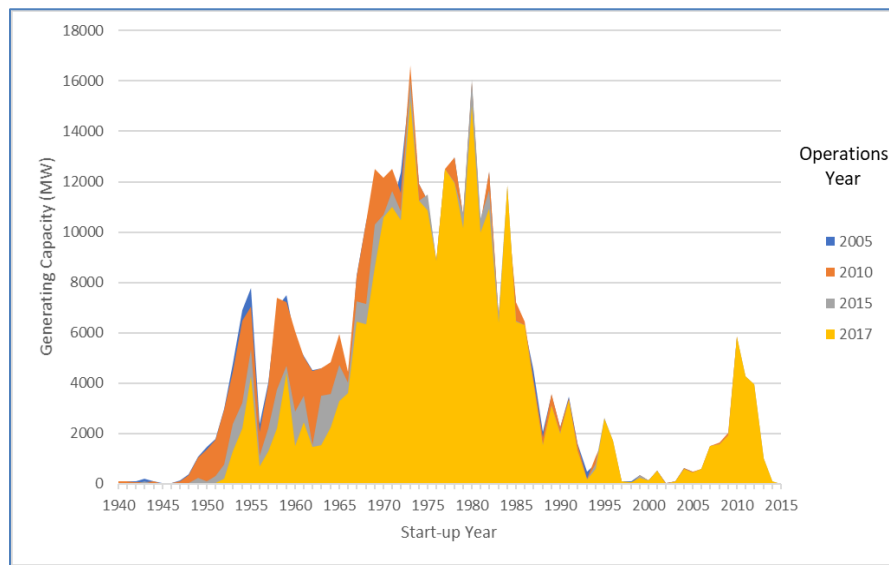


Figure 7. Start-up Year and New Generating Capacity for Plants Still in Operation in 2005, 2010, 2015 and 2017

The U.S. coal-fired electricity generating units that retired between 2005 and 2017 have largely been replaced by alternatives – mostly gas-fired generation with some IREs, the effects of which are shown in the net generation by fuel source depicted in Figure 8. This also corresponds to a decrease in average cost of natural gas-fired generation over the same period.

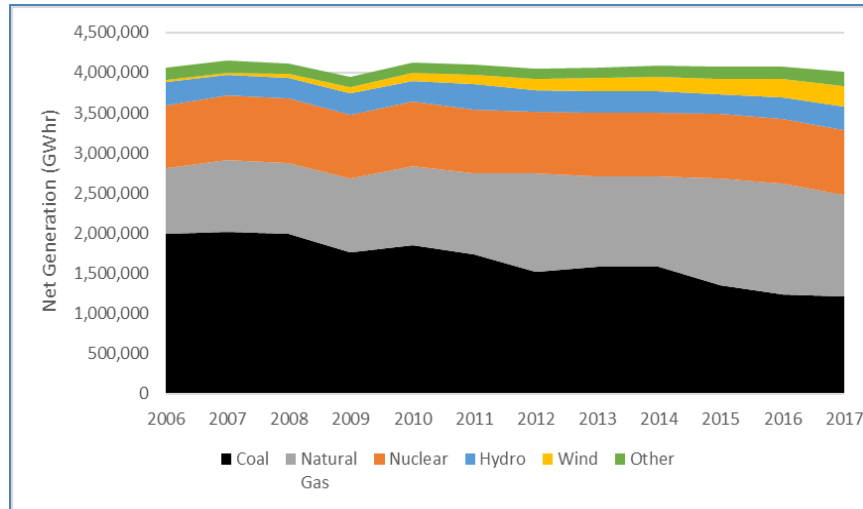


Figure 8. Net U.S. Electric Generation for 2006 to 2017

Evolution of the Existing U.S. Coal Fleet: Historic Drivers

It is instructive to examine the evolution of today’s coal fleet as a basis for defining the best path forward. Coal power plant retirements since the turn of the century have been driven by numerous factors, including competitive pricing from other fuel resources, federal and state energy and environmental policies, declining electricity demand, inadequate funding for technology innovation, and societal pressures.

Cost Considerations

Natural Gas Prices. The new economics associated with natural gas has been one of the most significant triggers for coal generating unit retirements. This change in economics began with the emergence of an unprecedented increase in natural gas supplies within the U.S. resulting from the development of shale gas reserves. The decline in natural gas prices began in 2009 because of both the 2008 economic recession and associated decreased demand for generation and also the increase in natural gas supply.^{xxxiv}

The shale boom emerged around 2006–2007 when hydraulic fracturing practices made previously inaccessible gas sources economically and technically recoverable. With this abundance, natural gas prices fell from an average of over \$7/MMBtu from 2003–2008 to an average of \$3.20/MMBtu in the period from 2012–2016. Typically, natural gas prices at \$3/MMBtu can result in simple cycle natural gas combustion turbine (CT) units and the more efficient natural gas combined cycle (NGCC) units being dispatched ahead of some coal units, possibly even some highly efficient supercritical coal-fired units. A price of \$4/MMBtu will cause CT and NGCC to be dispatched ahead of some subcritical and older coal-fired units. Thus, the decline in natural gas prices triggered retirement of smaller, older coal plants and as natural gas prices remained in this range, retirements continue. With abundant supplies from the Marcellus and Utica shales, along with construction of natural gas pipelines, natural gas price volatility has reduced (see Figure 9).^{xxxv}

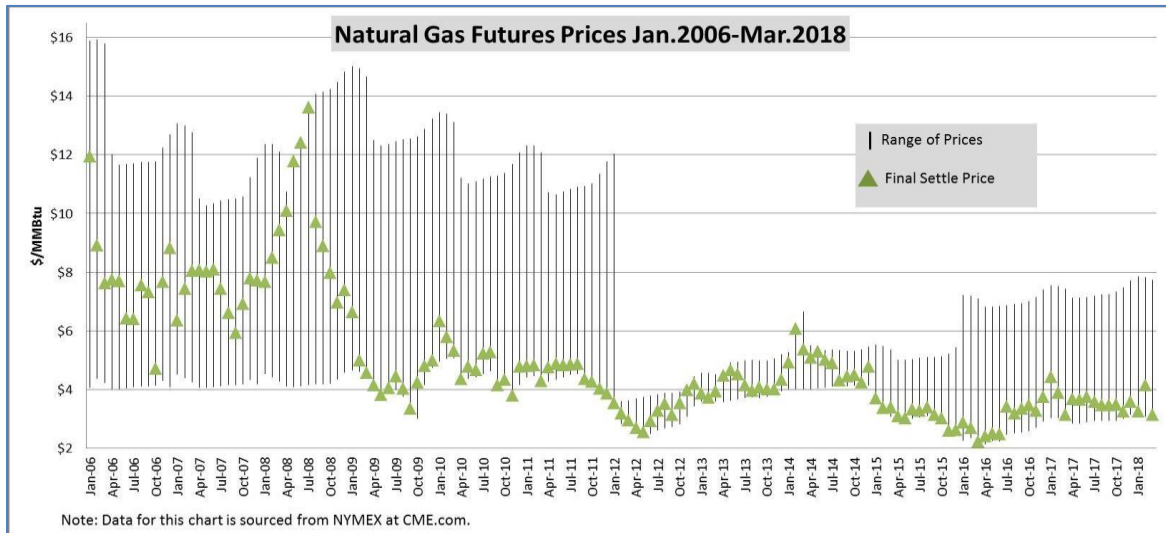


Figure 9. Natural Gas Futures Prices January 2006–March 2018

Renewable Energy Pricing - Impacts of PTC and ITC. As reported in the National Coal Council’s (NCC) report on Policy Parity,^{xxxvi} subsidies, mandates and other policies for IREs have tilted the playing field for wind and solar energy, competitively disadvantaging existing coal generation. Reports from EIA^{xxxvii} and the Congressional Research Service^{xxxviii} (CRS) confirm the significant disparity between energy subsidies for renewables and for fossil fuels. The EIA report documents that between 2010 and 2016, renewable energy’s share of energy-specific subsidies and support increased from 42% to 45%; coal’s share for the same period increased from 2% to 8%. Earlier EIA assessments noted that in 2013, renewables received more than 12 times the subsidies as received for coal — \$13.277 billion for renewables and just \$1.085 billion for coal.

Financial support available to renewable energy suppliers under the Internal Revenue Code Section 45 Production Tax Credit (PTC) and Section 48 Investment Tax Credit (ITC) has not only provided revenue to IREs, but has reduced revenue to fossil and other generators, many of whom have left the market in recent years as a result. Later sections of this report detail the potential fossil generation benefits associated with recently enacted revisions to 45Q and 48A tax credits, as well as the need for transparency in electricity markets that fully accounts for the all-in cost of energy resources generating electricity that consumers are buying.

In fact, the value of the renewable energy PTC artificially lowers the variable costs of wind generation that is bid into the market relative to non-subsidized generation. This disparity has enabled renewable energy producers to sell into energy markets at low – and at times even negative – prices, which has the effect of reducing market prices for non-subsidized fuels, such as fossil and nuclear (see Chapter 3 for a more detailed discussion of impacts of renewable energy PTC/ITC on wholesale electricity markets).

Regulation

Environmental Regulations. Existing and proposed environmental regulations with compliance deadlines between the years 2010–2017 factored into retirement decisions for coal-fired generating units that were already economically marginalized due to the competition from low natural gas prices and mandated deployment of renewable technologies. Capital investments required to meet regulatory requirements were best made on newer and more efficient coal-fired power plants leaving the already marginalized, and typically older, coal-fired units likely to retire. According to estimates by industry organizations, of the more than 115,000 MW of retired, converting or planned retirements, nearly 77,000 MW are explicitly attributed to U.S. Environmental Protection Agency (EPA) existing and proposed regulations/policies (from 2010–2030).^{xxxix} In its Staff Report for Secretary Perry, DOE noted that 48,800 MW of coal-fired generation capacity retired from 2002–2016, when environmental regulations were forcing a decision to either retire or upgrade.^{xi}

Key regulations that drove, or are believed to be driving, retirements are detailed in Appendix 1H. The regulation that resulted in the greatest number of retirements in one year was the Mercury Air Toxics Standards (MATS) Rule. Other regulations, including those that could be even more costly to meet, had later implementation deadlines so if the MATS Rule had not already triggered closure, these regulations might have.

In 2015, the same year for which MATS compliance was required, EPA finalized the Clean Power Plan (CPP). Although CPP was later stayed by the U.S. Supreme Court, the ensuing regulatory uncertainty was likely a consideration when weighing retirement decisions. The prospect of future CO₂ regulation, and regulatory uncertainty in general, may also have impacted consideration of investments in new and existing coal plants as there is little certainty that investments will get a fair opportunity to be earned back. There is an argument to be made that environmentally permitted investments should be given the opportunity to earn their value over their useful life or just compensation should be due if that opportunity is denied.

State Energy Policies. States have exercised considerable control over the electricity market through legislation that affects how and how much electricity is generated. Among the most significant of these are Energy Efficiency Resource Standards (EERS) and Renewal Portfolio Standards (RPS), which grew in prominence from about the year 2000. A comprehensive source of state-by-state information on EERS and RPS programs is the “Database of States Incentives for Renewables and Efficiency” (DSIRE).^{xii}

Energy Efficiency Resource Standards

An Energy Efficiency Resource Standard (EERS) is a mandatory requirement imposed by a state on electricity, and in some cases natural gas utilities, to reduce end use consumption by specific amounts by specific dates. Twenty-six states have implemented EERS programs. In addition, most other states have some form of electricity efficiency programs implemented by the utilities or by the state on a voluntary basis. The majority of the EERS programs became effective between 2000 and 2010. The American Council for an Energy-Efficient Economy (ACEEE) estimated that total electricity savings in 2014 was approximately 180 billion kWh^{xlii} or 4.4% of the total U.S. electricity consumption in that year. The energy savings in 2016, the most recent reporting year, was approximately 230 billion kWh, or about 5.5% of total U.S. demand.

Renewable Portfolio Standards

An RPS is a state law requiring electric utilities to sell a certain portion of their electricity from or maintain a certain portion of the generating capacity as renewable sources. According to the National Council of State Legislatures (NCSL), 29 states had enacted RPS legislation by August 2017. The NCSL reports that “Iowa was the first state to establish an RPS and Hawaii has the most aggressive RPS. In many states, standards are measured by percentages of retail electric sales. Iowa and Texas, however, require specific amounts of renewable energy capacity rather than percentages and Kansas requires a percentage of peak demand. Twenty (20) states and Washington, D.C., have percentage-based cost caps in their RPS bills to limit increases in ratepayers’ bills. One state caps RPS gross procurement costs.”^{xliii}

Technology Considerations

Through the Office of Fossil Energy, DOE at one time had a dedicated program – “Innovations for Existing Plants” – that supported R&D targeted at existing coal units. Technologies supported in the program included mercury and air toxics control technologies, particulate matter control technologies, water cooling and other types of water management technologies, as well as coal combustion byproduct processes. In 2009, DOE refocused the program exclusively on carbon capture retrofits for existing coal plants, phasing out all other existing plant R&D. Eventually, this program was renamed the “Carbon Capture” program.

Since then, every CURC-EPRI Roadmap^{xliv} that has been published has identified the need for a dedicated existing plant program to support R&D on innovative techniques for heat rate improvement, water management as it relates to existing units specifically, and improvement of both performance and operations of criteria emissions control systems that are operating in a much more flexible mode than originally designed.^{xlv} However, no funding has been made available for R&D specific to the existing fleet over nearly a decade, at a time when increasing amounts of renewables and competition with natural gas are forcing existing coal units to ramp up and down, significantly contributing to the wear and tear of those units that are designed to run in a steady baseload state.

The additional operation and maintenance (O&M) costs associated with operating baseload plants in a cycling mode has influenced operators' decisions to retire coal plants. Insufficient R&D funding and a lack of a dedicated DOE Existing Plants R&D program for development of technologies to support existing fleet operations in a flexible mode have also contributed to coal plant retirements. Technology options to reduce the impact of cycling, including heat and energy storage, are included in Chapter 3.

Societal Considerations

Public perception of coal has shifted dramatically over the past few decades as evinced by:

- Imposition of national and state policies in opposition to the development of coal production, transportation and consumption facilities
- Shareholder and advocate demands for divestiture of coal-related stock holdings
- National and local environmental NGO campaigns deriding coal and advocating for the closure of coal facilities
- Climate change advocate initiatives targeting coal as the primary culprit
- State government and advocacy group opposition to development of coal export infrastructure projects³
- International development bank and government reluctance to support deployment of advanced coal technologies

Also, as detailed in Chapter 2 (Societal Pressures), there has arisen over the last few years a belief that renewables can reliably and cheaply provide 100% of U.S. electricity needs. This perception has fostered public pressure on policymakers and companies to support the rapid growth of IREs. There has also been a lack of valuation of the importance of diversity and the role played by the existing coal fleet, which has facilitated the retirement of coal power plants. Improved transparency about the inherent costs and benefits associated with all energy resources and the value of a diverse energy mix will provide a more reasoned approach to energy decision and policy making.

Conclusion

A mere 50 years ago, coal was lauded as a champion for providing an affordable, secure domestic solution to combat OPEC's energy stranglehold. In responding to that call, U.S. coal producers, transporters and power generators established a world-class network to provide the U.S. with affordable, reliable electric power. Today, that coal network continues to demonstrate its value by enhancing the reliability and resilience of our nation's energy grid, even as the grid is rapidly changing.

³ See the National Coal Council's report on "Advancing U.S. Coal Exports" (September 2018) for a discussion of initiatives in opposition to coal export port developments and financial community proscriptions against international coal facility development, www.nationalcoalcoal.org.

International Lessons Learned

The headlines are revealing:

- “Germany shows how shifting to renewable energy can backfire”^{xlvi}
- “German household power prices at record high”^{xlvii}
- “Why South Australia’s blackouts are a problem for us all”^{xlviii}
- “South Australia power prices to rise to highest in the world”^{xlix}
- “Ontario household electricity prices to rise 52 percent from 2017 to 2035”^l
- “Ontario’s power-price crisis – how did happen and who got hurt”^{li}

The U.S. can learn from the hard lessons of other countries as they consider the importance of baseload power supplies and sustained utilization of existing utility assets. Other regions and countries, such as Germany, Australia and the province of Ontario (Canada), have experienced the negative impacts of aggressively pursuing renewable power at the expense of coal-fired baseload systems. Affordable, reliable and resilient electric supply is not only the cornerstone of manufacturing and the economy, it is critical to low income families. Higher energy costs result in these families having to expend a larger percentage of their household budget on electricity, reducing funds available for other household essentials such as food and medicine.

Germany has been one of the world leaders in the pursuit of increased renewable energy at the expense of baseload coal power and nuclear power. Germany has ramped up renewable power for over two decades and currently generates about 40% of its electricity from renewables. As a result, the country has some of the highest electricity costs in the world and residents are also paying additional taxes to cover the buildup of renewable power. Recently, Germany has begun reintroducing coal generation to its electricity portfolio in order to deal with the intermittency of their renewable power supply.

Similarly, Australia has incurred power price increases and outages over recent years as a number of coal plants have shut down. This has been especially true in South Australia where renewables provide around 40% of the region’s power. While outages can be attributed to many factors, increased intermittent renewables and coal plant retirements are a large part of the equation.

In North America over the past decade, Ontario Canada has transitioned to more renewables, retiring coal-fired power plants and relying on nuclear power for baseload energy. During this transition period, power prices in Ontario have increased roughly four times the rate of inflation and can vary broadly over time depending on the availability of renewable generation. Again, we see that energy policy and retirement of existing coal-fired utility assets can have significant consequences on energy pricing.

These international examples demonstrate the need for well thought out energy policies that maintain coal-fired generation in the mix. This will prevent negative impacts on our industry, economy and low-income households.

Chapter 2: Outlook for Coal Generation

Key Findings – Chapter 2

- **The U.S. power fleet is experiencing significant and rapid changes, presenting challenges to forecasting the outlook for power generation. Assessing the future of the nation’s generation portfolio will require evaluating many varied risk factors taken into consideration on a cumulative basis.**
- **Data on currently announced coal plant retirements do not capture all of the market dynamics that are prompting plants to retire and may be underestimating the loss of these critical generating and grid stabilization resources.**
- **Regulations, staffing constraints and societal pressures will continue to hamper efforts to preserve and optimize the existing coal fleet.**
- **Coal-fired generating capacity is likely to continue to decrease barring a proactive initiative to assess and take action to compensate the existing coal fleet for the value it provides in maintaining the diversity and stability of the U.S. power grid.**
- **There is a need for greater transparency in the comparative analysis of fuel resource options.**

Introduction

The U.S. power fleet is experiencing a period of rapid changes, which is making it challenging to forecast the outlook for power generation. Substantial year-over-year differences in projected future coal plant retirements are one indication of the uncertainty of these predictions. Many influences are aligning to force the retirement of coal plants and fundamentally alter the makeup of the U.S. electric generating system. This chapter brackets the trajectory of the existing coal-fired generation and addresses several of the key drivers for change.

Some impacts on the generation fleet are cumulative, such as the impact of load cycling on maintenance costs and expected life of power plants. Reliability projections tend to underestimate the impact of current operating conditions on coal plants, as can be seen by comparing projections of future capacity factors to recent operational data from existing coal plants. The result of load cycling may be sharp increases in electric generation costs, much larger than anticipated in current economic projections. A rapid decline in baseload and dispatchable power due to an accelerated aging of the fleet could also severely reduce power supply reliability unless the overall system can be structured to absorb these changes, especially during extreme weather conditions.

Other important factors include the social sentiment towards coal and lack of public understanding of its critical role in supporting the power grid. As explained in Chapter 1, this has resulted in more regulation, renewable power standards and limited market incentives for many of the attributes that coal plants bring to the grid and electric market, as well as consumer preference and Boardroom pressure for IRE generation. Although customer preference is sometimes assumed, and surveys show that while people state a willingness to pay more for electricity that is renewable-sourced, the reality is that few actually sign up to pay more, indicating that cost remains of high importance.^{lii}

Consumers have come to assume that the grid will reliably supply power into the future. However, in some cases this reliability has come on the back of coal, nuclear and even oil (electric sources with onsite fuel storage). This was perhaps best demonstrated most recently during the Bomb Cyclone – the term used to describe the extreme cold weather system that challenged the grid in the U.S. East Coast – in December 2017 and January 2018 (see sidebar article page 30 on high impact low frequency events). Power reliability is perceived as a long-term sustainable mode of operation, even while the coal-fired generation that underpins system stability is being retired. Maintaining stability of the grid during a shift toward new generation sources, including the role of the existing coal fleet, is a critical role for the Department of Energy.

Generation Mix Projections

Several sources have estimated the future generation mix and the range of predictions is broad. From 65 to 100 GW of coal-fired power is predicted to retire by 2030. EIA predicts in its 2018 Annual Energy Outlook^{liii} (the source of Figure 10 and Figure 11 below) that coal-fired power will remain flat from 2030–2050. At the other end of the spectrum, Bloomberg NEF’s New Energy Outlook 2018 predicts that by 2050: "Coal and nuclear are pushed out by age and economics, such that by 2050 both nuclear and coal have almost disappeared from the electricity mix."^{liiv}

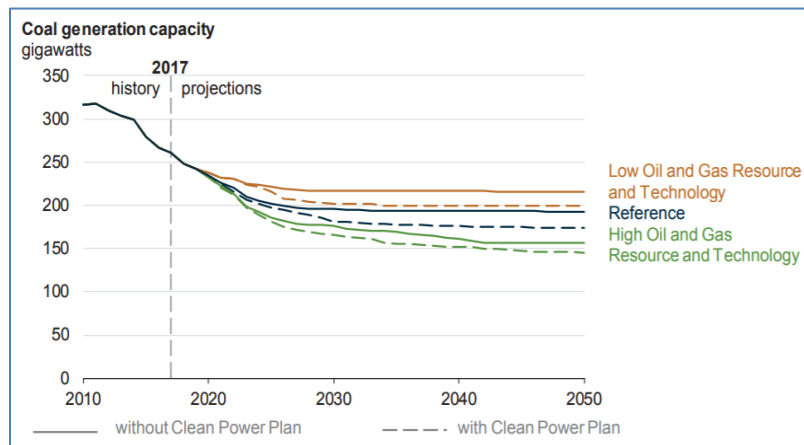


Figure 10. EIA U.S. Coal Generation Capacity^{lv}

Navigant predicts approximately 73 GW of coal-fired power will retire in the next ten years, and has said, "That's more than twice what we projected last year at this time. It's more than we had two years ago when the Clean Power Plan was in the assumptions."^{lvi}

As a result of these declines, coal generation is anticipated to lag well behind both natural gas- and renewable-based generation by 2050, while remaining slightly ahead of nuclear according to EIA (see Figure 11). Coal plant retirements are anticipated to continue through 2022, before coal generation stabilizes at about 1,200 billion kilowatt hours through 2050.^{lvii} However, the likelihood of flat-lined generation is very low given the age, competitive environment and deteriorating conditions of coal-fired plants. As addressed later in this chapter, a lack of investment incentives and increasing risk factors will most likely result in more dramatic declines in both generation and capacity of coal-fired power plants than are currently projected by EIA.

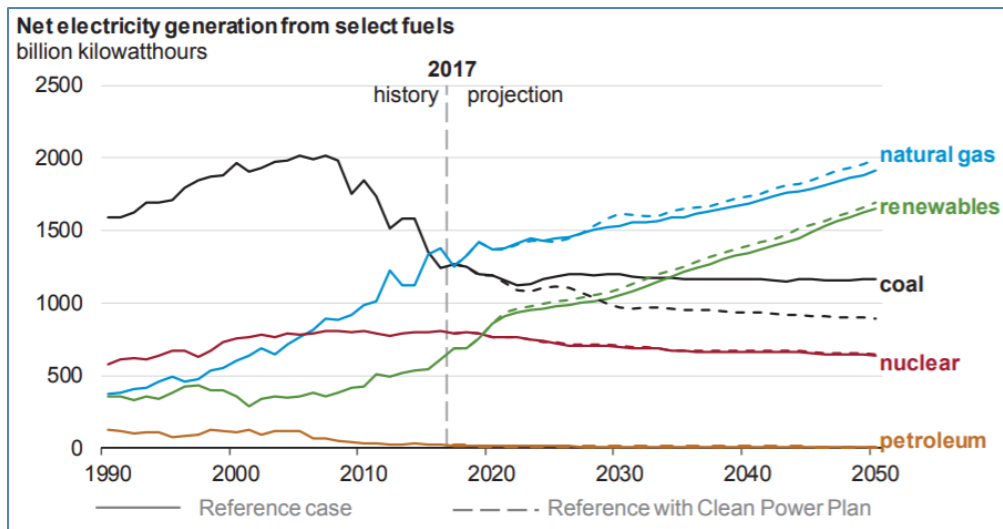


Figure 11. Net Electricity Generation from Select Fuels

These declines are also described in a current DOE National Energy Technology Laboratory (NETL) study on the existing fleet, which identified an implicit capacity gap attributed to coal unit aging that could result in up to 75 GW of coal retiring by 2025. This should be of great concern given the critical role coal plays as part of a diverse energy mix, including during severe weather events, such as the Bomb Cyclone event in early 2018. "The 30 GW of coal that ramped up to meet the surge in PJM load clearly includes the units most likely to retire due to insufficient market support, given those units were not running at baseload levels before the event."^{lviii} This report on the Bomb Cyclone is described in further detail later in this chapter.

Numerous analyses indicate that without appropriate mechanisms that value the diversity, reliability and resiliency provided by the existing coal fleet, the downside capacity predictions are much more likely than the EIA flat line projections. Additionally, many factors driving coal generation downward will have a cumulative impact. Chapter 2 focuses on the outlook for coal and factors that could affect coal generation into the future.

Coal Generation Trajectory Basis

As shown in Figure 10, EIA expects U.S. coal-fired electric generating capacity will continue to decrease from 2017 through 2030 by approximately 65 GW, then remain relatively stable at a level of approximately 190 GW through 2050. This comes on the heels of a net decrease in coal-fired electric generating capacity of nearly 60 GW between 2011 and 2016. As noted previously, currently announced retirements do not capture all of the market dynamics that are prompting coal plants to retire, and these data likely underestimate the loss of these critical generating and grid stabilization resources without tailored action to save them.

Factors that EIA cites for causing these expected declines include: (1) competitively priced and growing natural gas production; (2) environmental regulations; and (3) increasing renewables generation due to improvements in technology and economics as well as various incentives and mandates. EIA forecasts that wind and solar generation will account for 64% of total electric generation growth through 2050, with natural gas usage for power generation also expected to increase over the same period. In terms of renewables, generation from solar PV is expected to surpass that from wind by approximately 2040, with the gap between the two continuing to grow in favor of solar PV thereafter.

These nationwide figures mask a significant amount of variation in the generation mix at the state and regional level. For example, California has no coal-fired generation in-state, but significant amounts of generation from natural gas and renewables.^{lix} However, about 5% of California's electricity is coal-fired generation from other states. In 2015, at times as much as 50% of southern California's power was generated by coal via these inter-state imports.^{lx}

Georgia, in contrast, relies primarily upon electricity generated from natural gas, nuclear and coal.^{lxi} Due to a host of factors, from resource availability to state and regional energy and environmental policies, electricity generation mix variability is also reflected in the Integrated Resource Plans filed by utilities throughout the U.S.^{lxii}

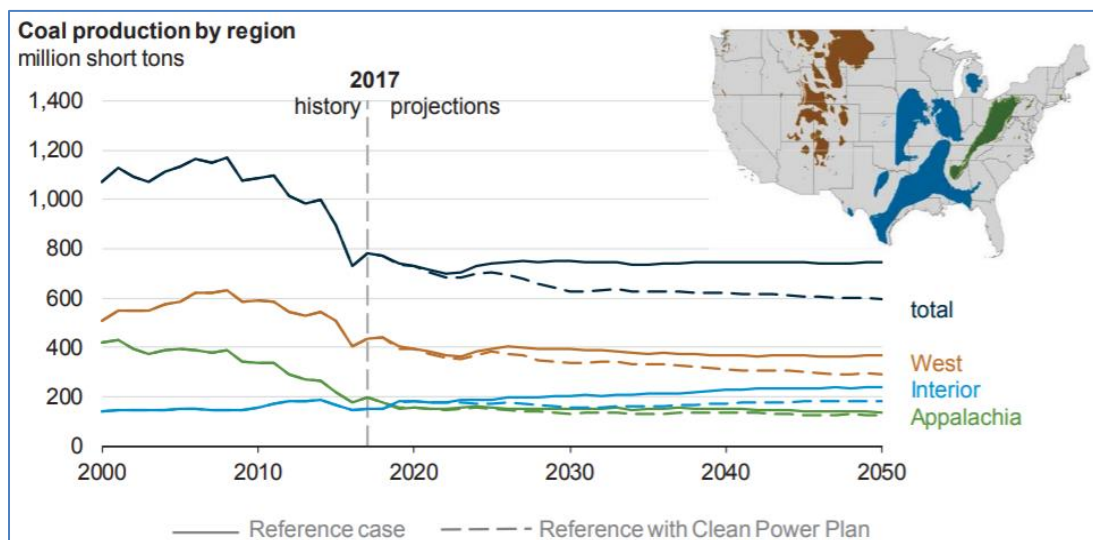


Figure 12. EIA Annual Energy Outlook 2018 Coal Production by Region

The impact of these retirements on coal demand, and thus production, is somewhat predictable. According to EIA, coal production continues to decline – from 784 million short tons (MMst) in 2017 to 699 MMst in 2022, then rises slightly in the mid-2020s to 750 MMst, before leveling off through 2050 (Figure 12).

Numerous private sector estimates and forecasts expect greater declines than are shown in the EIA estimates. For example, IHS has predicted that about a third of the U.S. coal fleet (about 100 GW) will retire in the years ahead.^{lxiii} And while energy forecasting is an imprecise science, and the need for greater transparency in the comparative analysis of fuel resource options remains, the broad consensus is that coal’s past position as the dominant fuel source for electricity generation remains under economic and policy pressure for the foreseeable future.^{lxiv}

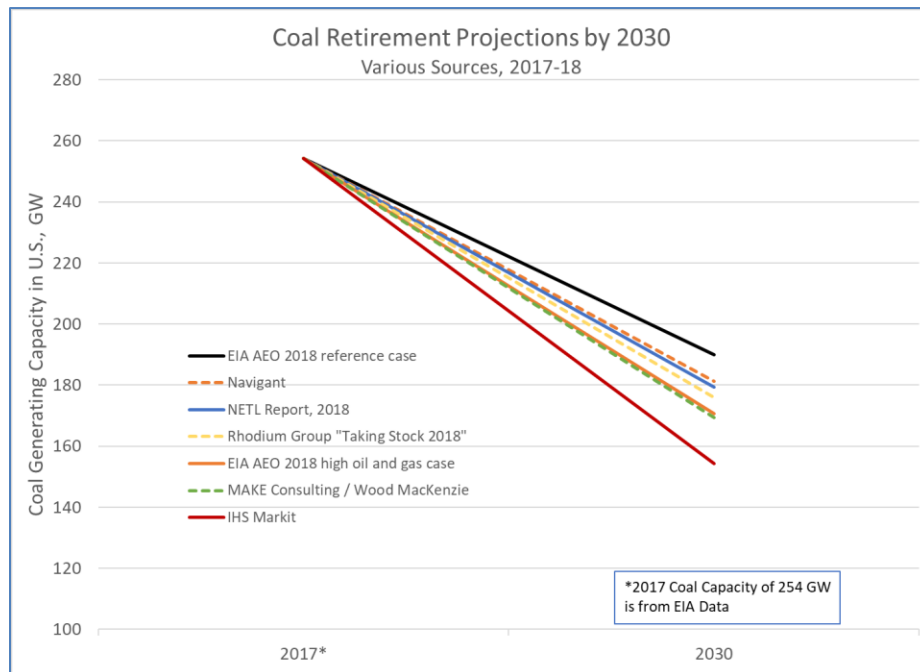


Figure 13. Coal Generation Retirements Projected through 2030^{lxv}

Figure 13 depicts various projections of coal generation from several analyses. Each year the predictions for coal plant retirements become more severe as awareness of the multiple factors and cumulative impacts of these factors are assessed. These very real factors lead to increased risk for coal-fired power plants, which must be managed against other pressures prompting a move away from coal.

Among the factors specifically influencing decisions to retain or retire coal generation assets are economics, unit age, unit size, impacts of load cycling, staffing, existing and future regulations and societal pressures.

Economic Pressures

The economic pressures on the power generation and distribution industry have created considerable uncertainty in financial decision-making regarding generating stations. Pricing curves tell the story well; pressure from low natural gas pricing is evident on average costs, as shown in Figure 14.

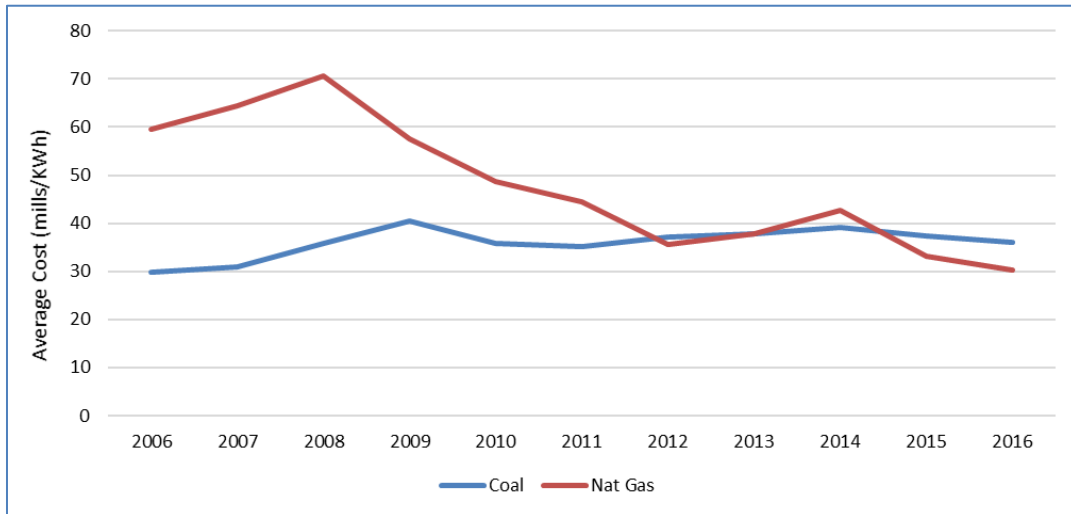


Figure 14. Average Power Plant Operating Expenses for Major U.S. Investor-owned Units

The EIA forecasts that U.S. natural gas prices to electric utilities will increase much more rapidly than coal prices. In its most recent Annual Energy Outlook (2018)^{lxvi}, EIA projects that natural gas prices to the electric power sector will increase at an annual average rate of 3.7% through 2050; whereas, for the same period coal prices will increase at an average of only 0.4%. In 2050, natural gas prices are forecast to be nearly five times as high as coal prices.

In the years to come, economic considerations associated with investments in aging assets will continue to exert pressure on generators to retire coal power plants. Recent years have seen reduced funding for O&M activities at coal-fired units, with little capital expended to replace aging equipment. As a result of these financial restrictions, many stations are now operating with limited redundancy in critical systems and deteriorating material conditions. This creates a situation where the rated capacity has not changed, but the reliability could be significantly less. If the U.S. plans to continue to rely on the existing coal fleet, the reliability and resiliency attributes will need to be compensated. Otherwise, uncertainty and other factors will lead to continued lower investment levels and reliance on these plants to continue to operate reliably, and at an only slight increase in O&M expenditures, is unrealistic. Thus, the flat operating expenses indicated by Figure 14 is likely unsustainable going forward.

Given competition with natural gas and that IRE resources dispatch ahead of firm, dispatchable plants, many coal plants are cycling. Increased cycling results in increased capital expenditures, increased O&M costs, increased outages and higher fuel consumption. The need for coal and other forms of dispatchable generation (e.g., nuclear) to backstop IRE poses an interesting conundrum when generators’ costs of operations increase for these cycled plants. When dispatched less, these coal and nuclear plants receive less investment, contributing to their decline.

Unit age, load cycling, staffing impacts and costs of existing and potential future regulatory compliance add further costs that cumulatively contribute to decisions to shutter the nation’s coal plants.

Unit Age

The projected age of the coal fleet in 2040, incorporating EIA 860 data from 2016, is shown in Figure 15. The average unit in 2040 will be 66 years old; many of these older units will presumably be retired prior to 2040. Other analyses have shown that the capacity factor for coal plants drops with age, with a steady loss that becomes more dramatic as the unit reaches 40 to 50 years of age. This age of the existing fleet as shown in Figure 15, as well as in projections by NETL showing that capacity factor shifts downward corresponding to age, with units losing at least 20% of actual capacity factor by age 51.^{lxvii} The additional maintenance costs and potential need for upgrades for these aging facilities are significant. Yet cost is not the only barrier. As addressed elsewhere in this report, New Source Review (NSR) requirements add additional burdens and barriers to improving efficiencies that could make coal plants more competitive.

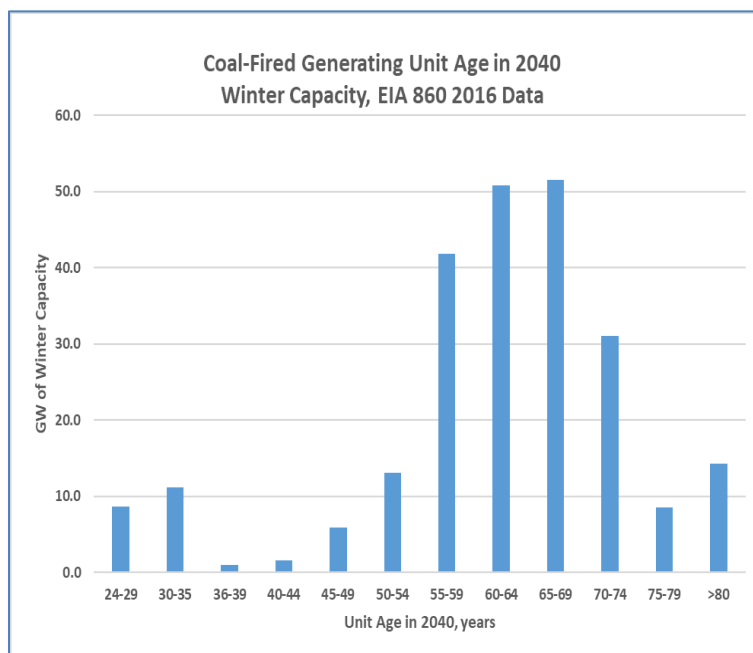


Figure 15. Projected Unit Ages in 2040 without Further Unannounced Retirements

With the challenging economics and uncertainty of environmental regulations' impact on coal plants, state regulated Investor Owned Utilities (IOUs) may have the opportunity to retire coal plants and replace the capacity with alternative generation, such as natural gas plants. This option could increase earnings opportunities for the IOUs, if earnings are based on its capital investment. With this incentive to shareholders, it is important that the IOUs and their regulators appropriately recognize the reliability and resiliency benefits of coal generation to the customers in its resource decisions.

Staffing Impacts

At utilities, the favorable career path was traditionally to work at plants for many years, or gain expertise and move among plants or upward to a corporate position. Today, this path is truncated or eliminated for early-career entrants. Desirable positions are shorter-term; many staff who have had the extensive exposure and training needed to run a plant are moved around.

The staff with broader expertise at plants are aging along with the plant equipment itself. Retirements of plant personnel and the associated loss of expertise is rampant, and this has direct impacts on quality of maintenance, plant knowledge and decision making. Strapped coal plant owners cannot afford to incentivize or retain staff, continually consolidating positions as attrition occurs, and cannot offer a promise of long-term positions at the many plants being evaluated for retirement. In addition to the challenges to staffing at plants, the scientists, researchers and engineers that will develop and deploy the next generation of coal technologies cannot be sustained without sufficient funding and continued commitment. Investment is needed to fill the pipeline of future works that will be needed to sustain the coal fleet as well as new technologies.

The status of industry staffing was studied several years ago showing that the expertise needed to keep these plants going has been an ongoing concern. For example, a National Academy of Sciences study published in 2013 concluded that most energy and mining industry workers were over age 45 and a retirement bubble was anticipated, all while recruitment of qualified entrants was already a challenge.^{lxviii} The loss of long-term staff who experience and then share the history of plant equipment, operations and problem solving is difficult to quantify. One impact is increased costs due to utilization of expert outsiders as in-house expertise decreases. Another impact is increased risk in the areas of environmental compliance, safety and equipment reliability as redundancy of core knowledge dissipates. Both cost and risk are key factors driving decisions to retire these plants.

Regulations⁴

The regulatory environment for coal plants has become increasingly challenging over the past few decades and is a significant contributor to plant operating and maintenance costs. As the costs associated with regulatory compliance increase, coal plants become increasingly vulnerable for retirement. Among the regulations that continue to impose costs on coal plant operators are NSR, the Coal Combustion Residuals (CCR) rule⁵, and the Effluent Limit Guidelines (ELG). During the preparation of this report, EPA released its Affordable Clean Energy (ACE) plan, which focuses on inside-the-fence efficiency improvements to coal power plants rather than system wide changes that characterized the Clean Power Plan (CPP).^{lxix}

Protecting the environment is a core value of the utility industry, which has significantly reduced emissions over the past decades. Nonetheless, the combined impact of regulations that target coal plants is significant.

Societal Pressures

As discussed in Chapter 1 (Societal Considerations), over the last few years, shifts have occurred in public perception that have already had a major impact and will continue to have a dramatic impact on the grid in the future. Two areas are significant. One is the criticism of coal and lack of transparency as to the benefits of the electricity system's current dependence on this critical resource. The second is the perception that renewables, led by wind and solar generation, are able to reliably and cheaply provide 100% of U.S. electricity needs. The common theme between these two, which the Department of Energy could address, is the lack of transparency regarding the value of diversity and how various fuel sources actually fit into the grid both today and in the future.

In addition, low-emission technologies for coal – such as improved efficiency and carbon capture, use and storage (CCUS) – are not well understood by the general public. This results in a lack of support for these important technologies and, thus, slower development and deployment. However, CCUS on coal and gas has been shown to be a cost-effective approach to reducing emissions, especially when compared to IREs at higher penetration. For example, according to a study that compared different emission reduction options, a coal plant retrofitted with CCUS could reduce CO₂ emissions at a cost of \$66/ton CO₂ compared to reducing CO₂ through the use of high-penetration solar with battery backup at a cost of \$432/ton CO₂ – the most expensive of the options studied.^{lxx} Just as a diverse portfolio of electricity sources provides the most reliable, cost-effective operation, diversity in emission reduction strategies also provides the most cost-effective approach – including coal plants with CCUS.

⁴ A more expansive discussion of regulations impacting the existing U.S. coal fleet is included in Chapter 3. Policy.

⁵ See Appendix 2B for a discussion of the CCR rule.

Educating the general public about these low-emission options, the general value of diversity, the contribution that coal-fired generation currently provides to our energy security and quality of life and will continue to provide in our nation’s energy resource portfolio is a key approach that will enable a multi-stakeholder discussion on the path forward to maintain energy stability. Education and transparency are also key to the integration of IRE into the grid.

While the progress made by IRE sources is significant, the general public does not realize the extent of the challenges of integrating large quantities of undispachable energy into the grid, or the real costs of IRE. The recent announcements by companies like Apple and Google – that they are running their facilities off of 100% renewables^{lxxi} – has exacerbated this view and is leading to a race among companies to be able to make a claim of 100% renewables by utilizing power purchase agreements (PPA).

By presenting numbers based on “average energy produced” versus “actual energy consumed”, these trusted names are indirectly perpetuating the view that a grid operated on 100% IREs is readily achievable in the near-term, which it is not. The use of PPAs also does not account for the challenges in transporting electricity, in that they treat electricity produced in distant regions as if it is being consumed locally. In the end, the public is being led to believe that intermittency and non-local generation are not challenges for the grid.

The resulting public pressure on politicians to support growth of IREs and retirement of coal plants has unforeseen consequences (e.g., the deterioration and retirement of baseload and dispatchable power plants) that may not be apparent until it is too late to plan for an effective approach to system stability. Education and transparency regarding these issues could benefit energy policy and the public’s support for development and implementation of a viable path forward. A current example demonstrating these risks will be elaborated in the next chapter.

Repercussions

As noted earlier, U.S. residential and business consumers assume that the grid will operate reliably 24/7. Maintaining the grid’s day-to-day stability and its ability to recover from either natural or manmade disruptions, depends in part on the availability of dispatchable resources, such as coal. The cumulative impact of the many factors addressed in this chapter suggest that coal-fired generation faces a precarious future. At issue is how an energy portfolio without adequate dispatchable power is likely to impact grid resilience.

In acknowledgement of their growing concerns with resiliency, regional transmission organizations (RTOs) and independent system operators (ISOs) are now assessing their fuel security vulnerabilities and other grid-resilient attributes that impact resource adequacy.⁶ The future reliability and resilience of the nation’s power grid depends on assessing these many risk factors.

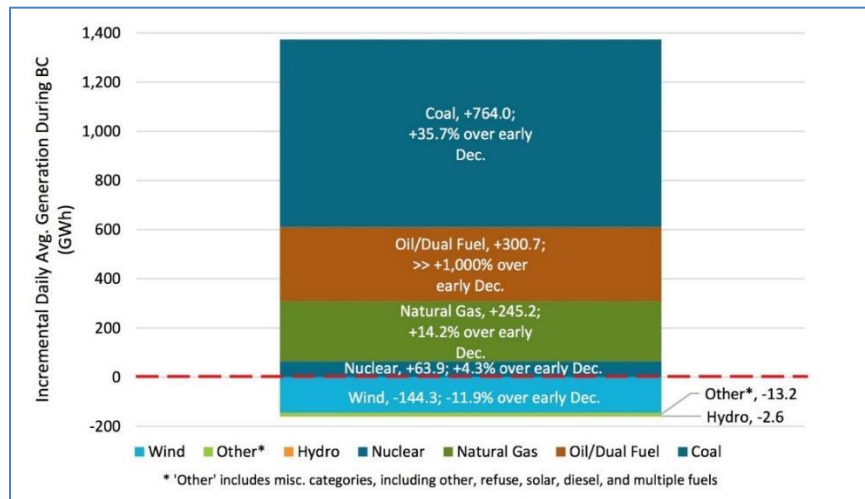
⁶ See Chapter 3 – Wholesale Electricity Markets.

High Impact – Low Frequency Events: Lessons Learned

In March 2018, the U.S. DOE National Energy Technology Laboratory (NETL) released a study entitled “Reliability, Resilience and the Oncoming Wave of Retiring Baseload Units, Volume I: The Critical Role of Thermal Units During Extreme Weather Events.”^{lxxii} The study fully documents how recent weather events (e.g., the Bomb Cyclone ‘BC’) make it clear that grid resilience is enhanced by coal and impaired by non-dispatchable generation such as wind and solar.^{lxxiii}

One of the compelling conclusions of the DOE/NETL report is that “Across the six ISOs, coal provided 55% of the incremental daily generation needed, or 764 out of 1,213 Gigawatt-hours per day (GWh/d)” and that “[d]uring the worst of the storm from January 5-6, 2018, actual U.S. electricity market experience demonstrated that without the resilience of coal- and fuel oil/dual-firing plants—its ability to add 24-hour baseload capacity—the eastern United States would have suffered severe electricity shortages, likely leading to widespread blackouts.”

Fuel-based generation resilience during the Bomb Cyclone, six ISOs



While statistics across all six impacted ISOs are impressive, the story of the largest impacted interconnection, PJM, is worthy of specific emphasis. DOE/NETL documented that:

*“In PJM, the largest of the ISOs, coal provided the most resilient form of generation, due to available reserve capacity and on-site fuel availability, far exceeding all other sources (providing three times the incremental generation from natural gas and twelve times that from nuclear units); **without available capacity from partially utilized coal units, PJM would have experienced shortfalls leading to interconnect-wide blackouts.**”*

The surge in coal accounted for 74% of incremental energy in PJM during the BC, with fuel oil providing 22%; other sources provided little to no surge capacity.

PJM output December 2017 - January 2018, average daily GWh

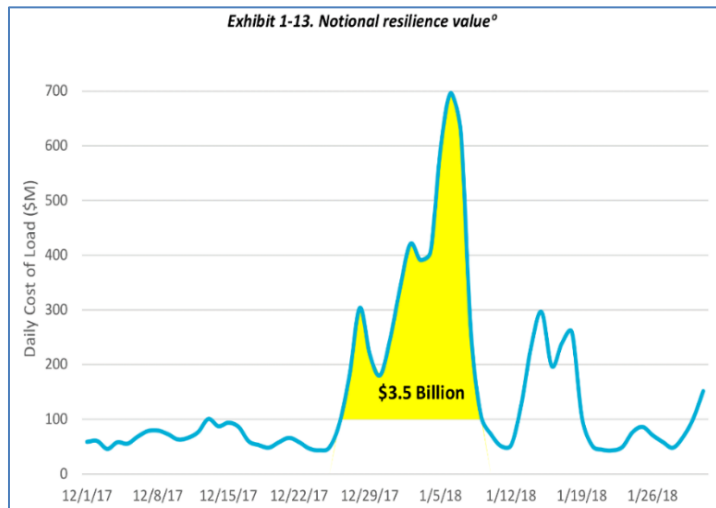
Fuel	12/1-12/26	12/27-1/9	Delta	Percentage Change	Share of Increase
Coal	746	1,113	367	49%	74%
Gas	607	619	12	2%	2%
Renewables	127	123	-4	-4%	-1%
Nuclear	846	851	5	1%	1%
Oil	2	111	109	455%	22%
Total	2,328	2,817	496	21%	100%

The resilience benefits imparted to the PJM market were so significant, in DOE/NETL’s opinion that PJM could not have survived this event without coal. Specifically, DOE/NETL concluded:

*“In the case of PJM, it can also be shown that the demand could not have been met without coal. At peak demand, January 5, 2018, natural gas prices exceeded \$95/MMBtu in eastern PJM. **Had coal been removed, a 9–18 GW capacity shortfall would have developed, depending on assumed imports and generation outages, leading to system collapse.**”*

Importantly, DOE/NETL’s analysis assessed the economic value of the energy resilience that coal provided during the Bomb Cyclone:

*“The value of the resilient coal- and oil-fired generation can be quantified by integrating over the term of the BC. The increase in the cost of energy services over the two-week period from December 27 to January 9 was \$288M per day, equivalent to \$98 per MW, compared with costs from the preceding two-week period, and \$225M per day, or \$73 per MW, higher than the following two-week period that featured a short return of extreme cold. This, in effect, represents a **value of resilience, which, during the BC, rose to \$3.5 billion.**”*



Chapter 3: Measures to Optimize Diversity & Resiliency

Key Findings – Chapter 3

- **Opportunities exist to streamline, re-evaluate, amend and implement regulatory and legislative measures to enable the U.S. existing coal fleet to operate more efficiently and effectively. Among the measures to be considered: reforms of NSR, PURPA, CCR and ELG regulations; tax credit support; and streamlined permitting for CCUS initiatives.**
- **Wholesale electricity market reform is needed to equitably value resilience as well reliability attributes. Various out-of-market subsidies and mandates put coal at a competitive disadvantage and fail to acknowledge coal’s role in providing fuel security and other benefits supporting grid stabilization.**
- **There are many technology options available to improve the competitiveness of the existing U.S. coal fleet. These technologies can lower the cost of fuel, increase coal quality, improve plant efficiency and flexibility, reduce the costs of environmental retrofits, advance carbon capture and the beneficial use of CO₂ and support the deployment of new products from coal and coal byproducts.**

Introduction

Secretary Perry requested that the NCC identify measures that could be taken to optimize the U.S. existing coal fleet to enable it to continue providing reliable, resilient and affordable power. In this chapter, actionable measures are detailed in the areas of policy, wholesale electricity markets and technology. No one area is more important; immediate, proactive engagement in each of these three areas is needed to optimize U.S. coal plants.

Policy Considerations

Opportunities exist to streamline, re-evaluate, amend and implement regulatory and legislative measures that will enable the U.S. existing coal fleet to operate more efficiently and effectively.

New Source Review

As noted in the National Coal Council report “Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies” (November 2015), “the uncertainties created by NSR rules, their enforcement by the EPA, and the prohibitive cost of administering NSR compliance have created strong disincentives to the widespread deployment of efficiency improvements.”^{lxxiv}

Recent regulatory initiatives at EPA and legislative proposals in Congress have the potential to eliminate regulatory uncertainty and reduce litigation risks for utilities seeking to implement energy efficiency measures at their coal plants. Several other benchmarks are also provided regarding the preliminary applicability tests for NSR.^{lxxv}

EPA Action. On August 21, 2018, EPA released its Affordable Clean Energy (ACE) plan. This proposed plan aims to reduce emission by relying largely on efficiency improvements that can be made to the existing fleet of coal units. To alleviate concern around some of these efficiency improvements triggering NSR, EPA has proposed permitting changes to the NSR permitting program. For example, EPA has proposed to use an hourly emissions rate to determine if an increase in emissions has occurred as part of a change to a power plant.

Legislative Initiatives. To better understand and respond to concerns related to the NSR program, the U.S. House of Representatives' Energy and Commerce's Subcommittee on the Environment recently held two hearings. In February 2018, the Subcommittee conducted a hearing entitled, "New Source Review Permitting Challenges for Manufacturing and Infrastructure."^{lxxvi} The background memorandum for the hearing explained that "an existing facility is required to obtain an NSR permit in order to perform efficiency upgrades or to install new pollution control technologies. However, since many existing facility owners are not willing to undergo the lengthy and uncertain NSR permitting process, they are effectively foregoing the opportunity to increase the efficiency of their facility, while also reducing emissions." The hearing detailed concerns relating to when a project should be subject to the NSR permitting process based on the computation of an "emissions increase."

To discuss possible legislative text to resolve uncertainty, the Subcommittee conducted a second hearing in May 2018, entitled, "Legislation Addressing New Source Review Permitting Reform."^{lxxvii} During that hearing, a discussion draft of proposed legislation detailed possible amendments to the NSR program. The proposed statutory text is narrowly focused to further define "modification" and resolve issues related to "routine maintenance, repair, and replacement". To reduce significant delays in permitting, the proposed amendment to the definition of "modification" would not apply to projects that implement efficiency measures which reduce the amount of any air pollutant emitted by the source per unit of output. The proposed statutory text also limits the emissions increases to the maximum achievable hourly emission rate demonstrated in the last ten years.

In their testimony on the proposed legislation at the May Congressional Subcommittee hearing, Ross Eisenberg, National Association of Manufacturers (NAM) and Jeffrey Holmstead, Bracewell LLP highlighted how NSR has led to the continued retirements of coal-fired power plants. Eisenberg stated that:

"An inability to define what is 'routine maintenance' has resulted in NSR Notices of Violation being issued for environmentally beneficial projects like economizer replacement, steam turbine upgrades, feed water heater replacements, and similar activities. In comments to the EPA's draft Clean Power Plan, the Utility Air Regulatory Group (UARG) cited more than 400 instances in which a regulated entity took on a project to improve the energy efficiency of a power generation unit, only to be targeted by the EPA or citizen suits alleging that it had violated NSR."

Holmstead's testimony demonstrates the need for clarity around the term major modification.

"The question of what is a 'major modification' that triggers NSR at an existing source has been the source of much controversy and is discussed in several EPA regulations, more than a thousand pages of guidance documents and Federal Register notices, and dozens of court cases – and there is still much uncertainty about how to determine whether something is a major modification. This is important to industry because, if a company makes a 'major modification' to a facility, the cost of going through NSR, and the delays it can cause, are very substantial. In some cases, companies that have undertaken a \$500,000 project that, according to EPA, is a 'major modification' that would force them to spend hundreds of millions of dollars in new control equipment. Even without the cost of new equipment, the time it takes to go through the NSR permitting process can be very long – about a year on average but, in some cases, many years. Because of the cost and delays, companies are very reluctant to do anything that might trigger NSR."

Tax Credits

Various tax credits have been proposed or passed that could provide support for the existing U.S. coal fleet.

Operation & Maintenance Tax Credits. Three bills have been introduced in Congress in 2018 that would provide a temporary tax credit to cover a portion of operation or maintenance expenses for existing coal-fired power plants. These bills have been introduced by Representative Larry Bucshon (Electricity Reliability and Fuel Security Act, H.R. 5270), Senator Shelley Moore Capito (Electricity Reliability and Fuel Security Act, S. 2677) and Senator Joe Manchin (Energy Reliability Act of 2018, S. 2681).^{lxviii} Offsetting a small portion of O&M expenses for the existing coal fleet is estimated to prevent the retirement of as much as 24,000 MW of coal-fired generation.

All three bills amend the Internal Revenue Code to provide a tax credit to offset a portion of the O&M expenses for existing coal-fired power plants. The purchase of coal for fuel does not qualify as an O&M expense under any of the bills. The tax credit is equal to either 30% of the plant's annual O&M expenses or \$13 per kilowatt of installed (nameplate) generating capacity, whichever is less. As proposed, the tax credit is available for tax years beginning 2018 and ending before 2023. The tax credit is transferrable under all three bills, although the two Senate bills include provisions – with slightly different language – that allow the tax credits to be transferred by any taxpayer, including rural cooperatives and municipal utilities, to certain eligible partners who can then claim the credits. The House bill limits transferability to rural cooperatives and municipal utilities but not all taxpayers.

45Q Implementation & Synergistic Policies to Enhance Implementation. On February 9, 2018, Congress passed and the President signed into law the 2018 Bipartisan Budget Act. Section 41119 amends the existing federal tax credit for CO₂ sequestration under §45Q (45Q) of the Internal Revenue Code (26 U.S.C. §45Q).^{lxxxix} Section 41119 contains the text of S. 1535, the “Furthering Carbon Capture, Utilization, Technology, Underground Storage, and Reduced Emissions Act of 2017” (“FUTURE Act”).

As detailed by the Carbon Capture Coalition,^{lxxx} key provisions of the FUTURE Act modify the existing 45Q tax credit in the following ways:

- Increases the credit value incrementally over 10 years from \$10 to \$35 per metric ton of CO₂ stored geologically through enhanced oil recovery (EOR) and from \$20 to \$50 per metric ton for saline and other forms of geologic storage.
- Provides \$35 per metric ton for CO₂ captured and put to beneficial uses beyond EOR that reduce lifecycle emissions.
- Authorizes the program for carbon capture projects that commence construction within six years from enactment; projects meeting that timeframe can claim the credit for 12 years from being placed in service.
- Reduces the minimum eligibility threshold for qualified facilities from 500,000 metric tons of CO₂ captured annually to 100,000 metric tons for industrial facilities and 25,000 metric tons for CO₂ captured and put to beneficial uses other than EOR. Retains the 500,000 metric ton eligibility threshold for electric generating units.
- Awards the credit to the owner of the carbon capture equipment and allows transfer of the credit to other entities responsible for managing the CO₂ to provide greater flexibility for companies with different business models to utilize the tax credit effectively, including cooperatives and municipal utilities.

Tax data are non-public, making any assessment of 45Q’s utilization by the existing coal fleet subject to substantial uncertainties. To date, only one coal-fired power plant in the U.S. has retrofitted CO₂ capture technology – the PetraNova project in Texas. Regardless of 45Q, retrofitting CO₂ capture technology to an existing coal plant involves resolution of a remaining host of CCUS-related technical, economic and policy issues. In 2012, the IEA concluded that only approximately 29% of the then existing installed global coal-fired fleet could potentially be retrofitted with CCUS for a variety of reasons, including plant age.^{lxxxix} For these and related reasons, some experts believe that in the absence of other incentives the amended 45Q is more likely to be used by industrial facilities with relatively pure CO₂ sources, such as ethanol plants, refineries and ammonia producers.^{lxxxii}

A recent analysis suggests that the amended 45Q could spur the construction of new coal plants by enabling them to bid “negative” into wholesale markets, based on a variety of assumptions.^{lxxxiii} In the meantime, a number of legislative proposals currently under consideration would complement and may further incentivize utilization of the 45Q tax credit for existing coal plants. The Carbon Capture Coalition notes that “While recent congressional extension and reform of the 45Q tax credit provides the most important federal incentive for encouraging private investment in carbon capture deployment, additional federal incentives would complement 45Q and enable more capture projects to become commercially feasible, thus accelerating deployment across multiple industries.”

Business Structures to Support 45Q. Federal legislation that would support 45Q use include initiatives to make carbon capture projects eligible for tax-exempt private activity bonds (PABs) and master limited partnerships (MLPs). PABs would allow developers of carbon capture projects access to tax-exempt debt to help finance their projects, thus lowering their capital costs. The Carbon Capture Improvement Act of 2017 (S. 843)^{lxxxiv} makes carbon capture projects eligible for PABs and has been introduced in the U.S. Senate by Senators Rob Portman (R-OH) and Michael Bennet (D-CO), and in the U.S. House of Representatives by Congressmen Carlos Curbelo (R-FL) and Marc Veasey (D-TX).

The MLP structure combines the tax benefits of a partnership with a corporation’s ability to raise capital in public markets. Thus, allowing carbon capture projects to be MLPs would reduce the cost of equity and provide access to capital on more favorable terms. The MLP Parity Act of 2017 (S.2005)^{lxxxv} would provide this eligibility and has been introduced in the U.S. Senate by Senators Chris Coons (D-DE) and Jerry Moran (R-KS) and in the House by Congressmen Ted Poe (R-TX) and Mike Thompson (D-CA).

In its Policy Parity report, NCC supported the application of PABs and MLPs to advance the deployment of CCUS.^{lxxxvi}

48A Investment Tax Credit. In 2005, Congress established an investment tax credit or “Credit for Investment in Clean Coal Facilities” in the Energy Tax Incentives Act (ETIA) of 2005. ETIA authorized \$1.3 billion in tax credits to support advanced coal-based generation technology that meets specific SO₂, NO_x, PM and mercury emission limits and that is:

- 1) An Integrated Gasification Combined Cycle (IGCC); or
- 2) A new unit meeting design heat rate requirements based on coal type of about 40%; or
- 3) An existing unit meeting a design heat rate requirement based on coal type, minimum of which is 35%, plus a 4 to 7 percentage point improvement in efficiency (depending on coal type) with the addition of new equipment compared to previous operations.

To be eligible, an advanced coal-based generation technology must meet both the emissions levels and efficiency requirements, unless it is an IGCC which is exempt from the efficiency requirements. In 2008, Congress provided an additional \$1.25 billion in tax credits through the Energy Improvement and Extension Act (EIEA) of 2008, or the “Expansion and Modification of Advanced Coal Project Investment Credit,” which increased the value of the tax credit to 30% of the eligible investment and imposed a new requirement to capture and store at least 65% of the CO₂ in order to be eligible for the tax credits. However, the heat rate requirements from the 2005 statute were not adjusted when the CCUS requirement was added to the 2008 bill. Adding CCUS equipment to a new or existing unit results in an efficiency loss to the generating unit, as auxiliary power (as steam and electricity) is needed from the unit to power the CO₂ capture system.

It is important to note that problems with the requirements of the 2008 statute are not limited to specific units. The efficiency requirements would make most CO₂ capture retrofits to an existing unit ineligible. In its current form, the tax credit does not incentivize CCUS on new or existing coal plants in the near term, which is a lost opportunity and, if changed to accomplish Congress’ intent of reducing emissions, could support CCUS projects on the existing fleet of coal-fired power plants. Relative to other potential policy levers discussed in this section, 48A may be more easily achieved as the funding has been appropriated and the program is already in existence.

Land Use Policies Related to Carbon Storage and Utilization

CO₂ storage resources in the U.S. are large (see Figure 16). The National Energy Technology Laboratory (NETL) estimates that saline formations could store from 2.4 to 21.6 trillion metric tons of CO₂ (MTCO₂). In oil and gas reservoirs, storage potential ranges from 185 to 230 billion MTCO₂.^{lxxxvii} Unminable coal areas could provide an additional 50 to 110 billion MTCO₂. Annual emissions from of the current coal-fired power plant fleet were about 1241 MTCO₂ in 2016.^{lxxxviii}

In West Texas and the Rocky Mountains, CO₂ flooding for EOR currently produces about 200,000 barrels (bbl) of oil per day.^{lxxxix} In a Senate Environmental and Public Works Committee hearing last year it was noted that carbon capture and storage (CCUS) faces bigger financial obstacles than technical ones if it is to spread beyond EOR. Committee Chair John A. Barrasso (R-Wyo.) indicated that CCUS and EOR should play an important role in a true “all of the above” energy strategy. “We have a win-win situation with CO₂-enabled oil recovery. We have the potential to make it economical to extract more than 60 billion bbl of oil in this country.”^{xc}

Several plants in the existing coal fleet are either located on federal and/or tribal lands, or have reasonably proximate access to the same. At least one of DOE’s CarbonSAFE^{xc} projects is located in Wyoming, a state with significant federal lands as well as tribal lands. As a result, the facilities could potentially benefit if the relevant authorities enacted CO₂ storage laws and regulations for these resources.^{xcii}

A 2009 DOE study concluded that the storage resource beneath Federal lands ranges between 126 and 375 billion metric tons, with the bulk of that west of the Mississippi River – specifically Montana, Wyoming and the Dakotas.^{xciii} Other benefits of storing CO₂ under federal lands include only having to deal with one landowner. This approach is no panacea, though, as utilization of federal lands comes with a host of regulatory restrictions, including but not limited to application of the National Environmental Policy Act (NEPA).

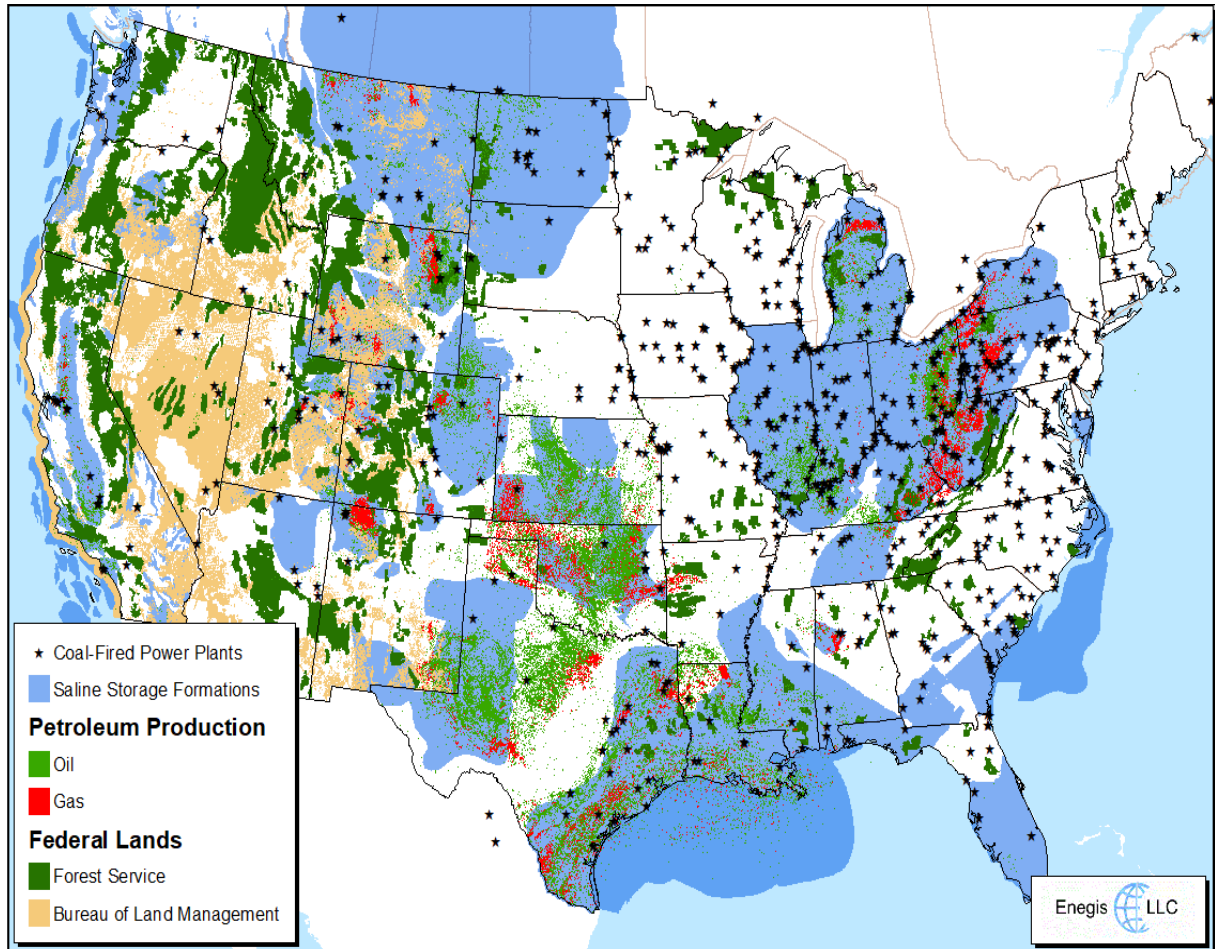


Figure 16. Location of Potential CO₂ Storage, Oil and Gas Production, and Coal-Fired Power Plants

Congress has never enacted a law that provides a regulatory framework for CCUS on public lands, nor has the U.S. Department of the Interior (DOI) published relevant regulations or guidance. There is no leasing program or established guidance, for example, on obtaining CO₂ injection and storage rights into federal pore space. The situation is better for pipelines, as the Bureau of Land Management (BLM) has authority to issue rights of way (ROW) for CO₂ pipelines pursuant to the Mineral Leasing Act (MLA); pipeline developers receiving a ROW pursuant to the MLA are required to operate the pipeline as a common carrier. The United States Geological Survey (USGS) also has developed a methodology to assess storage capacity in oil and gas reservoirs and saline formations.^{xciv}

Public Utility Regulatory Policies Act of 1978 Reform

The increasing pressure to reform the 1978 Public Utility Regulatory Policies Act (PURPA) is in response to changes in the 21st century electricity landscape compared with the energy crises that defined the 1970s. The overarching goal of PURPA was to promote energy conservation and the production of alternative sources of energy, including renewable energy. Efforts to reform or modernize PURPA focus on both regulatory reform for which FERC has authority, and more substantive reform that would have to be authorized by Congress. Rep. Tim Walberg (MI) has filed a bill (H.R. 4476), PURPA Modernization Act of 2017, and Congressional testimony took place in January 2018, before the U.S. House of Representatives Subcommittee on Energy.^{xcv} Senator Barrasso (WY) has also introduced a PURPA reform bill (S. 2776).^{xcvi}

To help achieve the alternative and renewable energy goals, PURPA established a new class of generating facilities – qualifying facilities (QFs). QFs were grouped into two categories – small power production facilities and cogeneration facilities. Small power production facilities are those hydro, wind, solar, biomass, waste or geothermal facilities producing 80 MW or less. A cogeneration facility produces electricity and another form of thermal energy such as heat or steam. PURPA required electric utilities to purchase power produced by QFs, a requirement referred to as the mandatory purchase obligation. Utilities were required to purchase this power at the utility’s avoided cost – the cost the utility would incur if it were to generate the power itself or purchase from another source. States have discretion in interpreting and determining avoided cost, and thus there is not a consistent rate across the country.

When PURPA was enacted, wholesale electricity markets did not exist, oil made up a large share of the electricity generation portfolio, electricity demand was growing and renewable energy technologies were nascent. The 1970s energy scenario looks nothing like today’s electricity landscape. Competitive power markets have emerged and most areas of the country no longer have capacity constraints as a result of abundant natural gas resources, declining costs of renewable technologies and flat or declining customer demand for electricity. In addition, many states’ policies mandating RPS have had a significant impact on the growth in renewable generation.

The key problem for existing electric generators is PURPA’s mandatory purchase obligation of QF resources using long-term contracts at the utility’s forecasted avoided costs. This leads to new unneeded resources coming on line, potentially resulting in prioritizing non-dispatchable resources at the expense of existing fossil resources. The National Association of Regulatory Utility Commissioners (NARUC) has proposed that FERC adopt regulations that base power purchased from a QF on competitive solicitations or market clearing prices, rather than use the current administratively determined avoided cost.^{xcvii} FERC has already indicated its willingness to look into regulatory changes — including reform of the so-called “one-mile” rule that has inadvertently allowed large renewable developers to disaggregate their projects into several QFs to avail themselves of the mandatory purchase obligation.

PURPA reform would more realistically reflect today's electricity landscape and ensure utilities are not forced to purchase power they do not need.

Coal Combustion Residuals

In 2015, EPA finalized new rules for coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA). The rules set standards for existing CCR impoundments and require closure of ash ponds found to be contaminating groundwater. Ash ponds or landfills must be closed if they lack structural integrity or are in sensitive locations. The CCR rule imposes high costs on certain disposal sites. The rule may drive units to retire as the compliance costs become prohibitive, adding to the cost of generation, or their disposal facility is forced to close, and the alternatives are too expensive.

While EPA considered the direct costs to utilities associated with the 2015 CCR regulations, the indirect impacts to the U.S. construction materials and infrastructure markets are having inflationary impacts on state and federal highway budgets, since cement substitution with fly ash pozzolans is reduced due to lack of availability or substantial price increases associated with added transportation costs. In the case of beneficial use of fly ash as a substitute for manufactured cement, the CO₂ reductions achieved are also a factor to be considered in rulemaking procedures. Since fly ash use in concrete usually offsets cement imports, the value of CCRs as a construction material helps meet the objectives of RCRA in resource conservation and recovery to assist in the U.S. balance of payments.

In March 2018, EPA proposed Phase 1-Part 1 revisions to the 2015 CCR rule, estimating that the proposed changes would save the regulated community between \$31 million and \$100 million per year. EPA finalized the first set of revisions in July 2018, noting that these will provide utilities and states more flexibility in how CCR is managed, and estimated that these provisions would save \$28 to \$31 million a year in regulatory costs. This revision would:

- Extend the life of some existing ash ponds from April 2019 until October 2020;
- Empower states to suspend groundwater monitoring in certain cases;
- Allow state officials to certify whether utilities' facilities meet adequate standards.

In addition, EPA plans to propose other Phase 2 reconsideration changes to the 2015 coal ash rule later in 2018 for finalization in 2019. A detailed discussion of the rule's impacts on coal plants and associated costs are presented in Appendix 2C.

Effluent Limitation Guidelines

The Clean Water Act directs EPA to establish effluent limitations guidelines and standards (ELGs) to control discharges of pollutants to surface waters. These standards are set based on the performance of available, demonstrated technologies, although facilities are not required to use those technologies and may instead use alternative approaches to comply. ELGs represent a minimum expected level of control, implemented through an individual plant's National Pollutant Discharge Elimination System (NPDES) permits for direct dischargers, establishing pretreatment standards that must be met before wastewater can be discharged to publicly owned treatment works (POTWs). The ELGs promulgated by EPA cover discharges of certain water streams produced within a coal-fired power plant, notably flue-gas desulfurization (FGD) wastewater, ash transport water and CCR leachate. The new ELGs are implemented by incorporation into NPDES permits as these permits are renewed and through local pretreatment programs.

For FGD wastewater, numerical limits were initially set for discharge of As, Hg, Se and NO_2+NO_3 . For ash transport water (including both fly ash and bottom ash), the ELGs mandate zero discharge. In September 2017, EPA suspended limits and pretreatment standards for bottom ash transport water and FGD waste water for two years, pending a review. EPA has indicated that they will propose an updated rule by December 2018, with a final rule by December 2019. The earliest compliance date would be in November 2020.

Plants are already faced with closing ash ponds as part of the CCR rule. The ELGs add the possibility of adding a wastewater treatment module to the FGD discharge stream, if the plant plans to continue discharging this stream. The numerical limits on FGD wastewater discharge are critical in the determination of the potential costs of wastewater treatment. In some cases, for example, very low levels of selenium in wastewater discharge can only be attained by costly secondary treatment processes such as biological reactors.

Water-Energy Nexus

The term “water-energy nexus” refers broadly to the necessary role that water plays in the extraction of energy on the one hand and the role that electricity plays in the extraction, treatment and distribution of water on the other. When water is “used” it can be reused quickly or after some form of treatment; when water is “consumed” it is not immediately available for another use. For example, water use includes a power plant withdrawing water from a supply, using it as cooling water in the plant's operation, and then reintroducing it back into a water supply. Water “consumed” is the water that is evaporated in the process and not directly reintroduced into the water supply.

Of the two most common cooling options for thermoelectric power plants, once-through and tower cooling, the latter typically “uses” 5% of the water used by the former, but consumes approximately 50% more total water.^{xcviii} In line with these consumption rates, one regulator’s default water consumption rate for coal- and natural gas-fired generation using once-through cooling systems is 0.35 gallon/kilowatt-hour (g/kWh). Comparatively, the cooling rates for coal-fired generation using tower cooling is 0.60 g/kWh and for natural gas-fired simple-cycle generation is 0.70 g/kWh.^{xcix}

A common misconception associated with the water-energy nexus is that shifting fuel sources or reducing electric demand will have a dramatic impact on water consumption. The data do not support this conclusion when set in context of other aspects of the water use and consumption picture. For example, the average American household requires 29 kW of power per day.^c To produce this much power, a typical once-through cooled steam electric power plant will consume 9½ gallons of water.^{ci} This is far less than the average household’s daily water use for showers (47 gallons), toilet flushing (75 gallons) or outdoor watering (120 gallons).^{cii}

Furthermore, electricity generation has been able to historically absorb large population increases without increasing water consumption. This is due mainly to new technologies and increased efficiencies that are able to reduce or maintain water use/consumption, while meeting increasing demand. Nationwide, since 1975, water withdrawals for thermos-electric power have essentially flat lined while population has increased by just shy of 100 million.^{ciii} Consumption rates have also significantly dropped from almost 50,000 gallons/MWh in the 1950s, to a rate of close to 15,000 gallons/MWh presently.^{civ}

As the U.S. continues to grow and its demand for water and energy grow along with it, knowledge and awareness about the water-energy nexus are likely to grow as well. This evolution has already led to increased awareness of the water-energy nexus and has proven to be a great enhancement of water planning processes around the nation. On the electric generation front, a better appreciation of the efficiencies already achieved in the electric generation sector and the relatively minor role that electricity production plays in the U.S.’ overall water consumption will hopefully keep the water-energy nexus from being further distorted.

Wholesale Electricity Markets

According to FERC, “Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest ... Utilities in these markets are frequently vertically integrated ... While the industry had historically traded electricity through bilateral transactions and power pool agreements, FERC Order No. 888 promoted the concept of independent system operators (ISOs) ... Along with facilitating open-access to transmission, ISOs operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants. In FERC Order No. 2000, the Commission encouraged utilities to join regional transmission organizations (RTOs) which, like an ISO, would operate the transmission systems and develop procedures to manage transmission equitably. Each of the ISOs and RTOs have energy and ancillary services markets in which buyers and sellers could bid for or offer generation. The ISOs and RTOs use bid-based markets to determine economic dispatch ... Two-thirds of the nation’s electricity load is served in RTO regions.”^{cv}

The U.S. has seven ISO/RTOs: ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), the Electric Reliability Council of Texas (ERCOT), and the California ISO (CAISO) (see Figure 17).

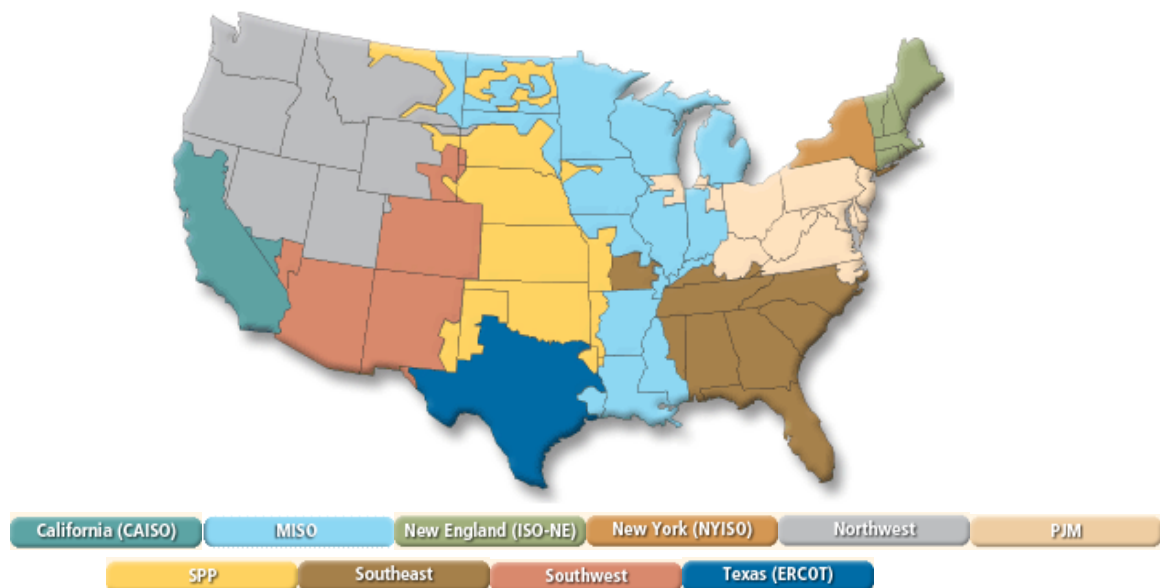


Figure 17. U.S. ISOs and RTOs^{cvi}

These ISO/RTOs were designed primarily to maintain competitive markets, low electricity prices and transmission reliability. They were not designed to ensure resilience, fuel diversity, or fuel security.

ISO/RTOs have a major effect on the nation’s coal fleet because some 164,000 megawatts (MW) of coal-fired generation — almost two-thirds of the fleet — are located in ISO/RTO footprints. Almost all of this coal-fired capacity is located in four regions: MISO’s footprint includes 63,000 MW; PJM 60,000 MW; SPP 26,000 MW; and ERCOT 15,000 MW. (The coal fleet in these four wholesale markets consumed some 460 million tons of coal in 2017, almost two-thirds of U.S. coal demand.) As a consequence, ISO/RTO market policies affect the competitiveness and economic viability of the coal fleet.

For a number of reasons, including market policies, 45,000 MW of coal-fired generating capacity in ISO/RTO regions have retired.^{cvii} An additional 17,000 MW in these regions are slated to retire over the period 2018 through 2020, of which 12,000 MW have been attributed to market conditions.^{cviii} The regions with the most retirements through 2020 are PJM (32,000 MW); MISO (14,400 MW); ERCOT (5,700 MW); and SPP (4,400 MW).

Compensation in Wholesale Markets

Generally, ISO/RTOs provide compensation to electricity generators for capacity, energy, and essential reliability services (frequency regulation, voltage support and reactive power). However, ERCOT and SPP do not have capacity markets.

The existing coal fleet is competing with natural gas in many of these markets. In addition, various out-of-market subsidies and mandates can put dispatchable sources, such as coal, at a competitive disadvantage. For example, wind and solar will have received \$36.5 billion in tax credits alone over the five-year period 2016–2020, according to the Joint Committee on Taxation.^{cix,7} Wind and solar benefit from a Federal PTC. In the case of wind, the PTC allows wind energy sources to bid into markets at a zero or negative cost that suppresses prices for other electricity resources and increases the need for load following and ramping from coal units. Without the PTC, coal units might be dispatched more frequently, potentially reducing the amount of retirements.

The economic value of the PTC for renewable energy projects is significant as is evident in a recent decision regarding what was to be the largest wind farm in the U.S. In late July 2018, American Electric Power (AEP) cancelled its \$4.5 billion Wind Catcher project when the Texas Public Utility Commission denied its approval saying it would not benefit Texas ratepayers. According to news reports,^{cx} the project required timely approvals from jurisdictions in Arkansas, Louisiana, Oklahoma and Texas in order to complete the project by 2020 and qualify for 100% of the Federal PTC.

In addition to tax benefits such as the PTC, 29 states have renewable portfolio standards requiring that specific percentages of electricity sales come from renewables as detailed in Chapter 1. These percentages range from 10% in Wisconsin to 100% in Hawaii.

⁷ For a more expansive Analysis of Federal Expenditures for Energy Development, 1950-2016, see <http://misi-net.com/publications/EnergyIncentives-0517.pdf>

There are other out-of-market subsidies that disadvantage the coal fleet. For example, within PJM's 13-state footprint, 4 states — Northern Illinois, Pennsylvania, New Jersey and Ohio — have adopted or considered zero-emissions credit policies to subsidize existing nuclear plants. Subsidies allow renewable and nuclear generators to enter capacity auctions at prices below their operating costs, pushing down overall market prices and sometimes leading to power plant retirements.

FERC Action

There are many actions that could be undertaken by the Federal Energy Regulatory Commission (FERC) to ensure that the services provided by the U.S. fleet of coal-fired power plants are appropriately valued. FERC has evaluated price formation issues in competitive markets for nearly a decade. In 2014, FERC initiated a proceeding (Docket No. AD14-14-000) to examine price formation in organized markets to ensure that pricing rules established in regional transmission organization (RTO) and independent system operator (ISO) markets would satisfy four objectives: “(1) maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.” Subsequently, FERC directed each RTO/ISO to publicly provide a report regarding five price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency.^{cxix}

Since that order, FERC has continued to evaluate these issues in a number of different proceedings, most notably in Order No. 825, FERC revised “its regulations to address certain practices that fail to compensate resources at prices that reflect the value of the service resources provide to the system, thereby distorting price signals, and in certain instances, creating a disincentive for resources to respond to dispatch signals.”^{cxix} Despite FERC’s action to date, price formation and market issues continue. As FERC further examines these issues, some of the proposed policy options include:

Price Formation. Among the policy options proposed by various organizations, FERC could examine and refine price formation in the RTO’s through rulemaking or ordering tariff changes by the respective RTOs/ISOs. Potential considerations include:

- Allowing fuel-secure resources to set the locational marginal price when running (even if operating at their economic minimum operating levels).
- Eliminating negative pricing.

- Minimum Offer Price Rule (MOPR): Establishing a price floor for fuel-secure resources in the energy or capacity markets. A price floor would guarantee that these resources are paid a rate that is adequate to cover their costs. Specific mechanisms could be developed in the individual markets so that they would be responsive to local needs and integrated with other policy goals.
- Requiring the value of tax and other subsidies to be imputed into the market bids of subsidized resources, thereby ensuring that subsidized entities are bidding at their actual unsubsidized cost.

Essential Reliability Services. FERC could ensure there are proper standards (building off of current NERC reliability standards and guidelines) and just and reasonable compensation for reactive power, frequency response and other ERS that support grid operations. Indeed, FERC has recently touched on this issue in Order No. 842, where it required “**new** large and small generating facilities, including both synchronous and non-synchronous ... to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.”^{cxiii} In addition, FERC should consider whether there are additional ERS that will be needed to support the grid with increased IRE penetration.

Capacity Market Reforms. Current capacity markets were not structured to value externalities such as resiliency or environmental attributes. As a result of recent regulatory and market trends, some traditional capacity resources are not clearing the market. There are several potential mechanisms that FERC could consider to rectify this:

- Fuel Security Value Curve or reforms to the clearing of resources in capacity auctions based on onsite fuel characteristics or technology type.
- Consider a separate market construct that would incentivize capacity resources that have onsite fuel or dual-fuel supplies.

Forward Resiliency Market. Regions could conduct an auction-type program to ensure that each market has sufficient onsite fuel to supply the MWh of production needed over a specific period. In another vein, the Commission could implement new products in the markets, such as a product that compensates units for ramping or flexibility, or a “stand-by” product that would compensate resources for staying online.

Demand Response Compensation Reform. FERC could consider how overcompensating demand response resources may distort the generation mix and act appropriately.

Specific Market Reforms

There have been increasingly serious discussions in energy policy circles about resilience because of the continuing retirement of large amounts of coal-fired and nuclear generation, both of which provide fuel security and essential reliability services. While coal-fired generation receives the same compensation as other generators for ERS, coal-fired units are not compensated for the increased operating costs associated with being dispatched to provide load following and ramping services.

Fuel security is important to resilience because it enables the grid to absorb and recover quickly from manmade or natural disturbances that could have potentially disastrous consequences. Markets compensate reliability attributes, but not resilience attributes, such as fuel security. Further, markets do not incent investments in fuel-secure infrastructure.

The coal fleet maintains a large coal stockpile at each power plant. In 2017, the average coal-fired power plant had an on-site coal supply ranging from 71 days to 104 days of coal burn.^{cxiv} Coal stockpiles provide resilience against high impact, low frequency disruptions because on-site fuel supplies minimize the potential for fuel supply disruptions. By contrast, at least 40% of the nation’s electricity resources are not fuel secure.⁸

The U.S. Department of Energy has highlighted concerns about coal and nuclear retirements in its “Staff Report to the Secretary on Electricity Markets and Reliability” and in a proposed “Grid Reliability and Resilience Pricing Rule” to compensate electricity sources that maintain a 90-day supply of fuel on site and provide essential reliability services.^{cxv}

FERC terminated the proposed rule and initiated a new proceeding to define resilience and to evaluate the resilience of the bulk power system in wholesale electricity markets.^{cxvi} FERC has proposed to define resilience as “the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.” It is unclear what steps FERC might take as a result of this proceeding, and the timing of any such steps is unknown. In the meantime, coal retirements continue.

PJM. PJM (see Figure 18) is a useful case study of the need for market reforms because its footprint includes a relatively large coal fleet, it has substantial amounts of at-risk coal and nuclear generation, and it has a diverse fuel mix that relies mostly on nuclear, coal and natural gas.

⁸ NERC indicates that only 27% of natural-gas-fired generating capacity built over the past two decades has dual-fuel capability. (Source: NERC “Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System,” November 2017.) This means that roughly 275,000 MW of gas-fired generating capacity lack dual-fuel capability. In addition, renewable generating capacity totaled some 204,000 MW last year. Thus, approximately 409,000 MW of electric generating capacity lack fuel security. U.S. electric generating capacity last year totaled slightly more than 1 million MW. (Source: EIA AEO 2018)



Figure 18. PJM ISO Territory^{cxvii}

PJM had proposed tariff revisions to address price suppression caused by out-of-market payments. As PJM explained its situation:^{cxviii}

“Over the last few years, the integrity and effectiveness of the capacity market administered by PJM have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market. The amount and type of generation resources receiving such out-of-market support has increased substantially. What started as limited support primarily for relatively small renewable resources has evolved into support for thousands of megawatts (MWs) of resources ranging from small solar and wind facilities to large nuclear plants. As existing state programs providing out-of-market payments continue to grow, more states in the PJM region are considering providing more support to even more resources, based on an ever-widening scope of justifications ... These subsidies enable subsidized resources to have a suppressive effect on the price of capacity procured by PJM through its capacity market ... Out-of-market payments, whether made or directed by a state, allow the supported resources to reduce the price of their offers into capacity auctions below the price at which they otherwise would offer absent the payments, causing lower auction clearing prices. As the auction price is suppressed in this market, more generation resources lose needed revenues, increasing pressure on states to provide out-of-market support to yet more generation resources that states prefer, for policy reasons, to enter the market or remain in operation. With each such subsidy, the market becomes less grounded in fundamental principles of supply and demand.”

However, FERC rejected the PJM proposal^{cxix} and, instead, is considering an alternative approach that could lead to market reforms.

Valuing Fuel Security

Both PJM and ISO-NE are conducting fuel security studies because of the importance of fuel security to resilience. Fuel security enables the grid to absorb and recover quickly from manmade or natural disturbances that could have disastrous consequences. However, the attribute of fuel security is not valued in wholesale markets at the present time.

ISO-NE. ISO-NE defines fuel security as “... the ability of the system’s supply portfolio, given its fuel supply dependencies, to continue serving electricity demand through credible disturbance events ... that could lead to disruptions in fuel delivery systems ... which could impact the availability of generation over extended periods of time.” ISO-NE has an ongoing analysis of fuel security which it considers to be the region’s most significant resilience challenge. ISO-NE is concerned that power plants in New England might not be able to obtain fuel, particularly in winter, because of coal, oil and nuclear retirements, constrained fuel infrastructure, and difficulty in permitting and operating dual-fuel generating capability.^{cxix} So far, the ISO has concluded the region is vulnerable to the season-long outage of any of several major energy facilities.

PJM. According to PJM, “Fuel security focuses on the vulnerability of fuel supply and delivery to generators and the risks inherent in increased dependence on a single fuel-delivery system.” PJM has initiated a three-phase effort to analyze and value fuel security.^{cxix} The PJM analysis will evaluate a dozen combinations of coal and nuclear retirements, as well as disruptions to fuel delivery systems. PJM plans to use the results to establish fuel-security criteria and then use markets to “allow all resources to meet those criteria.” PJM expects to complete its fuel security initiative by May 2019.

The American Coalition for Clean Coal Electricity (ACCCE) commissioned a similar study by Quanta to illustrate the potential consequences of ignoring risks from accelerated coal retirements and fuel insecurity for the PJM grid.^{cxix} Quanta’s modeling showed that when more coal-fired generation retired prematurely and natural gas-fired generation experienced supply disruptions, the PJM grid could not meet reliability criteria for transmission security, resource adequacy, or both. Figure 19 below from the Quanta report shows that scenarios based on coal retirements and gas outages exceed resource adequacy criteria.

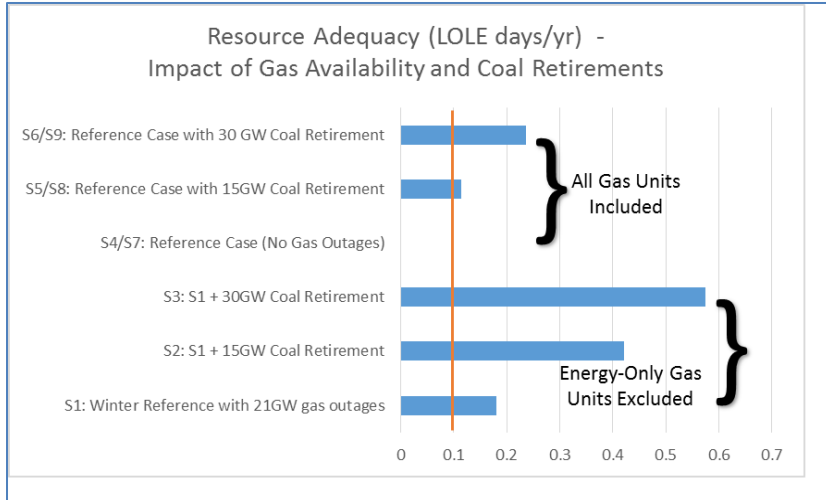


Figure 19. Resource Adequacy: Impact of Gas Availability & Coal Retirements^{CXXIII}

Among other things, the Quanta study showed that PJM will lose its resilience to natural gas outages if coal retirements continue.

The Role of Technology in Optimizing the U.S. Coal Fleet

The U.S. boasts a coal-fueled fleet of power plants that have historically provided a source of reliable, affordable power. Maintaining this fleet is essential to ensure that the country can continue to provide reliable, resilient, affordable power through a diverse electric mix. To improve the competitiveness of the existing U.S. fleet there are many technology options available, including lowering the cost of fuel through advancing mining practices, increasing coal quality, improving plant efficiency and flexibility, reducing the costs of environmental retrofits, advancing carbon capture approaches that generate saleable CO₂ and identifying other options for additional revenue through new products from coal or coal byproducts.

Reducing Fuel Costs

For a typical U.S. coal plant, delivered fuel cost accounts for the majority (about two-thirds) of the plant's O&M cost and an even greater portion (greater than 80%) of its variable cost, which is used to determine whether it dispatches ahead of or behind other sources of generation.^{cxxiv} As such, upstream technologies that improve the efficiency and reduce the cost of mining, processing or transporting coal could play an important role in improving the competitiveness of the existing fleet by reducing delivered fuel costs, which would improve dispatch priority and reduce the wear and tear from cycling.

In the past, these advances helped to boost U.S. coal mining productivity more than sixteen-fold, from 601 tons per employee-year in 1900 to 9,932 tons per employee-year in 2000, and brought even greater improvements in workplace safety.^{cxxv,cxxvi,cxxvii} However, while incremental technological enhancements have continued to be introduced, overall productivity in the U.S. coal mining industry has declined during the past 20 years (see Figure 20).^{cxxviii}

The recent decline in productivity suggests that advances in coal mining technology have failed to keep pace as the most prolific reserves have continued to be mined out (i.e., mines are increasingly moving to reserves characterized by thinner coal seams, more challenging geological conditions and thicker overburden). In contrast, the introduction of horizontal drilling and hydraulic fracturing technologies have allowed previously uneconomic shale gas reserves to become a major part of U.S. natural gas production and driven a more-than thirty-fold increase in new gas well productivity in the Appalachian Region since 2007.^{cxxix} A similar transformational change in coal mining technology would have major implications for the economic viability and utilization of the existing coal fleet.

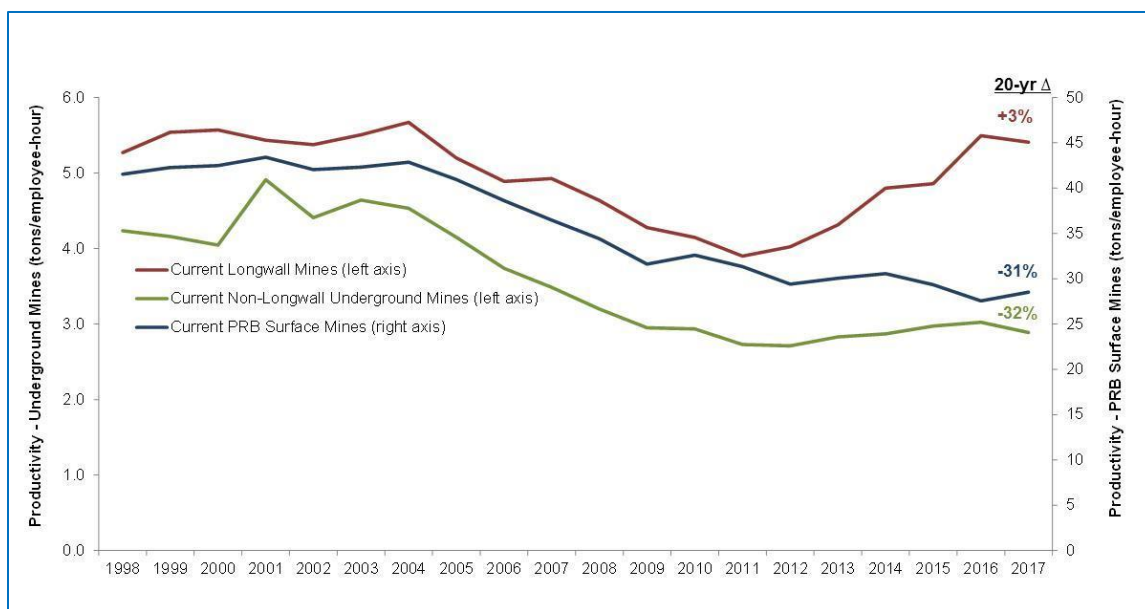


Figure 20. Productivity Trends for U.S. Longwall Mines, Non-longwall Underground Mines and PRB Surface Mines in Operation as of 2017

The National Research Council (NRC) studied upstream aspects of the coal industry and found that of more than \$538 million spent by Federal government agencies for coal-related research and technology deployment in 2005, less than 10% was directed toward upstream aspects of the coal industry.^{cxxx} The NRC recommended that “There should be renewed support for advanced coal mining and processing research and development ... The focus of this R&D should be on increased integration of modern technology in the extraction and processing phases of coal production, with particular emphasis on emerging advances in materials, sensors, and controls; monitoring; and automated mining systems.”^{cxxxi}

Opportunities for new technology implementation in coal mining and processing include automation and robotics, big data and advanced computing to improve mining productivity and efficiencies, fully remote mining technologies and advanced coal recovery and upgrading technologies. In underground coal mining, automated longwall shearer systems are offered commercially; these systems can boost efficiency by producing repeatable cuts, reducing the amount of rock that is mined with the coal, and reducing equipment wear and maintenance downtime.^{cxxxii} There is a need to extend automation to continuous miners, which account for a majority of the labor and cost required in both longwall mines and room-and-pillar mines, and to develop improved technologies for detecting the horizon of the coal seam (which is still done visually by the operator, even in automated longwall applications).

To highlight the magnitude of the opportunity, in general, for a typical continuous miner development unit in a longwall mine, less time is spent mining than is spent for routine and non-routine delays, providing a rich opportunity for improvements.^{cxxxiii} Notably, R&D funding, testing and implementation of new technologies underground will require cooperation from the Mine Safety and Health Administration (MSHA) to expedite the review and approval of these technologies for underground use.

In surface mining, efforts in the area of automation have focused largely on haul trucks, which provide one of the greatest opportunities to reduce unit cost.^{cxxxiv} However, EY notes that “This innovation has slowed. The first automated truck trials were 20 years ago, yet we still do not have a fully automated pit.”^{cxxxv} Automated haulage concepts could also be extended to underground mining applications.

There is an opportunity to take advantage of state-of-the-art digital technology, including consolidated data platforms, real-time analytics and optimization, advanced control systems, artificial intelligence and machine learning, and predictive maintenance to improve decision making and reduce downtime across the many interdependent processes involved in a mining operation. With respect to underground mining operations, continued development of wireless communication technologies capable of operating in an underground environment will be important for enabling the implementation of these digital technologies.^{cxxxvi} Opportunities for application of big data and advanced computing technologies also extend to coal preparation and transportation operations. EY notes that companies that successfully use data outperform their peers by 20%.^{cxxxvii}

Fully remote mining technologies would represent a transformational change in coal production. Leveraging experience in oil and gas horizontal drilling could present a novel approach for extracting coal from deep (>2,000 ft) seams, potentially reducing the cost of mining and providing access to high-quality resources that are uneconomic to mine with conventional technologies.^{cxxxviii} However, further proof of this concept is needed.

Coal Upgrading

There are material opportunities to further develop coal washing and upgrading.^{cxxxix} These technologies have the potential to reduce delivered fuel costs (on a \$/mmBtu basis), improve efficiency and reduce variable O&M costs at the power plant.

For example, when high-moisture lignites are burned in utility boilers, about 7% of the fuel heat input is used to evaporate fuel moisture.^{cxl} The use of high-moisture coals results in higher fuel use, higher flue gas flow rate, lower plant efficiency, and higher mill, coal pipe and burner maintenance requirements compared to that of the low-moisture coals such as eastern bituminous coals. Despite problems associated with their high-moisture content, lignite and sub-bituminous coals from the western U.S. are attractive due to their low cost, lower content of sulfur and mercury (Hg), and lower NO_x emissions.

In terms of coal upgrading, there is sufficient opportunity for U.S. low-rank coals, which have moisture contents ranging from 15% to 30% for sub-bituminous coals and from 25% to 40% for lignites. Coal upgrading processes at the power plant, such as DryFining™ (DOE Award Number DE-FC26-04NT41763), improves the heat content of low ranks coals, upgrading lignite from 7,503 Btu/lb to 10,397 Btu/lb and upgrading Powder River Basin (PRB) subbituminous coal from 8,830 Btu/lb to 11,329 Btu/lb.^{cxli} The extracted water can be used within the power plant, thereby reducing water withdrawal and consumption from local water supplies by 20% to 25% for water-cooled plants. The resulting efficiency improvement for a nominal 600 MW_e plant is significant in that it results in a net power increase of 30 MW_e for lignite and 34 MW_e for PRB coal.^{cxlii} Increased efficiency also lowers criteria emissions on a MWh basis, in addition to reducing CO₂. Table 2 shows what was accomplished by coal drying and cleaning on North Dakota lignite. The amount of emission reduction and efficiency improvement gained is dependent on the amount of thermal heat brought to the process.

Table 2. Results of the Dry Fining Process^{cxliii}

Component	Amount of Reduction	Explanation
Fuel H ₂ O	25%	Dries lignite from 38% to 29% moisture, improving HHV from 6,100 to 6,800 Btu/lb
SO ₂	54%	Segregation of ash minerals, plus improved collection efficiency
NO _x	32%	Reduced volumetric release rate, improved fineness and air and fuel distribution to furnace
CO ₂	4%	4% improved cycle efficiency

Coal preparation and beneficiation processes also offer value for higher rank coals. Many bituminous coals, such as coals from the Appalachian and the Illinois Basins, are washed in preparation plants to remove impurities (e.g., ash) and improve heat content. Washed coals, however, need to be dewatered. Recently, there has been a technology push to improve recovery of coal from the wet, fine coal refuse streams produced by these preparation plants, which have traditionally been disposed in slurry impoundments, and instead use those streams to produce high-quality coal or carbon products for use as power plant fuel or in alternative applications.^{cxliv,cxlv,cxlvi} These emerging processes have the potential to improve economic and environmental performance at both the coal mine and the end-use power plant.

In addition, mercury, arsenic and selenium heavy metals removal can be achieved to improve multi-pollutant emissions control performance and cost. Figure 21 shows the reduction of mercury achieved during bench-scale testing. Likewise, for PRB coal, arsenic was reduced from 4.8 parts per million detected (ppmd) to 1.8 ppmd and from 1.0 ppmd to 0.8 ppmd for selenium. A reduction in NO_x emissions up to 41.3% for lignite and 23.2% for PRB coal was also observed.^{cxlvii}

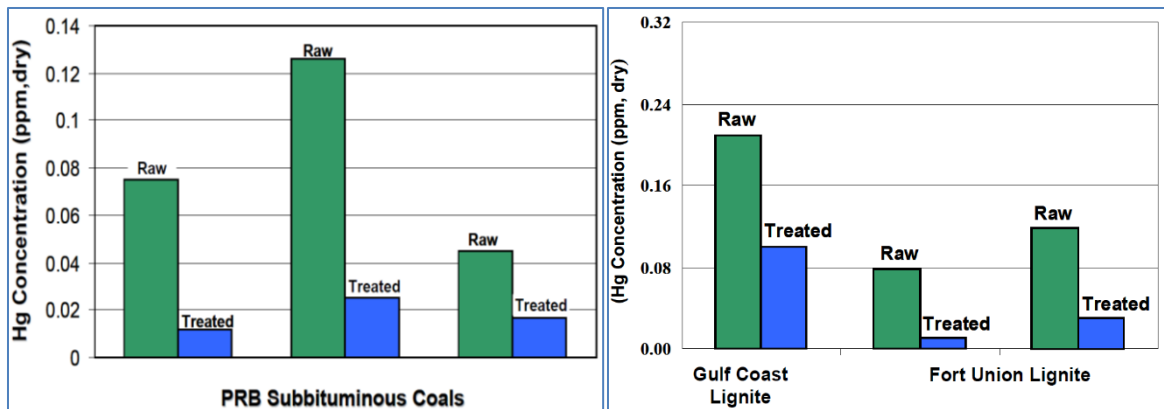


Figure 21. Bench-scale Mercury Removal Test Results Beneficiated Lignite and PRB Coals

Coal beneficiation processes provide significant performance, reliability and O&M benefits to the plant, as well as improving the potential fuel flexibility of the plant. Increased fuel flexibility directly benefits the busbar generation cost and dispatch importance of the power plant, which results in potential life extension of the valuable asset.

Improving Plant Efficiency

Coal plant efficiency improvement has proven to be one of the most vexing topics over the last decade. The topic is both diverse and complex. New technologies, such as high efficiency, low emissions (HELE) plants, offer dramatically improved efficiency and lower CO₂ emissions versus subcritical coal plants. For existing plants, there are substantial differences in potential improvements due to differences in technology, vintage, operational duties, environmental compliance equipment and coal sources. Finally, regulatory uncertainties, especially around New Source Review, have limited the ability of owners of existing plants to aggressively pursue energy efficiency improvement opportunities.⁹ In spite of these challenges, energy efficiency improvement remains a viable means to improve the competitiveness of and reduce emissions from coal-fired power. Retrofit and repowering options are discussed below.

Retrofits. For existing coal plants, the degree to which efficiency improvements can be realized is largely a function of level of capital expenditures made to either refurbish or in some cases upgrade existing plant systems. Aging plants, uncertainty in role/length of remaining service and lack of priority in maintaining optimal plant efficiency mean that most, if not all, coal plants would have substantive capability to realize efficiency improvement. There is no single formula that can be applied across all plants and, hence, the cost/benefit associated with improvements needs to be factored into such decisions.

⁹ As noted in the policy section of this chapter, NSR reform has been proposed as part of the EPA's Affordable Clean Energy plan.

Without substantial capital investment, improvements on the order of 1% to 2% can often be realized by tighter operational control of the plants and use of performance optimization tools/processes and plant tuning. Substantially higher improvements, on the order of 4% to 6% in efficiency gains, can generally be achieved if business-justified (acceptable cost/benefit ratios) capital investment is made. Plant improvements can also target ramping, load range or other factors that have the potential to add value to the plant.

Efficiency improvement opportunities can be classified, generally, into heat rate improvements for boiler/air systems, for turbine/condenser and via improved controls. The degree of improvement will vary by equipment present, its condition, and plant operating conditions, and will require a pragmatic plant condition and upgrade assessment. Fortunately, significant effort has been carried out to define such programs. Specifically, data analysis conducted by NETL and a consensus of selected industry experts indicate that this opportunity is technically and economically achievable, but will require leadership from power plant owners and operators and commitments from regulators, vendors, federal agencies, etc.^{cxlviii}

Audits or other methods can be applied to validate the sources and magnitude of efficiency improvements to be realized; a representative cost/benefit analysis is shown in Figure 22. As can be seen from the figure, targeted areas for capital investment can be broad, and include the boiler, turbine, air/gas handling and auxiliary systems. Combustion optimization systems, performance management systems and advanced monitoring and diagnostics systems enable more efficient operations and optimize fuel/gas/air/sootblower volumes.

Some newer and emerging opportunities may be able to improve efficiency or reduce power plant costs without major capital investment. For example, artificial intelligence and/or predictive maintenance enabled by big data analysis, etc., could help optimize plant operations. These options could be especially important when plants are cycling more than what they were originally designed to do.

Project Name	Capital Cost	B/C Ratio	B/C Ratio Rank
Circulating Water Pump Refurbishment	Low	High	1
Sootblowing Steam Source	Low	High	2
Coal Mill Inerting Source	Low	High	3
Add Condensate Polishing	Medium	High	4
HP/IP/LP Turbine Upgrade	High	High	5
Coal Mills Replacement	High	High	6
Boiler Feed Pump Refurbishment	Low	Moderate	7
Helper Cooling Tower Replacement & Pumps	Medium	Moderate	8
Replace Flame Scanners	Low	Moderate	9
VFD's for Forced Draft Fans	Medium	Low	11
Air Heater Overhaul	Medium	Low	10
Replace Air Preheat Coils	Low	Low	12
VFD's for Induced Draft Fans	Medium	Low	13
Alternate Air Heater Overhaul	Medium	Low	14
Alternate Air Preheat Coils Modification	Medium	Low	15

Figure 22. Coal-fired Power Plant Efficiency Audit Results

Repowering. NETL has recently studied the prospect of repowering coal-fired power plants that have invested in full air pollution control equipment, but that have a lower operating efficiency.^{cxlix} The study assumes that a power plant boiler, turbine and other steam cycle components could be replaced while continuing to use the existing air pollution control equipment and electricity generating and transmission infrastructure. In its study, NETL found that a repowering would cost about half that of building a new coal-fired power plant at a greenfield site. NETL concluded that there were no technical limitations to a repowering. However, there are likely regulatory hurdles, such as meeting New Source Performance Standards (a regulation under review by EPA) that would need to be better understood and addressed before any such repowering could occur. Still, this represents an important opportunity to continue to rely on existing infrastructure assets while investing in a new steam cycle that could be more competitive and offer lower emissions than the equipment it replaces.

Improving Flexibility

With the rapid increase in IRE generation, there is significant pressure on existing dispatchable coal resources to meet load and balance intermittency. In light of projections that IRE penetration will increase significantly in the coming years, the severity of this problem is expected to increase precipitously. While new power plants can be designed to be more flexible, there are some technologies that can assist the existing fleet to meet the needs of a diverse energy mix that includes greater IRE penetration.

While the existing coal fleet is presently able to deliver variable output to stabilize the grid, this comes at a cost in terms of lower plant efficiency, higher maintenance expenses and shorter life expectancy. Plant cycling results in 1) increased capital expenditures for component replacement, 2) increased routine O&M costs due to increased wear and tear, 3) lower availability due to increased failure rate and outage time and 4) higher fuel consumption during startup and shutdown due to inefficient heat transfer and non-optimum heat rate.

EPRI has described^d the damage mechanisms associated with conventional coal power plant cycling, and has also made recommendations for improving plant management, operation, monitoring, design, staff levels and training to optimize plant life cycle costs. There are some changes that can be made to power plants to improve their ability to cycle. EPA, in its recently proposed Affordable Clean Energy plan, has included variable frequency drives in its list of potential Best System of Emissions Reduction (BSER). Application of this technology could improve flexibility and improve efficiency as the existing coal fleet as it is increasingly required to ramp.

Nonetheless, with the rapid growth of wind and solar installations, more aggressive measures are needed to ensure the stability of the grid. A common misconception is that the challenges of IRE can be addressed with battery power storage. The impracticality of this can be understood by evaluating the economics of the Tesla battery pack installed at the Neoen Wind farm in Australia, where the cost of electricity storage is ~\$430/kWh.

A potentially lower-cost alternative to battery storage is thermal energy storage (TES) which utilizes steam turbine assets combined with thermal storage technologies. Depending on the storage technology, capital costs can be on the order of \$100/kWh, a factor of three to four less than for Li-ion batteries.

The concept behind TES is somewhat analogous to a hybrid electric vehicle in that it allows the coal-fired power plant to continuously operate at maximum efficiency, reducing the damaging impacts of cycling while storing energy for later use during periods of high demand. This approach to storage should be considered prior to decommissioning of coal plants, especially when decommissioning of one plant could lead to increased cycling for another, newer unit at the same site. For example, often a coal unit may be retired, while adjacent existing units are newer and more efficient, and have modern environmental controls. Under these conditions, rather than facing the damage and costs associated with cycling the newer units, TES can be employed in combination with the old (to be decommissioned) steam turbine.

TES is an established technology that has been applied for utility scale concentrated solar power (CSP) to allow for power generation when sunlight is not available. CSP systems typically use a molten-salt mixture to store high-temperature heat during the day for subsequent steam generation in the evening hours. Materials other than phase-change materials are also possible, e.g., concrete and sand.

A recent EPRI study investigated the economic feasibility of using various TES systems to facilitate flexible dispatch of electrical power from fossil plants.^{cli} This study concluded that TES can be a more cost-effective approach to stabilizing the grid than adding gas turbine peaking units or batteries, and could improve the competitiveness of the coal-fired power fleet if it was utilized in a way that reduced the frequency and rate of rapid ramping (see Figure 23).

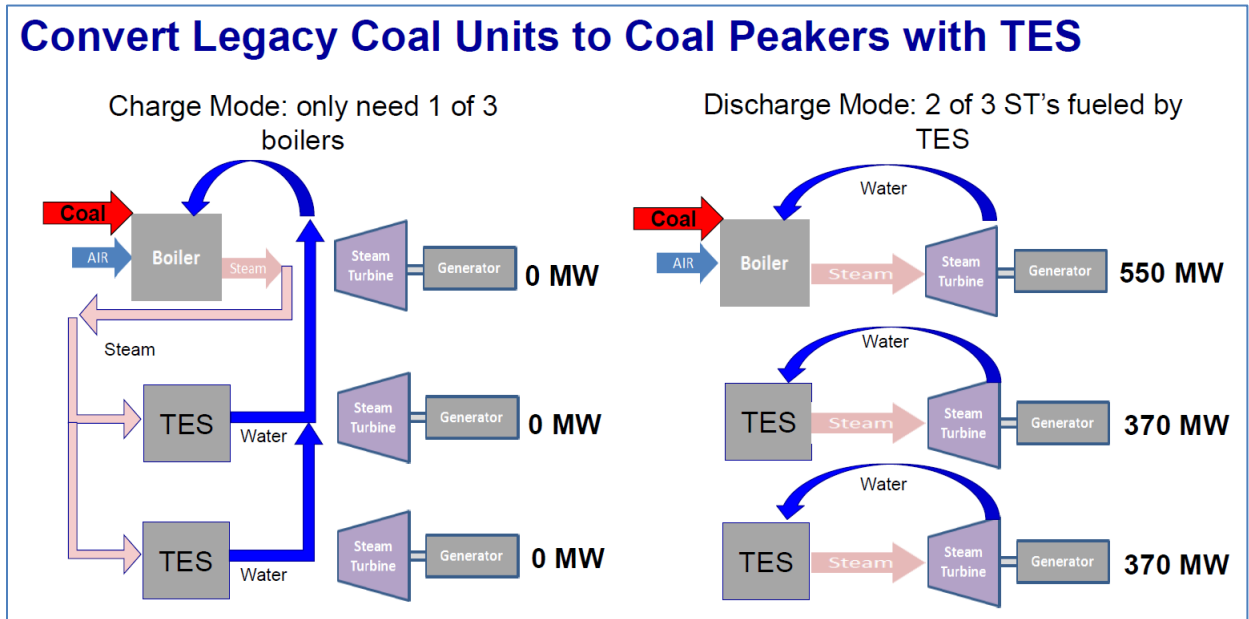


Figure 23. Charge and Discharge Mode for Coal Units Converted to Coal Peakers Using TES^{cli} (used with permission from EPRI)

Notably, other forms of energy storage could also be integrated with the existing coal fleet. Pumped hydro, batteries and any other option for energy storage could be integrated with the existing coal fleet or onto the grid, potentially reducing the frequency and rate of ramping.

Reducing the Cost of Environmental Retrofits

Today's coal-fired electric generating units have successfully controlled emissions such as SO₂, NO_x, PM, mercury and other air toxics to meet regulatory requirements under the Clean Air Act, the MATS and other regulations. The economic competitiveness of coal-fired electric generating units could be improved through the development of technologies to enhance efficiency and lower operating costs of air emissions control systems.

For example, new SO₂ scrubber designs that reduce the energy penalty of scrubbing (e.g., by reducing pressure drop across the scrubber), new reagents and additives which improve scrubber reactivity and scrubbing chemistries that produce valuable byproducts, represent potential avenues for plants to decrease operating costs associated with SO₂ controls.

Likewise, similar gains could be made with improved NO_x control technologies with lower capital and operating costs as well as reduced sensitivity to the composition of the coal ash. Improvements in the systems to control flue gas impurities, such as SO_x, NO_x, and PM, can also benefit performance of CO₂ capture systems by reducing the degradation of CO₂ solvents and adsorbents.

In terms of water discharge from coal-fired power plants, the Effluent Limitation Guidelines for Steam Electric Generating Plants is currently pending reconsideration by the EPA. The rule published in 2015 set requirements for the discharge of arsenic, mercury, nitrogen and selenium in wastewater streams from FGD processes; it also required zero-discharge of pollutants from bottom ash transport water and addresses other wastewater streams. EPA estimated in 2015 that 181 of the nation's steam electric generating stations (all of which are coal-fired power plants) would need to make new investments to comply with the rule.^{cliii} The Office of Management and Budget (OMB) prioritizes the rule as "economically significant",^{cliv} with the EPA estimating annual compliance costs for the final rule at \$480 million per year.^{clv} DOE-NETL has funded programs to improve effluent water management at coal-fired electric generating plants, although funding amounts have historically been modest.^{clvi}

There may be opportunities in both the areas of air emissions and water effluent to reduce the technology cost associated with meeting environmental standards. Existing coal-fired power plants with limited remaining life are sensitive to the payback periods for investment in new technologies. There is a role for the Department of Energy to reduce the cost of new technologies and to promote innovative financing opportunities so that aging plants can adopt the new technologies that are being developed in the U.S. and around the world.

Carbon Capture Opportunities

CCUS could play a critical role in reducing the number of coal-fired power plant shutdowns, by providing retrofit solutions with improved operational economics and near-zero emissions. This would be the case if the costs for CCUS can be lowered and/or revenue from CO₂ sales can be increased to the point at which CCUS projects become profitable. Recently there has been considerable progress in CCUS, with the commissioning and successful operation of the Petra Nova facility for over one year. However, this is the only full-scale CCUS project in the U.S. coal fleet. To reduce the costs associated with CO₂ capture and close the gap with potential sources of revenue by using the captured CO₂, many more such projects are needed – achieving technical advances through learning-by-doing, improved financing opportunities, etc.

Having multiple CCUS technologies commercially available would spur competition and be beneficial for the coal fleet; no single technology solution is likely to fit all the different types of plants. Currently in the U.S., only one technology has been demonstrated at the commercial scale, although many are ready for demonstration. For example, oxy-combustion technology has been available for demonstration since 2010, but has not been tested at scale in the U.S.

The demonstration of CCUS technologies on a commercial scale plant is essential in order to move to commercial deployment. However, given the financial scope of a CCUS retrofit commercial scale demonstration project, and risks for the private sector and financial community, government support is essential for demonstration of new CCUS technologies. Grants, similar to the \$190 million provided to the Petra Nova project, are a critical tool for advancing other first-of-a-kind demonstrations. The lack of additional government support for large-scale projects has impeded additional CCUS deployment.

Time is of the essence for the DOE to initiate efforts for new CCUS demonstration projects, in part because the reform of the 45Q tax credit represents an important opportunity to enhance the economics for early-mover projects. Given the large number of coal-fired power plants in close proximity to EOR opportunities across the U.S., CCUS deployment could be extensive, once successfully demonstrated. Demonstrations will help reduce costs and further deployment of CCUS technologies. The window for claiming the 45Q tax credit requires construction to begin before the sunset date of January 1, 2024, which may act as a limiting factor for broad application. Further deployment and advancement of CCUS technologies will pave the way for CCUS opportunities well into the future.

Rare Earth Elements

Rare earth elements (REE) are necessary materials in an incredible array of consumer goods, energy system components and military defense applications. Major market segments that rely on REE-based products or technologies include health care, transportation and vehicles, lighting, renewable energy systems, communications systems, audio equipment, military defense technologies and modern electronics. However, the global production and entire value chain for rare earth elements is dominated by China; the U.S. is currently completely reliant on imports of these critical materials.

There are numerous challenges associated with pursuing alternative sources of REEs, such as traditional mineral ores. Chief among these is that the content of the most critical and valuable of the REEs are deficient, making mining for these materials uneconomical. Further, the supply of these most critical rare earths is almost exclusively produced in China from a single resource that is only projected to last another 10 to 20 years. As a result, the U.S. currently considers the rare earths market an issue of national security, and accordingly, it is imperative that alternative domestic sources of rare earths be identified and methods developed to produce them.

Recently, coal and coal byproducts have been identified as one of these promising alternative resources.^{clvii} DOE is actively supporting studies to both characterize U.S. coal feedstocks for assessing the feasibility for REE recovery and to develop ways to improve their extraction.^{clviii} While REEs are used in relatively small volumes, they could provide a secondary source of revenue for coal mines, or slightly boost consumption, which could potentially lower fuel costs and thus benefit the competitiveness of the existing fleet.

Boosting Revenue by Co-locating Other Coal Uses

New markets for coal are being pursued worldwide for various applications. China, Korea, Japan and South Africa are already pursuing conversion of coal to synthetic oil, transportation fuels hydrogen and industrial chemicals. In the U.S., efforts are also underway to convert coal into advanced materials, such as carbon fibers, that can be used in aerospace, infrastructure, automotive and energy applications.^{clix}

In the U.S. there are potential opportunities to co-locate new technologies for processing coal at existing power plants and to enhance the use of U.S. coal in markets beyond those for power generation. These new markets for coal include coal conversion (coal to liquids, coal volatiles directly to transport fuel, coal to gas, coal to chemicals); carbon engineered products (value-added non-Btu products); REEs; methanol; and biotechnology approaches (agriculture, liquid fuels) among others.

In all instances, the coal conversion process itself requires electricity, providing the existing plant with a new dedicated customer. In some instances, the conversion process itself will use electricity as the primary heat input to disassociated atoms for recombination into coal resins (coal tar).

RD&D Recommendations from the CURC-EPRI Roadmap

As noted earlier in this report, coal plants are being called upon in today's markets to operate more flexibly in a range of cycling modes as power generators expand their use of IRE. This is resulting in units operating at much lower capacity utilization factors than originally designed as a baseload system. The consequences of the lower capacity factor result in greater complexity in managing the numerous sub-systems within the power plants and it can be economically challenging for those units to recover costs in some markets. Operating in a flexible mode also results in significant wear and tear, which could compromise these units in the future if research is not undertaken to understand and remedy the impacts of rapid and frequent cycling.

The CURC-EPRI Roadmap^{clx} identifies a comprehensive research program for addressing these impacts on existing coal and gas power generation systems. This includes RD&D to provide:

- Improved technologies to reduce the cooling water consumption
- Improved approaches to treat power plant water effluent and manage byproducts
- Improved criteria emissions control systems, capable of performing well (i.e., maintaining high capture efficiencies) on units with flexible modes of operations
- Improved ability to operate with different fuels, such as biomass co-firing
- Improved net plant efficiency through combustion optimization, advanced controls, the use of advanced topping or bottoming cycles and waste-heat utilization
- More reliable operation for units operating in “cycle mode” by developing improvements in welding and component fabrication using new materials and by providing improved diagnostic techniques, including better sensors and controls for early identification of “wear and tear” problems
- Developing advanced (high-temperature-tolerant) materials for units undergoing replacement of major subsystems
- Demonstration of A-USC components for possible retrofit to improve efficiency, capacity factor and reliability of existing power plants

The Roadmap does not specifically recommend CO₂ capture technology development tailored for existing units, but notes that many types of CO₂ capture technologies designed for new facilities would also be practical for existing fossil-fired power plants if RD&D can sufficiently reduce costs and mitigate significant negative impacts on plant efficiency. Consideration of CO₂ capture on existing units not only must take into consideration costs, but other site-specific issues such as access to EOR or other geologic storage options, and the amount of space available onsite to accommodate the equipment to capture and transport CO₂.

Conclusions

Although there are many challenges facing the existing U.S. coal fleet, it continues to play an important role in the current diverse energy mix. A wide range of policy mechanisms, market changes and technology solutions exist or could be developed that could enable this fleet to continue to play an important role in the U.S. electricity system well into the future. DOE has the ability to take action and/or influence many of the key areas discussed throughout this section that would benefit the nation’s coal fleet.

Chapter 4: Key Recommendations and Findings

The existing U.S. coal fleet offers unique benefits and value in the nation's interests that must be valued or it will continue to erode. Accordingly, the National Coal Council advocates a four-step approach –

ASSESS | SUPPORT | REFORM | RENEW

Strategic Objectives

The key strategic objectives of this approach are:

ASSESS the value of the coal fleet.

Steps must be undertaken to ensure that the reliable and resilient attributes of U.S. coal generation are acknowledged and that the nation's existing coal fleet is equitably compensated for the services it provides. Firm, dispatchable power must remain a sustained part of the nation's fuel mix; targeted minimum levels for key fuel sources should be strongly considered.

SUPPORT efforts to retain continued operation of the existing coal fleet.

By ensuring compensation for all the attributes of the existing coal fleet, put an end to the precipitous retirement of dispatchable coal. This can provide an opportunity to assess future power demand scenarios and the ability of various energy resources to realistically, reliably and resiliently meet those needs. Economic and regulatory support are needed to stem the tide of plant retirements and ensure the sustainability of a diverse energy portfolio.

REFORM the regulatory environment.

The efficiency, environmental performance and cost-competitiveness of the existing U.S. coal fleet can be enhanced with reforms to various regulatory mandates. Environmentally permitted investments should be afforded the opportunity to recoup value over their useful life and enable the power grid to take full advantage of existing resources. Just compensation is warranted should that opportunity be denied.

RENEW investment in coal generation.

Optimizing existing coal fleet assets requires a targeted Research Development, Demonstration & Deployment (RDD&D) program focused on increasing the efficiency, flexibility and competitiveness of the fleet. Public funding and support mechanisms, complemented by public-private partnerships will ensure grid reliability, dispatch effectiveness and power system resilience.

Tactics

Specific actionable items recommended to achieve strategic objectives are detailed here. Tactical recommendations are framed to specify WHAT must be done and WHY.

ASSESS the value of the coal fleet.

- Establish a uniform definition of grid resilience.
A standardized definition of resilience is needed in order to assess and compensate the value of various energy resources and the range of grid services they supply.
- Assess the fuel security of ISOs/RTOs.
Fuel security is critical to grid resilience as it enables the grid to absorb and recover quickly from manmade or natural disruptions in the power system.
- Establish quantitative metrics against which to evaluate grid resilience.
Resilience metrics can be used to assess and equitably compensate electricity generators for services provided.
- Evaluate the experience of other nations regarding the value of firm, dispatchable power and challenges associated with intermittent renewable energy deployment.
Lessons learned from other nations are instructive in defining pathways to a stable and sustainable energy future for the U.S.

SUPPORT efforts to retain continued operation of the existing coal fleet.

- Provide appropriate economic and regulatory incentives to stem the tide of plant retirements.
Acknowledge the significant and disproportionate impact on the existing U.S. coal fleet of market distortions, over-regulation and regulatory uncertainty.
- Establish an environment that values and compensates diversity.
Resource diversity is critical to maintain a reliable and resilient grid, especially in the event of manmade and natural high impact-low frequency events.
- Support mechanisms to immediately compensate the U.S. coal fleet for the essential services it provides.
Acknowledge the explicit economic, dispatchable and grid-resilient value provided by the existing U.S. coal fleet.

REFORM the regulatory environment.

Policy Reforms

- Reform New Source Review rules.
Eliminate regulatory uncertainty and reduce litigation risks for utilities seeking to implement energy efficiency measures and enhance operational flexibility solutions at coal plants.
- Reform the Public Utilities Regulatory Policies Act of 1978.
Reforms will more realistically reflect today's electricity landscape and ensure utilities are not forced to purchase power they do not need.
- Revise the 2015 Coal Combustion Residuals ruling.
Reforms could provide states and utilities with flexibility in how CCR is managed.
- Support changes to Effluent Limitation Guidelines establishing wastewater treatment standards.
Changes would support standards that could be more realistically and cost-effectively met with technologies commensurate with the resultant health and welfare benefits realized.
- Advance CO₂ storage laws and regulations on Federal and tribal lands.
Regulations could facilitate deployment of CCUS technologies by existing coal plants located near Federal and tribal lands.
- Engage EPA as it progresses the Affordable Clean Energy plan.
Provide technical guidance to EPA on the potential technologies and the role of efficiency gains and flexibility improvements that could reduce emissions from the existing fleet.

Market Reforms

- Support FERC capacity market reform initiatives.
Provides opportunities to ensure that resilience, fuel diversity and/or fuel security are valued along with low electricity prices and transmission reliability.
- Support FERC initiatives to refine ISO/RTO price formation.
Allows fuel-secure resources to set locational marginal prices, eliminate negative pricing, establish a price floor for fuel-secure resources and require the value of tax and other subsidies to be imputed into market bids of subsidized resources.
- Support FERC efforts to establish and enforce standards for essential reliability services.
Allows for a more realistic assessment of attributes, such as fuel security, that support a reliable and resilient grid.
- Support efforts by ISOs/RTOs to conduct assessments evaluating fuel security and resilience of the bulk power system.
Assessments provide critical data on the resilience of wholesale electricity markets.

Tax Reforms

- Support legislative initiatives to provide temporary tax credits to cover a portion of O&M expenses for existing coal plants.
Offsetting a small portion of O&M expenses for the existing coal fleet is estimated to prevent the retirement of as much as 24,000 MW of coal-fired generation.
- Support legislative initiatives that would complement and further incentivize utilization of the 45Q tax credit for existing coal plants, including Master Limited Partnerships and Private Activity Bonds.
The recent 45Q tax credit reform provides an important Federal incentive encouraging private investment in the deployment of carbon capture technologies. Additional Federal incentives would complement 45Q and enable more capture projects to become commercially feasible.
- Support changes to the 48A tax credit, such as removing the efficiency increase requirement that would facilitate retrofits of CCUS technology to the existing coal fleet.
In its current form, the tax credit does not incentivize CCUS on new or existing coal plants.

RENEW investment in coal generation.

- Support the development and deployment of the following technologies.
Government and public-private partnership support for advanced coal technologies enhances the competitiveness, efficiency and environmental performance of the existing coal fleet.
 - Advanced coal mining and processing technologies.
Renewed R&D initiatives would enhance productivity and cost-competitiveness of coal supply. Working in concert with MSHA would help expedite the review and approval of these technologies.
 - Coal beneficiation technologies, including coal washing and upgrading.
Advanced R&D initiatives would improve power plant performance and reduce operating costs.
 - Retrofitting and repowering technologies.
Various technologies and processes could be deployed at existing plants to improve energy efficiency and coal plant cost competitiveness.
 - Energy storage technologies.
Various storage technologies – notably Thermal Energy Storage – could potentially allow coal-fired power plants to continuously operate at maximum efficiency while reducing the damaging impacts of cycling.

- Advanced air emissions control system technologies.
Enhancements to existing technologies could improve efficiency and reduce costs associated with controlling SO₂, NO_x, PM and Hg.
 - Water effluent technologies.
R&D initiatives are needed to reduce technology costs associated with meeting environmental standards.
 - Carbon capture technologies/projects, including demonstrations at commercial scale retrofitted to existing coal-fired units.
Only one CCUS retrofit project is operational in the U.S. today. More projects would reduce costs associated with CO₂ capture, improve project financing opportunities and advance technical knowledge.
 - Rare earth element extraction from coal and coal byproducts.
R&D initiatives could advance the development of and reduce the costs associated with REE extraction, providing a secondary source of revenue for coal producers/consumers and enhancing the cost-competitiveness of the existing fleet.
 - New advanced markets for coal technologies such as coal conversion, carbon engineered products and other coal-derived value-added products.
Co-locating coal-to-X projects at existing coal plants could support the economics of both facilities.
 - Technologies identified in the CURC-EPRI Roadmap that enhance the efficiency and cost-competitiveness of the existing coal fleet.
Provides a focused and comprehensive R&D program to address the many and varied coal generation system components in concert.
- Promote education and awareness about the water-energy nexus.
Education enhances national water planning processes and facilitates a more reasoned approach to decision and policy making.
- Promote initiatives to enhance transparency about the inherent costs and benefits associated with all U.S. energy resources.
Provides a more reasoned approach to energy decision and policy making.

APPENDIX 1A – Definitions of Reliable and Resilient

There is a need to establish a uniform definition of grid resilience. The Federal Energy Regulatory Commission (FERC) initiated efforts in January 2018 to define resilience and to assess whether the U.S. bulk power system is, in fact, resilient. In addition, PJM and ISO-NE are undertaking studies to assess the fuel security of their respective systems.^{clxi}

- The Federal Energy Regulatory Commission (FERC): Resilience is “... the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.”
- PJM’s definition of resilience focuses on HILF events. “The ability to withstand or quickly recover from events that pose operational risk.”
- The North American Electric Reliability Corporation (NERC) defines Bulk Power System reliability as a function of adequacy and operating reliability. In this context, NERC defines adequacy as, “the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.” Operating reliability is defined as, “the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.”^{clxii}
- National Academy of Sciences, Engineering and Medicine (NAS): A reliable electric system minimizes the likelihood of disruptive electricity outages, while a resilient system acknowledges that outages will occur, prepares to deal with them, and is able to restore service quickly and draws lessons from the experience to improve performance in the future.^{clxiii}
- National Infrastructure Advisory Council (NIAC) definition of resilience:
- “Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends on its ability to anticipate, absorb, adapt to and/or rapidly recover from a potentially disruptive event.”^{clxiv}
- Absorptive Capacity – ability to endure a disruption without significant deviation from normal operating performance
- Adaptive Capacity – ability to adapt to shock to normal operating conditions
- Recoverability – ability to recover quickly and at low cost from disruptive events

APPENDIX 1B – Reliable and Resilient Attributes

Markets must value resiliency as well as reliability. While there are quantitative metrics on which to evaluate the reliability of the grid, there are no agreed-upon criteria to determine if a grid is resilient.

Attribute	Coal	Natural Gas	Wind/Solar	Nuclear	Demand Response
Dispatchability	✓	✓		✓	
Inertia	✓	✓	✓(wind)	✓	
Frequency Response	✓	✓	✓ ³		
Contingency Reserves	✓	✓			✓
Reactive Power	✓	✓		✓	
Ramp Capability	✓	✓			✓
Black Start		✓			
Resource Availability	✓	✓		✓	
On-Site Fuel Supply	✓			✓	✓
Reduced Exposure to Single Point of Disruption	✓		✓	✓	✓
Price Stability	✓		✓	✓	✓

Source: PA Consulting

- Dispatchability – The operation of baseload power plants can be scheduled well in advance to meet predicted load with minimal need to forecast factors which affect many other generation technologies. Over shorter time-frames, baseload power can be adjusted to increase or decrease output as necessary, providing flexibility in meeting fluctuations in demand.
- Frequency Response – active control to maintain a constant 60 Hz to keep grid operating safely and reliably.
- Inertia – When load changes occur rapidly in a system with baseload power, the inertia provided by these heavy rotating machines resists the changes in frequency helping the grid ride through disturbances.
- Frequency Response – Provides active control to maintain a constant 60Hz – this is the frequency that must be maintained to keep the grid, and all connected equipment, operating safely and reliably.

- Contingency Reserves – Baseload plants are able to provide spinning reserves for backup power in case of system disruptions.
- Reactive Power – Baseload generators can supply reactive power to counteract fluctuations in voltage levels both on command and through Automatic Generation Control (AGC).
- Ramp Capability – Resources that can quickly increase or decrease their power output.
- Black Start Capability – Resources that can provide post-blackout electric connections to re-start the grid.
- Resource Availability – Ability to supply power on an uninterrupted basis for long periods of time.
- On-Site Fuel Supply – Minimizes potential for fuel supply chain disruptions.
- Reduced Exposure to Single Point of Disruption – Grid resources rely on external systems to ensure they operate reliably; coal benefits from on-site fuel stockpiles and multiple means of delivery.
- Stable, Predictable Pricing – Coal has traditionally had low and predictable variable fuel costs.

PJM analyzed 360 different portfolio mixes of electricity resources and their effect on electric reliability.^{clxv} The portfolios represented different combinations of coal, natural gas, nuclear, wind, solar and other resources. Slightly more than one-quarter (1/4) of these (98) were “desirable,” exhibiting high levels of reliability. Almost half (1/2) of the desirable portfolios consisted of 30%+ coal-fueled capacity. PJM also analyzed the effects of a polar vortex – one of several possible HILF events that could threaten electric grid resilience. Under assumed polar vortex conditions, only one third (1/3) of the desirable portfolios (34 of 98) were resilient – portfolios with coal at 30%+ remained resilient; due to “higher unavailability rates of natural gas under a polar vortex event” fewer portfolios with a higher percentage of natural gas were considered resilient. The conclusion is that PJM needs significant coal-fueled generating capacity to ensure a resilient grid, especially when encountering a HILF event.

Resource Type	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
	Frequency Response (Inertia & Primary)	Voltage Control	Ramp			Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Cycle	Short Min. Run Time (< 2 hrs.) / Multiple Starts Per Day	Startup / Notification Time < 30 Minutes	Black Start Capable	No Environmental Restrictions (That Would Limit Run Hours)	Equivalent Availability Factor
Regulation	Contingency Reserve	Load Following											
Hydro													
Natural Gas - Combustion Turbine													
Oil - Steam													
Coal - Steam													
Natural Gas - Steam													
Oil/ Diesel - Combustion Turbine													
Nuclear													
Battery/ Storage													
Demand Response													
Solar													
Wind													

Source: PJM Interconnection, "PJM's Evolving Resource Mix and System Reliability," March 2017

APPENDIX 1C – Indirect Costs Associated with Intermittent Renewable Energy (IRE)

- Transmission is needed to move distant renewables to load centers (multi-billion dollar renewable-driven transmission projects are socialized across entire markets).
- Ancillary services that are necessary to “balance” non-dispatchables are not factored into renewable energy prices.
- Market distortions favoring IRE are discouraging investments in and driving retirements of other generation options with stranded costs of prematurely retired units being born by customers in regulated markets and utilities in deregulated markets.
- IREs increase the Levelized Cost of Electricity (LCOE) for conventional resources by reducing their utilization rates without reducing their fixed costs.^{clxvi}
- Negative pricing, a consequence of production tax credits which occurs when the wholesale price of power is actually less than zero, is forcing generators to incur costs to stay online and generate power.
- Land use associated with IRE is significant – replacing a 400 MW coal power plant requires 4,350 acres of solar panels or 161,000 acres of non-coastal wind turbines.

APPENDIX 1D – Renewable Energy and Dispatch

The addition of renewable energy resources in any state or region will increase the need for and enhance the value of coal baseload plants because consumers require reliable power that is available at all times. It could even have the unintended consequence of increasing the value of some coal plants.^{clxvii}

Consumer demand for 100% availability is accommodated by generating units supplying energy which matches the load shape forecast over a 24-hour period. Generating units are dispatched to match this 24-hour cycle, and additional operating (spinning) generation is held in reserve to meet unanticipated and anticipated unit interruptions or changes to the load forecast. The units supplying this energy are termed dispatchable and may be further categorized as:

- Base Load (called upon to operate 24 hours per day)
- Intermediate Load (which typically operate 8-10 hours per day)
- Peaking (called upon to operate a few hours per day, typically during peak periods)
- Operating Reserve (called upon either immediately or in a very short time frame to accommodate load which becomes un-served based on an operating unit coming off line very quickly or based on an unusual unscheduled demand for supply)

In order to operate, the system must constantly be in balance, with the supply of energy equal to the load. If there is too little supply, reserves are called on; if there is too much supply, generator output is reduced or curtailed. After the bilateral contracts are scheduled into the daily dispatch, the bids received from the generators are generally in a one-to-one correspondence with the costs to supply the energy, with the supply cost curve typically moving up in price from base load to peaking. Base and intermediate load generators are currently fueled primarily by coal and nuclear, and, increasingly in recent years, by natural gas. Peak power is typically fueled by natural gas.

Electric power from wind generators varies according to the cube of the wind speed impacting the turbine blades, but wind speeds vary dramatically over the course of a day, week, month, and year. Variations in wind power thus range from zero (no or very little wind blowing) to full nameplate capacity of the wind generators (during excessively high wind speeds, generators are shut down to avoid damage). Such on- again, off-again cycling of wind generators, as well as solar generators, is termed intermittent. Thus, the dispatching of wind turbines must accommodate intermittency, which is a significant system operational concern because consumers require reliable, always-available power-on-demand.^{clxviii}

One consequence of intermittency is that wind power requires near 100% back-up by power plants that are reliable and dispatchable. Such backup plants must be capable of quickly ramping up or down to compensate for wind variations to provide power-on-demand to the consumer. Further, the backup plants must be maintained in a fully operational state at all times in order to be able to quickly respond to wind variations. The reserve called on to operate immediately to assure the changes to the supply/ demand requirements are in balance is called “spinning reserve.”^{clxix}

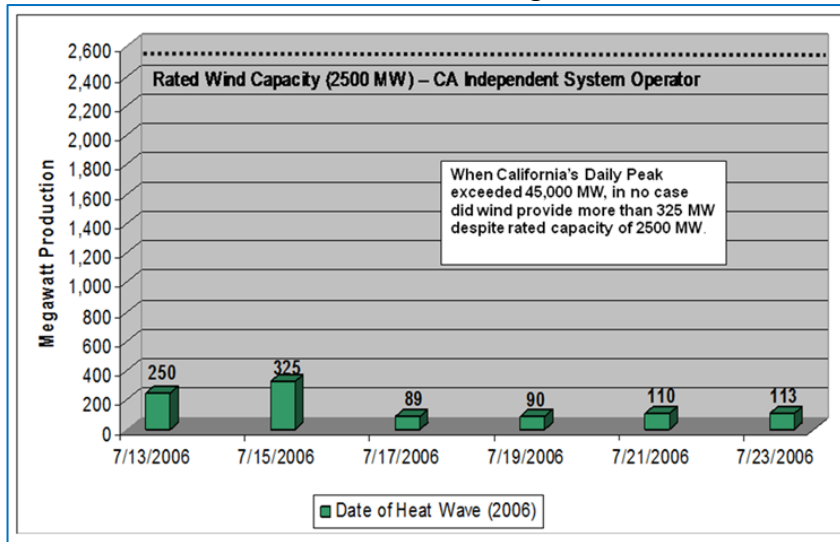
Wind power is a growing percentage of total generation in many states. For example, in New York State, installed wind capacity increased from 279 GW in 2006 to 1,826 GW in 2016, and wind generation increased from 518 GWH in 2006 to 3,943 GWH in 2016.^{clxx} However, wind's inherent nature-related variations must be accommodated by adjustments in on-line generators. As wind power is planned to grow significantly in many states, the backup power burden can no longer come from minor adjustments to dispatchable power plants. On this basis, the cost of large-scale wind generation must include not only the cost of the wind generators themselves but also the cost of dedicated dispatchable backup generation of a size which accommodates significant intermittent units operating on the system. The location of backup generators for wind power must be relatively close to the wind generators, otherwise large blocks of backup electric power would have to be shuttled over long distances over routes that at times are constrained and thus cannot accommodate such shuttling.

To reiterate, wind turbines do not generate electricity when the wind does not blow. However, few understand the degree to which these resources fail to operate when electric power is most urgently required. Production data on the U.S. power industry clearly illustrate that wind's intermittency requires significant generation resources to be operating on the electric system to assure reliable continuous supply, which can only be accommodated by generation of sufficient size and operating capability to furnish such backup.

The U.S. Energy Information Administration (EIA) estimates average capacity factors for wind of about 33%, for solar thermal of about 22%, and for photovoltaics of about 25%.^{clxxi} Other estimates of wind capacity factors are in the range of 20% to 30%, and could be even lower.¹⁰ Given the time frame during the course of the daily load cycle during which peak loads occur, capacity factors for wind turbines are often much lower. For example, as shown in Figure 1, during the California heat wave in July 2006, which resulted in significant increases in electric demand, actual wind generation was at only about five percent of available name plate capacity. Thus, in this case, the capacity factor for wind was closer to five percent than 33% or even 20%. Balancing off such wind turbine availability is the availability of solar arrays during peak summer periods, but as is the case in the Northeast during periods of summer peak, solar arrays are also adversely impacted by thunder storm cloud cover.

¹⁰ Centre for Sustainable Energy, "Common Concerns About Wind Power," June 2017. In addition, Hughes found that the normalised load factor for UK onshore wind farms declines from a peak of about 24% at age 1 to 15% at age 10 and 11% at age 15. He found that the decline in the normalised load factor for Danish onshore wind farms is slower but still significant, with a decline from a peak of 22% to 18% at age 15. Gordon Hughes, "Analysis of Wind Farm Performance in UK and Denmark, prepared for the Renewable Energy Foundation," December 2012. Similarly, Bocard noted "For two decades, the capacity factor of wind power measuring the mean energy delivered by wind turbines has been assumed at 35 percent of the nameplate capacity. Yet, the mean realized value for Europe over the last five years is closer to 21 percent thus making levelized cost 66 percent higher than previously thought." Nicolas Bocard, "Capacity Factor of Wind Power: Realized Values vs. Estimates," October 2008. The actual capacity factors for wind in Germany ranged between 14 and 21 percent over the period 2000 through 2007; see *Wind Energy Report Germany 2008*, ISET, Univ. Kassel, Germany, 2008.

Figure 1. Wind Generation's Performance during the 2006 California Heat Wave



Source: U.S. Department of Energy

Similar availability issues have been encountered in Texas, which also has an aggressive wind power program. In 2008, the state installed nearly 2,700 MW of new wind capacity, and if Texas were an independent country, it would have then ranked sixth in the world in terms of total wind power production capacity. However, the Electric Reliability Council of Texas (ERCOT) analyzed the capacity factor of wind and estimated it to be less than nine percent. In a 2007 report, ERCOT determined that only "8.7 percent of the installed wind capability can be counted on as dependable capacity during the peak demand period for the next year." It went on to say "Conventional generation must be available to provide the remaining capacity needed to meet forecast load and reserve requirements." In 2009, ERCOT re-affirmed its decision to use the 8.7% capacity factor.^{clxxii}

For non-coastal wind, ERCOT has measured a historical capacity factor of only 12% in summer months.^{clxxiii} Analysis of Seasonal Assessment of Resource Adequacy (SARA) reports and historical data from the summers of 2012 through 2015 indicates that wind capacity utilization could be as low as 4.1%. This implies that total wind output across ERCOT could total only 679 MW on a peak summer day – when the power is most needed. ERCOT planners continued to estimate that that wind projects would provide less than 9% of their nameplate capacity towards meeting peak demand.^{clxxiv} That estimate for Effective Load-Carrying Capability (ELCC) was based on the fact that wind production is not dependable and may be inversely correlated with demand, especially during hot summer days with little or no breeze.

A widely publicized report by the Texas Comptroller of Public Accounts found that little wind power is available in the summer months when Texans use the most power.^{clxxv} The report highlighted the monumental failure of wind power to be available when it is required, stating "For summer 2014, even though Texas had more than 11,000 MW of total wind capacity, ERCOT counted on just 963 MW of wind generation being available. The lack of wind generation during summer peak demand means that energy planners, such as ERCOT, have to ensure that a lot of flexible natural gas generation is available to meet the reserve margin." Thus, as shown in Table 1, wind generation is lowest during the summer months when energy demand is the highest.

Table 1. Comparison of Generation Ability in ERCOT

GENERATION SOURCE	AVAILABILITY OF INSTALLED CAPACITY, 2013	2013 GENERATION (% OF TOTAL)	ELECTRICITY DELIVERED AT 2013 PEAK DEMAND
GAS (ALL TYPES)	81%-89%	41%	59%
COAL (ALL TYPES)	84%-86%	37%	29%
NUCLEAR	85%	12%	7.5%
WIND	8.7%*	10%	3.5%

Note: *Because wind generation varies so much each day, wind percentage is reported as the effective load-carrying capacity used by ERCOT for forecasting purposes. Total available wind capacity was 11,066 MW as of May 1, 2014. Other resources were excluded from this comparison due to their limited capacity.

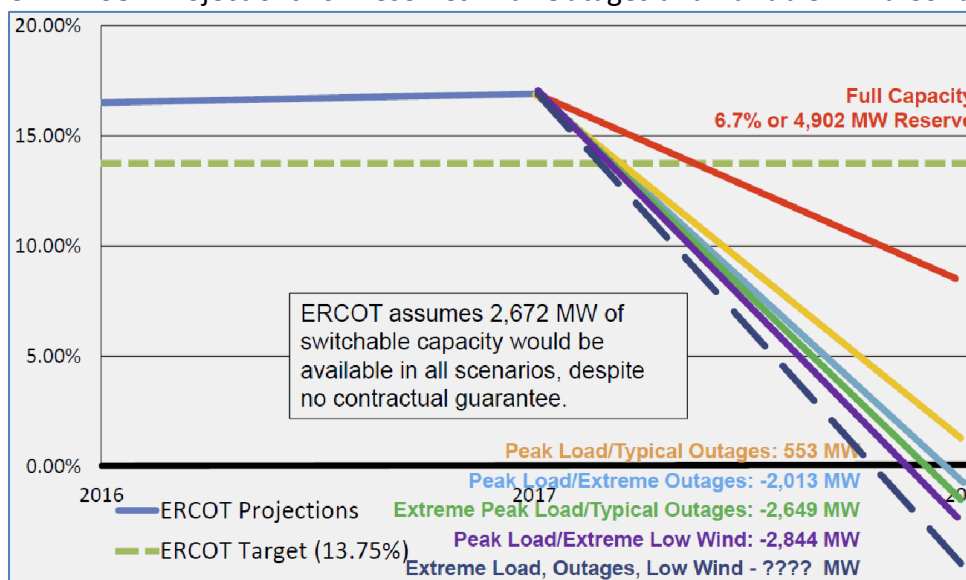
Source: Electric Reliability Council of Texas and Texas Reliability Entity.

More recently, Mike Nasi (Jackson Walker LLP) analyzed the Texas power market and found that:^{clxxvi}

- Baseload coal has been a backbone of the Texas Success Story, but renewable subsidy market distortions are endangering the grid.
- The cost of transmission and ancillary services to build and “balance” renewables is socialized to entire market and masked by low natural gas prices.
- The more the grid is exposed to large “swings” when the wind stops blowing, the more blackouts and price spikes are a risk.
- Prolonged market distortions erode the economics of baseload, drive retirements, and discourage investments in new baseload (even gas).
- Basic realities of physics and energy density make renewables an inadequate replacement to baseload electricity from coal.

As shown in Figure 2, the near-term implications for Texas may be ominous.

Figure 2. ERCOT Projections for Reserves with Outages and Variable Wind Conditions



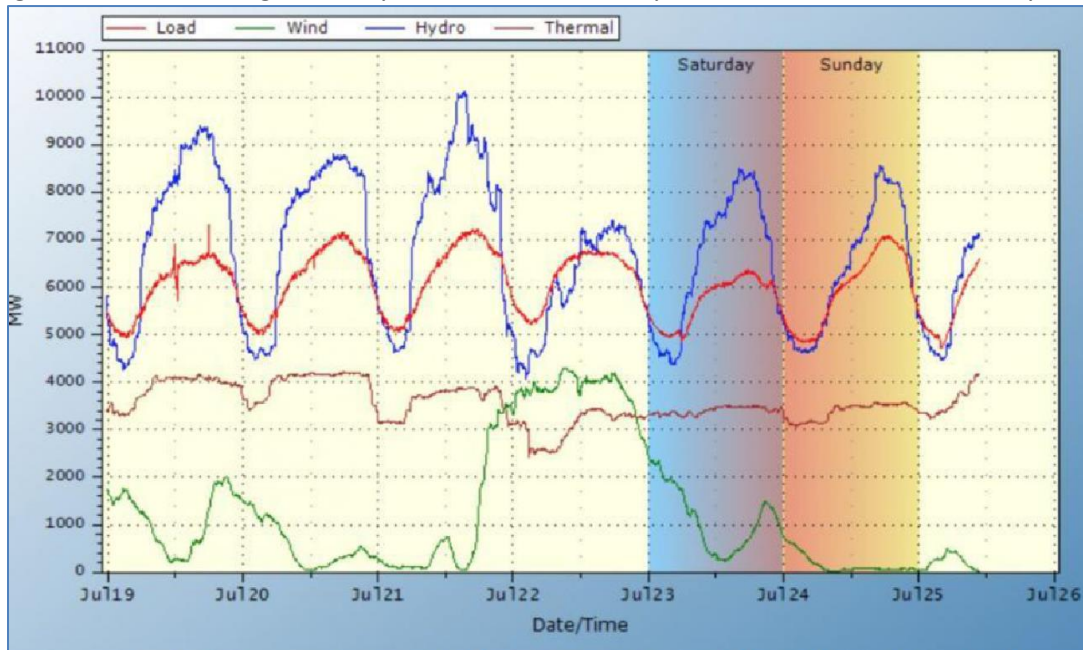
Sources: ERCOT, Capacity, Demand and Reserves Reports, Winter Updates, 2007-2017; Seas. Assess. of Res. Adeq., Mar. 2018.

Thus, despite massive investments and continuing subsidies, wind power has been providing only a small percent of Texas's total reliable generation of energy, and ERCOT's projections show that wind will continue to remain an insignificant player in terms of reliable capacity. Accordingly, Texas will continue to rely almost entirely on natural gas, coal, and nuclear power to generate electricity.

The experience of the Pacific Northwest, another region with an aggressive wind program, is similar. Often when it is very hot or very cold and electric power demand is greatest, wind generation is simply not available. For example, during the cold days of January 5 to 28, 2009 wind generation in the region was virtually non-existent.^{clxxxvii} Another example of wind generation variability took place on October 16, 2012 when wind generation on the Bonneville Power Administration system was producing 4,300 MW, accounting for 85 percent of total generation in the pre-dawn hours. The next day, wind generation was practically non-existent, falling to almost zero.^{clxxxviii}

Similarly, an extreme 2016 heat in Washington State illustrated the reliability problems with wind power.^{clxxxix} Figure 3 illustrates that during the heat wave, nuclear power (the largest proportion of the thermal curve shown) provided power continuously at a capacity factor of 98% and hydro was used to load-follow. Wind blew occasionally, and mostly when it was not needed. Most of the electricity needed to combat this heat wave was concentrated during peak hours of the afternoon when the wind turbines were not turning.

Figure 3. BPA Balancing Authority Load & Total Wind, Hydro & Thermal Generation, July 2016



Source: Bonneville Power Administration

Analysis of almost four years of generation data in ERCOT with over 10,000 MW of wind capacity, the Midwest ISO (MISO) with almost 12,000 MW of wind capacity, and the PJM Interconnection (PJM) with over 5,000 MW of wind capacity, found that:^{clxxx}

- In all three regions, over 84% of the installed wind generation failed to produce electricity when electric demand was greatest.

- In MISO, only between 1.8% and 7.6% of wind capacity was available and generating power during the peak hours on the highest demand days.
- In ERCOT, only between 6.0% and 15.9% of wind facilities generated power during peak summer periods.
- In PJM, the range was between 8.2% and 14.6% during peaks.
- These availability values are significantly lower than median availability for the entire period.

The July 2012 heat wave in Illinois, where temperatures reached 103 degrees in Chicago, provides another example of wind generation’s limitations to perform when needed most. During this heat wave, Illinois wind units generated less than five percent of nameplate capacity, producing only an average of 120 MW of electricity from over 2,700 MW installed. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago averaged 22,000 MW, the average amount of wind power available during the day was virtually nonexistent at 4 MW.^{clxxxix}

More generally, the greatest amounts of wind generation occur in the spring and fall, when the demand for electricity is lowest, and the smallest amounts of wind generation occur in summer, when the demand for electricity is the greatest. Wind generation data in PJM, the nation’s largest independent system operator, show that the “load–wind gap” (the difference between summer electric demand and summer wind availability, relative to respective annual averages) was almost 70% in the summers of 2010 and 2011. In summer 2012, the load–wind gap was 59%.^{clxxxix}

Thus, “While renewable energy sources have made many advances in recent years, they are not widespread enough to be able to support an electrical grid as a base load. Renewable energy is intermittent, unreliable, requires back-up, is non-dispatchable, and not available during emergencies.”^{clxxxix}

The New York State wind experience is similar to that in other regions and indicates the need for baseload facilities to back-up renewable generation intermittency. For example, an analysis of 16 wind projects in New York State between 2008 and 2011 found that, despite vendor promises prior to installation of capacity factors of 30% to 35%, average annual capacity factors ranged between 14.1% and 22.7%.^{clxxxix}

Researchers also analyzed four New York State wind projects since their inception in a comprehensive study centered on the Noble Chateaugay project, which has 71 GE 1.5 SLE turbines and is capacity-rated at 106.5 megawatts.^{clxxxix} Their research determined that the actual annual output of the Chateaugay project was only 23 megawatts, giving it a capacity factor of 21.6%. The other northern New York projects had similar capacity factors. The researchers noted that this is substantially less than the 30% to 35% commonly predicted by wind developers. They also found that all northern New York wind projects had more than 1,200 hours annually that produced no electricity at all -- the equivalent of 50 24-hour days, or 14% of the time, with zero generation. Thus “It appears wind developers notoriously inflate expected capacity factors to entice investors and increase chances of permitting approvals.” Further, “Both Vesta and GE turbines have a manufacturer’s life expectancy rating of 20 years, yet no northern New York wind project is on track to sell enough electricity in 20 years to pay for itself.”^{clxxxix}

All New York generating units, both renewable and non-renewable, have an “unforced capacity value” (UCAP) for purposes of the capacity markets, which is used for reliability planning and which load serving entities such as the state’s electric utilities purchase to assure that installed generating reserve is available to serve customer load during peak periods.^{clxxxvii} This UCAP value is a percentage of a resource’s nameplate MW value; for wind and solar this number is based on an initial NYISO designated rating for Year 1 of operation and on actual historical energy output for every year thereafter. The values are facility specific, but the UCAP for onshore wind in NY is 10-14% for the summer peak – when electricity is needed the most and electricity prices are the highest.^{clxxxviii}

This unforced capacity value is not unique to New York State, or even to the U.S. Similar unforced capacity values are the case in the Netherlands, Denmark, England, Germany, Spain, Portugal, and Ireland, or anywhere that large scale wind generation is part of the installed generation mix.^{clxxxix} An Australian study found that even wind farms spread over large, widely dispersed areas and interconnected into a single electric system cannot produce electricity with capacity factors close to name plate capacity.^{cx}

Further, the performance and capacity factors of wind turbines deteriorate over time. A seminal study analyzed the rate of ageing of a national fleet of wind turbines using public data for the actual and theoretical ideal load factors from the UK’s 282 wind farms.^{cxci} It found that:

- Load factors declined with age, at a rate similar to that of other rotating machinery.
- Onshore wind farm output declines 16% a decade.
- Performance declines with age occurred in all farms and all generations of turbines.
- Decreasing output over a farm's life increased the levelized cost of electricity.

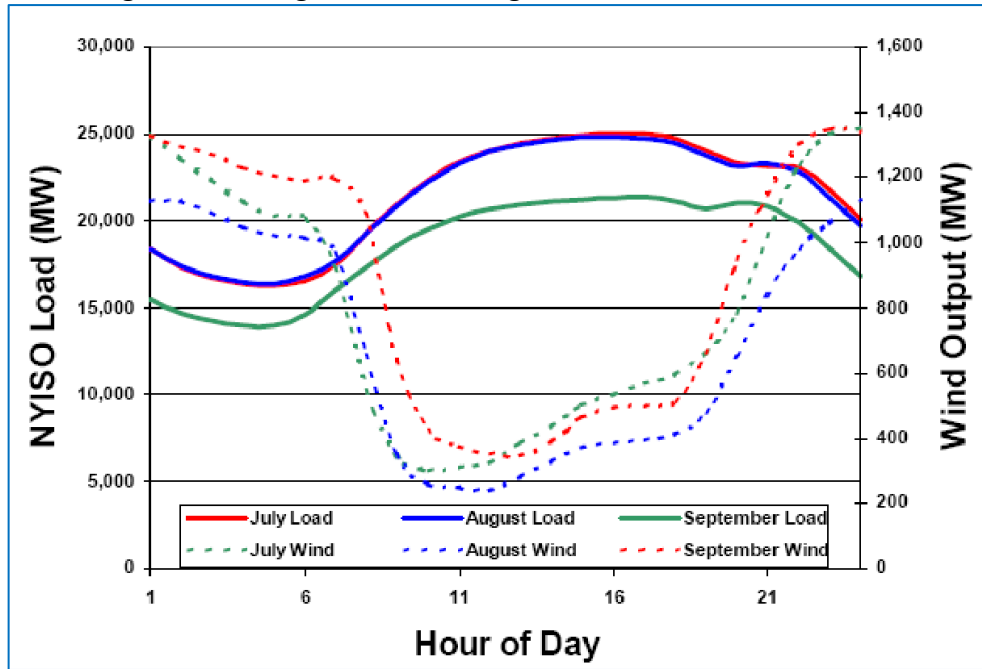
The study determined that this degradation was consistent for different vintages of turbines and for individual wind farms, ranging from those built in the early 1990s to early 2010s.^{cxcii}

The Renewable Energy Foundation, an organization that advocates in favor of renewable energy facilities, also conducted a comprehensive study of the available capacity factors over time for wind turbines in the UK and came to similar findings. Using monthly observations for 282 onshore installations in the UK with an age range of zero to 19 years, it found “the normalized load factor for UK onshore wind farms declines from a peak of about 24% at age one to 15% at age 10% and 11% at age 15.”^{cxci} In other words, the capacity factors for wind generators decline significantly every year after installation.

State renewable portfolio standards contributed to more than half of all renewable electricity growth in the U.S. since 2000.^{cxci} Expanding the supply of electricity from renewable resources and enhancing energy efficiency are among the longstanding goals of many states. In addition, many states have established extremely ambitious renewable energy goals.

However, wind generation, for example, presents serious challenges to system operators due to the variability of output and to the fact that wind energy production tends to increase much later in the day, when power use is declining, and to decline in the morning when power use is building. Figure 4 demonstrates this for New York State. In addition, wind projects in New York are predominantly being developed in the northern and western portions of the state, based on available wind resources situated almost exclusively in this region, while the population centers of southeastern New York are the regions with the highest demand for electric supply.^{cxci} This presents a dispatch encumbrance for the future of NY electric markets because most of the proposed new electric generation in NY consists of renewables.^{cxci}

Figure 4. Average Load v. Average Wind in New York State

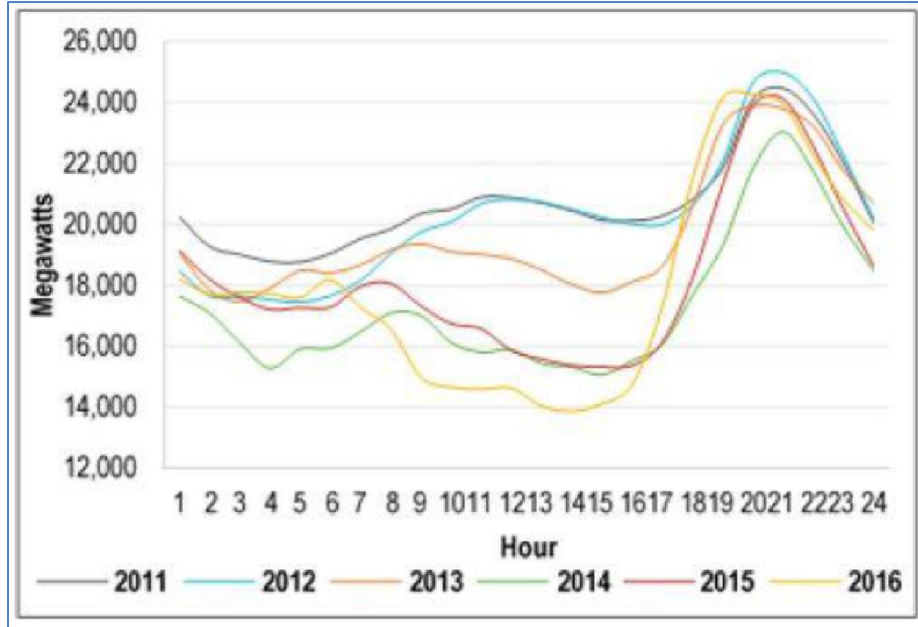


Source: GE Energy Consulting

Solar energy is also ill-suited to supplying reliable electric power when it is needed. The duck curve -- named after its resemblance to a duck -- shows the difference in electricity demand and the amount of available solar energy throughout the day. When the sun is shining, solar floods the market and then declines rapidly off as electricity demand peaks in the evening. The duck curve in Figure 5 is a snapshot of a 24-hour period in California during springtime -- when this effect is most extreme because it is sunny but temperatures remain cool, so demand for electricity is low since people aren't using electricity for air conditioning or heating.

In commercial-scale electricity generation, the duck curve is a graph of power production over the course of a day that shows the timing imbalance between peak demand and renewable energy production. In many energy markets the peak demand occurs after sunset, when solar power is no longer available. In locations where a substantial amount of renewable electric capacity has been installed, the amount of power that must be generated from sources other than solar or wind displays a rapid increase around sunset and peaks in the mid-evening hours, producing a graph that resembles the silhouette of a duck.^{cxcvii} The most pertinent example is currently in California, as illustrated in Figure 5. This shows that the problem has become significantly worse in recent years as California has mandated increasing amounts of renewable energy and should serve as a warning to other states as they pursue ambitious renewable energy goals.

Figure 5. California Duck Curve: Lowest Daytime Net Load, 2011-2016



Source: California Independent System Operator

In sum, numerous studies indicate that baseload facilities, which provide backup for intermittent power, can provide increasingly valuable system support which increases in importance every year as more wind facilities are installed. As renewable energy generation increases as a percentage of U.S. generation capacity mix over the coming decades, the more necessary sources of non-intermittent generation from baseload facilities will become. The planning processes in many states currently rely on renewables as a major generation source.^{cxviii} Replacement of baseload non-intermittent generation with intermittent renewable capacity will require generation from reliable sources to be available and to be on-line more frequently. This will make them all that more valuable. Further, since the performance and capacity factors of wind turbines deteriorate over time – starting at the year of installation, the need for and the value of more reliable power sources will increase every year.

APPENDIX 1E – Highlights of NERC Testimony on the Performance of the Electric Power System Under Certain Weather Conditions

U.S. Senate Energy & Natural Resources Committee, January 23, 2018

Testimony of Charles A. Berardesco, Interim President & CEO, North American Electric Reliability Council (NERC)

https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=D982B4F9-ECAF-403B-88BA-C82D2634E2DA

“In its long-term reliability assessments, NERC identifies how reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions. Against a backdrop of low natural gas prices and policies that promote increased natural gas generation, regions of the country have significantly increased dependence on natural gas over the past decade. Four of NERC’s assessment areas now meet their peak electric demand with greater than 50% of that sourced from natural gas-fired generation.

NERC’s 2017/2018 Winter Reliability Assessment observes an increasing trend since 2012 of natural gas-fired generation outages during winter months. These historical outages that resulted from fuel unavailability during the winter months underscore the need for fuel assurance and operational readiness during periods when reliance on natural gas can be critical.

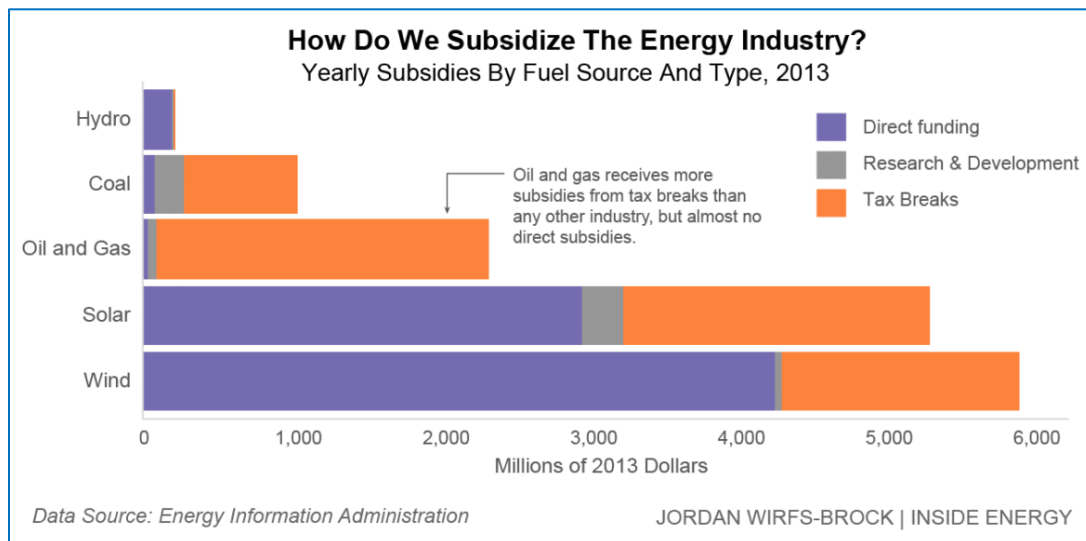
During the extreme cold, a diverse generation mix with adequate flexible fuel resources and back-up fuel was key to meeting increased electricity demand. All forms of generation contributed to serving load ... Accordingly, NERC recommends policymakers and regulators should consider measures promoting fuel diversity and supplemental fuel sources as they evaluate electric system plans, consistent with policy objectives.”

APPENDIX 1F – Perspectives on Energy Subsidies

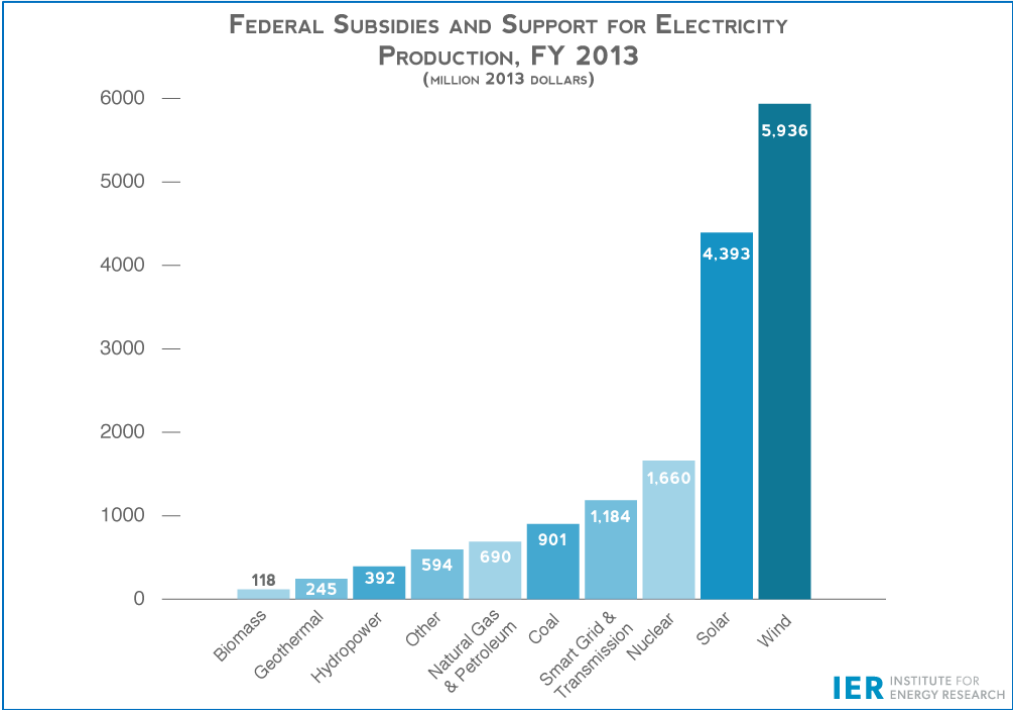
Environmental regulations, subsidies and policy mandates contribute to the cost of electric generation and skew the playing field for deployment of energy resources. Renewables, which are subsidized to a larger degree than other sources of energy, have benefited for years from tax credits, direct funding, and research and development support funding. This level of support has put other energy resources at a market disadvantage, fostering the need for corrective, compensatory measures that will facilitate parity.

Among the key findings in an April 2018 report¹¹ by the Energy Information Administration (EIA) is that “Most current federal subsidies support developing renewable energy supplies (primarily biofuels, wind, and solar) and reducing energy consumption through energy efficiency. In FY 2016, nearly half (45%) of federal energy subsidies were associated with renewable energy, and 42% were associated with energy end uses.” The report documents that between 2010 and 2016, renewable energy’s share of energy-specific subsidies and support increased from 42% to 45%; coal’s share for the same period increased from 2% to 8%. Analysis by other entities for prior years documents similar findings.

In addition to the market disadvantages imposed by such distortions, tilted playing field has curtailed investment in advanced technologies capable of furthering environmental objectives associated with all energy resources. Inequitable mandates, subsidies and policies have contributed to increased electric prices by forcing the early retirement of power plants, leaving valuable stranded assets that can only be compensated for through increased consumer prices.



¹¹ EIA, “Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2016,” April 2018, <https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf>

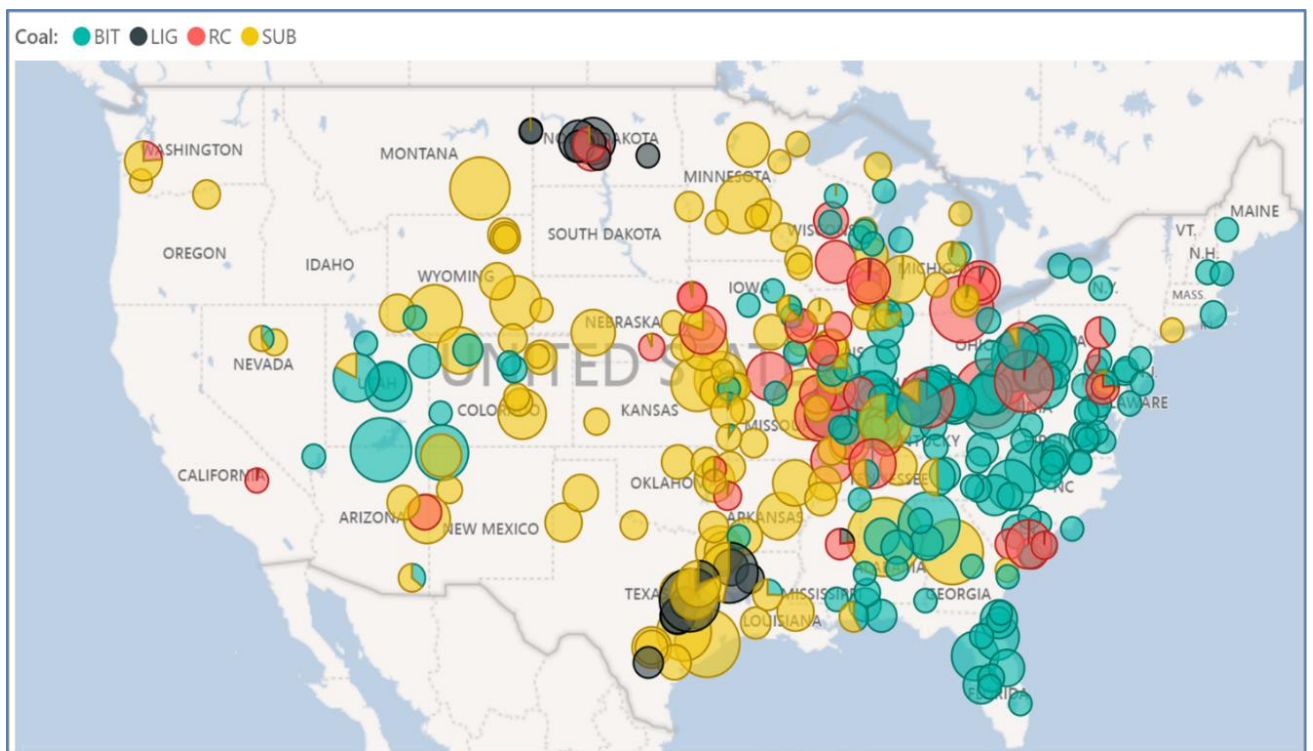


Beneficiary	Direct Expenditures	Tax Expenditures	Research and Development	Federal and RUS Electricity	Total	Share of Total Subsidies and Support
Coal	61	642	167	30	901	6%
Natural Gas and Petroleum Liquids	18	662	10		690	4%
Nuclear	37	1,109	406	109	1660	10%
Renewables	7,408	3,373	722	176	11678	72%
Biomass	62	9	47	-	118	1%
Geothermal	221	22	2	-	245	2%
Hydropower	194	17	10	171	392	2%
Solar	2,448	1,712	234	-	4393	27%
Wind	4,274	1,614	49	-	5936	37%
Other	209	-	380	5	594	4%
Subtotal Renewables Electric	7,408	3,373	722	176	11678	72%
Electricity - Smart Grid and Transmission	8	211	831	134	1184	7%
Total	7,532	5,996	2,136	449	16112	100%

Source: DOE Grid Study: Fiscal Year 2013 Electricity Production Subsidies and Support

APPENDIX 1G – U.S. Coal-fired Power Plants Location, Coal Type and Generation (MW)

The location and size of coal-fired power plants in the contiguous U.S. is shown below. The largest density of plants and generating capacity is in the eastern half of the country, with the exception of the New England states. The type of coal-fired plant typically varies by region, with a higher density of bituminous-fired plants in the east and southeast with the exception of several units firing local bituminous coals in the west. Most of the subbituminous coal is shipped by rail from the Powder River Basin in Montana-Wyoming to plants in the mid-west and west. Lignite plants are typically located near lignite mines in the Gulf region and in North Dakota.



Location, coal type, and relative electricity generation (MWhr) for coal-fired plants in contiguous U.S. RC = plants reporting using refined coal.

Source: U.S. EIA Forms EIA-860 and EIA-923 data

APPENDIX 1H – Environmental Regulations Impacting Coal Generation

Regulation	Federal Register Publication	Implementation Period	Provision Highlights	Potential and Realized Impacts
Cooling water intake rule (316b) under the Clean Water Act (CWA)	Phase 1 – 2001 rev., 2003, Phase 2 – 2014	Phase II 2014 - 2018	Requires controls to reduce mortality to fish and aquatic organisms	Upgrades to cooling water intake structures to reduce and elimination of once through cooling through use cooling towers
Cross-State Air Pollution Rule under the Clean Air Act (CAA)	2011	Phase 1 – 2015 and Phase 2 - 2016	Requires states to reduce emission of SO ₂ and NO _x .	Requires new or upgrades to emission control equipment such as FGD scrubber systems and SCR catalyst systems.
Steam Electric Effluent Limitations Guidelines, CWA, 40 CFR 423	Initially in 1974 with the last publication in 2015	2015 update is stayed while EPA reviews Rule	Establishes limitation on the discharge of chemical pollutants and thermal discharges from steam electric power plants. The 2015 update sets federal limits on levels of metals that can be discharged	No wet sluicing of bottom or fly ash to ash ponds. New limits of metals can only be achieved with new technology of a combination of physical chemical systems. The EPA estimated annual, industry-wide cost for power plants to comply would be \$480 million. The actual cost is significantly different from site to site.
New Source Review (CAA)	1980 initially with last update in 2002	2002 updates under court challenge	Requires new or modified power plant upgrades most obtain a pre-construction permit to ensure modern emission control equipment is installed. New Source Performance Standards (NSPS) makes it nearly impossible to retrofit existing facilities because rules stipulated plants can emit no more than 1,400 pounds of CO ₂ per megawatt hour of electricity generated. A standard coal plants can't meet without carbon capture and storage.	Requires new or modified power plant upgrades most obtain a pre-construction permit to ensure modern emission control equipment is installed. New Source Performance Uncertainty stemming from NSR process has led to a lack of investment in efficiency upgrades which would have led to more efficient power generation and reduced environmental impacts.

Mercury and Air Toxics Standards (CAA)	2012	2015 and for some units qualifying for a 1 year extension to 2016	Establishes emission limits for mercury, arsenic, acid gases, and other toxic pollutants	Implementation of a combination of control technology such as FGD scrubber systems, Selective Catalytic Reduction (SCR) systems, fuel additives, and/or activated carbon injection systems. “Of the 87 GW of coal capacity that installed pollution control equipment to comply with MATS, activated carbon injection (ACI) was the dominant compliance strategy. More than 73 GW of coal-fired capacity installed ACI systems in 2015 and 2016, effectively doubling the amount of coal capacity with ACI.” At least \$6.1 billion was invested from 2014-2016 to comply with MATS or other environmental regulations. ^{cxcix}
Coal Combustion Residuals Rule under Resource Conservation and Recovery Act (RCRA)	2015	2015 - 2018	New regulations on the disposal of coal combustion residuals (CCRs) by electric facilities. Rules establish national standards for disposal. Address dike and pond stability requirements. Addresses groundwater contamination risks from coal combustion residuals (CCRs) disposal in landfills and ponds by establishing national standards for disposal	Triggers landfill and pond closures if stability and locations standards and groundwater standards are not met. Retiring a coal-fired unit after the effective date of the Rule isn’t a compliance option so this Rule alone doesn’t trigger retirements. Enforcement was through citizen enforcement (the threat of lawsuits) until passage of the WIIN Act. The reporting burden and threat of lawsuits is one more consideration that weighs in favor of closures of coal fired plants. If closure occurred prior

				to effective date of Rule, the Rule wasn't applicable.
Regional Haze Rule under CAA	1999 with policy revisions in 2017	Revised state plans due in 2021	Requires states to develop long-term strategies and enforceable measures to improve visibility in 156 national parks and wilderness areas. Aims to return visibility to natural conditions by 2064.	Uncertainty about implementation impacts power plant compliance and retirement planning.
Carbon Pollution Standards and Clean Power Plan (CPP) under CAA	2015	Under EPA review and is currently stayed (Feb 2017, U.S. Supreme Court decision put the initiative on hold. October 2017 a Notice of Proposed Rulemaking was issued to repeal the CPP.	Establishes CO2 emission standards for new and existing power plants	The never implemented CPP was still damaging because the prospects of compliance triggered retirements because coal emits roughly twice the carbon as natural gas electricity generators. Even the prospect of compliance weighed heavily with decision makers



RETIREMENT OF COAL-FIRED ELECTRIC GENERATING UNITS¹²

As of August 12, 2018

All Retirements

Since 2010, power plant owners have announced either the retirement or conversion to other fuels of a large number of coal-fired electric generating units.¹³ The table on the following pages summarizes all publicly announced retirements through 2030. The table shows that 630 coal-fired generating units in 43 states — totaling over 115,000 megawatts (MW) of generating capacity — have retired or announced plans to retire. These retirements are approaching 40% of the U.S. coal fleet that was operating in 2010. Through 2017, approximately 68,000 MW of coal-fired generating capacity have retired. For 2018-2020, an additional 25,000 MW are expected to retire, bringing total retirements to 93,000 MW by the end of 2020.

EPA-Attributed Retirements

The table also includes retirements that have been explicitly attributed to EPA regulations and policies. These EPA-caused retirements total 463 units and represent almost 77,000 MW of coal-fired generating capacity. Of the total, 58,000 MW have already retired.

ISO/RTO Retirements

Over 50,700 MW of coal-fired generating capacity in ISO/RTO regions have retired. An additional 5,400 MW in these regions are slated to retire over the remainder of 2018-2020, of which 3,100 MW have been attributed to wholesale electricity market conditions. The regions with the most retirements through 2020 are PJM (32,400 MW), MISO (14,700 MW), ERCOT (5,100 MW) and SPP (5,100 MW).

¹² Retirements and conversions are based primarily on public announcements by the owners of the coal units. We also use other information sources that are reliable. These retirements and conversions are *not* based on modeling projections. We do not include small (less than 25 MW) cogeneration units. Since most of these units are retiring, not converting to another fuel, we use the term “retirements” in this paper to characterize units that may be *either* retiring or converting.

¹³ In 2010, according to EIA, the U.S. coal fleet was comprised of 1,396 electric generating units located at 580 power plants for a total electric generating capacity of approximately 317,000 MW.

	MW RETIRING	UNITS RETIRING
1. Ohio	12,131 ¹⁴ / 6,421 ¹⁵	59 / 40
2. Indiana	6,569 / 6,129	39 / 34
3. Pennsylvania	5,847 / 5,548	34 / 30
4. Texas	5,672 / 1,399	10 / 3
5. Illinois	5,663 / 3,076	21 / 14
6. Alabama	5,166 / 5,166	26 / 26
7. Michigan	4,911 / 4,075	44 / 31
8. Florida	4,752 / 1,568	14 / 7
9. North Carolina	4,615 / 2,783	37 / 20
10. Kentucky	4,168 / 3,743	20 / 18
11. West Virginia	4,040 / 2,740	20 / 18
12. Georgia	3,752 / 3,249	17 / 15
13. Arizona	3,482 / 3,482	8 / 8
14. Virginia	3,258 / 2,354	29 / 16
15. Wisconsin	2,928 / 1,287	27 / 16
16. Nevada	2,689 / 0	8 / 0
17. Tennessee	2,659 / 2,659	17 / 17
18. Oklahoma	2,414 / 2,414	5 / 5
19. Colorado	2,405 / 1,776	19 / 16
20. Missouri	2,372 / 2,355	24 / 23
21. Minnesota	2,288 / 2,150	17 / 15
22. Montana	2,248 / 154	5 / 1
23. New Mexico	2,222 / 2,222	7 / 7
24. Utah	2,072 / 272	7 / 5
25. Iowa	1,847 / 1,579	33 / 29
26. South Carolina	1,768 / 1,768	14 / 14
27. New York	1,708 / 475	14 / 3

¹⁴ Total coal retirements.

¹⁵ Coal retirements attributed to EPA regulations and policies.

28. Massachusetts	1,663 / 1,408	8 / 6
29. Arkansas	1,659 / 1,659	2 / 2
30. New Jersey	1,543 / 268	6 / 2
31. Washington	1,376 / 0	2 / 0
32. Nebraska	757 / 637	6 / 5
33. Mississippi	706 / 706	2 / 2
34. Maryland	635 / 115	5 / 2
35. Oregon	585 / 585	1 / 1
36. Louisiana	575 / 575	1 / 1
37. Connecticut	566 / 0	2 / 0
38. Kansas	550 / 478	7 / 6
39. Delaware	360 / 0	4 / 0
40. North Dakota	189 / 0	1 / 0
41. California	129 / 0	3 / 0
42. Wyoming	49 / 49	4 / 4
43. South Dakota	22 / 22	1 / 1
43 / 37 States	115,010 / 77,346 MW	630 / 463 Units

Appendix 2B – Coal Combustion Residuals Rule

Summary

The Coal Combustion Residuals (CCR) rule imposes high costs on certain disposal sites. The rule may drive units to retire as the compliance costs become prohibitive, adding to the cost of generation, or their disposal facility is forced to close, and the alternatives are too expensive. A detailed discussion of the rule's impacts on coal plants and associated costs are presented here.

Background

EPA promulgated the current regulation governing the management of Coal Combustion Residuals CCR Rule at power plants on April 17, 2015 (“the 2015 CCR Rule”). The 2015 CCR Rule established national minimum criteria for existing and new CCR landfills and surface impoundments. The minimum national standards include location restrictions; design and operating criteria; groundwater monitoring and corrective action; closure requirements and post closure care; and recordkeeping, notification and Internet posting requirements. The 2015 CCR Rule, promulgated under RCRA 1008(a), 4004(a) and 4005(a), did not require facilities to obtain a federal or state permit, nor did it establish any requirements on states or state programs. EPA took the position that it did not have the authority under RCRA to require or recognize state permits (or other systems of prior authorization) and, as a result, the 2015 CCR Rule is strictly a self-implementing program, enforceable solely through RCRA citizen suits.

In December 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act was enacted, establishing new statutory provisions applicable to CCR units. The WIIN Act authorized states to implement the CCR Rule through an EPA-approved permit program; and also authorized EPA to enforce the rule and in certain situations to serve as the permitting authority. Accordingly, states may submit a program to EPA for approval and authorizations or permits issued pursuant to the approved state program operate in lieu of the federal requirements. To be approved, a state program must require each CCR unit to achieve compliance with the federal regulations, or alternative state criteria that EPA has determined are “at least as protective” as the Federal regulations. Facilities are to continue to comply with the CCR Rule, however, until a state program is in effect for the regulation of the CCR units.

CCR Rule Provisions that Could Drive Retirements

The two most significant potential coal plant retirement drivers in the CCR Rule are: (1) location restrictions applicable in varying degrees to all CCR units and (2) retrofit/closure requirements applicable to “unlined” CCR surface impoundments.

Location Restrictions. The 2015 CCR rule contains five location restrictions that apply to new CCR units and selectively to existing CCR units. These restrictions include: (1) disposal within five feet of the uppermost aquifer; (2) disposal in wetlands; (3) disposal in unstable areas, including karst areas; (4) disposal near active fault zones; and (5) disposal in seismic impact zones. In addition, the current subtitle D regulation (40 CFR 257.3-1) that applied to these units before the final rule was issued, already restricts facilities that dispose of wastes in floodplains. For fault areas, seismic impact zones, and unstable areas (using karst areas as a proxy) the EPA's

Regulatory Impact Analysis (RIA) projected that 51 of the 1045 waste management units would be subject to the location restrictions resulting in an estimated 26 waste management units closing as a result. The remaining waste management units are expected to make certifications either that they are not subject to these three location restrictions or that their continued operation in these areas is protective.

Surface Impoundment Retrofit/Closure Requirements. The 2015 CCR Rule establishes a robust groundwater monitoring and corrective action program. Under the Rule, by January 15, 2018 owners/operators were required to complete a statistical evaluation to determine if data from wells downgradient of the CCR unit demonstrate that there is a statistically significant increase over background levels. The constituents that are of relevance at this stage of the evaluation are referred to as “Appendix III constituents.” If a statistically significant exceedance of an Appendix III constituent requires a facility to proceed to “assessment monitoring.”

At this stage, a different set of constituents, referred to as “Appendix IV constituents,” are evaluated. Sampling and resampling of wells occurs through October 2018, and a statistical evaluation needs to be completed by January 2019. If statistically significant increases are observed, then different paths are taken depending on whether the exceedance is observed at CCR landfill versus a CCR surface impoundment and whether the relevant surface impoundment is deemed “lined” versus “unlined.” The 2015 CCR Rule required owners and operators of a CCR surface impoundment to document whether or not each CCR surface impoundment was constructed with the liner requirements of the rule no later than October 17, 2016. 40 CFR 257.71(a)(1). The documentation required certification by a professional engineer (PE).

An existing CCR surface impoundment is considered to be an unlined unit if compliance with the liner requirements cannot be documented. 40 CFR 257.71(a)(3). Under the Phase I CCR rule changes currently proposed by EPA, state agency officials could be empowered to make liner determinations in the absence of a PE certification, which could prove significant for older units that might lack the documentation necessary for a PE to be able to certify what the state agency might have previously concluded.

The designation of a CCR surface impoundment as “unlined” is critical insofar as unlined CCR surface impoundments will have to be discontinued to be used and ultimately closed if certain groundwater conditions are observed, whereas if the same groundwater conditions are observed in relation to a CCR landfill or lined surface impoundment, such units will not have to close as a result of those conditions but will have to take corrective action measures to address the groundwater contamination.

The timeline for discontinued use and ultimate closure of unlined units can vary depending on the closure path that is chosen, but the default rule is that an owner/operator of an unlined CCR surface impoundment must cease to place CCR and non-CCR waste within 6 months of making a determination that a constituent listed in Appendix IV is detected at statistically significant levels above the established groundwater protection standard. This could occur as early as July 2019. This timeline can, however, be extended if an alternative closure path is allowed because the owner/operator can certify that CCR must continue to be managed in the CCR unit due to the absence of both on-site and off-site alternative disposal capacity or that the facility will cease operation of the coal-fired boilers no later than the dates specified in the rule,

but lacks alternative disposal capacity in the interim. Under either of these situations, CCR units may continue to receive CCR so long as the conditions of the rule are satisfied.

Significantly, if the owner or operator has not identified alternative capacity within five years after the initial certification of a lack of capacity, the CCR units must cease receiving CCR and must initiate closure following the timeframes established in the CCR Rule. Therefore, unless an alternative is identified prior to the 5 year term, the CCR unit will have to cease receiving CCR by July 2024 and closure must be completed by July 2029, unless the requirements of a 2 year extension are met. If so, closure must be completed by July 2031.

Rule Costs

The costs of compliance with CCR regulations at power plants, closing ash ponds and non-compliant landfills, are substantial. A recent study of plant decommissioning costs suggests that environmental remediation can be more than fifty percent of decommissioning costs.[1] A study commissioned by the Office of Management and Budget in 2009 [2] estimated that closure-in-place of the 155 wet ash impoundments in the U.S. would cost about \$39 billion over 10 years. Consider that \$39 billion represents about 10 percent of total revenue generated by electricity sales in the U.S., according to the EIA. A more recent report [1] has suggested that these costs for closure may be even higher, because of the monitoring and remediation requirements in the updated CCR rule.

The Tennessee Valley Authority estimated the costs of closure-in-place for six of its wet coal ash impoundments (see table below). The total cost for these six plants is \$0.28 billion, which is about 3% of TVA’s total revenue from electricity sales for fiscal year 2016.

Costs of Closure-In-Place at TVA Wet Coal Ash Impoundments. [Cited in Ref. 1]

Plant	Total Cost, \$	Cost per acre
Allen	\$3,500,000	\$159,000
Bull Run	\$13,000,000	\$338,000
Colbert	\$10,000,000	\$192,000
Sevier	\$13,000,000	\$310,000
Kingston	\$40,000,000	\$1,290,000
Widow’s Creek	\$200,000,000	\$571,000
Total	\$279,500,000	\$521,942

Duke Energy will close all its CCR facilities in the Carolinas. While Duke has not released closure costs for individual sites, it reported asset retirement obligations (AROs) associated with 35 CCR impoundments in the Carolinas of \$4.24 billion (or \$1,560,000 per acre). [3] For reference, Duke Energy’s net income from the Carolinas was \$1.2 billion in 2016.

Kentucky Utilities (KU) estimated in 2016 that the cost of compliance with both state and federal regulations to close surface impoundments at six of its plants (three operating and three closed plants) was \$0.42 billion.[4] KU proposed to increase the cost of electricity to a portion of its municipal customers of up to 3.5 percent between 2016 and 2019.

Thus, the cost of environmental compliance for coal-fired power plants is substantial and rising, as utilities begin to assess the cost of complying with CCR requirements. These costs represent substantial liabilities that will, in many cases, be passed along to rate payers. The cost of compliance with the Effluent Limitation Guidelines (ELGs) will also be substantial, although it is harder to estimate this until EPA provides a promised review and revision of certain key provisions of the ELGs in 2019.

Recent Developments (as of publication of this NCC report)

On March 15, 2018, EPA published a proposed rule to amend the CCR Rule (“Phase I CCR Rule Changes). EPA proposed two general categories of changes – the first was associated with a judicial remand in connection with a settlement agreement that resolved four claims brought by two sets of plaintiffs against the final CCR Rule. The second category was a set of revisions that were proposed in response to the WIIN Act. Many commented on the propose rule that an extension of the deadlines is necessary in order for the benefits of the concepts in the proposed rule can be realized by CCR unit owners/operators.

On July 30, 2018, EPA published a rule finalizing key portions of the Phase I Proposal. EPA included in the final rule an extension of key deadlines and the adoption of two critical flexibility provisions that have the potential to significantly alleviate the burdens of the April 2015 CCR Rule. The EPA summary of the final rule provides a good overview of the changes:

Amendments to the National Minimum Criteria Finalized in 2018 (Phase One, Part One)

EPA is finalizing certain revisions to the 2015 regulations for the disposal of CCR in landfills and surface impoundments to:

Provide states with approved CCR permit programs under the Water Infrastructure Improvements for the Nation (WIIN) Act or EPA where EPA is the permitting authority the ability to use alternate performance standards;

Revise the groundwater protection standard for constituents which do not have an established drinking water standard (known as a maximum contaminant level or MCL); and

Provide facilities which are triggered into closure by the regulations additional time to cease receiving waste and initiate closure.

More specifically, with this final rule, EPA is finalizing two types of alternative performance standards that were proposed in March 2018. The first one allows a state director (in a state with an approved coal ash permit program) or EPA (where EPA is the permitting authority) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and post closure care. The second allows issuance of technical certifications in lieu of a professional engineer.

In addition, EPA is revising the groundwater protection standards for four constituents in Appendix IV to title 40 of the Code of Federal Regulations (CFR) part 257 for which MCLs under the Safe Drinking Water Act have not been established. EPA also is extending the deadline by which facilities must close coal ash units for two situations:

Where the facility has detected a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or

Where the unit is unable to comply with the location restriction regarding placement above the uppermost aquifer.

Provisions from the March 2018 proposed rule that are not finalized in this Federal Register notice will be addressed in a subsequent rulemaking.

Note that, in the last sentence, EPA indicated that there are some issues not addressed in this Phase I Final Rule that they anticipate addressing in a subsequent rulemaking. Noticeably absent from the Phase I Final Rule is their decision not to finalize the proposal to add Boron to the list of “Appendix IV Constituents,” which has significant programmatic implications.

References:

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[2] EOP Group. Cost Estimates for Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities. 2009.

[3] Duke Energy Corporation. 10-K Filing to the U.S. Securities and Exchange Commission. 2016.

[4] Federal Energy Regulatory Commission. Order Accepting and Suspending Revised Rate schedules and Establishing Limited Hearing and Settlement Judge Procedures, Docket No. ER 17-234-000, December 30, 2016.

Appendix 3 – Additional Perspectives

Appendix 3A. The reality of the shift towards a new power generation mix

Coal Retirements and the Risky Dynamics Ahead

Richard L. Axelbaum

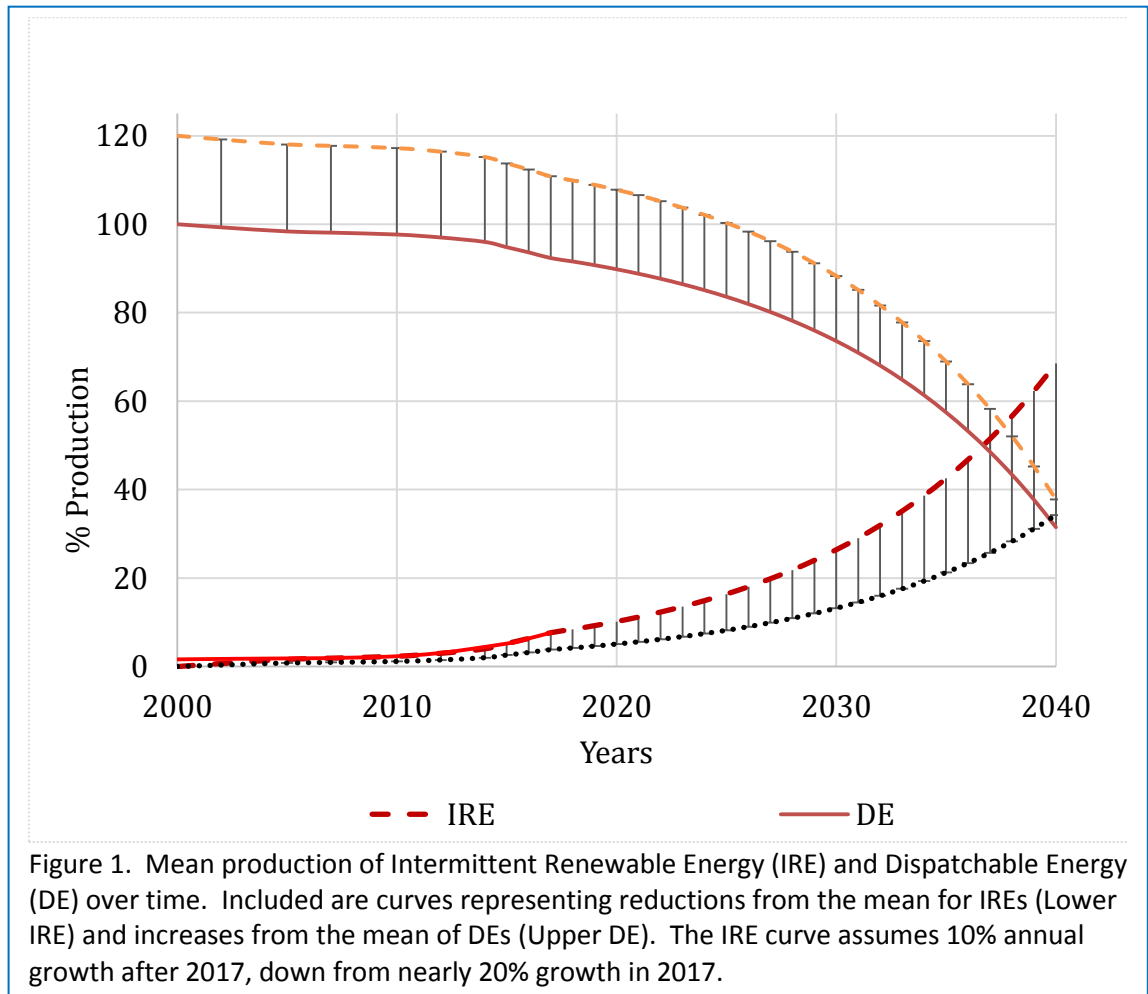
Energy, Environmental & Chemical Engineering – Washington University St. Louis

Understanding the potential impacts that changes to the generation mix can have on grid stability, reliability and resilience will be essential going forward since we are entering a new era of power generation, and there is no precedent to draw on for experience. The scenario in which renewable energy growth continues on its current trajectory for another two decades is examined here to provide a basis for understanding the system wide/macro implications. The approach used involves a simplified analysis that allows the basic dynamics to be understood and the implications to be realized. The results indicate that the present trajectory could rapidly lead to risks to grid reliability if not properly managed. To understand why this is so, first, the drivers for growth in wind and solar are discussed, and then the analysis is presented.

In the past decade, efforts to replace dispatchable fossil fuel energy with non-dispatchable wind and solar [1–4] have grown rapidly. More recently, these efforts have gained momentum to the extent that it is now common for cities and companies to set goals to be 100% renewable within the next 10-30 years [5]. This movement can be found among most branches of society, including businesses, government leaders, major philanthropists, environmentalists and academics [9-13]. The movement has become so mainstream that a large segment of the population believes that 100% renewables is possible in the near future [6]. Of course, since hydropower is quite limited, this implies that about 90% of our electricity would need to come from wind and solar [7], i.e., non-dispatchable energy. This perspective has contributed to a major push to retire coal plants and replace them with wind and solar. The conviction that 100% renewables is achievable in the near future has also given rise to opposition for new natural gas pipelines, as they are considered unnecessary [14].

What are the implications of building massive amounts of Intermittent Renewable Energy (IRE), while at the same time retiring dispatchable coal plants? Is it a serious problem or can the system naturally support this transition to a new energy paradigm? The model below illustrates the scenario using some conservative assumptions.

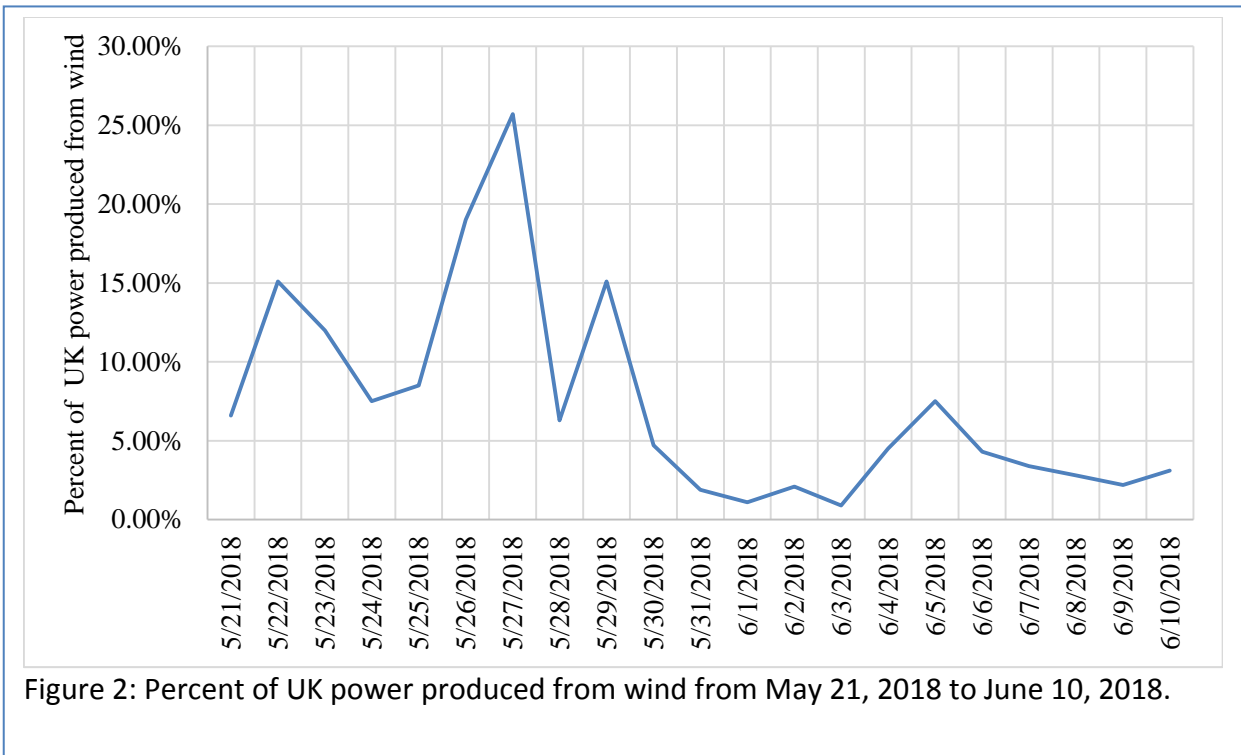
First, consider Figure 1, where the increased penetration of wind and solar is shown over time. The solid red curve represents the IRE production in the U.S. since 2000 [8]. While the growth in IREs was nearly 20% in 2017, the dashed red curve represents an extrapolation based on a more *modest 10% annual growth*. This curve shows the mean production of IRE, not instantaneous production. The production lows associated with wind and solar generation are represented by a deviation from the mean during times of unfavorable conditions (for example, low or excessive wind speeds), represented by the black dotted curve. In this example, this curve represents 50% lower production compared to the average. Of course, the production of wind and solar can and does drop to less than 50% of the mean, but for the purposes of illustration we will *assume that it can only drop to 50% of the mean* for any significant length of time (say a few days or a week). The black dotted curve indicates how much energy can be produced during those periods of low IRE production.



To illustrate the intermittency of IRE, Figure 2 shows the energy produced in the UK from wind during the end of May and early June of this year [15-16]. While wind resources are plentiful in the coastal regions in England, wind production went from supplying 20% of UK energy to less than a few percent and stayed that way for over a week. The black dotted curve in Figure 1 depicts such a phenomena but assumes that the drop is only 50% less than the mean production rate, which theoretically could be accomplished with significant battery resources. A key point here is that *there must be a dispatchable resource that can make up for the lost production during these periods of low IRE production*. More importantly, the *absolute* amount of energy that needs to be made up grows as the amount of IRE grows (see Figure 1).

Now consider the orange curve in Figure 1. This curve represents the reduction in dispatchable energy (DE) that occurs due to, for example, coal and nuclear retirements, and reflects the natural trend in retirements that occurs as IRE grows. In other words, as more IREs are brought into the grid, the average annual energy produced from dispatchable resources will decrease, because those plants that are no longer economical to run will be retired for financial reasons. This represents the phenomena the country is facing now. For this example, the sum of the IRE and the DE curves always adds up to 100%, as this is the natural state of the

economic drivers, i.e., excess capacity will not exist without policy incentives. The dotted green curve above this curve represents the added capacity that is available from these DE sources by running them at a capacity over their mean. For the curve in Figure 1, this is assumed to be 20%. Note that for the purpose of this illustration, many assumptions have been made, and the impact of these assumptions on the conclusions will be considered later.



An important point to note is that as the number of coal plants is reduced, the *absolute* amount of energy that *can be made up* by ramping them up reduces as well. Similarly, as the amount of IRE is increased, the *absolute* amount of energy that *needs to be made up* during the lulls increases.

While the above idea is shown in Figure 1, further analysis can identify certain conditions where the reliability of power availability becomes at risk. This is not an effort to quantify the precise timing or risk magnitude, which is a much more complex analysis. Rather the analysis that follows illustrates, for a given set of assumptions, when the risk of falling short of power starts to increase dramatically. The overarching point is that as the mix of generation sources changes, the risk to power reliability undergoes a sudden, steep and irreversible increase.

Figure 3 illustrates the consequences of the increase in intermittent energy as dispatchable energy drops shown in Figure 1. With increasing IRE penetration, and the subsequent retirement of dispatchable plants, there is a risk that a short-term fall off in IRE production may not be able to be made up by available DE resources.

The potential of falling short of power is characterized here by a risk factor, RF. For the purposes of this illustration, RF will be defined as $RF = D / (AC - D)$, where D is the demand and

AC, Available Capacity, is the maximum amount of electricity that can be produced from both DE and IRE resources when the DEs are supplying their maximum and the IREs are supplying their assumed minimum. The denominator then represents the excess capacity that would be available if IRE production is further limited (such as in the UK discussion above). This definition of RF captures the dynamic that when available capacity is much larger than demand, the risk factor is low, and when it approaches demand, risk of electricity being unavailable rises rapidly. As an example, if there is an 80%/20% split of DE and IRE resources in the generation mix and DE production can be increased by 20% of its mean and IRE production can drop by 50% of its mean (i.e., the conditions of Figure 1), the available capacity will be $\%DE \cdot 1.2 + \%IRE \cdot 0.5 = 106$, which gives a risk factor of about 16%. The RF gradually increases with time initially, as IRE growth follows the 10% annual path shown in Figure 1, and eventually shows a rapid and dramatic increase, indicating a high likelihood of power shortfall.

Several scenarios of varying IRE/DE proportions are shown in Figure 3 to evaluate the impact of the various assumptions that have been made, to observe how the mix and range of IRE/DE plays out. For all of these scenarios the growth in IRE capacity is taken as that depicted in Figure 1 (i.e., 10% annual growth in IRE). The conditions labeled IRE50/DE20 represents the conditions shown in Figure 1 (i.e., IRE production can fall to 50% of its mean and the DE production can be increased 20% above its mean capacity.) The extreme increase in risk occurs at a different point in time, but is nonetheless a dramatic change in the relatively near future.

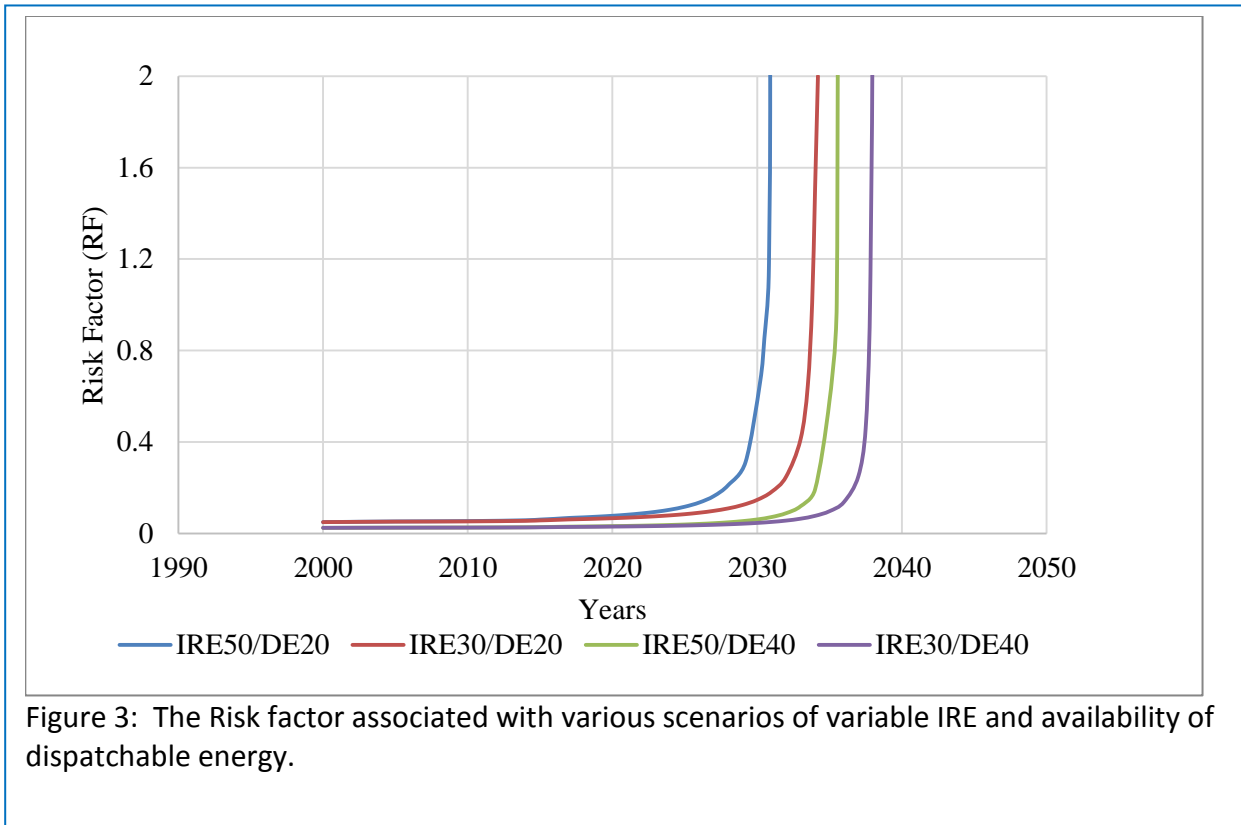
The key point to bring out from this analysis, is that the change from a safe, reliable grid to an unreliable grid transitions rapidly (i.e., as IRE penetration increases the risk factor rises rapidly to a condition where the potential of falling short of power is high).

More optimistic scenarios, such as IRE30/DE40, are also considered in the figure. For IREs to never fall below 30% from the mean (IRE30) would require massive battery installations. Also, in this case the DEs are assumed to be able to ramp up 40% more than their mean capacity (DE40). Note that new dispatchable plants typically operate at a capacity factor between 70-85%. The DE40 assumption implies that these plants are typically running at only 50-60% of their rated capacity. This is an uneconomical way of producing electricity and for anything much below this, the plant would be a candidate for retirement.

As can be seen from Figure 3, for all of these scenarios the general shape of the curve remains the same, in that there is limited risk followed by a rapid rise in risk; only the date for the rapid rise changes. Thus, with the present push to rapidly expand IREs, while simultaneously retiring coal plants, there can be a sudden change in the stability of the grid, unfelt until it may be too late. Of course, replacing coal with natural gas can reduce these risks, but it is clear that public opinion is beginning to view natural gas plants as unnecessary [17], making a major expansion of natural gas pipelines unlikely. Also, as pointed out elsewhere in this report, winter demand, gas pipeline bottlenecks and rising exports suggest that natural gas will not be able to curtail this situation, especially recognizing the rate at which risk factor curves in Figure 3 rise.

This analysis, while simplistic, identifies an important dynamic that should be considered in determining policy, particularly when considering the strong public sentiment of wanting to shift to a grid based on wind and solar. **The key finding is that the transition from a reliable to unreliable grid can occur quite rapidly.** Often advocates of 100% renewables will point to times of severe weather conditions, such as a heat wave or cold spell, where the grid was able to satisfactorily supply electricity, and then this example is used as a demonstration that the

grid can safely handle the addition of more wind and solar. The analysis outlined here shows that there is a potential risk associated with extrapolating that argument to future times.



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