Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

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Acknowledgments and Disclaimers

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Executive Summary

Over the last decade, the U.S. electric power sector has gone through one of the most dramatic changes in its existence. The combination of low natural gas prices as a result of the shale gas revolution and significant reduction in construction and operating costs for renewable resources, in part due to federal tax credits such as the production tax credit and investment tax credit mainly benefitting wind and solar, respectively, has resulted in a significant shift away from coal-fired generation, and instead towards natural gas and renewable generation.

Furthermore, the operating profile of existing coal-fired electric generating units has changed significantly. As new natural gas combined cycle plants have become increasingly more efficient and cheaper to operate than older existing coal-fired power plants, coal units continue to lose baseload generation share and more frequently operate as load-following, or cycling, resources. These trends are of particular importance to state public utility commissions (commissions). Functioning as economic regulators, commissions oversee investments in a reliable, efficient system while balancing emissions goals, customer demands, and other policy objectives. Changes to coal plant operations as a result of increased competition from other fuel sources may have a bearing on system reliability and economics, and therefore constitute an important area for commissions to monitor.

Increased cycling operations of coal plants, including more frequent startups and shutdowns, as well as faster changes in unit output, have a considerable impact on the reliability and cost of the plant. More frequent cycling increases wear-and-tear of plant equipment and can lead to shorter equipment lifespan due to thermal fatigue, thermal expansion, increased corrosion, and increased cost of start-up fuel. Without proper maintenance of the plant during these operations, unexpected plant outages become more frequent.

Despite the increase in plant operating costs due to cycling, there exist numerous options for plant operators to minimize the financial impact and optimize the plant's operation. One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Examples include sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and boiler draft control schemes and operating philosophy.

Other options include establishing and following cycle chemistry guidelines for flexible operations, accurate damage estimation, flexible operation studies, and plant operator coaching. Additionally, areas to minimize coal plant cycling costs, outside the control of coal plant operators, include the increased deployment of energy storage and demand-side management resources and curtailing wind and solar generation during times of high generation or low demand.

Most of the cycling cost mitigation strategies require significant capital investment. However, recent market developments have undercut the profitability of existing coal-fired power plants and reduced the amount of working capital plant owners are able or willing to spend on the maintenance necessary to ensure plant reliability.

While they are currently being discussed, no specific market mechanisms to compensate unit flexibility provided by fossil fuel power plants exist in the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) power markets, the two independent system operators (ISO) with the largest share of intermittent renewable energy resources in their generation mix. However, without any additional source of revenue for coal plants (e.g., for providing necessary operational flexibility for these power markets), more coal retirements due to poor economics are likely, increasing the risk of potential power outages in states like Texas. In areas with regulated utilities, the increased cost of coal plant cycling is being passed on to utility customers. Any market mechanisms that financially reward the flexibility of coal-fired generating units will arguably result in lower overall system costs while ensuring the reliable operation of the electric power grid.

Thoughtful market mechanisms that financially compensate coal-fired generating units for providing essential market balancing attributes, such as short-term generation flexibility, could arguably result in lower electric retail rates for end-use customers while equally, if not more importantly, helping to ensure reliable operation of the nation's electric power grid.

Introduction

Over the last ten years, the U.S. electric power system has gone through significant changes, creating new challenges for various stakeholders, including state public utility commissions (commissions). Following the Great Recession from 2007 to 2009, demand for electricity has mostly remained flat due to changes in consumer behavior and a heightened focus on energy efficiency and conservation. Additionally, technical advancements in hydraulic fracturing and horizontal drilling have revolutionized the U.S. natural gas and oil industry, resulting in record domestic production of natural gas and crude oil.

Subsequently, pricing for both commodities has decreased substantially. The shale gas revolution has created an environment where natural gas-fired power plants in the U.S. are becoming increasingly more cost-competitive with their coal-fired counterparts, resulting in a major shift from coal to natural gas generation.

Additionally, climate change has arguably been one of the most discussed topics of this decade and will likely be a leading global issue going forward. Societal pressure to move to zero-emissions energy sources, combined with renewable energy mandates, tax incentives for renewable development, and significant cost reductions for wind and solar technologies, have resulted in the continued addition of new wind and solar generating facilities across the country. With intermittent resources accounting for over one-third of total generation in some states, traditional baseload generators have been forced to be more flexible in their operating profile and complement fluctuations in generation from intermittent renewable sources.

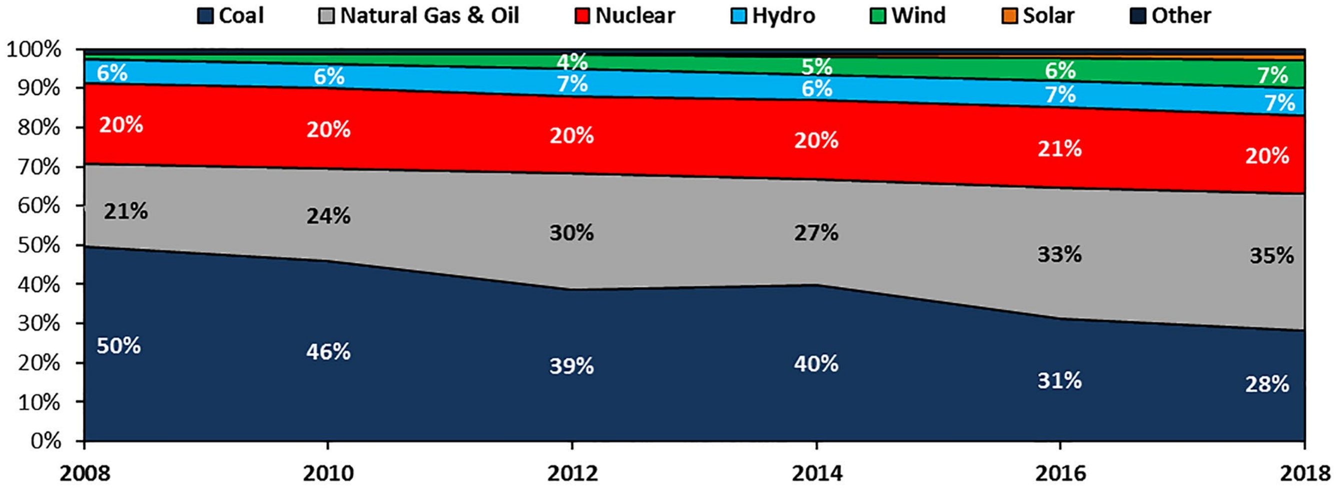
These conditions have resulted in new challenges for commissions. As economic regulators, they are charged with overseeing the reliable, safe, and affordable operation of the electricity generation and delivery system. The asset life for electric generation can span decades, making today's decisions impactful for customers well into the future. Similarly, commissioners inherit a system of assets at various stages in their operating lifespans. As new generation sources become competitive with coal — a fuel that was, for much of the twentieth century, one of the cheapest sources of electricity — commissions can benefit from two things: (1) a more complete understanding of how coal generation is or can be responding to competition, and (2) a discussion of an important attribute of the electricity system: flexibility. This paper focuses on operational changes experienced by U.S. coal-fired power plants as a result of high renewable penetration. The report also explores how fossil fuel plant flexibility is currently procured and compensated. Future research in this area may consider options for states to maintain flexible, reliable, and affordable electricity.

Overview of the Changes in the U.S. Electric Power System between 2008 and 2018

Over the last decade, the U.S. electric generating fleet has experienced some significant changes. Cheap natural gas, as a result of the shale gas revolution and falling construction and production costs for new wind and solar generation, in conjunction with public policy initiatives supporting renewables, have caused a shift from coal-fired power generation to natural gas and renewable generation.

As shown in **Exhibit 1,** in 2008, electric generation from coal-fired power plants accounted for 50% of total U.S. electric generation. Natural gas and oil generation accounted for 21%, and non-hydro renewable generation accounted for less than 2% of total generation. A decade later, the generation mix has changed dramatically. In 2018, coal-fired power plants accounted for just 28% of the total electricity produced in the U.S., while natural gas and oil's share increased to 35% and non-hydro renewable's share to 10%. This shift, which shows little sign of slowing, is creating both new opportunities and challenges for stakeholders.

EXHIBIT 1: U.S. ELECTRIC GENERATION[1] MIX – 2008 TO 2018[2]



In 2018, U.S. coal generation dropped by more than 40% from 2001 levels, while natural gas and renewable generation more than doubled their combined generation during the same period. Since renewable generation from wind and solar is generally considered non-dispatchable and is widely perceived as a nominally zero marginal cost resource, any available generation from these resources is on a "take-when-available" agreement and is displacing baseload coal generation at the bottom of the dispatch stack.[3]

In addition, the fall of natural gas prices and the resulting wave of new natural gas combined cycle power plants (CCGTs) have increased the competition between coal-fired and natural gas-fired generation for meeting baseload power needs. As a result of the shift from coal to natural gas and non-hydro renewables and resulting change in the

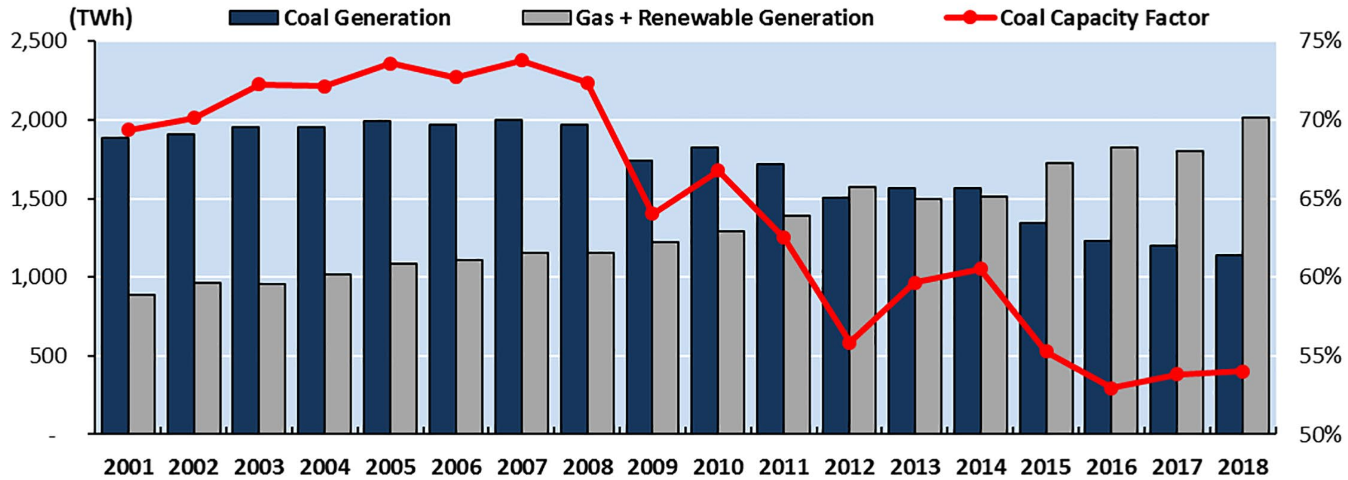
1 Generation throughout this report refers to the amount of electricity generated in a certain period measured MWh. Capacity refers to the maximum generation output a unit can generate in one hour, measured in MW.

2 Source: Department of Energy - Energy Information Administration (EIA) Annual Form-923 data

3 Some power markets have experienced times when renewable generation was greater than the total electricity demand at that time, forcing the system operator to curtail (i.e., stop from generating electricity) renewable generation.

economic dispatch order, coal plant utilization rates, also referred to as capacity factors,[4] have dropped from a high of 74% in 2007 to just 54% in 2018, as shown in **Exhibit 2.**

EXHIBIT 2: U.S. COAL GENERATION AND CAPACITY FACTOR VS. COMBINED NATURAL GAS & RENEWABLE GENERATION[5]



It should be noted that the magnitude of this shift from coal to natural gas and non-hydro renewable generation varies from state to state. From 2008 to 2018, all but one state (Alaska) experienced a drop in their coal generation share. **Exhibit 3** shows the top 25 states with the largest reduction in coal generation share between 2008 and 2018. Some states have seen their in-state coal generation share drop from the most dominant to just a minor role in 2018. For example, Virginia's coal fleet accounted for more than half of the total in-state generation in 2003. By 2018, that share dropped below 10%, while natural gas generation increased from 14% to 55% over the same period.

Other states with significant coal generation declines include Delaware (-71% generation share decline between 2008 and 2018), Georgia (-39%), and Ohio (-38%). On the other hand, states like Washington, Arkansas, and Nebraska, have seen only modest declines (<4%) of coal generation over the same period.

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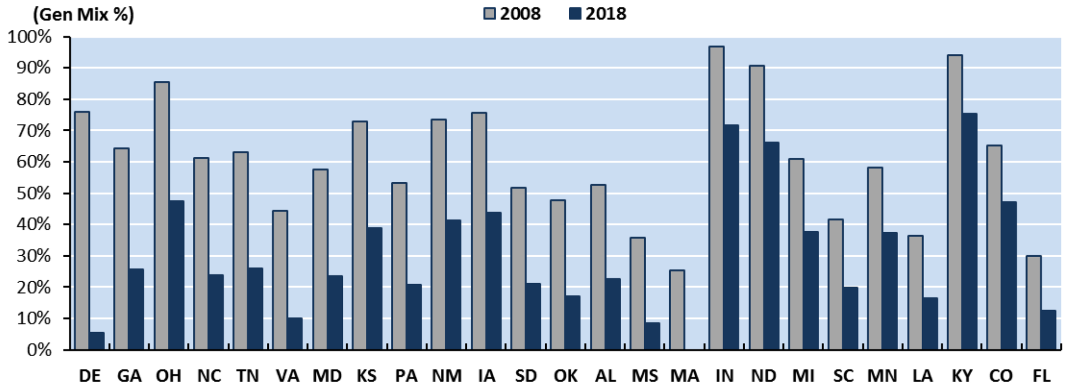
4 Capacity factor measures the utilization of a generating unit over time. For example, an electric generating unit with a generating capacity of 100 MW is capable of generating 100 MW per hour, or 876,000 MWh per year. If the same unit only generated 438,000 MWh during the year, it only generated 50% of the electricity it is theoretically capable of. Therefore, its capacity factor is 50%.

5 Source: Annual EIA Form-923 and Form 860 Data

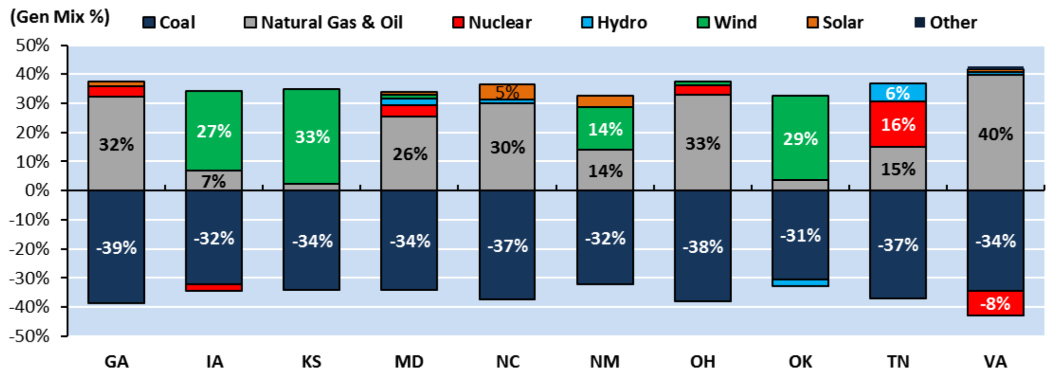
EXHIBIT 3: TOP 25 DECLINES IN COAL GENERATION SHARE BY STATE – 2008 VS. 2018[6]



While the magnitude of coal displacement varies from state to state, so does the source of replacement energy, as shown in **Exhibit 4.** For example, in Georgia, the vast majority of the 39% loss in coal generation over the last 11 years has been replaced by natural gas generation. In states like Iowa, Kansas, and Oklahoma, which have substantial wind resources, coal has been displaced predominantly by wind generation.

Lastly, another group of states has used falling costs of natural gas and renewable generation to diversify their in-state generation mix significantly. For example, New Mexico replaced the loss of 32% of coal generation share with equal parts natural gas and wind generation (14% each), as well as 4% from new solar generation. Tennessee, which is home to the recently-completed Watts Bar 2 nuclear reactor, also added significant amounts of natural gas and hydro generation to displace coal generation.

EXHIBIT 4: REPLACEMENT OF COAL GENERATION MIX SHARE BY OTHER FUELS FOR VARIOUS STATES – 2008 VS. 2018[7]



6 Source: Annual EIA Form-923 Data

7 Source: Annual EIA Form-923 Data

Operational Changes at Coal Plants between 2008 and 2018

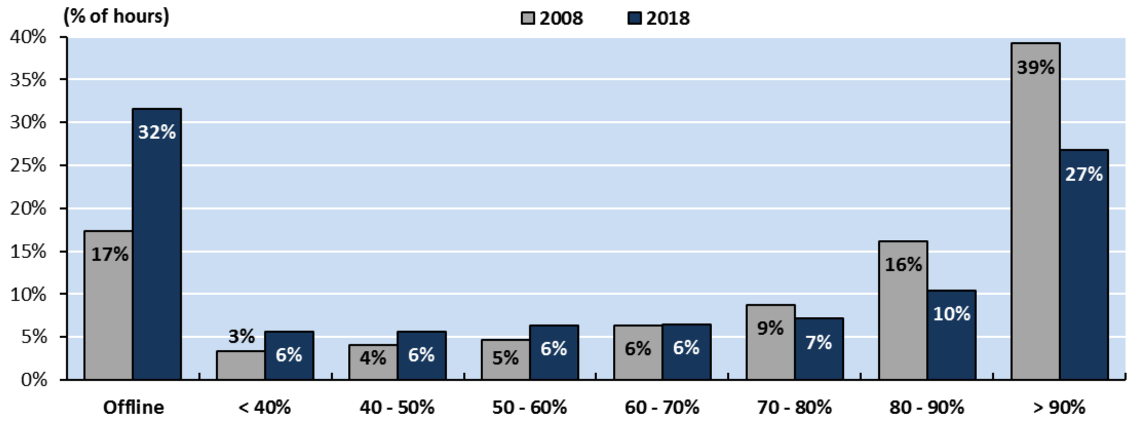
These dramatic changes in the generation mix have significant impacts on the operation of the remaining coal-fired generating fleet. To highlight these differences, this report presents an in-depth analysis of hourly gross generation data from EPA's Continuous Emission Monitoring System (EPA CEMS) for all operating coal-fired electric generating units (EGUs) in 2008 and 2018. Plants with only partial-year data (due to reporting requirements, in-year retirements, or online dates) and glaring reporting errors were excluded. In total, the hourly generation dataset included 8.1 million observations for 927 EGUs across 43 states in 2008 and 4.7 million observations for 531 EGUs across 42 states in 2018. 2008 marked the last year of historically "normal" coal plant operation (as indicated by the 72% capacity factor for the U.S. coal fleet shown in **Exhibit 2**) and was, therefore, chosen as comparison to current market conditions.

The analysis focused on four key metrics for coal plant operations: (1) gross capacity factor by segment, (2) number of hot, warm, and cold starts, and average duration that the coal unit was offline, (3) maximum turndown rate, defined as the *lowest* safe power output level, and (4) hourly ramping rates. Differences in these metrics were analyzed on a state level, in addition to the age and size of the coal plant. Highlights of the results are presented below.

As shown in **Exhibit 5,** the distribution of hourly capacity factors for the U.S. coal fleet has changed dramatically over the last decade. As described earlier, the annual capacity factor for the U.S. coal fleet dropped from 72% in 2008 to 54% in 2018. However, annual capacity factors do not provide sufficient detail on the actual operation of individual coal-fired EGUs. For example, an EGU that operates at a 100% capacity factor for half of the year, while offline the other half, has the same capacity factor as an EGU cycling equally between 30% and 70% capacity factors for the entire year. Exhibit 5 highlights a few significant shifts in operations for the U.S. coal fleet.

First, as a result of higher wind penetration, increased competition with natural gas-fired EGUs, and overall higher ramping and startup and shutdown costs (as described later in this report), coal plant operators in 2018 more often chose to keep the EGU offline and only brought it online when favorable market conditions persisted over a more extended period of time, such as high wholesale power prices during elevated demand periods. Therefore, coal units were offline an additional 14% of the time compared to 2008. Second, when online, coal-fired EGUs in 2018 operated at much lower capacity factors than their 2008 counterparts. Coal units operated only 37% of the time above 80% of their gross capacity, which is considered the highest efficiency range for most coal-fired EGUs. In 2008, the U.S. coal fleet operated during more than 55% of all hours in that same range. Additionally, coal plants in 2018 operated more often at lower capacity factors near maximum turndown levels, the utilization level at which boiler temperatures and pressures are being maintained so that the unit can ramp up more quickly in response to changes (increased demand) in electric load and/or decreased wind output. In 2018, coal plants operated more than 18% of the time at capacity factors below 60%, compared to just 12% of the time in 2008.

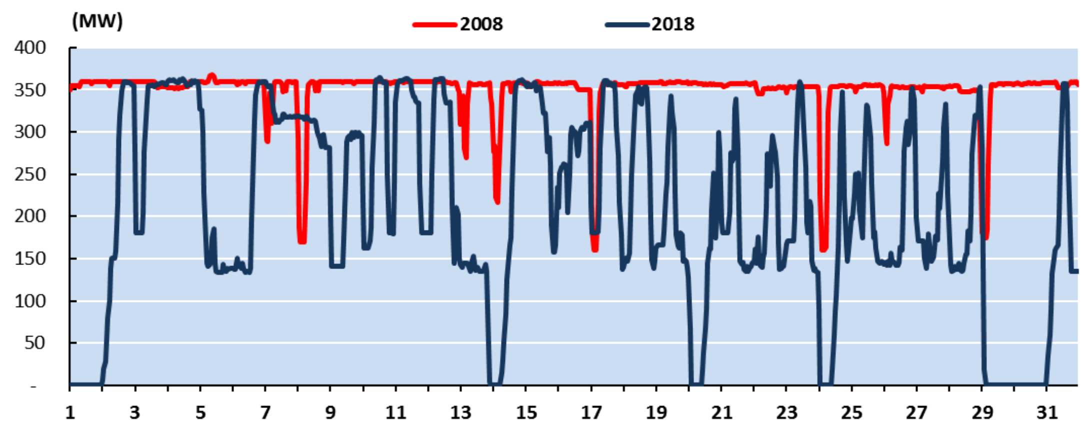
EXHIBIT 5: DISTRIBUTION OF HOURLY CAPACITY FACTOR FOR U.S. COAL-FIRED EGUS – 2008 VS. 2018[8]



An example of such an operation change is presented in **Exhibit 6.** Exhibit 6 shows the hourly gross generation profile of Xcel Energy's 350-MW Harrington unit 1, located in Texas, for the months of December 2008 and December 2018. As mentioned earlier (and in greater detail below), Texas has added a significant amount of wind generation and natural gas-fired generating capacity over the last decade. During December 2008, Harrington 1 remained relatively steady output near its maximum capacity throughout the month, with just eight turndowns, and it never fell below 150 MW.

Conversely, in December 2018, Harrington 1's gross generation output varied significantly. First, the unit was offline five times during the month of December. Second, when online, the unit cycled almost continuously between the maximum and minimum unit output, depending on current load requirements. The data also shows that plant operators turned down the unit to much lower levels than in 2008, with output falling below 150 MW on multiple occasions. Examples like these are much more frequent in 2018 than in previous years and are likely to become more numerous as more wind and solar resources are added to the generation mix.

EXHIBIT 6: XCEL ENERGY'S HARRINGTON UNIT 1 HOURLY GROSS GENERATION DURING DECEMBER[9]



8 Source: EVA Analysis of Environmental Protection Agency (EPA) Continuous Emissions Monitoring System (CEMS) Hourly Data

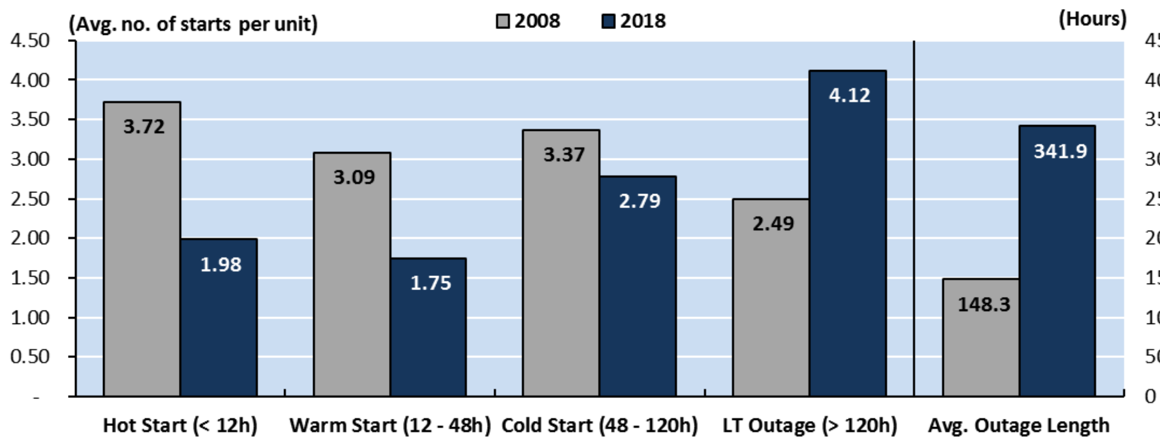
9 Source: EPA CEMS Hourly Data

Operating a coal-fired EGU below its optimal boiler design utilization rate has adverse effects on both the efficiency of the unit and its structural integrity. At lower utilization rates, coal units consume more fuel to produce the same amount of electricity, resulting in both higher fuel costs and emissions of SO_2, NO_x, and CO_2. Additionally, more frequent and faster load changes increase the stress on the boiler equipment and shorten the time between maintenance outages for the unit. The impacts are described in more detail in the next section.

Another metric to consider when assessing the flexibility of coal-fired EGUs and the impacts of unit cycling are its number of hot, warm, and cold starts. Hot starts are typically defined to have very high (700°F to 900°F) boiler and turbine temperatures and occur after 8 to 12 hours offline. Warm starts generally have boiler and turbine temperatures between 250°F and 700°F and occur after the unit has been offline for 12 to 48 hours. Starts at ambient temperatures are considered cold starts after the boiler was offline for 48 to 120 hours.[10] These definitions vary from unit to unit based on design, unit size, and manufacturer.

Generally, the colder the temperature of the boiler and turbine, the higher the startup cost of the unit. **Exhibit 7** shows the comparison between the average number of hot, warm, and cold starts for all U.S. coal-fired EGUs, as well as the average number of long-term outages and the average length of outages between starts in 2008 and 2018. Although the total average amount of starts per unit is similar between 2008 and 2018 (12.67 vs. 10.64 total starts per year respectively), Exhibit 7 clearly shows a shift away from more frequent starts at various temperature levels to longer-term outages (greater than 120 hours, or five days). On average, coal-fired EGUs in 2018 experienced less than four hot and warm starts (starts after being offline for less than 48 hours), compared to almost eight such starts in 2008. Conversely, coal units in 2018 have experienced long-term outages (greater than five days) more frequently, with over four such outages per year compared to just 2.5 per year in 2008. Finally, the average outage length for U.S. coal units in 2018 has more than doubled from less than 150 hours (approximately six days) per outage to over 340 hours per outage (approximately 14 days).

EXHIBIT 7: AVERAGE NUMBER OF STARTS PER COAL-FIRED EGU – 2008 VS. 2018[11]



10 Source: Lefton S A, Besuner P M, Grimsrud G P, Kuntz T A (2010) *Experience in cycling cost analysis of power plants in North America and Europe.*

11 Source: EVA Analysis of EPA CEMS Data

A third metric to consider when analyzing the operational changes the U.S. coal fleet experienced over the previous decade is the rate of change of generation output over a period of time, also known as ramp rates. Ramp rates can vary significantly between plant and fuel types. **Exhibit 8** shows various flexibility capabilities by technology type, according to IEA.

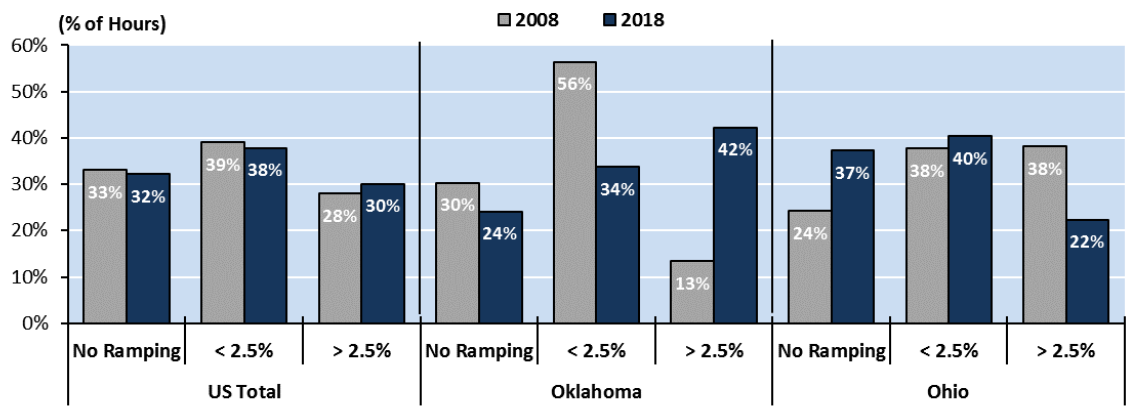
EXHIBIT 8: CAPABILITY OF DIFFERENT POWER GENERATING TECHNOLOGIES TO PROVIDE FLEXIBILITY[12]

Plant Type	Start-up time	Max Change in 30secs, %	Max ramp rate, %/min
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 h	5 - 10	1 - 5
Nuclear Plant	2 h - 2 d	< 5	1 - 5

Although coal plants are far more flexible than nuclear power plants, they are generally less flexible than their natural gas-fired competition. Simple cycle and combined cycle natural gas-fired combustion turbines (CTs) have much shorter start-up times than coal-fired units as well as faster ramp rates and spinning capabilities. (For this report, ramp rates refer to the hourly change in gross electric output.) The ramp rates listed above are maximum ramp rates that also depend on the unit's specific design characteristics. Frequent ramping of a unit at these maximum ramp rates can significantly shorten the life of the unit before certain parts need to be replaced. The analysis in this report focuses on hourly changes in output for the coal units in 2008 and 2018 and does not make any inference on the maximum ramping capabilities of these units.

Exhibit 9 shows the average distribution of hourly ramp rates (when online) for the U.S. coal fleet in 2008 and 2018 in three categories: no ramping (i.e., no change in output from the previous hour), less than 2.5% change in output, and greater than 2.5% change in gross electric output.

EXHIBIT 9: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES FOR THE U.S. COAL FLEET AND TWO SPECIFIC STATES – 2008 VS. 2018[13]



12 Source: International Energy Agency – Clean Coal Centre (2016) *Levelling the intermittency of renewables with coal.*

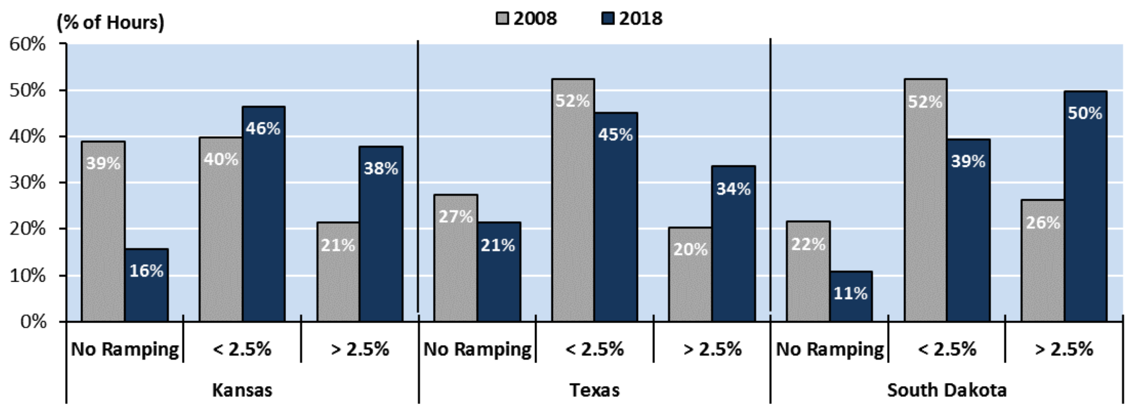
13 Source: EVA Analysis of EPA CEMS Data

As shown in **Exhibit 9,** there is little change in ramp rates for the average coal unit when comparing the ramp rates on a national level between 2008 and 2018. For all three categories, the 2018 values are within two percentage points of its 2008 counterparts, indicating little change on a national level. However, there are significant differences on a regional level.

Between 2008 and 2018, Oklahoma's coal fleet lost more than 30% of generation share, mostly to new wind resources in the state. Since little to no new peaking units have come online in the state since 2008, the responsibility of balancing the possible sudden loss of wind generation fell on the remaining Oklahoma coal units. As a result, Oklahoma's coal units have significantly increased their share of output changes greater than 2.5%, from 13% in 2008 to over 42% in 2018. Conversely, the percentage of ramping at less than 2.5% has fallen tremendously, from 56% in 2008 to 34% in 2018.

As shown in **Exhibit 10,** other states where coal generation was mainly displaced by wind with almost no new peaking capacity have seen similar developments. For example, in Kansas, the number of times an average coal unit in the state ramped up or down at rates greater than 2.5% increased from 21% in 2008 to 36% in 2018.

EXHIBIT 10: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN WIND STATES – 2008 VS. 2018[14]

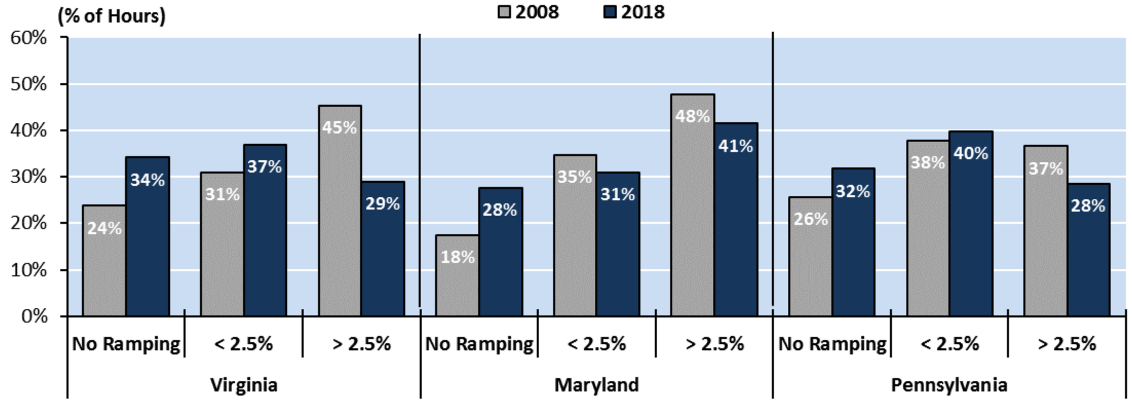


On the other hand, coal units in states where coal has been displaced mainly by new natural gas simple cycle and combined cycle power plants have been subject to less ramping at higher percentages. In Ohio, coal's generation share fell by 38 percentage points between 2008 and 2018, while natural gas's share increased by 33 percentage points over the same period. With cheap natural gas supply in the region, Ohio's new and highly efficient natural gas power plants are more economical to operate than most of the remaining in-state coal fleet. As a result, Ohio natural gas plants are being dispatched ahead of most of the Ohio coal fleet, while also providing flexibility support. Ohio coal plants are mainly called upon during times of high electricity demand to provide additional baseload generation, while the new natural gas plants provide load-following support. As a result, as seen in Exhibit 9, coal's ramp rates above 2.5% have fallen between 2008 and 2018, from 38% to 22%, respectively. Conversely, hours during which coal plants did not ramp at all increased from 24% in 2008 to 37% in 2018.

14 Source: EVA Analysis of EPA CEMS Data

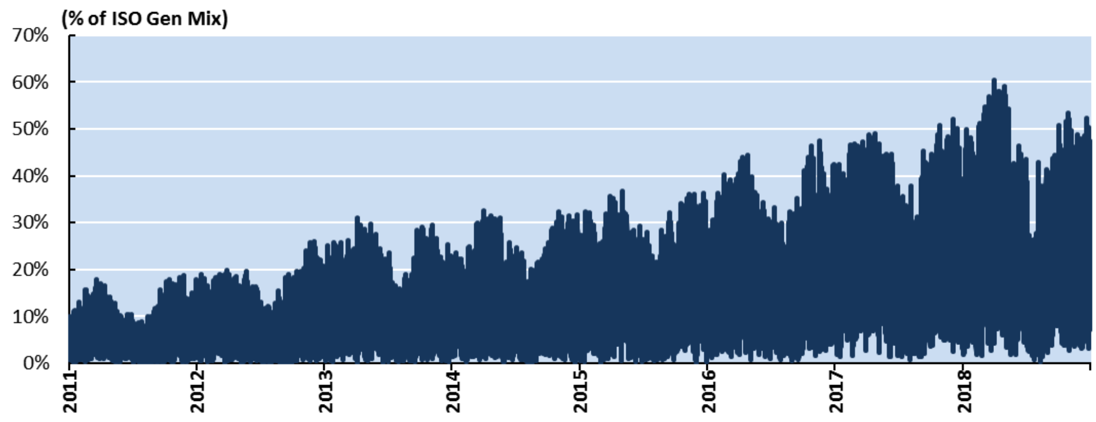
Again, states where electric generation shifted predominantly from coal to natural gas have seen similar developments, as shown in **Exhibit 11.** For example, in Virginia, another state where coal has been displaced mainly by natural gas, the share of ramp rates for coal units greater than 2.5% has fallen since 2008, from 45% to just 29% in 2018.

EXHIBIT 11: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN NATURAL GAS STATES – 2008 VS. 2018[15]



High ramp rate requirements for coal units in states with a significant share of wind generation already will continue to increase as more wind resources are added to the generation mix. **Exhibit 12** shows the hourly wind generation share in the SPP, the ISO for states with some of the highest percentages of wind generation in 2018, including Kansas, Oklahoma, and both of the Dakotas. In 2018, the generation share of wind rose to 60% on March 31 and fell to almost zero on August 8, with fluctuations of more than 9 GWh of generation in six hours on February 17. With coal still accounting for more than two-thirds of fossil fuel generation in SPP, that variation in wind generation is being balanced mostly by coal-fired EGUs.

EXHIBIT 12: HOURLY WIND GENERATION SHARE IN SPP – 2011 TO 2018[16]

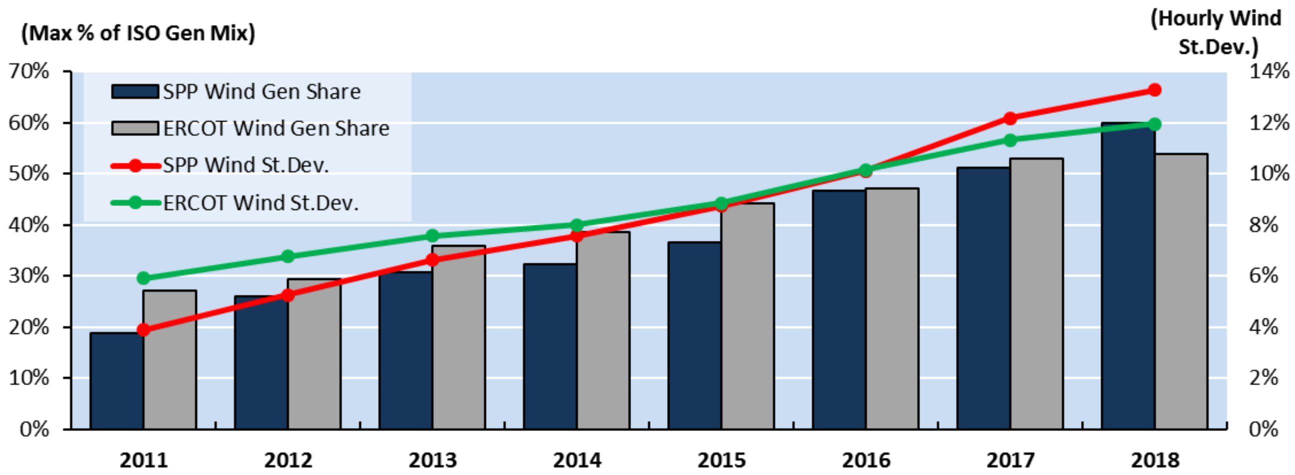


15 Source: EVA Analysis of EPA CEMS Data

16 Source: Southwest Power Pool (SPP) Hourly Generation Mix Data

As more wind generation is being added to the electric power system, utilities and ISOs, such as ERCOT and SPP, have to balance more considerable amounts of the variable generation with dispatchable generating units such as coal and natural gas. **Exhibit 13** shows the trend since 2011 in annual wind generation share for ERCOT and SPP, as well as the standard deviation for hourly wind generation for the two ISOs. Although wind developers and ISOs attempt to diversify wind farms locationally to minimize the variability of wind output, wind variability has continued to increase significantly in both ISOs. In 2011, when hourly wind output peaked at just 20% of SPP's generation, the standard deviation for the hourly generation mix share from wind was below 4%. In 2018, however, when the peak hourly generation share of wind increased to 60%, the standard deviation more than tripled to over 13%. As more wind is added to the ISO's generation mix, flexibility from dispatchable resources such as coal and natural gas has become more critical.

EXHIBIT 13: MAX HOURLY WIND GENERATION SHARE & STANDARD DEVIATION FOR ERCOT & SPP ISO – 2011 TO 2018[17]

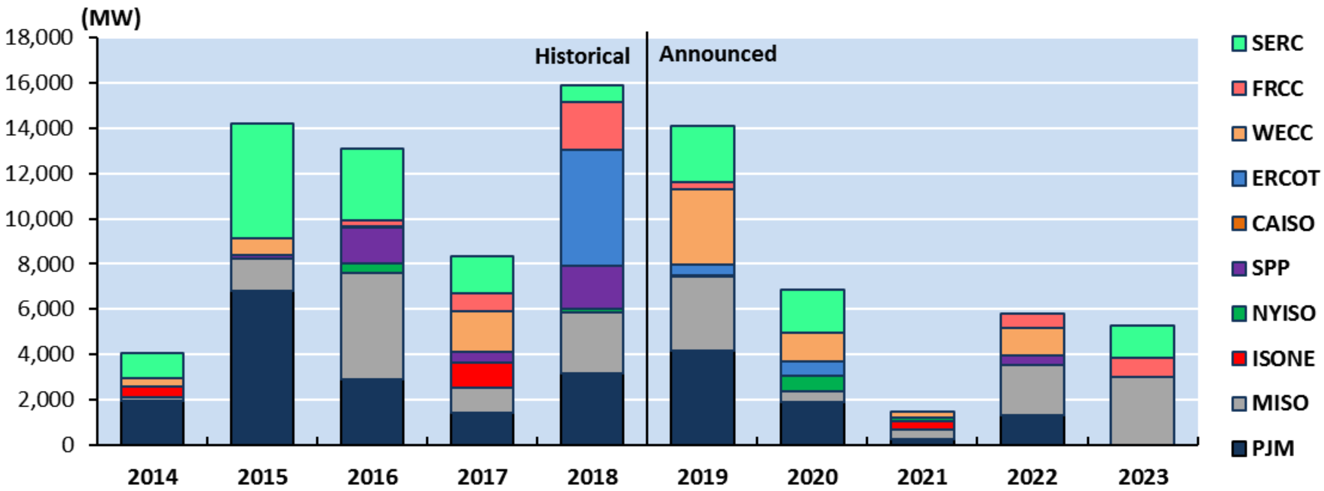


Despite the increased importance of flexible and dispatchable generation to balance the variability of a growing renewable fleet, more and more coal plants are being retired in power markets with an ever-increasing share of renewable generation. **Exhibit 14** shows historical and announced coal retirements by power market. In 2018, a record 16 GW of coal-fired generation retired, more than in any other previous year. 2019 follows close behind with another 14 GW of coal capacity either already retired or scheduled to retire. More than 30 GW of additional coal capacity have already retired or are announced to retire by 2023 in MISO, ERCOT, and SPP alone, the three power markets with the highest share of wind generation in 2018. Unlike the massive amounts of coal retirements in 2015 and 2016 due to the compliance deadline for the EPA Mercury and Air Toxics Standard (MATS), these coal retirements are mainly due to reduced revenues as a result of lower utilization rates. The next section discusses the structural and financial implications of increased cycling of coal-fired power plants and

17 Source: EVA Analysis of SPP and ERCOT Hourly Generation Mix Data

how coal plant owners are, or are not, currently compensated for providing much needed operational flexibility to the grid.

EXHIBIT 14: HISTORICAL COAL RETIREMENTS BY POWER MARKET – 2008 TO 2018[18]



18 Source: EVA Power Plant Tracking System Database

The Costs and Implications of Coal Plant Cycling

As described in the previous section, coal-fired power plants are operating less frequently in baseload operation, where they provide a constant level of electric output with minimal variation. Instead, they are asked to provide more operational flexibility in response to higher shares of intermittent generating resources, such as wind and solar entering the market.

There are two main types of coal plant cycling practices to facilitate changes in output, as mentioned previously: completely shutting down the coal unit or changing its electric output to follow load. As both types imply a diversion from designed operating practices, operating costs for coal-fired power plants are expected to increase (substantially in some cases) as revenue from decreased energy market payments falls. These operational changes and other factors associated with more flexible operation can have the following effects on coal-fired EGUs:

- Increased wear-and-tear on high-temperature and high-pressure plant components and associated costs
- Increased wear-and-tear on balance-of-plant components and related costs
- Shorter periods between maintenance time but more prolonged outages
- Decreased thermal efficiency at high turndown levels
- Increased fuel costs due to more frequent and inefficient unit starts, which require start-up fuel
- Difficulties in maintaining optimal steam chemistry leading to accelerated corrosion
- Potential for catalyst fouling on NO_x control equipment
- Long-term loss of critical equipment life
- Efficiency losses during startup through synchronization and loading to zero load
- Increased risk of human error in plant operations

Exhibit 15 shows the typical costs for a medium-sized coal-fired power plant during various types of operation, based on previous studies analyzing the financial implications of the increased wear-and-tear and associated maintenance and capital costs listed above.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW) Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

category for all four operation types above is "maintenance and capital." According to a previous study from the National Renewable Energy Laboratory (NREL), there is a trade-off between high capital and maintenance costs and corresponding lower equipment-forced outage rates (EFORd).

According to a study by the Electric Power Research Institute (EPRI)[20], some of the **damage mechanisms** that occur due to increased load-following and on/off operations include:

- **Thermal fatigue.** This phenomenon, caused by frequent changes in equipment temperature, can produce cracking in thick-walled components, especially castings such as turbine valves and casings. Also affected are boiler superheater and reheater headers, where ligament cracking is commonly seen between tube stubs. These headers are expensive, thick-walled vessels operating under high steam pressure, making this damage of particular concern to plant owners.

- **Thermal expansion.** Several systems in a coal plant consist of components that undergo high thermal growth relative to surrounding components. The most notable example of this phenomenon is the enormous movement of boiler structures relative to the cooler support framework. These support ties are designed to accommodate growth, but are subject to accelerated life consumption if the frequency of thermal cycling increases.

- **Corrosion-related Issues.** Two-shifting, or any other operation that challenges the ability of a plant to maintain water chemistry, can lead to increased corrosion and accelerated component failure. Increased levels of dissolved oxygen in feedwater can be the result of condenser leaks, aggravated by more frequent shutdowns.

- **Fireside corrosion.** Load cycling and relatively quick ramp rates under staged conditions will hurt both fireside corrosion and circumferential cracking.

- **Rotor bore cracking.** When subjected to transients in the temperature of the admitted steam, the high-pressure and intermediate-pressure steam turbine rotors can suffer thermo-mechanical stress excursions, resulting in low-cycle fatigue damage. This damage can result either from introducing hot steam to a relatively cold rotor exterior, or the opposite.

The more accurately costs to repair or replace the issues described above can be predicted and included in the current unit dispatch operation methodology, the lower the risk for a particular coal-fired EGU to experience an unexpected equipment failure and unit outage, and miss out on potentially significant energy revenues.

Numerous studies have explored how to mitigate flexible operation damage. Some of the suggested **mitigation strategies** to reduce the damage and associated costs extensive cycling has on coal plants include:

- **Efficiency improvements.** One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Mitigation examples

20 Source: Hesler S (2011) *Mitigating the effects of flexible operation on coal-fired power plants.* http://www.powermag.com/mitigating-the-effects-of-flexible-operation-on-coal-fired-powerplants/

include: sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and changes to boiler draft control schemes and operating philosophy. However, many plants today do not have sufficient capital, whether internally or through the investment community, available to undertake these major system modifications.

- **Establishing and following cycle chemistry guidelines for flexible operations.** An area of particular concern for plants under cycling duty is following appropriate cycle chemistry guideline limits during plant startup, shutdown, and layup. Proper protection of the entire steam circuit (boiler, piping, feedwater, and turbine) is critical during these modes of flexible operation. Correct layup procedures, combined with appropriate chemical treatment during shutdown and startup, will significantly reduce corrosion and deposits in the steam cycle equipment, including the boiler, steam-touched tubing, and the turbine.

- **Accurate damage estimation.** Estimates can be made of damage costs per start to inform the plant's trading position. Cost estimates are based on increased routine maintenance costs, damage to major components, and estimated cost of consumables per start.

- **Flexible operation studies.** These studies reduce component damage through procedure optimization and design modification. Included in the reviews are: an initial appraisal of plant-specific risk areas, installation of additional instrumentation, flexible operation trials, assessment of thermal transients, changes to operating procedures and design to address issues identified, repeat tests to confirm success, and detailed stress analysis to inform strategy going forward.

- **Operator coaching.** Simplified damage algorithms for creep and fatigue are also developed for operator coaching. Plant data for critical components are screened to identify and understand the most damaging operational conditions. Operators can then seek to minimize the extent of such conditions during future unit starts. Proper operator training can reduce the risk of human error during increased coal plant cycling operations.

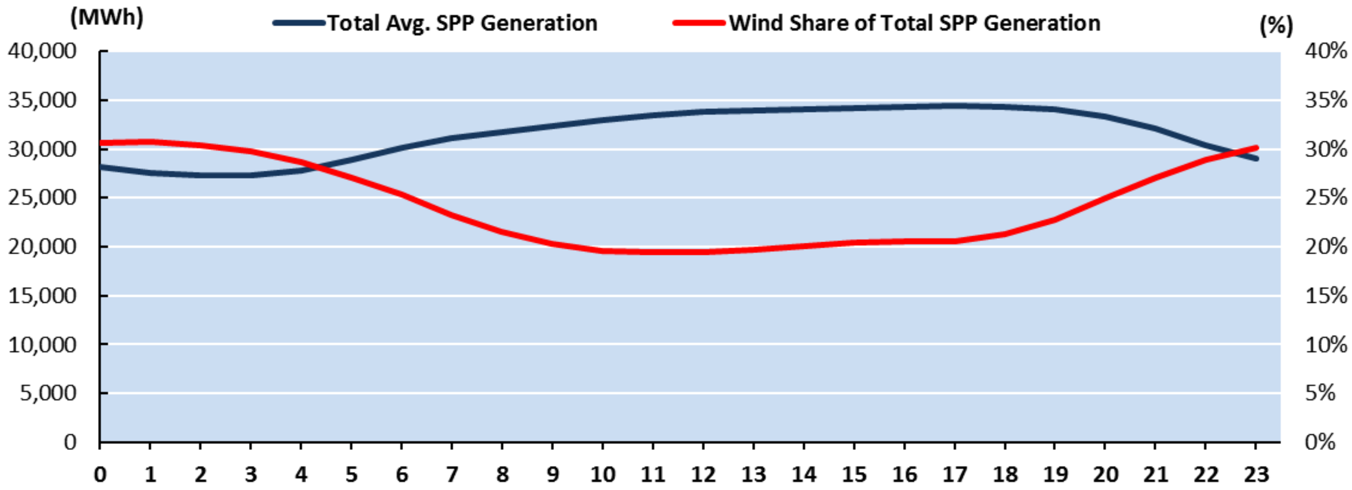
Other areas to minimize coal plant cycling costs, outside the control of coal plant owners, include increased deployment of energy storage and demand-side management resources to shift some of the renewable generation from wind and solar to peak demand hours or reduce the demand fluctuations over the course of the day. A more drastic approach is to curtail wind and solar generation during times of high generation or low demand to minimize the requirement for fossil fuel plant cycling.

Current Financial Compensation Practices for Plant Flexibility Operation

The previous section described various mitigation strategies to counteract the increased maintenance and capital costs due to increased coal plant cycling and shutdowns/startups. Most of these mitigation strategies require significant amounts of additional capital investments by coal plant owners. Recent market developments described previously, including increased renewable generation from wind and solar and low natural gas prices due to the shale gas revolution, have eroded the revenue stream of coal plants significantly. Still, maintaining a flexible baseload fleet is vital to complement the variability of wind generation and keep electricity reliable and affordable, especially during times when new natural gas power plants face additional regulatory hurdles.

One issue with wind generation in SPP is shown in **Exhibit 16.** Exhibit 16 shows the average hourly total generation for SPP during a 24-hour cycle in 2018 along with the wind generation share during those same hours. In 2018, wind supplied over 30% of the generation between 11 pm and 3 am, while dropping to just 20% between 10 am and 5 pm. Conversely, demand for electricity in SPP reaches its low point at 3 am and starts to climb throughout the day, before beginning to decline again around 6 pm. Therefore, during peak electricity demand times, wind generation in SPP is generally at its lowest, requiring other generating resources such as coal and natural gas to increase generation accordingly.

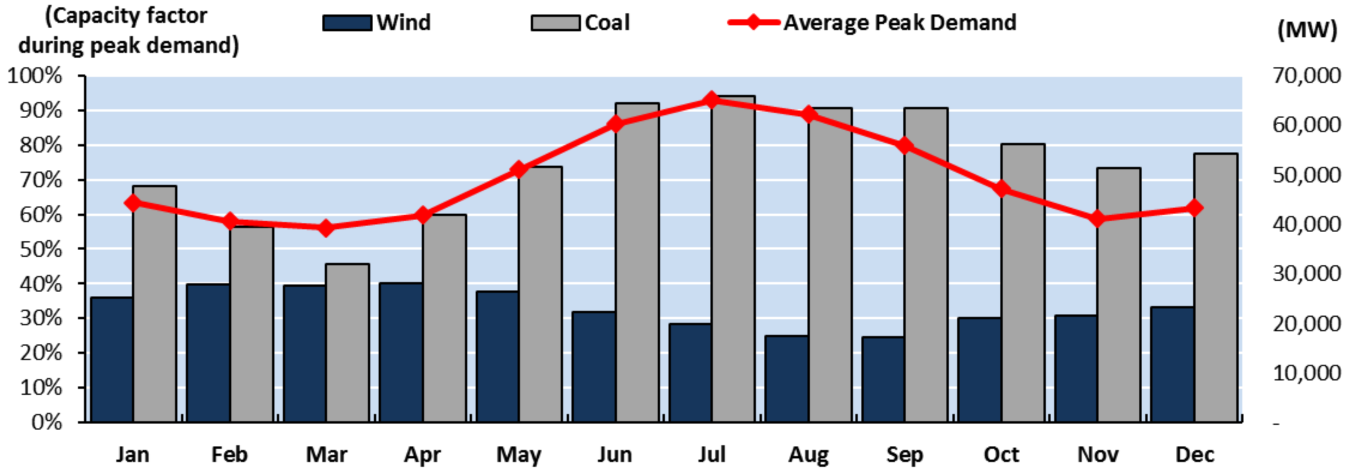
EXHIBIT 16: 2018 AVERAGE HOURLY SPP GENERATION VS. WIND GENERATION SHARE[21]



Additionally, wind generation varies significantly from month to month. Exhibit 17 shows the average capacity factors for both coal and wind and during peak demand hours by month for ERCOT for the years 2016 through 2018. Wind generation tends to achieve its highest capacity factors during the spring and fall seasons while being at its lowest during the hot summer months. On the other hand, demand for electricity reaches its peak during the hot summer months when the use of air conditioning drives up demand. Again, due to the seasonality of wind, additional generating resources are needed to increase generation to ensure reliable electricity delivery.

21 Source: SPP Hourly Generation Mix Data

EXHIBIT 17: AVERAGE CAPACITY FACTOR OF WIND AND COAL GENERATION DURING PEAK DEMAND HOURS IN ERCOT BY MONTH – 2016 TO 2018[22]



Historically, as shown in **Exhibit 17,** coal-fired EGUs operated at full capacity during high demand seasons, such as summer and winter, while frequently cycling between minimum load and full load during the shoulder months when online. During shoulder months, power prices during off-peak hours (late night to early morning hours) would sometimes drop below the coal unit's operating costs, therefore losing money during those hours. However, coal unit operators would accept the overnight losses to be available during peak demand hours, subsequently having the opportunity to recoup lost revenue.

The shale gas revolution and the increased development of renewable generating resources have changed this equation dramatically. As a review, power prices in deregulated power markets are set by the EGU that provides the marginal MWh to meet electricity demand at that time. As the dispatch cost for wind is essentially zero, the increased share of wind generation has caused off-peak power prices to decline in recent years. Additionally, on-peak power prices have fallen at even higher rates, as natural gas prices have plummeted, reducing the dispatch costs for combustion turbines which historically used to be the marginal resources and set the on-peak power prices. In some regions, dispatch costs for combustion turbines and combined cycle power plants have dropped well below coal-fired power plants, leaving an increasing number of coal plants "out-of-the-money."

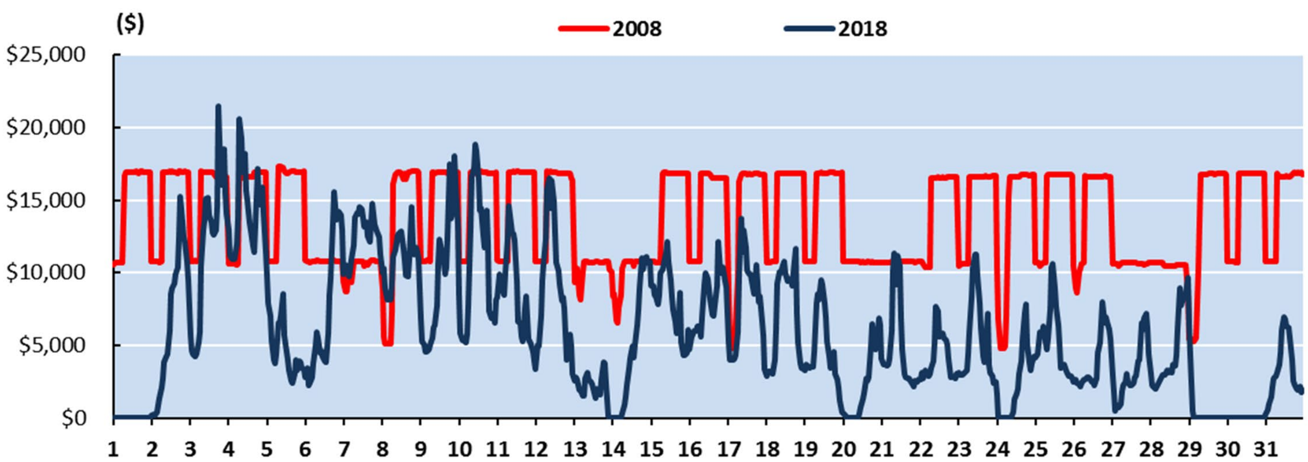
As a result, coal plants frequently find themselves in a vicious cycle. Due to the low revenue expectation during on-peak hours and to minimize losses during off-peak hours, coal plants more often shut down operations for longer periods and only return to service when more extended periods of profitability are expected. However, the longer coal-fired EGUs remain offline, the more expensive it becomes to return them to service. In fact, cold starts are often more than three times more expensive than hot starts, increasing the capital and maintenance costs associated with operating the unit. On the other hand, lower revenues due to lower wholesale power prices and lower plant utilization rates have reduced the working capital for many coal plant operators, therefore limiting the amount of available capital to spend on maintenance or to make significant improvements to reduce the overall cycling cost of the unit.

22 Source: ERCOT Hourly Generation Mix Data

Consequently, the combination of falling on-peak and off-peak power prices and increased cycling operations have significantly eroded the economic viability of many coal-fired power plants across the country, even though they can provide essential reliability and flexibility services.

Xcel's Harrington 1 coal-fired unit in Texas, the example from earlier, provides a useful case study of this issue. In December 2008, the EGU operated at a capacity factor of 94.7%, had zero shutdowns over the course of the month, and its average hourly ramp rate was 1.1%. In December 2018, these numbers were drastically different. Harrington 1's capacity factor dropped to 57.1%. It experienced five different startups (three hot starts and two warm starts), and its average hourly ramp rate increased to 4.9%. Additionally, on-peak and off-peak power prices for SPP-South, where Harrington is located, dropped 38% and 23% between December 2008 and 2018, respectively. **Exhibit 18** shows Harrington's estimated hourly energy revenue for the month of December in 2008 and 2018.

EXHIBIT 18: ESTIMATED ENERGY REVENUE FOR XCEL ENERGY'S HARRINGTON 1 COAL UNIT – DECEMBER 2008 & 2018[23]



As shown in **Exhibit 6,** Harrington 1 operated at full capacity almost all of December 2008 and generated over $10 million in energy revenue as a result. In December 2018, however, as power prices collapsed and Harrington 1 operated at much lower utilization rates, its energy revenue fell to $4.5 million. Including the additional costs of approximately $500,000 for the two warm starts and three hot starts, Harrington 1 generated more than $6 million less in net revenue in December 2018 compared to 2008. This does not include any additional O&M requirements to offset the greater stress on plant equipment due to the more frequent cycling operations.

As is recognized by market participants in both regulated and deregulated power markets, it is of utmost importance to retain a significant amount of electric generating capacity above peak electricity demand to account for unexpected losses in variable energy generation from wind and solar, unscheduled fossil plant outages, and under-forecasts of load. This amount of excess capacity is referred to as the reserve margin. Because wind resources tend to be at lower generation levels during peak demand hours as described previously, wind resources are rated at lower capacity

23 Source: S&P Global Platts Megawatt Daily Power Price Data

values than other resources. While some power markets such as PJM provide capacity payments to generating resources to provide capacity when needed, the two markets with the highest share of intermittent renewable generation, SPP and ERCOT, do not have capacity markets. Both markets are considered energy-only markets (although SPP does have a resource adequacy requirement tariff).

Both ERCOT and SPP acknowledged in their latest State of the Market Reports[24] that it is in the best interest for the market to develop compensation mechanisms or products to pay for capacity to cover uncertainties, such as the loss of the significant amount of generation during high demand times, as was the case in ERCOT this summer. The independent market monitor for ERCOT acknowledged that in 2018, coal units in ERCOT received just enough revenue from energy and ancillary services to cover operating costs.[25]

The other two major independent power markets with significant coal generation, PJM and MISO, are also in the process of developing new market mechanisms to better support and compensate the coal plants in their markets for the reliability and flexibility they provide. MISO, for example, is currently exploring the introduction of a so-called multi-day operating margin forecast. The forecast provides key power market metrics such as expected renewable generation, forecasted load, and scheduled plant outages for the next seven days to allow plant operators to make commitment decisions well ahead of the day-ahead market auction. PJM, on the other hand, tries to minimize the financial losses coal plants incur overnight. As mentioned previously, many coal plants cannot turn off completely overnight as they have to be available during peak demand hours in the morning. However, with the rise in renewable generation and drop in natural gas prices, off-peak power prices during the late night/early morning hours have dropped well below the operating costs of many of these coal plants, forcing them to incur huge losses these plants are struggling to recoup during the day. PJM is working on a pricing tool that allows certain baseload power plants to receive higher prices during off-peak hours to ensure they provide flexible and reliable generation during the day.

Regulated Utilities

Regulatory mechanisms minimize the financial exposure regulated utilities face compared to their merchant counterparts. However, they do experience their own unique struggles. Regulated utilities generally have two options to recover the costs for operating their generating fleet.

First, every few years, regulated utilities forecast their expenditures for maintaining affordable and reliable electricity supply, and request an electric rate adjustment through a “rate case” to recoup their expected capital expenditures and guarantee a set rate of return. However, there is generally no true-up to previous rate cases. If a utility greatly underestimated the costs to operate its generation fleet during its last rate case, the utility incurs these costs with no possibility to recoup those losses. Regulated utilities do use past projections versus performance measures to inform their next rate adjustment.

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24 Southwest Power Pool. “State of the Market 2018” (May 2019) https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf

25 Potomac Economics. “State of the Market Report for ERCOT Electricity Markets” (June 2019) https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf

The second option for utilities to recoup their investments in their generating fleet is through short-term adjustments. Based on the state, these adjustments vary in name and frequency. For example, in Alabama, regulated utilities can recover increased fuel or purchased power expenditures through the Energy Cost Recovery Rider. In other states, such as Wyoming, utilities are also allowed to recover some of their increased O&M costs through annual adjustment riders. However, in states where capital expenditures for increased O&M caused by operational changes at coal-fired power plants discussed throughout this report can only be recovered through projected going-forward costs as part of a rate case, some utilities have likely incurred some unexpected losses over the last decade.

As the example in Texas this summer has shown, sufficient backup flexible capacity is needed to ensure reliable electricity supply during peak demand times, coupled with a higher-than-expected loss of variable generation from wind or solar. Without any other market mechanisms incentivizing new capacity entry into the market, keeping existing fossil generation from retiring becomes paramount. Even in regulated states, continued operation of and investment in existing coal-fired power plants can oftentimes be the more economical choice than building a new natural gas plant. Besides the technology options discussed in this report to make existing coal plants more flexible and efficient, new technologies begin to emerge and provide viable alternatives to natural gas peaking resources in the near future. According to a recent report from Bloomberg New Energy Finance, lithium-ion battery prices have dropped faster than projected, from over $1,100/kWh in 2010 to $156/kWh in 2019.[26] As the industry focuses on bringing new energy storage and flexible generation to commercial operation, utilities focus on maintaining the existing fleet of fossil resources to bridge that timing gap.

Regulators in California are now pursuing a similar strategy. In order to achieve its aggressive GHG emission reduction goal, California required utilities to invest in new non-hydro renewable generation heavily, mainly solar and, to a lesser extent, wind, while also banning new natural gas generation from entering the market. As older fossil plants have retired over the last few years due to the loss of energy revenue and increased operating costs, California's reserve margin began to shrink, and the risk of a potential loss of load increased. Now, regulators in California required existing natural gas generation to continue operating and provide much-needed backup flexible generation while new non-GHG emitting energy storage resources such as battery storage enter the market.[27]

26 BNEF. "Battery Pack Prices Fall As Market Ramps Up With Market Average At $156/kWh In 2019" (December 2019) https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/?sf113554299=1

27 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M312/K522/312522263.PDF

Conclusion

In summary, it is worth highlighting the following points:

- Coal plant operations have changed dramatically over the last decade, forced by changing market dynamics due to low natural gas prices and increased generation from intermittent renewable energy resources such as wind and solar.

- While not originally designed to be load-following, many coal plants are capable of providing flexible generation at efficient and cost-effective levels to complement increased renewable generation. Additionally, technology improvements exist to increase the efficiency and flexibility of existing coal plants that are oftentimes more economical than building new generation capacity.

- However, the current market and regulatory mechanisms are not sufficient to offset some or all of the increased one-time and ongoing costs for coal-fired power plant operators to support this change in plant operations. Power markets and regulatory commissions provide different options to help mitigate the issue and are focusing on developing new mechanisms or making changes to existing ones.

- Recent examples in Texas and California have shown the necessity of maintaining existing generating resources to provide much-needed flexible and reliable generation while new energy storage technologies are being developed and deployed.

EXHIBIT 19: GENERATION MIX BY STATE – 2008 VS. 2018

	2008							2018						
	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other
US Total	**50%**	**21%**	**20%**	**6%**	**1%**	**0%**	**1%**	**28%**	**35%**	**20%**	**7%**	**7%**	**2%**	**1%**
Alaska	6%	76%	0%	18%	0%	0%	0%	9%	64%	0%	24%	2%	0%	0%
Alabama	53%	15%	28%	4%	0%	0%	0%	23%	41%	28%	8%	0%	0%	0%
Arkansas	49%	15%	27%	9%	0%	0%	0%	46%	29%	19%	5%	0%	0%	0%
Arizona	37%	33%	25%	6%	0%	0%	0%	27%	33%	28%	6%	1%	5%	0%
California	1%	56%	17%	13%	3%	0%	9%	0%	44%	10%	14%	8%	15%	9%
Colorado	65%	25%	0%	3%	6%	0%	0%	47%	30%	0%	3%	18%	2%	0%
Connecticut	15%	28%	51%	2%	0%	0%	5%	1%	50%	44%	1%	0%	0%	3%
District Of Columbia	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Delaware	76%	22%	0%	0%	0%	0%	2%	6%	92%	0%	0%	0%	1%	1%
Florida	30%	53%	15%	0%	0%	0%	2%	13%	72%	12%	0%	0%	1%	2%
Georgia	64%	10%	24%	1%	0%	0%	0%	26%	42%	28%	2%	0%	2%	1%
Hawaii	15%	79%	0%	0%	2%	0%	3%	14%	71%	0%	1%	6%	2%	7%
Iowa	76%	4%	10%	2%	8%	0%	0%	44%	12%	8%	2%	35%	0%	0%
Idaho	0%	15%	0%	82%	2%	0%	1%	0%	18%	0%	62%	15%	3%	1%
Illinois	48%	2%	48%	0%	1%	0%	0%	31%	8%	53%	0%	7%	0%	0%
Indiana	97%	3%	0%	0%	0%	0%	0%	72%	22%	0%	0%	5%	0%	0%
Kansas	73%	5%	18%	0%	4%	0%	0%	39%	7%	17%	0%	36%	0%	0%
Kentucky	94%	4%	0%	2%	0%	0%	0%	75%	18%	0%	6%	0%	0%	0%
Louisiana	36%	39%	23%	2%	0%	0%	0%	17%	58%	24%	1%	0%	0%	0%
Massachusetts	25%	55%	14%	1%	0%	0%	5%	0%	68%	16%	2%	1%	5%	7%
Maryland	58%	5%	31%	4%	0%	0%	1%	23%	31%	35%	7%	1%	1%	2%
Maine	1%	47%	0%	32%	1%	0%	18%	1%	22%	0%	35%	26%	0%	17%
Michigan	61%	9%	28%	0%	0%	0%	2%	38%	28%	27%	1%	5%	0%	2%
Minnesota	58%	6%	25%	1%	8%	0%	2%	37%	15%	24%	2%	18%	2%	2%
Missouri	81%	6%	10%	3%	0%	0%	0%	73%	8%	13%	2%	4%	0%	0%
Mississippi	36%	44%	20%	0%	0%	0%	0%	9%	80%	11%	0%	0%	1%	0%
Montana	62%	2%	0%	34%	2%	0%	0%	48%	3%	0%	39%	8%	0%	1%
North Carolina	61%	4%	32%	2%	0%	0%	0%	24%	34%	32%	4%	0%	5%	1%
North Dakota	91%	0%	0%	4%	5%	0%	0%	66%	2%	0%	6%	26%	0%	0%
Nebraska	66%	2%	29%	1%	1%	0%	0%	63%	3%	15%	4%	14%	0%	0%
New Hampshire	15%	31%	41%	7%	0%	0%	5%	4%	18%	58%	9%	2%	0%	9%
New Jersey	14%	33%	51%	0%	0%	0%	2%	2%	52%	43%	0%	0%	2%	2%
New Mexico	74%	21%	0%	1%	4%	0%	0%	41%	35%	0%	1%	19%	4%	0%
Nevada	22%	68%	0%	5%	0%	0%	4%	6%	67%	0%	5%	1%	12%	9%
New York	13%	34%	31%	19%	1%	0%	2%	1%	38%	33%	23%	3%	0%	2%
Ohio	86%	3%	11%	0%	0%	0%	0%	47%	35%	15%	0%	1%	0%	0%
Oklahoma	48%	44%	0%	5%	3%	0%	0%	17%	48%	0%	3%	32%	0%	0%
Oregon	7%	29%	0%	59%	4%	0%	1%	2%	27%	0%	57%	11%	1%	1%
Pennsylvania	53%	9%	36%	1%	0%	0%	1%	21%	36%	39%	1%	2%	0%	1%
Rhode Island	0%	98%	0%	0%	0%	0%	2%	0%	93%	0%	0%	2%	1%	3%
South Carolina	42%	6%	52%	0%	0%	0%	0%	20%	23%	54%	2%	0%	1%	1%
South Dakota	52%	4%	0%	42%	2%	0%	0%	21%	9%	0%	46%	24%	0%	0%
Tennessee	63%	1%	31%	6%	0%	0%	0%	26%	16%	46%	12%	0%	0%	0%
Texas	40%	44%	11%	0%	4%	0%	0%	26%	46%	10%	0%	18%	1%	0%
Utah	82%	16%	0%	1%	0%	0%	1%	66%	21%	0%	3%	2%	6%	2%
Virginia	44%	15%	40%	0%	0%	0%	1%	10%	54%	32%	0%	0%	1%	3%
Vermont	0%	0%	72%	22%	0%	0%	6%	0%	0%	0%	59%	17%	6%	18%
Washington	8%	9%	8%	71%	3%	0%	1%	5%	9%	8%	71%	6%	0%	0%
Wisconsin	66%	9%	20%	2%	1%	0%	1%	50%	26%	15%	4%	3%	0%	1%
West Virginia	98%	0%	0%	1%	0%	0%	0%	94%	2%	0%	2%	3%	0%	0%
Wyoming	96%	0%	0%	2%	2%	0%	0%	87%	1%	0%	2%	9%	0%	0%

EXHIBIT 20: AVERAGE UTILIZATION DISTRIBUTION BY STATE – 2008 VS. 2018

	2008						2018					
	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown
US Total	**17%**	**3%**	**9%**	**15%**	**55%**	**52%**	**32%**	**6%**	**12%**	**14%**	**37%**	**43%**
Alabama	13%	3%	11%	16%	58%	50%	34%	9%	17%	11%	29%	43%
Arkansas	15%	2%	5%	9%	70%	53%	20%	4%	9%	12%	55%	43%
Arizona	7%	1%	2%	9%	81%	70%	15%	8%	13%	29%	36%	44%
Colorado	11%	1%	5%	12%	71%	63%	20%	0%	12%	27%	41%	57%
Connecticut	7%	6%	3%	3%	81%	36%	85%	4%	1%	2%	8%	12%
Delaware	18%	13%	15%	19%	34%	35%	85%	2%	7%	2%	4%	10%
Florida	19%	3%	12%	15%	52%	52%	33%	11%	14%	14%	28%	35%
Georgia	11%	5%	23%	16%	44%	46%	54%	8%	13%	9%	15%	34%
Iowa	21%	3%	12%	24%	40%	50%	30%	7%	12%	10%	42%	35%
Illinois	14%	3%	10%	15%	57%	53%	28%	5%	13%	16%	39%	46%
Indiana	18%	3%	8%	13%	59%	52%	30%	4%	12%	13%	41%	46%
Kansas	12%	1%	6%	19%	62%	61%	29%	9%	11%	14%	38%	41%
Kentucky	13%	3%	8%	16%	60%	52%	24%	4%	12%	17%	43%	43%
Louisiana	13%	2%	3%	8%	75%	57%	28%	6%	13%	19%	33%	43%
Maryland	22%	8%	13%	18%	39%	40%	71%	8%	6%	5%	11%	19%
Michigan	16%	3%	11%	22%	48%	51%	35%	3%	15%	20%	26%	43%
Minnesota	21%	3%	9%	20%	47%	52%	20%	2%	21%	16%	42%	49%
Missouri	14%	2%	5%	14%	66%	58%	21%	2%	10%	13%	54%	51%
Mississippi	15%	2%	5%	7%	71%	53%	49%	29%	17%	4%	1%	35%
Montana	12%	2%	4%	11%	72%	55%	30%	4%	4%	19%	42%	46%
North Carolina	31%	7%	13%	11%	38%	39%	54%	12%	9%	7%	19%	33%
North Dakota	10%	0%	1%	8%	80%	75%	11%	0%	7%	13%	67%	69%
Nebraska	9%	1%	11%	33%	47%	56%	16%	5%	20%	14%	44%	42%
New Hampshire	14%	2%	2%	6%	77%	73%	68%	1%	2%	5%	23%	47%
New Jersey	48%	6%	9%	15%	22%	40%	98%	0%	1%	0%	1%	7%
New Mexico	15%	1%	2%	4%	78%	71%	26%	4%	9%	17%	45%	56%
Nevada	19%	2%	3%	7%	69%	57%	36%	19%	10%	13%	22%	38%
New York	10%	1%	5%	14%	70%	59%	88%	3%	2%	2%	6%	24%
Ohio	24%	5%	11%	17%	44%	42%	42%	5%	11%	9%	33%	30%
Oklahoma	12%	2%	4%	10%	72%	57%	43%	6%	11%	9%	30%	39%
Oregon	18%	1%	1%	1%	80%	87%	63%	3%	2%	3%	28%	26%
Pennsylvania	19%	6%	11%	18%	46%	47%	47%	3%	13%	7%	30%	42%
South Carolina	22%	3%	8%	20%	47%	52%	45%	5%	10%	19%	22%	44%
South Dakota	4%	0%	4%	12%	79%	60%	23%	2%	22%	17%	36%	42%
Tennessee	8%	1%	6%	18%	67%	55%	48%	1%	14%	11%	26%	45%
Texas	10%	1%	2%	7%	79%	68%	17%	10%	12%	10%	51%	41%
Utah	6%	1%	2%	7%	85%	75%	8%	16%	12%	16%	48%	37%
Virginia	32%	7%	8%	15%	38%	40%	64%	4%	8%	6%	17%	38%
Washington	23%	1%	2%	2%	72%	71%	43%	3%	7%	11%	37%	40%
Wisconsin	23%	5%	13%	22%	37%	40%	21%	6%	13%	20%	41%	43%
West Virginia	28%	4%	7%	13%	48%	45%	29%	3%	12%	12%	44%	53%
Wyoming	7%	1%	3%	6%	83%	70%	9%	4%	11%	13%	63%	55%

EXHIBIT 21: AVERAGE NUMBER OF STARTS & AVG. OUTAGE LENGTH BY STATE – 2008 VS. 2018

	2008					2018				
	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length
US Total	**3.7**	**3.1**	**3.4**	**2.5**	**148.3**	**2.0**	**1.7**	**2.8**	**4.1**	**341.9**
Alabama	3.2	2.5	1.5	2.0	147.6	2.7	0.8	1.5	3.5	407.5
Arkansas	2.8	0.8	2.2	2.0	186.8	1.1	1.4	0.4	2.1	542.0
Arizona	4.0	1.5	2.5	0.8	76.8	2.4	1.0	3.1	2.5	170.2
Colorado	2.3	1.6	2.3	1.5	140.7	2.1	0.7	1.0	2.3	372.7
Connecticut	5.0	5.0	3.0	1.0	47.2	3.0	-	2.0	9.0	532.8
Delaware	2.3	3.7	5.0	3.3	114.0	2.0	3.0	7.0	10.0	339.5
Florida	3.9	2.9	2.0	2.5	180.3	2.7	1.6	2.2	3.8	303.7
Georgia	1.9	2.5	1.1	1.6	160.2	1.7	1.4	1.6	2.9	870.1
Iowa	3.8	1.9	3.6	2.3	183.7	2.2	3.5	3.6	3.0	402.1
Illinois	2.7	3.6	3.4	2.1	122.6	2.3	2.9	5.0	4.8	176.4
Indiana	2.9	3.6	3.7	2.6	131.7	1.6	2.0	3.2	4.4	262.3
Kansas	2.8	3.7	2.3	1.1	129.0	1.1	1.7	5.1	3.6	242.6
Kentucky	3.0	4.2	2.7	1.5	120.1	1.7	1.6	2.4	3.6	258.8
Louisiana	2.8	3.3	1.8	1.8	114.1	1.3	2.1	2.6	4.3	268.6
Maryland	7.1	4.4	4.7	3.3	131.8	0.9	0.2	2.6	10.6	536.6
Michigan	2.5	2.8	5.0	2.2	156.9	1.5	0.8	1.3	4.1	597.0
Minnesota	2.5	3.7	3.7	2.5	167.0	2.6	3.9	4.4	4.3	126.8
Missouri	2.9	2.8	2.3	1.7	138.8	1.9	1.9	3.3	3.3	199.8
Mississippi	2.8	1.2	1.0	2.0	296.9	4.0	1.7	1.0	4.7	758.6
Montana	5.0	3.3	1.7	2.4	84.1	3.0	1.7	4.0	2.7	267.3
North Carolina	4.8	5.0	6.0	5.0	145.7	1.1	0.8	3.2	7.1	473.3
North Dakota	2.0	3.2	2.6	1.0	126.7	1.1	2.6	3.2	2.0	131.0
Nebraska	2.5	1.2	1.6	1.7	145.4	1.7	1.6	1.9	3.1	207.1
New Hampshire	1.0	1.2	2.8	2.0	174.3	12.0	5.8	6.0	11.0	221.5
New Jersey	1.9	5.1	6.4	6.0	301.5	3.0	-	-	4.0	1,229.3
New Mexico	6.6	2.5	4.2	1.5	88.4	2.4	3.4	2.8	2.6	280.7
Nevada	6.0	3.0	5.5	2.3	106.2	5.0	1.3	-	2.0	391.4
New York	2.2	1.4	2.5	1.8	127.4	1.5	0.5	3.0	7.5	622.7
Ohio	7.0	3.2	5.2	3.5	234.0	1.3	2.3	4.9	5.9	287.8
Oklahoma	5.0	2.2	2.2	1.8	105.9	3.5	2.7	5.3	8.7	217.6
Oregon	4.0	3.0	3.0	1.0	143.6	1.0	1.0	2.0	4.0	694.4
Pennsylvania	2.0	2.8	3.7	3.6	134.0	1.6	1.1	2.7	6.8	502.4
South Carolina	2.3	3.8	2.7	2.8	176.0	1.0	1.5	3.2	6.2	495.9
South Dakota	-	4.0	1.0	1.0	66.3	1.0	3.0	2.0	2.0	253.5
Tennessee	0.5	0.8	2.2	1.6	131.5	0.4	0.4	0.8	3.7	978.7
Texas	2.2	2.2	1.9	1.3	139.2	2.4	1.7	1.6	2.3	214.9
Utah	3.6	4.4	3.1	0.2	52.3	3.1	1.8	1.5	1.4	111.7
Virginia	13.0	4.0	5.6	5.5	130.1	0.5	0.8	3.7	7.7	462.9
Washington	2.0	3.5	3.0	2.5	191.0	2.0	3.0	3.5	1.0	404.4
Wisconsin	9.8	3.0	3.3	3.3	171.3	1.1	1.6	2.1	3.3	226.3
West Virginia	1.9	4.0	5.2	4.3	165.6	1.0	2.1	4.1	4.3	253.5
Wyoming	4.7	4.0	2.4	0.6	65.9	4.0	2.7	2.2	1.1	88.7

EXHIBIT 22: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES BY STATE – 2008 VS. 2018

	2008			2018		
	No Ramping	< 2.5%	> 2.5%	No Ramping	< 2.5%	> 2.5%
US Total	**33%**	**39%**	**28%**	**32%**	**38%**	**30%**
Alabama	37%	37%	26%	49%	27%	24%
Arkansas	24%	43%	33%	20%	42%	38%
Arizona	44%	37%	19%	37%	27%	35%
Colorado	48%	39%	14%	32%	39%	30%
Connecticut	68%	14%	18%	19%	32%	49%
Delaware	47%	24%	28%	33%	24%	43%
Florida	31%	39%	29%	41%	29%	29%
Georgia	30%	35%	35%	39%	32%	29%
Iowa	35%	34%	31%	29%	38%	33%
Illinois	25%	43%	31%	30%	41%	29%
Indiana	30%	43%	27%	32%	36%	32%
Kansas	39%	40%	21%	16%	46%	38%
Kentucky	32%	40%	28%	32%	38%	29%
Louisiana	22%	57%	21%	19%	49%	32%
Maryland	18%	35%	48%	28%	31%	41%
Michigan	45%	32%	23%	44%	31%	24%
Minnesota	40%	36%	24%	27%	38%	35%
Missouri	38%	40%	22%	24%	46%	30%
Mississippi	30%	44%	26%	46%	27%	27%
Montana	48%	43%	9%	43%	36%	21%
North Carolina	39%	27%	34%	29%	32%	39%
North Dakota	35%	53%	12%	36%	50%	14%
Nebraska	40%	37%	23%	27%	40%	33%
New Hampshire	64%	28%	8%	46%	22%	32%
New Jersey	33%	35%	31%	20%	32%	48%
New Mexico	40%	45%	14%	28%	47%	25%
Nevada	38%	47%	15%	48%	27%	25%
New York	38%	39%	23%	24%	35%	41%
Ohio	24%	38%	38%	37%	40%	22%
Oklahoma	30%	56%	13%	24%	34%	42%
Oregon	32%	65%	3%	30%	46%	24%
Pennsylvania	26%	38%	37%	32%	40%	28%
South Carolina	33%	38%	29%	22%	44%	34%
South Dakota	22%	52%	26%	11%	39%	50%
Tennessee	40%	39%	21%	43%	35%	22%
Texas	27%	52%	20%	21%	45%	34%
Utah	35%	52%	13%	23%	38%	38%
Virginia	24%	31%	45%	34%	37%	29%
Washington	22%	70%	7%	19%	59%	21%
Wisconsin	34%	30%	36%	31%	36%	33%
West Virginia	25%	37%	38%	27%	43%	30%
Wyoming	31%	59%	9%	35%	39%	25%

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

DEDICATED TO PUBLIC SERVICE

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