The Economic Impacts and Risks Associated with Electric Power Generation in Appalachia

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Photo of the Longview Power plant in Morgantown, WV, by project team, courtesy of Shutterstock.com.

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Executive Summary

The electric power industry is a crucial part of the coal ecosystem, accounting for the large majority of the total coal production sold within the United States. This report provides a detailed examination of the economic impact of changes in electric power generation in Appalachia over the past decade. We begin in Chapter 1 with an overview of the industry, paying special attention to coal-fired power generation. In Chapter 2, we estimate the effect of a loss of a power plant on county economic outcomes. Last, in Chapter 3, we examine the risk factors for further power plant retirements. Highlights of this research are as follows:

THE ELECTRIC POWER INDUSTRY

- OVERALL ELECTRICITY GENERATION: Overall electric power generation changed little nationally over the years 2005 through 2015. However, generation from the Appalachian Region fell by more than 15 percent during that period, while generation outside the Region rose by nearly 3 percent.
- ELECTRIC POWER GENERATION FUEL MIX: Coal has fallen substantially as a fuel for electric power generation in Appalachia. Coal represented around 53 percent of total generation in Appalachia in 2015, down from just over 74 percent 10 years prior. However, Appalachia remains much more reliant on coal for electric power generation compared with the rest of the nation, where coal represents around 35 percent of generation.
- ELECTRIC POWER SECTOR EMPLOYMENT: Total electric power employment has fallen considerably over the period of analysis. However, employment declined to a greater degree in Appalachia, falling from just over 50,000 workers to about 48,500, a decline of more than 3 percent, compared with a decline of less than 1 percent in the rest of the United States.
- COAL-FIRED POWER PLANT RETIREMENTS: Coal-fired generation capacity has fallen by around 18 percent since 2005, while natural gas-fired generation capacity has risen more gradually by around 4 percentage points per year on average over the decade of analysis. Appalachia contains less than 20 percent of the operating coal-fired generation capacity in the four NERC regions surrounding it. However, over 40 percent of the retired coal-fired capacity can be found in Appalachia.

THE REGIONAL ECONOMIC IMPACT OF ELECTRIC POWER PLANTS: We estimate the economic impact of electric power plants on regional economies using regression analysis with data from all counties in the 13 Appalachian states that contained any electric power generation capacity during any year between 2005 and 2015. In particular, we estimate wage and salary income in a county as a function of the coal-fired electric power generation capacity and the natural gas-fired electric power generation capacity in the county. Results are as follows:

- We are able to statistically identify a positive effect of coal-fired electric power generation capacity on wage and salary income in a county.
- We estimate that the effect of coal-fired electric power generation capacity on wage and salary income is relatively large for small population counties, but that the effect diminishes to zero for sufficiently large population counties.

- Our estimates of the magnitude of the effect of a coal-fired power plant shutdown range dramatically. For illustrative purposes, in the one extreme, we estimate that the shutdown of a large coal-fired power plant in a small county can lead to a loss of around two-thirds of the county's wage and salary income. In contrast, for a mid-size plant shutdown in a mid-size county, we estimate that the plant shutdown reduces wage and salary income by around 5 percent.
- We are not able to statistically identify an effect of natural-gas fired electric power generation capacity on county-level wage and salary income.

RISK FACTOR ANALYSIS FOR COAL-FIRED GENERATION RETIREMENTS AND REPOWERINGS: We use data on 57 coal-fired unit retirements in the Appalachian Region to inform a stochastic dynamic programming model to identify three primary and three secondary risk factors that shorten the economic lifetime of a coal-fired generating unit. Primary risk factors are those where a 5 percent change results in a greater than 5 percent decrease in the economic lifetime of the unit. Secondary risk factors are those where a 5 percent change results in a 1 to 5 percent decrease in the economic lifetime of the unit. We also identify factors that have very little influence on the economic lifetime of a coal-fired unit.

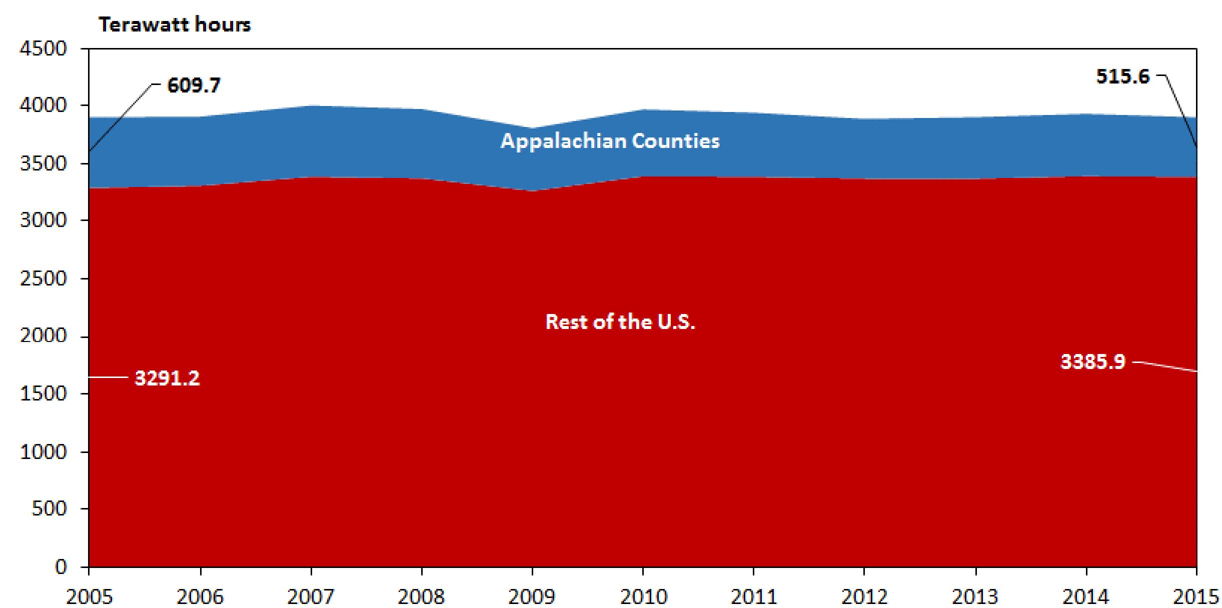
- Primary risk factors include a high fixed cost of generation, low cost of retiring the unit, and a low discount rate used by utilities in decision-making. These primary risk factors are influenced by a variety of drivers including construction costs, land values, macroeconomic factors, and whether the unit is in a regulated market.
- Secondary risk factors include low fuel efficiency, low generation responsiveness, and low/stable generation revenues. These secondary risk factors are influenced by a variety of drivers including age, capacity factor, ramp rate, and electricity markets.
- Coal prices have very little influence on the retirement decision due to the prevalence of long-term coal contracts in the electricity generation industry. The insensitivity of the retirement decision to coal prices suggests that there is little that the coal industry could do to delay the recent spate of coal-fired plant retirements. It also suggests that government intervention in the coal industry that lowers delivered coal prices or adds stability to the coal market would have little to no impact on retirement decisions.

Chapter I: An Overview of the Electric Power Industry in Appalachia

Electric Power Generation

ELECTRICITY GENERATION: We begin with an overview of electric power generation in Appalachia with special attention given to coal-fired generation. In Figure 1 we report overall electric power generation in the U.S., by region. As illustrated, Appalachian counties produced around 515 terawatt hours of electricity in 2015. This is down from production of 610 terawatt hours in 2005, representing a decrease of 15 percent. This compares to an increase of nearly 3 percent in the U.S. outside Appalachia. Expressed another way, Appalachian production amounted to around 13 percent of total national electric generation in 2015, which is down from nearly 15 percent in 2005. This compares to the nearly 8 percent of the U.S. population that lived in Appalachia in 2015.

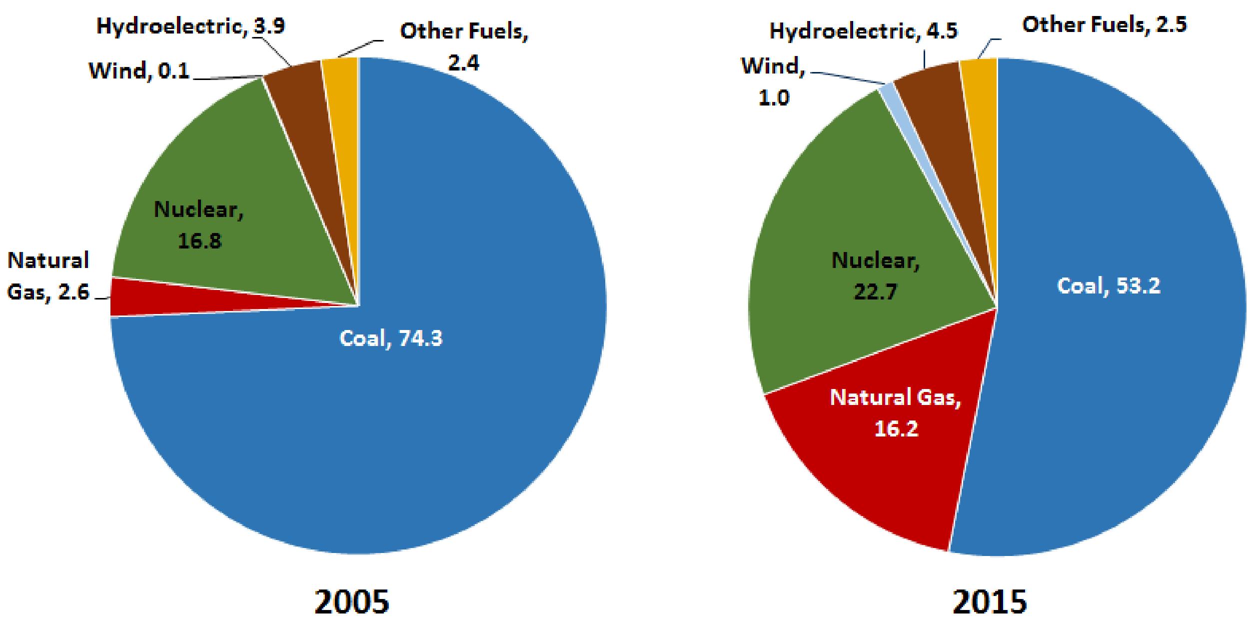
Figure 1: Electricity Generation, Appalachia and U.S.



Source: U.S. Energy Information Administration, sum of EIA-923 plant-level data.

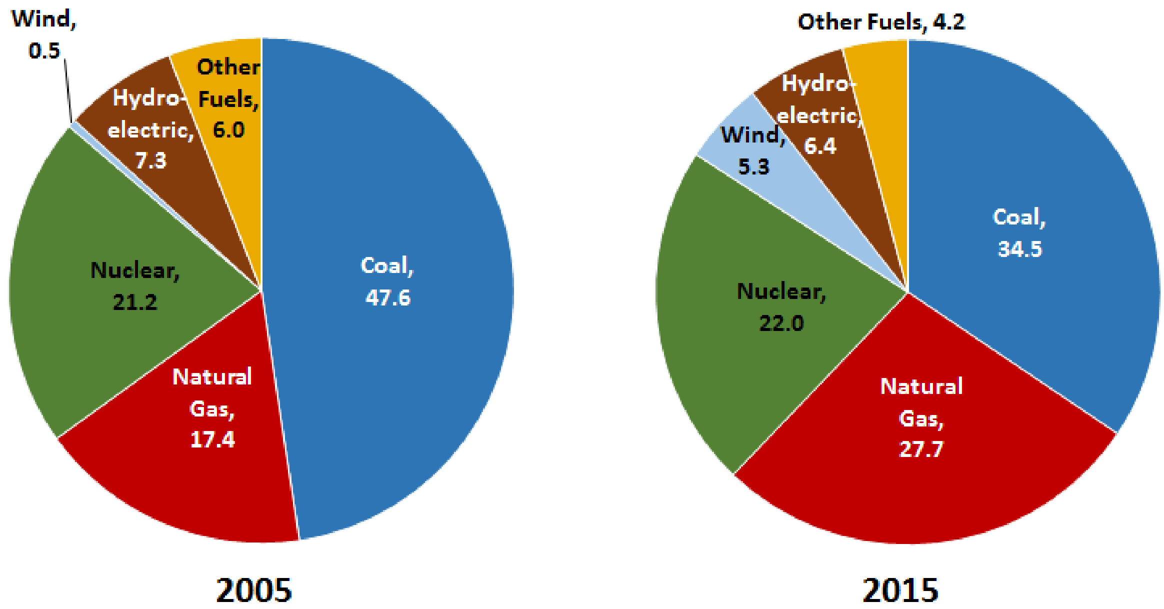
FUEL CONSUMPTION—ELECTRIC POWER GENERATION: Here we consider fuel consumption in electric power generation. As illustrated in Figure 2, coal is by far the largest fuel source for electric power generation in Appalachia. As of 2015, coal was the source fuel for more than 53 percent of electric generation in Appalachia. However, this figure has fallen significantly over the past decade. Importantly, over the past decade natural gas as a fuel source has risen to more than 16 percent of electric generation, up from only around 2.6 percent. Nuclear and renewables have also risen over the period of analysis as a source of electric power generation in Appalachia. In Figure 3 we report the source fuel for electric power generation nationally. Nationally we see less reliance on coal and hydroelectric and more reliance on natural gas and wind.

Figure 2: Fuel Consumption for Electric Power Generation, Appalachia



Source: U.S. Energy Information Administration, authors' calculations of unit level data
Notes: Fuel consumption is measured in terms of heat output (MMBtu). Btu = British thermal unit. A Btu is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit. 1 MMBtu = 1 million Btu.

Figure 3: Fuel Consumption for Electric Power Generation, U.S. Excluding Appalachian Counties

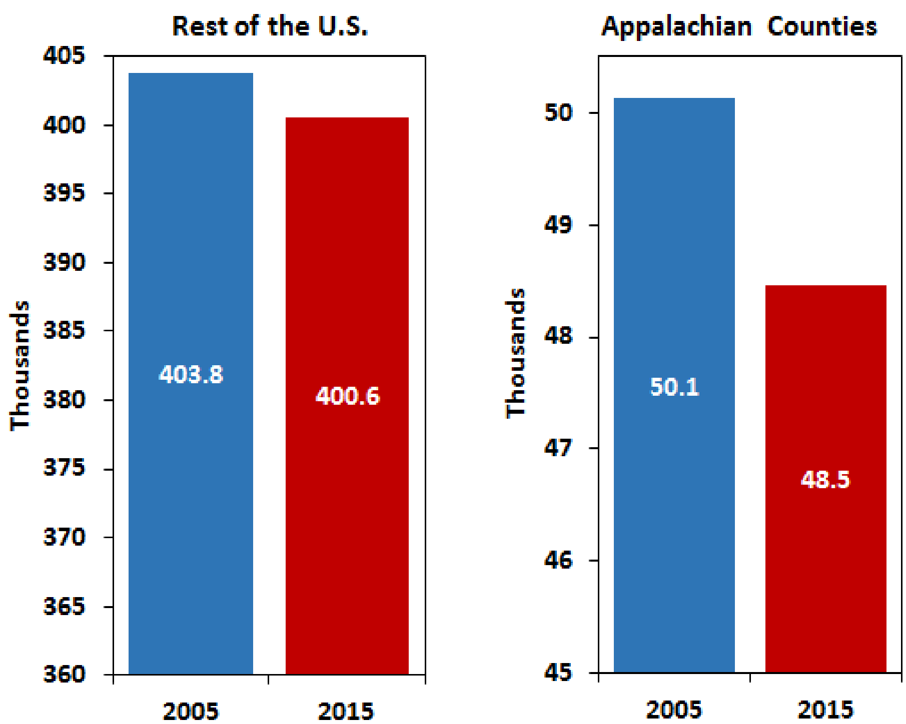


Source: U.S. Energy Information Administration, authors' calculations of unit level data
Notes: Fuel consumption is measured in terms of heat output (MMBtu). Btu = British thermal unit. A Btu is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit. 1 MMBtu = 1 million Btu.

Electric Power Sector Employment

EMPLOYMENT BY REGION: Next we turn to employment in the electric power sector. In Figure 4 we report total employment across geographic areas for electric power generation. Most noticeably, total electric power employment has fallen considerably over the period of analysis across both geographic areas as total electric generation is down and as the industry has become more capital intensive. However, employment declined to a greater degree in Appalachia, falling from just over 50,000 workers to about 48,500, a decline of more than 3 percent, compared with a decline of less than 1 percent in the rest of the United States.

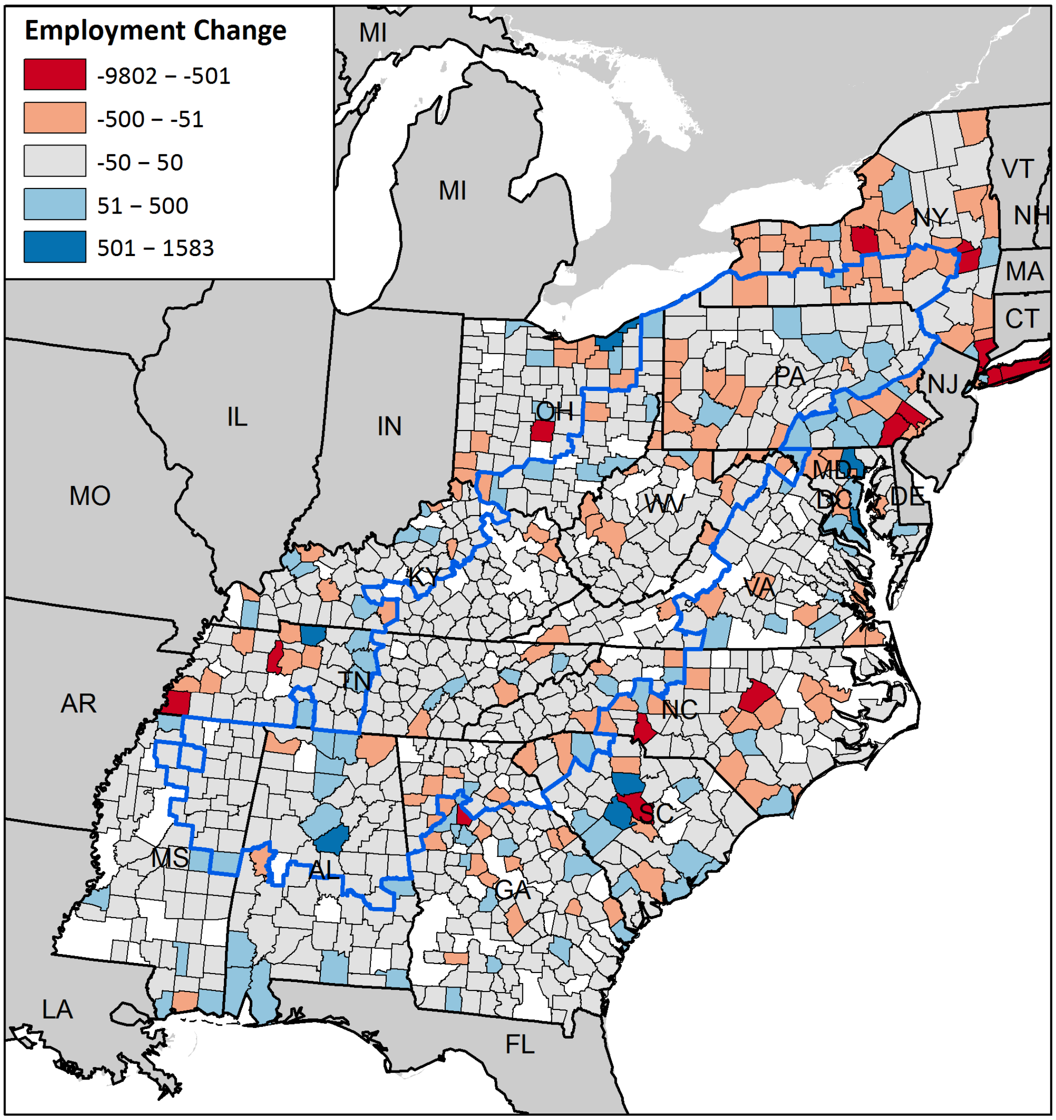
Figure 4: Employment in Electric Power Generation



Source: U.S. Bureau of Labor Statistics - QCEW. Missing data are imputed by IMPLAN.

EMPLOYMENT BY COUNTY: In Figure 5 we report the change in employment in the electric power generating and distribution industries by county between 2005 and 2015. The figure reports data for all counties within the 13 Appalachian states, with the Appalachian Region highlighted in blue. Among the 262 counties in the 13 Appalachian states—including those counties outside of the ARC designation—that had a noticeable change in employment (a gain or loss of 50 or more jobs), 106 saw employment gains while 156 saw employment losses. Within Appalachia, employment losses were concentrated in the northern states, particularly in New York, Pennsylvania, and West Virginia.

Figure 5: Employment Change in Electric Power Generation by County, 2005-2015

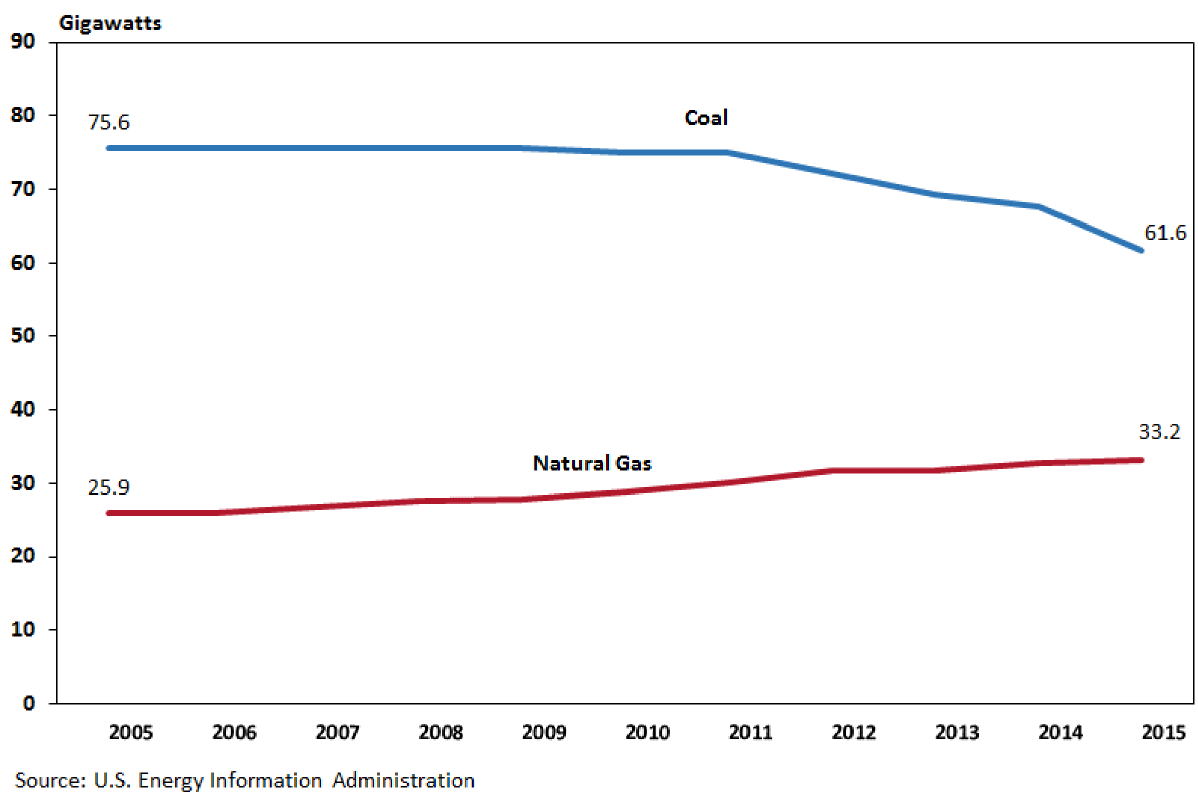


Source: U.S. Bureau of Labor Statistics - QCEW. Missing data are imputed by IMPLAN

Electric Power Plants

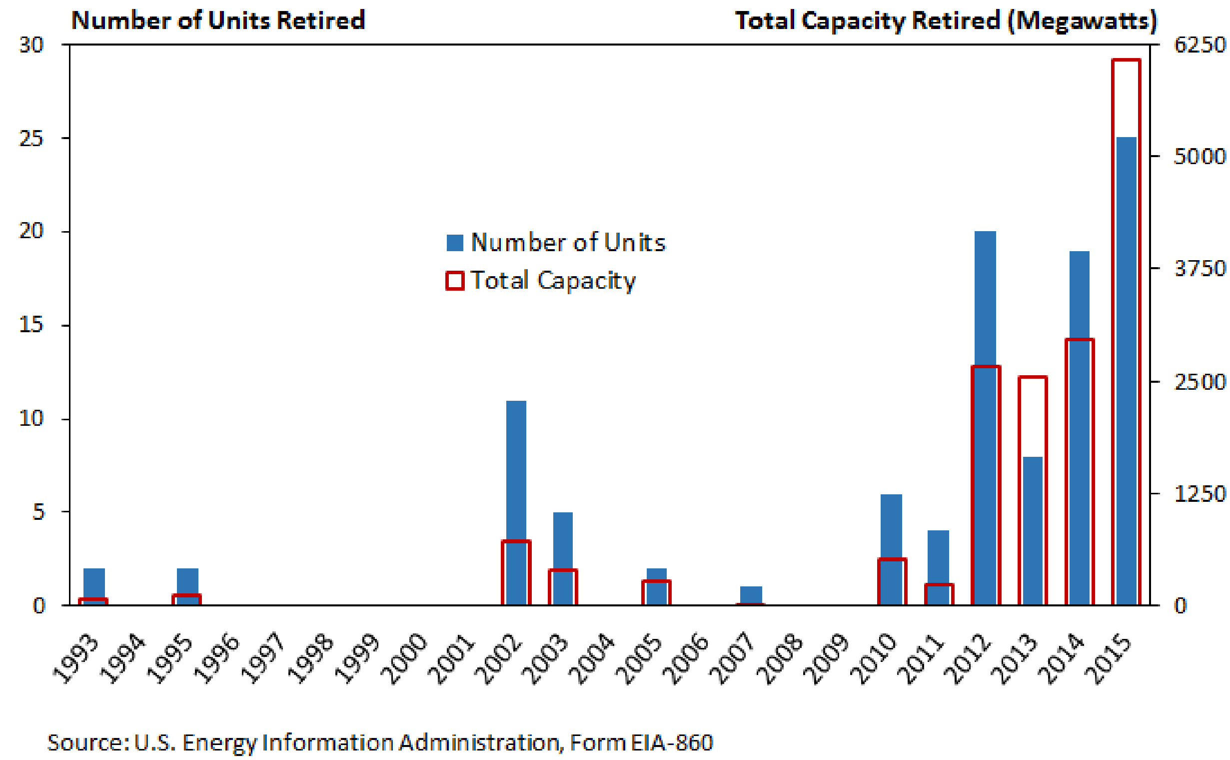
OVERALL GENERATION CAPACITY: Coal is playing a smaller role in electricity generation today than at any time since World War II and its shrinking role has accelerated over the last five years. This national trend is especially prominent in Appalachia. In Figure 6 we report the total electric power generation capacity in the 13 Appalachia states for coal-powered and natural gas-powered generators. Consistent with the figure above, as of 2015 coal-fired capacity far exceeded that of natural gas by around a factor of four. However, coal-fired generation capacity has fallen by more than 18 percent since 2005 while natural gas-fired generation capacity has risen by around 28 percent during the same period.

Figure 6: Coal and Natural Gas Power Plant Capacity, 13 Appalachia States



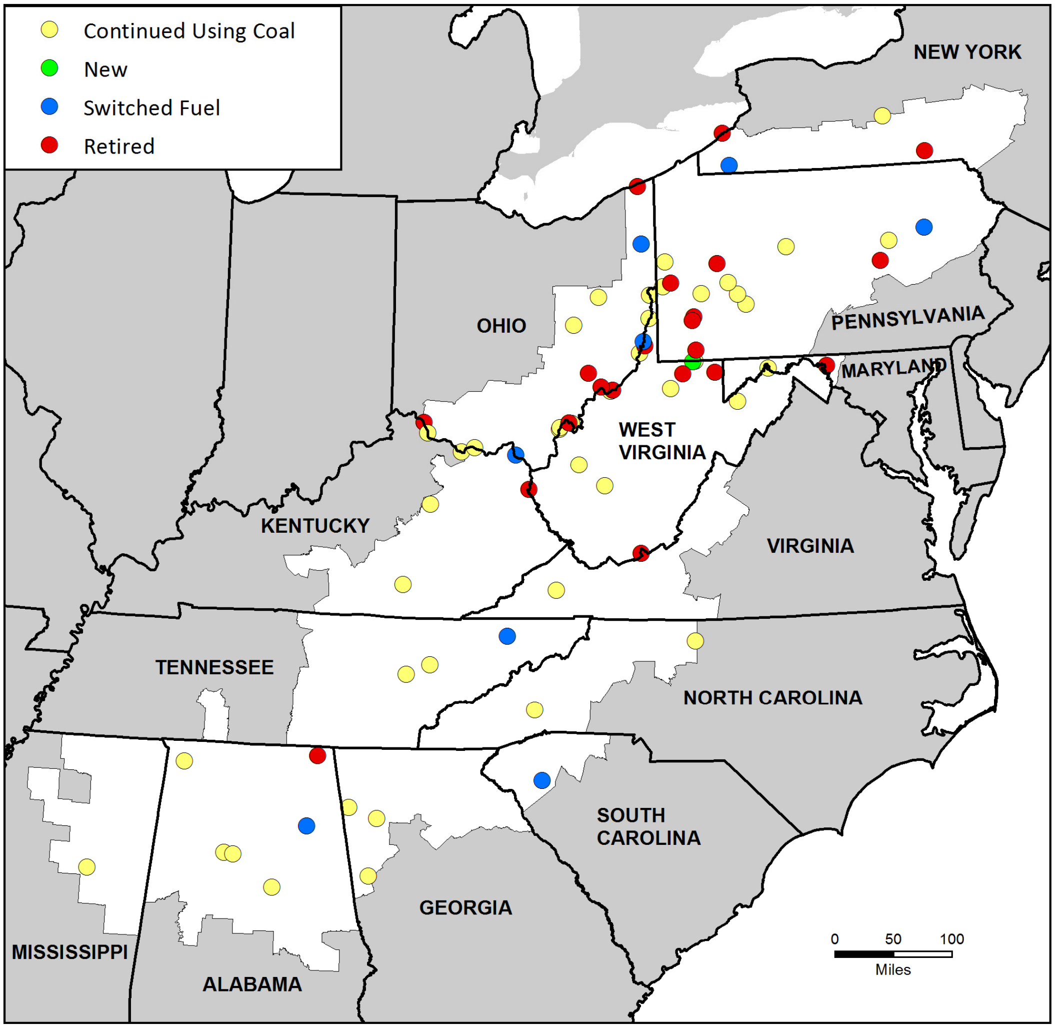
COAL-FIRED GENERATION RETIREMENTS: Each year since 2009, an increasing number of coal-fired units in Appalachia were retired, as reported in Figure 7. Since 2011, roughly 15,000 MW of coal-fired capacity were retired in Appalachia. This is roughly a quarter of the current coal-fired capacity still operating in Appalachia. These units used an average of over 1.5 million tons of mostly bituminous coal annually. In 2015 alone, more than 6,000 MW of coal-fired generation capacity was retired; more than double any previous year.

Figure 7: Retired Coal-Fired Generating Units and Capacity in Appalachia



COAL FIRED ELECTRIC POWER GENERATION LOCATIONS: In the following figures, we report electric power generation plants within Appalachia that used either coal, natural gas, or both coal and natural gas as fuel anytime between 2005 and 2015. Overall, there were 127 electric power plants that operated in Appalachia at some point between 2005 and 2015, spread over 86 counties. In Figure 8 we report any changes that have occurred between 2005 and 2015 in coal-fired electric power generation in Appalachia. Out of 72 coal-fired power plants operating any time during the period, 42 (nearly 60 percent) continued using coal, 22 (more than 30 percent) were retired, seven switched to another fuel, and only one was a new plant. Of the seven power plants that switched fuels, five permanently repowered to natural gas.

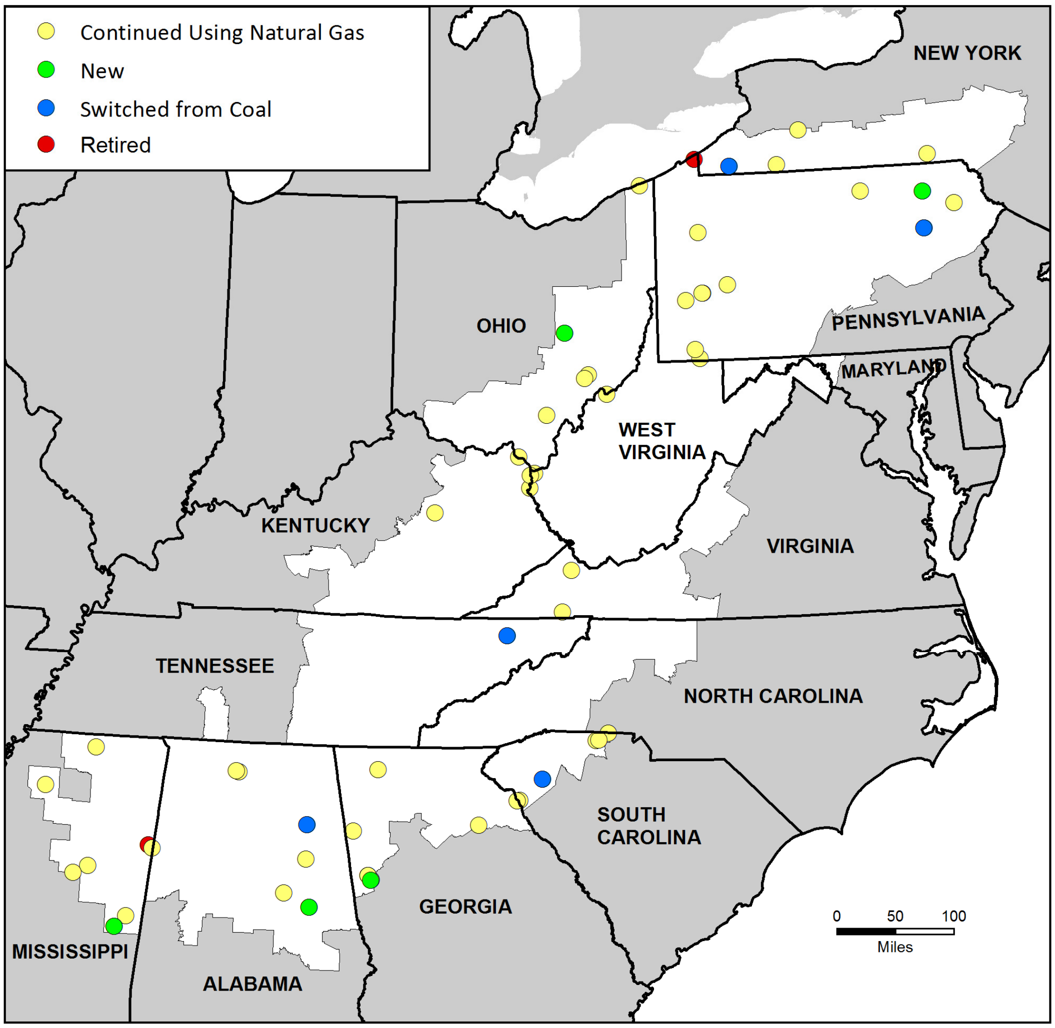
Figure 8: Change in Use of Coal in Electric Power Generation, 2005-2015



Sources: U.S. Mine Safety and Health Administration and U.S. Energy Information Administration
Notes: Retired power plants are defined as those where 50 percent or more of capacity was officially retired or not in operation for at least two years. The majority were officially retired. A fuel switch includes a permanent switch (repowering) as well as a temporary switch to another fuel. The large majority of switches were repowering to natural gas.

NATURAL GAS FIRED ELECTRIC POWER GENERATION LOCATIONS: In Figure 9 we report changes that have occurred between 2005 and 2015 in natural gas electric power generation in Appalachia. Out of 59 natural gas power plants operating any time during the period, 47 (80 percent) continued using natural gas, 10 (17 percent) were new, and only two were retired. Of the 10 new power plants, five were repowered coal-fired power plants.

Figure 9: Change in Use of Natural Gas in Electric Power Generation, 2005-2015



Sources: U.S. Mine Safety and Health Administration and U.S. Energy Information Administration
Note: The two retired power plants shown were officially retired.

Chapter 2: Regional Economic Impact of Electric Power Plants in Appalachia

In this chapter we econometrically estimate the effect of the loss of an electric power generation facility on county economic outcomes. We use a panel of county-level data for all counties in the Appalachian states that had some electric power generation capacity during any year between 2005 and 2015—157 counties in total. Altogether, we rely on 1,727 observations for our econometric estimates—157 counties times 11 years.

DEPENDENT VARIABLE: We consider total wage and salary income in each county as the measure of economic activity in that county. We specifically focus on wage and salary income (as opposed to total personal income) in order to abstract from transfer income and various sources of capital income so that our model is more reflective of current economic activity.

INDEPENDENT VARIABLES: Our two key explanatory variables are the coal-fired electric power generating capacity and natural gas-fired electric power generation capacity in a given county. County-level data on power plant employment are not available but we assume that capacity is a good proxy of employment and other power-plant-specific variables that would capture the economic presence of the power plant in the county. We chose capacity as the proxy rather than generation, as employment at a plant is relatively fixed by the level of capacity and does not vary considerably with plant utilization.

INTERACTION EFFECTS: We consider the possibility that the effect of a power plant on county-level economic outcomes may depend on the size of the county. As such, we include county population as a control variable as well as an interaction term between coal-fired electric generating capacity and county population.[1] Our model is summarized in the equation below.

$$\text{Wage and Salary Income}_{i,t} = \beta_0 + \beta_1\,\text{Coal Fired Generating Capacity}_{i,t} + \beta_2\,\text{Coal Fired Generating Capacity}_{i,t} * \text{Population}_{i,t} + \beta_3\,\text{Natural Gas Fired Generating Capacity}_{i,t} + \beta_4\,\text{Population}_{i,t} + \beta_5\,C_i + \beta_6\,T_t + \varepsilon_{it},$$

where C and T represent county and year fixed effects to control for unobserved county- and year-specific heterogeneity, and ε_{it} is a typical error term.[2] Summary statistics are reported in Table 1.

[1] We also considered a parallel interaction effect on natural gas fired capacity but our results did not indicate that this specification was appropriate.

[2] We did not include any additional county-level variables (e.g., urban/rural) as such typical county-level characteristics are often highly correlated with the county fixed effects.

Table 1: Summary Statistics

Variable	Mean	Median	Std.Dev.
Wage and Salary Income (000s)	1,846,163	582,952	3,128,754
Coal-Fired Generation Capacity (Megawatt)	902	514	972
Natural Gas-Fired Generation Capacity (Megawatt)	300	0	584
Population (Persons)	184,765	92,634	241,770

Source: Authors' calculations

REGRESSION RESULTS: The results of our regression model are reported in Table 2. Results indicate that coal-fired electric power generation capacity in a county is related to wage and salary income in the county and, indeed, that the effect depends on county population. In general, we find that the effect of coal-fired generation capacity is relatively high for small population counties, but that the effect diminishes to zero as counties grow larger. This result is likely reflective of the idea that as county population grows larger, a given size coal-fired power plant is a relatively smaller part of the county's economy and its effect is therefore more difficult to identify statistically. To explain further, our statistical methods are able to identify the effect of a coal fired power plant in a county with, say 10,000 residents, but these methods are not sophisticated enough to be able to disentangle the effect of a power plant in New York City from the tremendous amount of surrounding economic activity. In contrast, results do not identify a statistically significant relationship between natural gas-fired generation capacity and wage and salary income in a county. This may be due to a lower labor intensity at natural gas-fired plants, which would translate into a lower broader economic impact in the county. Alternatively, this lack of statistical significance may simply be the result of far fewer natural gas-fired power plants in our dataset, making statistical inference more difficult.

Table 2: Regression Results

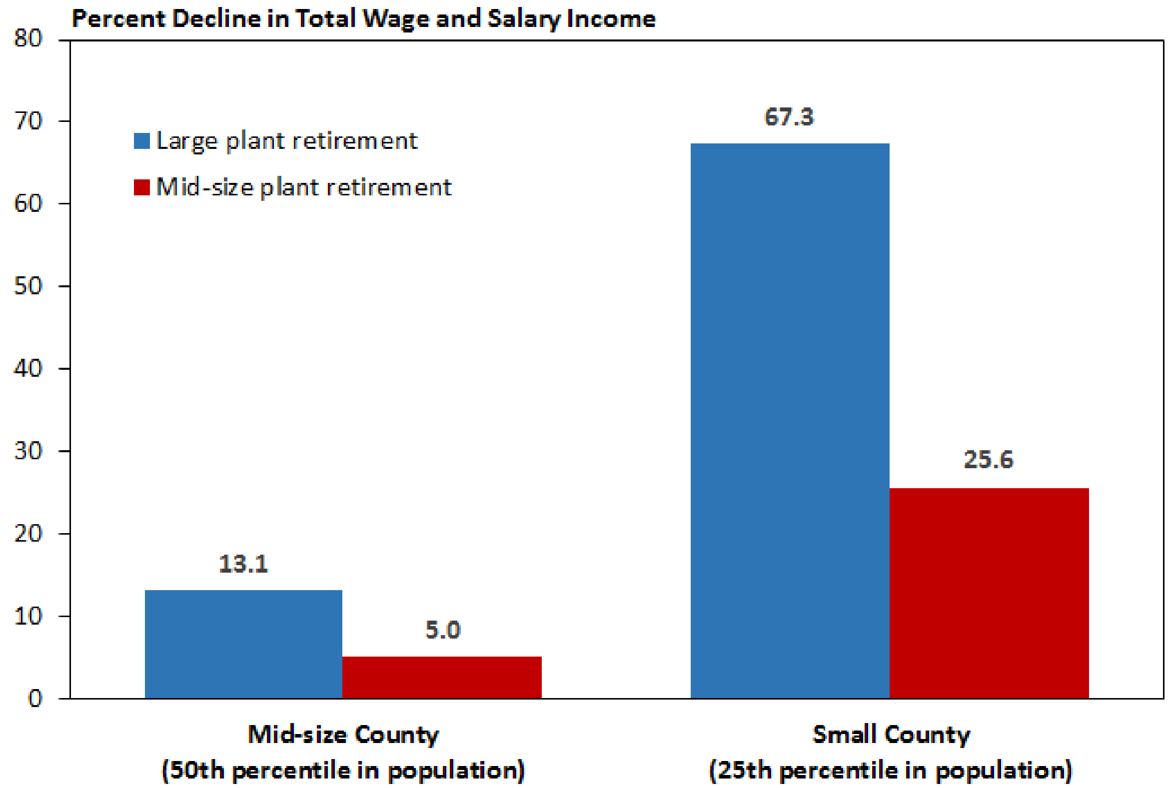
Variable	Wage and Salary Income	
Coal-Fired Generation Capacity (Megawatt)	88.148	***
	(23.522)	
Natural Gas-Fired Generation Capacity (Megawatt)	10.160	
	(19.791)	
Population (000s)	5.277	***
	(0.468)	
Coal-Fired Generation Capacity* Population	-0.0007	***
	(0.0001)	
Constant	72,993	
	(74,708)	
R-squared	0.999	

Source: Authors' calculations

ESTIMATED EFFECT OF SHUTDOWN: To consider the above regression results more fully, recall that we estimate that the effect on a county's wages of a one-megawatt increase in coal-fired generation capacity is $88,000 - $0.0007*county population. This finding indicates that power plant capacity has a diminishing effect on a county's total wages as population rises. In Figure 10 we illustrate the magnitude of this effect across two dimensions. First, we consider this for mid-size counties versus small counties. We do not consider large counties since our estimated effect diminishes to zero for large counties.[3] Second, note that our estimated coefficient reflects the effect of a one-megawatt change in capacity. Therefore, to approximate the effect of a complete shutdown, we multiply our estimated effect by the total capacity of a mid-size plant versus a large plant.

[3] Technically our estimated effect becomes negative for sufficiently large counties. However, this is undoubtedly the result of a forced linearization within our model.

Figure 10: Estimated Effect of a Coal-Fired Power Plant Retirement

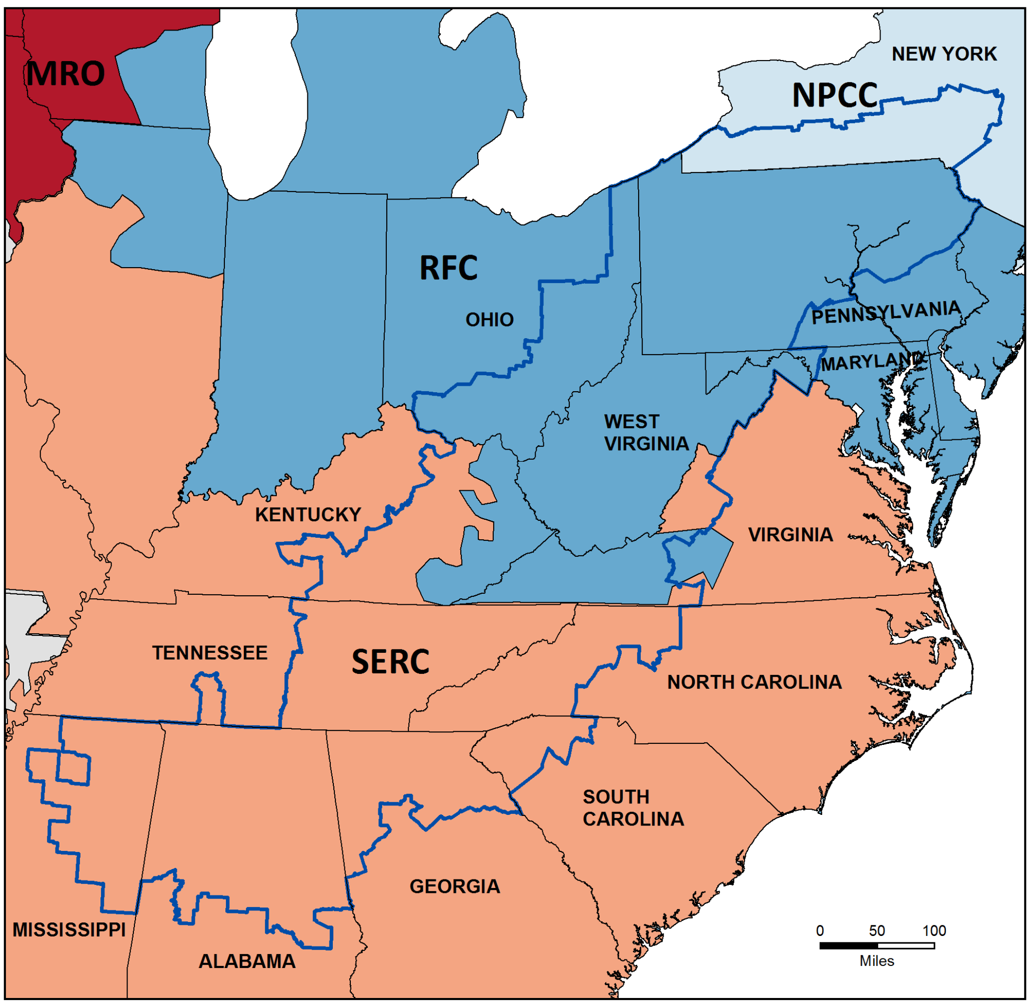


Source: Authors' calculations
Note: A large plant is defined as a plant at the 75th percentile of power-plant capacity (1487 megawatts) and a mid-size plant is defined to be at the 50th percentile (566 megawatts). The 50th percentile and 25th percentile in population are 93.7 thousands and 39 thousands, respectively.

Chapter 3: Risk Factor Analysis of Coal-Fired Generation Retirements and Repowerings in Appalachia

In this chapter we develop and estimate a real options model (Dixit and Pindyck 1994) to assess the risk factors for future power plant retirements (see Appendix A for a description of the real options model). To populate this model, we use a dataset of plant-level variables based on data from EIA forms 860 and 923. The data include all coal-fired power plants in Appalachia and surrounding North American Electric Reliability Corporation (NERC)[4] regions (see Figure 11 for a map of the NERC regions considered). A detailed description of this dataset is provided in Appendix C.

Figure 11: Appalachia and Surrounding NERC Regions



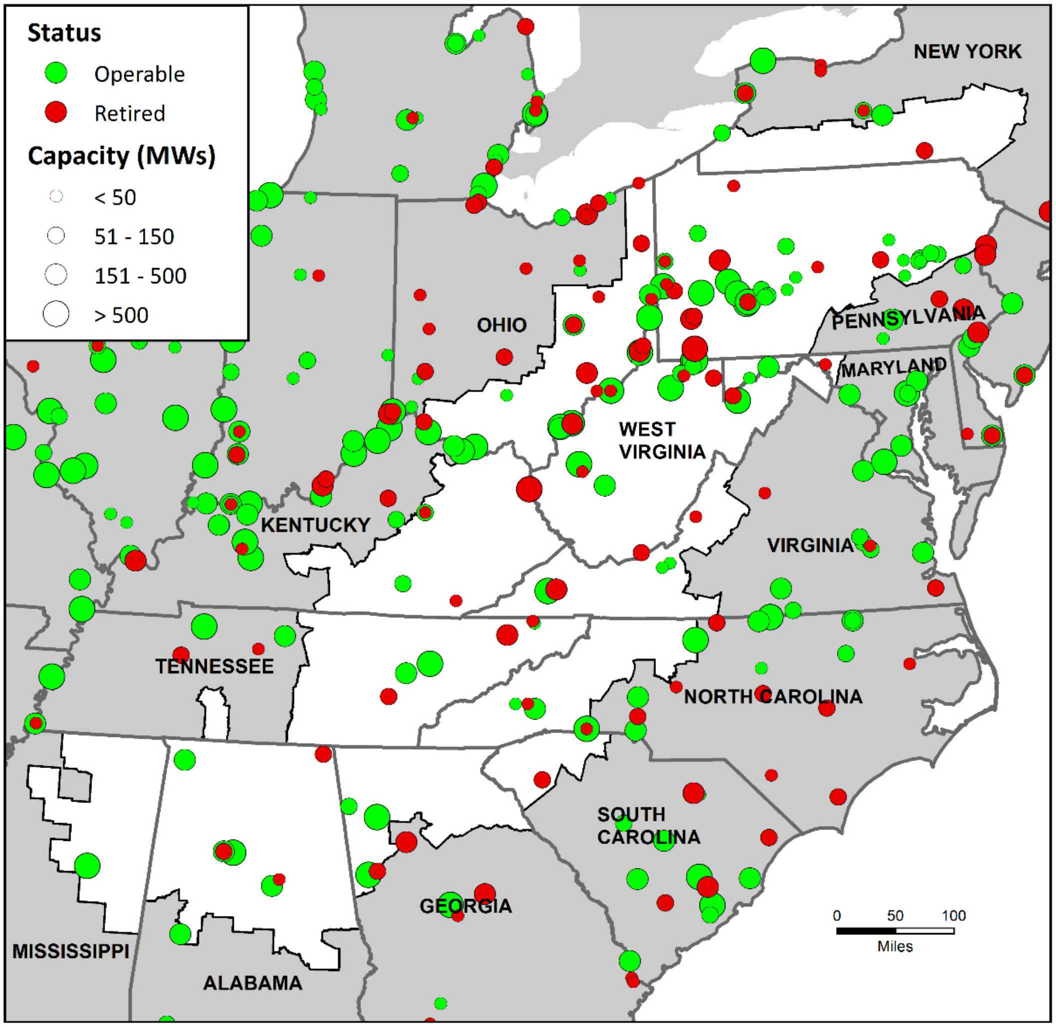
Source: North American Electric Reliability Corporation
Notes: NPCC = Northeast Power Coordinating Council; MRO = Midwest Reliability Organization; RFC = Reliability FIrst Corporation; and SERC = SERC Reliability Corporation. Other NERC regions are not visible in this figure, including Florida Reliability Coordinating Council (FRCC), Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

Our risk analysis focuses on coal-fired units in Appalachia that retired or repowered from coal to another fuel source between 2011 and 2015. Appalachia has experienced a disproportionate number of coal-fired unit retirements. Even though Appalachia contains less than 20 percent of the operating coal-fired generation capacity in the four surrounding NERC regions, Appalachia accounts for over 40 percent of the retired coal-fired capacity. We identify two repowered units and 59 retired units that used coal as their stated main energy source for generation[5] and have a primary-purpose North American Industry Classification System (NAICS) code of 22: electric power generation, transmission, and distribution. See Figure 12 for a map showing the location and capacity of these units. Focusing on NAICS code 22 eliminates a small number of units that produce electricity but are primarily industrial rather than suppliers to the electric grid. For example, the U.S. Alliance Coosa Pines coal plant retired in 2008 but its sole purpose was to provide electricity for a paper plant. Retirement decisions for these units will differ greatly from units that generate electricity to sell exclusively on a wholesale electricity market.

The 59 units that we consider represent about 55 percent of all coal-fired units with NAICS code 22 that have retired in Appalachia between 2011 and 2015.[6] Of these 59 units, 43 were in deregulated electricity markets (PJM) and 16 were in a regulated market (Southern Company, TVA, Duke Power). The 59 units were distributed across 21 different power plants. A list of plants included in our retirement risk analysis is reported in Table 3.

[5] Coal includes anthracite, bituminous, lignite, subbituminous, waste, refined, and coal-derived synthesis gas.
[6] The remaining units were excluded due to data limitations.

Figure 12: Coal-Fired Generating Units in Appalachia and Surrounding NERC Regions, 2011-2015



Source: U.S. Energy Information Administration, Form EIA-860

Table 3: Coal-Fired Power Plants that Retired Between 2011 and 2015

Plant	State	Owner	Balancing Authority	Total nameplate capacity retired (MW)	Average age of unit when retired
Gorgas	AL	Alabama Power Co.	Southern Company	250	64
Widows Creek	AL	Tennessee Valley Authority	Tennessee Valley Authority	1969	59
Big Sandy	KY	Kentucky Power Co	PJM Interconnection, LLC	816	46
Dale	KY	East Kentucky Power Coop, Inc	PJM Interconnection, LLC	54	61
GMMM Westover	NY	AEE 2, LLC	New York Independent System Operator (NYIS)	119	63
Walter C Beckjord	OH	Duke Energy Ohio Inc	PJM Interconnection, LLC	1221	55
FirstEnergy Ashtabula	OH	American Transmission Systems Inc	PJM Interconnection, LLC	256	57
Conesville	OH	Ohio Power Co	PJM Interconnection, LLC	162	50
Niles Power Plant	OH	Ohio Edison Co	PJM Interconnection, LLC	293	58
Muskingum River	OH	Ohio Power Co	PJM Interconnection, LLC	1529	57
Elrama Power Plant	PA	Duquesne Light Co	PJM Interconnection, LLC	510	59
FirstEnergy Armstrong Power Station	PA	West Penn Power Co	PJM Interconnection, LLC	326	54
Hatfields Ferry Power Station	PA	West Penn Power Co	PJM Interconnection, LLC	1728	43
FirstEnergy Mitchell Power Station	PA	West Penn Power Co	PJM Interconnection, LLC	299	50
W S Lee	SC	Duke Energy Carolinas, LLC	Duke Energy Carolinas	180	63
John Sevier	TN	Tennessee Valley Authority	Tennessee Valley Authority	800	57
Clinch River	VA	Appalachian Power Co	PJM Interconnection, LLC	238	54
Glen Lyn	VA	Appalachian Power Co	PJM Interconnection, LLC	338	65
Philip Sporn	WV	Appalachian Power Co	PJM Interconnection, LLC	953	61
FirstEnergy Albright	WV	Monongahela Power Co	PJM Interconnection, LLC	278	59
Kammer	WV	Ohio Power Co	PJM Interconnection, LLC	713	57

Source: U.S. Energy Information Administration, Form EIA-860 & EIA-923

CHARACTERISTICS OF RETIRED PLANTS: There are a variety of economic, regulatory, and technical factors that utilities consider when choosing to retire or repower a coal-fired unit. On average, units selected for retirement in Appalachia were smaller, older, less fuel efficient, more likely to burn bituminous coal, and more likely to be located in a regulated electricity market compared with the operating fleet of coal-fired units in the Region. The average fuel cost of retired units is approximately 16 percent less than that of operating units, while capacity factors are 12 percent lower. This suggests that fuel costs were not a primary consideration in retirement decisions but units with greater unutilized capacity were at greater risk of retirement. Environmental considerations also appear to have influenced retirement decisions prior to 2015. Coal-fired units in a state with a Renewable Portfolio Standard were nearly 13 percent more likely to be retired. Retired units in Appalachia also emit far more SO_2, NO_x, and CO_2 per MWh generated than the fleet of operating units. These trends persist outside the Appalachian Region with one exception: average fuel costs of retired units were slightly higher than the average operational unit outside of Appalachia. This suggests that fuel costs may have been a more prominent concern for unit owners outside of Appalachia.

Table 4 compares operating coal-fired units to coal-fired units that have been retired or are planning to be retired. Due to larger capacity, units in Appalachia use more coal on average than the average unit outside of Appalachia. Coal-fired plants in Appalachia also paid more per MMBtu of heat generated than other units in 2015. This is partially explained by the quality of coal used. Operating coal-fired plants in Appalachia are more likely to use bituminous coal than operating coal-fired plants in neighboring NERC regions. Bituminous coal has a higher heat content than the sub-bituminous coal preferred by coal-fired plants outside Appalachia, but it is also more expensive. Bituminous coal is also more likely to have originated from mines in central and southern Appalachia. The bituminous coal preferred by units in Appalachia also has a higher sulfur and ash content. On average, coal-fired units in Appalachia emit more nitrogen oxides (NO_x) and carbon dioxide (CO_2) but less sulfur dioxide (SO_2) than coal-fired units in neighboring regions. All of the coal-fired units in Appalachia have some form of pollution control technology in place.

Table 4: Coal-Fired Unit Retirements, 1993-2015

	Operating Conventional Steam Coal Units		**Retired Coal Units**		**Planned Coal Unit Retirements**	
	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions
Number of Units	134	411	105	190	11	65
Total Nameplate Capacity (MW)	63,225	148,033	16,582	23,170	2,365	11,363
Avg. Nameplate Capacity (MW)	472	360	158	122	215	175
Avg. Capacity Factor (%)	38	40	33	30	22	24
Avg. Fuel efficiency (MMBtu output/MMBtu input)	0.38	0.33	0.32	0.32	0.32	0.33
Avg. Age (years)	45	44	59	59	57	54
% Single Ownership	69	83	88	93	100	97
% in State with RPS	54	55	61	65	18	66
% Regulated	57	53	65	58	100	76
% Use Bituminous Coal	78	52	98	83	100	49
% Pulverized Coal	87	89	73	78	100	91
Avg. SO_2 Emission Rate (tons/MWh)	0.00111	0.00142	0.01006	0.00901	0.00315	0.00294
Avg. NO_x Emissions Rate (tons/MWh)	0.00089	0.00089	0.00315	0.00305	0.00106	0.00113
Avg. CO_2 Emissions Rate (short tons/MWh)	1.12	1.21	1.51	1.43	1.00	1.33
% with Emission Control Technology	100	100	98	97	100	100
Avg. Quantity of Fuel (tons)	2,602,880	2,371,218	1,556,942	728,776	394,869	1,060,481
Avg. Sulfur Content (%)	2.10	1.30	2.24	1.36	1.05	0.95
Avg. Ash Content (%)	12.68	7.40	11.50	8.64	10.38	6.69
Avg. Fuel Cost (2015$/MMBtu)	2.66	2.47	2.22	2.59	2.71	2.42

Source: U.S. Energy Information Administration, Form EIA-860 & EIA-923

FUTURE RETIREMENTS: As of 2015, 2,365 MW of coal-fired capacity in Appalachia were planned for retirement in the coming years. These units share many characteristics with the units that were retired prior to 2015. Units planned for retirement are larger, younger, and less polluting than the units retired prior to 2015, but they remain smaller, older, and more polluting than the operating fleet. Units planned for retirement are also less fuel efficient and have a lower capacity factor than those units that remain operating. All of these units planned for retirement are owned by a single entity, reside in a regulated electricity market, and use bituminous coal. The motivations that influenced retirements prior to 2015 will persist into the future in Appalachia. The one exception may be average fuel cost. While units retired prior to 2015 paid a lower delivered coal price than those units that remained operational, the units planned for retirement after 2015 paid a slightly higher fuel price than the average unit in the operating fleet.

In addition to retirements, 38 coal-fired units in Appalachia and the regions applied to switch permanently from coal to another fuel source (repower) between 2011 and 2015. In most instances, utilities choose to retire or repower a few coal-fired units but keep the overall plant operating. However, in a few instances, the utility has chosen to retire every coal-fired unit at a plant. For example, the Tennessee Valley Authority (TVA) chose to retire all eight coal-fired units at its Widows Creek plant in Alabama between 2013 and 2015.

Analytical Approach

The real options approach utilizes stochastic dynamic programming to calculate an economic lifetime for each coal-fired unit. Economic lifetime represents how long the coal-fired units should remain in operation to maximize their expected value to the utilities that own and operate those units. According to the National Association of Regulatory Utility Commissioners, the expected engineered lifetime of a coal-fired unit is 40 years (O'Brien, Blau, and Rose 2004). This lifetime is an engineering estimate of the time it takes for the net present value of the unit (inclusive of capital costs associated with initial construction) to fall to zero. Once the net present value of operating the plant becomes negative, the unit is assumed to have reached the end of its economic life.

Unlike engineering approaches that utilize discounted cash flow analysis, a real options approach accounts for the future uncertainty associated with coal and electricity markets. Uncertainty in future market conditions will cause firms to be more hesitant to make decisions that are difficult to reverse or adjust when new information arrives (Yang and Blyth 2007; Kellogg 2014). Coal-fired generation retirement is a classic example. Once it has been permanently retired, it is difficult (if not impossible) to restart a coal-fired unit if demand for the electricity produced by that unit unexpectedly increases or the price of the coal delivered to that unit unexpectedly falls.

Future market uncertainty has two implications for the economic lifetime of coal-fired units. First, a coal-fired unit's economic lifetime cannot be expressed in terms of years since utilities are unable to predict market conditions in the future. Instead, the economic lifetime of a coal-fired generating unit is characterized by a critical electricity price P_E^*. The coal-fired unit should remain in operation if electricity prices exceed P_E^*, but it should be immediately retired when electricity prices fall below this threshold. Second, economic lifetimes will exceed engineering lifetimes due to the hesitancy of utilities to engage in the irreversible retirement of coal-fired generation. This hesitancy explains why the average age of retired coal-fired units in Appalachia (59 years old) far exceeds the 40-year lifetime suggested from engineering economic studies.

We apply the real options model to each of the 57 retired units in our analysis to provide a measure of the economic lifetime (critical electricity price threshold) of each unit. See Appendix B for details of the data collection, parameter estimation, and solution procedure used to generate the critical electricity price thresholds. Means and standard deviations of all parameter estimates used in our analysis are included in Table 5.[7] While we investigate risk factors for each unit, we report averages of all unit-level parameter estimates to be concise.

Table 5: Average of Parameter Values Used in Economic Lifetime Analysis

Description	Parameter	Regulated	Deregulated
Coal price rate of reversion (%)	r_C	12.9	9.35
		(5.77)	(4.31)
Coal price long-run mean ($/MMBtu)	$\bar{P}_C$	3.02	2.83
		(0.48)	(0.29)
Coal price volatility (%)	σ_C	8.35	10.13
		(1.21)	(5.63)
Electricity price rate of reversion (%)	r_E	0.27	0.86
		(0.07)	(0.75)
Electricity price long-run mean ($/MMBtu)	$\bar{P}_E$	15.05	18.94
		(0.86)	(3.81)
Electricity price volatility (%)	σ_E	17.55	22.78
		(0.68)	(6.68)
Responsiveness of unit supply to changes in electricity price (MMBtu)	β_E	15,240	13,782
		(3,801)	(17,387)
Unit capacity (MMBtu)	q_{cap}	199.91	236.25
		(146)	(179)
Quantity of coal used per MMBtu generated (MMBtu)	β_C	3.08	2.92
		(0.24)	(0.36)
Average monthly fuel used (MMBtu)	$\bar{q}_C$	865,037	922,336
		(633,147)	(859,896)
Discount rate (%)	δ	9	
Variable cost/unit of generation ($/MMBtu)	v	2.35	
Fixed costs ($)	F	$17.58\bar{q}_c$	
Sunk Costs ($)	S	$590{,}500q_{cap}$	

Source: Authors' calculations
Note: Standard deviations are in parentheses.

[7] All measures of electric power in this chapter have been converted to measures of heat output using the U.S. Energy Information Administration's standard conversion factor of 1 KWh equals 3,412 Btu.

The first six rows in Table 5 describe the average future expectations for delivered coal and electricity prices for each of the 57 units in our analysis. The coal-fired units that retired in a regulated market experienced, on average, less volatile but higher coal prices than those in deregulated markets. The average long-run mean coal price is $3.02 per MMBtu for regulated coal units and $2.83 per MMBtu for the retired coal units in deregulated markets. Average coal price volatility is more than 21.3 percent higher in deregulated markets than regulated markets. Average coal price volatility is 8.4 percent for regulated markets and 10.1 percent for deregulated markets. The larger the percent volatility in a unit's coal price, the more uncertainty the owner of that unit has about the future prices they will have to pay for fuel. While coal prices are more volatile (unpredictable) in deregulated markets, they revert back to the long-run mean 27.5 percent quicker than their counterparts in a regulated market. The average rate of reversion to the mean coal price across regulated coal units is 9.4 percent, compared with 12.9 percent for deregulated coal units. This suggests that while deregulated units are faced with more unpredictable coal prices, these unexpected shocks do not persist as long as the smaller shocks experienced by retired units in regulated markets.

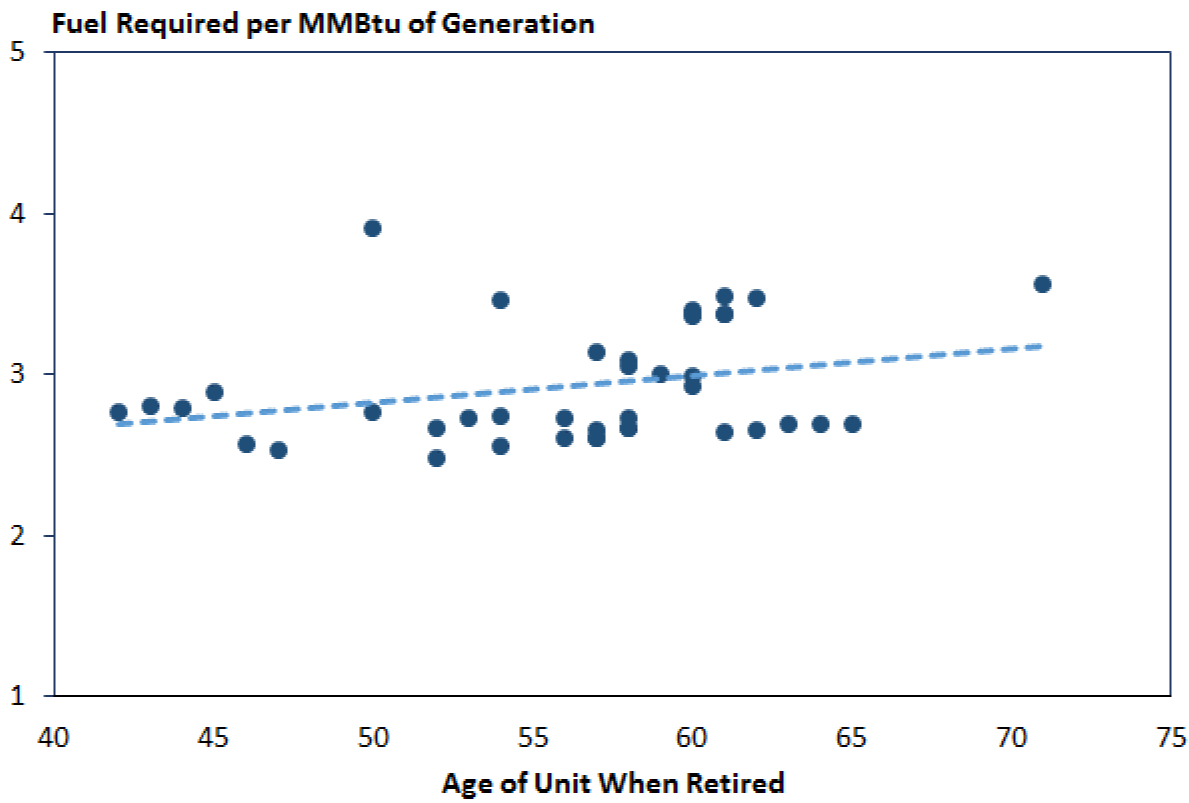
The coal-fired units that retired in a regulated market were paid, on average, lower but more predictable wholesale electricity prices than those in deregulated markets. The average long-run mean electricity price is $15.05 per MMBtu for regulated coal-fired units and $18.94 per MMBtu for the retired coal units in deregulated markets. The average electricity price volatility is much larger than the volatility in coal prices—17.6 percent for coal-fired units that retired in a regulated market and 22.8 percent for those that retired in deregulated markets. On average, electricity prices revert back to the long-run mean much slower than coal prices—0.3 percent in regulated markets and 0.9 percent in deregulated markets. This suggests that much of the economic uncertainty that was facing retired coal-fired units was rooted in electricity markets and not coal markets.

Rows seven through ten in Table 5 describe the generation technology associated with retired units. The average supply responsiveness of retired coal-fired units (β_E) captures whether the coal-fired unit was used for generating base load. Units devoted to supplying base load run continuously with little or no change in generation in response to market conditions. Supply responsiveness in a regulated and deregulated market is 15,240 and 13,782, respectively. This means that for every $1 per MMBtu increase in electricity prices, the quantity of electricity supplied increases by 15,240 and 13,782 MMBtus.[8] Retired coal-fired units in our study were more responsive to price signals in the regulated markets. The average fuel efficiency for retired coal-fired units in our analysis is 3.1 for those in a regulated market and 2.9 in deregulated markets. This means that a 1 MMBtu increase in electricity requires 3.1 MMBtus of coal in a regulated market and 2.9 MMBtus of coal in deregulated markets.

[8] To put that number into context, it takes around 0.064 MMBtus to increase the temperature in a 1,600 square foot home with 10 feet ceilings by 50 degrees Fahrenheit.

Figure 13 shows the slope of the inverse production function for each unit mapped against the age of the unit when retired. The positive slope shows that younger generating units are more efficient.

Figure 13: Coal-Fired Unit Fuel Efficiency by Age of Unit



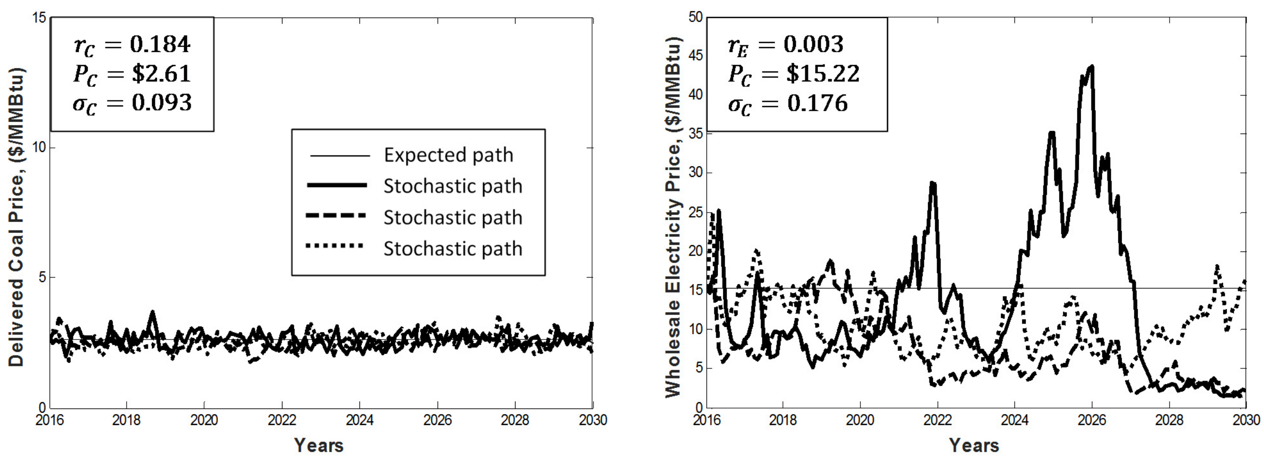
Source: U.S. Energy Information Administration, Form EIA-860 & EIA-923

The last four rows of Table 5 provide the costs and discount rates used in our analysis. We are unable to estimate costs and discount rates for each unit due to a limited amount of publicly available information. Instead, we use a variety of previous studies and technical reports to provide feasible estimates of the costs considered when these coal-fired units were retired. Following Hepbasli (2008), we assume utilities use a 9-percent discount rate.

The results of our coal-fired unit post-mortem analysis consist of measures of the economic lifetime of coal-fired units that retired in the Appalachian Region and the factors that shortened this economic life. The economic lifetime of a coal-fired unit is characterized by 1) recent coal and electricity prices facing a coal-fired unit and 2) a critical electricity price that would cause a utility to retire the coal-fired generating capacity. These critical electricity price thresholds represent retirement rules provided each coal-fired unit forms expectations of future electricity prices and coal prices based on past prices. Given recent prices paid for delivered coal, a coal-fired unit has reached the end of its economic life if the price for electricity generated by that unit falls below its critical price threshold.

To illustrate our approach, consider the retirement decision for unit 1 at Widows Creek in Alabama, which retired in 2014. TVA (the owner/operator of Widows Creek) uses past prices and market knowledge to form expectations of future delivered coal prices and electricity prices at Widows Creek. These price expectations are characterized by a probability density function. Prices in the mass of the distribution are prices that TVA will most likely observe in the future. Prices in the tails of the distribution represent prices that are possible but unlikely. This density function changes over time to reflect 1) trends in the markets and 2) the recognition that near-term price forecasts will be more accurate than long-term price forecasts. Figure 14 presents a visual depiction of future expectations of coal and electricity prices at Widows Creek. Based on historic prices for coal delivered to Widows Creek, TVA expects future prices to be within a small interval around \$2.61 per MMBtu. Based on historic prices for electricity generated at Widows Creek, TVA expects future prices to be around \$15.22 per MMBtu but also recognizes that prices could drop to \$5 or increase to more than \$30.

Figure 14: Expected Price and Three Monte Carlo Simulations of Price, Widows Creek

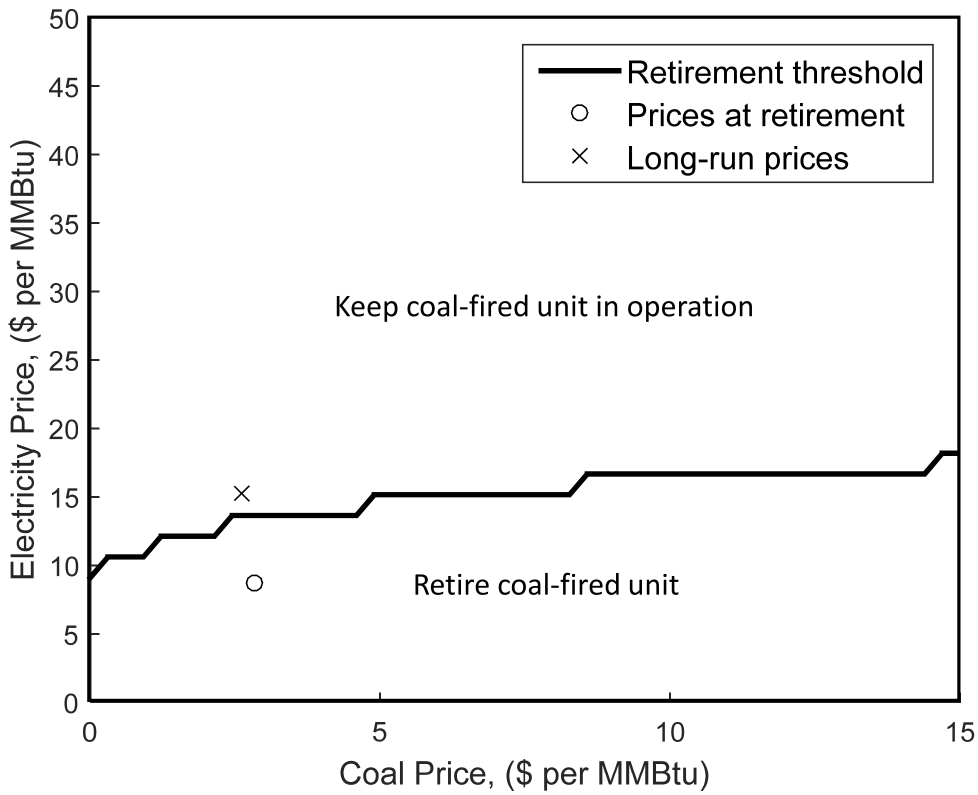


Panel A: Simulated Coal Prices **Panel B: Simulated Electricity Prices**

Source: Authors' calculations

Based on the price expectations illustrated in Figure 14, the critical electricity price threshold for Widows Creek unit 1 is presented in Figure 15. If TVA observes electricity and coal prices above the price threshold, there is an economic incentive to continue operating Widows Creek unit 1. The price threshold is upward sloping since higher coal prices would require higher electricity prices for TVA to have an economic incentive to continue operating. If TVA observes electricity and coal prices below the price threshold, retiring the unit would maximize its value (discounted electricity profits) to TVA.

Figure 15: Widows Creek Retirement Threshold



Source: U.S. Energy Information Administration Form EIA-860 and authors' calculations

The combination of historic average delivered coal price and wholesale electricity price for Widows Creek is identified by an "×" on the graph. If TVA were able to pay this historic average price for delivered coal and receive the historic average price for the electricity it generates, there is an economic incentive for Widows Creek unit 1 to remain in operation. However, these prices deviate from the historic average over time. The "○" indicates the combination of delivered coal and wholesale electricity prices when the unit was retired in 2014. At the point of retirement, the price paid for coal was only slightly higher than historic averages, but the wholesale price of electricity was more than 43 percent lower than historic averages. This drop in wholesale electricity price crossed the retirement threshold, causing unit 1 to transition from economically viable to a candidate for retirement.

As illustrated by the Widows Creek example, whether a coal-fired unit has reached the end of its economic life depends on whether recent coal and electricity prices fall below its retirement threshold. The economic lifetime of coal-fired units varies due to differences in the prices paid for delivered coal, the price received for electricity, and the location of a unit's retirement threshold. To summarize the economic lifetime of each unit in our analysis, Table 6 categorizes each of the retired coal-fired units into three categories. The first category are those units with a strong economic case for retirement. These units were experiencing coal and electricity prices that had recently (within the previous one to two years) fallen below their retirement threshold. The second category are those units with a very strong economic case for retirement. These units were experiencing coal and electricity prices that had been below their retirement threshold for many years. The third category are those units with a weak economic case for retirement. Coal and electricity prices prior to retirement were not below the economic retirement threshold. For these units, the decision to retire was either 1) more influenced by non-economic drivers (changes in policy or regulatory regimes) or 2) based on expectations of future market conditions that were inconsistent with historic market conditions. For instance, the owners and operators of many of the units with a weak economic case for retirement cite impending Mercury and Air Toxics Standards (MATS) as a justification for retirement. While all retirement decisions are driven by both economic and policy considerations, those units with a weak economic case for retirement are likely more influenced by the latter.

Table 6: Economic Case for Coal-Fired Generating Unit Retirement

Plant	State	Unit	Age (years)	Capacity (MW)	Pollutants controlled	Economic case for retirement
Big Sandy	KY	2	46	816	NOx, PM	very strong
Dale	KY	1	61	27	NOx, PM	very strong
		2	61	27	NOx, PM	very strong
Walter C. Beckjord	OH	1	60	115	PM	strong
		2	60	113	PM	strong
		3	59	125	NOx, PM	very strong
		4	56	163	NOx, PM	very strong
		5	52	245	NOx, PM	very strong
		6	45	461	NOx, PM	very strong
FirstEnergy Ashtabula	OH	5	57	256	None	strong
Conesville	OH	3	50	162	NOx, PM	weak
Niles Power Plant	OH	1	58	133	NOx, PM, SO2	weak
		2	58	133	NOx, PM	weak
Muskingum	OH	1	62	220	NOx, PM	strong
		2	61	220	NOx, PM	strong
		3	58	238	NOx, PM	weak
		4	57	238	NOx, PM	weak
		5	47	615	NOx, PM	strong

continued on the next page

Plant	State	Unit	Age (years)	Capacity (MW)	Pollutants controlled	Economic case for retirement
Elrama	PA	1	62	100	NOx, PM, SO2	strong
		2	61	100	NOx, PM, SO2	weak
		3	60	125	NOx, PM, SO2	weak
		4	54	185	NOx, PM, SO2	strong
FirstEnergy Armstrong	PA	1	54	163	NOx, PM	very strong
		2	53	163	NOx, PM	very strong
Hatfields Ferry	PA	1	44	576	NOx, PM, SO2	very strong
		2	43	576	NOx, PM, SO2	very strong
		3	42	576	NOx, PM, SO2	very strong
FirstEnergy Mitchell	PA	3	50	299	None	weak
Clinch River	VA	3	54	238	NOx, PM	weak
Glen Lyn	VA	5	71	100	NOx, PM	very strong
		6	58	238	NOx, PM	weak
Philip Sporn	WV	2	65	153	NOx, PM	very strong
		3	64	153	NOx, PM	strong
		4	63	153	NOx, PM	very strong
		5	52	496	None	strong
FirstEnergy Albright		1	60	69	None	strong
		2	60	69	None	strong
		3	58	140	None	very strong
Kammer	WV	1	57	238	NOx, PM	weak
		2	57	238	NOx, PM	weak
		3	56	238	NOx, PM	strong
Gorgas	AL	6	64	125	NOx, PM	very strong
		7	63	125	NOx, PM	very strong
Widows Creek	AL	1	62	141	NOx, PM	strong
		2	62	141	NOx, PM	very strong
		3	61	141	NOx, PM	very strong
		4	61	141	NOx, PM	very strong
		5	59	141	NOx, PM	strong
		6	60	141	NOx, PM	very strong
		7	54	575	NOx, PM, SO2	very strong
		8	50	550	None	very strong
W S Lee	SC	1	63	90	NOx, PM	weak
		2	63	90	NOx, PM	strong
John Sevier	TN	1	57	200	NOx, PM	very strong
		2	57	200	NOx, PM	very strong
		3	58	200	NOx, PM	very strong
		4	57	200	NOx, PM	very strong

Source: U.S. Energy Information Administration, Form EIA-860 and authors' calculations

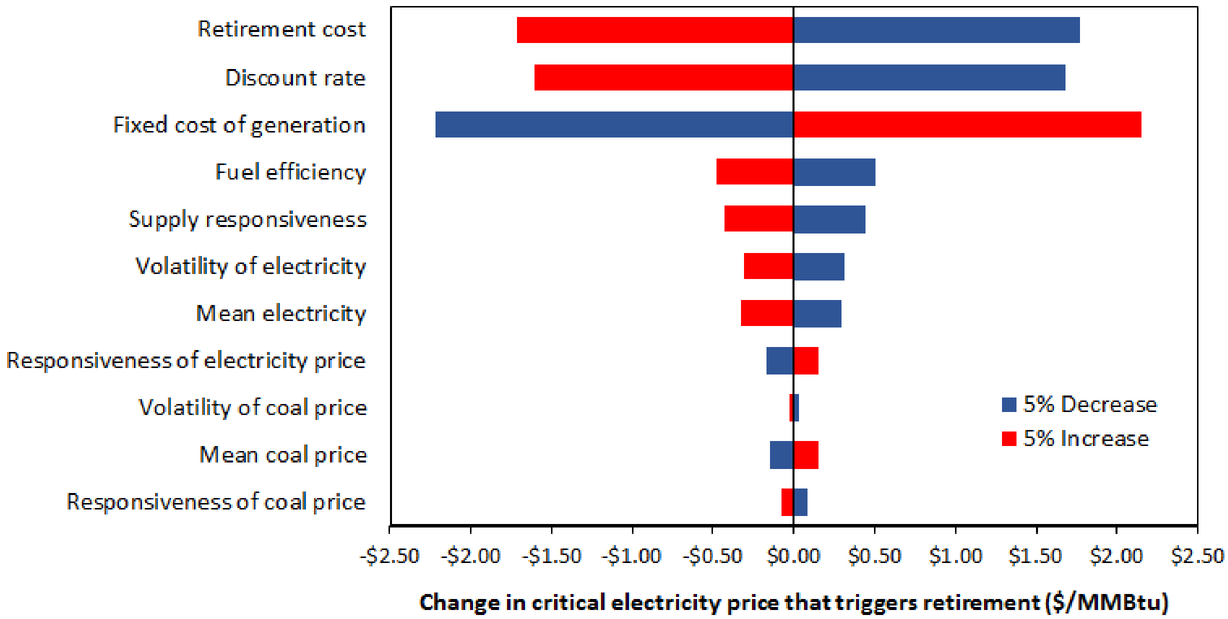
More than 80 percent of the coal-fired capacity that retired between 2011 and 2015 have a strong or very strong economic case for retirement—including all but one of the units in regulated markets. Thirteen units have a weak economic case for retirement meaning that recent coal and electricity prices remain slightly above the retirement threshold. Potential changes to environmental policy (particularly the MATS rule) or regulatory considerations likely combined with economic forces to incentivize the retirement of these units. Note that the economic case for retirement can vary even within a plant. Since all units at a plant pay the same price for delivered coal and receive the same price for electricity, these differences are driven entirely by within-plant differences in the location of the retirement threshold. These differences in retirement thresholds are in turn driven by features of the individual units at the plant.

Risk Factors

Using the results from our model described above, we can identify risk factors for retirement by undertaking a sensitivity analysis that allows us to determine which factors shortened the economic lifetime of each coal-fired unit. The sensitivity analysis uncovers a set of primary and secondary risk factors. We then discuss the economic, regulatory, and technical considerations that will drive each risk factor. Figure 15 illustrates how this decision is generated by instantaneous factors (coal and electricity prices at a point in time), and a retirement threshold that takes account of the full spectrum of costs and benefits associated with operation and retirement of coal-fired generation and the generation technology associated with a particular unit. As expected, declining wholesale electricity prices and rising fuel costs encourage retirement. However, the factors that shift a coal-fired unit's retirement threshold are less clear.

We can identify these factors by utilizing a sensitivity analysis. Specifically, we determine the impact of changes in coal price expectations, electricity price expectations, fuel efficiency of the generating unit, and supply responsiveness on the unit. For each parameter listed in Table 5, we find the percent change in the retirement threshold when we increase the parameter value by 5 percent holding all other parameters constant at the values in Table 5. Figure 16 shows the results of our sensitivity analysis categorized by direction of the parameter change. Parameter changes that increase the critical electricity price are risk factors for retirement since they make retirement more likely.

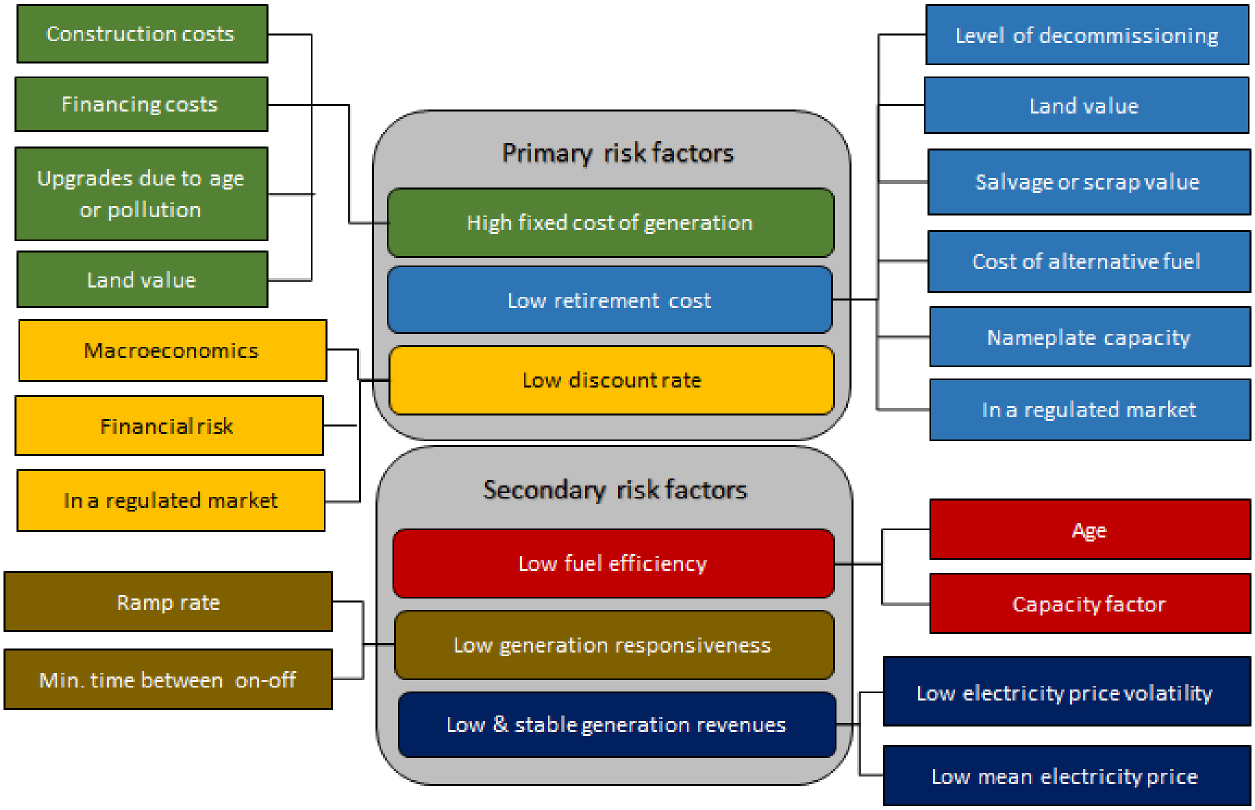
Figure 16: Effect of a 5-Percent Change in Each Factor on Coal-Fired Unit Retirement Threshold



Source: Authors' calculations

This sensitivity analysis allows us to categorize the importance of the risk factors we find in the model. We define primary risk factors as those where a 5 percent change in conditions results in a greater than 5 percent increase in the critical retirement threshold. Secondary risk factors are those where a 5 percent change results in a 1 to 5 percent increase in the critical retirement threshold. Each risk factor may be influenced by multiple economic and technological drivers. Risk factors and associated drivers are detailed below and summarized in Figure 17.

Figure 17: Primary and Secondary Risk Factors for Coal-Fired Unit Retirement



Source: Authors' analysis of real-options model results

Primary Risk Factors

HIGH FIXED COST OF COAL-FIRED GENERATION: The fixed costs associated with operating a coal-fired unit are equal to the capital costs. Capital costs are payments a utility must make to finance the initial fixed expenses incurred to purchase land and generation equipment and build the generation facilities. Three main drivers determine these capital costs. The first is the initial construction cost. The more costly it is to build a coal-fired unit, the larger the fixed costs of operation and the greater the risk of retirement. The second is the cost of financing. Financing costs are driven by a variety of factors but one that is particularly germane to financing coal-fired plants is the time-to-build. Constructing a coal-fired unit takes time and the longer the time to complete construction, the more it costs to finance construction. The third driver is the cost of any upgrades. Due to their age (the average age of operating coal-fired units in Appalachia is 45 years), many utilities are forced to make investments to upgrade components of the generation technology. Older units with more investments in upgrades will carry a larger fixed cost of generation and a higher risk of retirement.

One prominent upgrade in the electric power industry is investments in pollution control technologies. Fifty out of the 57 units in our analysis have some form of pollution control technology installed to control particulate matter (PM), nitrogen oxides (NO_x), or sulfur dioxide (SO_2). These technologies add to the fixed cost of generation. Because utilities are more likely to retire a plant that is more costly to operate, more investments to meet current pollution regulations increase the risk of retirement. However, this positive relationship between pollution control investment and retirement does not hold for regulations that have not yet been enacted. Prior to 2016, many utilities retired coal-fired units without mercury control technologies to avoid the costly investments needed to meet MATS. According to AEP and TVA annual reports, investment needed to meet the MATS requirement can run up to $400 million. Thus, new pollution control regulations (such as MATS) will increase the risk of retirement for units that are not currently in compliance.

LOW RETIREMENT COSTS: Retirement costs depend on the level of decommissioning and the need to offset lost generation. Thus, units with a smaller nameplate capacity are more likely to be retired due to the less costly retirement these units allow. In fact, the average nameplate capacity of retired coal units in the Appalachian Region is 67 percent smaller than operational units. However, this risk factor can be broken down into multiple drivers.

There is no legal requirement to demolish an old coal-fired power plant. The lack of a minimum level of decommissioning leaves utilities three options. The first option is to undertake decommissioning before the land is sold for redevelopment or converted to another generation technology such as a natural gas combined-cycle plant. The costs associated with decommissioning depend on the quantity of asbestos and regulated materials, the presence or absence of ash impoundments, local labor markets, proximity to salvage and scrap markets like steel and copper, and the means and methods of demolition. A second option is to sell the plant to developers as-is in exchange for a lower purchase price. However, the lower the purchase price, the higher the retirement costs. A strong local real estate market will lower retirement costs by commanding a higher sale price for the land and facilities and/or allowing utilities to engage in less decommissioning. If decommissioning costs are high and the local real estate market is weak, utilities may choose a “no action” option and simply accumulate the retired facilities. The accumulation of retired assets on a company’s balance sheet creates different costs through the introduction of financial risk and a drag on earnings.

Utilities may also be able to lower retirement costs by passing these costs onto shareholders or obtaining government grants and tax breaks to decommission and redevelop sites and create jobs. In states that are deregulated, utility shareholders must pay the cost of decommissioning. However, in states that are still regulated, decommissioning costs could be passed on to ratepayers. Since those making the retirement decision do not incur the cost of decommissioning, we should expect a greater risk of retirement in regulated markets. This finding is supported in Figure *15473* where there was a strong or very strong economic case for retirement for all but one unit in regulated markets.

Decreasing costs of alternative generation technologies (particularly natural gas) can also work to lower retirement costs. If a utility must offset lost coal-fired generation, then a decrease in the cost of building and operating other generation technologies will increase the risk of coal-fired retirement. For example, the oft-cited decline in natural gas prices will lower the cost of coal-fired retirement by lowering the cost of offsetting the lost coal-fired generation. How much natural gas prices influence the retirement decision depends on how much of the retired coal-fired generation will be replaced. If a utility does not plan to make new investments in natural gas generation and its gas-fired units are operating at near capacity, natural gas prices will play a small role in the retirement decision. But if the utility must replace the retired capacity with new gas-fired capacity or currently own gas-fired unit that are currently operating well below capacity, then the decline in natural gas prices will influence the retirement decision.

DISCOUNT RATE USED BY UTILITY IS LOW: Because retirement decisions involve costs and benefits that accrue at different times, utilities must use a discount rate to compare these payoffs. There is no definitive rule for selecting a discount rate. Firms should choose a discount rate that is at least as large as the firm's financial cost of capital since this represents the opportunity cost of tying up funds in coal-fired generation. The opportunity cost of investing in coal-fired generation is the value of alternative investments that utilities could make with those funds, and is closely linked to macroeconomic conditions. During economic downturns, returns from alternative investments are lower. This suggests that the recent economic downturn in the United States may have partially contributed to retirement decisions.

However, firms may choose discount rates that exceed their financial cost of capital to reflect an intolerance for financial risk. Firms in regulated markets are able to pass on capital costs to ratepayers, effectively eliminating financial risk (IEA 2003). These utilities could finance investments in coal-fired generation at interest rates close to government debt yields. Compared to utilities in regulated markets, utilities in deregulated markets use higher discount rates to evaluate coal-fired investments due to the risk they face in competitive markets (IEA 2003). The degree to which a deregulated utility will increase their discount rate beyond government debt yields is determined by the degree to which the risk associated with coal-fired generation is correlated with the larger economy. Financial risk considerations suggest that coal-fired units in regulated markets are at a greater risk of retirement.

Secondary Risk Factors

UNIT'S FUEL EFFICIENCY IS LOW: Two main factors determine the fuel efficiency of a coal-fired unit: age and utilization. Older coal-fired units tend to be less fuel efficient than newer units. The older technologies in these older units were generally less efficient when they were installed. Fuel efficiency also degrades over time. The oldest retired unit in our analysis could generate 0.2 MMBtu per MMBtu of heat input at retirement. Some of the newest coal-fired units in our study could generate 0.4 MMBtu per MMBtu of heat input when retired. Fuel efficiency also tends to be lower at very low or very high levels of utilization (Campbell 2013). Thus, units with a very low or very high capacity factor will tend to be less efficient and at a greater risk of retirement.

LOW RESPONSIVENESS OF UNIT GENERATION TO CHANGES IN ELECTRICITY PRICES: Historically, coal-fired units were used to generate base load. This role did not require generation to respond to changing electricity market conditions. However, the ability to adjust generation (either by load following or switching between on-off modes) in response to changing market conditions is becoming more valuable to utilities as gas-fired units take over baseload generation. One prominent measure of a unit's ability to respond to changing market conditions is the unit's ramp rate. Ramp rate is the increase or decrease in generation per minute. Utilities can improve ramp rates by installing distributed control systems. Another measure is the minimum amount of time required to bring the unit to full load from shutdown. Units that require substantial time to switch between on and off modes and/or units with small ramp rates will be less able to respond to changing market conditions and will be at greater risk for retirement.

EXPECTED GENERATION REVENUES ARE LOW AND STABLE: Utilities are more likely to retire a plant if they expect generation revenues at that plant to be low in the future. Expectation of future generation revenues are captured by the long-run mean electricity price received for electricity generated by a unit and the volatility of that electricity price. A lower long-run mean electricity price implies lower generation revenues and a greater risk of retirement. Decreases in electricity price volatility add certainty to these low revenue forecasts. This certainty makes utilities more willing to make large irreversible investments like retiring a coal-fired unit. Thus, units in markets with large amounts of volatility in electricity prices are at less risk of retirement than those units in stable markets.

Coal prices have very little influence on the retirement decision (this is also evident from the flat retirement thresholds). While the primary cost of generation is the cost of purchasing fuel, the prices for delivered coal are relatively low and stable for the coal-fired units in our study. This can be explained by the prevalence of coal contracts. According to the EIA-923 database, all of the 57 units in our analysis used coal contracts to supply their stock of fuel before they retired. Long-term contracts typically afford utilities lower and more stable prices in exchange for less flexibility in choosing suppliers and contract terms. The insensitivity of the retirement decision to coal prices suggests that there is little that the coal industry could do to delay the recent spate of coal-fired plant retirements. It also suggests that government intervention in the coal industry that lowers delivered coal prices or adds stability to the coal market would have little to no impact on retirement decisions. These retirement decisions are driven by factors outside the coal market such as real estate markets, construction costs, and electricity markets.

Repowered units

Repowered units are those coal-fired units that make a non-transitory change in generation technology away from coal. This does not include units that can use multiple fuels and periodically switch between fuels. We use a two-step approach to identify if and when a coal-fired unit repowered. In step one, we identify those units that plan to repower. Beginning in 2007, the Form EIA-860 began providing a space for firms to identify planned changes from the primary energy source used to produce electricity. Each year we identified generating units within Appalachia and the surrounding NERC regions that reported "planned energy source 1" changes. In step two, we cross-referenced these planned energy source 1 changes with the actual listed planned energy source 1 in each year. Several units are listed with planned energy source changes over multiple years and several planned energy source changes did not actually occur. This second step allows us to confirm a planned energy source change actually took place and identify the year the change occurred.

We identified 38 coal-fired units in Appalachia and the surrounding NERC Regions that applied to switch permanently from coal to another fuel source between 2011 and 2015. However, 33 units either withdrew their application to repower, delayed repowering until after 2016, or retired the unit instead of repowering.[9] Of the five remaining units that repowered prior to 2015, all five repowered from coal to natural gas, and only two were in the Appalachian Region. These five units are listed in Table 7.

The limited number of repowered units hinders identifying risk factors for repowering using the methods we adopted for retirement. With 17 units planned for repowering as of 2015, a more formal analysis of risk factors associated with repowering may be possible in the coming years. Regardless, repowered units seem to share many characteristics with retired units. Specifically, the few repowered units we observed had a smaller nameplate capacity, smaller annual capacity factor, and lower fuel efficiency compared with operational units. Repowered units were also more likely to be under single ownership. This is consistent with previous research in the area (Knittel et al. 2015). Similar to the retired units, the two repowered units in the Appalachian Region were also older than the average age among operational units. However, the three repowered units in surrounding NERC regions were, on average, more than 5 years younger than the average age of operational coal-fired units.

Repowered units differ from retired units with respect to fuel costs. The average fuel cost before retirement in the ARC and surrounding NERC regions is $2.22 and $2.59 per MMBtu, respectively, compared with $3.92 and $3.08 per MMBtu for repowered units. Additional insights can be found by looking at how these units were used after repowering. We revisited each repowered unit in 2015 after they began to use natural gas as their primary fuel source. The nameplate capacity did not change

[9] As of 2016, there are still ten units in the ARC Region and seven units in surrounding NERC Regions that list plans to retire in Form EIA-860.

after repowering any of these units. However, the average annual capacity factor for four out of the five units was lower after repowering. A lower capacity factor is characteristic of load-following or peaking units that adjust generation in response to load demand. Thus, baseload coal-fired units that were marginally profitable or even loss centers for utilities were converted to load-following and peaking units. This suggests that lower fuel prices may not be the only motivation for repowering. A need for greater generation flexibility may also be influencing repower decisions. The one unit that did experience an increase in capacity factor after repowering was in the Appalachian Region.

Table 7: Coal-Fired Units that Repowered to Natural Gas After 2011

Plant Name	Unit ID	State	Appalachia Region	Repower From	Repower To	Year Re-powered	Nameplate Capacity (MW)	2 years prior to repowering		2015	
								Net Generation (MWh)	Capacity Factor	Net Generation (MWh)	Capacity Factor
Hunlock	3	PA	yes	waste coal	natural gas	2011	49.9	141,748	32.40%	187,561	42.90%
NRG Dover	COG1	DE	no	bituminous	natural gas	2013	18	63,197	40.10%	35,824	22.70%
Yates	6	GA	no	bituminous	natural gas	2015	403.7	825,809	23.40%	354,460	10.00%
Yates	7	GA	no	bituminous	natural gas	2015	403.7	427,273	12.10%	150,641	4.30%
W S Lee	3	SC	yes	bituminous	natural gas	2015	163.2	30,597	2.10%	88,390	6.20%

Conclusion

We find no single factor driving the increase in coal-fired plant retirements in Appalachia. Instead, the increase in coal-fired plant retirements is due to a confluence of factors. Lower natural gas prices are often cited as the root of the increase in retirements. However, lower prices alone would not have triggered such an increase in retirements if coal-fired units in Appalachia were younger. Instead, we highlight six primary and secondary risk factors and discuss the economic, technical, and regulatory changes that would influence each of these risk factors. The three primary risk factors are a large fixed cost of generation, small cost of retirement, and a low discount rate used by the utility for decision making. A strong local land market, large investments made to mitigate pollution emissions, high financing costs, and whether the unit is in a deregulated market are all likely drivers of these risk factors.

Appendix A: Real Options Model for Economic Retirement of Coal-Fired Generation

An operating electricity generating unit[10] receives a flow payoff

$$\pi(P_E, P_C) = \left(P_E(t)q_E(t) - P_C(t)q_C(t) - vq_E(t) - Fq_{cap}\right) \qquad (1)$$

where $P_E(t)$ is the wholesale electricity price received for the electricity generated by the unit, $P_C(t)$ is the price of coal delivered to the unit, v is the variable operating and maintenance (O&M) costs of electricity generation, and F is the fixed levelized capital cost associated with the unit. $q_E = \beta_E P_E < q_{cap}$ is the quantity of electricity supplied by the unit with generation capacity $q_{cap} > 0$ and $\beta_E > 0$. $q_C = \beta_C q_E$ is the quantity of coal used to generate q_E with $\beta_C > 1$. This relationship between q_C and q_E captures the generation technology of a specific generating unit with newer and more fuel efficient units requiring less fuel to generate an additional unit of electricity (β_C closer to 1).

Current electricity prices and coal prices are known with certainty by the owner of the generating unit. However, future prices are subject to unpredictable fluctuations in the electricity and coal markets and will be unknown to unit operators. For example, prices paid for the firm's on-site stock of coal are known, but future prices of coal will be determined by the spot market or coal delivery contracts that have not yet been established. Future coal price uncertainty can be somewhat mitigated by purchasing coal on long-term contracts. Thus, generating units that utilize long-term coal contracts will be less exposed to coal price uncertainty than units that purchase coal on the spot market. Pindyck (1999) utilizes a century's worth of data to conclude that coal prices return to a long-run average following a market shock. Following Pindyck, future coal prices are treated as a random variable and assumed to evolve according to geometric mean reversion (GMR),

$$dP_C = r_C(\bar{P}_C - P_C)P_C dt + \sigma_C P_C dz_C \qquad (2)$$

where $\bar{P}_C$ is the long-run average (mean) coal price, r_C is the rate of reversion to the average coal price, σ_C is the standard deviation rate, and $dz_C = \epsilon(t)\sqrt{dt}$ is the increment of a standard normal Weiner process. The first term on the right-hand side captures the deterministic trend in coal prices while the second term captures volatility or random shocks in the coal market. For example, an exceptionally cold winter or hot summer will temporarily increase electricity usage and coal demand. This unexpected shock will manifest itself in the coal market as an unexpected increase in the price of coal. By not reaching zero in any finite time (Karlin and Taylor, 1981), geometric mean reversion (GMR) prevents any negative coal prices. The rate of reversion to the mean, the long-run mean coal price

[10] A generating unit contains all the equipment needed to produce electricity and typically operates independently. Electric power plants can include multiple generating, which can use different fuels. For that reason, we conduct our analysis at the unit level.

level, and the standard deviation rate are all allowed to vary by unit to capture differences across units in the types of coal used, the cost of transporting coal, and regional differences in coal demand.

Unexpected shifts in supply and demand also influence the prices units receive for the electricity they produce. For example, electricity demand is sensitive to weather conditions since weather variations lead to large variations in heating and cooling demand. Electricity supply is subject to uncertainty surrounding entry of new and exit of old generating capacity. Uncertainty on both the supply and demand side of electricity markets introduces volatility into electricity prices (Joskow 2007). To capture this uncertainty in electricity prices, electricity prices evolve randomly around a long-run mean following a geometric mean-reverting process:

$$dP_E = r_E(\bar{P}_E - P_E)P_E dt + \sigma_E P_E dz_E \qquad (3)$$

The mean reverting process captures the flat load demand in many parts of the country in recent years. Similar to the coal price process, the parameters that govern the stochastic electricity price process are allowed to vary by unit to capture regional differences in regulated and unregulated electricity markets.

Based on expectations of future coal and electricity prices, a unit may choose to retire a coal-fired unit at some point in the future. Retirement instantaneously eliminates the flow payoff $\pi(P_E, P_C)$ at some sunk retirement cost, S.[11] Retirement costs can vary widely depending on the level of decommission. Retirement costs may be minimal if the site can be maintained in its current condition with minimal cleanup needed to meet environmental compliance[12] and ensure safety. In contrast, full decommissioning requires substantial sunk costs associated with dismantling all equipment, demolishing structures, and site cleanup including wet and dry disposal areas and coal yards. In summary, while the unit is operating, it produces electricity $q_E(t) > 0$ using coal $q_C(t) > 0$ with costs $vq_E(t) + F\bar{q}_C$, which generates a flow of profits. If the unit is retired, it produces no electricity and uses no fuel but incurs a sunk retirement cost: $q_E(t) = 0, q_C(t) = 0, F = 0$, and $S > 0$.

The decision problem is presented in terms of a risk-neutral utility whose objective is to determine if and when to retire, t_R, a generating unit to maximize the utility's expected discounted profits net of any sunk retirement costs and subject to any grid stability constraints that must be met to in the

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[11] Following Baumol and Willig (1981), we define sunk cots as costs that cannot be eliminated even by terminating electricity generation. In contrast, fixed costs are costs that are not reduced by decreases in generation so long as generation is not discontinued altogether. Thus, not all sunk costs are fixed and not all fixed costs are sunk.

[12] Environmental compliance includes adhering to the EPA's Interstate Air Pollution Transport Rule, National Emissions Standards for Hazardous Air Pollutants regulations, the industrial waste rule for fossil fuel combustion waste, the Cooling Water Intake Structures rules of the National Pollutant Discharge Elimination System, the Steam Electric Power Generating Effluent Guidelines and Standards, and the most recent Mercury and Air Toxics Standards.

process of retiring coal-fired capacity. Using traditional discounted cash-flow analysis, the utility would retire the coal-fired unit when the expected net present value of generation profits is less than the cost to retire the unit. However, since the costs associated with retirement are sunk, there is an incentive (the option value) to delay retirement longer than suggested by discounted cash-flow analysis. This option value captures the economic value to a utility from being able to respond to new information about coal and electricity markets. The size of this option value is key to determining the timing of coal-plant retirements and will vary by unit depending on coal and electricity market conditions, the efficiency of the coal-fired generation technology currently being utilized, and the sunk costs required to retire.

At each instant in time, the utility must determine whether to continue operating the coal-fired unit or retire it. Given the discount rate δ, the optimal retirement time satisfies the following:

$$V\left(P_{E_0}, P_{C_0}\right) = \max_{t_R} E_0 \left[\int_0^{t_R} \pi\left(P_E(t), P_C(t)\right) e^{-\delta t} dt + \left\{V\left(P_E(t_R), P_C(t_R)\right) - S\right\} e^{-\delta t_R} \right] \quad (4)$$

subject to dP_E, $dP_C, P_{E_0} = P_E(0)$, and $P_{C_0} = P_C(0)$. The evaluation at each instant in time maximizes the expected profits from coal-fired generation from that point forward by making a choice to continue to generate electricity using coal (whose payoff is defined as V) or to retire and incur S.

Dixit and Pindyck (1994) show that the retirement decision can be specified as an optimal stopping problem. Treating retirement as an optimal stopping problem will ensure the retirement decision maximizes the value of the coal-fired generation asset. While the unit is operating, it not only provides a flow of profits $\pi(P_E, P_C)$, but it also means the utility holds an option to retire the unit when market conditions deteriorate $V(P_E, P_C)$. This option value represents the value of delaying retirement to gain more information about the profitability of continuing to use the coal-fired unit. When the utility retires the unit, sunk retirement costs S are incurred and the option value is terminated - making it an additional opportunity cost of retirement. This opportunity cost causes a more cautious response by the utility in the face of uncertainty.

The utility's unknown value function can be found by employing stochastic dynamic programming with the following Hamilton-Jacobi-Bellman (HJB) equation:

$$\delta V(P_E, P_C) \geq \pi(P_E, P_C) + r_E(\bar{P}_E - P_E)P_E \frac{\partial V(P_E, P_C)}{\partial P_E} + r_C(\bar{P}_C - P_C)P_C \frac{\partial V(P_E, P_C)}{\partial P_C} + \frac{1}{2}\sigma_E^2 P_E^2 \frac{\partial^2 V(P_E, P_C)}{\partial {P_E}^2} + \frac{1}{2}\sigma_C^2 P_C^2 \frac{\partial^2 V(P_E, P_C)}{\partial {P_C}^2} \quad (5)$$

and the value matching condition:

$$V(P_E, P_C) \geq S \qquad (6)$$

In financial terms, the utility faces an obligation to a flow of profits and option value before retirement. The obligation is treated as an asset whose value $V(P_E, P_C)$ must be optimally managed (i.e. maximized). The left-hand side of the HJB equation is the return the utility would require to delay retiring the coal-fired unit over the time interval dt. The right-hand side of the HJB equation is the expected return from delaying retirement of the coal-fired unit over the interval dt based on expectations of future coal and electricity prices. This equation acts as an equilibrium condition ensuring a willingness to delay retirement prior to the time a retirement actually occurs. The value matching condition describes where the utility is indifferent between continuing to generate using the coal-fired unit and retiring the coal-fired unit.

Either the HJB equation of value matching condition is satisfied at each point in the state space of $P_E(t)$ and $P_C(t)$. If the HJB equation holds as an equality, it is optimal to delay retirement of the coal-fired unit. However, if the value matching condition holds as an equality, it is optimal to retire the coal-fired unit. The solution to the HJB equation and value matching condition can be characterized by a retirement threshold ${P_E}^*$ that separates the state space where retirement should occur. Specifically, the retirement threshold is the set of points where the HJB and value matching conditions are met. If electricity prices are above this threshold, continuing to utilize the coal-fired unit will maximize value of that unit to the utility. If electricity prices fall below this threshold, the utility should retire the coal-fired unit. This retirement threshold is dependent on the cost of coal. Specifically, the higher the coal price, the larger the threshold electricity price that would optimally trigger retirement of the coal-fired unit $\partial {P_E}^* / \partial P_C > 0$.

Appendix B: Parameter Estimation and Solution Procedure

Electricity and Coal Price Expectations

Estimating the economic life of a coal-fired unit requires defining utility expectations for future coal and electricity prices. In our model, these expectations are determined by equations (2) and (3) in Appendix A. To estimate the parameters in these equations, we assume utilities base expectations of future prices on the evolution of past prices.

Coal price and quantity data for plants operating in regulated electricity markets (more than 70 percent of the coal units in our analysis) comes from EIA's 923 database. This database includes information on monthly fuel receipts like the quantity and price of fuel delivered to the plant. Since an electricity plant can have more than one fuel delivery per month, we use a weighted average of the fuel-specific quantity and price delivered each month to compile monthly fuel quantities (in million British Thermal Units, MMBtu) and prices ($/MMBtu) for units in regulated electricity markets from 2002 to 2015. Coal price data for plants in deregulated electricity markets are not publically available. We entered into a confidential data agreement with EIA to have access to the proprietary fuel cost data for plants in deregulated markets from 2002 through 2012. Because fuel deliveries are not associated with a unique unit, we apply the plant level parameter estimates for each retired unit at that specific plant.

Utility expectations of electricity prices are calculated using historic data on wholesale electricity prices at each generating plant ($ per MMBtu). For deregulated retired coal units whose balancing authority is PJM, we use the hourly PJM zonal wholesale electricity price data to estimate expectations of electricity prices. For all other retired coal units (those in a regulated market and those in a deregulated market but outside PJM), we use Federal Energy Regulatory Commission (FERC) Form 714 hourly system lambda electricity prices by balancing authority area. Since electricity price data are either at the balancing authority level or the PJM zone level, expectations for electricity prices are the same for units within the same balancing authority or PJM zone.

For our purposes, correctly specifying expectations for future prices is akin to identifying and estimating a stochastic process that accurately captures the trends and volatility of historic coal and electricity prices facing each retired coal-fired unit. The correct stochastic process could be one where the price follows a random walk with drift, like geometric Brownian motion, or one where the price reverts to a trend, like geometric mean reversion. We use a unit root test to verify that the functional form assumption in equations 2 and 3 (geometric mean reversion) are consistent with the data. Unit root tests provide a platform to determine if a time series follows a random walk. Therefore, an augmented Dickey Fuller test is used to check the mean reversion assumptions for coal and electricity prices. We reject the null hypothesis that both price processes follow geometric Brownian motion for each unit in the study and conclude that both price processes revert to a stationary long-run trend. With empirical support for our geometric mean reversion assumption, we follow Pachamanova and Fabozzi (2011) to estimate the long run trend in prices ($\bar{P}_E$ and $\bar{P}_C$), the speed of reversion to that trend (r_E and r_C), and the volatility around that trend (σ_E and σ_C) using data from 2002-2015.[13]

Generation and Fuel Use

Electricity supplied by a unit $\boldsymbol{q_E}$ is assumed to follow a simple supply function. We utilize the EPA's Continuous Emission Monitoring Systems (CEMS) data on electricity quantity with electricity price data described above to calculate the slope of a linear generation supply curve for each of the retired units in our study. Aggregate hourly electricity price data is aggregated to a monthly level and used as a right-hand-side variable for the ordinary least squares regression: $q_E = \beta_E P_E + \varepsilon$. We suppress the constant so a unit would not supply electricity if the price of electricity is zero.

An important factor for coal unit retirements is the age of the unit. We are able to account for the effect of age on retirement through β_E. Because coal units are largely used to generate baseload electricity, owners of coal-fired units seek to minimize the cost of supplying this baseload. This means the quantity of electricity generated and the efficiency of the generation technology determines the amount of fuel used. To capture unit technology and efficiency, we use ordinary least squares regression to determine the fuel efficiency of each unit in our sample: $q_C = \beta_C q_E + \varepsilon$. Suppressing the constant recognizes that generation is impossible without a fuel source. This relationship is representative of an inverse production function. The higher β_E the less efficient is the generating unit.

Variable, Fixed and Sunk Costs

In order to produce electricity, a firm faces fixed costs (e.g., capital costs, financing costs, land costs) and variable or O&M costs (e.g., fuel, labor, maintenance). While fuel costs are available at the plant level (see *Electricity and Coal Price Expectations* section above), plant-level data on payrolls, maintenance costs and capital costs are limited. According to the EIA, the average operating and maintenance expenses (less fuel) for fossil steam units between 2005 and 2015 is $2.35 per MMBtu. Faced with limited data on variable costs of generation, we apply this average measure to each unit in our study: $v = 2.35$.

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[13] For the coal-fired units that retired from deregulated markets, we use the proprietary EIA 923 data ending in 2012 to estimate expectations of future coal prices. We assume that coal price expectations do not substantially change for those handful of units that retire after 2012 where our proprietary data end.

The fixed costs associated with operating a coal-fired unit are equal to the levelized capital costs. A coal-fired unit that is still operating incurs these levelized capital costs over its productive life (until it retires). We take EIA estimates of the projected levelized capital costs for conventional coal generation resources in 2019 (provided in the Annual Energy Outlook) and transform it into dollars per MMBtu. We calculate per unit levelized capital costs to be $17.58 per MMBtu. Each unit's fixed costs are found by multiplying the per unit levelized capital cost by size of the unit (proxied by average annual coal used).

There is little public information on the sunk costs required to retire a coal-fired unit due to their proprietary nature. A report by the Electric Power Research Institute (EPRI) places costs required to decommission a coal-fired plant at $108,000 per MW of capacity (Henson 2004). However, the level of decommissioning can vary. If the site is going to be reused for other operations at the power plant, decommission includes removal of equipment and hazardous materials associated with generation. If full remediation is necessary, the cost and extent of hazardous material cleanup depends on the anticipated reuse of the site and the type and location of hazardous materials stored or disposed on the property. If this is the only or last generating unit at the plant, then coal ash ponds or solid waste landfills must follow federal and state permit requirements before closure. In some instances, the utility can choose to leave the generating unit intact and maintain environmental permits or sell the facility as is.

Decommissioning costs are only part of the costs incurred by a utility to retire a coal-fired unit. Utilities are often required to offset some of the generation capacity lost when a coal-fired unit is retired. According to Form EIA-860 data, the average construction cost per MW of natural gas-fired capacity installed in 2014 was $965,000. For exposition, we assume that each a utility must offset half of the generation lost when a coal-fired unit is retired. While there is little data linking coal-fired retirements to new investments in generation, there is reason to believe that utilities will not replace all of the retired coal-fired generation. The average capacity factor for existing natural gas plants in the ARC Region is less than 10 percent. This suggests that much of the retired generation capacity could be easily offset by increasing generation at existing gas-fired units. While coal-fired retirements can necessitate transmission improvements, power plant owners are typically not required to make these investments. This leaves us with the following relationship between a unit's capacity and the sunk costs required to retire it: $S = \$108{,}000 * q_{cap} + \frac{1}{2} * \$965{,}000 * q_{cap}$.

Solution Procedure

A closed-form solution for the retirement threshold does not exist. Instead, we utilize computational methods to approximate the value function associated with the decision to retire a coal-fired unit (Miranda and Fackler 2002). Using piecewise linear basis functions, we approximate the value function associated with retirement of each coal-fired unit that was retired between 2005 and 2015 over a subset of the state space (Marten and Moore 2011). The approximation procedure solves for the $2 \times n \times m$ basis function coefficients which satisfy the HJB equation and value matching condition at a set of $n = 50$ and $m = 150$ nodal points spread evenly over the two-dimensional state space. Upwind finite difference approximations are used to construct a linear spline, which approximates the unknown value function. We use Matlab along with the CompEcon Toolbox and the smoothing-Newton root finding method to solve the resulting complementarity problem. The approximated state space ranges from \$0 to \$15 in the P_C dimension and from \$0 to \$150 in the P_E dimension. Extending the state space in either the P_C or P_E dimension or increasing the number of nodal points does not alter our general results.

Appendix C: Plant Database Description and Additional Detail on Power Plants

DATABASE DESCRIPTION: Much of the analysis presented in chapters 1 and 3 relies on a database of every electric generating unit in Appalachia and the surrounding NERC regions. Here we provide a more detailed description of this dataset and a comparison of the current fleet and recent trends in Appalachia to coal-fired units outside of Appalachia and other types of electricity generating units (for example natural gas units and wind turbines).

A power plant houses multiple generators, which may differ in generation capacity, fuels used, age, and fuel efficiency. An analysis performed at the generator level provides a clearer picture of the role of coal in electricity generation in the Appalachian Region. This generator-level dataset draws from three main sources: Energy Information Administration (EIA) Form EIA-860 dataset, Form EIA-923 dataset, and the Environmental Protection Agency's Superfund Enterprise Management System (SEMS) database. By drawing from multiple datasets, we are able to provide plant and generator information in eight general categories:

1. **Plant name and location**: Address, county, and balancing authority for each plant. This category also contains dummy variables that indicate whether the plant is located in a county that is within the ARC Region or in a state with a Renewable Portfolio Standard (RPS).
2. **Plant information**: Plant's regulatory status, water source, transmission or distribution system, and presence of natural gas pipelines and ash impoundments.
3. **Generator information**: Generator's operating company, operating status, ownership, and year of first operation.
4. **Generation technology**: Description of generation technology, prime mover (for example hydroelectric turbine, steam turbine), capacity (nameplate, summer, and winter), average heat input and gross load, average annual capacity factor, and fuel efficiency.
5. **Fuel and cost data**: energy sources, startup sources, quantity of fuel used, quality of the fuel used, fuel price, and primary mode of fuel delivery (for example pipeline or rail)
6. **Ancillary technologies employed by the generator**: Dummy variables indicating the presence or absence of a variety of technologies.
7. **Retirement and modifications**: Month and year of unit retirement or planned retirement, years of repower and planned repower, original and new primary fuel sources for those units that repowered.
8. **Emissions**: Average emissions of SO_2, NO_x, and CO_2. Description of pollution control technologies for SO_2, NO_x, particulate matter, and mercury.

MORE DETAIL ON COAL-FIRED POWER PLANTS: Table 8 presents characteristics of the electricity generating fleet operating in the counties that constitute Appalachia and the surrounding area. As of 2015, there were 1,094 electric generating units operating in Appalachia with a total nameplate capacity of 132,284 megawatts (MW). These units are large with an average nameplate capacity (120 MW) that is 72 percent larger than the average nameplate capacity in the four NERC regions that border Appalachia.[14]

Table 8: Characteristics of the U.S. and Appalachian Electric Generating Fleet, 2015

	Operating Conventional Steam Coal Units		**Retired Coal Units**		**Planned Coal Unit Retirements**	
	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions
Number of Units	1,094	7,565	240	2,183	134	411
Total Nameplate Capacity (MW)	132,284	529,658	33,186	235,415	63,225	148,033
Average Nameplate Capacity (MW)	121	70	138	108	472	360
Average Capacity Factor (%)	24	16	8	14	38	40
Average Fuel efficiency	0.34	0.30	0.30	0.28	0.38	0.33
Average Age (years)	35	31	15	23	45	44
% Single Ownership	87	89	89	85	69	83
% in state with RPS	43	66	37	58	54	55
% Regulated	63	64	51	80	57	53

Source: U.S. Energy Information Administration, Form EIA-860 & EIA-923

In Appalachia, coal-fired units are less likely to be owned by a single entity and more likely to be located in a state with a renewable portfolio standard (RPS) compared with other types of generating units such as gas-fired or nuclear generators. Coal-fired units currently operating are also older and slightly more efficient than the gas-fired units. However, gas-fired units are not inherently less efficient than coal-fired units. Instead, the relative inefficiency of the gas-fired units reflects how natural gas plants have traditionally been used. Historically, coal was the least expensive way to generate electricity in Appalachia. Because of this cost-advantage, coal-fired plants were designed to supply base load, meaning that these units would run continuously with little or no change in generation in response to daily or seasonal variation in electricity demand. Many natural gas plants were designed to only generate electricity when demand outstripped the baseload being generated by

[14] These NERC regions include the Northeast Power Coordinating Council (NPCC), Reliability First (RF), SERC Reliability Corporation (SERC), and the Southwest Power Pool (SPP).

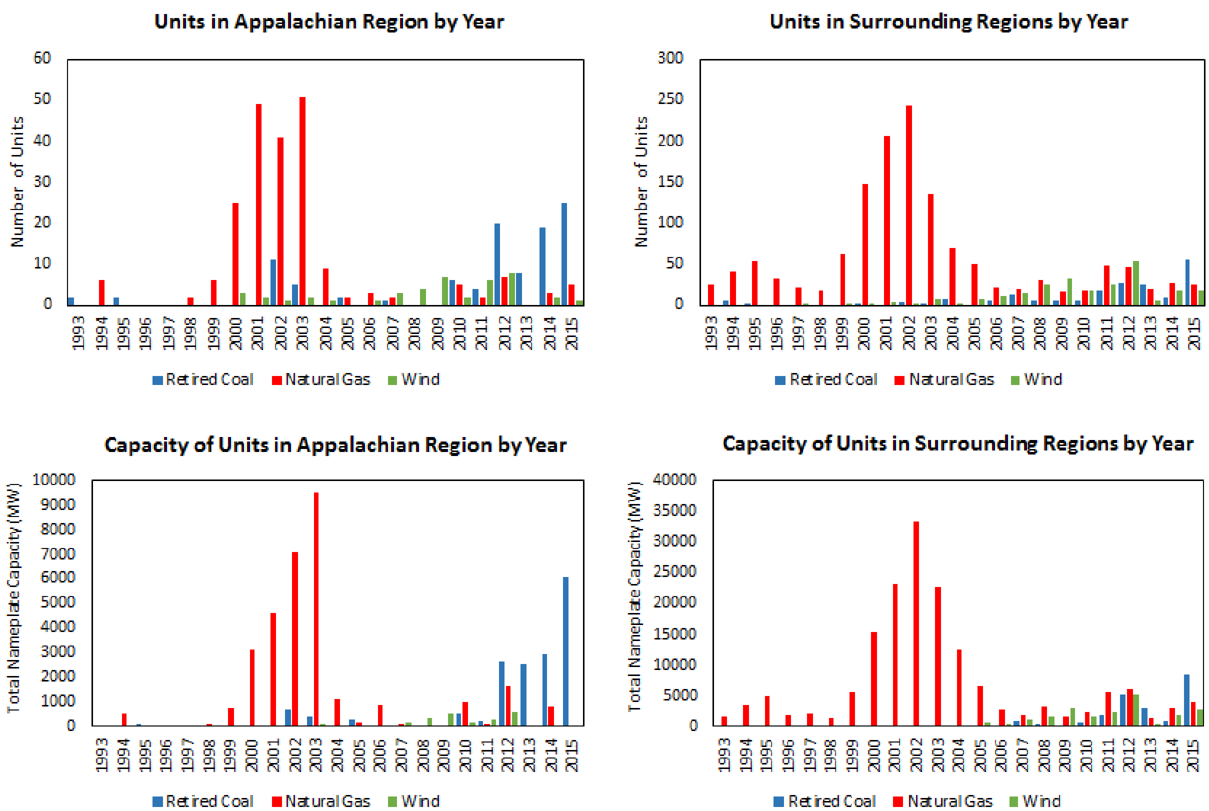
coal plants. This role, known as load-following, means natural gas plants in Appalachia are often cycling between little or no generation and maximum capacity. This difference between baseload coal plants and load-following natural gas plants is evident in the difference in average capacity factor between the two types of units. Capacity factor is the ratio of actual annual electrical energy output to the maximum annual electrical energy output. Intermittently cycling between periods of low and high generation results in an 8 percent capacity factor for gas-fired units compared with a 38 percent annual capacity factor for coal-fired units. This intermittent cycling is also less efficient as more energy is needed to increase generation than is need to maintain a constant flow of generation.

Regardless of these differing roles, the coal-fired units currently operating in Appalachia are relatively efficient. The average capacity factor of coal-fired units in Appalachia and the surrounding NERC regions are similar suggesting that baseload generation is the primary role of coal-fired units in both areas. However, the heat rate (the ratio of energy output to energy input) of the average coal-fired unit in Appalachia is 0.38 compared with 0.33 in the surrounding NERC regions. This means that coal-fired units in Appalachia generate more electrical energy per unit of coal than similar units in surrounding areas. The coal-fired units in Appalachia are more efficient than base load units in surrounding areas despite being over a year older on average. The slight edge in fuel efficiency could be a result of the quality and cost of coal used in Appalachia. On average, the coal delivered to units in Appalachia is more expensive and has a higher sulfur and ash content than coal delivered to units in surrounding areas. The higher cost alone creates an incentive to adjust plant operations or make upgrades to improve efficiency. Federal regulations on sulfur emissions and the cost of managing and disposing of ash creates additional incentives to unit owners in Appalachia to make efficiency improvements.

REPLACEMENT ELECRIC POWER GENERATION – NATURAL GAS AND WIND: Most of the generation capacity lost due to coal-fired retirements will likely be replaced by increasing generation at existing natural gas plants in Appalachia and wind turbines from surrounding areas. Figure 18 shows that the spate of coal-fired unit retirements was preceded by a drastic increase in gas-fired generation capacity both within Appalachia and in surrounding regions. Between 2000 and 2003, roughly 25,000 MW of gas-fired capacity was added to the grid in Appalachia. These gas-fired units have an average capacity of 145 MW which is comparable to the average size of the retired coal-fired units. This expansion in the early 2000s allowed natural gas to account for more than a quarter of generation capacity in Appalachia. However, much of this gas-fired generation capacity is underutilized. The average annual capacity factor for gas-fired generating units in the ARC Region is only 8.2 percent. This is far lower than the capacity factors for existing coal-fired units (38%) and slightly lower than gas-fired units outside the ARC region (14%). Given flat and even declining load demand in the ARC Region and the low capacity factors for gas-fired units, the expansion of natural gas capacity in the ARC Region could easily offset the baseload generation lost when coal-fired units were retired. Gas-fired units will likely continue to play their traditional load-following role given the amount of gas-fired capacity added to the grid.

These trends are not unique to Appalachia. In the surrounding NERC regions, gas-fired generation expanded to an even greater degree in the early 2000s and persisted into recent years. Between 2000 and 2003, roughly 100,000 MW of gas-fired capacity was added to the grid in the surrounding NERC regions. In 2015 alone, nearly 4,000 MW of gas-fired capacity was added in the same areas. This gas-fired expansion was also coupled with a non-trivial increase in wind generation that has not occurred in Appalachia.

Figure 18: Transition from Coal to Natural Gas and Wind by Year



Source: U.S. Energy Information Administration, Form EIA-860

REPLACEMENT ELECRIC POWER GENERATION – REPOWERINGS: Coal-fired units are also being converted or repowered to natural gas though to a far lesser extent. Table 9 summarizes these repowerings between 1993 and 2015. Instead of building new gas-fired capacity to offset coal-fired losses, coal-fired unit owners may choose to convert the old coal-burning unit to operate using natural gas. On the surface, repowered units share many characteristics with retired units. Repowered units tend to be smaller, less fuel efficient, have a lower capacity factor and are more likely to be under single ownership than the operating fleet of coal-fired units. However, a small number of units that have been repowered as of 2015 (two in Appalachia and three in surrounding NERC regions). This suggests repowering may be a viable option in a more limited set of circumstances. In the surrounding NERC regions, the average repowered unit was younger than the fleet of operating coal-fired units. The average capacity factor of those units planned for repower in the surrounding NERC regions is also higher than the fleet of operating coal-fired units. Outside of Appalachia, coal-fired unit owners may be more likely to undertake repowering on younger baseload coal-fired units. However, these conclusions are based on a limited number of observations. There is also no guarantee that those units planned for repower will actually be repowered.

Table 9: Coal-Fired Unit Repowerings, 1993-2015

	Operating Conventional Steam Coal Units		**Retired Coal Units**		**Planned Coal Unit Retirements**	
	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions	Appalachia	Surrounding NERC Regions
Number of Units	134	411	2	3	10	7
Total Nameplate Capacity (MW)	63,225	148,033	213	825	1,730	2,106
Average Nameplate Capacity (MW)	472	360	107	275	173	301
Average Capacity Factor (%)	38	40	17	25	14	42
Average Fuel efficiency	0.38	0.33	0.25	0.31	0.32	0.32
Average Age (years)	45	44	57	37	57	46
% Single Ownership	69	83	100	100	60	100
% in state with RPS	54	55	50	33	70	14
% Regulated	57	53	100	100	30	100

Source: U.S. Energy Information Administration, Form EIA-860 & EIA-923

Terms and Abbreviations

Term	Definition
MMBtu	**Million British thermal units**. Btu is a measure of heat output required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit. It is used to measure the heat produced when fossil fuels are burned for power generation.
MW	**Megawatts**. A measure of electric generating capacity. Equal to 1 million watts, or 1,000 kilowatts.
MWh	**Megawatt-hour**. A measure of electricity production or consumption. Equal to one megawatt operating for one hour.

Abbreviation	Definition
EIA	U.S. Energy Information Administration
MSHA	U.S. Mine Safety and Health Administration
BLS	U.S. Bureau of Labor Statistics
QCEW	Quarterly Census of Employment and Wages, implemented by the U.S. Bureau of Labor Statistics
NERC	North American Electric Reliability Corporation

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