U.S. Coal: More Market Erosion is on the Way

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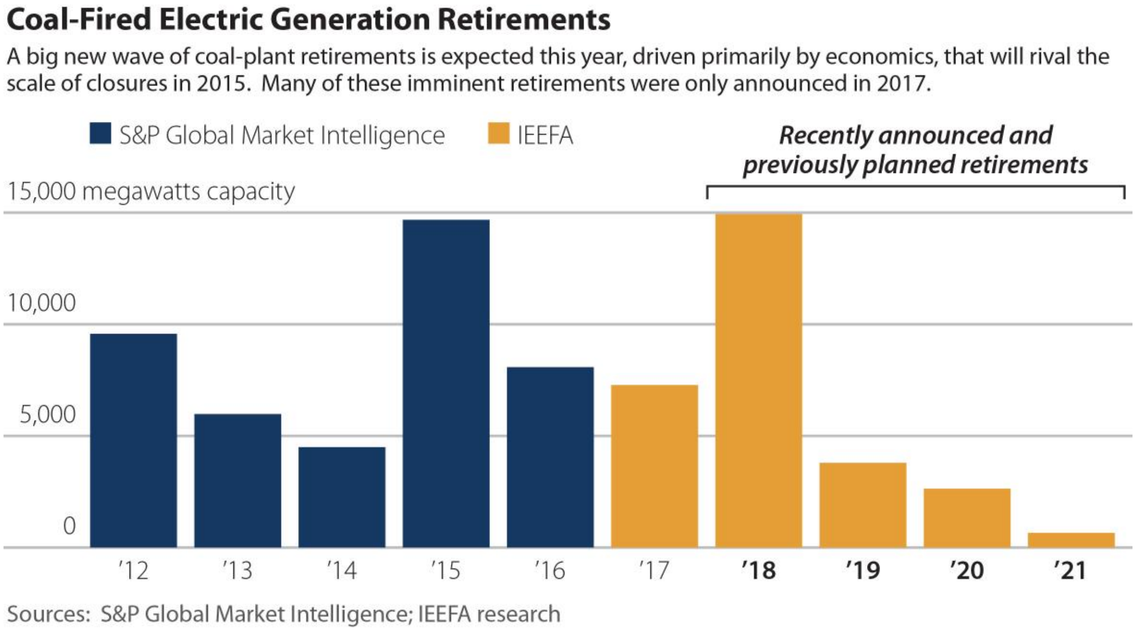
Executive Summary

The U.S. coal industry continued to shrink in 2017, and its trend toward long-term structural decline is all but sure to persist in 2018.



That is the core conclusion of this report, informed by the following fundamentals:

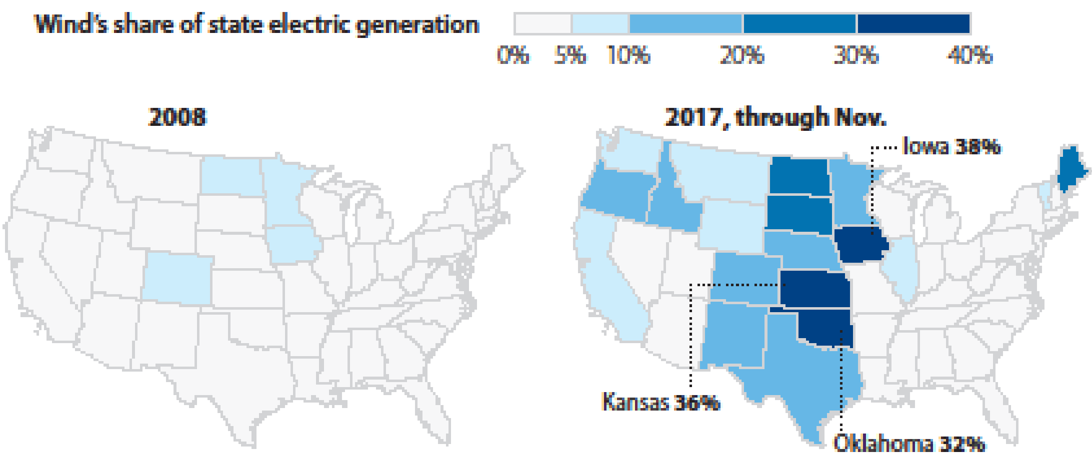
- In electricity generation—the key market for coal—the industry is increasingly uncompetitive and is losing market share.
- Coal's main competitors continue to be natural gas and renewables.
- The cost of generating electricity with wind and solar power is declining rapidly and, as a result, solar and wind are gaining market share. Significantly, wind power is showing strong growth in the competitive energy markets that are home to most of the country's remaining coal-fired generating capacity.
- Natural gas prices remain relatively low today and are expected to remain low for the foreseeable future, which means that energy market prices will remain low, further undermining the financial viability of many coal-fired generators.
- Demand for electricity is growing very slowly.
- As more renewable and gas-fired generating capacity is added to the grid, coal faces increasing competition from these lower-cost alternatives.
- Further declines in coal's energy generation market share can be expected through 2018 and beyond.
- Coal mining continues its long-term decline.
- Coal consumption stayed at record lows in 2017.
- Prices for thermal coal—used for electricity generation—remained low.
- Coal producers continued to lose customers. Following a well-established trend toward reduction of coal-fired generating capacity, more plants were retired in 2017 and more coal-plant closures were announced.

- In 2018, the total reduction in generating capacity of coal-fired plants will be double that of 2017.
- In several western U.S. locations—including for the first time in the Powder River Basin coal field, which is long the country's strongest coal producer—attempts to buy and sell coal reserves ran into difficulty in 2017. Some deals could not find financing, and some posted negative valuations—meaning that the seller either received no cash or had to take a loss on the transaction.
- Employment in coal mining was essentially flat.
- Rollbacks of federal environmental regulations and other federal policy changes have not significantly improved coal's market competitiveness.

All these trends aside, the coal industry showed improvement in some respects in 2017. Production was up in the largest one-year increase in more than a decade. This gain was due to increased demand and higher prices in the export market both for metallurgical coal (for steel production) and thermal coal (for energy production). The fourth quarter of the year saw improvement in the stock prices of industry leaders Arch Coal and Peabody Energy after their emergence from bankruptcy.

Rapid Growth of Wind Power Generation

Wind power has grown enormously over the last 10 years. In 2017, through November, wind's share of electric generation was over 10 percent in 13 states — up from zero in 2008.



Source: Energy Information Administration

Nonetheless, IEEFA sees 2018 as a year of further decline for coal-fired electricity generation and the coal industry generally. Coal's competitors—natural gas and renewable energy—begin the year with competitive tailwinds on price and outlook. Coal consumption and production are likely to decline, and coal prices and coal company margins will continue to be under pressure. Thermal coal export levels and global pricing of both metallurgical and thermal coal will decline. Even if promised regulatory relief at the federal level is achieved, market forces will continue to prevent a sustained coal recovery.

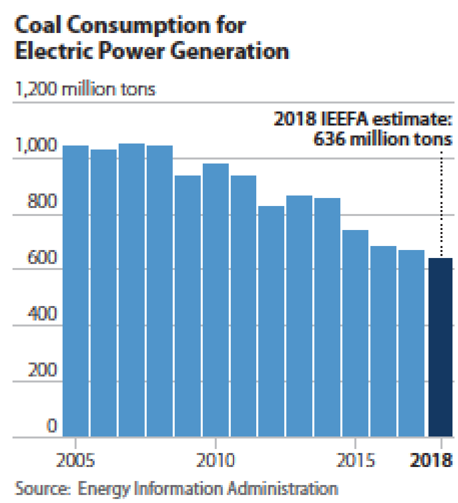
Additional findings on U.S. electricity-generation trends:

- There two ways to look at coal's declining share of electricity generation:
    - Coal's relative share of the total amount of electricity generated across the U.S. in 2017 was 30%, a continuation of a decline from 45% in 2009.
    - The absolute amount of energy generated by coal decreased by more than a third from 2010, and by 1.7% in the first 11 months of 2017 from the same period in 2016.
- Coal's regional market share continued to decline as well, specifically in the Southwest Power Pool (SPP), the PJM Interconnection (PJM), the Mountain West, and in Southeast states. Although coal posted market-share gains in 2017 in the Electric Reliability Council of Texas (ERCOT) and the Midcontinent Independent System Operator (MISO), IEEFA expects these gains are only temporary as more coal-fired plants are retired and additional renewable resources (particularly wind) are added to these regional grids.
- Almost 7,300 MW of coal-fired generation were retired in 2017 and more than 16,000 MW of new, future retirements were announced. IEEFA estimates that 15,000 MW of coal-fired electricity generation will be retired in 2018, double the total in 2017 amount, and—for the first time—many retirement will be of plants with more than 1,000 MW of capacity.
- The market share of wind and solar has increased four-fold since 2009, and in four states—Iowa (37%), Kansas (36%), Oklahoma (32%), and South Dakota (30%)—wind's share of total electricity generation exceeded 30% in 2017. Trends in long-term utility-scale investment in renewables show that more wind and solar are coming.
- Peak energy market prices for wholesale electricity remained low in 2017, with prices projected to remain below $40 megawatt-hour (MWh) in all regions of the country at least through 2025. Off-peak prices are expected to be even lower.
- Prices at capacity auctions, where owners of power plants receive payments to keep plants open and available for dispatch, declined substantially in MISO and PJM.
- While natural gas prices rose some in late 2016 and early 2017, they are expected to decline by 4% in 2018 and to remain below $3MMbtu[1] at the Henry Hub through 2025. In most of the regional gas hubs in the country, gas prices will remain substantially below $3MMbtu for the foreseeable future.
- IEEFA sees coal-fired generation continuing to drop in 2018, both in absolute terms and in market share.

[1] MMbtu stands for one million British Thermal Units (BTU). A BTU is a measure of the energy content in fuel.

Additional findings on U.S. coal producers:

- Consumption of coal for electricity generation tilted downward and remained at historic lows, falling by 1.8% in 2017 to 666 million tons, down from 678 million tons in 2016. This occurred even with a 20% increase in natural gas prices, and IEEFA projects consumption in 2018 will drop by an additional 30 million tons, or 4.5%.
- While coal production increased in 2017 by 6%, to 773 million tons from 728 million tons in 2016, IEEFA sees the trend reversing in 2018, with coal production declining by 20 to 40 million tons.
- Thermal spot coal price trajectories varied regionally in 2017: Illinois Basin spot prices declined, Central Appalachian prices rose, and prices in the Powder River Basin (PRB) and Northern Appalachia were flat for most of the year (PRB prices rose in the latter part of the fourth quarter).
- Coal prices have declined for the most part over the past four years, according to company-reported numbers. In 2017, this downward trend continued in the Powder River Basin and Illinois Basin. In Northern and Central Appalachia, company-reported prices for domestic thermal coal also continued to drop. Where company-reported coal price increases did occur, they were driven by improvements in thermal coal exports and the metallurgical market.
- IEEFA projects that in 2018 coal prices will decline further in the Powder River Basin, Illinois Basin and Central Appalachia.
- Driven by solid demand and good prices in metallurgical and thermal coal markets, coal exports rose by 48% in 2017. In 2018, metallurgical and thermal coal export markets will likely see price erosion; decline in U.S. thermal exports is likely.



- Coal employment in 2017 was essentially flat as compared to 2016, and over the past two years coal-mine employment has been at its lowest levels in a decade.
- The buying and selling of coal mines continued to reflect a severely distressed market with announced deals failing to materialize and deal closings characterized by investor value losses. Stock price gains among coal producers have been limited to companies that have emerged recently from bankruptcy with reduced debt and are selling coal outside U.S. For producer's dependent on domestic coal sales, stock performance remains subpar.
- Rollbacks of federal environmental regulations on coal mining and electricity production, as well as rescissions of reforms to the federal coal-leasing program, have proven largely ineffective in improving the balance sheets of coal producers in 2017. IEEFA expects little impact going forward.

Introduction

The purpose of this review and outlook is to assess the impact that market forces and policy changes have had, and are likely to continue to have, on the financial viability of coal-fired electricity generation across the U.S.—and on the viability of the coal industry as a whole.

Our analysis focuses on changes reflected in actual market-, and company- and plant-reported results, rather than on models built around flawed, hypothetical assumptions about future circumstances and developments. This report considers the performance of specific individual mines and coal–fired generators and the finances of plant and mine owners.

This report is our second on the topic in two years. The first, published in January 2017,[2] took a bare-bones approach to quantifying trends in coal markets—focusing on consumption, production, prices, employment and the underlying market forces driving those trends. This year's outlook takes a deeper look at the energy-generation side of the equation, recognizing that demand is the key to the future of coal producers.

Projections in IEEFA's January 2017 outlook turned out to be largely accurate, as described below, but did miss the mark on one key factor: While IEEFA had coal production in 2017 either flat or declining, it actually increased by 45 million tons. IEEFA's analysis a year ago missed seeing the improvement that occurred in export market conditions for coal in 2017, which was what drove the increase.

- IEEFA predicted in January 2017 that U.S. coal *consumption* would total 675 million tons, a decrease from 2016. And coal consumption indeed dropped, to 666 million tons. Here IEEFA expected that natural gas prices would rise, mitigating consumption losses for the year. Natural gas prices in fact did rise early in the year and on a year-to-year basis, but coal consumption for electricity dropped nonetheless during the first 11 months of the year. [3]
- IEEFA expressed scepticism in January 2017 that any price or financial recovery would result in new investment in the industry. Coal transactions during the year continued to demonstrate severe distress. The industry's strongest regional producer—the Powder River Basin—saw the year close with the collapse of the Belle Ayre/Eagle Butte deal, for the first time reflecting market-based impairments of coal reserve values in the PRB.
- IEEFA also expressed doubt that employment in the coal sector would significantly improve. Although the industry saw certain months of gain, overall employment levels were flat, with the year ending on a downward trend.

[2] Institute for Energy Economics and Financial Analysis, 2017 U.S. Coal Outlook: Short-Term Gains Will Be Muted by Prevailing Weaknesses in Fundamentals, January 2017

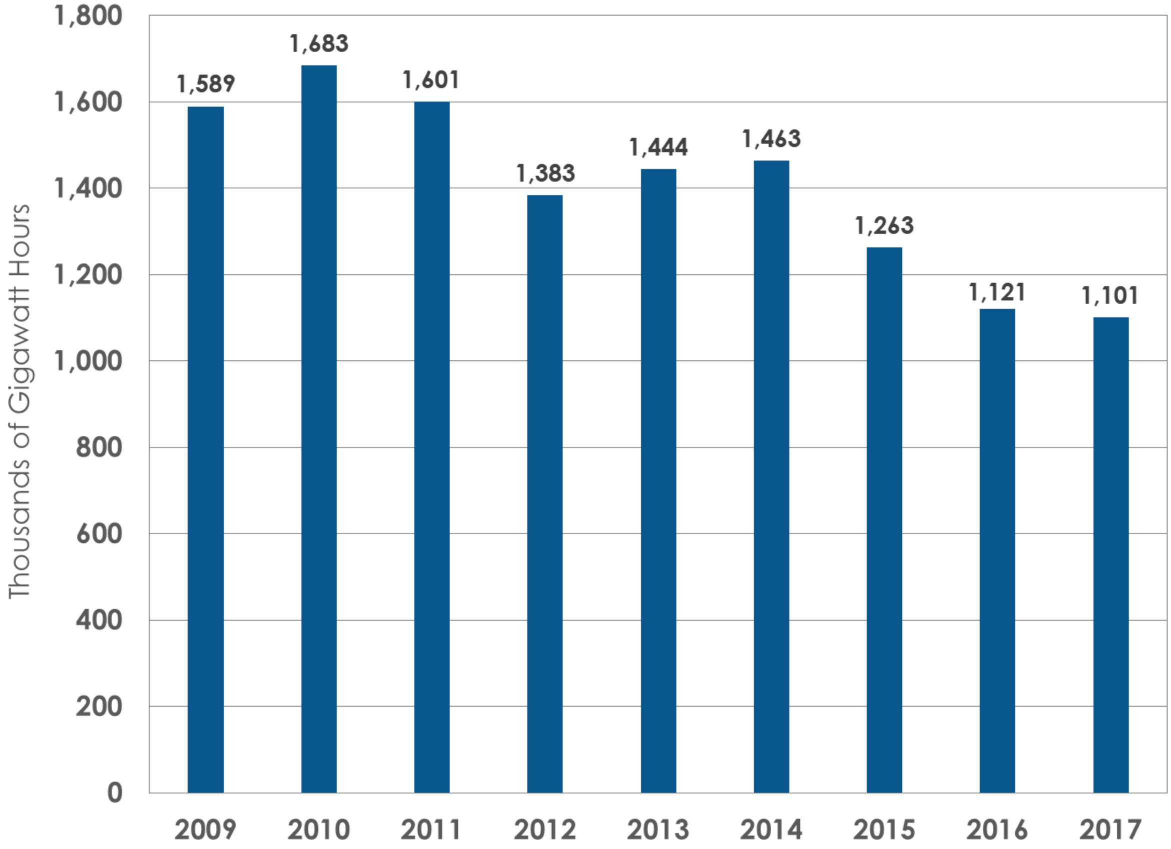
[3] Data for the period January-November 2017 are the most recent electric generation data available at this time.

Market Forces Will Continue to Undermine the Financial Viability of Coal-Fired Power

The decline in the use of coal for generating electricity slowed in 2017, but indications are that the trend will re-accelerate in coming years.

It appeared by the middle of 2017 that electricity generation from coal-fired plants would be higher nationally in 2017 than it had been in 2016. However, by the fall, it was clear that coal-fired generation in the U.S. would be down in 2017 relative to 2016, following a trend established in 2015 and 2016 (see Figure 1). Total generation from coal in the first 11 months of 2017 was 1.7% lower than in the same period of 2016 and 35% below the first eleven months of 2010.[4]

Figure 1: U.S. Coal-fired Generation During the First 11 Months of 2009 through 2017[5]

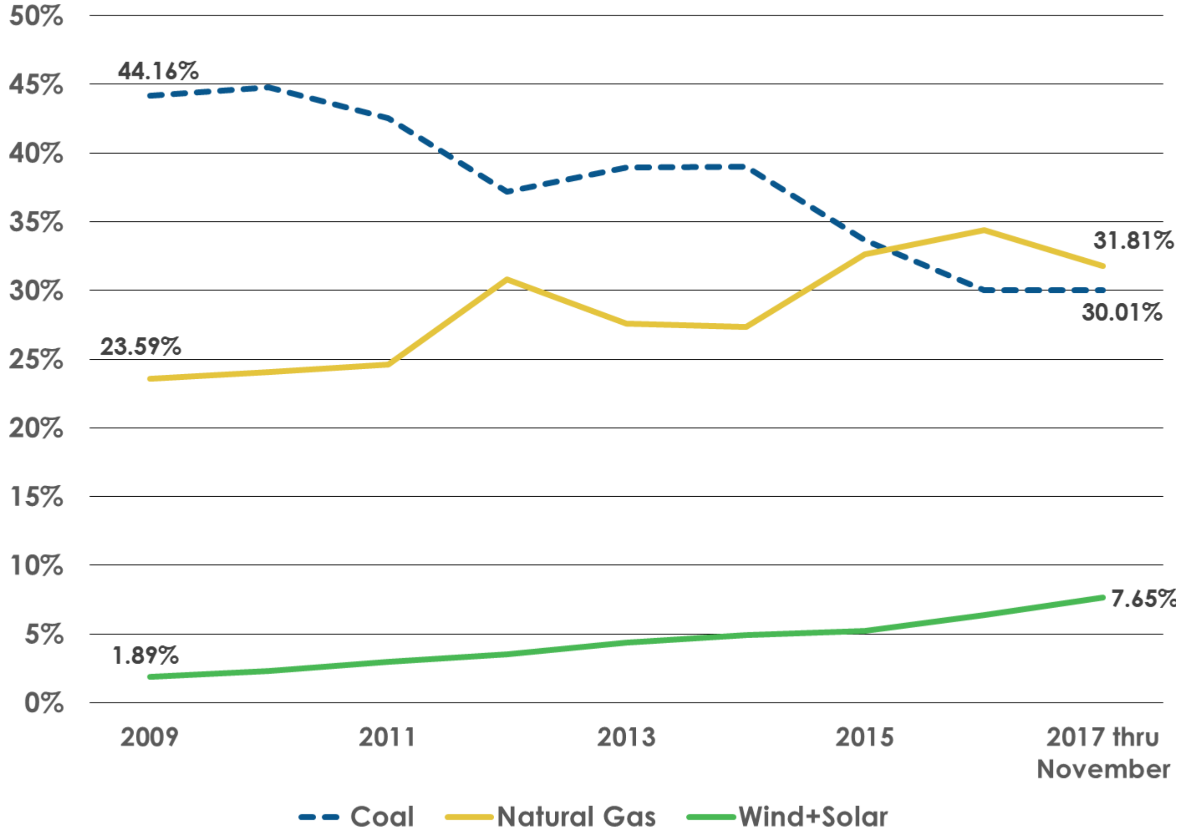


4 Figures 1 and 2 present generation during the first eleven months of each year. This is because full-year results are not yet available for 2017 and to compare full year results for other years with those for only the first eleven months of 2017 would not be reasonable.

5 Source data from EIA Electric Power Monthly

Figure 1 shows no reversal in 2017 in the long-term decline in coal's share of the U.S. electricity generating mix. At best, coal's market share declined much less in the first 11 months 2017 than it had in previous years, but given the market forces that IEEFA expects will continue to undermine coal's use as a fuel to produce electricity, it is very likely that coal-fired generation will continue to decline in 2018 and beyond, although it is difficult to project the specific rate of decline.

Figure 2: U.S. Electricity Generation Mix[6]



Although the data shown in Figures 1 and 2 provide a good overview of coal's role in electricity generation, regional data reveals how coal is faring in key regions around the country in which the fuel continues to play a significant role in electricity production. The U.S. coal fleet is concentrated in six main areas of the nation. These include four competitive wholesale markets (the Southwest Power Pool[7] (SPP), the Electric Reliability Council of Texas[8] (ERCOT), the Midcontinent Independent System Operator [9](MISO) and the PJM

[6] Source data from EIA Electric Power Monthly.

[7] Southwest Power Pool, Inc. manages the electric grid and wholesale power market for the central United States covering 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

[8] The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 24 million Texas customers -- representing about 90 percent of the state's electric load.

[9] The Midcontinent Independent System Operator (MISO) operates the transmission system and a centrally dispatched market in portions of fifteen states in the Midwest and the South, extending from Michigan and Indiana to Montana, and from the Canadian border south to Louisiana and Mississippi.

Interconnection[10] (PJM)' and two regions that don't have competitive wholesale markets (the Southeast and the Mountain West states).

Figure 3, below, shows coal-fired generation in the years 2009-2017 in SPP, ERCOT, MISO and PJM.[11]

Figure 3: Coal-Fired Generation in SPP, ERCOT, MISO and PJM 2009-2017[12]

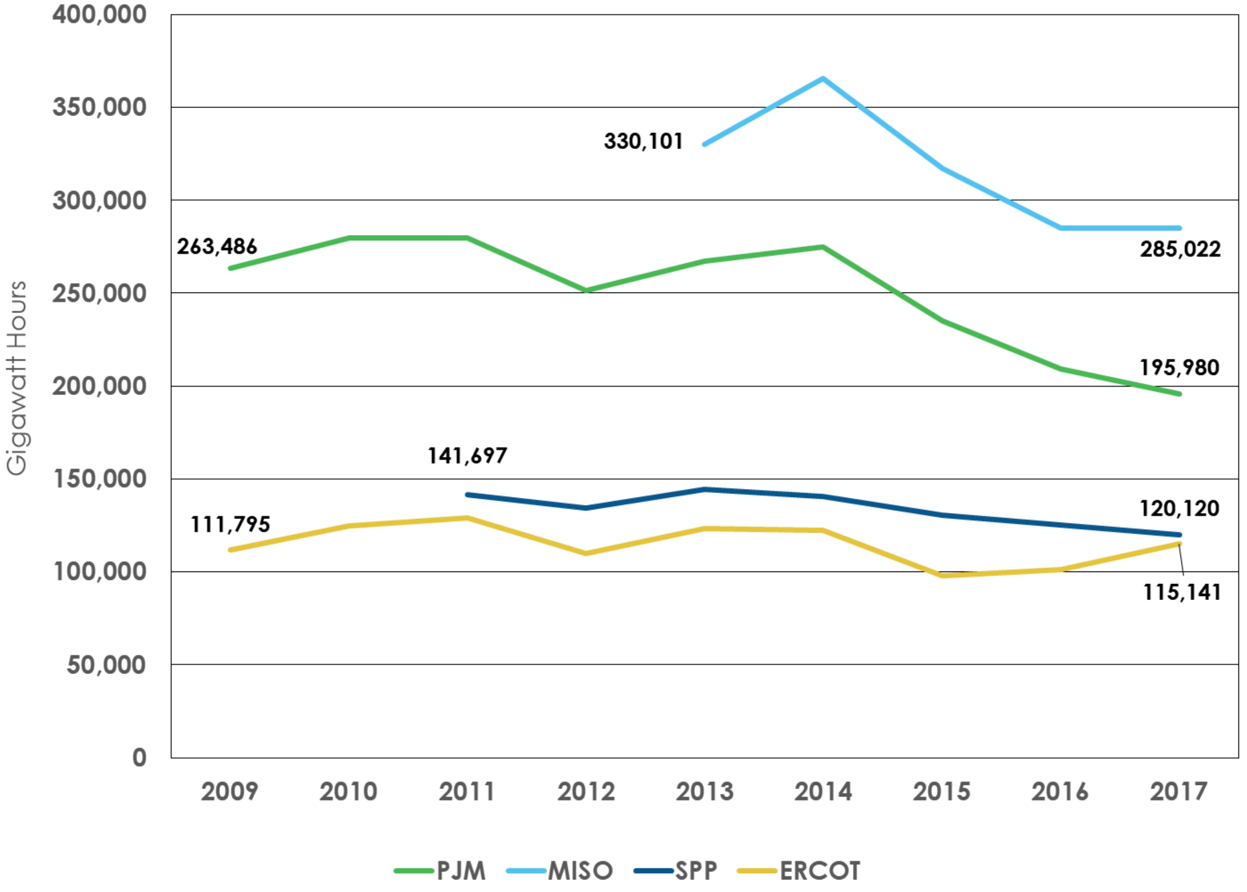


Figure 3 makes it clear that that generation from coal-fired facilities has been in decline in the MISO, PJM and SPP markets in recent years—with especially substantial declines in MISO and PJM. Generation from coal-fired facilities also has declined in ERCOT, except for what IEEFA anticipates will prove to be a temporary upturn in 2017.

Figure 4 shows how coal's market share has declined in each of these competitive wholesale markets. As explained below, IEEFA sees coal plant retirements, persistently low natural gas prices, and the addition of large amounts of renewable resources (particularly wind) leading

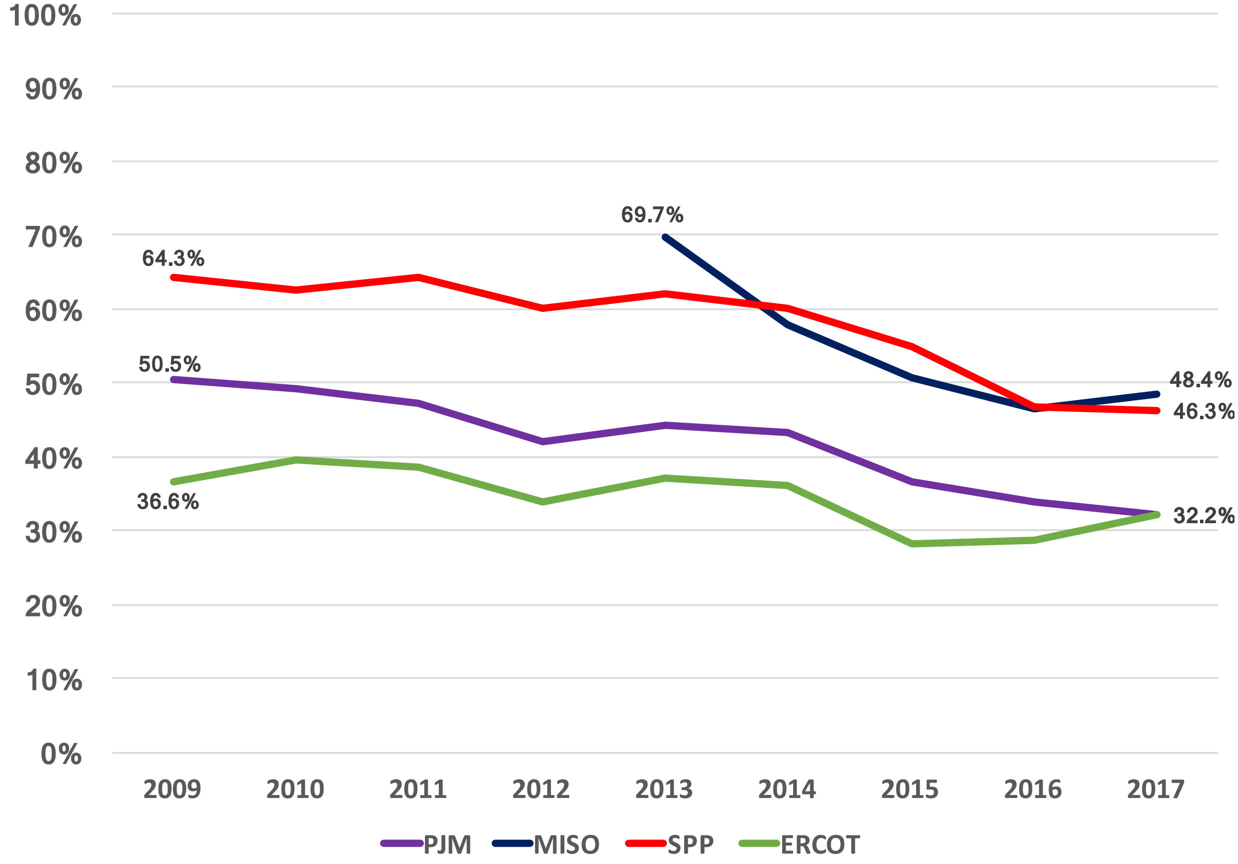
[10] PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[11] The generation data shown in Figure 3 is for all of each calendar year for SPP, ERCOT and MISO. The PJM generation data is for the months January-September only, as the annual data for PJM is not available.

[12] Source data from PJM, MISO, SPP and ERCOT websites.

to further market-share declines for coal in these regions.

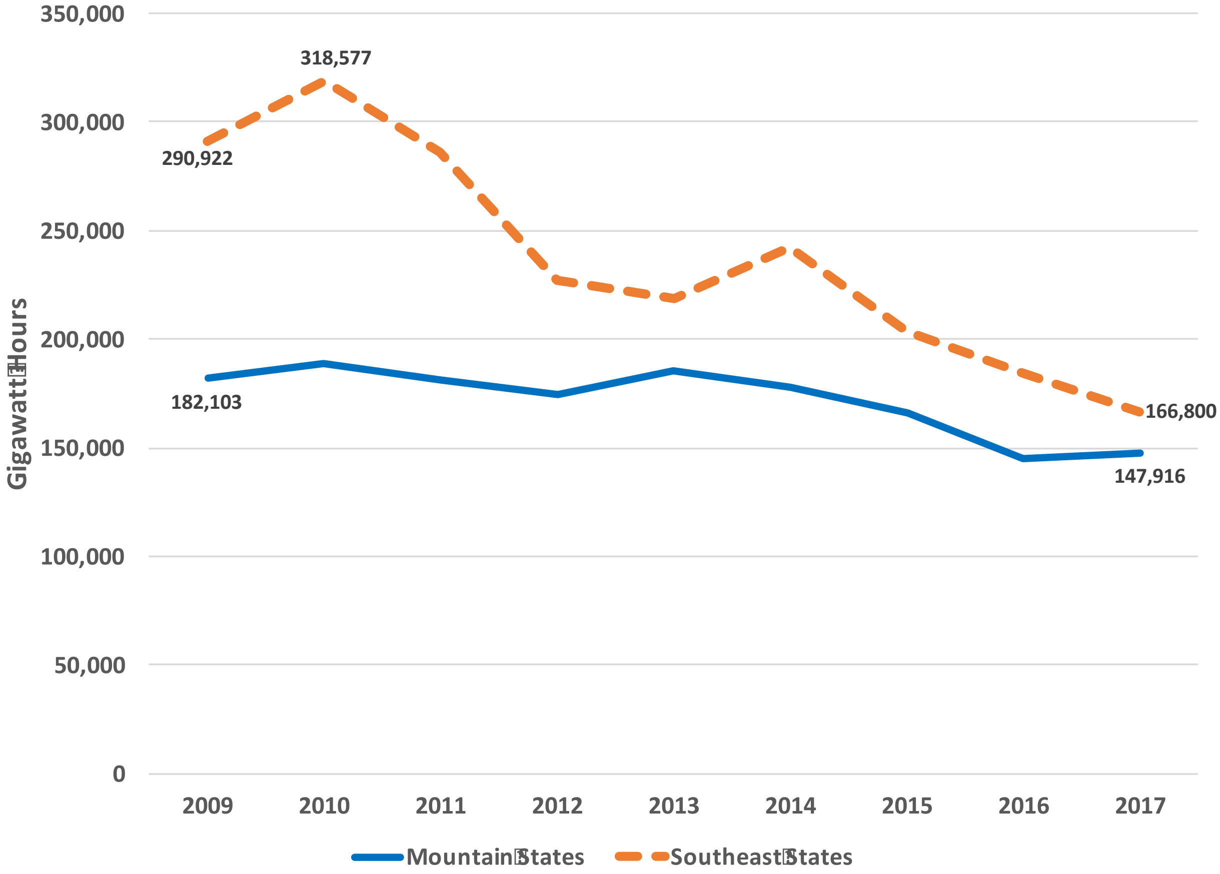
Figure 4: Coal's Declining Share of the Energy Mix in SPP, ERCOT, MISO and PJM[13]



Figures 5 and 6, below, show coal-fired generation in the Mountain West and Southeast regions of the U.S., both in absolute terms (GWh) and as shares of the regional energy mix.

[13] Source data from PJM, MISO, SPP and ERCOT websites.

Figure 5: Coal-Fired Generation in the Mountain West[14] and Southeast U.S.[15] [16]

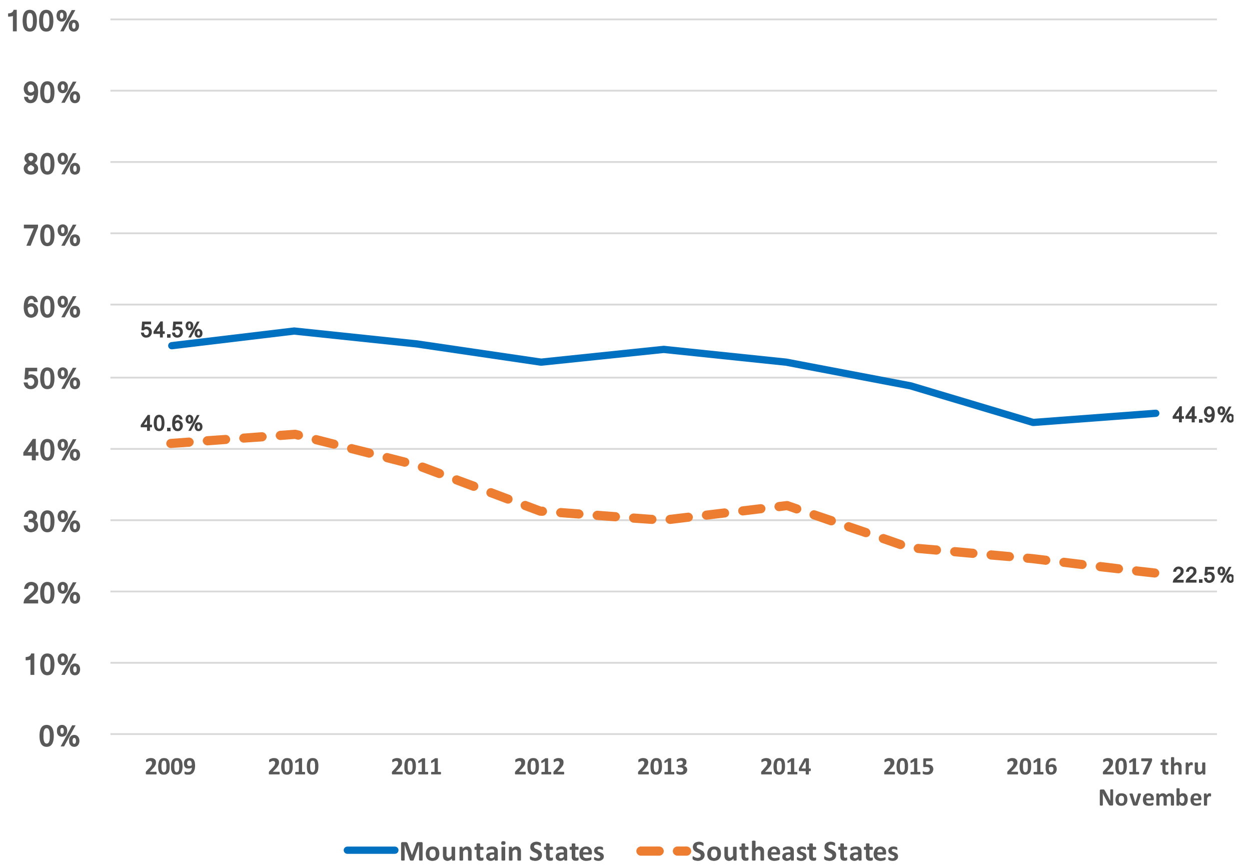


14 The eight mountain states included in Figures 5 and 6 are Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah and Wyoming. The six southeastern states included are Alabama, Florida, Georgia, North Carolina, South Carolina and Tennessee. Significant portions of the other southern states are part of PJM, MISO or SPP. Therefore, the generation data from these states are not included in the analysis shown in Figures 5 and 6.

15 Source data from EIA Electric Power Monthly.

16 The generation data in Figures 5 and 6 is for the first ten eleven months only as full-year results for 2017 is not available.

Figure 6: Coal's Declining Share of the Energy Mix in the Mountain West and Southeast U.S.[17]



The use of coal to generate electricity has been in a long-term decline in the Mountain West and the Southeast, as well, a decline IEEFA anticipates will continue.

Retirements of Coal-Fired Generators Accelerated in 2017

Nearly 7,300 megawatts of U.S. coal-fired generating capacity were retired in 2017. More important, the pace of retirements accelerated; 16,600 MW of new coal retirements were announced, and more than 10,000 MW of this capacity is scheduled to be retired by the end of 2018. When combined with previously announced retirements, IEEFA expects that about 15,000 MW of coal-fired assets will be shut down this year, more than double the total closed in 2017.

Another 6,500 MW of coal-fired capacity is currently scheduled to be retired in 2019 and 2020, with an additional 4,977 MW in closures planned by the end of 2025. As will be discussed in the following sections of this review, we see coal plant retirements continuing in coming years as more and more generators find it financially infeasible to continue

[17] Source data from Electric Power Monthly.

operating in the face of increased competition from renewables and low natural gas and energy market prices. The Federal Energy Regulatory Commission's January 2018 decision to reject the Department of Energy's proposed coal plant bailouts[18] puts tens of gigawatts (GW) of additional coal-fired generators at risk of retirement.

It is also significant that a large number of recently announced retirements are of large coal-fired generators. The overwhelming majority of previously retired coal-fired plants have been smaller units.

Table 1: Large Coal-Fired Generators Slated for Retirement

Plant	Size (MW)	State	Planned Year of Retirement
Big Brown	1208	TX	2018
Monticello	1865	TX	2018
Sandow 4 & 5	1200	TX	2018
Pleasant Prairie	1184	WI	2018
St. John's River	1276	FL	2018
J.M. Stuart Units 1-4	2308	OH	2017 & 2018
Navajo Units 1-3	2250	AZ	2019
San Juan Units 1-4	1674	NM	2017 & 2022
Jim Bridger Units 1 & 2	1955	TX	2028 & 2032

[18] https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14633130

Prospects for Coal-Fired Generation in 2018 and Beyond Are Bleak

The same constellation of market forces that drove past coal plant retirements will continue to undermine the financial viability of coal-fired generators and will lead to further retirements in coming years.

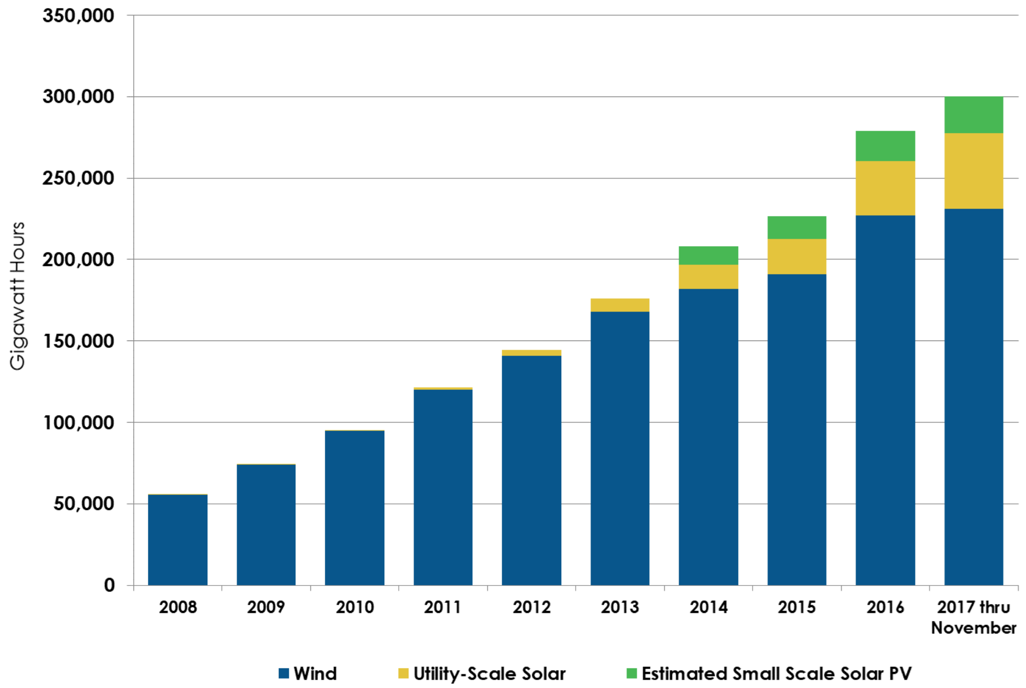
These market forces include:

- Increased competition from lower cost renewables.
- Low natural gas prices and increased competition from natural gas-fired generators.
- Low or, at best, volatile capacity market prices.
- Low energy market prices.
- Flat or nearly flat demand for electricity.

Increased Penetration of Renewable Resources Poses a Growing Threat to Coal

The U.S. electric grid's reliance on renewable energy has grown dramatically in the past decade, with generation from wind and solar resources having increased five-fold from 2008 to 2016. Wind and solar generation in the first 11 months of 2017 exceeded wind and solar production in all of 2016 by nearly 8%.

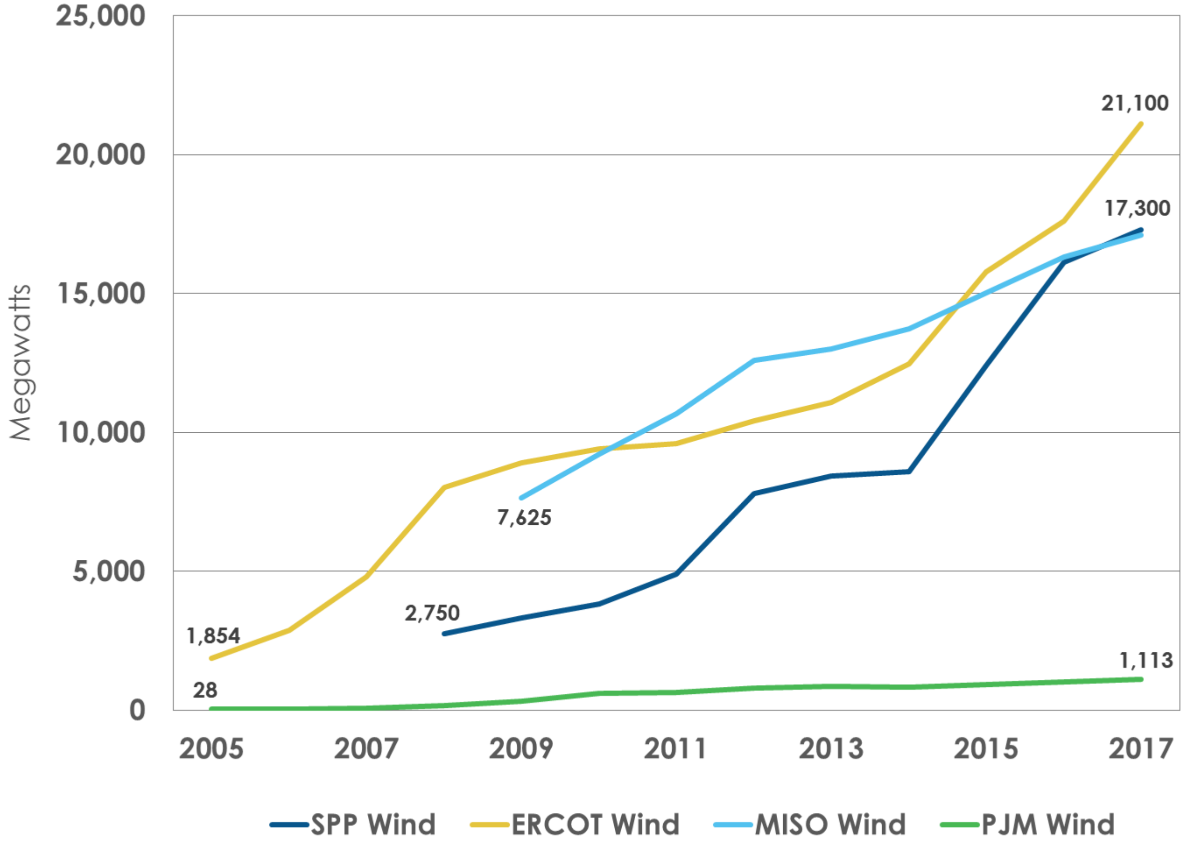
Figure 7: Annual U.S. Generation from Wind and Solar Resources[19]



[19] Source Data from Electric Power Monthly.

Installed wind capacity in SPP, ERCOT and MISO has grown dramatically in recent years. These are all areas with substantial amounts of coal-fired capacity, with which new wind farms compete. In MISO specifically, new wind-powered electricity production comes predominantly from its North Region, which extends from western Wisconsin through portions of the Dakotas into eastern Montana.

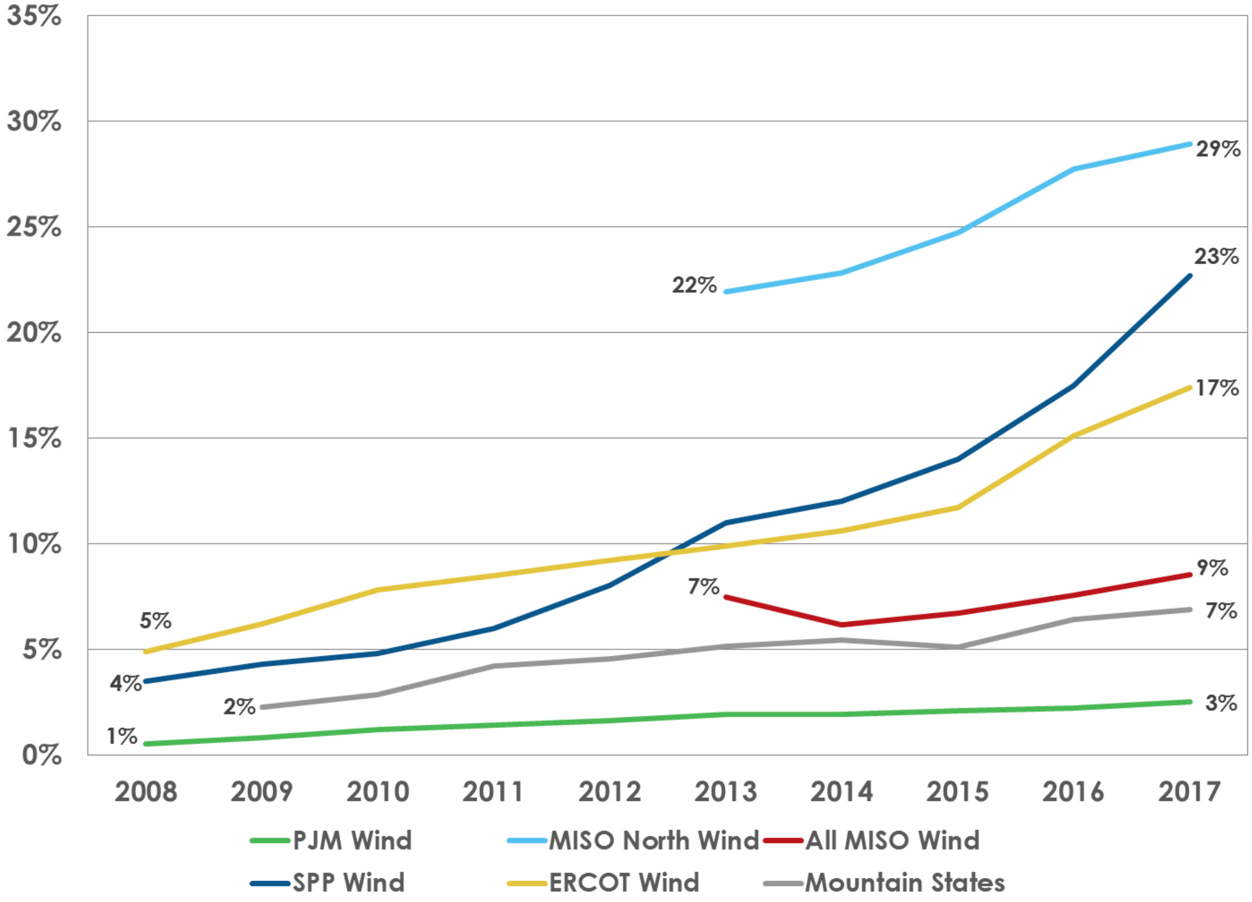
Figure 8: Increasing Installed Wind Capacity in Competitive Wholesale Markets[20]



Because wind-powered generation has no fuel costs, it is dispatched ahead of coal-fired generation. As a result, generation from wind power has displaced coal and captured growing market shares in the SPP, ERCOT and MISO North markets—areas that have the strongest on-shore wind potential in the U.S.

[20] Data from SPP, ERCOT, MISO and PJM quarterly and annual State of the Market Reports and from the ISO websites.

Figure 9: Wind's Growing Share of the Generation Mix in Competitive Wholesale Markets[21]



Through November 2017, seven states generated more than 15% of their electricity with wind power: Iowa (37%), Kansas (36%), Oklahoma (32%), South Dakota (30%), North Dakota (26%), Minnesota (18%), and Texas (15%).

Some snapshot instances from the past year that demonstrate how wind stands to dominate the electricity generation market in some of these areas: Wind power served 56.25% of the load in the Southwest Power Pool on the morning of Dec. 4, 2017, beating the previous record of 54.47%, set on April 24, 2017, and the record of 54.2% on March 19, 2017.

Although solar-power penetration in the SPP, ERCOT, MISO and PJM markets stands at less than 1%, solar also remains a risk to coal-fired electricity in these markets because it helps keep energy market prices low by displacing coal-fired generation during the peak hours of the day. This risk will grow in coming years as the installed MW of both utility-scale and distributed solar capacity rises dramatically.

Increases in installed wind and solar capacity nationally have been driven by steep declines in installation costs. The average installed cost of wind projects has dropped 333% from the peak in 2009/2010[22]. The median installed price for utility-scale solar projects has fallen by

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[21] Source data from PJM, MISO, SPP and ERCOT websites and the EIA Electric Power Monthly.
[22] 2016 Wind Technologies Market Report, Lawrence Berkeley National Laboratory, August 2017. https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf

two-thirds over the past decade or so[23]. The installed prices for small-scale distributed solar projects have also fallen.[24]

Moreover, the performance of new renewable energy facilities has improved. Wind turbine capacity factors have increased significantly as a result of design improvements such as higher hub heights and larger turbine blades. Solar capacity factors also have improved, although not as dramatically.

As a result of lower installation costs and better performance, utility-scale solar and wind power purchase agreement (PPA) prices have declined sharply in recent years. Average levelized wind PPA prices went from $70 per MWh in 2009 to about $20 in 2016. Average levelized solar PPA prices declined by 75% from 2009 to 2016 and were about $35 per MWh for projects executed in 2016.

Solar and wind PPA prices dropped further in 2017. In December 2017, Austin Energy signed a PPA for 150 MW of solar power for 15 years in a deal reported as "the lowest solar PPA the U.S. has ever seen," according to published reports.[25] Also in December, Xcel Energy reported on the results of a power-generation solicitation in Colorado in which the bids for renewable power were "incredible."[26]

The median price for wind projects in 2017 was $18.10 per MWh: for wind-plus-storage projects the median price was $21 per MWh; the median bid for solar projects was $29.50 per MWh: for solar-plus-storage it was $36 per MWh.

Some clean energy investors expect wind and solar installation costs to decline by so much that PPA prices will remain low even after wind production tax credits (PTC) and solar investment tax credits (ITC) are phased out, with unsubsidized PPA prices of $20–$30 per MWh for wind and $30–$40 per MWh for solar by the early 2020s. These unsubsidized prices would be less than the operating costs of many coal-fired generators.

Wind and solar capacity, in short, pose long-term threats to coal plants. Because they have no fuel costs, wind and utility-scale solar power is dispatched first in competitive markets, helping keep energy market prices low, as noted above, while displacing energy from coal- and even gas-fired generators.

Moody's Investors Service has concluded that declining wind generating costs put 56 GW of coal capacity in the Great Plains "at risk" of retirement[27] and that "wind power economics are driving coal generation up the dispatch curve[28] and into early retirement."[29] Utility-scale solar has an even greater impact on coal capacity, as it undercuts coal-fired generation during the traditionally highest-priced, most profitable peak hours. Generation from wind and

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[23] Utility-Scale Solar 2016, Lawrence Berkeley National Laboratory, September 2017. https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical.

[24] Tracking the Sun 10, Lawrence Berkeley National Laboratory, September 2017. https://emp.lbl.gov/publications/tracking-sun-10-installed-price.

[25] https://www.greentechmedia.com/articles/read/amidst-201-trade-case-uncertainty-austin-energy-signs-historic-low-solar-pp#gs.b60afWg.

[26] https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/.

[27] *Rate-Basing Wind Generation Adds Momentum to Renewables*, Moody's Investor Service, March 15, 2017.

[28] The dispatch curve is the order in which generating plants are brought on line to meet demand and with higher cost generators called on after lower cost ones.

[29] UtilityDive, March 23, 2017.

solar have led frequently to zero and negative energy market prices during some hours in competitive wholesale markets.

Distributed rooftop solar also undercuts the profitability of coal-fired generators. By reducing the loads on the grid, distributed solar leads to lower energy market prices at the same time it reduces demand for coal-fired electricity.

More wind and solar is coming—perhaps as much as 100 GW by 2022, according to S&P Global Market Intelligence.[30] In ERCOT alone, more than 30 GW of new wind and almost 25 GW of new solar projects are going through some form of review.[31] Studies by regional ISOs show that, with upgrades, the grid can handle substantially more renewables. Administrators of the Southwest Power Pool say that, with transmission improvements, SPP has the potential to deliver as much as 75% of its load from wind resources.[32]

A growing number of utilities and merchant generators are adopting "steel for fuel" policies—replacing fossil-fired generators with renewables—which will drive growth in renewables. That's because utilities can profit by rate-basing investments[33] in new wind resources, so many are replacing older, inefficient coal-fired plants with wind capacity.[34]

Meanwhile, as utilities have realizing that investing in renewables is profitable, more demand for renewables is coming from the corporate sector as a number of companies (including Google, Walmart, Facebook, Mars and Nestle) aim to source 100% of their electricity from renewables. It is estimated that this direct purchase of renewables from generators, which is outside traditional utility resource procurement, will grow to between 10 GW and 50 GW over the next five to seven years.

Natural Gas Prices Are Likely to Remain Low

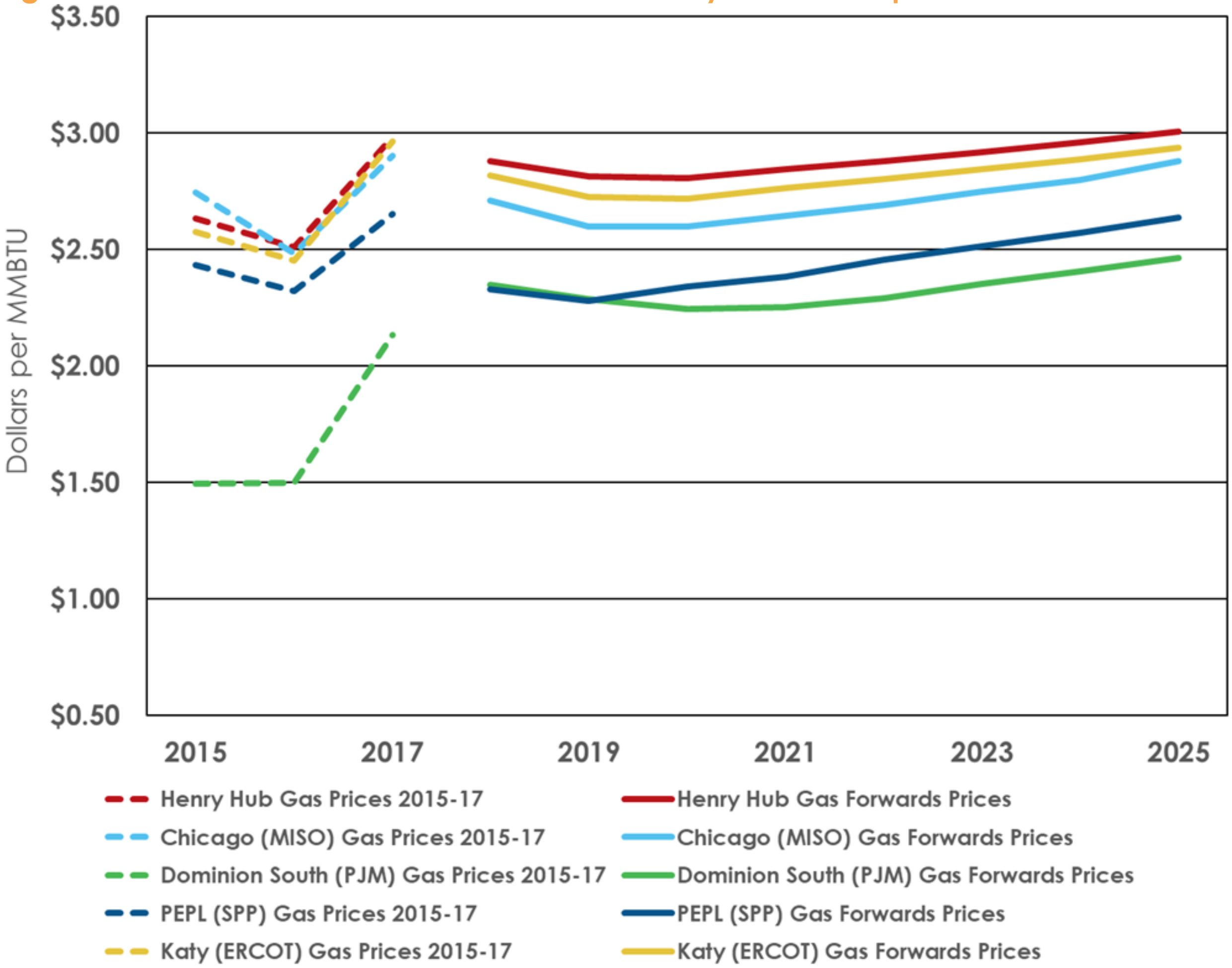
Natural gas prices collapsed in 2008 and 2009 as a result of the shale gas revolution. Except for a few spikes, prices have remained low, particularly in recent years, when average annual prices ranged from $2 to $3 per MMbtu.

While Henry Hub, in Louisiana, is considered a major pricing point for natural gas, prices at other hubs around the country also undermine the financial viability of coal-fired generators. A number of these hubs are in regions that have wholesale energy markets in which natural gas-fired plants are in direct competition with coal-fired capacity.

Figure 10 shows past and forward prices as of Jan. 2, 2018 at the Henry Hub and at hubs in four competitive wholesale energy markets with large concentrations of coal-fired capacity. As can be seen in Figure 10, natural gas prices were extremely low in 2015 and 2016, recovered somewhat in 2017, and are expected by the market to remain low for the foreseeable future.

30 SNL Financial, November 2, 2017.
31 http://ercot.com/gridinfo/resource
32 *STP Eyes 75% Wind Penetration Levels*, RTO Insider, February 20, 2017.
33 Utilities can add their capital investments to the costs used to determine the rates they can charge for power, which is an incentive for them to make capital investments.
34 *Rate-Basing Wind Generation Adds Momentum to Renewables*, Moody's Investor Service, March 15, 2017.

Figure 10: Recent and Forward Natural Gas Prices at Key Hubs in Competitive Wholesale Markets[35]



Both demand-side and supply-side factors are expected to keep natural gas prices low, according to many forecasts:

- On the supply side, technology improvements have pushed the break-even price of natural gas to below $3 per MMbtu—and even lower in Appalachia.[36] Morgan Stanley says that "$2-3/MMbtu natural gas, not $3-4, is the new normal" and has recently forecast that natural gas prices at Henry Hub will average $2.90 in 2018 and fall to $2.80 in 2019.[37] Even lower prices ($2.25-$2.50) can be expected across Appalachia.
- Significant efficiency gains in the production of shale gas were achieved in 2016. According to an analysis by Sanford Bernstein & Co., the fact that these efficiency gains were achieved amid a supply glut was "terrifying" to producers.[38] Bernstein said

[35] Prices downloaded from SNL Financial on January 3, 2018.

[36] Morgan Stanley Research, *Don't Bet Against Innovation: Sub-$3 is the New Normal* (Mar. 28, 2017), *available at* https://fa.morganstanley.com/hillgroup/mediahandler/media/41640/Natural%20Gas_Don%27t%20Bet%20Against%20Innovation_Sub-%243%20Is%20the%20New%20Normal.pdf.

[37] https://www.benzinga.com/analyst-ratings/analyst-color/17/12/10915534/natural-gas-morgan-stanleys-2018-outlook.

[38] SNL Financial, Bernstein calls shale gas efficiency gains 'terrifying' amid supply glut (Aug. 7, 2017).

that that "[t]hese gains, coming when drillers were already overproducing, "is even more bearish for our view of gas price . . ..."[39]

- On the demand side, electricity demand nationally is forecast to be essentially flat, and, even with the planned addition of approximately 20 GW of new natural gas-fired combined cycle capacity in PJM, renewables are competing directly with natural gas in major markets in the West, the Great Plains states and Texas. The hoped-for big growth opportunity for natural gas is in liquid natural gas (LNG) exports. However, while the U.S. is on track to become the third-largest exporter of LNG (after Qatar and Australia), a global glut is occurring in LNG markets, and there is not enough global demand for LNG to soak up American LNG excess and drive prices up.[40] As a result, Deloitte has concluded that "there will likely be continued record levels of production combined with historically low prices for the near to medium term."[41]
- Moody's does not expect natural gas prices to increase over the next three years, which means the ratings agency expectats that Henry Hub natural gas prices through 2019 will remain at about $3 per MMbtu or less.[42]

Low natural gas prices have disadvantaged and will continue to disadvantage coal in several ways

First, low gas prices create lower energy market prices in competitive wholesale markets because they reduce the cost of operating natural gas-fired combined-cycle plants (NGCC)—especially new, highly-efficient units that have come online in the last 15 to 20 years. These units set many hour-to-hour market prices.

Second, because these NGCC units are less expensive to operate, they are increasingly dispatched ahead of power from coal-fired plants, whose operating costs have been flat or rising. This has led to the displacement of generation at coal-fired plants.

Lower natural gas prices have made many formerly profitable coal plants operate at a loss because they generate (and sell) fewer MWh of electricity while at the same time earning less from each MWh they are selling. The U.S. Department of Energy has documented the "advantaged economics of natural gas-fired generation" as the "biggest contributor to coal plant retirements."[43]

SNL Financial has identified more than 89 GW of planned new NGCC capacity, with 28.3 GW already under construction and another 13.5 GW in advanced development.[44] 18.6 GW of this capacity is scheduled to come online just in 2018, (13 GW in PJM) with 85% already under construction.[45] The 28.3 GW of new NGCC capacity under construction includes 13 GW in MISO, ERCOT and SPP as of October 2017.[46] When these additions and other planned NGCC capacity is built, coal-fired generators will face even stronger competition from gas and greater financial peril.

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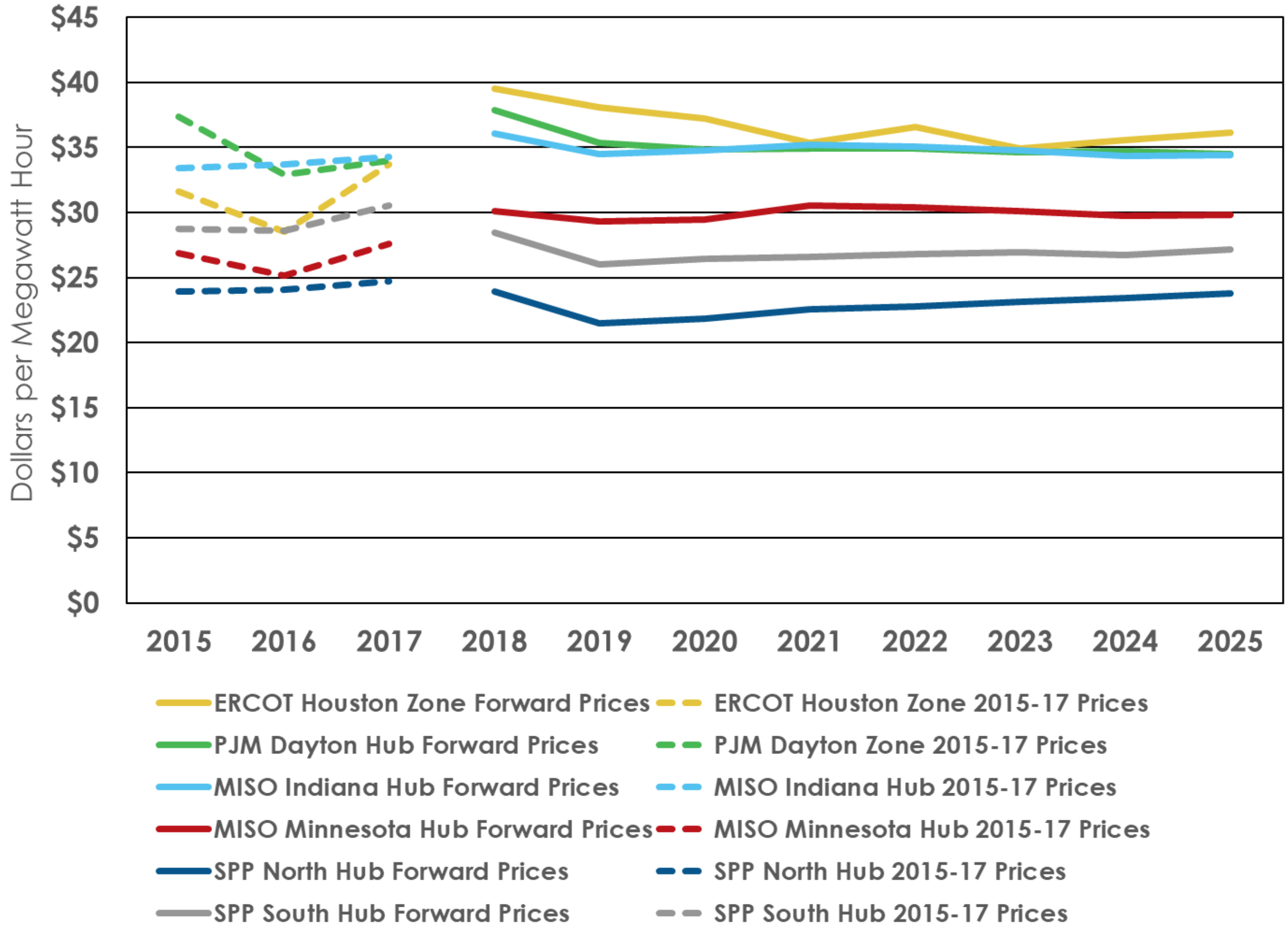
[39] *Id.*
[40] Deloitte, *Seeking Growth: What will drive US natural gas demand* (2017), *available at* https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/us-natural-gas-consumption-demand.html.
[41] *Id.* at page 5.
[42] Moody's Investors Service, *PJM Merchant Generation Facing Refinancing Risk* at page 4 (Apr. 21, 2017).
[43] DOE, Staff Report to the Secretary on Electric Markets and Reliability, August 2017, page 13)
[44] *Planned US natural gas combined-cycle capacity totals more than 89,000 MW*, SNL Financial, December 22, 2017.
[45] Id.
[46] *Gas. wind make up most of late-stage US power generation developments,* SNL Financial, October 4, 2017.

Energy Market Prices Are Likely to Remain Low

The combined effect of increased market penetration by wind and solar, low natural gas prices, and new gas-fired capacity will keep energy market prices low for the foreseeable future.

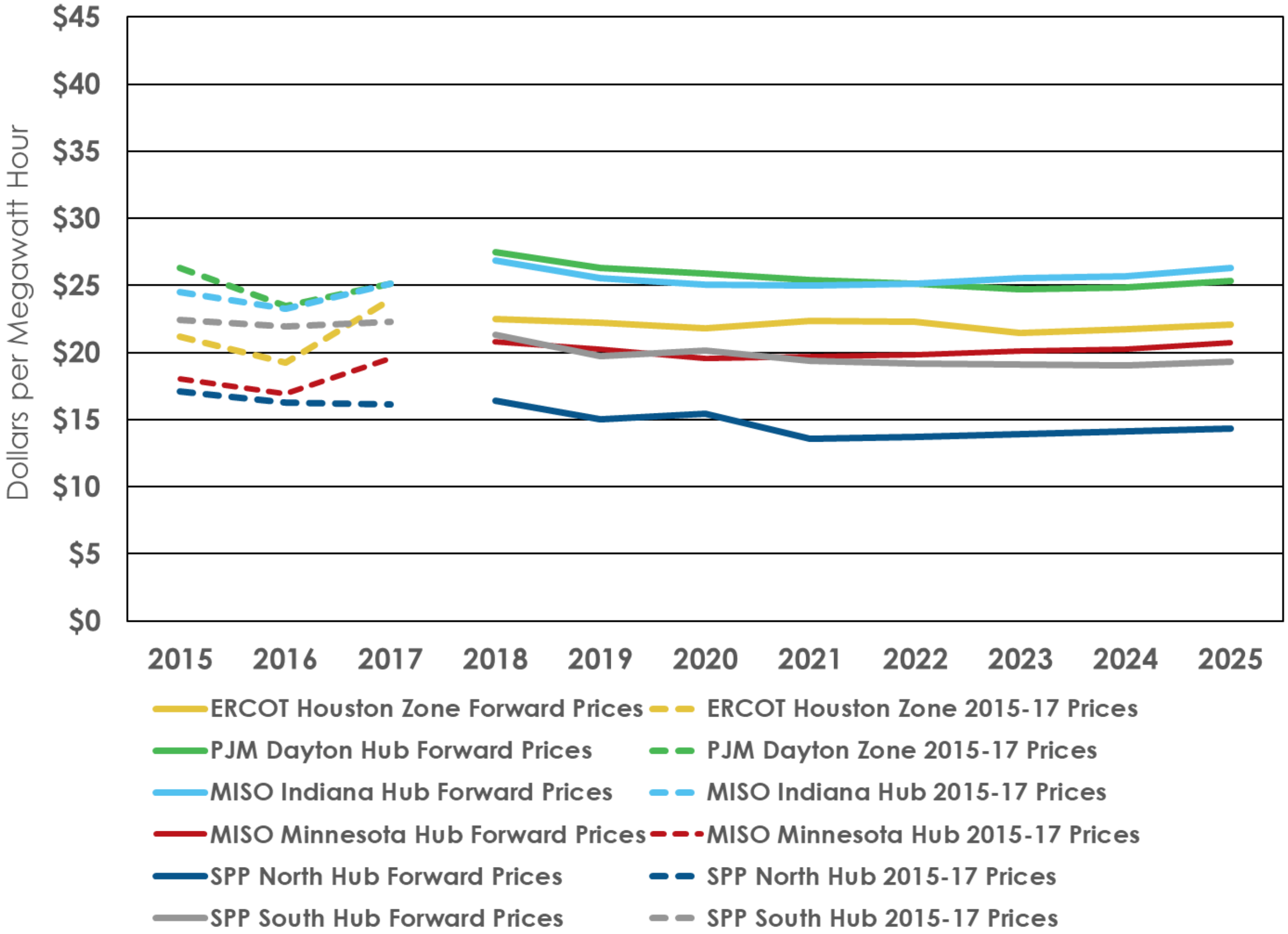
Figures 11 and 12 show forward prices through 2025 for peak and off-peak periods for six representative hubs in SPP, ERCOT, MISO and PJM as of Jan. 2, 2018.[47] These prices reflect market expectations at each of these hubs.

Figure 11: Market Expectations for Future Peak Period Energy Market Prices[48]



[47] Although each grid operator has its own definition of which hours are peak and off-peak, approximately 48 percent of the hours in a week are considered peak periods (weekdays 7am-11pm). The remaining 52 percent of hours are off-peak.
[48] Prices downloaded from SNL Financial on January 3, 2018.

Figure 12: Market Expectations for Future Off-Peak Period Energy Market Prices[49]



These figures suggest that although energy market prices may at times be a bit higher than they were in 2016 and 2017, they will remain low and relatively flat for the foreseeable future.

Low energy market prices will continue to put pressure on the ability of coal-fired generators to produce positive net earnings. Coal-fired plants can be expected to generate less power due to the increased penetration of renewables and the increased availability of lower-cost NGCC capacity. This trend will mean higher per-MWh operating costs because fixed operating and maintenance costs will be spread over a fewer number of MWh of output.

Moreover, the growing presence of renewables (wind during off-peak and solar and wind during peak hours) will lead to a greater number of hours during which energy market prices are zero or negative. In hours with negative prices, generators have to pay to continue supplying power to the grid; coal-fired generators will have to pay such costs because they are, in general, inflexible and cannot quickly respond to increases or decreases in demand.

Coal-fired generators are also disadvantaged by the fact that they have to spend millions of dollars each year in capital expenditures (capex) to replace degraded equipment or structures or to address environmental requirements. Consequently, even if a plant does

[49] Prices downloaded from SNL Financial on January 3, 2018.

generate positive earnings from its energy sales, it might not produce any net profits for its owner when these capex costs are considered.

Capacity Prices Declined Significantly in 2017 Auctions in PJM and MISO

Independent System Operators (ISOs) mange seven competitive wholesale markets in the U.S. Three of these competitive markets are for energy only. The other four have both competitive energy markets and capacity auctions, but two of these, New York Independent System Operator (NYISO) and ISO New England (ISO-NE), have very small amounts of coal-fired generating resources. PJM and MISO are the only two ISOs conducting annual capacity auctions that include substantial amounts of coal-fired resources.

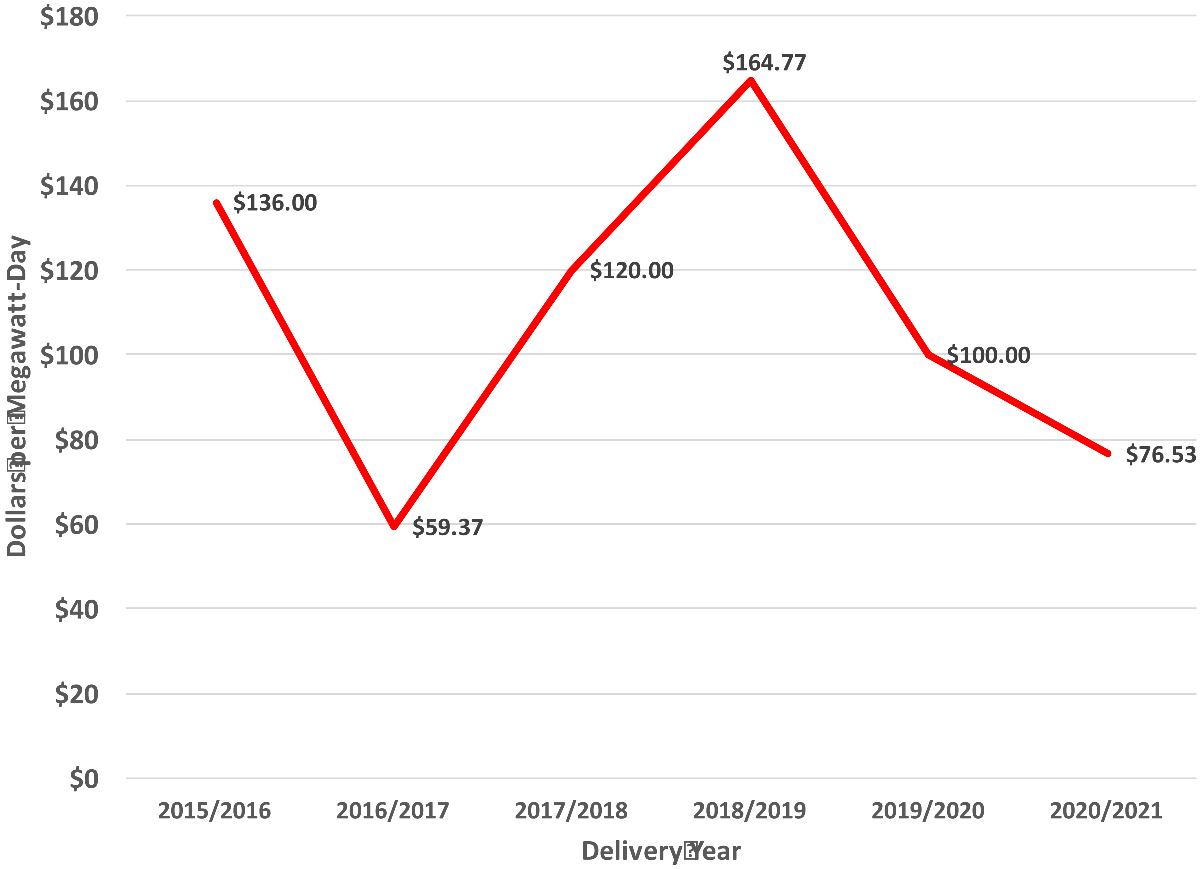
A plant owner bids its generating capacity in an auction. The amount of capacity that clears the auction is a function of an ISO's need for capacity and the supplies that are being bid by plant owners. All of the capacity that clears the auction receives whatever price is set through the competitive auction. It is possible for an entire generating unit to clear an auction and receive capacity revenues for only part of the unit's capacity (say, for example, 500 MW of a 1,000 MW plant).

Every year PJM and MISO conduct competitive auctions to acquire capacity for an upcoming planning or delivery-year. PJM's auction is for a delivery year that is three years in the future, while MISO's auction is for a planning year that starts several months after the auction is held. The capacity auction conducted by PJM in 2017 was for a delivery year that will begin on June 1, 2020, and end on May 31, 2021. The auction conducted by MISO in 2017 was to acquire capacity from June 1, 2017, through May 31, 2018.

Capacity markets can provide revenues for coal plants that would otherwise be uneconomic. However, the combination of new renewable resources and gas-fired capacity that has been added to the grid (or is under construction) and relatively flat loads has led to sharply lower prices in competitive capacity auctions managed by PJM and MISO.

For example, the May 2017 Base Residual Auction that PJM conducted for the 2020/2021 delivery year produced prices that were about 23% lower than had been set in the 2016 auction and some 54% below the capacity prices set in the 2015 auction for the delivery year 2018/2019.

Figure 13: Recent PJM Capacity Auction Results[50] [51]



This means that a typical 600 MW coal-fired plant that will receive $33 million in capacity revenues during the 2018/2019 delivery year will earn only $15.4 million in the 2020/2021 delivery year. This represents a sharp drop in revenues and could render unprofitable previously profitable units.

The situation poses even more trouble for coal-fired generation in MISO. Figure 14 shows the results of the last four MISO capacity auctions.

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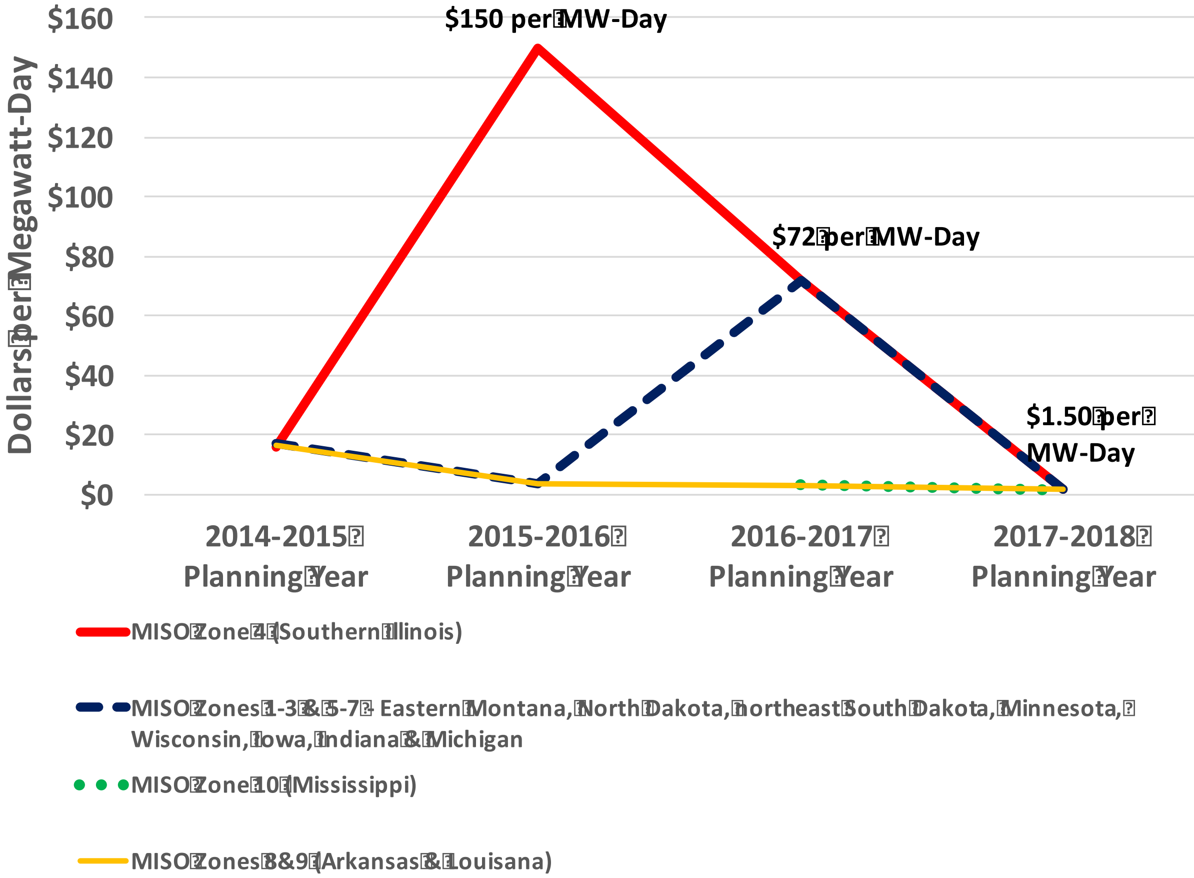
50 The prices in this Figure are for the PJM RTO region, which is the largest zone in PJM. There also are several transmission-constrained zones that do have higher capacity prices.

51 Source data from auction results reported on PJM website.

Figure 14: Recent MISO Capacity Auction Results[52]



These auction results mean that a typical 600 MW coal-fired unit in MISO Zones 1-3 & 5-7 that was earning $14.5 million in capacity revenues during the 2016-2017 planning year is currently earning a mere $302,220 in the 2017/2018 planning year.

These losses in capacity revenues severely undermine the financial viability of large numbers of coal plants and make many plant owners even more frantic in their pursuit of bailouts by state and federal governments. Moreover, the imbalance between supply of capacity and demand suggest that capacity prices will remain low in coming PJM and MISO auctions for the following reasons: (1) the expectation of flat or nearly flat loads; (2) the thousands of MW of new NGCC capacity under construction, mainly in PJM; (3) the large amount of new wind being added in the northern Zone of MISO; and (4) the fact that over 18 GW of capacity did not clear the auction, despite the fact that—by seeking a 23.3% reserve margin,[53] well above the required 16.6% reserve—PJM was agreeing to pay for additional capacity.

52 Source data from auction results reported by MISO.

53 Reserve margin is the extra generating capacity (in megawatts) a utility or RTO needs to have above the expected peak system load.

Electricity Demand Growth Has Been Slow

Faced with increasing lower-cost competition, coal-fired generators need greater demand to maintain market share. Here also prospects are bleak.

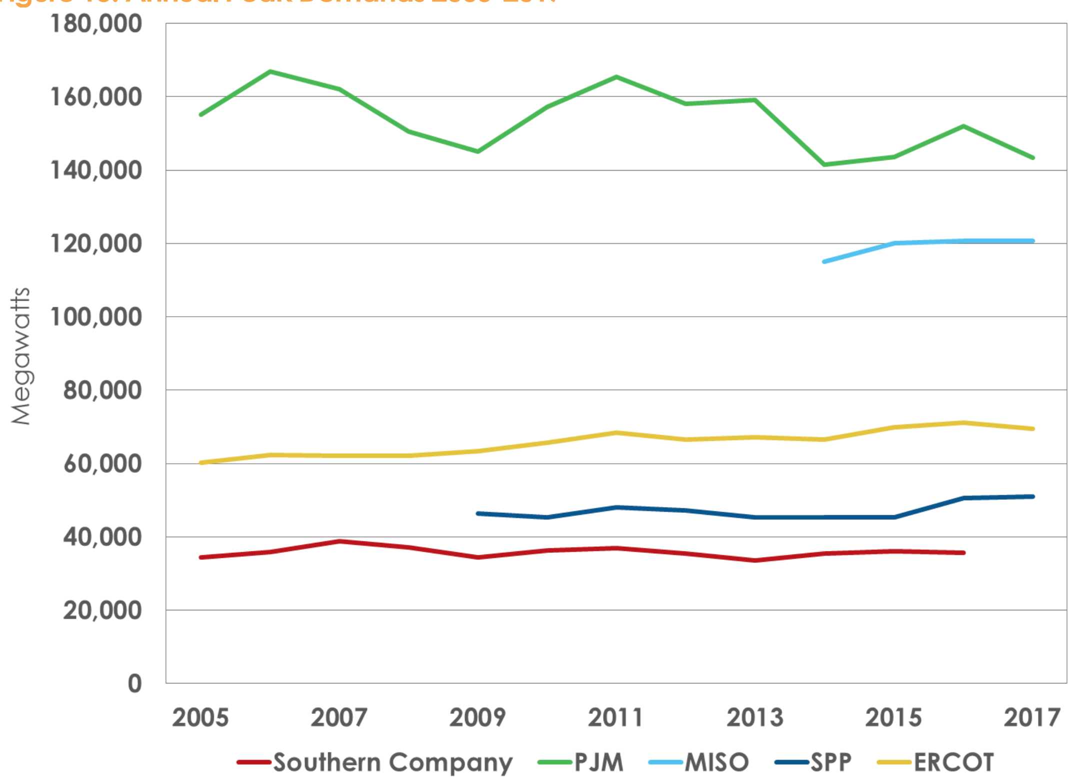
Growth in domestic U.S. electricity demand has slowed considerably in recent years. After averaging 2.5% annually in the late 1990s, growth slowed to an annual average of 1% from 2000 to 2008, and has remained relatively flat since then. In some areas, demand has actually declined. This slowing of demand has been due to a number of factors, including:

- The impact of formal energy efficiency programs and investments.
- Increased interest from consumers in saving energy.
- Rising generation from distributed rooftop solar,
- Most important, a decoupling between energy consumption and economic growth.

U.S. gross national product grew by 1.6% in 2016, while energy consumption fell by 0.2%. This decoupling has resulted from strategies of industrial customers and large utilities that have enabled them to better manage their power use, and from changing residential consumption habits. All these factors are likely to dampen future demand growth.

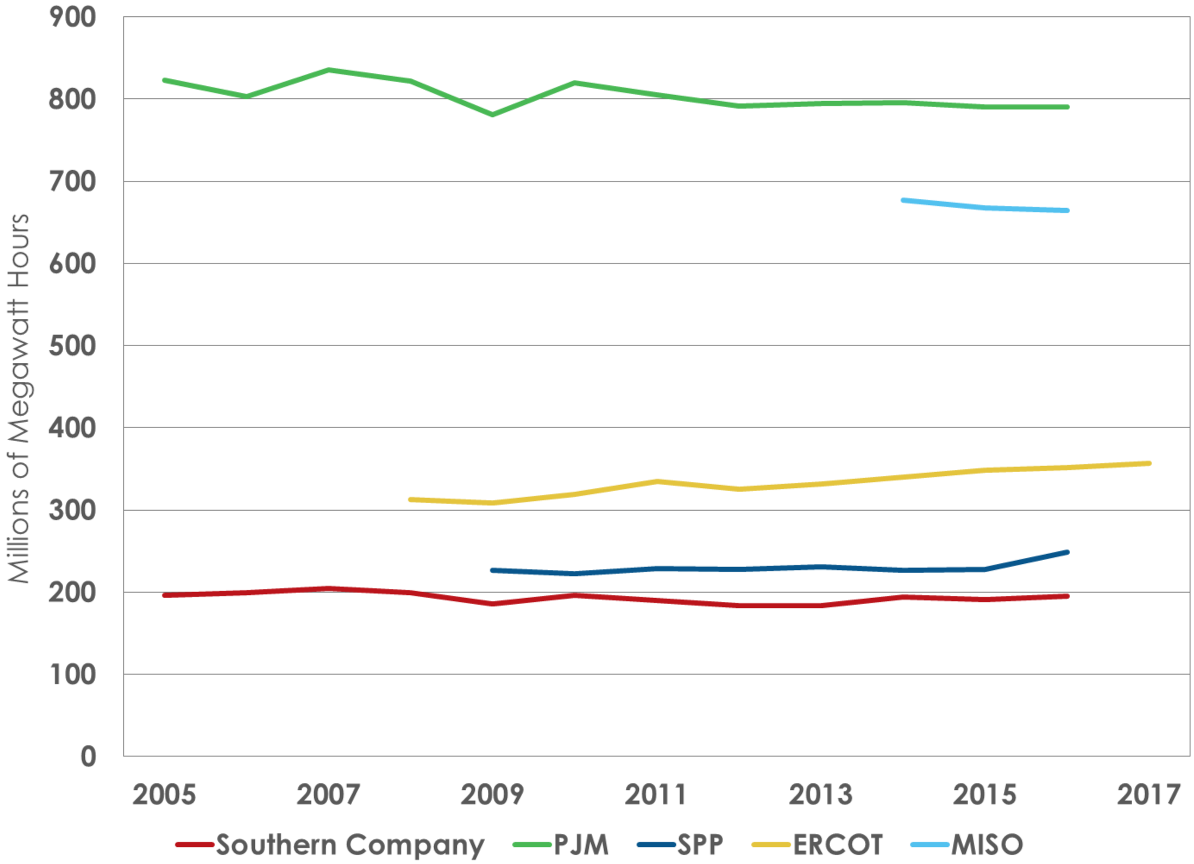
Figures 15 and 16 show the annual peak demands and energy loads for SPP, ERCOT, MISO, PJM and Southern Company (a proxy for the Southeast).

Figure 15: Annual Peak Demands 2005-2017[54]



[54] Source data from Southern Company annual 10-K reports and quarterly and annual State of the Market Reports for PJM, SPP, ERCOT and MISO.

Figure 16: Annual Energy Loads, 2005-2017[55]



Neither demand nor energy loads have seen increases in any of these five areas for more than a decade (with the exception of some growth in energy loads in ERCOT). Increases in peak demands and energy loads in SPP in 2016 and 2017 were due substantially to the addition of new utilities with additional loads and generation. The same was true for the apparent jump in MISO's annual peak demands from 2014 to 2015.

However, some insights on the 2017 energy loads in some of these areas can be gleaned from partial-year data:

- While Southern Company's third-quarter earnings report noted that the company's total energy sales for 2017 were 2% higher than in the first three quarters of 2016, its total retail sales were down 4.6%.
- Total energy loads in MISO for the first 11 months of 2017 were down about 1% compared to the same period in 2016.

This flat-to-slow growth means that as new gas-fired and renewables capacity is added to the grid, competition increases for an electricity demand pie that is not expanding much, if at all. This competition will continue to disadvantage coal-fired plants by keeping both energy market and capacity market prices low for the foreseeable future.

[55] Id.

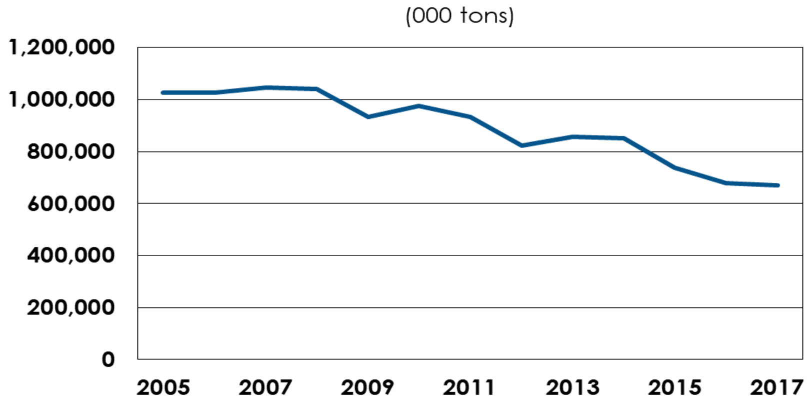
The U.S. Coal Mining Industry Will See Less Consumption & Production, Flat Employment and Distressed Assets in 2018

The changing mix of electricity generation in the U.S. has a profound impact on the coal-mining industry, including on its consumption, production and pricing.

Coal Consumption Will Drop by 30 Million Tons in 2018 and Will Continue Its Long-Term Decline

Consumption of thermal coal is down 36% in the U.S. over the past decade, declining to an estimated 666 million tons[56] in 2017 from 1.04 billion tons in 2008—an average annual drop of 37 million tons. The 666 million ton estimate of coal consumption for electricity in 2017 is the lowest consumption figure in more than a decade.

Figure 17: U.S. Coal Consumption for Electricity, 20025 - 2016



The relative flattening out of coal consumption in 2017 was attributable largely to the regional impact of increases in natural gas prices during the year. Even though the price of natural gas rose by 20% in 2017[57], coal consumption still declined.[58] Natural gas prices are

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[56] This estimate is taken from the January 2018 Energy Information Administration Short Term Outlook, Electric Power Coal Consumption (2012-2018), https://www.eia.gov/outlooks/steo/report/coal.php.

[57] (See: Figure 10: Recent and Forward Natural Gas Prices at Key Hubs in Competitive Wholesale Markets)

[58] https://www.eia.gov/outlooks/steo/data/browser/#?v=8. U.S. Electricity, Power Generation Fuel Costs, Coal and Natural Gas (2012-2018)

expected to decline again, by 4%, in 2018.[59] If this bearish price outlook is correct, natural gas prices will continue to displace coal at the dispatch.

Coal consumption is also affected by the fact that many coal-fired power plants in the U.S. are running less frequently, therefore burning less coal. Coal plant capacity factors, which measure the amount of time a plant is online, averaged in the 70% range from 2000-2008. From 2008 through 2012, however, coal plant capacity factors were in the 60% range and today they are in the lower 50% range.[60] In 2018, IEEFA expects capacity factors to continue to be in the lower 50% range.[61]

IEEFA sees 2018 as a year in which the long-term retirement of coal plants will become a more pronounced factor in the short-term consumption of coal. In 2017, 7300 MW of coal-fired generation were retired, and a total of 16.6GW of coal-generation retirements were announced. Of these, 10,500 MW are expected to close in 2018, bringing the total number of 2018 closures to 15,000 MW. While the full impact of these closures will not be evident until 2019, the effect in 2018 will be less demand for coal as operations wind down. This could result in a 2018 loss of 12 to 15 million tons of consumption and a 2019 impact of between 30 and 40 million tons.[62]

According to the EIA, renewable energy—wind and solar—will gain more than 2% in market share from 2016 to 2018, [63] and the increase in renewables will have a particularly intense impact in Texas and MISO. A 1% loss of market share for coal in the current market reduces coal consumption by approximately 20 to 22 million tons, assuming flat energy consumption.

IEEFA sees coal consumption declining by 30 million tons in 2018 due to the combined effects of lower natural gas prices, the retirement of coal-fired power plants and the growth in market share for renewable energy.[64] Of note here: The EIA recently adjusted its estimate for thermal coal down to 656 million tons in 2018, a drop of 10 million tons, or 1.5%.[65] IEEFA sees a steeper decline than the EIA predicts.

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59 See Figure 10: Recent and Forward Natural Gas Prices at Key Hubs in Competitive Wholesale Markets https://www.eia.gov/outlooks/steo/data/browser/#?v=8. U.S. Electricity, Power Generation Fuel Costs, Coal and Natural Gas (2012-2018)

60 https://www.mjbradley.com/sites/default/files/MJBAcoalretirementissuebrief.pdf

61 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a

62 See discussion in Section II: Coal Retirements

63 https://www.eia.gov/outlooks/steo/

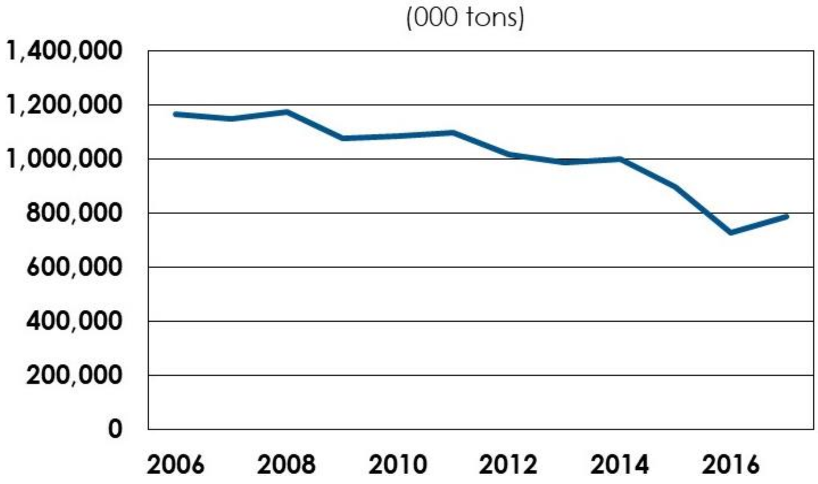
64 The many factors brandished by the coal industry as evidence of a comeback will have little to no impact on 2018 dispatch decisions. The recent actions by the Department of Energy to provide subsidies to coal plants may have future impact on coal's market share, but not in 2018. http://www.washingtonexaminer.com/ferc-chairman-proposes-interim-plan-to-keep-coal-and-nuclear-power-plants-afloat/article/2640243. Similarly, the repeal of various environmental regulations related to coal will have no positive impact for coal at the dispatch in 2018.

65 https://www.eia.gov/outlooks/steo/data/browser/#/?v=18&f=A&s=0&maptype=0&ctype=linechart

Coal Production Will Decline by as Much as 40 Million Tons in 2018

Coal production increased in 2017[66] by 56 million tons, the largest one-year increase in a decade. Coal production growth was strongest in the first two quarters, up by over 50 million tons from the same period in 2016.[67] Growth occurred in all major coal regions.

Figure 18: U.S. Coal Production 2006 - 2016



That said, the 2016 uptick is not a sign of things to come. The year-over-year growth masked quarter-over-quarter declines. From a recent peak in the fourth quarter of 2016 of 199 million tons, coal production showed a steady quarter-to-quarter decline in 2017 from 197 million tons in the first quarter[68] to 190 million tons in the fourth quarter. [69]

Much of the 2017 increase came from exports, which are expected to decline this year.

IEEFA is projecting little upside potential in 2017 and a decline in production. IEEFA presents two possible scenarios:

- The first possibility is that production will decline by 20 million tons in 2018 from 2017[70] due to three factors: low but stable natural gas prices, weaker thermal coal exports to Europe, and weak but stable electricity demand.
- The second scenario would involve a steeper decline, of 40 million tons year over year. This scenario assumes natural gas prices at the Henry Hub will decline by 4% in 2018 (prices rose by 20% in 2017).[71] At these levels, natural gas prices should result in

[66] The 2017 number is based on a recent updated end of year estimate provided by Platts Coal Trader. Andrew Moore, Weekly U.S. Coal production estimate dips as stockpiles remain high: EIA, December 14, 2017.
[67] https://www.eia.gov/coal/production/quarterly/pdf/t2p01p1.pdf
[68] https://www.eia.gov/coal/production/quarterly/pdf/t1p01p1.pdf
[69] https://www.eia.gov/coal/production/quarterly/pdf/t1p01p1.pdf, Table 1: U.S. Coal Production
[70] https://www.eia.gov/outlooks/steo/query/
[71] https://www.eia.gov/outlooks/steo/query/

reduced use of coal except for very limited time periods within a few regions. Natural gas prices throughout the country will be lower than those at the Henry Hub.[72]

This scenario includes declining energy demand and no growth in wholesale electricity prices.[73] This would give very little room for coal price increases to be passed to consumers. In this scenario, dark-spread[74] improvements will emerge only as a function of coal plant operational cost reductions. This downward pressure would maintain a ceiling on coal prices, placing producer operating margins under stress.

IEEFA's long-term outlook, through 2050, is for a steady, downward decline in coal production as more plant closures occur, natural gas prices remain relatively low, renewable energy continues to gain market share, and coal demand from utilities decreases.

The EIA presents two starkly contrasting long-term scenarios: a reference case and a scenario without the Clean Power Plan. The production for both scenarios through 2019 is basically the same: a slight rise in annual production. The potential impact of regulatory relief grows over time, by the EIA's lights, and by 2050, the difference between the reference scenario and the without the Clean Power Plan scenario would be 278 million tons in annual production.[75]

IEEFA has concluded that coal plant retirements and a lack of interest by utilities, state regulators, and capital markets in new coal plant construction will drive demand for coal lower. According to the Edison Electric Institute (EEI), of the 195 GW of new generation additions projected from 2018 to 2021, just over 1% will be new coal-fired coal plants.[76] This would occur at a time when EEI estimates at least 20 GW of coal-fired generation will be retired.[77]

The repeal of several regulatory protocols, including the Clean Power Plan, will not reverse utility decisions[78] or state public service commission policies to invest more in renewable energy, efficiency and natural gas.

Over the long term, IEEFA sees the U.S. coal industry becoming even smaller than regulatory and government projections suggest. Coal-fired power plants could be retired at a more rapid pace than current estimates by EIA, EEI and SNL.

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[72] See Figure 10: Natural Gas Prices at Key Hubs in Competitive Wholesale Markets

[73] See: Charts Figure 11: Market Expectations for Future Peak Period Energy Market Prices and Figure 15: Annual Peak Demands 2005-2017

[74] The dark spread is a common metric used to estimate returns over fuel costs of coal-fired electric generators. A dark spread is the difference between the price received by a generator for electricity produced and the cost of coal needed to produce that electricity.

[75] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=95-AEO2017&region=0-0&cases=ref2017~ref_no_cpp&start=2015&end=2050&f=A&sourcekey=0

[76] http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2016.pdf, p. 56.

[77] http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Documents/FinancialReview_2016.pdf

[78] Declaration of David Schlissel, Case No. 15-1363 and Consolidated Cases: State of West Virginia v. USEPA , December, 2015; Sweeney, Darren, "CEOs prepare for clean energy future during 'tremendous movement away from coal," SNL, November 6, 2017.

Coal Prices in the Powder River Basin, Illinois Basin and Central Appalachia Will Decline

Coal producers sell coal under long-term contracts and on the spot market. Long-term contracted coal is typically higher in price, as utilities pay a premium for supply and price stability. Contracts also historically have acted as a hedge for utilities during a rising price cycle. IEEFA focuses principally on actual prices received by coal producers, and supplements this information with spot price data to inform its conclusions about current and future price direction.

Thermal spot coal price trajectories varied in 2017. Illinois Basin spot prices declined; Central Appalachian rose; and Powder River Basin and Northern Appalachia were flat for most of the year (with PRB prices up in the latter part of the fourth quarter).

Company-reported information, driven by contract prices, shows that thermal coal prices generally declined over the past four years. The trend continued into 2017 in the Powder River Basin, Illinois Basin and among those mines serving domestic power plants in Central and Northern Appalachia.

The exceptions to the trend were company-reported increases in prices for coal mines In Northern and Central Appalachia that serve export and metallurgical customers. CONSOL[79] and Alliance Resource Partners (ARLP-APP) posted 5% and 2% price gains, respectively.

In general, prices improved for metallurgical coal and coal for export. But the thermal side of the equation generally saw continued price declines; all three of the companies with holdings in the Powder River Basin, a region that serves largely domestic coal plants, saw price declines continue for 2017 despite a late-year uptick.

[79] CONSOL reports that its overall increase in coal prices received during 2017 were driven by metallurgical and export demand. file:///C:/Users/Tom/Downloads/CEIX%20(CONSOL%20Energy%20Inc.)%20%20(10-Q)%202017-12-13%20(3).pdf, p. 34.

Figure 19: Coal Company Prices by Region, 2014 – 2017 (3Q)

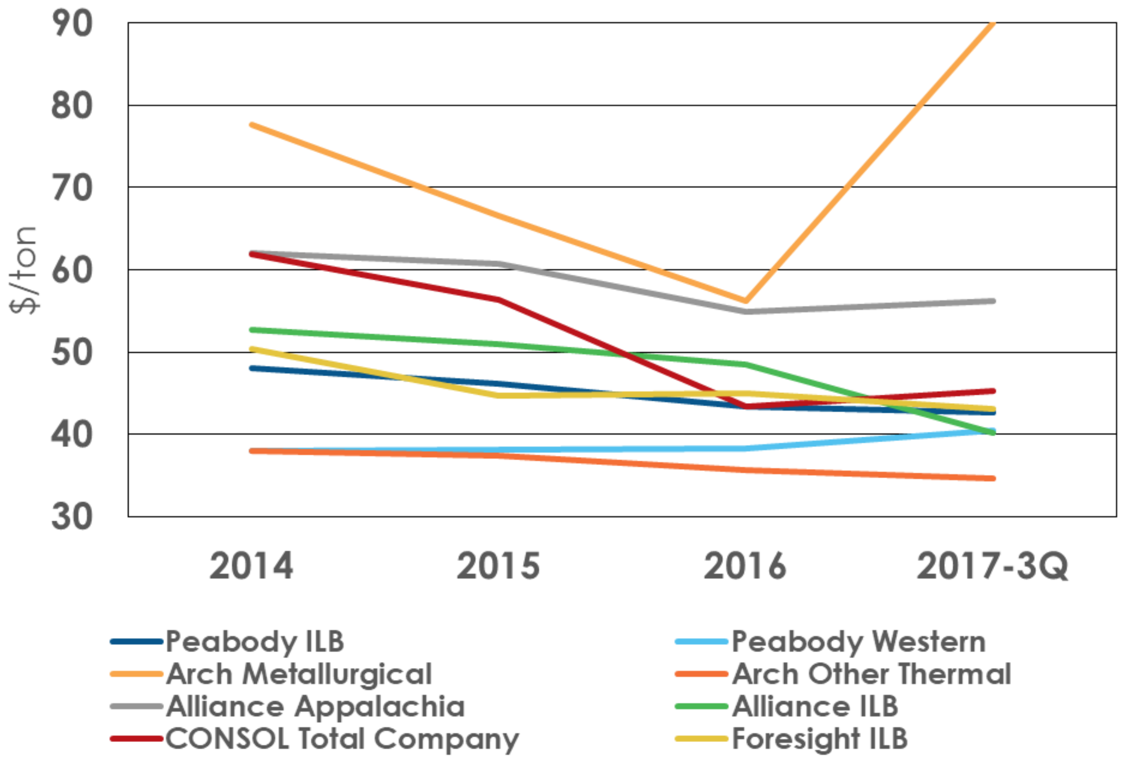
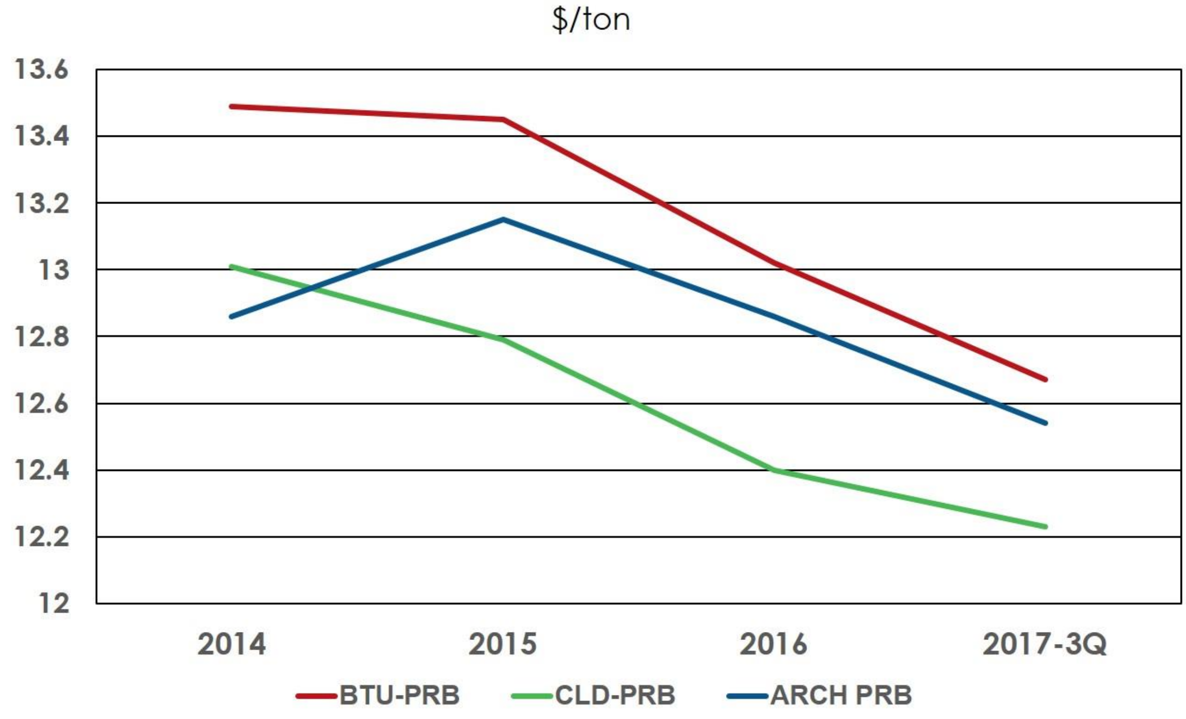


Figure 20: PRB Coal Prices by Region, 2014 – 2017(3Q)



Guidance from both Arch[80] and Peabody[81] for 2018 is for lower PRB contract prices through 2018, though spot prices are expected to be elevated at the beginning of the year. Arch and Peabody 2018 guidance is for flat Illinois Basin prices. Illinois Basin companies reported 2017 contract price declines at the same time spot prices generally underperformed.

Declines in thermal prices continued, even as Henry Hub natural gas price rose by 20% compared to 2016.[82] Henry Hub prices started the year trading in the $3.3 MMbtu range, but fluctuated to as low as $2.8 MMbtu and ended the year below $3.0 MMbtu.

Figure 10, tracks the futures contract market for Henry Hub natural gas prices through 2025. The prices in the futures market never rise above $3 MMbtu at any of the hubs. IEEFA sees low prices for natural gas persisting. Assuming that U.S. coal prices in 2018 remain in their current range, coal producers will remain under pressure to maintain cost discipline, as coal consumption is likely to decline.

While natural gas prices are the primary factor affecting coal prices, history has shown that other variables can come into play. In 2011, although the price of natural gas was in the mid-$3 MMbtu range, coal prices in the Powder River Basin were in the $14-per-ton range due to more robust annual export sales and a supportive export outlook. In 2017, improvements in Northern and Central Appalachian prices were due largely to higher-than-expected demand for exported thermal coal.

The 2017 overall price story was a rise in natural gas prices, but declining consumption. The result was flat to declining coal prices in the PRB, mostly declines but some price improvement in the Illinois basin, and rising prices in Central and Northern Appalachia driven by export price improvement.[83]

The 2017 story shows also that energy prices driven by relatively low natural gas prices (despite the 2017 increase) and wind generation additions in Texas and the Midwest are placing downward pressure on energy prices and capping upside for coal prices.

IEEFA sees a spot coal prices in 2018 declining[84] and continued deterioration in contract pricing. Natural gas prices will remain low and—as a result—utilities will have little incentive to accept higher coal spot prices or to sign long-term contracts with higher coal prices to hedge against future increases.

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80 http://investor.archcoal.com/phoenix.zhtml?c=107109&p=irol-newsArticle&ID=2312696

81 https://www.peabodyenergy.com/Media-Center/Newsroom

82 See Figure 10: Recent and Forward Natural Gas Prices at Key Hubs in Competitive Wholesale Markets, see also the changes in Henry Hub prices: https://www.eia.gov/outlooks/steo/data/browser/

83 https://www.eia.gov/outlooks/steo/report/

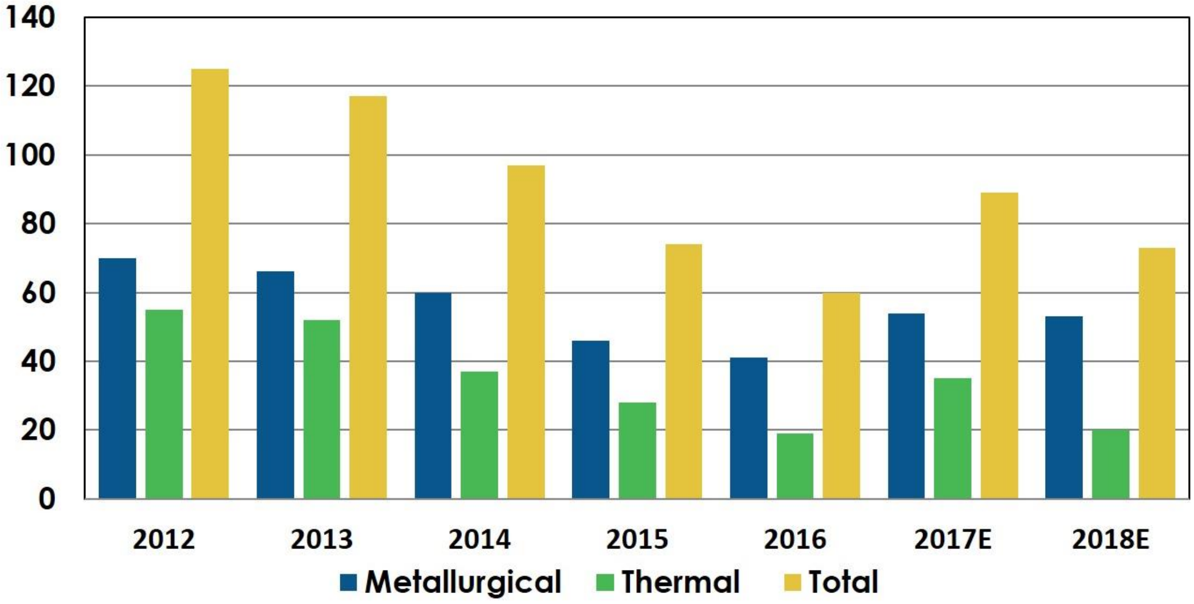
84 Annual Energy Outlook is flat https://www.eia.gov/outlooks/aeo/data/browser/#/?id=94-AEO2017&cases=ref2017~ref_no_cpp&sourcekey=0, and Short Term Outlook is slight rise https://www.eia.gov/outlooks/steo/query/

Thermal Coal Exports Rose by 48% in 2017, But Will Most Likely Decline in 2018

In 2017, U.S. coal exports increased by 48% due in large measure to an improvement in both metallurgical and thermal demand and pricing in Europe and Asia. U.S. producers saw greater demand for thermal coal from India, Japan, Brazil, Mexico, Chile and Europe in 2017. It is anticipated in 2018 that demand will decline in Europe[85] and that prices will weaken for both Newcastle[86] and API2 coal.[87]

Figure 21: U.S. Coal Exports, Metallurgical and Thermal, 2012 - 2018

(million tons)



Metallurgical and API2 coal sales have served to bolster company bottom lines in 2017. Through the third quarter of 2017, Arch Coal's metallurgical sales and exports accounted for 17% of production and 68% of company profits. Cloud Peak Energy, a U.S. producer selling into Asia, increased its thermal coal shipments to more than 4 million tons in 2017 and improved its financial position from 2016. The company nevertheless sells in the Asian export market at a loss.[88]

[85] https://www.bloomberg.com/news/articles/2017-12-18/coal-s-two-year-rally-to-end-in-europe-as-china-addiction-fades
[86] https://www.barchart.com/futures/quotes/LQ*0/all-futures
[87] http://www.cmegroup.com/trading/energy/coal/coal-api-2-cif-ara-argus-mccloskey.html
See also: https://home.kpmg.com/content/dam/kpmg/au/pdf/2017/coal-price-fx-consensus-forecast-september-october-2017.pdf
[88] http://investor.cloudpeakenergy.com/press-release/earnings/cloud-peak-energy-inc-announces-results-third-quarter-and-first-nine-months-7

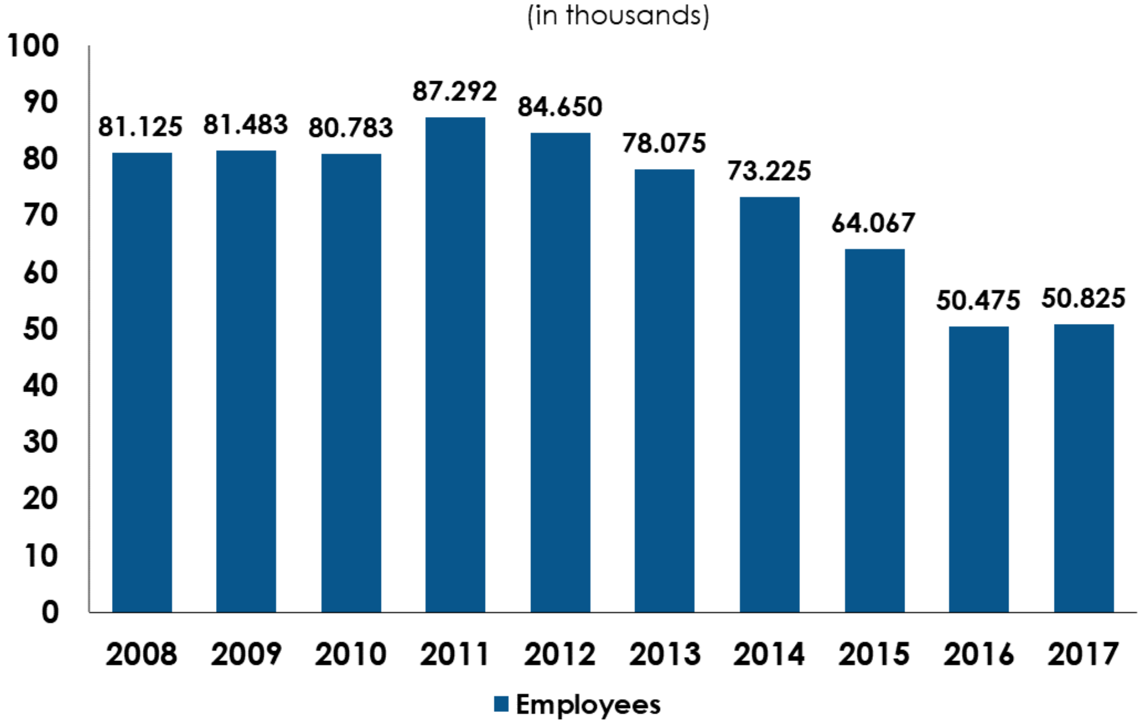
Coal Employment, Flat in 2017, Will Either Be Flat Again or Will Fall in 2018

Coal employment levels for 2017 were basically flat as compared to 2016. Jobs data over the past two years shows that coal-mine employment remains at decade lows.

The federal government publishes two versions of statistical presentations of coal mine employment. One comes from the Bureau of Labor Statistics (BLS) and another from the Mine Safety Health Administration (MSHA).[89]

The most recent Bureau of Labor Statistics figures show that the monthly average number of coal mine employees was up slightly from 50,475 in 2016 to 50,825 in 2017. This is an increase of 350 jobs in the monthly average. In 2017, coal mine employment rose every month from January to September, from 50,000 to 51,700, and then declined in each of the final three months to a BLS estimated December monthly level of 50,500.

Figure 22: Bureau of Labor Statistics: Monthly Average Number of Coal Mine Employees (2008-2017)



Bureau of Labor Statistics (https://data.bls.gov/timeseries/CES1021210001)

[89] IEEFA has offered an extended treatment of the different policy purposes and quantitative composition of each database. See: http://ieefa.org/ieefa-update-two-sets-data-tell-tale-u-s-coal-industry-continues-shed-jobs/. The overall trends show a basically flat employment picture for 2017.

Figure 23: Mine Safety and Health Administration: Average Number of Contractor and Operator Coal Mine Employees, Final for Year 2016 Compared with Data through 3Q 2017

Type of Coal Employee	Average Full Year 2016	Through 3Q 2017
Contractor	27,836[90]	25,676[91]
Operator	54,051[92]	54,689[93]
Total	**81,887**	**80,365**

The most recent Mine Safety and Health Administration jobs data shows that for 2016 the average number of mine employees (Contractor, Operator and Office Workers) was 81,887. By the end of the third quarter of 2017, (the most recent published data) coal mine employment decreased to 80,365, a loss of 1,522 employees, or 2%. The final data for 2017, including fourth quarter employment performance, will be available in the spring of 2018.

IEEFA projects that coal employment will continue to be flat or will decrease in 2018.

The Investment Market for Coal Shows Signs of Severe Weakness

The U.S. coal industry's claims of recovery are manifested in several ways:

- The industry applauded the reversal in 2017 of various federal actions taken to restrict, waive or eliminate environmental and financial regulations implemented under the prior administration.
- The industry is openly hoping that more federal actions will be taken to subsidize coal by enacting favorable rules through the Federal Energy Regulatory Commission (FERC), despite the recent rejection of one such proposal.
- Coal industry leaders Peabody Energy and Arch Coal improved their operating profits after emerging from bankruptcy and writing off liabilities ($8 billion for Peabody and $5.3 for Arch[94]).

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90 https://arlweb.msha.gov/STATS/PART50/WQ/2016/table5.pdf
91 https://arlweb.msha.gov/STATS/PART50/WQ/2017/table5.pdf
92 https://arlweb.msha.gov/STATS/PART50/WQ/2016/table1.pdf
93 https://arlweb.msha.gov/STATS/PART50/WQ/2017/table1.pdf
94 http://investor.archcoal.com/phoenix.zhtml?c=107109&p=irol-SECText&TEXT=aHR0cDovL2FwaS50ZW5rd2l6YXJkLmNvbS9maWxpbmcueG1sP2lwYWdlPTExMjIwNzkwJkRTRVE9MCZTRVE9MCZTUURFU0M9U0VDVElPTl9FTlRJUkUmc3Vic2lkPTU3

- U.S. coal producers reported increased exports of both metallurgical and thermal coal over the past year.
- The equity values of some coal stocks improved as the year closed.
- CONSOL and Warrior Met Coal maintained access to the capital markets with successful placements. Both companies rely heavily on exported metallurgical and thermal coal sales.
- A wave of bankruptcies came to a halt, with only Armstrong Energy filing during 2017.[95]

Negative Financial Events Are Widespread

A series of significant negative financial events occurred during 2017 that indicate that if any industry recovery is to take place it will be a long and bumpy road. In sum, if there were good prospects for a coal recovery, there would be a robust market for coal assets. As the transactions below indicate, there isn't.

Peabody Energy Wrote Off $6.5 Billion in Value in its Land and Coal Interests

The major storyline for Peabody Energy in 2017 was the write-off of $8.4 billion in liabilities through bankruptcy. This write-down created value destruction for investors. A largely overlooked effect was the company's reassessment of its asset values in the wake of the structural decline of the industry.

Through "fresh start"[96] accounting, the company wrote off an additional $6.5 billion in the asset value of its U.S. and Australian land and coal interests, from $10.3 billion to $3.8 billion, a 63% drop in value (and Peabody took an additional $2.2 billion in the write down of its buildings and machinery).[97]

A recent company investor presentation[98] put the company's reserves as of December 2016 at 5.7 billion tons. A 63% write-down in the value of coal assets should indicate that at least some portion of the company's physical reserves are no longer economically viable, and that therefore the company's 2017 year-end statements should show a reduction in its reserves to reflect that new reality.

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[95] https://www.prnewswire.com/news-releases/armstrong-energy-files-for-chapter-11-reorganization-as-part-of-strategic-transaction-300547448.html

[96] https://www.peabodyenergy.com/Investor-Info/Financial-Information/SEC-Filings, Form 10Q for the nine months ending September 30, 2017, November 3, 2017, p. 6.

[97] https://www.peabodyenergy.com/Investor-Info/Financial-Information/SEC-Filings, Form 10Q for the nine months ending September 30, 2017, November 3, 2017, p. 20

[98] https://www.peabodyenergy.com/Peabody/media/MediaLibrary/Investor%20Info/Cowen-Conference-Nov-2017_FINAL_1.pdf

Further adjustments to the company's bankruptcy plan, asset valuation and reserve levels can be expected in 2018.

Contura Transferred Eagle Butte and Belle Ayre Mines to New Owner in the First Negative Valuation of 8400 BTU Coal in the Powder River Basin

Coal companies in the Powder River Basin (PRB), like the rest of the coal industry, have seen declining production. The Powder River Basin nevertheless remains the most prolific coal production region in America. The recent transfer of Contura's PRB assets to another company is the first known PRB transaction based upon a no-cash transfer of liabilities and a posted loss by the seller. It is in IEEFA's estimation a negative value transaction, underscoring ongoing financial fallout from the sector's declining competitiveness.

In late 2017, Contura Energy, a bankruptcy spinoff of Alpha Natural Resources, transferred its Eagle Butte and Belle Ayre mines to Blackjewel, LLC, a newcomer to the Powder River Basin. The transaction transferred the liabilities of the mine to Blackjewel and promised future revenue payments to Contura. The deal did not require any financing. Contura announced it would take a write-off on the value of the mines. This transaction was a reversal of Contura's previous position. When it was created as part of Alpha's emergence from bankruptcy in January 2017, the company said it would not pursue further divestment or acquisitions.[99] Moody's downgraded Contura after it transferred the mines to Blackjewel because Contura is no longer diversified and depends solely on its eastern metallurgical assets.[100]

During bankruptcy, Alpha Natural Resources also pledged to rid itself of failing coal reserves. In 2017, the company paid Revelation Energy $200 million to take over several mines in eastern Kentucky.[101]

Murray Energy's Proposed Acquisition of Bowie Resources Collapsed as Investors Said 'No'

In November 2017, Bowie Resource Partners announced that Murray Energy would take over its Utah operations. Murray was not putting up any cash in the deal, which was to be financed with $510 million in a bond issuance. The issuance was meant to pay off current notes to Trafigura Ltd. (which have a 2020 maturity date) and to cash out Trafigura, which had financed Bowie's operations. The deal collapsed.[102]

The market signal from this transaction was that coal reserves owned by both Bowie and Murray Energy in Utah[103] are largely unbankable.[104] Trafigura, a commodity-trading firm, now

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[99] http://www.heraldcourier.com/news/alpha-contura-sounding-an-optimistic-note/article_7fdbc68d-bcee-5030-b698-cbfb0518dbae.html
[100] https://www.moodys.com/research/Moodys-downgrades-Contura-CFR-to-B3-from-B2-outlook-stable--PR_377046
[101] https://www.platts.com/latest-news/coal/houston/revelation-to-acquire-lone-mountain-other-arch-26778782
[102] https://www.wsj.com/articles/coal-company-bowie-resource-partners-pulls-debt-deal-backing-takeover-1510354844?shareToken=st79479f5100f14b629ee643c4047cd308&reflink=article_email_share&mg=prod/accounts-wsj
[103] http://ieefa.org/ieefa-note-arizona-colorado-new-mexico-utah-looking-end-coal-industries/
[104] http://ieefa.org/ieefa-update-coal-deal-collapsed-almost-overnight/

faces the choice of either waiting until 2020 for improved market conditions or acting now in the face of market evidence that the value of its investment is substantially impaired.

The Collapse of Bowie's Proposal to Buy Peabody Holdings in 2016 Was a Sign of Impaired Values of Western Coal Holdings

In 2016, a deal for Bowie Resources to buy three coal properties in Colorado and New Mexico from Peabody Energy fell apart. The $358 million transaction failed because Bowie was unable to find investors willing to finance the deal. The collapse of this deal was a triggering event for Peabody's bankruptcy filing.

Peabody's Kayenta Mine in Arizona is Likely to Shut Down Due to Planned Closure of the Navajo Generating Station

In 2017, the owners of the Navajo Generating Station (NGS) in Arizona decided to close the 2,250 MW coal-fired plant by 2019.[105] The plant is served exclusively by Peabody Energy's Kayenta mine. The mine, which produced six million tons of coal at its peak,[106] will likely close as well, since its only customer is NGS. Peabody Energy is seeking a new owner for the plant and mine, but to date no new owner or financial commitments have been announced. The plant and mine closure are slated for the end of 2019.

Westmoreland's Mines Hit by Closed Plants and Customer Losses

Westmoreland Coal, which sells to coal-fired power plants across many states, lost significant parts of its customer base in 2017 as some plants closed and other customers moved their business to competitors.

Announced plant closing will result in the loss of more customers. This negative news left the company with late-year credit downgrades and discussion of a potential Chapter 11 filing.[107] The year closed with a heavy influx of hedge fund investors pursuing short-term investment strategies.[108]

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105 http://ieefa.org/ieefa-report-end-era-reti -generating-station-vast-subsidies-required-keep-aging-plant-online-retirement-seen-viable-option/
106 http://ieefa.org/ieefa-report-kayenta-mine-unlikely-find-new-customers-navajo-generating-station-closes/
107 https://www.denverpost.com/2017/12/22/montana-coal-mine-expansion-approved/
108 https://www.dispatchtribunal.com/2017/12/24/macquarie-group-ltd-invests-531000-in-westmoreland-coal-company-wlb.html

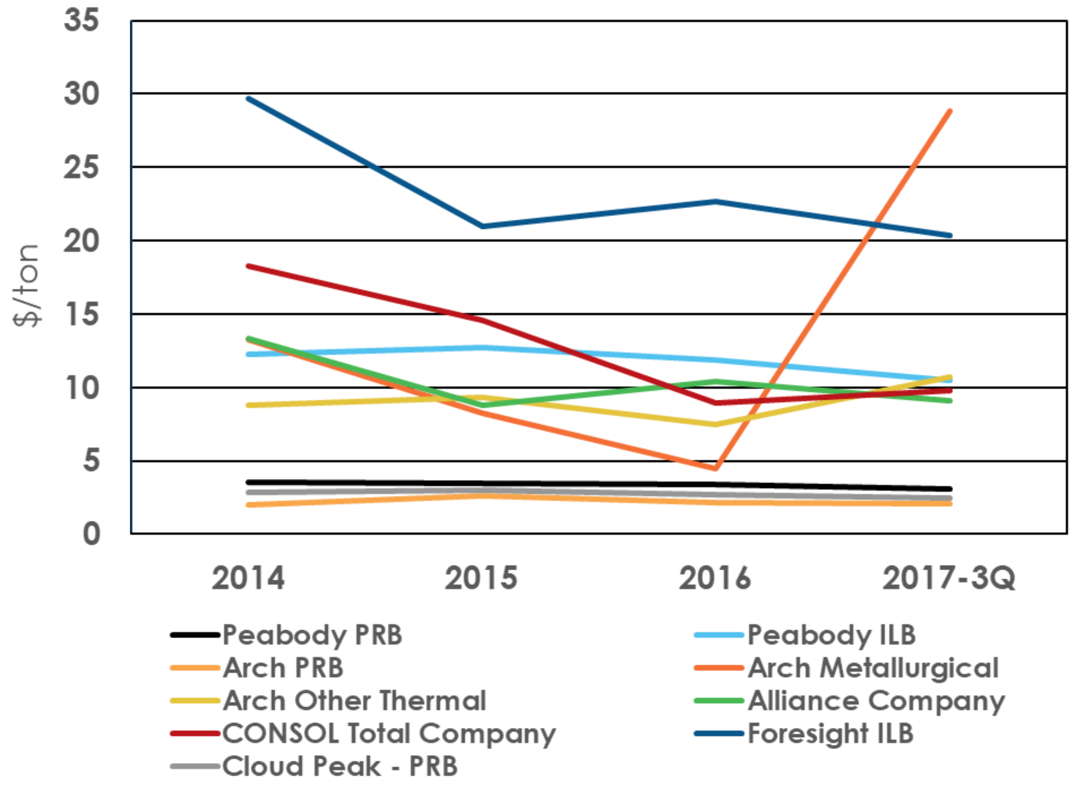
Coal Stock Price Increases Will Be Short-Lived

Coal stock indexes rose during the fourth quarter of 2017. Peabody Energy and Arch Coal stock prices have generally gone up since each company exited bankruptcy.[109] Both Peabody and Arch showed improvements in their cash positions in 2017, a reflection of higher global metallurgical and thermal export prices. But both companies continued to experience weak performance in their U.S. thermal portfolios.

A closer look at the industry uptick shows that several coal companies—Cloud Peak Energy, Alliance Resources and Foresight Energy—continued to underperform the stock market as the long-term coal investment outlook remains bleak.[110]

We expect recent stock price increases to be short lived as domestic sales will continue to decline in 2018, and we expect price decreases for metallurgical coal exports and decreases in the volume of thermal coal sales to Europe.

Figure 24: Coal Company Margins by Region



[109] https://www.bloomberg.com/news/articles/2017-11-10/america-s-coal-miners-are-profiting-and-looking-for-investors
[110] Taylor Kuykendall, *'A few puffs yet on that cigar': Investors comb U.S. coal for value,* SNL Energy, January 17, 2018.

As shown in the coal company margin table above, margin increases have occurred for companies with metallurgical holdings and thermal export business (Arch, CONSOL). For companies with largely thermal coal holdings, margins remain flat or are declining.

Longer-term stock and financial performance of coal producers will remain capped by the rising market share of renewable energy, limited upsides for exports and no planned capex investments by utilities in the coal sector.

In the post-bankruptcy coal market, many companies are trying to maintain and attract investors by concentrating on dividends and other strategies to bolster investor confidence. With tight margins in U.S. domestic coal markets, an emphasis on dividend payments attracts short-term investors and limits capex expenditures for efficiency upgrades or new mines. This only underscores the limited long-term potential of coal investments.

Federal Regulatory Changes Will Not Bring Industry Relief

On January 20, 2017, a new administration took office in Washington, promising to cut taxes, rescind regulations and promote pro-growth macroeconomic policies. It also promised to support coal and, in so doing, to rollback several initiatives by the previous administration that were seen as detrimental to the coal industry.

IEEFA's 2017 coal outlook concluded that regulatory relief initiatives being contemplated at the time would not stop the decline of the coal industry.

The new administration promised the following pro-coal changes:

- A study of the nation's grid system and new pro-coal and pro-nuclear policies ostensibly to improve resiliency.
- An end to the federal moratorium on federal coal leases.
- Rescinding of the Clean Power Plan.
- Rescinding of the prior administration's plan to reform the federal public coal royalty program.
- Rollback of environmental regulations designed to protect water quality
- Issuance of an "energy Independence: executive order

These initiatives—and the results of each—are described below.

Department of Energy Grid Study and Recommendations for Resiliency

In 2017, the Department of Energy (DOE) published a study[111] that purported to examine the resilience and reliability of the nation's electricity grid. The agency then proposed a plan to would provide subsidies to coal and nuclear plants, seeking fast-track approval for a rule from the Federal Energy Regulatory Commission to take "action to ensure that the reliability and resiliency attributes of generation with on-site fuel supplies are fully valued." The DOE proposal required regional markets to guarantee full recovery costs and profits on power generators that maintained 90-day on-site fuel supplies.

The initiative was hailed by Robert Murray, CEO of Murray Energy, who said his company faced bankruptcy without such a rule in place. Murray said he saw it as a way to correct "imbalances from unreasonable and unsupportable market mechanisms."

The DOE proposed the bailout even though an August 2017 study had found that environmental rules had not been a significant cause of coal and nuclear plant retirements. The author of that study said that coal plants that have closed in response to new environmental regulations "were all failing economically" and that their operators had used regulatory compliance deadlines as a logical date to close them.[112] The author also stated that coal and nuclear plants that would have benefited from the DOE proposal "cannot provide the essential resiliency and reliability" required of the grid, adding that "Coal and nuclear plants are just not good at anything but spinning reserve. They can't do anything except generate electricity that was once cheap and now ain't so cheap relative to the other stuff.[113]"

The proposed rule was widely opposed by state governments [114] and a host of natural gas and renewable energy organizations.[115]

Many of these groups opposed the proposal as an expensive bailout for old, inefficient coal and nuclear plants, arguing that it would damage and possibly wreck competitive power markets. Monitoring Analytics LLC, the market monitor for PJM Interconnection estimated that, depending on the precise rule adopted, electric customers in PJM could pay anywhere from $10 billion to $288 billion over 10 years to subsidize the continued operation of coal and nuclear plants that fell within the scope of the proposed rule.[116]

In January 2018, FERC unanimously rejected[117] the proposed rule, finding that it would not improve grid resiliency if implemented and that it failed to meet various statutory standards for either a current reliability concern or how the current rate structures created an unjust

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111 https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf
112 *Author Describes Writing Controversial DOE Grid Reliability Report*, Forbes, 12 November 2017
113 Id.
114 http://www.powermag.com/what-states-told-ferc-about-the-does-grid-resiliency-rule-infographic/?pagenum=2
115 https://www.reuters.com/article/us-usa-powergrid-ferc/gas-renewable-groups-oppose-u-s-does-call-to-support-nuclear-coal-idUSKCN1C72RK
116 Comments of the Independent Market Monitor for PJM in Federal Energy Regulatory Commission Docket No. RM18-1-000
117 https://www.washingtonpost.com/news/energy-environment/wp/2018/01/08/trump-appointed-regulators-reject-plan-to-rescue-coal-and-nuclear-plants/?utm_term=.f4feeb1aee2b

and unreasonable discriminatory imbalance.[118] Murray and FirstEnergy (an Ohio-based utility) issued statements critical of the decision that also said more coal plant retirements were likely. Murray, however, did not repeat previous assertions that his company would go into bankruptcy in the absence of the rule.

FERC also said in its decision that it would initiate an investigation into the grid-resiliency claims, and a DOE representative continued to suggest that FERC's market management created price distortions that undermined resiliency. These assertions were dismissed by the commission in its 5-0 vote. [119]

Lifting the Moratorium on Federal Coal Leases

The new administration in Washington shortly after taking power cancelled a moratorium on federal coal leasing that had been imposed by the prior administration. The moratorium stemmed from a series of audits and reviews of the federal coal lease program that found the program was selling federal coal to mining companies at below-market rates and had failed on a number of other important accountability measures.

The reversal of the moratorium has not spurred a wave of new lease applications, however. Instead, four companies—Contura Energy, Cloud Peak Energy, Kiewit Mining Group and Arch Coal—have cancelled active lease applications[120] due to weak market conditions. This was in stark contrast to the way markets responded the last time federal officials canceled restrictions on lease applications, in the late 1980's. Then, the Department of Interior saw a significant rise in the number of new applicants, reflecting increased demand for coal. A number of extensions of leases have been approved since the new administration's decision, all based on applications already in the pipeline.

Rescinding the Clean Power Plan

The new administration has moved also to rescind the prior administration's efforts to curb carbon emissions. The Environmental Protection Agency (EPA) has now rescinded the Clean Power Plan[121] and is working to replace it with a new program by the end of 2018. Any new plan by the administration would meet with extended litigation,[122] and the consensus among utility executives is that they are not changing investment plans that currently do not include any new coal-fired generation.[123] Many states have decided to comply with the plan even as it is being challenged.[124]

118 https://www.ferc.gov/CalendarFiles/20180108161614-RM18-1-000.pdf
119 https://www.kallanishenergy.com/2018/01/11/murray-blasts-ferc-for-killing-support-for-coal-nuclear/
120 http://ieefa.org/ieefa-update-federal-coal-policy-reversals-trump-handing-snowballs-blizzard/
121 https://www.utilitydive.com/news/pruitt-axes-clean-power-plan-asks-industry-to-shape-replacement/506916/
122 https://www.politico.com/story/2018/01/05/epa-climate-rule-2018-327113
123 https://news.stanford.edu/2017/10/12/effects-rolling-back-clean-power-plan/
124 https://insideclimatenews.org/news/22102015/states-challenge-clean-power-plan-also-comply-obama-administration-coal

Rescinding Reforms of the Coal Royalty Program

In August, the Department of Interior (DOI) rescinded the prior administration's rules on valuation of exported coal. The old rule had been aimed at closing a loophole that allowed coal companies to avoid royalty payments to the federal government on export sales.[125]

Rescinding the rule will allow for a business-as-usual approach to royalties on coal sold for export. In 2017, under the business-as-usual rule, Cloud Peak Energy exported 3.3 million tons of U.S. coal, and according to Cloud Peak's third-quarter 2017 filings, the company continued to export coal, citing improved market conditions and pricing. The company's export sales for the first nine months of 2017, however, continued to post financial losses.[126]

Rollback of Environmental Regulations Designed to Protect Water Quality

The new administration enacted legislation repealing the Stream Protection Rule, which had gone into effect in January 2017 under the Office of Surface Mining Reclamation and Enforcement.

[127] The rule was designed to protect communities from the deleterious effects of mountaintop mining on local water systems. The new administration is also working to overturn various other clean water actions taken by the prior administration.[128]

While harmful to the environment, these regulatory actions have proven to be ineffective and impractical tools to reverse the fundamental economic problems the coal industry faces.

In the short term, it is clear that these changes will not offset coal market losses, which are driven by low natural gas prices, rising investment in increasingly affordable renewable energy, and the resulting low energy prices. It is possible that the cumulative effect of the reduced regulations could marginally reduce coal's costs and create some upside potential, but it is unlikely that these changes will be enough to overcome the intense and growing competition from low natural gas prices and the declining costs of renewables in a flat market for energy.

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[125] https://www.doi.gov/pressreleases/interior-repeals-defective-federal-mineral-valuation-rule
[126] http://investor.cloudpeakenergy.com/press-release/earnings/cloud-peak-energy-inc-announces-results-third-quarter-and-first-nine-months-7
[127] https://www.osmre.gov/programs/rcm/streamprotectionrule.shtm and http://www.register-herald.com/news/contemplating-trump-signs-repeal-of-clean-stream-law/article_5225bd4d-e767-5a21-af32-c1ec5a049997.html
[128] https://www.apnews.com/e3f97d87ee884445b80a0826e5d4eeac

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David Schlissel, director of resource planning analysis for IEEFA, has been a regulatory attorney and a consultant on electric utility rate and resource planning issues since 1974. He has testified as an expert witness before regulatory commissions in more than 35 states and before the U.S. Federal Energy Regulatory Commission and Nuclear Regulatory Commission. He also has testified as an expert witness in state and federal court proceedings concerning electric utilities. His clients have included state regulatory commissions in Arkansas, Kansas, Arizona, New Mexico and California. He has also consulted for publicly owned utilities, state governments and attorneys general, state consumer advocates, city governments, and national and local environmental organizations.

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Tom Sanzillo

Tom Sanzillo, director of finance for IEEFA, is the author of several studies on coal plants, rate impacts, credit analyses, and public and private financial structures for the coal industry. He has testified as an expert witness, taught energy-industry finance training sessions, and is quoted frequently by the media. Sanzillo has 17 years of experience with the City and the State of New York in various senior financial and policy management positions. He is a former first deputy comptroller for the State of New York, where he oversaw the finances of 1,300 units of local government, the annual management of 44,000 government contracts, and where he had oversight of over $200 billion in state and local municipal bond programs and a $156 billion pension fund.

Sanzillo recently contributed a chapter to the Oxford Handbook of New York State Government and Politics on the New York State Comptroller's Office.

Seth Feaster

Seth Feaster has 25 years of experience creating visual presentations of complex data at The New York Times and more recently at the Federal Reserve Bank of New York. He specializes in working with financial and energy data.