

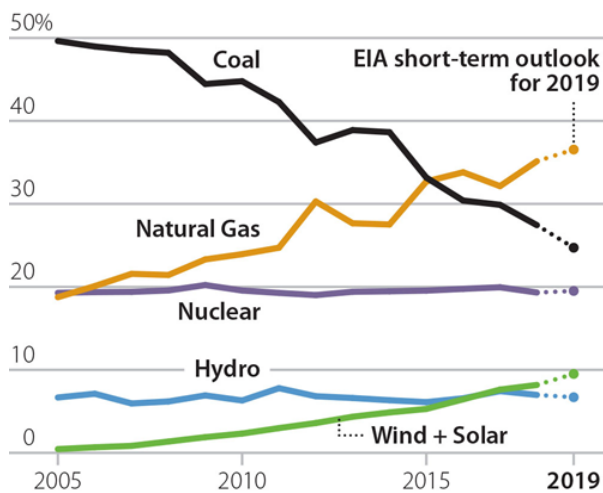
Coal Outlook 2019

Domestic Market Decline Continues

Executive Summary

The long-term structural decline of the U.S. coal industry continued in 2018, with a record total of coal generation capacity retired and a further drop in utility coal consumption to levels not seen since the early 1980s.¹

Fuel Share for Electric Power Generation (Utility Scale, All Sectors)



Source: Energy Information Administration (STEO, March 2019)

This year, the outlook is worse, with the latest forecast from the Energy Information Administration (EIA) projecting that coal's share of the electric generation sector will drop below 25%, the lowest level since 1949.²

We believe the EIA could even be understating the decline. We expect the erosion of the utility market for coal to accelerate through 2019 and into the coming decade due to a combination of factors that have fundamentally changed the domestic electricity generation sector, the prime market for the U.S. coal industry.

These factors include:

- The fracking revolution, which has turned natural gas from a premium fuel into a readily available, low-cost baseload generation resource;
- Persistent cost declines in the renewable energy industry, particularly in wind and solar, a trend that has resulted in clean, reliable alternatives to coal;
- The aging of the coal fleet, which has significant negative impacts on operating performance and costs;

¹ EIA. [Monthly Energy Review](#) data browser. Accessed March 18, 2019.

² S&P Global Market Intelligence. [EIA expects coal-fired share of power generation to fall below 25% in 2019](#). March 13, 2019.

- Significant changes in grid operations, driven by the three factors above, which continue to reduce the importance of coal generation;
- Growing utility sector interest in, and planning for, coal generation phase-outs;
- Rising corporate interest in greener energy resources and sustainable development practices; and
- Growing concern about climate risk and carbon dioxide emissions.

The only piece of good news for the coal industry in 2018 was the significant growth in coal exports, a development that we missed in our outlook last year. For 2018, exports totalled 115.6 million tons, a sharp increase from 2017, but still below past record levels. We also believe it likely represents a high-water mark for U.S. exporters, who have traditionally been swing suppliers in the global market.

Last year, we concluded that coal would continue to lose market share in electricity generation. This year, we expect that erosion to speed up, pushed by the record amount of coal capacity retired last year, projections of continued retirements this year and beyond, and significant changes in grid operations that favor renewable energy and natural gas over coal.

Market forces are driving the transition from coal towards cleaner fuels.

Coal industry executives and the sector's backers have grasped for bits of good news for years, echoing the refrain that "eventually things are going to turn around."³

We disagree, and find that a careful look at the data, the number of plant closures, the sharp decline in domestic consumption and stagnation in electricity demand, as well as the mediocre stock performance of the coal industry can lead only to one conclusion: there will be no turnaround for coal. We believe that market forces are driving a transition away from coal toward cleaner fuels, and that this transition is gaining momentum.

³ *New York Times*. [Coal Production Plummets to Lowest Level in 35 Years](#). June 10, 2016.

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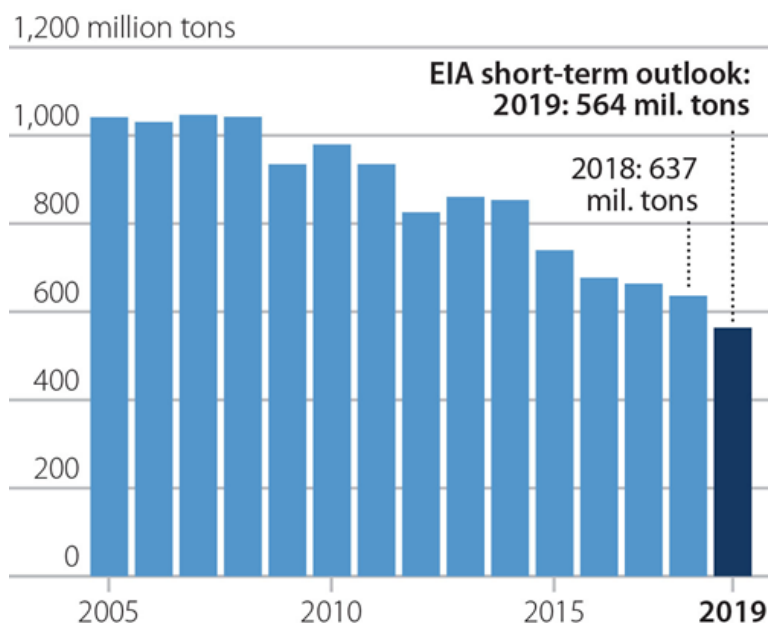


Consumption and Production Overview

We expect the structural decline in the coal industry that began a decade ago to continue in 2019 and beyond.

Total coal consumption in the U.S. fell to 688 million tons (MT) in 2018, dropping below the 700-million-ton level for the first time in 40 years⁴. The 2018 decline, which saw consumption drop 4% from 716.9 MT in 2017, continues the trend that began in 2007, when total consumption peaked at 1,128 MT.⁵ It can be traced to declining demand in the U.S. utility sector, the predominant market for U.S. coal. According to EIA statistics, the electric power sector accounted for 93% of total demand for coal from 2007-2018.⁶

Figure 1: Coal Consumption for Electricity Generation, 2005-2019



Source: Energy Information Administration (STEO, March 2019).

As the above graph indicates, 2019 is shaping up to be another year of declining demand for coal, with the EIA projecting that U.S. generators will use less than 600 MT of coal for electricity generation—a consumption level last seen in 1982.⁷ Specifically, EIA’s Short-Term Energy Outlook data browser estimates that utility

⁴ EIA. [Monthly Energy Review](#) data browser, last accessed March 18, 2019.

⁵ Ibid.

⁶ EIA. Today in Energy, [U.S. coal consumption in 2018 expected to be the lowest in 39 years](#). December 28, 2018.

⁷ EIA. [Total Energy](#).

sector coal consumption will fall to 563.9 million tons this year, a decline of 72.6 MT, or 13%, from 2018.⁸

While this decline is significant, we believe it is well within the bounds of probability and could even fall more given the amount of coal-fired capacity retired last year, coupled with expectations of more closures going forward. According to IEEFA data, the industry shuttered (or converted to natural gas) a record-setting 15.4 gigawatts (GW) of generating capacity in 2018, and 2019 is already shaping up to be another important year for coal plant retirements, with almost 10GW of planned closures announced through the end of February.⁹

In addition to the capacity being retired, the decline in coal consumption can be traced to structural changes that are occurring in the utility industry, changes that will continue to push down demand for coal. For starters, the continued buildout of highly efficient natural gas combined cycle (NGCC) generation has fundamentally changed market operations in the utility sector to coal's lasting detriment, as will be discussed below. In 2018, for the first time, natural gas combined cycle (NGCC) operating capacity exceeded that of coal, 263 gigawatts to 243 GW,¹⁰ with the two sectors trending in opposite directions.

The decline in coal consumption is rooted in structural changes in the utility industry.

Similarly, continuing improvements in the performance and cost of renewable energy alternatives, particularly wind and solar, have introduced price competition that coal cannot match, which we also will address in greater detail below.

This decade-long transition can be traced to a number of interlocking developments that have worked together to undermine coal's economic competitiveness:

- The fracking revolution that has brought ample supplies of relatively low-cost natural gas to the domestic market, with the expectation that supplies will remain readily available and prices stable;
- The commercialization of renewable energy resources at steadily falling prices; and
- The growing willingness (and in many cases, eagerness) of utilities to consider alternatives to traditional coal generation options.

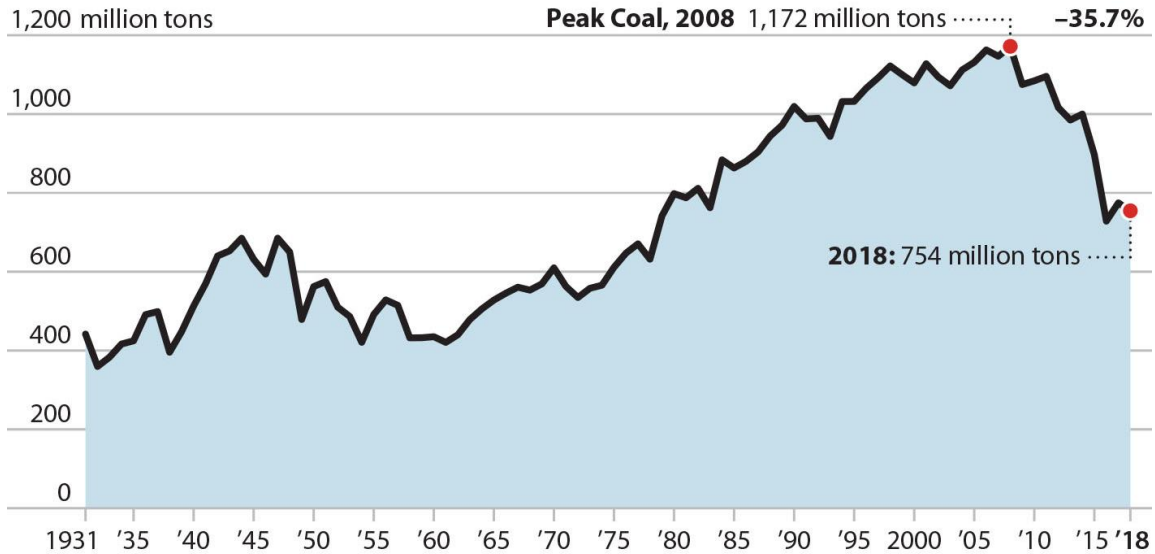
⁸ Coal information in the EIA Short-Term Energy Outlook data browser goes back to 1997; numbers in the Monthly Energy Review data browser go back to 1949. When using either site, the coal information is in chapter or section 6; users can view/download standardized tables or create their own. [The STEO link](#). The [Monthly Energy Review link](#).

⁹ IEEFA tallies coal plant retirement data using information reported to EIA, company press releases and financial filings, and utility correspondence with transmission operators.

¹⁰ EIA. [Electric Power Monthly](#). Table 6.1. February 2018 and February 2019 editions.

Figure 2: Total U.S. Coal Production, 1931-2018

Overall coal production fell by about 20 million tons in 2018 compared to 2017, resuming its precipitous slide from 'peak coal' in 2008, and despite an increase in exports of about 19 million tons.

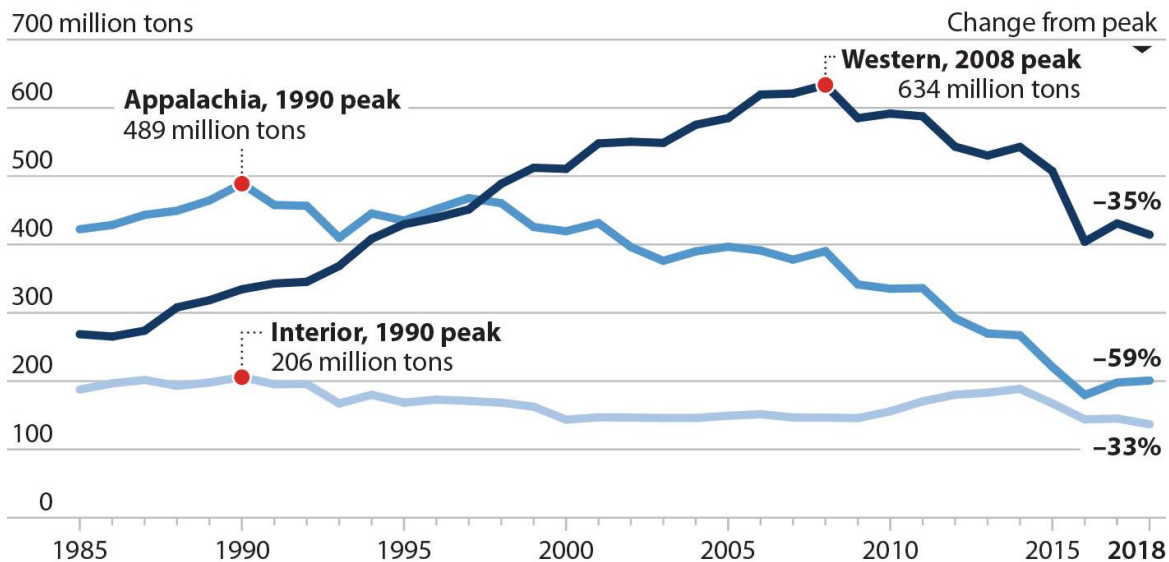


Source: Energy Information Administration (EIA).

The following graph breaks down the total by region, demonstrating that the industry's erosion is nationwide in scope.

Figure 3: Regional U.S. Coal Production, 1985-2018

Coal production has fallen significantly in all three major coal mining regions. Since their peak production years, output is down by more than 33 percent in the West and the Interior, and down 59 percent in Appalachia.



Source: EIA.

2019 Trends and Beyond

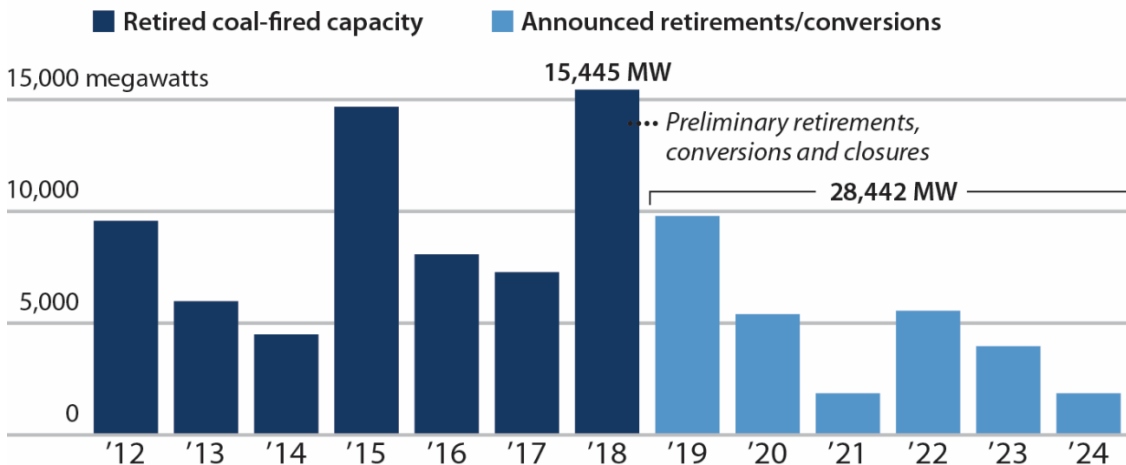
Coal Plant Retirements

Since 2011, when installed coal capacity in the U.S. peaked at 318GW¹¹, 75GW of capacity have been retired, 23.5% of the total. According to our analysis, more than 15.4GW were retired in 2018, slightly above the earlier record of just under 15GW in 2015, the year the U.S. Environmental Protection Agency's (EPA's) mercury emissions regulation took effect.

We do not expect retirement levels in 2019 to be quite that high, but they will still be considerable. IEEFA estimates that roughly 10GW of capacity will be taken offline this year and that at least an additional 18GW will retire in the five years from 2020-2024 (see figure below).

Figure 4: Coal-Fired Electric Generation Retirements and Conversions

Preliminary figures show that in 2018, nearly 15.4 gigawatts of coal-fired capacity retired or was converting to natural gas. New announcements continue to add to the list of closures expected over the next six years.



As of March 12, 2019. Sources: EIA; PJM; S&P Global; IEEFA research (2017-2024).

While the graph above tells a compelling story regarding the total capacity of recent coal plant retirements, it almost certainly understates the amount of capacity that will be retired in the next six years. For example, in our 2018 report released last February,¹² we estimated that roughly 4 GW of coal-fired capacity would be retired in 2019. That figure has shot upward over the past year and now is nearing 10 GW, which would put it on pace to be the third-highest total for coal plant retirements ever. And more announcements could be on the way, as the sector's worsening economics continue to force utility decision-makers to move ahead with closures.

Already this year, Georgia Power has formally asked state regulators to approve the immediate closure of 982.5 MW of coal-fired capacity at its Hammond and McIntosh

¹¹ EIA electricity data.

¹² IEEFA. U.S. Coal: More Market Erosion is on the Way. February 2018.

plants,¹³ and Alabama Power has announced plans to close its three-unit, 1,062MW Gorgas plant in April.¹⁴

Going forward, we expect similar announcements of near-term closures to raise the retirement totals from 2020-2024. So far this year, the Tennessee Valley Authority (TVA) and the Montana-Dakota Utilities have both announced plans to close coal-fired capacity in the next few years that had not previously been scheduled.

The Tell-Tale Story Told by Plant Capacity Factors

Since the fracking boom began in 2008, expanding natural gas supplies and sharply cutting prices, highly efficient NGCC generation units have been pulling market share away from coal.¹⁵ In 2008, EIA data showed that the average annual capacity factor for U.S. combined-cycle natural gas generators was 40.1%, compared to 73.4% for coal-fired generators. The annual average capacity factor for gas generation has been rising steadily from 39.8% in 2009 to more than 50% since 2015, averaging 57.6% in 2018.¹⁶

Meanwhile, U.S. coal plant capacity factors have been dropping. The average capacity factor for all coal-fired generators fell below the 70% level in 2009 and dropped below 60% in 2012. It has trended slowly downward ever since and has hovered around 54% for the past four years.¹⁷ It is important to point out here that this decline has occurred even as 75GW of coal-fired capacity were closed from 2011-2018, much of it older and operated only occasionally. All else being equal, those retirements should have improved the average coal-fleet capacity factor, but that proved not to be the case.

In truth, those retirements may mask a much larger transition under way in the generation sector, where natural gas combined cycle units have become the new baseload go-to capacity resource, while coal is being relegated to daily and seasonal load following operations, significantly reducing overall capacity factors and coal demand. IEEFA has examined the capacity factor over time of the nation's largest coal-fired power plants; the units that previously had provided much of U.S. baseload electricity generation. The results were eye opening.

Focusing on the 50 largest U.S. coal plants, which together have an installed capacity of just under 104GW, we found that all but two posted a lower capacity factor in 2017 when compared to the plants' average from 2007-2017.¹⁸ Twenty-two of the 50 recorded a capacity factor in 2017 that was 20% or more lower than the previous 10-year average, while the capacity factor at an additional eight plants fell by more than 15%. In other words, the capacity factor at 60% of the nation's largest

¹³ *Rome News Tribune*. [Georgia Power submits plan to close Plant Hammond](#). January 31, 2019.

¹⁴ *Daily Mountain Eagle*. [Gorgas plant closing April 15 after 102 years](#). February 21, 2019.

¹⁵ EIA. [Electric Power Annual](#). Tables 4.7.A and 4.7.C.

¹⁶ EIA. [Electric Power Monthly](#). Table 6.7.B.

¹⁷ *Ibid.*

¹⁸ Information on plant size and capacity factor was gathered from EIA and S&P data; analysis by IEEFA.

coal-fired units fell by at least 15% in 2017 compared to those units' 10-year average.

Another way of looking at this data is to pull out the highest performers. In 2007, only 8 of the 48 operating units (two of the current top 50, Oak Grove and Prairie State, had not yet entered commercial service in 2007) posted a capacity factor of less than 70%. In contrast, in 2017, only 10 of the 50 posted a capacity factor of more than 70%. Equally telling, in 2007, only one of these plants had a capacity factor of less than 60%; by 2017, 12 of them operated at less than 40%.¹⁹

The Plant Wansley Example

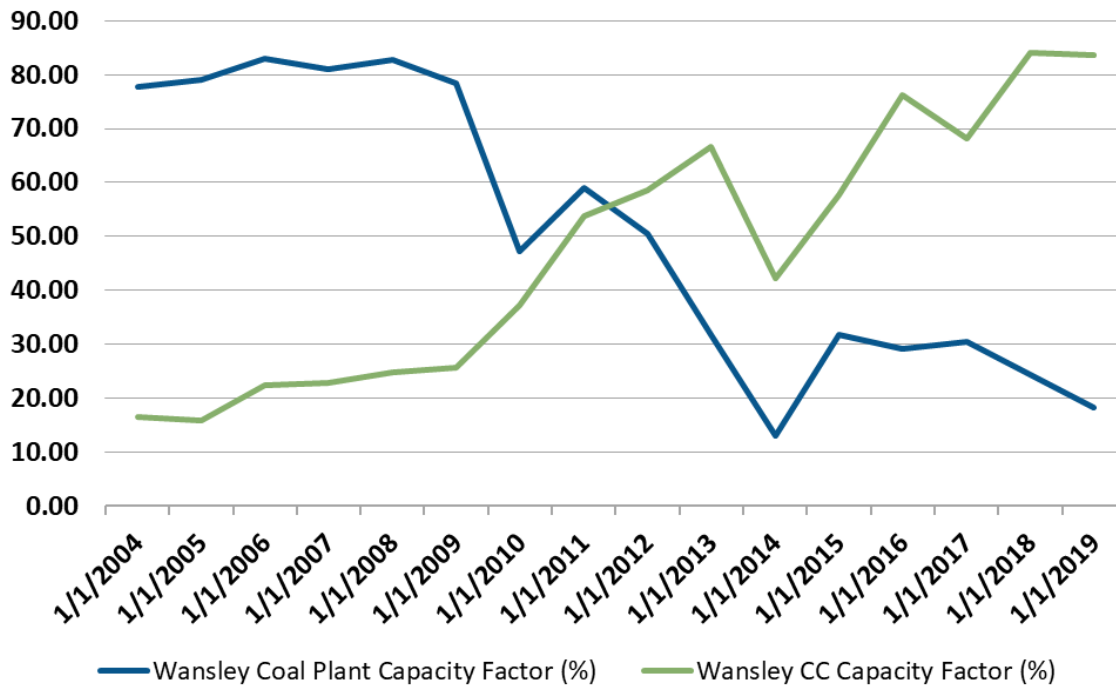
The Plant Wansley complex 60 miles southwest of Atlanta illustrates this trend. Wansley includes two supercritical coal-fired units owned by Southern Co. subsidiary Georgia Power that entered commercial service in 1976 and 1978. The two units have identical net summer capacity ratings of 872 megawatts (MW). The complex also includes two combined cycle natural gas units owned by Southern that came online in 2002 and have a combined summer capacity of 1,150 MW.²⁰

The chart below shows capacity factors for the coal and combined cycle units at Wansley since the gas units came into service. From 2004 to 2008, Wansley's coal units operated at a capacity factor of near or above 80%, while the gas units operated at less than 30% of capacity. Gas price declines and revised perceptions about long-term stable supplies that have taken hold since 2008 have turned the equation upside down. Since 2014, the gas-fired units have posted an average capacity factor of slightly less than 65%, and for the past two years have been well above 80%. The coal-fired units at Wansley have operated at or below 30% of capacity since 2013 and fell below 20% in 2018. While the graphic is specific to Wansley, similar changes have occurred across the utility industry.

¹⁹ The capacity factor information is drawn from the S&P Global Market Intelligence website using EIA data.

²⁰ See also IEEFA analysis: [IEEFA Georgia: The Diminishing Importance of Coal-Fired Generation](#). December 14, 2018.

Figure 5: Capacity Factors at the Wansley Coal and Combined Cycle Plants



Source: IEEFA analysis, S&P data.

What This Means for Coal Consumption

These declining capacity factors have had a major impact on coal consumption. Looking at the top 50 units discussed above, IEEFA found that their coal consumption fell by almost 92 million tons from 2007-2017, dropping from 353.3 million tons to 261.4 million tons, a decline of 26%.²¹

These declining capacity factors have had a major impact on coal consumption.

At Georgia Power's Wansley plant, the nation's 30th largest coal plant by capacity, the decline has been even more dramatic. Coal consumption at Wansley totalled 4.88 million tons in 2007 and tumbled to 1.61 million tons in 2018, a 67% decline.

Another example of this new normal is Duke Energy's massive Roxboro coal plant in North Carolina.²² At 2,462 MW of capacity, the four-unit plant is the 12th largest operating coal facility in the country. Generation at Roxboro has been dropping steadily since 2014 and totalled only about 6 million megawatt-hours (MWh)

²¹ Based on EIA and S&P data; analysis by IEEFA.

²² See IEEFA analysis: [IEEFA U.S.: Two Duke Plants in North Carolina Indicate Baseload Slippage for Coal](#). October 29, 2018.

annually in 2017 and 2018, well under half the plant's average generation from 2007-2014 of more than 13.8 million MWh annually. Coal consumption at the plant has dropped as well, falling from an average of 5.8 million tons annually from 2007-2014 to 2.4 million tons in 2017 and 2018, a 59% decline.²³

The reason for the decline at Roxboro is similar to Georgia Power's Wansley plant: Natural gas combined cycle units that now operate primarily in baseload mode are taking generation away from existing coal plants. Duke has brought two large NGCC units into operation in North Carolina since 2012 and a third is due in service this year. In addition, a growing amount of solar PV capacity, which comes to the market with no variable costs and is dispatched first when available (more on this issue below), is being brought online in the Southeast.

Until 2011, for example, North Carolina essentially had no installed solar generating capacity; It now exceeds 5.2GW and is climbing.²⁴ The Solar Energy Industries Association projects the solar capacity total in North Carolina will increase by an additional 3,939 MW, over the next five years.

While IEEFA has focused on the top 50 plants for detailed review, it is clear that market erosion caused by natural gas and renewable energy is affecting coal-fired plants of all sizes. For example, Duke's Mayo plant, a single 746MW generator that is newer than all four of the Roxboro units, has suffered a similar decline in production in past two years, with output dropping from 2.9 million MWh in 2015 to less than 1.5 million MWh in 2017 and 2018 and coal burn dropping from 1.2 million tons to an average of 680,000 tons.

We believe this is the new operating paradigm for many U.S. coal generation units, even the largest plants. IEEFA does not expect these units to recover this lost market share given expectations of continued long-term availability of relatively low-cost natural gas supplies and the steady decline in costs of wind, solar and energy storage. It is increasingly clear that the market for coal has shrunk permanently, and we believe it will continue to decline in the years ahead as additional renewable generation enters the market.

The Impact of Price

Another problem facing the coal industry is the lack of response to the relatively high natural gas prices of 2018, both compared to coal and to prior years. For the year, the price paid by U.S. utilities for natural gas averaged \$3.42 per million British thermal units (mmBtu).²⁵ This was up from 2017 and significantly higher than 2016, a development that, according to conventional wisdom, should have prompted fuel switching away from gas to coal. But that did not happen. For the year, total electricity generation rose 3.6% and coal-fired production fell 4.9%.²⁶ Perhaps more worrisome for the coal industry, EIA's March 2019 Short-Term Energy Outlook projects a decline in natural gas prices for utility generation over the next two years.

²³ IEEFA calculations using EIA and S&P data.

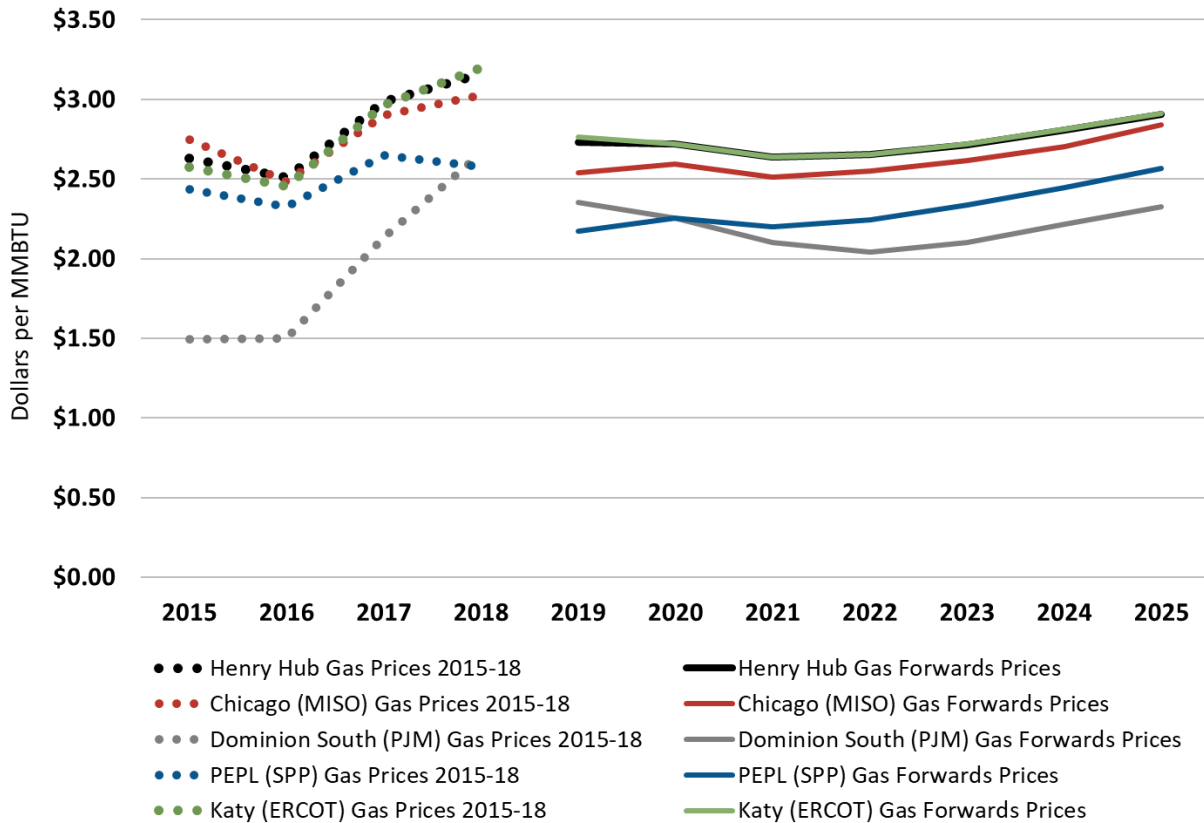
²⁴ Solar Energy Industries Association (SEIA). [Top Ten Solar States](#). 2018 Q4.

²⁵ EIA. [Short-Term Energy Outlook](#) data browser. Accessed March 15, 2018.

²⁶ EIA. [Electric Power Monthly](#). February 2019.

Looking further ahead, the figure below shows current market expectations at the major trading hubs project natural gas prices through 2025 as remaining below last year's level.

Figure 6: Natural Gas Trading Hub Price Estimates, 2019-2025

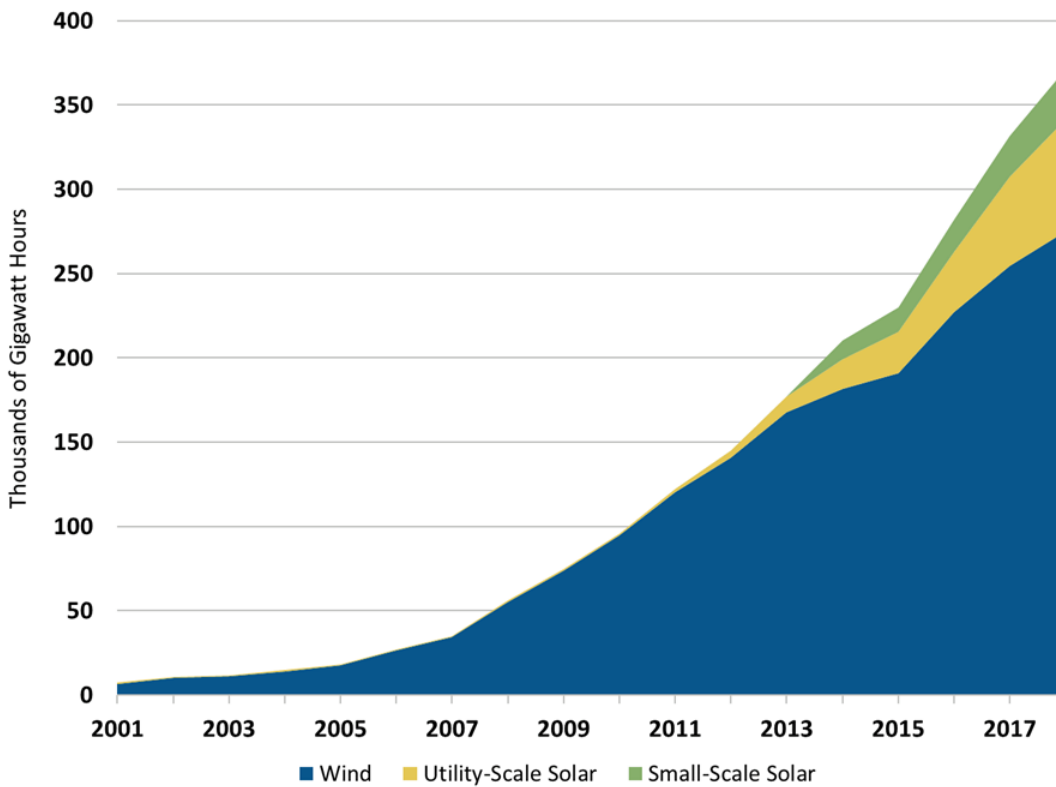


Source: OTC Global Holdings, forward prices as of January 24, 2019, downloaded from S&P Global Market Intelligence.

It is not only low natural gas prices that are hammering the coal industry. The sharp increase in the amount of installed renewable energy capacity, particularly wind and solar which have no fuel costs, is changing the structure of electricity generation across the country, with clear and ongoing negative impacts on coal consumption.

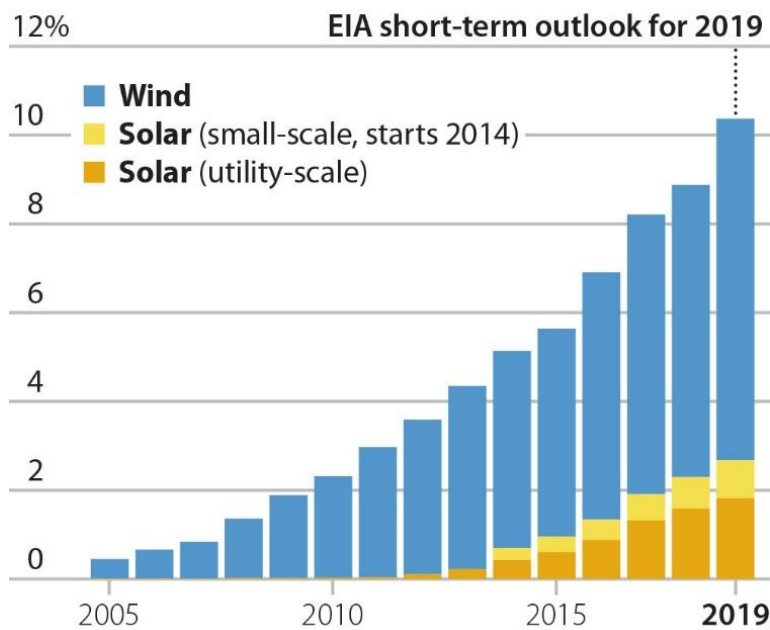
As of the end of 2018, the U.S. had 96.48 GW of wind capacity and 62.4 GW of solar capacity installed. All told, utility-scale wind and solar generated 341.55 terawatt-hours of electricity, up 11% from the year before and accounting for just under 9% of the national power supply. The two figures below chart this steep rise, first by gigawatt-hours of generation and second by percentage of the total U.S. electricity market; they also incorporate data from small-scale generation, particularly residential and commercial rooftop installations.

Figure 7: Rising Output from Wind and Solar Generation



Source: EIA data.

Figure 8: Wind and Solar Share of U.S. Generation, All Sectors

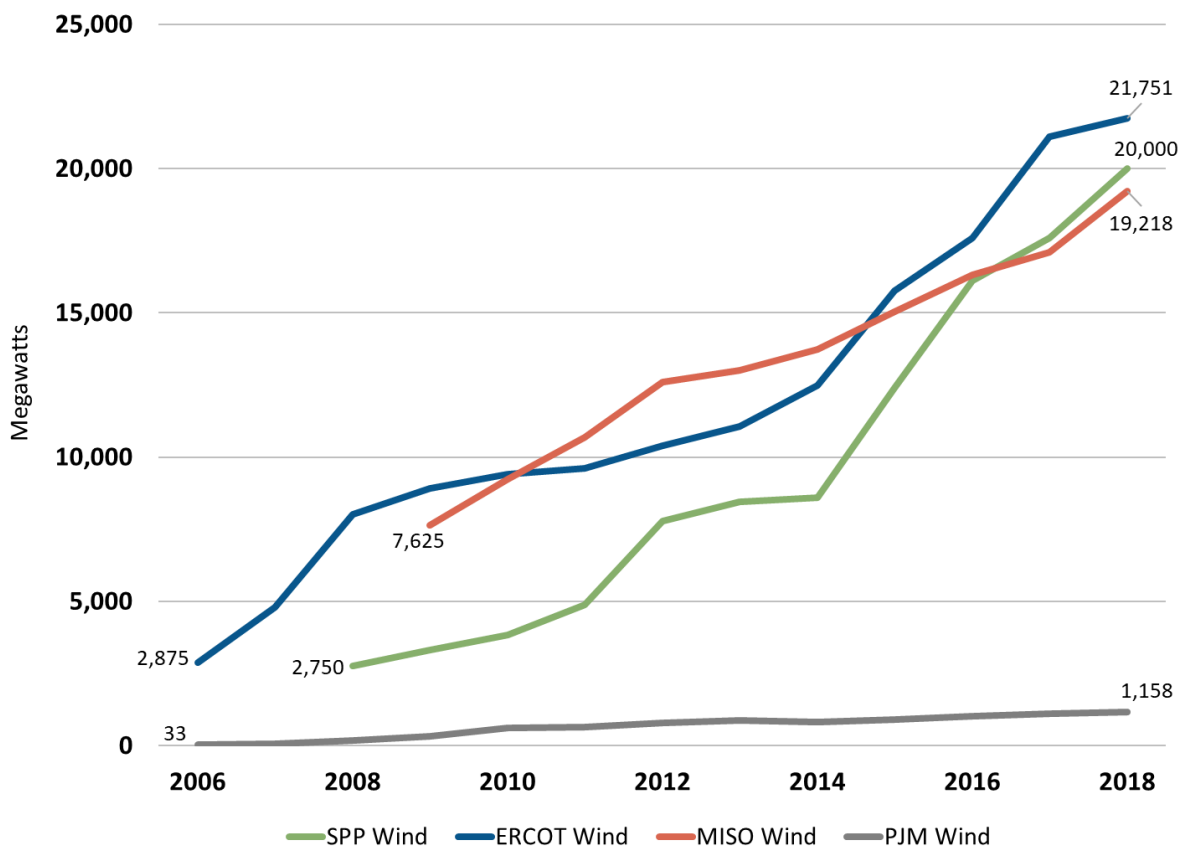


Source: EIA (STEO, March 2019).

Another way of viewing this data—one that leads to a clearer understanding of the impact on the coal industry—is to focus on several of the competitive wholesale markets in the U.S. that have significant amounts of installed coal capacity and increasing amounts of wind generation. Those regions are the Southwest Power Pool (SPP), the Mid-Continent Independent System Operator (MISO), the Electric Reliability Council of Texas (ERCOT), and PJM (the grid operator for all or parts of 13 states in the Midwest and Mid-Atlantic plus the District of Columbia). (The focus is on wind in the charts below because much of the installed solar capacity is situated in California, which has no coal generation to speak of, or in southwestern and western states that lack competitive wholesale markets.)

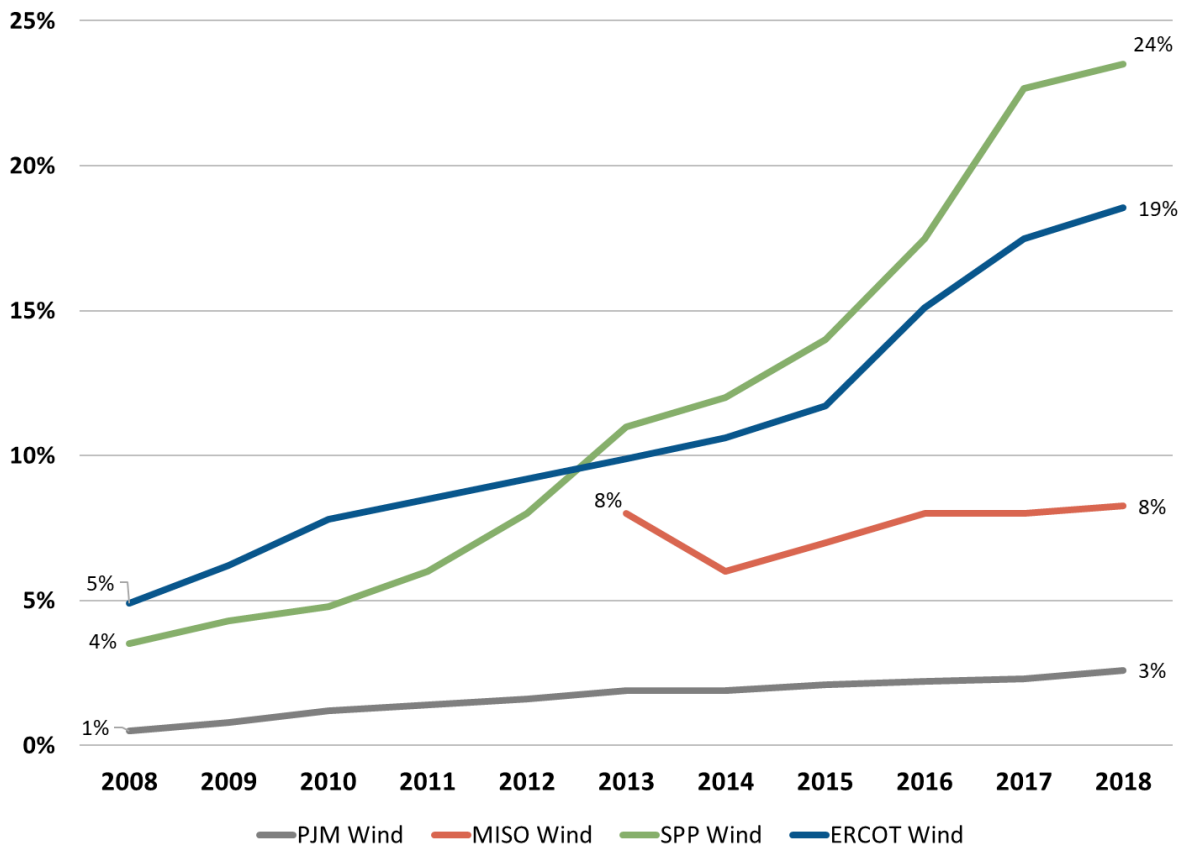
As the two charts illustrate, installed wind capacity and generation have risen sharply in three of the four wholesale markets. Renewable generation in the PJM market has risen, but much more slowly, largely because PJM is one of the focal points of the natural gas fracking revolution and its wind resources are not as attractive as those in the other three independent system operators (ISOs). Neither development—rising wind or natural gas generation—has been good for coal.

Figure 9: Installed Wind Capacity in the Competitive ISOs



Source: Data from SPP, ERCOT, MISO, and PJM websites; IEEFA analysis.

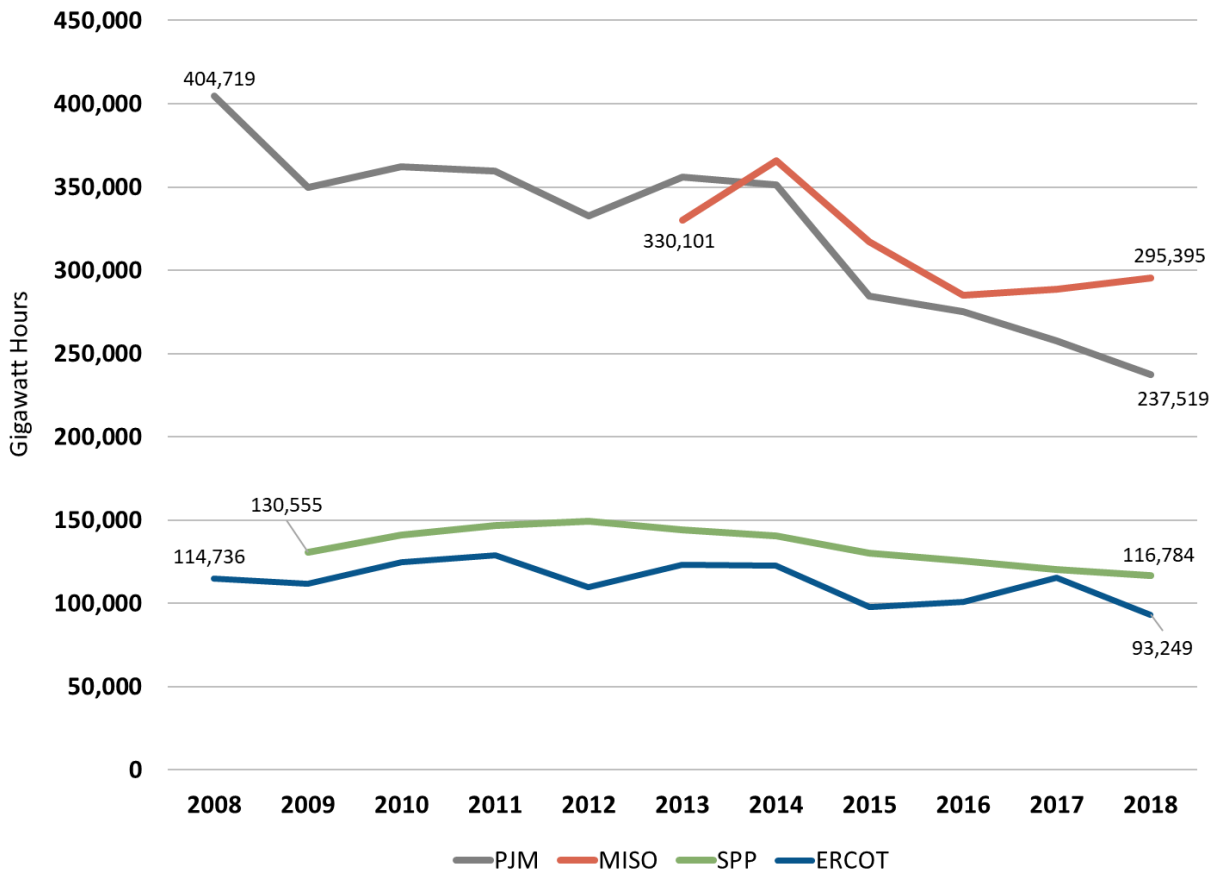
Figure 10: Wind Generation Market Share in the Competitive ISOs



Source: Data from SPP, ERCOT, MISO, and PJM websites; IEEFA analysis.

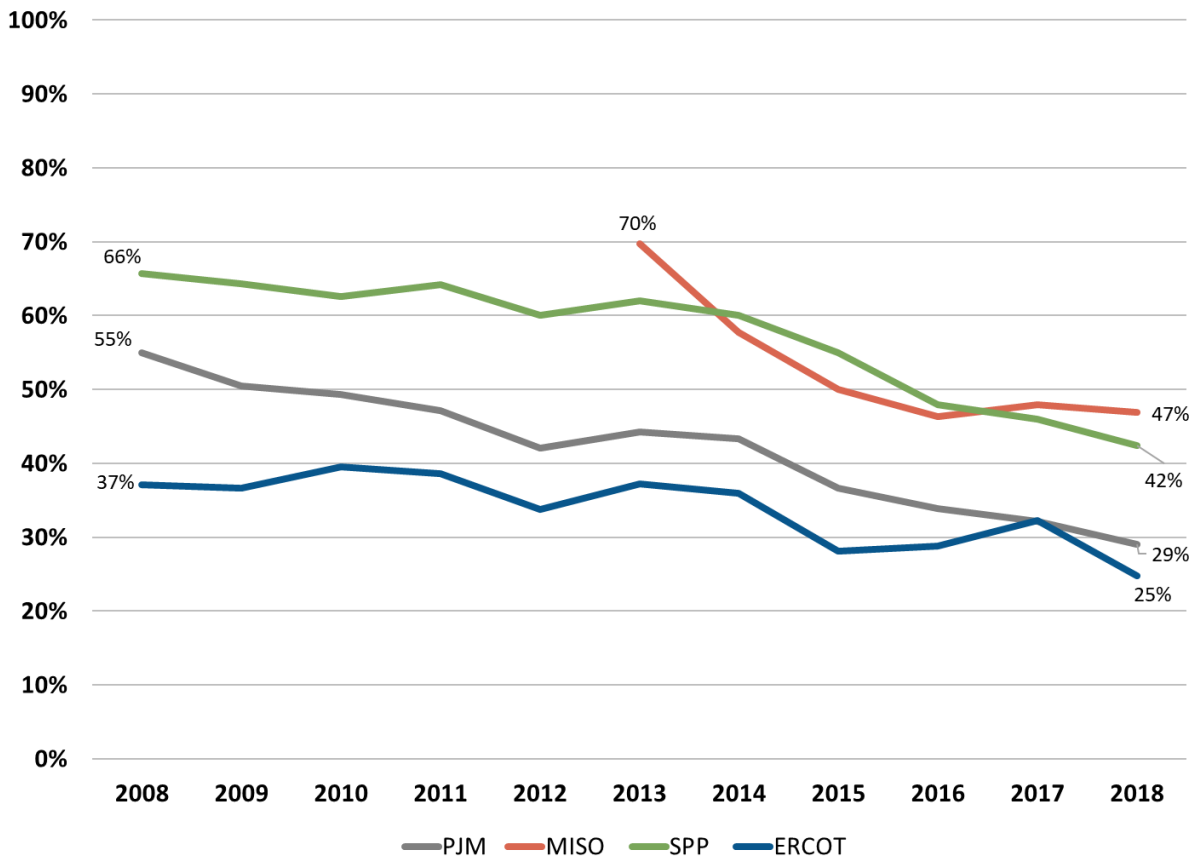
The problem for coal, on this front, is that renewable generation comes with zero variable costs, meaning when those resources are available, they are almost certain to be the first choice of a utility or the operator running the local area transmission grid. Meanwhile, booming gas production in the Marcellus and Utica shale formations has turned natural gas generation units into market makers, also at coal's expense, as the figure below illustrates.

Figure 11: Coal Generation in the Competitive ISOs



Source: Data from SPP, ERCOT, MISO, and PJM websites; IEEFA analysis.

Figure 12: Coal Generation Market Share in the Competitive ISOs



Source: Data from SPP, ERCOT, MISO, and PJM websites; IEEFA analysis.

Renewable Energy’s Impact on the Generation Supply Curve

The impact that no-variable-cost renewables and low-cost natural gas plants have on existing coal plants can be easily shown by returning to Georgia Power’s Plant Wansley discussed above. The graph that follows charts Georgia Power’s generation supply curve. The circles represent a generating unit on the utility’s system, starting at the far left with the roughly 790MW of existing zero variable cost solar installed in the state. Moving to the right, the Wansley NGCC units come in at a variable cost of roughly \$22.50 per MWh, while further to the right is Georgia Power’s Scherer coal plant, the lowest-cost coal unit on its system at about \$28.30/MWh. Finally, the two-unit Wansley coal plant comes into view, with a variable operating cost of about \$37/MWh. The three vertical lines are also key, showing, from left to right, the utility’s minimum (about 5,000MW), average (about 10,000MW) and peak (about 16,000MW) loads in 2017.

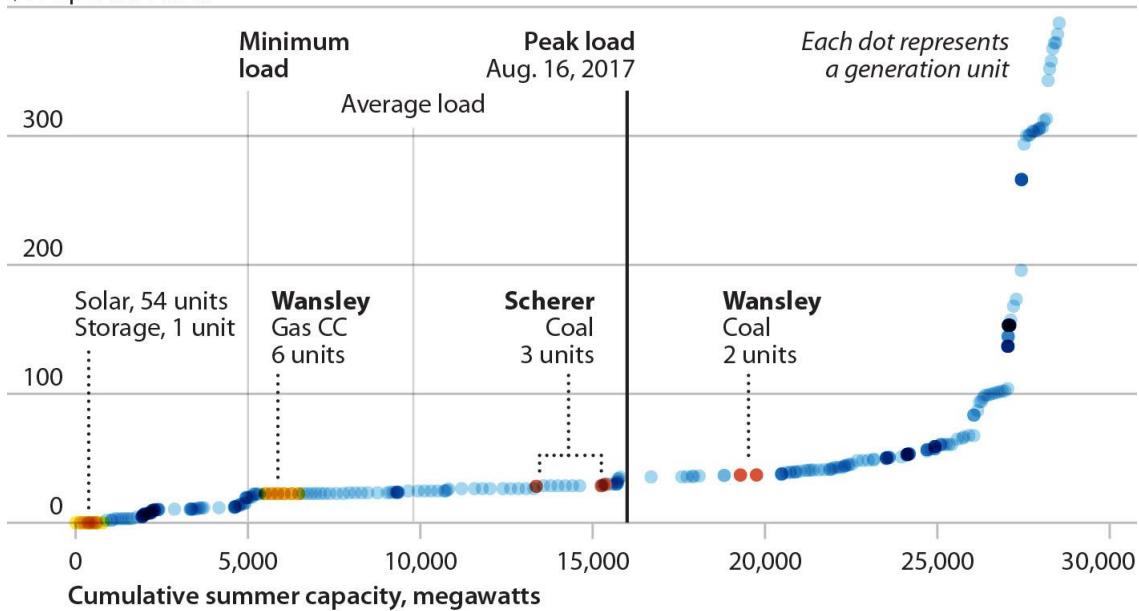
Put natural gas and renewables together and the problem facing coal in Georgia—and elsewhere—is stark. The Wansley CC gas plant will run essentially all the time, while the Scherer plant generally will only be needed on days with above-average demand or when other units are unavailable. This is borne out by the plant’s

generation over the past few years. The four-unit facility is the nation's largest operating coal-fired power plant and from 2000-2011 its average capacity factor was more than 75%. Since then, its capacity factor has declined steadily, hitting 47.7% in 2017 and 51.9% in 2018. (Georgia Power operates all four Scherer units, but has no ownership stake in Unit 4, which is why only three units are included in the figure below.)

As for the Wansley coal plant, it will only be needed on the hottest and coldest of days, as demonstrated by its 18% capacity factor in 2018. And the problem for coal grows only more pronounced as more renewable capacity is added to Georgia Power's grid, which is happening continually, with Silicon Ranch recently announcing plans for a \$150 million investment in three projects in the state including a 102.5MW unit that will supply a Facebook data center. Ever-rising totals of zero variable cost generation will drive coal plants further and further down the energy dispatch curve.

Figure 13: Georgia Power's Generation Supply Curve

Variable operating and maintenance costs for each generation unit
\$400 per MW hour



Source: IEEFA analysis, S&P Global Market Intelligence data.²⁷

²⁷ The supply curve is illustrative, not representative of an actual day's generation.

More Wind and Solar Are On the Way in 2019

Looking ahead, IEEFA sees the coal sector's problems worsening. Construction of new wind and solar capacity is surging across the country, and each and every unit that comes online has an immediate impact on the generation supply curve, pushing existing fossil fuel resources to the right on the supply curve and making the economics of competing in the market that much more difficult.

This year, EIA projects that 24 GW of new generating capacity will be added in the U.S., 46% of which will be wind and 18% solar. Much of this new capacity will be located in the competitive wholesale markets discussed earlier:

1. More than 80% of the 10,440 MW of new capacity expected to be added in ERCOT will be wind or solar.
2. Wind is expected to account for 75% of the 8,600 MW of new capacity planned for MISO.
3. Just under 80% of the 4,900 MW of the new capacity expected to be added in SPP will be wind.

In addition, the American Wind Energy Association notes that just under 6,000 MW of capacity in 17 states came online during the fourth quarter of 2018, meaning that this generation's impact on dispatch decisions is only beginning to be felt. All told, the group says more than 35 GW of capacity is currently under construction or in advanced development.²⁸

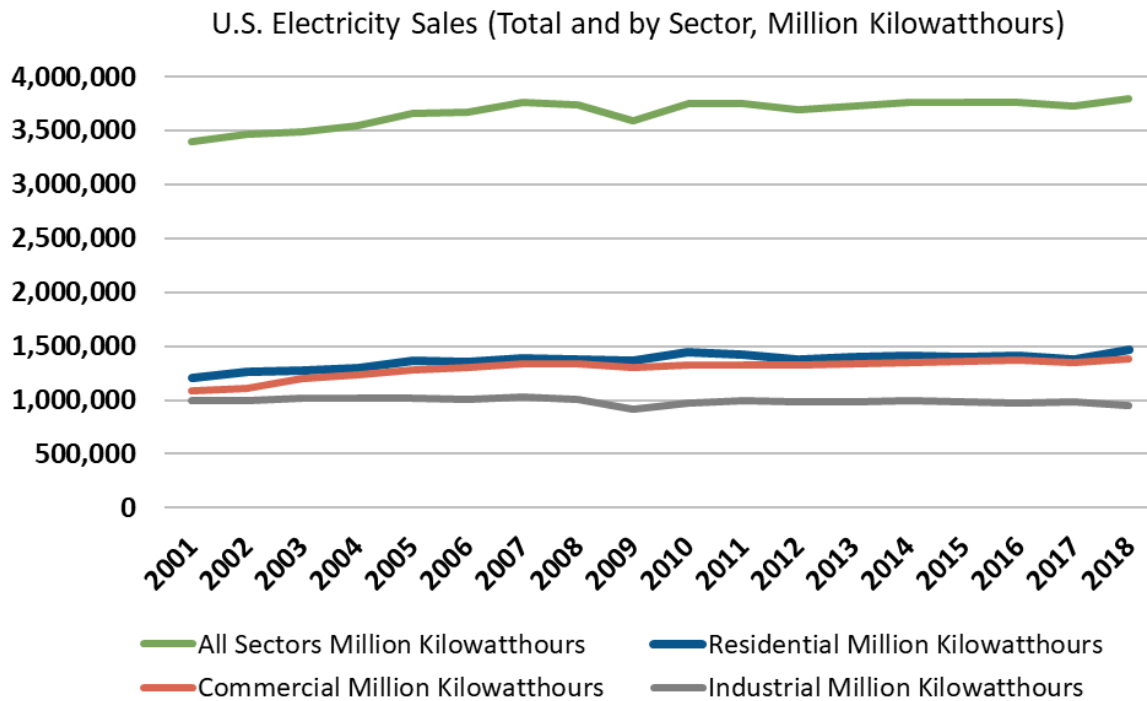
On the solar side, there currently is 34.3 GW of operating utility-scale capacity, with another 23.8 GW either under construction or having a signed PPA in hand, bringing the total to just over 58 GW. Going forward, SEIA estimates that roughly 68GW of new capacity (about 60% of which will be utility-scale PV) will be brought online through 2023, all pushing down the need for coal generation, especially given the largely flat demand curve for electricity nationwide.

The Absence of Demand Growth

The EIA's latest data shows net electricity generation climbing 3.6% in 2018 to 4,178 million MWh, topping the previous peak of 4,157 million MWh set in 2007. The increase was largely weather related, with more heating degree days in the winter and more cooling degree days in the summer, which pushed residential retail sales up by 6% during the year.

²⁸ According to the American Wind Energy Association (AWEA), a wind unit in "advanced development" means that it has a signed PPA, has announced a turbine order or is owned by a utility, and has a high likelihood of getting built and entering commercial operation.

Figure 14: U.S. Electricity Sales Have Flat-Lined



Source: EIA.

These sales totals do not include distributed solar generation, particularly residential rooftop solar, which now totals about 12 GW of total capacity nationwide. The EIA calculates that these customer-sited installations generate about 30 million MWh of electricity, compared to 1 million MWh a decade earlier. In other words, without these units, total electricity sales last year would have been well over 4,200 million MWh.

Strong growth in energy efficiency also has helped to keep electricity demand in check, in spite of steady economic growth overall.

For coal, flat growth is a problem, particularly in connection with the continued construction of new renewable and natural gas-fired generation. These cheaper resources are taking an ever-larger share of what has been the same-sized pie for the past decade.

The Game-Changing Impact of Storage

We expect the continued rollout of energy storage, both stand-alone utility-scale batteries and linked solar and storage, to begin having a substantial impact on the electricity generation market this year and to grow significantly in importance in the years to come. Price declines in lithium-ion batteries, the most commonly used option today, have brought the cost in line with more conventional options, which has prompted some utilities to begin adopting the technology; more will follow.

For example, in Nevada, NV Energy is moving ahead with plans to install 1,001 MW of new solar capacity along with 100 MW/400 MWh of storage capacity. A key rationale for the new capacity, and the storage assets in particular, is to enable the company to retire Unit 1 at the North Valmy coal plant by 2021. Three of the solar facilities, totalling 401 MW in capacity, and all of the storage are located in the northern portion of the state, as is North Valmy. The new renewable capacity and storage is scheduled for completion by 2021, which will enable the coal plant's closure without compromising reliability, the company has said.²⁹ Before these solar and storage proposals came to fruition, NV Energy had asked state regulators to delay the plant's closure until 2025, because otherwise it would not be able to guarantee the system's reliability.

North Valmy 1, with a net summer capacity of 254 MW, has largely operated only from June-September for the past three years, providing electricity during the high-demand Nevada summer. During those three years, the unit's average capacity factor has ranged from 38%-46%. The unit's highest monthly output was 138,000 MWh, in July 2018.³⁰

While not designed to be a one-to-one replacement, but rather to serve systemwide needs, the new solar and storage should have no trouble matching the coal plant's output. The area gets roughly 15 hours of daylight daily during July, and full output for 8 hours per day would generate 3,208 MWh daily or 99,448 MWh for the month. Using 50% production for an additional six hours daily produces 1,203 MWh daily, or 37,293 MWh during the month. In addition, solar storage provides 400 MWh that can be used when needed and recharged when not in use, helping to provide the reliability that addresses the variability critique leveled by coal and nuclear proponents against both wind and solar.

And it is not just in the sunny Southwest that solar plus storage is disrupting the utility sector and undercutting coal plant economics. Northern Indiana Public Service Company's blockbuster decision last year to pursue the phase-out of its coal-fired generation over the next 10 years demonstrates how the economics of solar-plus-storage have changed, and the threat this poses for coal generation.

It is not only in the sunny Southwest that solar plus storage is disrupting the utility sector.

NIPSCO serves some 466,000 customers in the northern third of Indiana and, like other utilities in the state, relies heavily on coal for its electricity needs, currently getting more than 60% of its generation from two coal plants. When the utility solicited bids for future power supply needs as part of its most recent integrated resource planning process, it received some competitive proposals that convinced NIPSCO's executive team that change was both possible and economic. In its preferred resource plan released late in 2018, the utility proposed adding 1,145

²⁹ Power Magazine. [NV Energy Accelerates Retirement of One of Nevada's Last Coal Units](#). December 27, 2018.

³⁰ Data from S&P Global Market Intelligence.

megawatts (MW) of solar and solar-plus-storage by 2023, which would push its renewable generation well above 50% and its coal-fired power capacity down to 17%.³¹

What is most striking is that these developments are occurring even though the market is still in early development. In its most recent outlook for the Energy Storage Association, Wood Mackenzie reported that 310.5 MW of new storage capacity was installed in the U.S. in 2018, and behind-the-meter applications (largely smaller storage units installed with residential rooftop solar systems) accounted for more than half of that total.³²

Wood Mackenzie expects annual growth to speed up quickly, doubling in 2019 to almost 650 MW and then almost tripling in 2020, with a growing share of the total coming from front-of-the meter or utility applications.³³

Numbers aside, perhaps the best take on the rapidly developing renewable energy and storage market was offered by Jim Robo, chairman and CEO of NextEra Energy, which brands itself as the world's largest producer of solar and wind energy. During the company's 2018 earnings call in January, Robo said:

"In 2018, more than 40% of the solar projects that were added to our backlog included a battery storage component, highlighting the beginning of the next phase of renewables development that pairs low cost wind and solar energy with a low-cost battery storage solution. With continued technology improvements and cost declines, we expect that without incentives wind is going to be a 2 to 2.5 cent per kilowatt-hour product and solar is going to be a 2.5 to 3 cent per kilowatt-hour product early in the next decade.

"Combining these extremely low costs with a one-half to three-quarter cent adder for a 4-hour storage system will create a nearly firm renewable generation resource that is cheaper than the operating cost of coal, nuclear and less fuel-efficient oil and gas-fired generation units. We continue to believe that this will be massively disruptive to the nation's generation fleet and create significant opportunities for renewables growth well into the next decade."

While we believe that Robo is right, we think that solar-plus-storage (and wind to a lesser degree) will push the industry to recognize the fact that early retirements of coal-fired generation units are both feasible from a reliability perspective and cost-effective in terms of dollars and cents.

The Push for Clean Energy: From Utilities, Businesses and Consumers

The close working relationship that previously existed between the utility and coal industries has changed notably in the past several years. Today, a growing number of utilities have committed to coal phase-out plans over varying stretches of time.

³¹ NIPSCO [Integrated Resource Plan](#) 2018. p. 186.

³² Q4 Energy Storage Monitor, Wood Mackenzie.

³³ Ibid.

And even when a complete phase-out plan has not been adopted, long-term utility resource plans increasingly conclude that closing coal plants and replacing that capacity, if needed, is the preferred economic alternative.

Last month, for example, just prior to releasing its proposed long-term resource plan, the Tennessee Valley Authority (TVA) voted to close the 971MW Paradise and the 870MW Bull Run coal plants. In discussing the closures, TVA CEO Bill Johnson said: “Analysis over the past several months shows that closing two additional fossil fuel plants is the right action to take at this time, financially and operationally. It is not about coal. This decision is about economics.”³⁴

This decision is just the latest in a string of closures in the past 10 years that have cut the TVA’s reliance on coal from 58% in 2008 to 24% today. And further reductions are obviously on the way.

Other utilities are moving in the same direction, pushed by the economics that have turned coal into a higher cost resource than either natural gas or renewables. This new approach is best epitomized by Ben Fowke, chairman, CEO and president of Xcel Energy. Early last year, Fowke had this to say: “Coal is on the way out. I will tell you, it’s not a matter of if we’re going to retire our coal fleet in this nation, it’s just a matter of when.”³⁵ Then, in December, Fowke and Xcel went even further, committing the company to being carbon-free by 2050. While a step outside the bounds of this report, Fowke’s justification for pursuing the carbon-free goal is relevant. First, he noted that improvements in technology had made more rapid reductions in carbon emissions possible. Second, he pointed out that customers were asking for it.

This customer interest or, in reality, demand is a key driver of the market erosion affecting the coal industry. Utilities are being pushed hard to get out of coal by many of their largest corporate clients, who in turn are catering to customer preferences. Led by household-name companies like Apple, Facebook, and Google, U.S. corporations have signed deals for more than 15 GW of renewable energy power supplies in the five years through 2018 (see figure below), and as we saw earlier, these deals continue to get signed.

Beyond these direct purchases, companies have been pushing utilities to offer green tariffs so that they can buy clean electricity without being forced to negotiate their own separate power supply deals. Large companies are also beginning to factor the availability of renewable energy resources into their expansion and/or relocation plans, a trend that is further pushing utilities toward cleaner alternatives.

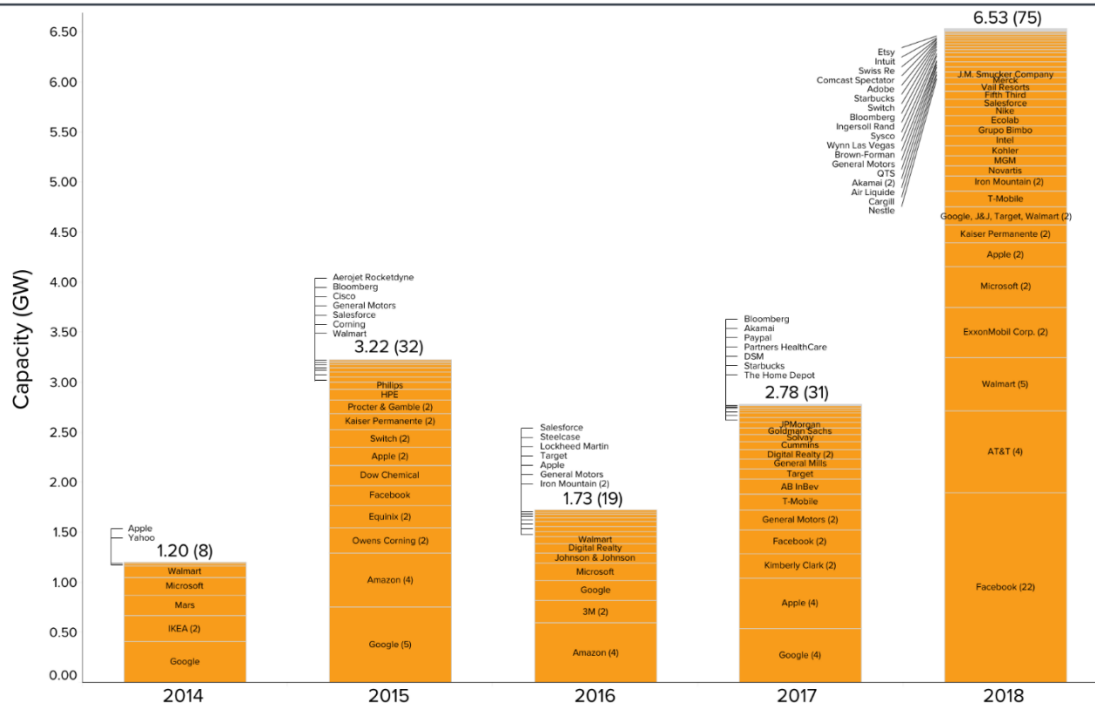
³⁴ *Knoxville News*. [TVA to close coal-fired power plants in Kentucky, Tennessee](#). February 14, 2019.

³⁵ *Greentech Media*. [Xcel CEO Says Retiring the U.S. Coal Fleet ‘Just a Matter of When.’](#) Julia Pyper. June 8, 2018.

Figure 15: Rising Number of Companies Signing Green Energy Deals



Corporate Renewable Deals 2014 – 2018



As of December 31, 2018. Publicly announced contracted capacity of corporate Power Purchase Agreements, Green Power Purchases, Green Tariffs, and Outright Project Ownership in the US, 2014 – 2018. Excludes on-site generation (e.g., rooftop solar PV) and deals with operating plants. (#) indicates number of deals each year by individual companies. Copyright 2018 by Rocky Mountain Institute.

Source: Rocky Mountain Institute.

Coal Company Finances

Some of the leading U.S. coal companies posted positive results in 2018. But those reports hinged on strong demand for both thermal and metallurgical coal exports and high prevailing prices worldwide. In contrast, the industry’s principal market, the domestic electric generation sector, continued to shrink. And the industry as a whole fared poorly in the stock market in 2018, with the Dow Jones coal index dropping from \$67.09 at the beginning of the year to \$52.78 by the end, a 21.3% drop.³⁶

In its 2018 earnings release, Peabody touted three positive developments. First, its acquisition of the Shoal Creek Mine in Alabama, which sold 2.4 million tons of metallurgical coal for export in 2017. Second, the strong pricing for both thermal and metallurgical seaborne coal. And third, its continued, aggressive stock buyback program, geared to helping investors and creditors in the company following its April 2016 bankruptcy, which had allowed it to shed more than \$5 billion in debt.

References to the company’s principal market, U.S. thermal coal sales, were more muted, focusing on a hoped-for increase in demand due to low utility stockpiles.

³⁶ S&P Dow Jones indices. Accessed March 18, 2019.

Looking ahead, however, glimmers of concern were evident in the company's outlook. Acknowledging that its Powder River Basin thermal coal assets are under stress, the company said it would cut production at its flagship North Antelope-Rochelle mine by 10 million tons in 2019 because of falling U.S. demand. The mine, the largest in the U.S., produced 98.3 million tons of coal in 2018 and accounted for about 13.1% of all U.S. coal production in 2017, according to federal data and IEEFA research.

Elsewhere, Peabody said it would be "easing production across several complexes" in the Midwest. And it said that it expected to shut down the Kayenta Mine in Arizona in the third quarter of 2019 due to the planned closure of the Navajo Generating Station (NGS) at the end of the year. Kayenta, a dedicated mine with NGS as its sole customer, has sold an average of more than 7 million tons of coal to the Navajo facility annually since 2012.

Regardless of how executives have spun the results, the stock market has not been impressed, with Peabody's share price dropping from \$38.50 a year ago to less than \$30 recently.

Much like Peabody, Arch Coal in its 2018 earnings call, highlighted plans to open a new metallurgical mine in West Virginia capable of producing 3 million tons of high-quality coking coal annually, much of which the company plans to export. Given prevailing coking coal prices, Arch said it could recover the \$360-\$390 million capital investment in the new mine in as little as 18 months.

But the outlook is not nearly so bright for Arch's domestic thermal coal market. Production from the company's two Powder River Basin coal mines totalled 79.5 million tons in 2018, with 8 million tons produced at the Coal Creek mine and the remainder coming from the company's Black Thunder mine. For 2019, Arch says it expects to produce between 70 and 80 million tons of coal at the Black Thunder facility. Operations at the Coal Creek site, which produces lower-quality coal, will be "much reduced" this year, the company said.

By comparison, as recently as 2015, production at the Black Thunder mine was just less than 100 million tons, while in 2011 it was more than 116 million tons.

Arch's creditors and early post-bankruptcy investors have done well since the company re-emerged with nearly \$5 billion in debt wiped off its books in October 2016. Recent results have not been as positive, with the stock now trading at around \$91 per share recently compared to \$93 a year ago.

Cloud Peak Energy, another major U.S. thermal coal producer, is currently on the edge of bankruptcy and delisting from the New York Stock Exchange. It has said that production from its export-oriented Spring Creek PRB mine rose by 1 million tons in 2018, but that increase was not nearly enough to offset a more than 9 million ton decline at its two domestic-focused thermal coal mines, Cordero Rojo and Antelope.

The company this month announced that it lost \$718 million in 2018 and acknowledged in an SEC filing that there were serious questions about its viability.³⁷

Shares in Cloud Peak stock have tumbled in the past year, dropping from around \$3.50 to about 20 cents as of March 18, 2019.

The other publicly traded coal companies include:

- CONSOL Energy, a major Eastern producer, sold a record 27.7 million tons of coal in 2018 from its Pennsylvania Mining Complex (PAMC). Its stock price has gone up from \$30.18 to just under \$37.57 in the past year, but it is worth noting that the sales increases at PAMC in the past two years are due almost exclusively to a rise in thermal coal exports.
- Foresight Energy, an Illinois Basin coal producer, mined a record 23.4 million tons of coal in 2018. Despite the record production, the company lost \$61.6 million for the year and its stock price has dropped from \$3.90 in March 2018 to \$2.70 on March 18, 2019.
- Warrior Met, a leading producer of metallurgical coal, mined 7.7 million tons in 2018. Despite the record output and strong pricing for its export-destined product, the company's adjusted net income fell slightly in 2018 from the prior year and its stock price has dropped from \$31.50 last March to \$28.60 currently.

And there also is the case of Westmoreland Coal, one of the oldest publicly traded coal miners in the U.S. The company filed for bankruptcy in October, 2018, reporting \$1.4 billion in debt and just \$770 million in assets.³⁸ Founded in 1854, the company owned several mines serving power plants with uncertain futures, included the Colstrip power plant in Montana and the San Juan plant in New Mexico. The company emerged from bankruptcy on March 15, 2019 as a privately held company owned and operated by a group of its former creditors.³⁹

Coal Exports

Exports have never been a major segment of the U.S. coal market, generally accounting for less than 10% of U.S. production. In 2017 and 2018 that changed. Exports in 2017 totalled 97 million tons, 12.5% of the year's overall 774.6 million tons produced. Unexpectedly, at least in our view, the increase continued in 2018, with exports rising to 115.6 MT and accounting for 15.4% of the year's 753.7 MT in production.

The U.S. has been a traditional and relatively consistent exporter of metallurgical coal used in steelmaking. Since 2010, U.S. coal companies have exported an average

³⁷ S&P Global Market Intelligence. [Cloud Peak stalls on debt payment, starts clock on potential bankruptcy filing](#). March 15, 2019.

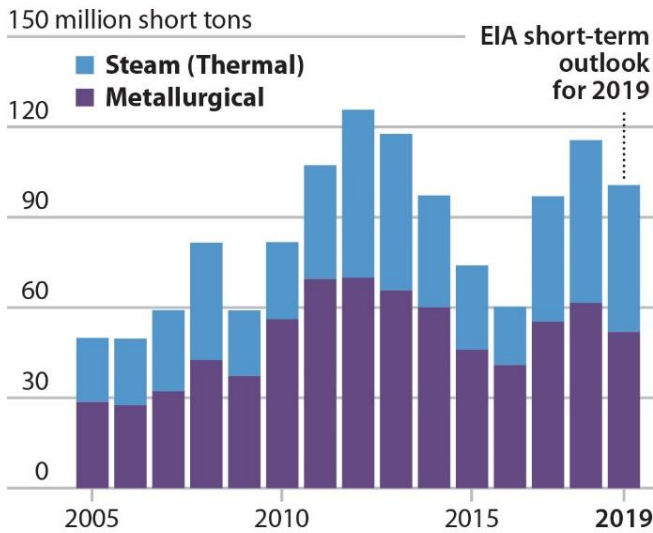
³⁸ *The Denver Post*. [Englewood-based Westmoreland Coal files for bankruptcy](#). October 9, 2018.

³⁹ S&P Global Market Intelligence. [Westmoreland Coal emerges from bankruptcy as Westmoreland Mining](#). March 15, 2019.

of 58.3 MT, with the largest share of that going to European steelmakers. Other major importers of U.S. metallurgical coal include Canada, Brazil, Japan and India. While a consistent source for exports, metallurgical coal demand is a limited market. Coal companies with the right reserves in the right locations can profit from this market. Witness Arch Coal's plans for its new met coal export mine.

Figure 16: Variability of U.S. Coal Exports

U.S. Coal Exports of Steam and Metallurgical Coal



Source: EIA (STEO, March 2019).

Turning to the thermal coal side of the export market, the U.S. has traditionally been regarded as a swing supplier, selling into the market when other suppliers could not meet demand, largely because the distance from the U.S. to major importers such as India and other Asian countries rendered the economics borderline except during the strongest markets. The past two years have been just that, strong markets that pushed U.S. thermal coal exports up sharply. In 2017, those markets more than doubled, to more than 41 MT from 19.7 MT in 2016. The upswing continued in 2018, with total thermal exports hitting 54.2 MT. Thermal coal exports to India accounted for much of the growth, climbing 92% to just under 9 million tons from 2017 through the end of September in 2018.

As quickly as these exports go up, they can fall, as the graph above illustrates. We believe the mini-export boom of the past couple years has hit its peak. European countries are moving quickly to reduce their thermal coal consumption, and more than 20% of current U.S. shipments are bound for Europe. In addition, India has aggressive plans to reduce its reliance on coal-fired generation, and in the Indian market, U.S. exporters face intense competition from Australia and other closer-to-market suppliers.

As Stephen Doyle, the founder of Doyle Trading Consultants who now runs BtuBaron LLC, warned last month: "If this export market of ours cycles down, we're in big trouble because that coal is not going to have a home in the United States."⁴⁰

We think the problem of diminishing export demand is going to begin showing up this year, with markets for U.S. thermal coal declining around the world due to slowing economic growth, government policies to curb coal consumption, continued development of renewable energy technologies and competition from other exporters.

Conclusion

The outlook for the U.S. coal industry is one of continuing decline. Cheaper, cleaner generation options are readily available, and utilities increasingly are turning to those alternatives for their capacity needs, as the steady decline in coal's market share demonstrates.

We expect this transition to continue and perhaps even quicken this year and into the 2020s, driven by the ready availability of low-cost natural gas and the steadily rising amount of renewable energy generating capacity. Utility-scale storage will serve to further undercut coal's competitiveness, dispelling already declining concerns over variable energy generation.

Coal companies likely will continue talking up their export plans, but we do not believe this is a long-term growth strategy for the industry. Metallurgical coal exports are limited by the productive capacity of the steel industry and can never serve as a replacement for the industry's declining domestic coal sales. At the same time, efforts to replace lost domestic thermal coal sales by boosting exports will be constrained by changing overseas markets, particularly efforts in Europe and India to reduce their coal use, and the inherent problems associated with the U.S.'s geographic distance from most major importers.

It is not a good time to be a coal producer. We do not expect that to change this year.

⁴⁰ S&P. [Global hesitation to invest in coal is boon to US exporters, consultant says](#). February 26, 2019.

About IEEFA

The Institute for Energy Economics and Financial Analysis conducts research and analyses on financial and economic issues related to energy and the environment. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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