BROOKINGS

THE U.S. COAL SECTOR

Recent and continuing challenges

Howard Gruenspecht

PAPER 6
JANUARY 2019

ACKNOWLEDGEMENTS

I benefited from helpful comments and suggestions from participants at workshops held at the Brookings Institution and the Center for Strategic and International Studies and an outside reviewer. However, I am solely responsible for this paper and any errors it may contain.

INDEPENDENCE

The Brookings Institution is a nonprofit organization devoted to independent research and policy solutions. Its mission is to conduct high-quality, independent research and, based on that research, to provide innovative, practical recommendations for policymakers and the public. The conclusions and recommendations of any Brookings publication are solely those of its author, and do not reflect the views of the Institution, its management, or its other scholars.

ABOUT THE AUTHOR

Howard Gruenspecht is a senior energy economist at the Massachusetts Institute of Technology Energy Initiative. From 2003 through mid-2017, he was deputy administrator of the U.S. Energy Information Administration (EIA), directing energy data and analysis programs. From 1991 to 2000, he held leadership positions in the Department of Energy's (DOE) Policy Office, including as deputy assistant secretary for economic and environmental policy. Gruenspecht has also served as a resident scholar at Resources for the Future, senior staff economist at the White House Council of Economic Advisers, faculty member at Carnegie Mellon University's Tepper School of Business, and assistant director of economics and business on the White House domestic policy staff.

EXECUTIVE SUMMARY

The 40 percent decline in U.S. coal-fired power generation over the last decade accounted for 75 percent of the total reduction of 800 million metric tons in U.S. energy-related carbon dioxide (CO_2) emissions between 2005 and 2017.[1] The shift away from coal was mainly driven by lower natural gas prices due to the shale revolution and stagnant U.S. electricity demand, and to a lesser extent by policy-supported growth in wind and solar generation. With power generation accounting for over 90 percent of U.S. coal use, there was a comparable reduction in U.S. coal production over the last decade.

Coal production and use in the United States has fluctuated over the past 100 years, with declines following peaks in 1920 and 1945 subsequently being reversed. However, current market and policy factors suggest that another significant recovery is not likely. Future prospects for the U.S. coal industry remain closely tied to its role in electricity generation, where forecasts suggest challenges to coal-fired plants, including competition from abundant and low-priced natural gas, additions of wind, solar, and gas-fired capacity, and stagnant electricity sales. New coal plants are much more expensive to build than either natural gas or renewable capacity, and also face the same dispatch competition as existing coal plants, making it highly unlikely that potential investors could ever recover their costs or earn a return on investment.[2]

Turning to the role of government policies, it is important to distinguish developments that are largely symbolic from those that could significantly affect coal use. For example, the Trump administration is planning to replace the Clean Power Plan for existing fossil fuel plants that was issued in 2015 and was subsequently stayed by the Supreme Court. Changes to the rule might slow, but would not reverse, the decline in coal-fired generation. However, they could make future coal generation more responsive to any sharp rise in natural gas prices, posing a conundrum for those who support emissions reductions, but also oppose shale gas development and the buildout of gas pipeline infrastructure.

Looking beyond the Clean Power Plan, several recent changes to federal policy, including lifting a coal-leasing moratorium, ending a review of royalty rates, and provision of expanded tax credits for carbon capture and sequestration (CCS), are unlikely to improve coal's competitiveness as a fuel for domestic electricity generation. A Trump administration proposal to require wholesale electricity market operators to enable full recovery of investment costs and a guaranteed return on equity to economically uncompetitive coal plant operators might have increased coal-fired generation, but it was unanimously rejected by the Federal Energy Regulatory Commission (FERC) in early 2018. As of November 2018, the administration is considering use of the Federal Power Act and the Defense Production Act (DPA) provisions to mandate retention of coal-fired units and purchases of coal-fired power. It is facing significant opposition as it seeks to apply these authorities, which were not designed or intended to achieve such purposes.

States, acting alone or jointly with the federal government, play a key role in shaping the market for coal-fired generation through mandates for increased renewable generation, subsidies for generation at existing nuclear plants facing economic challenges, and energy efficiency programs that reduce electricity demand. For the most part, state-level energy policies have not experienced the significant swings that have occurred at the federal level with new presidencies in recent years.

U.S. coal-fired generators also face significant downside risk from the possibility of future policy changes toward more aggressive greenhouse gas (GHG) mitigation. Truly deep decarbonization would ultimately require emissions reductions across all sectors. However, further displacement of coal-fired generation, which, despite recent declines, still accounted for 23 percent of total U.S. energy-related CO_2 emissions in 2017, compares very favorably in both cost effectiveness (cost per ton) and scale of impact over the next 15-20 years to other emission reduction strategies currently under review, such as higher fuel economy standards for light-duty vehicles.

On coal exports, overseas sales by U.S. producers increased substantially in 2017, but they are still below levels realized during the 2011-14 period.[3] Demand for U.S.-sourced coal tends to be episodic, driven by price spikes caused by natural or policy events that disrupt production in China, Australia, and Indonesia. Projected global demand for metallurgical coal (met coal), which dominates overall U.S. coal exports, is flat to slightly declining.[4] This outlook reflects both a slowdown in global steel production growth and changes in steelmaking techniques that are likely to reduce the amount of metallurgical coal used per ton of steel produced. Europe, the largest market for U.S. met coal exports, is expected to have weaker demand than Asia, where Australia, the world's dominant met coal exporter, benefits from close proximity to the market. The focus of current mine development projects on high-quality, low-cost resources outside the United States suggests that U.S. producers will continue in their current role as peak rather than baseload sources of met coal.

Steam coal producers also face challenges in export markets. The United States currently accounts for less than 2 percent of total global steam coal exports, having experienced a steady decline in its global export market share over the past two decades.[5] Europe's strong commitment to greenhouse gas reduction poses a major risk to sustaining, let alone increasing, sales to the largest historical U.S. steam coal importer. Rapid growth in sales to Asia, where U.S. producers face significant logistical disadvantages relative to other suppliers, is made even more challenging by the increasing efficiency of new coal-fired generators in the region that keep coal consumption growth below the rate of generation growth.

The bottom line is that U.S. coal production is unlikely to again rise from the ashes. This outlook reflects the combined effects of stagnant domestic electricity demand growth, advances in competing generation technologies offering low or no fuel costs and attractive capital costs, the risk of future emissions mitigation as a threat to existing coal-fired generation and new investment in coal and other emissions-intensive technologies, and unfavorable export market conditions.

THE U.S. COAL SECTOR

Recent and continuing challenges

Howard Gruenspecht

Introduction

This paper focuses on recent developments in the market for U.S. coal and its future prospects. It begins with an overview of the U.S. electric power sector, which accounted for 92 to 94 percent of annual U.S. coal use over 2005-17 (Table 1).[6] The paper reviews the underlying drivers of the decline in U.S. coal-fired generation over the past decade, considering differences across U.S. regions and the relative role of plant retirements or dispatch changes, which have implications for the potential reversibility of recent trends. I then turn to the future prospects for coal-fired power, considering both the continuing role of market forces and the effects of current and future policies. The paper addresses both the situation of existing plants as well as challenges for new investment in coal-fired power generation.

Next, I briefly review industrial coal use, which accounted for 6 to 7 percent of annual U.S. coal use over 2005-17.[7] Industrial coal use is highly concentrated in specific uses with limited scope for future growth.

The paper closes with a look at coal export markets, which absorbed between 4 and 13 percent of annual U.S. coal production over the 2005-17 period.[8] Despite an upturn in 2017, exports remain below their recent 2011-14 peak levels. Once considered promising, the outlook for sustained growth in U.S. coal exports is challenging.

Coal-fired generation in the United States

Recent developments in U.S. coal-fired generation

As summarized in Table 2, coal lost nearly 20 percentage points of generation market share in the United States between 2005-08 and 2017.[9] With total electricity sales almost constant over 2005-17, and coal providing roughly half of total generation in 2005, the absolute level of coal-fired generation fell by 40 percent. Natural gas and non-hydro renewables have both gained generation share, with the gas share increasing by more than 50 percent and the non-hydro renewables share tripling, albeit from a low baseline.[10]

Table 1: Overview of U.S. coal production and consumption, 2005-17

Year	Coal production (million short tons)	Met coal share of production*	Export share of production	Coal consumption, total (million short tons)	Electric power sector share of consumption	Industrial sector share of consumption
2005	1,131	4.6%	4.4%	1,126	92.1%	7.4%
2006	1,163	4.3%	4.3%	1,112	92.3%	7.4%
2007	1,147	4.8%	5.2%	1,128	92.7%	7.0%
2008	1,172	5.5%	7.0%	1,121	92.9%	6.8%
2009	1,075	4.9%	5.5%	997	93.6%	6.1%
2010	1,084	7.1%	7.5%	1,049	93.0%	6.7%
2011	1,096	8.3%	9.8%	1,003	93.0%	6.7%
2012	1,016	8.9%	12.4%	889	92.6%	7.2%
2013	985	8.8%	11.9%	924	92.8%	7.0%
2014	1,000	8.1%	9.7%	918	92.8%	7.0%
2015	897	7.3%	8.2%	798	92.5%	7.3%
2016	728	7.9%	8.3%	731	92.8%	7.0%
2017	774	9.4%	12.5%	717	92.7%	7.1%

Note: *Met coal production estimated as sum of exports and domestic use.

Sources: U.S. Energy Information Administration, "Monthly Energy Review," Tables 6.1 and 6.2; U.S. Energy Information Administration, "Quarterly Coal Report October-December 2017," export data.

Table 2: Generation share by fuel and total sales, 2005-17 (fuel shares in percent; total sales in terawatt-hours)

	Coal	Natural gas	Nuclear	Hydro	Non-hydro renewable	Other	Total sales
2005	49.60%	18.80%	19.30%	6.70%	2.20%	3.50%	**4,055**
2006	49.00%	20.10%	19.40%	7.10%	2.40%	2.10%	**4,065**
2007	48.50%	21.60%	19.40%	6.00%	2.50%	2.00%	**4,157**
2008	48.20%	21.40%	19.60%	6.20%	3.10%	1.50%	**4,119**
2009	44.40%	23.30%	20.20%	6.90%	3.70%	1.40%	**3,950**
2010	44.80%	23.90%	19.60%	6.30%	4.10%	1.40%	**4,125**
2011	42.30%	24.70%	19.30%	7.80%	4.70%	1.20%	**4,100**
2012	37.40%	30.30%	19.00%	6.80%	5.40%	1.10%	**4,048**
2013	38.90%	27.70%	19.40%	6.60%	6.20%	1.20%	**4,066**
2014	38.70%	27.40%	19.50%	6.30%	6.90%	1.20%	**4,094**
2015	33.20%	32.70%	19.60%	6.10%	7.20%	1.20%	**4,078**
2016	30.40%	33.80%	19.80%	6.60%	8.40%	1.10%	**4,077**
2017	30.1%	31.7%	20.00%	7.5%	9.6%	1.0%	**4,014**

Note: Utility-scale only; including small-scale solar photovoltaic generation would raise non-hydro renewable generation share by 0.6 percent in 2017 and by smaller amounts in earlier years.

Source: U.S. Energy Information Administration, "Electric Power Monthly with Data for February 2018," Table 1.1.

Key factors explaining declining coal generation over 2005-17 include the significant reduction in natural gas prices relative to coal prices, increased generation from wind and solar, which was initially driven by federal subsidies and state-level mandates but is becoming more economically attractive as costs are reduced, and virtually flat total electricity sales over 2005-17, all of which caused any growth in generation from natural gas and renewables to translate directly into reduced generation from coal.[11]

Table 3 shows recent trends in the prices of coal and natural gas paid by electric power generators. Natural gas prices rose over 2000-08, generally following oil price trends.[12] Even accounting for rising coal prices and the greater efficiency of new natural gas combined-cycle generators, which use about 30 percent less energy per kilowatt-hour of generation than coal-fired power plants, generators using coal had a significant fuel cost advantage through 2008.[13] The growth in shale gas production, which accelerated as the Great Recession began in 2008, led to dramatic and persistent changes in relative fuel prices that significantly reduced the average fuel cost advantage of coal-fired plants. A much narrower average fuel cost advantage, coupled with other disadvantages for coal-fired plants, including higher fixed and non-fuel variable operation and maintenance costs, higher environmental costs, and less operational flexibility, implied a significant loss in the overall competitiveness of coal plants in both restructured and vertically integrated markets.

The stagnation of electricity demand, growth in renewables, and fuel cost competition between coal and natural gas all vary significantly across states and regions. For example, while nationwide electricity sales were virtually unchanged between 2005 and 2017, annual average growth rates at the state level ranged from -1.8 percent in Kentucky to +4.7 percent in North Dakota.[14]

Variation across the states reflects population shifts, changes in commercial and industrial activity, and differences in policies to promote renewables and energy efficiency improvements. There are also important differences in relative fuel costs across regions, with transport costs between the mine and the power plant often a significant component of coal's delivered fuel cost. Delivered coal prices are generally lower in regions that have the lowest transportation costs from the Powder River basin, the largest source of steam coal in the United States.[15] For example, delivered coal prices in the West North Central region versus the South Atlantic region, two areas that use considerable amounts of coal, differ by about $1 per million British thermal units (Btu) of energy produced.[16] Coal's loss in competitiveness has been most severe in regions with relatively high delivered coal prices.

Table 3: Average delivered cost of fuels to generators, 2005-17 (dollars per million Btu)

	Coal	Natural gas	*Gas-to-coal price ratio, adjusted for plant efficiency
2005	$1.54	$8.21	373%
2006	$1.69	$6.94	287%
2007	$1.77	$7.11	281%
2008	$2.07	$9.01	305%
2009	$2.21	$4.74	150%
2010	$2.27	$5.09	157%
2011	$2.39	$4.72	138%
2012	$2.38	$3.42	101%
2013	$2.34	$4.33	130%
2014	$2.37	$5.00	148%
2015	$2.22	$3.23	102%
2016	$2.11	$2.87	95%
2017	$2.08	$3.39	120%

Note: *Relative price adjusted for efficiency is calculated as 70 percent of the gas price divided by the coal price, since an efficient gas-fired plant uses only 70 percent of primary energy input used by a coal-fired plant per unit of electricity generation.

Source: U.S. Energy Information Administration, "Electric Power Monthly with Data for February 2018," Table 4.1.

The decline in coal-fired generation over the last 10 years was realized through a combination of lower coal plant utilization rates and plant retirements. Unlike retirements, reductions in utilization rates can be easily reversed if relative fuel prices change. Nearly all of the initial adjustment in generation came through reduced utilization, with average coal plant utilization rates declining from over 73 percent in 2005-08 to below 64 percent in 2009-12, with a continuing decline below 54 percent over 2015-17.[17] While reduced utilization still accounts for the bulk of reduced generation, coal plant retirements began to accelerate starting in 2012, as overall electricity sales failed to rebound and prospects for low natural gas prices over an extended period became clearer with the rapid expansion of gas production in both the gas-rich Northeast plays (Marcellus and Utica) and in oil-dominant shale plays (Bakken, Eagle Ford, and Permian), where it was a byproduct of oil-targeted development. Deadlines for compliance with the Environmental Protection Agency's (EPA) Mercury and Air Toxics rule, which in many cases would require significant investments, further accelerated retirements. In sum, over 50 gigawatts of coal-fired capacity retired over 2012-17, with more retirements anticipated over the coming years with continuing adverse conditions.[18]

The outlook for U.S. coal-fired generation

Recent projections in the EIA's 2018 Annual Energy Outlook, the International Energy Agency's (IEA) 2017 World Energy Outlook, Bloomberg New Energy Finance's (BNEF) New Energy Outlook 2017, and IHS Markit's 2017 outlook reflect the importance of both market factors and policies regarding the future of coal generation in the United States.[19]

U.S. generation from coal reached its historical high of 2016 billion kilowatt-hours (BkWh) in 2007. By 2016, coal-fired generation was 1239 BkWh. Projections for coal-fired generation in 2025 from the EIA, IEA, BNEF, and IHS outlooks range from about 900 BkWh to over 1350 BkWh.[20]

These projections are sensitive to both market and policy assumptions. In the EIA's 2018 outlook, assumptions about future natural gas market conditions play a big role. In scenarios without the Clean Power Plan rule, projected coal-fired generation in 2025 declines to 1183 BkWh in the reference case, as the average delivered price of natural gas to power plants increases to about $4.50 per million Btu. In the "high oil and gas resource and technology" case, where delivered natural gas in 2025 costs about $3.50 per million Btu, consistent with the price outlook of many private analysts, coal-fired generation declines more steeply, reaching 909 BkWh. In the IEA's 2017 outlook, projected coal-fired generation in 2025 is 1293 BkWh in the "new policies" scenario and 1363 BkWh in the "current policies" scenario, which includes fewer policies to promote renewables and efficiency.[21] Coal-fired generation in BNEF's outlook for 2017 is 1278 BkWh in 2025, close to the two IEA cases, while the IHS 2017 outlook projection for coal-fired generation falls between the two EIA cases at 1081 BkWh.[22] IHS and Bloomberg, which substantially reduced their projections for coal-fired generation in the 2018 edition of their outlooks, are not explicit regarding the market and policy assumptions used in their projections.

The range of projections for coal-fired generation is considerably wider in 2040 than in 2025. The IEA projects relatively stagnant coal-fired generation between 2025 and 2040 in its "current policies" case, reaching 1347 BkWh in 2040; in its "new policies" case, coal-fired generation declines modestly, reaching 1199 BkWh in 2040. In the EIA's 2018 projection, coal-fired generation in 2040 is 829 BkWh in a scenario with abundant natural gas that keeps delivered prices to generators below $3.50 per million Btu and 1164 BkWh in the reference case, in which the average delivered natural gas price to the power sector in 2040 rises to nearly $4.90 per million Btu. BNEF projects a more than 50 percent decline in coal-fired generation over the 2025-40 period, with coal generation at 606 BkWh in 2040.[23]

As part of its 2018 outlook, the EIA developed alternative cases that assume full implementation of the Clean Power Plan issued in 2015.[24] Under the reference case's relatively pessimistic assumptions about natural gas supply, the Clean Power Plan lowers projected coal-fired generation in 2030 from 1196 BkWh to 966 BkWh. This projection is higher than the 935 BkWh projected without the plan in the "high oil and gas resource and technology" case. This outcome highlights the dominant role of gas market conditions in determining the level of future coal use. A combination scenario that includes both abundant natural gas and the Clean Power Plan reduces projected coal-fired generation in 2030 to 779 BkWh. Thus, the Clean Power Plan provides some further reduction in coal-fired generation even when gas market conditions are unfavorable for coal, although the impact is smaller than under reference case market conditions that are more supportive of coal generation.

All of the projections reviewed above include no significant new builds of coal-fired power plants. New coal-fired capacity is too expensive even without consideration of the additional risk of future policies to mitigate emissions in a world where GHG emissions remain a concern. Levelized cost, as calculated by the EIA, Lazard Freres, and other analysts, is a simple yet imperfect summary metric for comparing the total capital and operating cost of power generation from new plants given their capital cost, fuel costs (if applicable), and other operating costs under assumptions that each technology is utilized at a rate defined by its operating capabilities and purpose. Given estimated capital costs for new coal-fired power plants, which exceed global averages, and reference case U.S. natural gas prices, which are below global averages, the EIA estimates that the levelized cost of a new coal plant to be roughly twice that of a new natural gas plant, which is also more flexible and easier to site and build, as is shown in Figure 1.[25] The advantage for natural gas is even larger in the EIA's "high resource and technology" case, which has gas prices closer to the current futures market prices for deliveries over the next 6 years. Renewables, which unlike coal and gas cannot be dispatched by operators to follow variation in load, also have a significant levelized cost advantage relative to coal.

With the exception of the EIA's "low resource and technology" cases, where average delivered gas prices to generators escalate rapidly to exceed $6.50 per million Btu in the early 2020s and nearly $8 per million Btu by 2040, all available projections from the EIA, the IEA, BNEF, and IHS Markit show a reduction in coal-fired generation over time, driven primarily by a combination of weak electricity demand conditions and continuing competition from natural gas and renewables.

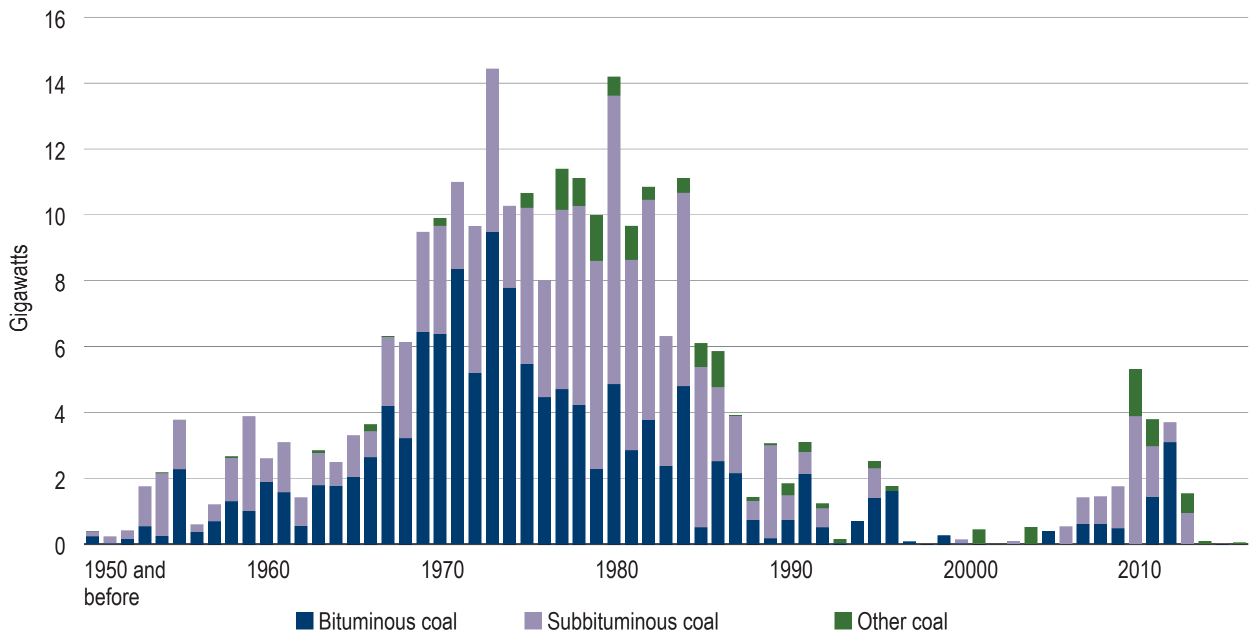
Figure 1: Estimated levelized cost of electricity (LCOE) for plants entering service in 2022

Estimated LCOE (2016 $/MWh) for new generation resources for plants entering service in 2022. (NOTE: simple average of regional values for dispatchable technologies, weighted average of regional values based on projected capacity additions for non-dispatchable technologies.)

	U.S. average LCOE (2016 $/MWh) for plants entering service in 2040							
Plant type	Capacity factor	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system LCOE	Levelized tax credit1	Total LCOE including tax credit
Dispatchable Technologies								
Coal-fired								
Conventional Coal	85%	67.4	5.6	25.7	1.2	**99.9**	NA	**99.9**
Advanced Coal	85%	74.7	7.2	26.7	1.2	**109.8**	NA	**109.8**
Coal 30% with carbon sequestration[2]	85%	94.9	9.3	34.6	1.2	**140**	NA	**140**
Coal 90% with carbon sequestration[2]	85%	78	10.8	33.1	1.2	**123.2**	NA	**123.2**
Natural Gas-fired								
Conventional Combined Cycle	87%	13.9	1.4	**40.8**	1.2	**57.3**	NA	**57.3**
Advanced Combined Cycle	87%	15.8	1.3	**38.1**	1.2	**56.5**	NA	**56.5**
Advanced Nuclear	90%	73.6	12.6	11.7	1.1	**99.1**	NA	**99.1**
Non-Dispatchable Technologies								
Wind – Onshore	41%	39.8	13.1	0	2.9	**55.8**	-11.6	**44.3**
Solar PV[4]	25%	59.8	10.1	0	3.8	**73.7**	-15.6	**58.1**

Would be lower with abundant gas

Figure 2: U.S. coal-fired generating capacity by vintage and fuel type (vintage reflects date of initial operation)



Source: U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," Figure 3.8.

The obsolescence of existing coal plants and their possible need for significant investments to remain operable represent an additional risk for coal that is not considered in EIA and IEA modeling. As shown in Figure 2, more than 60 percent of the coal-fired capacity used in 2018 began operation prior to 1980, including 20 percent that began operation before 1970.[26] By 2050, plants in the latter category would be at least 80 years old, while those entering service in the 1970-79 period would be in their 70s.[27] The EIA has announced its intention to pay more attention to obsolescence and upkeep costs in its future modeling.

Other policies affecting future U.S. coal-fired generation

While much attention has focused on the Clean Power Plan, other policies can also affect coal's future role in the power generation mix. Such policies potentially include decisions by federal and state electricity regulators, federal or state environmental compliance strategies, support for non-coal energy, federal coal leasing, royalty policies, and subsidies to coal producers or users. It is important to distinguish policy developments that are largely symbolic from those that could really affect coal use.

Electricity market regulations: In September 2017, Secretary of Energy Rick Perry proposed that the Federal Energy Regulatory Commission adopt a Grid Resiliency Pricing Rule requiring operators of wholesale electricity markets to assure that coal and nuclear power plants that maintained a 90-day on-site fuel supply could fully recover their plant investment costs along with a guaranteed return on equity.[28] The rule, which the FERC unanimously declined to adopt,[29] would have led coal plants in affected regions to increase the size of their fuel stockpiles and to continue operating despite the availability of lower-cost power from natural gas and renewable energy. As discussed in Box 1, the secretary's claim that his proposal was justified by the need to assure reliability and resiliency of the grid was not supported by the underlying facts.

BOX 1: SECRETARY PERRY'S PROPOSED GRID RESILIENCY PRICING RULE

FERC's unanimous decision to reject Secretary Perry's proposed rule was consistent with data presented in a study requested by Perry in April 2017, and released a month before his proposal to FERC, showing that the decline in the combined share of coal and nuclear power over 2002-16, whether measured in terms of capacity (from 47 percent to 35 percent) or generation (from 70 percent to 50 percent), had occurred without adverse impact on reliability or resiliency. Wide differences in the generation mix across U.S. regions further undercut the secretary's rationale, with all areas maintaining reliable electricity systems despite combined coal and nuclear capacity and generation shares that vary widely. For example, in 2016 coal and nuclear plants combined accounted for 46 percent of capacity and 60 percent of generation in the Midwest, but only 6 percent of capacity and 13 percent of generation in California.

The secretary's further claims, that coal's loss of competitiveness reflects flaws in the design of wholesale power markets and policy support for renewable energy, failed to explain or account for coal's loss of competitiveness in the Southeast. In this area, generation and capacity market shares fell respectively from 39 percent and 51 percent in 2002 to 26 percent and 25 percent in 2016, despite that region's maintaining traditional cost-of-service regulation of electric utilities that remain vertically integrated, with very limited or nonexistent mandates for renewable energy.

The proposed 90-day on-site fuel storage requirement, about 20 percent higher than the average level of fuel stocks actually held at coal plants over the past five years, would mainly have served to promote a one-time increase in coal sales as coal plant operators seek to qualify for guaranteed cost recovery and returns on equity. Guaranteed cost recovery would also subsidize coal plants, with consumers covering the costs of economically uncompetitive plants that would grow in numbers due to the elimination of competitive pressure and the cost of artificially large coal stockpiles.

The secretary's proposed rule treated existing coal and nuclear plants as equally deserving of support, despite the two technologies being at opposite ends of the spectrum with respect to GHG emissions and other pollutants that are not currently regulated or taxed. New York and Illinois have enacted state-level policies to preserve existing nuclear generation. These policies include support comparable to incentives provided to other emissions-free energy sources including wind and solar power. In contrast, guaranteed cost recovery for coal plants that are not competitive even without a price on emissions would only serve to increase emissions.

Other options to mandate coal plant use: In March 2018, First Energy Solutions, which owns and operates four coal-fired and three nuclear power plants located in Pennsylvania, Ohio, and West Virginia, asked the DOE to invoke its emergency authority under Section 202(c) of the Federal Power Act[30] to support baseload coal and nuclear plants in the PJM Interconnection[31] over the next four years. This provision, which applies in times of war or when an emergency exists "*by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy, or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes,*" authorizes the secretary nia, Ohio, and West Virginia, asked the DOE to invoke its the emergency and serve the public interest. Past uses of this authority have dealt with emergencies involving actual or imminent gaps between supply and demand rather than to assist particular generators that are not economically competitive.

The 1950 Defense Production Act (DPA), which provides broad presidential authorities to intervene into industrial activities and commercial contracts "to promote the national defense," is, according to media reports, also being considered as a possible tool to support some existing coal-fired generation.[32] The use of the DPA for this purpose would represent a significant departure from past practice, including its use by the Clinton and George W. Bush administrations during the 2000-01 California power crisis to address Pacific Gas & Electric's inability to procure natural gas supplies due to a lack of credit. In some respects, the potential application of the DPA based on national security concerns parallels the national security justification recently used by the Trump administration as the basis for other controversial policies, including the recent imposition of new tariffs on a variety of imports and threats to impose additional tariffs unless our trading partners are prepared to change practices and policies that the administration finds objectionable. Because the courts and the Congress have generally deferred to executive branch authority over national security matters, the DPA is a particularly powerful lever. However, it is not yet clear how far the administration would be prepared to go in mandating generation using coal on national security grounds, particularly given the high demonstrated reliability of electricity supply in major U.S. regions such as the Northeast and California, where coal is not a major generation source.

Subsidies for coal production or use: A tax credit is currently available to producers of refined coal, which is processed with additives to achieve a 20 percent reduction of nitrogen oxide emissions and a 40 percent reduction of either sulfur dioxide or mercury emissions compared with the emissions that would result from burning the unprocessed feedstock coal. The tax credit, which is adjusted annually for inflation and is available during the first 10 years of production for a processing facility placed in service before 2012, was $6.91 per ton in 2017. The price-equivalent value, which generally exceeds the face value, depends on the claimant's marginal tax rate.[33] The Energy Information Administration reports that refined coal represented 19 percent of total coal consumed at U.S. power plants during the first nine months of 2017.[34] A smaller tax credit is available for the production of coal on Native American lands. The credit for Native American coal was recently extended through 2017, along with a series of other energy tax credits as part of the budget agreement reached in February 2018. A bill was recently proposed that would extend the credit available for refined coal produced at existing facilities for an additional 10 years and also open a three-year window for new refining facilities to be added to the program.[35]

Federal coal leasing policy: Coal production on federal lands accounts for nearly all coal production in the western United States and about 40 percent of total U.S. coal production. In January 2016, the Obama administration announced a moratorium on coal leasing and the launch of a programmatic environmental impact statement (PEIS) to determine, among other topics, whether the current leasing regime offers a fair return to the federal government due to the tension between producing very large quantities of federal coal while pursuing policies to reduce U.S. GHG emissions substantially, including from coal combustion. Former United States Secretary of the Interior Sally Jewell's order on behalf of the Obama administration also noted that the current leasing system did not provide a way to systematically consider the climate impacts and costs to taxpayers of federal coal development.[36] Obama's Council of Economic Advisers issued a paper that explored possible approaches to changing leasing practices and royalty rates that would increase royalties paid, including options that, would significantly increase the delivered price of the subject coal. This would in turn reduce its economic competitiveness with generation fueled by renewables, natural gas, and coal sourced from private lands in the eastern United States and the Midwest, which have lost significant market share to Western coal since the early 1990s.[37]

With the advent of the Trump administration, Secretary of the Interior Ryan Zinke lifted the leasing moratorium and cancelled the PEIS, noting that "the public interest is not served by halting the federal coal program for an extended time, nor is a PEIS required to consider potential improvements to the program."[38] Given the absence of significant interest in new leasing activity under current coal market conditions, the immediate effects of the policy reversal are more symbolic than substantive. While the coal industry has avoided, for now, leasing and royalty regime changes that would be detrimental to coal's competitive position that has already been weakened by other developments, possible changes under a future administration remain a continuing downside risk for coal.

Subsidies for carbon capture and sequestration: The recently enacted Bipartisan Budget Act of 2018 substantially raised the pre-existing carbon capture and sequestration (CCS) tax credits ($10 per ton of CO_2 used for enhanced oil recovery [EOR] or other use, and $20 per ton for permanent storage).[39] Under the new law, tax credits start at $12.83 per ton for EOR and $22.66

per ton for permanent storage, increasing linearly to $35 per ton and $50 per ton respectively by the end of 2026, with continuing adjustment for inflation. The new law also allows any qualified facility to receive credits for up to 12 years after the CCS equipment is placed in service, effectively removing the 75-million-ton cap on CCS capacity eligible to receive tax credits under the pre-existing law.

While the increase in CCS subsidies was strongly supported by members of Congress from coal-producing states, new coal-fired plants incorporating CCS or significant retrofits of CCS at existing coal plants remain a doubtful proposition.[40] Existing coal plants are economically challenged even without requirements to limit their CO_2 emissions. Subsidies for CCS retrofits cannot improve their economic competitiveness unless they fully cover all capital and operating costs of CCS beyond returns, if any, from sales of CO_2 from CCS for enhanced oil recovery or other uses. The subsidies provided under the Bipartisan Budget Act of 2018 do not satisfy this test.

The new, higher subsidies for CCS are more likely to be effective in advancing its application in other areas such as industrial plants and ethanol production facilities that produce relatively clean streams of CO_2. They may also be applicable to new generation technologies, such as the NET Power Allam cycle that uses high-pressure supercritical CO_2 rather than steam as a working fluid and oxy-combustion of carbon-based fuels in a highly recuperated cycle that captures all emissions, with liquid water and a stream of high-purity, pipeline-ready CO_2 as the only byproducts.[41] If the promise of full and free emissions capture in a very high-efficiency generation cycle is realized, the newly enhanced CCS credits could provide a significant impetus to commercial deployment fueled by natural gas, increasing competition for coal-fired generators.

Policies reducing investments required to operate existing coal plants: The continued operation of some coal-fired plants can depend on how existing environmental rules are interpreted and implemented, as illustrated by recent developments in Arkansas. In 2016, the EPA issued a federal implementation plan (FIP) for coal-fired power plants in Arkansas after determining that the state had failed to develop an adequate implementation plan (SIP) to address their contributions to regional haze. The FIP mandated the installation of over $2 billion in sulfur dioxide scrubbers on 3.3 gigawatts (GW) of coal-fired capacity at two plants. Entergy, an owner of the plants, challenged the EPA's determination in court, noting that the added cost of scrubbers would make the plants uncompetitive with other supply options and therefore result in their closure.[42]

With the advent of a new administration, the EPA reversed course and agreed to let Arkansas develop a new SIP proposal. In January 2018, the EPA approved the first part of the new SIP, which deals with nitrogen oxide emissions, noting that "this action represents the first step in replacing the embattled one-size-fits-all FIP."[43] Arkansas submitted the second part of its new SIP, which addresses sulfur dioxide and particulates, in August 2018. In November 2018, the EPA announced a proposed rule that would approve the Arkansas proposal. In that same month, Entergy and environmental groups reached an agreement under which environmentalists would withdraw their lawsuit seeking enforcement of the FIP mandate for scrubber installation at the two plants in exchange for an Entergy commitment to cease coal use at one plant by the end of 2028 and at the other by the end of 2030.

State-level policies: Key state-level policies that matter most for future coal use often focus on generation sources that compete with existing coal plants, such as renewables, natural gas, and existing nuclear generation, or on energy efficiency initiatives that curtail demand. States and regions also differ significantly in renewables policies, with wide variation across the 37 states that have either a renewables mandate (29 states) or target (eight states).[44] Policies to promote renewables are constantly under review, with states considering proposals to either increase or reduce their stringency. Recent enactments have generally increased mandates for renewable generation, reducing the need for other types of generation.[45] Renewable generation mandates are particularly challenging for coal-fired generators and other sources of traditional baseload power that cannot be quickly and efficiently ramped up or down to accommodate swings in generation from variable renewable energy sources that, when available, have the lowest marginal cost of all generation resources.

Existing nuclear plants currently provide 20 percent of U.S. generation, but many nuclear generators are economically challenged by low natural gas prices, expanding renewable generation, and stagnant overall electricity sales. According to several recent analyses, the majority of existing nuclear plants are not profitable under current market conditions.[46] Several plants have already closed or set shutdown dates, while others have announced plans to do so unless the states they serve offer subsidies to support their continued operation, as Illinois and New York have already done. The impact of future nuclear shutdowns on coal use varies across regions, with Pennsylvania, Ohio, the Midwest, and the South likely having some prospect for more generation from existing coal plants should nuclear capacity be retired.

Cost-effective decarbonization: Existing U.S. coal-fired generators continue to face a significant downside risk from future policy change toward more aggressive GHG mitigation. In 2017, coal-fired generation still accounted for 1207 million metric tons of CO_2 emissions.[47] A 50 percent reduction in coal generation, less than the absolute reduction over 2005-17, replaced by a 50-50 mix of natural gas and emissions-free sources, would reduce annual U.S. CO_2 emissions from electricity generation by roughly 950 million metric tons.[48] Further decarbonization of electricity compares very favorably in both cost-effectiveness and scale of impact over the next 15-20 years to other emissions reduction strategies, such as higher fuel economy standards for light-duty vehicles currently being reviewed.[49] While deep decarbonization would ultimately require emissions reductions across all sectors, the adoption of economically efficient instruments such as carbon taxes or cap-and-trade programs would favor an immediate focus on additional emissions reductions in electricity through further displacement of coal-fired generation. Efficient emissions reduction strategies also need to address low-cost opportunities to non-CO_2 greenhouse gases, including the reduction of methane emissions from natural gas production and transportation systems.

Industrial coal use in the United States

Steam coal for industrial heat and power applications and metallurgical (met) coal used to make steel account for less than 7 percent of overall U.S. coal consumption. Over 2005-17, aggregate industrial coal use declined nearly 40 percent. Industrial steam coal use, now about two-thirds of total industrial coal use by volume, fell by 44 percent over 2005-17, while the use of met coal in steelmaking fell 25 percent over the same period.[50]

As in the case of electricity generation, substitution across fuels has played a key role in reducing industrial steam coal use over 2005-17, with industrial natural gas use rising 24 percent and industrial petroleum use declining 13 percent over the same period. The total energy content of fossil fuels used in industry was virtually unchanged over 2005-17, while total industrial production rose slightly.

In contrast to the electricity sector, where changes in the dispatch ordering of plants using different fuels has been the main driver of reduced coal use, a combination of retirements and permanent fuel switches for economic advantage or environmental compliance have driven declines in industrial coal use. For this reason, there is less opportunity for coal to make a significant comeback in U.S. industrial applications if the price of coal was to decline relative to other fuels than there is in the electricity sector.

Available industrial energy coal consumption projections show continued weaknesses in U.S. industrial coal use. The EIA's 2018 Annual Energy Outlook projects 0.2 percent compound annual growth in overall industrial coal use over 2017-50 in the reference case, where delivered natural gas prices to industry increase, reaching $5.25 per thousand cubic feet (mcf) in 2030 and $6.09 per mcf in 2050. In the abundant gas resources and technology scenario, where delivered natural gas prices to industry remain close to $4 per mcf over 2030-50, industrial coal use declines at a 0.3 percent compound annual rate. Only in the "low gas resources" case, with delivered natural gas prices to industry reaching $8 per mcf in 2030 and over $10.50 per mcf by 2050, is there significant growth in industrial coal use (0.7 percent compound annual growth rate over 2017-50). Projected met coal use—which is roughly flat in the reference case, declines at a 1 percent compound annual rate in the "high natural gas availability" case and grows at about that same rate in the "low natural gas availability" case—is significantly more responsive to relative fuel prices than industrial steam coal use.

All of the cases from the IEA's World Energy Outlook 2017 project declines in U.S. industrial coal use, with annual average compound rates of 0.7 percent and 0.6 percent declines over the 2016-40 period in the "new policies" and "current policy" cases. In the IEA "sustainable development" scenario, which aims to be consistent with achieving the goals of the Paris Agreement on climate change, the annual compound decline rate in industrial coal use is significantly higher at 1.8 percent over this period.

U.S. coal exports

As is shown in Table 4,[51] U.S. coal exports increased substantially in 2017, but still remain well below levels realized during the 2011-14 period. Coal exports are either met coal, which is used in certain steelmaking processes, or steam coal, which is used to generate heat for power generation, industrial applications, and to a much lesser extent in commercial and even residential applications. Below, I consider both the demand and supply factors affecting global markets for both coal types.

In contrast to domestic consumption, coal exports have generally been rising over the past decade, albeit with significant interannual variability. With rising exports and overall declines in U.S. production driven by declining domestic coal use, the share of U.S. production that is exported grew from an average of 5.3 percent over 2005-09 to slightly more than 10 percent over 2010-17. The divergence between rising exports and declining consumption has led some to suggest that coal exports might be a bright spot for the U.S. coal sector. However, as discussed below, the balance of available information suggests that exports are unlikely to significantly change the industry's challenging trajectory.

The distinction between met coal and steam coal is of particular importance with respect to U.S. coal exports. Export volume and value measures can differ significantly because met coal has a significantly higher value than steam coal. While met coal as a whole makes up less than 10 percent of U.S. coal production, over 75 percent of U.S. met coal is exported, representing more than 57 percent of U.S. coal exports by volume and 75 percent of coal export value in 2017. Since 2005, met coal's share of total coal export value ranged from a low of 68 percent in 2013 to a high of 83 percent in 2010.[52]

Australia is by far the world's largest met coal exporter. In 2016, Australia (which produced 188 million metric

Table 4: U.S. Coal Exports, 2005-2017

Year	Coal exports, total volume (thousand tons)	Export share of U.S. production volume	Met coal share of export volume	Coal exports, total value ($ million)	Met coal share of export value
2005	49,942	4.40%	57.40%	3,313.90	70.30%
2006	49,647	4.30%	55.40%	3,537.20	71.10%
2007	59,163	5.20%	54.40%	4,150.20	69.20%
2008	81,519	7.00%	52.20%	7,965.70	71.90%
2009	59,097	5.50%	63.10%	6,018.50	72.90%
2010	81,716	7.50%	68.70%	9,832.60	83.10%
2011	107,259	9.80%	64.80%	15,934.60	81.20%
2012	125,746	12.40%	55.60%	14,855.60	71.10%
2013	117,659	11.90%	55.80%	11,248.40	68.20%
2014	97,257	9.70%	61.80%	8,456.50	70.70%
2015	73,958	8.20%	62.20%	5,669.90	72.50%
2016	60,271	8.30%	67.90%	4,336.50	79.00%
2017	96,953	12.50%	57.00%	9,857.10	75.40%

Sources: U.S. Energy Information Administration, "Annual Coal Report 2017"; U.S. Energy Information Administration, "Quarterly Coal Report October-December 2017"; "Foreign Trade," U.S. Census Bureau.

tons) accounted for 60 percent of global met coal exports, well ahead of both the United States (37 million metric tons) and Canada (28 million metric tons), whose shares of global exports were 12 percent and 9 percent respectively.[53] Mongolia (24 million metric tons) and Russia (22 million metric tons), which round out the top five exporters, have been experiencing rapid growth in recent years.[54] While Asian countries are the dominant consumers and importers of met coal, Europe is the leading destination for U.S. met coal exports. In contrast, Australia sent 82 percent of its total met coal exports to five Asian countries–India, Japan, China, South Korea, and Taiwan.

Turning to steam coal, the top five exporters (Indonesia, Australia, Russia, Colombia, and South Africa) together account for over 90 percent of global exports. In 2017, the United States provided less than 2 percent of global exports, with Europe as the primary destination. Over the last two decades, the U.S. share of global exports has been declining, but effects of this decline on total export tonnage have been significantly offset by growth in global exports averaging nearly 6 percent over 1996-2016. With the recent slowdown and possible reversal in global coal export growth, significant growth in U.S. steam coal exports would require a rapid increase in U.S. producers' share of the global export market.

The outlook for U.S. met coal exports

The future market for U.S. met coal exports is usefully considered in terms of three main drivers: 1) growth in global steel demand; 2) the mix of technologies used to produce steel, which determines the amount of met coal needed to produce steel; and 3) the competitiveness of U.S.-sourced met coal relative to foreign suppliers. Below, we consider each of these factors in turn.

The outlook for steel demand, as reflected in a recent presentation to the Organization for Economic Co-operation and Development (OECD) steel committee, suggests continued global growth at a 1.1 percent compound annual rate over 2015-35.[55] This is substantially below the growth rate in the decade prior to 2015, when China's steel demand and production was growing very rapidly. Key factors driving the analysis include per capita GDP growth, the urbanization rate, fixed-asset investment intensity, and manufacturing intensity. Disruptors including product demand shifts, increased product lifetimes, and the possible substitution between steel and other materials in the automotive, capital equipment and machinery, construction, consumer and durable goods, and infrastructure sectors that are the dominant steel-using sectors. The core scenario reflects an intermediate effect of steel demand disruptors, bounded by scenarios with no disruptors (1.4 percent compound annual growth) and more radical disruptions (0.8 percent compound annual growth).

The steelmaking technology mix also has major implications for met coal use. Met coal is used in producing pig iron, which is then used in basic oxygen furnace (BOF) steelmaking, but not in electric arc furnace (EAF) steelmaking, the other major technology. While EAF and BOF technologies represent extremes with respect to the use of met coal, the intensity of met coal use in BOF steelmaking can also be reduced through the increased use of either steel scrap or direct reduced iron (DRI) as inputs to the BOF steelmaking process. All else equal, relatively low prices for electricity and natural gas and the availability of steel scrap favor increased reliance on EAF and DRI technology.

Both BOF and EAF technology are available globally, with BOF currently accounting for about 75 percent of global production. The technology mix varies widely across regions. In 2016, EAF production accounted for 67 percent of steel produced in the United States and 39 percent of steel produced in the European Union, but only 6 percent of China's steel production.[56] In North America, which has inexpensive electricity and natural gas as well as abundant steel scrap, the EAF share of total steel production has steadily grown, while the EAF share of EU production has been stable over the past decade. Over the same period, the EAF share in Asia declined. Given China's growing dominance in global steel production, the global EAF share also fell.

Several factors suggest a trend toward increased future reliance on technologies that reduce met coal intensity. Beyond their potential economic advantages, EAF and BOF technologies that reduce reliance on met coal can reduce emissions of greenhouse gases and other pollutants associated with traditional BOF steelmaking. This may be particularly important in Europe, which is strongly committed to reduction in greenhouse gases, and China, where emissions of conventional pollutants from steelmaking are a major policy concern.

The increased availability of steel scrap also favors reduced met coal intensity of steel production. As of 2016, BOF steelmakers in North America and the European Union used substantially more scrap input to produce crude steel (220 and 180 kilograms per metric ton, respectively) than China's BOF producers (110 kilograms per metric ton).[57] The rapid growth in China's steel consumption over 2000-14, a period of urbanization, industrial growth, and infrastructure buildout, has created a large stock of recyclable steel products that significantly increased the forward-looking scrap supply. At the same time, an expected leveling and decline in China's future steel use would eliminate and reverse steel production growth. Together, these trends will encourage higher scrap-use intensity through increases in EAF use and more scrap use in BOF steelmaking.

Finally, markets with abundant low-priced natural gas, including North America, Russia, and the Middle East, are likely to increase the use of DRI technology using natural gas, displacing the need for some production of pig iron using coal.

The combined effect of slow steel demand growth and increased reliance on technologies that lower met coal intensity imply overall weakness in met coal demand. While met coal use is still rising in some countries and regions, the IEA's latest coal market forecast projects no growth in global met coal use through 2022.[58] Europe, the leading destination for U.S. met coal exports, is projected to see a decline in met coal use over 2016-22, while Asia is expected to register an increase as growth in India offsets a modest decline in China, by far the largest met coal user.

While the OECD steel committee presentation cited earlier does not directly consider the met coal demand outlook, it also provides some indirect insights through its forecast of iron ore demand, since met coal use is closely linked to the production of pig iron in blast furnaces.[59] The forecast is for slow growth in iron ore demand through 2023, followed by declining iron ore demand through 2035, despite rising steel production through that year.

With overall global met coal demand stable or declining, sustained growth in U.S. exports would require that U.S. producers gain market share from other suppliers. Recent market developments and capacity plans both suggest significant challenges to such an outcome. As already noted, Europe, the main market for U.S. met coal exports, is expected to experience declining demand relative to Asia, where U.S. producers face more competition from other producers. Recent trade data suggest that the United States is a relatively high-cost met coal producer, with output and exports that tend to rise at times when supplies from other sources are disrupted. Examples include the effects of cyclones on Australian production and recent policy restrictions curtailing China's production.[60]

Finally, tracking of major coal mine projects by both the IEA and Australia's Department of Industry, Innovation, and Science, identify major met coal capacity additions planned in Australia, Russia, Mongolia, Mozambique, and Canada (which the Australian government views as a low-cost producer). The United States does not have any major projects on these lists. The new projects in Russia, Mongolia, and Mozambique should help them sustain their recent rapid growth in met coal exports. Absent an unexpected rise in demand, or further disruptions to production due to natural disasters or China's production policy, the outlook for U.S. met coal export growth does not appear promising.

While future U.S. met coal exports may experience periodic surges, as have occurred in the past, improvements in the met coal market would benefit only the small group of mines and states that produce met coal, rather than the entire coal mining sector. There is no published state-level data on met coal exports. However, national-level reporting on total bituminous coal exports includes data breakouts for met coal and other types of bituminous coal. These data show that met coal accounts for more than 75 percent of the value of total bituminous coal exports. U.S. census data also show that West Virginia, Pennsylvania, Alabama, and Virginia together accounted for 85 percent of total bituminous coal export value in 2017,[61] suggesting that changes in global met coal markets would primarily affect mines located in those states. Finally, while met coal's relatively high value is clearly an important metric, many of the ancillary activities associated with coal mining, such as truck, rail, and barge activity related to the movement of coal and the manufacturing and maintenance of coal mining equipment, are more closely tied to coal volumes than to coal value. For other key indicators, employment data on underground mining productivity suggest the possibility that met coal mining uses more labor per ton than other underground coal mining, but that the productivity difference is not so great as to explain all of the difference in product value.

The outlook for U.S. steam coal exports

Electricity generation is the dominant global use for steam coal. Throughout most of the world, and particularly in developing countries, electricity demand is growing at a faster rate than demand for other fuels delivered to end users. As in the United States, however, coal-fired generation faces strong economic competition from renewables and other technologies. The economic competitiveness of natural gas relative to coal varies widely across global regions given the significant expense of liquefying and transporting it to markets that, unlike the United States, do not benefit from abundant supplies of low-cost gas that can be transmitted from wells to customers via pipeline.

The IEA's coal outlook to 2022 projects global steam coal demand to grow at a 0.7 percent compound annual rate over 2015-22.[62] This figure is above the flat projection for met coal demand, but far below the 2.8 percent growth rate experienced over 1995-2016. The forecast shows a clear contrast between the developed OECD economies and the non-OECD economies. In the OECD, steam coal demand declines at a 1.4 percent annual average rate, led by an average annual decline rate of 2.5 percent in the European Union, a leading market for U.S. steam coal exports. In the non-OECD economies, steam coal use is expected to grow at a 1.3 percent annual average rate. Among the non-OECD markets, the fastest annual average growth rates are expected in India (3.3 percent), the Association of Southeast Asian Nations (ASEAN) (5.9percent), and other developing Asian countries (5.7 percent). However, despite faster growth in overall demand, total seaborne exports of steam coal are projected to decline at a 0.6 percent annual rate, while total seaborne exports of met coal grow at a 1.5 percent annual rate. The divergence between trends in overall demand and seaborne export markets largely reflects the situation in India, where there is significant growth in demand for both types of coal. For steam coal, demand growth is outpaced by increased domestic production, leading to a reduction in seaborne imports. However, in the absence of significant domestic met coal resources, almost all of India's incremental met coal demand is satisfied by increased seaborne imports.

The IEA's World Energy Outlook 2017 provides longer-run projections through 2040 for three main scenarios.[63] The "new policies" and "current policies" scenarios reflect specific sets of policies. Meanwhile the "sustainable development scenario" starts with a vision of how the energy sector can achieve sustainable development goals for universal energy access, limiting climate change consistent with the Paris Agreement, and reduction in pollutants other than greenhouse gases. Global demand for steam coal in power generation varies greatly across scenarios, with the compound annual average growth rate very close to zero in the "new polices" scenario (+0.05 percent), bracketed by the rates in the "current policies" scenario (+1.5 percent) and the "sustainable development" scenario (-5.6%).[64] This outcome illustrates the role of policies in influencing what is, by far, the largest market for steam coal. Looking at trade flows, the IEA projections show an overall decline in both the volume and share of global coal exports from the United States. The Bloomberg New Energy Outlook 2018, which is not explicit about assumed policy drivers, projects slow growth in global coal-fired generation over the next decade followed by a steep decline thereafter.[65] Projected coal-fired generation falls to less than half of today's level by 2050, despite a roughly 50 percent increase in global electricity demand. With coal providing 11 percent of total generation in 2050, down from 38 percent in 2017, coal use for power generation declines at a 2.5 percent annual compound rate over 2017-50, with consumption in 2050 at just 43 percent of its 2017 level.

The EIA's 2018 projections, which are most directly comparable to the IEA's WEO2017 "current policies" scenario, suggest a more pessimistic future for U.S. coal demand, as previously discussed in the section on U.S. electricity generation, but a somewhat more optimistic future for U.S. coal exports. Over 2017-40, U.S. coal demand declines at average annual rates of 0.3 percent in the reference case and 1.7 percent in the "high oil and gas resource" case, where natural gas prices do not rise appreciably. In the same two cases, coal exports are projected to increase at average annual rates of 0.6 percent and 0.9 percent respectively. Because exports absorb a relatively small share of U.S. coal production, the more pessimistic outlook for domestic demand pulls the EIA's projection for U.S. production below the IEA projection despite the more favorable market for exports.

While the EIA's outlook does not provide separate projections for met coal and steam coal exports, the average price for total exports suggests that steam coal is the primary growth market for U.S. coal exports. One challenge for a significant increase in steam coal exports will be the availability of export terminal capacity on the West Coast of the United States to serve growing markets in Asia. All but one of the West Coast terminal projects, planned when enthusiasm for coal exports was at its peak in the early part of the decade, have already been canceled. The project in Washington State that is still being actively pursued was denied permits by the state government. This action may be litigated by the project developers, with the support of coal producers and states that want to ensure the availability of low-cost transportation routes to serve Asian markets. The ultimate outcome of this dispute could have significant implications for future export opportunities.

Concluding observations

Employment and community concerns

While coal mining and the use of coal for electricity generation are relatively minor activities in the context of the national economy and overall employment, reductions in coal-fired generation have significant implications for workers and communities where coal is mined and coal-fired generation plants are located. Beyond those directly affected, shifts away from coal use are emblematic of a larger decline in high-wage, blue-collar job opportunities throughout the nation.

Coal mines averaged just under 80,000 direct and contract workers in 2017,[66] a significant decline from 137,000 in 2011 when coal mining employment was at its highest level since 1992. Recent reductions in coal mining employment are geographically concentrated, with a 64 percent reduction in Kentucky and greater than 50 percent reductions in Alabama, Colorado, Ohio, Virginia, and West Virginia between the end of 2011 and the end of 2016. As a percentage of the total state workforce, declines in coal mining employment over this period were 1.6 percent in West Virginia and 0.6 percent in Kentucky and Wyoming, but 0.1 percent or less in other states.[67] Nonetheless, displaced coal miners seeking alternative employment face significant challenges, such as leaving homes in remote communities where few opportunities are available, and the inability to find positions that offer pay comparable to mining wages.

Productivity trends are also a key employment driver in the coal industry. Coal mine employment, which was just over 250,000 in 1979, declined throughout the 1980s and 1990s as growth in the market share of surface-mined coal and increases in mining productivity more than offset growth in coal production. With a reversal in labor productivity trends since 2000, mining employment increased over 2000-11 as production fluctuated in a narrow range.

Workers and communities where coal-fired generation plants are located also face significant challenges. Coal-fired generation is more labor-intensive than gas-fired or renewable generation. Between 2008 and 2017, employment in fossil-fired generation declined by 33 percent, from 137,432 to 92,627, as combined coal and natural gas generation fell by just 13 percent. In addition to being a significant source of high-wage employment, coal-fired power plants often constitute a significant share of the local property tax base for their host communities. Particularly in smaller jurisdictions, plant retirements can create significant revenue losses. On a nameplate basis, 60 GW of the 344 GW of coal-fired capacity in the fleet at the end of 2011 was retired by the end of 2017. Coal, which is predominantly shipped by rail and accounts for a larger share of overall ton-miles than any other commodity, is also important to the railroad industry and its workers.

Implications for climate negotiations

President Trump's support for coal and his disparagement of national action and international commitments have raised considerable concern both domestically and globally among those wishing to advance the goals of the Paris Agreement. However, decarbonization of U.S. electricity generation will continue to be driven by markets and state-level policies. Very few, if any, new investments that would lock in U.S. coal use for the long term are expected. Recent independent assessments suggest that the United States can possibly reduce greenhouse gas emissions to 17 percent below the 2005 level by 2020, the target announced by the Obama administration in conjunction with the Copenhagen Accord.[68] The 26 to 28 percent reduction below 2005 levels by 2025, announced as the U.S. Nationally Determined Contribution in conjunction with the Paris Agreement, does appear to require new federal policies. While the current U.S. approach remains subject to future change, the protracted U.S. regulatory process means that time lags in implementing new policies, including actions to reduce emissions from coal use beyond what can be achieved by markets and state-level policies, are inevitable.

While the expected slowdown in U.S. emissions reduction beyond 2020 is unwelcome, a greater concern is that current U.S. positions on coal and climate will sow despair and provide a pretext for widespread weakening of the Paris Agreement. To avoid this outcome, it is helpful to focus attention on constructive developments in the United States. The United States is hardly unique in having a mixed record on emissions reduction progress. Germany, which is often characterized as a leading proponent of climate action, strongly supports both renewable energy and ambitious long-term climate objectives. However, it has made only small emissions reductions over the past decade and expects to fall well short of its 2020 reduction commitment.[69] It has also supported coal and is phasing out nuclear power, a major source of emissions-free generation. The international community has wisely chosen to emphasize the positive aspects of Germany's record rather than its weaknesses, and would benefit from adopting a similar approach to maximize opportunity for the future participation of the United States.

ENDNOTES

1. U.S. Energy Information Administration, “Monthly Energy Review,” (Washington, DC: United States Department of Energy, August 2018), Tables 12.1 and 12.6, https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.
2. U.S. Energy Information Administration, “Electricity Market Module,” (Washington, DC: United States Department of Energy, April 2018), https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.
3. See Table 1. Coal export volume equals coal production times coal export share.
4. International Energy Agency, “Coal 2017,” (Paris, France: December 18, 2017), https://www.iea.org/publications/freepublications/publication/CoalInformation2017Overview.pdf; Accenture, “Steel Demand beyond 2030: Forecast Scenarios Presented to OECD,” (Paris, France: Accenture, September 28, 2017), https://www.oecd.org/industry/ind/Item_4b_Accenture_Timothy_van_Audenaerde.pdf.
5. International Energy Agency, “Coal 2017.”
6. U.S. Energy Information Administration, “Quarterly Coal Report January – March 2018,” (Washington, DC: United States Department of Energy, July 2018), Table 6.1 and 6.2, https://www.eia.gov/coal/production/quarterly/archive/qcr.pdf; U.S. Energy Information Administration, “Monthly Energy Review.”
7. See Table 1.
8. Ibid.
9. U.S. coal-fired generation peaked in 2007, exceeding its level in 2005 by just 0.2 percent. Changes since 2005, which is widely used as a base year for greenhouse gas emissions reductions, are virtually identical to changes over the last decade (2007-17) and are discussed interchangeably throughout this paper. U.S. Energy Information Administration, “Electric Power Monthly with Data for February 2018,” (Washington, DC: United States Department of Energy, April 2018), Table 1.1, https://www.eia.gov/electricity/monthly/archive/april2018.pdf.
10. See Table 2.
11. Joshua Linn and Kristen McCormack, “The Roles of Energy Markets and Environmental Regulation in Reducing Coal-Fired Plant Profits and Electricity Sector Emissions,” (Washington, DC: Resources for the Future, October 2017), http://www.rff.org/files/document/file/RFF%20Rpt-NOx%20Costs.pdf, shows that lower natural gas prices, stagnant demand, and renewable generation growth explain virtually all of the reduction of carbon dioxide emissions from electricity generation, with little or no incremental effects from environmental regulation during this period.
12. U.S. Energy Information Administration, “Electric Power Monthly with Data for February 2018,” Table 4.1.
13. U.S. Energy information Administration, “Table 7.1. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 2007 through 2017,” (Washington, DC: United States Department of Energy), https://www.eia.gov/electricity/annual/html/epa_07_01.html.
14. Author’s calculations based on state-level electricity sales data for 2005 and 2017. U.S. Energy Information Administration, “Retail Sales of Electricity by State by Sector by Provider (EIA-861),” Washington DC: United States Department of Energy), https://www.eia.gov/electricity/data/state/.
15. While natural gas prices in some regions of the country, notably New England and New York, may experience significant spikes during extreme cold weather when heating demand is high and transport capacity is constrained, delivered gas prices do not vary significantly across markets under normal conditions.
16. U.S. Energy information Administration, “Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2017 and 2016,” (Washington, DC: United States Department of Energy), https://www.eia.gov/electricity/annual/html/epa_07_17.html.
17. U.S. Energy Information Administration, “Electric Power Monthly with Data for February 2018,” Table 6.7A; U.S. Energy Information Administration, “Electric Power Monthly with Data for January 2014,” (Washington, DC: United States Department of Energy, March 2018), Table 6.7A, https://www.eia.gov/electricity/monthly/archive/march2014.pdf; U.S. Energy Information Administration, “Electric Power Annual 2009,” (Washington, DC: United States Department of Energy, January 2011), Table 5.2, https://www.nrc.gov/docs/ML1104/ML110410547.pdf.
18. “Almost all power plants that retired in the past decade were powered by fossil fuels,” U.S. Energy Information Administration, January 9, 2018, https://www.eia.gov/todayinenergy/detail.php?id=34452#.
19. U.S. Energy Information Administration, “Annual Energy Outlook 2018,” (Washington, DC: Energy Information Administration, February 6, 2018), https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf; International Energy Agency, “World Energy Outlook 2017,” (Paris: International Energy Agency, 2017), https://www.iea.org/weo2017/; Bloomberg New Energy Finance, “New Energy Outlook 2018,” (New York, NY: Bloomberg New Energy Finance, 2018), https://about.bnef.com/new-energy-outlook/; IHS Markit, “North American Gas and Power Scenarios,” (London: IHS Markit), https://ihsmarkit.com/products/north-america-gas-power.html.
20. The 2018 Bloomberg New Energy Outlook, released after this paper was prepared, projects coal generation

in 2025 at 739 BkWh, much lower than the 1278 BkWh projected in the 2017 edition.
21. International Energy Agency, "World Energy Outlook 2017."
22. IHS Markit, "North American Power Market Outlook 2017," (Washington, DC: IHS Markit, 2017).
23. In the BNEF 2018 Outlook, projected coal-fired generation in 2040 is only 211 BkWh. See Bloomberg New Energy Finance, "New Energy Outlook 2017." The BNEF 2018 Outlook was discussed at a Center for Strategic and International Studies seminar in June 2018. See "BNEF's New Energy Outlook 2018, *Center for Strategic and International Studies*, June 20, 2018, https://www.csis.org/events/bnefs-new-energy-outlook-2018.
24. The Clean Power Plan rule sets emission performance rates, phased in over the period from 2022 through 2030, for fossil fuel-fired electric utility steam-generating units and stationary combustion turbines. These rates, applied to each state's particular mix of fossil fuel-fired units, generate the state's carbon intensity goal for 2030 (and interim rates for the period 2022-29). Each state then decides whether to apply the rule to each affected unit or to take an alternative approach and meet an equivalent statewide rate-based goal or mass-based goal. U.S. Energy Information Administration, "Annual Energy Outlook 2018."
25. Levelized cost as reported in the 2017 *Annual Energy Outlook*. Includes author's estimate for new coal plants without carbon capture and sequestration in row for "Conventional Coal." Does not include recently enacted tax credits for coal with carbon capture and sequestration. U.S. Energy Information Administration, "Annual Energy Outlook 2017," (Washington, DC: January 5, 2018), https://www.eia.gov/pressroom/presentations/sieminski_01052017.pdf.
26. See Figure 3.
27. U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," (Washington, DC: U.S. Department of Energy, August 2017), Figure 3.8, https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.
28. Federal Energy Regulatory Commission, "Grid Resiliency Pricing Rule," *Federal Register*, 82 (Washington, DC: October 10, 2017), https://www.federalregister.gov/documents/2017/10/10/2017-21396/grid-resiliency-pricing-rule.
29. Federal Energy Regulatory Commission, "Grid Reliability and Resilience Pricing, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures," (Washington, DC: U.S. Department of Energy, January 8, 2018), https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14633130.
30. Federal Power Act of, U.S.C. 824a § 1 et seq (2018).
31. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.
32. Jeff St. John, "Legal Considerations for DOE's Leaked Coal and Nuclear Bailout Plan," *Greentech Media*, June 6, 2018, https://www.greentechmedia.com/articles/read/legal-doe-leaked-coal-and-nuclear-bailout-plan#gs.amOEDRk.
33. The price-equivalent value is the face value multiplied by 1/(1-t), where t is the claimant's marginal tax rate. The Tax Cut and Jobs Act enacted in December 2017 reduced the maximum corporate tax rate from 35 percent to 21 percent.
34. "Short Term Energy Outlook," U.S. Energy Information Administration, https://www.eia.gov/outlooks/steo/report/coal.php.
35. A bill to amend the Internal Revenue Code of 1986 to extend the credit for production of refined coal, S.2373, 115th Cong., 2nd sess., introduced in Senate February 5, 2018, https://www.congress.gov/bill/115th-congress/senate-bill/2373/text.
36. U.S. Department of the Interior, "Secretarial Order 3338: Discretionary Programmatic Environmental Impact Statement to Modernize the Federal Coal Program / Moratorium on Federal Coal Leasing," (Washington, DC, January 15, 2016), https://www.documentcloud.org/documents/2691724-Secretarial-Order-3338-Coal.html.
37. The White House Council of Economic Advisers, "The Economics of Coal Leasing on Federal Lands: Ensuring a fair Return to Taxpayers," (Washington, DC: June 2016), https://obamawhitehouse.archives.gov/sites/default/files/page/files/20160622_cea_coal_leasing.pdf.
38. U.S. Department of the Interior, *Secretarial Order 3348: Concerning the Federal Coal Moratorium* (Washington, DC, March 29, 2017), https://www.doi.gov/sites/doi.gov/files/uploads/so_3348_coal_moratorium.pdf.
39. Bipartisan Budget Act of 2018, H.R. 1892, 115th Cong., 2nd sess., introduced in House April 4, 2017, https://www.congress.gov/bill/115th-congress/house-bill/1892/text.
40. For a similar perspective, see Energy Futures Initiative, "Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit," (Washington, DC: Energy Futures Initiative, May 2018), https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5b0604f30e2e7287abb8f3c1/1527121150675/45Q_EFI_5.23.18.pdf.
41. James Temple, "Potential Carbon Capture Game Changer Nears Completion," MIT Technology Review, August 30, 2017, https://www.technologyreview.com/s/608755/potential-carbon-capture-game-changer-nears-completion/.

42. Arkansas Department of Environmental Quality, "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule,"(Little Rock, AR: Arkansas Department of Environmental Quality, November 2016), https://www.adeq.state.ar.us/air/pdfs/2016-11-22-adeq-petition-for-reconsideration-and-adminstrative-stay-epa-r06-oar-2015-0189.pdf.
43. "EPA Approves Revisions to Arkansas Regional Haze Plan: Revised air quality plan created through cooperative federalism," *U.S. Environmental Protection Agency*, January 29, 2018, https://www.epa.gov/newsreleases/epa-approves-revisions-arkansas-regional-haze-plan.
44. "State Renewable Portfolio Standards and Goals," National Conference of State Legislators, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.
45. Galen L. Barbose, "U.S. Renewables Portfolio Standards: 2017 Annual Summary Report," (Berkeley, CA: Berkeley Lab, July 2017), https://emp.lbl.gov/publications/us-renewables-portfolio-standards-0.
46. Geoffrey Haratyk, "Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options," (Cambridge, MA: MIT Center for Energy and Environmental Policy Research, March 2017), http://ceepr.mit.edu/files/papers/2017-009.pdf; Ronaldo Szilard et al., "Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet – Cost and Revenue Study," (Idaho Falls, ID: Idaho National Laboratory, September 2017), https://lwrs.inl.gov/Systems%20Analysis%20and%20Emerging%20Issues/Economic_Market_Challenges_Facing_the_US_Nuclear_Commercial_Fleet_Cost_Revenue_Study.pdf.
47. U.S. Energy Information Administration, "Electric Power Monthly," (Washington, DC: October 2018), Table 12.6, https://www.eia.gov/totalenergy/data/monthly/.
48. Author's calculation based on the assumption that an efficient gas-fired power plant generates power with 60 percent lower emissions than a coal plant due to the lower carbon content of natural gas and higher efficiency of converting primary fuel into electricity.
49. For example, the effects of permanently freezing fuel economy standards at the level required under existing rules for model year (MY) 2021 rather than proceeding with tighter standards for MY2022-25 would increase projected carbon dioxide emissions from light duty vehicles by 34 million metric tons (MMT) in 2025, 69 MMT in 2030, and 93 MMT in 2035. Author's calculations made using the 2017 edition of the EIA National Energy Modeling System.
50. Further discussion of met coal is deferred until the discussion of coal exports in the next section of the paper.
51. U.S. Energy Information Administration, "Annual Coal Report 2017," (Washington, DC: U.S. Energy Information Administration, November 2018), https://www.eia.gov/coal/annual/pdf/acr.pdf; U.S. Energy Information Administration, "Quarterly Coal Report October-December 2017," (Washington, DC: U.S. Energy Information Administration, April 2018), https://www.eia.gov/coal/production/quarterly/archive/012117q4.pdf; "Foreign Trade," U.S. Census Bureau, https://www.census.gov/foreign-trade/index.html.
52. "Foreign Trade," U.S. Census Bureau.
53. International Energy Agency, "Coal 2017."
54. Australian Department of Industry, Innovation and Science, "Resources and Energy Quarterly," (Canberra, Australia: Australian Department of Industry, Innovation and Science, December 2017), https://publications.industry.gov.au/publications/resourcesandenergyquarterlydecember2017/documents/Resources-and-Energy-Quarterly-December-2017.pdf.
55. Accenture, "Steel Demand beyond 2030."
56. World Steel Association, "Steel Statistical Yearbook 2017," (Brussels, Belgium: World Steel Association, 2017), Table 6, https://www.worldsteel.org/en/dam/jcr:3e275c73-6f11-4e7f-a5d8-23d9bc5c508f/Steel+Statistical+Yearbook+2017.pdf.
57. World Steel Association, "Global steel industry: outlook, challenges, and opportunities. 5th International Steel Industry and Sector Relations Conference," (Istanbul, Turkey: April 2017), https://www.worldsteel.org/en/dam/jcr:d9e6a3df-ff19-47ff-9e8f-f8c136429fc4/International+Steel+Industry+and+Sector+Relations+Conference+Istanbul_170420.pdf.
58. International Energy Agency, "Coal 2017."
59. As noted above, increased use of DRI technology would raise the spread between iron ore and met coal demand growth.
60. Australian Department of Industry, Innovation and Science, "Resources and Energy Quarterly"; Trevor Houser, Jason Bordoff, and Peter Marsters, "Can Coal Make a Comeback?" (New York, NY: Center on Global Energy Policy, Columbia University, April 2017), https://energypolicy.columbia.edu/sites/default/files/Center%20on%20Global%20Energy%20Policy%20Can%20Coal%20Make%20a%20Comeback%20April%202017.pdf.
61. The bituminous export value share of these states exceeds 80 percent in all years since 2014 and 73 percent annually over the past decade.
62. International Energy Agency, "Coal 2017."
63. International Energy Agency, "World Energy Outlook 2017."
64. Note that these estimates incorporate IEA's previously discussed estimates for coal-fired generation in the United States, which in both the "new policies" (-0.5 compound annual decline rate) and "current policies" scenarios (virtually flat) are substantially above those from EIA and other sources.

65. Bloomberg New Energy Finance, "New Energy Outlook 2018."
66. U.S. Department of Labor, "MSHA at a Glance, CY1978-2017," (Arlington, VA: U.S. Department of Labor: 2018), https://www.msha.gov/sites/default/files/Data_Reports/at-a-glance-legacy-2.12.2018.pdf. Data includes employees and contractors working at mines and excludes office workers. With a civilian labor force of 160.3 million in 2017, coal miners represented 0.05 percent of the civilian labor force.
67. Trevor Houser, Jason Bordoff, and Peter Marsters, "Can Coal Make a Comeback?"
68. John Larsen, et al., "Taking Stock– 2018 Edition," (New York, NY: Rhodium Group, June 2018), https://rhg.com/research/taking-stock-2018/.
69. Kertine Appunn and Julian Wettengel, "Germany's greenhouse gas emissions and climate targets," (Berlin, Germany: Clean Energy Wire, July 2018), https://www.cleanenergywire.org/factsheets/germanys-greenhouse-gas-emissions-and-climate-targets.

BROOKINGS
1775 Massachusetts Ave., NW
Washington, D.C. 20036
brookings.edu