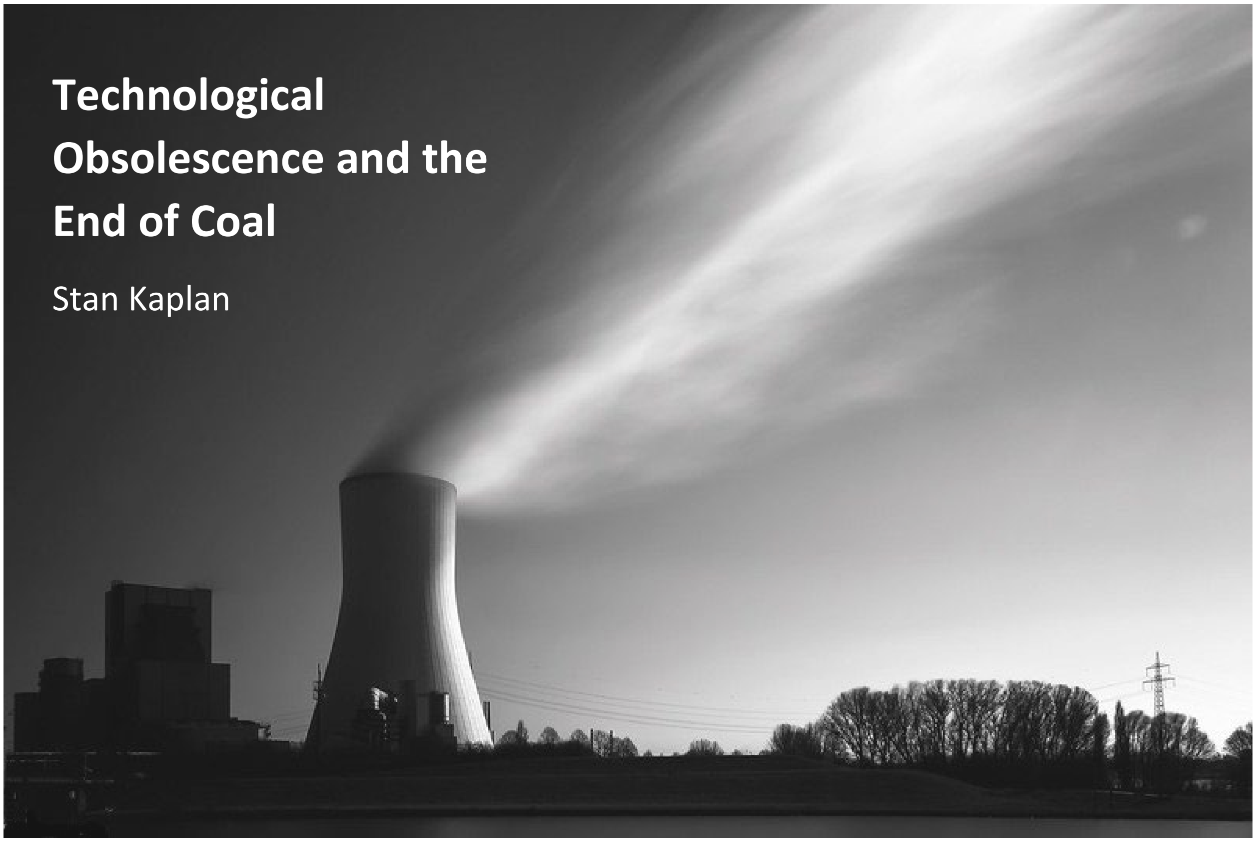

Technological Obsolescence and the End of Coal

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Cover illustration credit: Frank Henkemeyer (Flickr: t.ly/AdgD)

About the Author

Stan Kaplan has worked in the energy area since 1978, including as the fuel supply manager for Austin Energy, manager of fuel analysis for the Texas Public Utility Commission, and as a consultant in the electric, coal, and natural gas areas. Before retiring from the federal government in December 2018 he was a senior energy analyst with the Congressional Research Service and the manager responsible for electric power, coal, uranium, and electric renewable data at the U.S. Energy Information Administration. In 2020 he taught a graduate-level energy policy class at George Washington University.

Technological Obsolescence and the End of Coal

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July 2020

Abstract: *Across all dimensions – fuel production, transportation, combustion -- coal-fired electric generation technology has been surpassed by the natural gas combined cycle. Because electric power accounts for about 90 percent of domestic coal consumption, the displacement of coal for generation has devastated total coal demand. By the end of 2020 coal demand will have dropped by almost two-thirds in just 13 years.*

The rapid decline in power demand for coal – accelerated but not primarily caused by the COVID-19 crisis – repeats a historical pattern in which markets that are sensitive to fuel costs and ease of operation abandon coal rapidly once a better technology is available. The residential, commercial, and rail markets for coal all disappeared or became de minimis in 26 years or less. Electric power is following the same path.

The federal government is funding the development of coal plants that can better compete with combined cycles, but these initiatives are unlikely to stabilize coal demand. New technology will have little benefit for the existing fleet of obsolete units, and it is improbable many new coal plants will be built. But the basic issue is that aiming for incremental improvements to coal plants is already several steps behind the technology curve. The cost of wind, solar, and battery power is plunging. The future seems to lie with electricity generated without combustion.

Introduction and Summary

> "How did you go bankrupt?" Bill asked.
>
> "Two ways," Mike said. "Gradually and then suddenly."
>
> — *From The Sun Also Rises, by Ernest Hemingway, 1926*

The immediate causes of the collapse in American coal demand – down more than half since peaking in 2007 – are well known: Competition from cheap natural gas and renewable energy, tighter environmental regulations, and low wholesale power prices. But there is an underlying root cause, technological obsolescence. The end of coal in America is the final stage of decades of relative technological decline.

In the middle of the last century technical obsolescence overtook coal in its non-power markets: the rail, residential and commercial, industrial, and metallurgical sectors. In the markets where the cost and handling disadvantages of coal were most pronounced, coal demand disappeared with remarkable speed. As shown in Table 1, it took 10 years or less for coal to lose half of its sales in the residential, commercial, and rail sectors.

Table 1. Contraction in Coal Demand

		Number of Years from the Peak Demand Year to:		
Market Sector	Peak Demand Year	Loss of 50% of the Market	Loss of 90% of the Market	Number of Years Between loss of 50% and 90% of Market
Rail	1944[a]	6	12	6
Residential & Commercial	1944	9	26	17
- Residential	From 1949[b]	10	23	13
- Commercial	From 1949[b]	7	23	16
Industrial	From 1943[b]	28	NA[c]	NA
Metallurgical	1953	29	NA[d]	NA
Electric Power	2007	13[e]	NA	NA

Notes: [a] Post-Depression rail demand peaked at 138 million tons in 1944. The all-time peak was 146 million tons in 1920. [b] The data do not distinguish between residential and commercial demand prior to 1949. [c] The largest recorded Industrial demand is 235 million tons in 1917, the first year for which data for the sector are available. Afterwards, volumes show large positive and negative changes due to the Depression and World War II. The peak post-depression year is 1943. By 2019 industrial demand had decreased 83 percent from 1943. [d] By 2019 demand for coking coal had declined 82% from its 1953 peak. [e] Thirteen years is estimated based on EIA's forecast for coal demand in 2020. By the end of 2020 demand is expected to be down 65 percent from 2007.

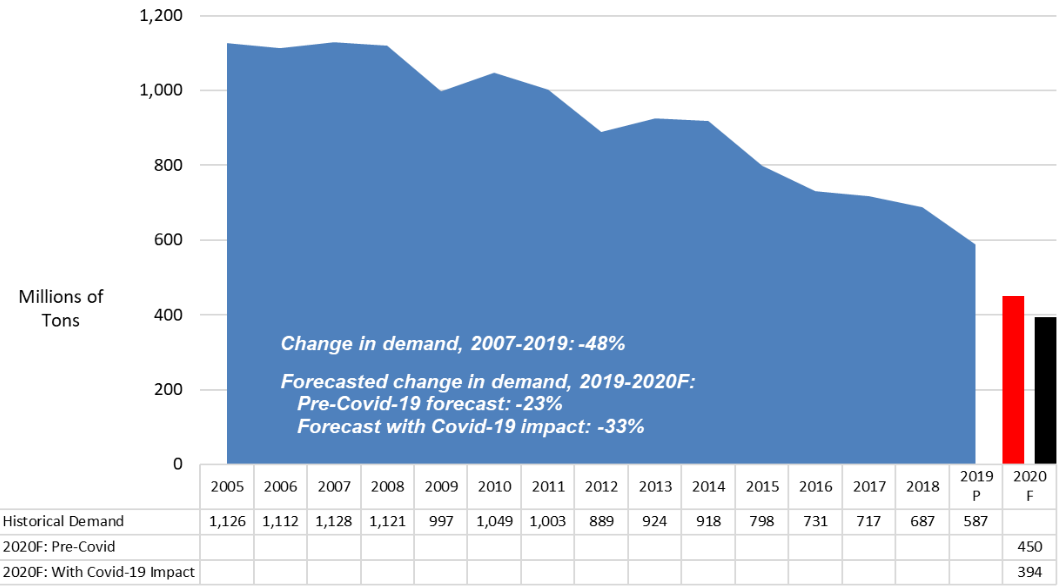
Sources: Pre-1949: "Minerals Yearbook." Washington: U.S. Bureau of Mines, various years; and "Historical Statistics of the United States, Colonial Times to 1970: Part 1." Washington: U.S. Bureau of the Census, 1975, p. 591. 1949 to present: EIA, Monthly Energy Review data file (Table 6.2), https://www.eia.gov/totalenergy/data/monthly/. Estimate for 2019 and forecast for 2020: "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Technological obsolescence has now overtaken coal in its last large market, power generation. By the end of 2020, just 13 years after coal consumption peaked in 2007, demand is expected to be down almost two-thirds. The COVID-19 crisis is quickening this collapse by causing a natural gas glut and recession. But COVID-19 has been an accelerant, not the cause, of coal demand destruction. As shown in Figure 1, even before the COVID-19 crisis coal consumption was expected to decline in 2020.

The evaporation of coal demand is likely to continue through the decade. Based on historical experience and absent government intervention, technological obsolescence will drive coal out of the power market in the next 10 to 15 years.

The balance of the paper discusses the elimination of the non-power coal markets, the collapse in power market coal demand, and presents a conclusion.

Figure 1. Decline in U.S. Coal Demand, 2005-2020F



Change in demand, 2007-2019: -48%

Forecasted change in demand, 2019-2020F:
Pre-Covid-19 forecast: -23%
Forecast with Covid-19 impact: -33%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019 P	2020 F
🟦 Historical Demand	1,126	1,112	1,128	1,121	997	1,049	1,003	889	924	918	798	731	717	687	587	
🟥 2020F: Pre-Covid																450
■ 2020F: With Covid-19 Impact																394

Note: All-time peak demand was 1.128 billion tons in 2007. **Sources**: Historical data and the preliminary estimate for 2019: EIA, Monthly Energy Review Excel file (Table 6.2.), https://www.eia.gov/totalenergy/data/monthly/. The pre-COVID-19 2020 forecast and the forecast reflecting the impact of COVID-19 for are from, respectively, "Short-Term Energy Outlook." Washington: U.S. Energy Information Administration, February 2020 and June 2020, Table 6.

End of the Non-Power Markets for Coal

In 1900 coal accounted for 93 percent of fossil fuel consumption in the United States and 71 percent of all primary energy consumption. [1] As late as 1944 coal still met half of total primary energy demand. Petroleum consumption did not exceed coal until 1950.

Coal dominated the early fossil fuel markets because it was a "ready-made" fuel for an evolving-technology economy.[2] Coal deposits could be located from surface outcrops; mined with explosives and men using pickaxes and shovels; transported by animals and steam locomotives; stored in outdoor piles; and burned by literally being shoveled onto the grate of a boiler or home furnace. With simple and even

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[1] Most of the balance was wood. Primary energy is the initial consumption of fuel for direct use or for transformation into another form of energy (most commonly electricity). The percentages are calculated from Sam Schurr and Bruce Netschert. *Energy in the American Economy, 1850 - 1975*. Baltimore: The Johns Hopkins Press, 1960, Table VII, 511.

[2] James P. Johnson. *The Politics of Soft Coal: The Bituminous Industry from World War I Through the New Deal*. Urbana: University of Illinois Press, 1979, 21

crude methods coal could be produced and consumed in enormous volumes. Over a half-billion tons of coal was produced in 1912, more than will likely be mined in 2020.[3]

But as energy technology evolved coal benefited much less than other fuels, and the greater costs and complications of using coal became manifest. In 1945 coal had five robust markets, including electric power and four non-power segments: residential/commercial, industrial, railroads, and coking coal for the steel industry. By 2019 non-power demand for coal had almost disappeared. The electric power industry accounted for 92 percent of coal consumption in 2019 (Table 2 and Figure 2), and now the power market for coal is dying.

Table 2. Domestic Coal Demand, Selected Years, Millions of Tons and Percent of Total

Year	Residential and Commercial		Coking		Industrial		Railroad		Subtotal, Non-Power Coal Demand		Electric Power		Total	
1920	127	21%	76	13%	208	35%	146	25%	557	94%	37	6%	594	100%
1945	155	25%	96	16%	157	26%	129	21%	536	88%	75	12%	611	100%
1960	41	10%	81	20%	96	24%	3	1%	221	56%	177	44%	398	100%
1980	6	1%	67	9%	60	9%	-	-	133	19%	569	81%	702	100%
2007	4	-	23	2%	57	5%	-	-	84	7%	1,045	93%	1,128	100%
2019P	1	-	18	3%	29	5%	-	-	48	8%	539	92%	687	100%
2020F	2	1%	17	4%	25	6%	-	-	43	11%	351	89%	394	100%

Notes: Coal demand reached its all-time peak in 2007. Detail may not add to total due to rounding. Railroad includes a small amount of vessel bunker fuel. "-" signifies less than one percent or less than one million tons. Detail may not add to totals due to independent rounding.

Sources: Pre-1949: "Minerals Yearbook." Washington: U.S. Bureau of Mines, various years; and "Historical Statistics of the United States, Colonial Times to 1970: Part 1." Washington: U.S. Bureau of the Census, 1975, p. 591. 1949 to present: EIA, Monthly Energy Review data file (Table 6.2), https://www.eia.gov/totalenergy/data/monthly/. Estimate for 2019 and forecast for 2020: "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6**.**

This section of the paper will describe how the inherent problems in using coal as a fuel and the limits of coal combustion technology led oil and gas to displace coal in the non-power sectors. Analogous factors are causing the rapid decline in electric power demand for coal, as discussed later in the paper.

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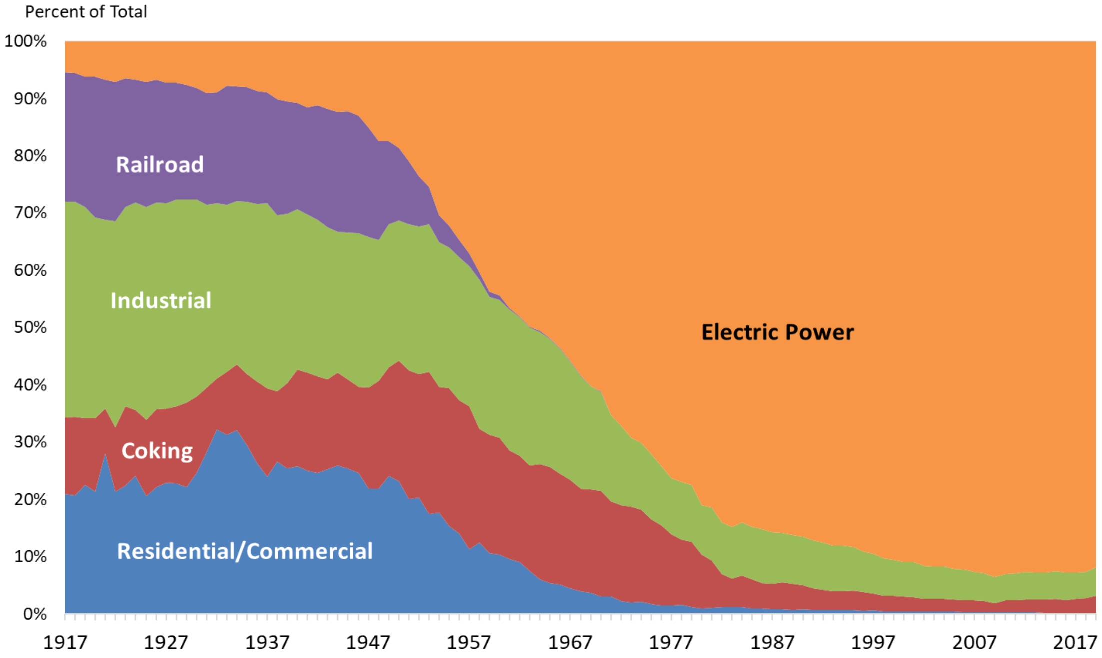
[3] Coal production in 1912 was 534.5 million tons. The U.S. Energy Information Administration (henceforth "EIA") estimates production of 530 million tons in 2020. "Coal Data: A Reference." Washington: EIA, February 1995, Tables 18 and 19; "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Figure 2. Shares of Total Domestic Coal Demand, 1917-2019P



Sources: Pre-1949: "Minerals Yearbook." Washington: U.S. Bureau of Mines, various years; and "Historical Statistics of the United States, Colonial Times to 1970: Part 1." Washington: U.S. Bureau of the Census, 1975, p. 591. 1949 to present: EIA, Monthly Energy Review data file (Table 6.2), https://www.eia.gov/totalenergy/data/monthly/. Preliminary data for 2019: "Short-Term Energy Outlook." Washington: U.S. Energy Information Administration, June 2020, Table 6.

Coal Combustion Technology

The principal means of using coal is in a boiler, in which the heat from burning coal is used to convert water flowing through tubes in the boiler walls (water wall technology) and other surfaces into steam. In a power plant the steam is used to rotate a turbine that drives a generator. In the residential and commercial sectors, the steam is used for space heating. In industry the steam is an input to a manufacturing process.

The first coal boilers burned coal on a grate (stoker systems) but by the 1920s this technology had reached its physical limits.[4] To build bigger boilers that could produce more steam designers turned to pulverizers that grind coal to the consistency of talcum powder. The powdered coal is blown into the furnace section of the boiler where it burns in suspension, much more quickly, efficiently, and in larger quantities than the chunks of coal used in stoker systems.

By the 1930s the basic technology of modern coal combustion and steam and power generation was in place: pulverized coal, the water wall boiler operating at relatively low ("subcritical") pressures[5], and the

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[4] David A. Tillman. *Coal-Fired Electricity and Emissions Control: Efficiency and Effectiveness*. Cambridge, MA: Butterworth-Heinemann, 2018, 76.

[5] At subcritical pressures boilers could be built without resort to advanced metallurgy or manufacturing technology. The advance to higher-pressure supercritical technology is discussed later in the paper.

steam turbine and generator. These technologies remain the primary means of using coal.[6] The limitations of these technologies, and the power industry's inability to find more cost-effective alternatives, are at the heart of the technological stagnation problem that afflicts coal.

Coal as a Problematic Fuel

Coal was an ideal early industrial fuel because it could be extracted and burned without sophisticated technology. But as alternative technologies improved the benefits of using coal were increasingly outweighed by the disadvantages. A standard reference notes that "of the major fossil fuels, coal is also the most complicated and troublesome to burn."[7]

Volumes and Handling

Coal has a low energy density[8] and as discussed in more detail below steam-electric boilers and generators are not very efficient in converting coal into energy. Consequently coal-fired plants require vast quantities of fuel, typically in the millions of tons, which in turn requires plants to have extensive equipment for handling bulk solids, including conveyors, truck or rail loadouts, and outdoor storage and retrieval systems. This equipment is expensive, takes up a lot of land, and is maintenance intensive.

Combustion

To operate efficiently a boiler needs a fuel that burns intensely and fast, but even pulverized coal burns relatively slowly. To provide enough "residence time" for the coal particles to fully burn a coal boiler must encompass a large volume of combustion space, which makes the unit large and expensive.[9]

Ash

Five to 15 percent of coal by weight is non-combustible mineral matter. Burning large volumes of coal therefore produces formidable amounts of ash, mainly metal oxides including toxics such as lead and

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[6] There have been two major alternatives to the pulverized coal and stoker boilers. The cyclone boiler burns crushed coal at extremely high temperatures with the object of reducing the non-combustible matter to a molten slag that can be easily captured. Cyclone technology fell by the wayside because the high combustion temperatures produced large volumes of nitrogen oxide emissions, a precursor to smog, acid rain, and fine particulates. No cyclone units have been built since the mid-1970s. The other alternative is the circulating fluidized bed boiler, which burns crushed coal in an air-suspended bed of limestone. Fluidized bed boilers have found a limited niche largely in the use of low grade and waste fuels such as lignite, petroleum coke (a solid residue from petroleum refining), and waste coal, including material recovered the waste piles and ponds that remain from old anthracite mining operations. Tillman*, Coal-Fired Electricity and Emissions Control*, 112-116, 170-190, 218-224; EIA, EIA-860 data file for 2017 (data for Schedule 6B, 'Emission Standards and Control Strategies').

[7] J.B. Kitto, and S.C. Stultz. *Steam: Its Generation and Use*. 41st ed. Barberton, OH: Babcock & Wilcox Company, 2005, 26-3. For a less technical summary of coal combustion technology see "The Direct Use of Coal: Prospects and Problems of Production and Consumption." Washington: Office of Technology Assessment, 1979, 87-93.

[8] Distillate fuel oil contains about 39 MMBtu per ton, compared to an average of 18.9 million MMBtu per ton for the coal used for power generation in 2018, a 106 percent difference. Joseph G. Singer, ed. *Combustion Fossil Power: A Reference Book on Fuel Burning and Steam Generation*. 4th ed. Windsor, CT: Combustion Engineering, 1993, 2-31; "Monthly Energy Review." Washington: EIA, May 2020, Table A5.

[9] "Slowly" in this case means it may take a couple of seconds for a coal particle to fully combust. But this is slower than for fuel oil or natural gas and the difference is enough to require coal boilers to be significantly bigger and more costly than oil or gas units. Kitto and Stultz, *Steam*, 14-2.

mercury.[10] Even a relatively small unit can produce tens of thousands of tons of ash annually.[11] Some ash can be recycled, for example in cement manufacture, but most ash and boiler slag must be securely stored on-site or elsewhere. The failure of an ash impoundment can be catastrophic.[12]

In addition to its environmental impacts, a build-up of ash on boiler surfaces can cause severe operating problems, including reduced heat transfer and corrosion. Control of ash slagging and fouling is another factor dictating the large size and cost of coal-burning boilers.[13]

Pollution

Coal is a heterogenous rock that contains sulfur and other pollutants. Coal plants must operate an expensive array of control equipment to limit the emissions of particulates, sulfur dioxide, nitrogen oxides, mercury, acid gases, and air toxics. [14] Ideally the contaminants would be removed from the coal before it is burned but most of the sulfur and other pollutants are chemically bound to the fuel. Coal washing can remove some extraneous rock and sulfur, but this is of marginal benefit.

Economies of Scale

As discussed above the technology for handling and burning coal is mechanically and technically complex, maintenance intensive, and needs a lot of land for equipment, fuel storage, and ash disposal. Consequently, coal has been relegated to the two business sectors with the staff, technical support, and economies of scale to compensate for these factors: Electric power and, to a much smaller degree, large industrial facilities.

Oil and Gas Characteristics and Combustion Technologies

Coal became a dominate fuel because it was abundant, suitable for use by an evolving-technology economy, and inexpensive. In contrast it took decades for oil and natural gas exploration, delivery, and combustion technologies to mature, and adoption was further delayed by the Depression and World

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[10] Singer, *Combustion Fossil Power,* 3-2.

[11] For instance, a relatively small 250 MW coal plant can produce over 60,000 tons of ash annually (assuming a 70 percent capacity factor, heat rate of 10,000 Btus per kWh, and a coal with 25 MMBtu per ton and a 10 percent ash content).

[12] The cleanup cost for the large 2008 spill in Kingston, TN, was about $1.2 billion. Duane W. Gang, "5 Years After Coal-Ash Spill, Little Has Changed," *USA Today*, December 22, 2013, https://www.usatoday.com/story/news/nation/2013/12/22/coal-ash-spill/4143995/.

[13] Singer, *Combustion Fossil Power*, 3-1. The boilers also must have additional equipment (sootblowers) that use high pressure air or steam to keep boiler surfaces clean.

[14] Even before the health effects of coal emissions were fully understood pervasive coal smoke and dust were a household and community problem, particularly in cities. The history of smoke control makes for an interesting comparison with current debates over carbon emissions. The public attitude on smoke was split. Coal smoke was a nuisance but was also viewed as a sign of technical progress and prosperity. The costs of switching to low-emissions combustion equipment and fuel were unpopular. Stefano Luconi. "The Enforcement of the 1941 Smoke-Control Ordinance and Italian-Americans in Pittsburgh." *Pennsylvania History* 66, no. 4 (Autumn 1999): 580–94, 580-581, 586-587. Also, muddying the waters were "smoke deniers" (to use current language) who argued that breathing coal smoke was harmless or improved health. Daniel French. *When They Hid the Fire: A History of Electricity and Invisible Energy in America*. Pittsburgh: University of Pittsburgh Press, 2017, 50. (In a similar vein some doctors told coal miners that the coal dust in their lungs would help prevent tuberculosis. Office of Technology Assessment, "Direct Use of Coal," 133.)

War II. After the war, the confluence of improved technology and expanded availability allowed oil and gas to displace coal from most of its markets.

Characteristics of Distillate Fuel Oil and Natural Gas

Distillate fuel oil (also referred to as light oil and No. 2 oil) is a liquid with relatively low viscosity that can be pumped through pipelines or delivered by truck, rail, barge, and vessel. Unlike coal It contains minimal ash and sulfur. Distillate is used, with some variations in characteristics, for home heating, diesel engines, and combustion turbines for power generation. It is easier to handle, transport, and store than coal because it is a stable liquid with a much higher energy density.

Natural gas consists almost entirely of methane (CH_4) and is free of ash and sulfur. It is delivered continuously by pipeline, eliminating the need for users to maintain an on-site inventory. It ignites easily and burns clean except for nitrogen oxide emissions, which can be controlled, and carbon dioxide.

Unlike coal, pollutants are removed from distillate oil and natural gas before it shipped to users. Sulfur is removed from fuel oil during crude oil refining. Contaminants such as hydrogen sulfide are stripped from natural gas at processing plants before the gas enters the trunk pipeline system.

The advantages of using oil and gas were eventually so manifest that for decades attempts have been made, with minimal success, to capture these benefits for coal by converting coal into a liquid or gas. Appendix A summarizes the failed efforts to turn coal into an economical gaseous or liquid synfuel.

Discovery, Processing, and Availability

Compared to coal, the large-scale exploitation of oil and natural gas was more dependent on the development of sophisticated technologies that took many years to develop. For example, hydraulic fracturing, a technique central to oil and gas production even before it was adapted with spectacular effect to tight formations in the 21st century, was not introduced until 1947.[15] Many years of effort went into improving refining methods to yield more light products.[16] The Depression and World War II also delayed the displacement of coal by oil and gas. Although fuel oil began to replace coal as early as the 1900s in markets distant from coal fields, such as the southwest, it was not until after 1945 that fuel oil for home heating and other purposes became widely available at competitive prices.[17]

Natural gas was discovered in the mid-1800s, but it could not be widely used until the development of several technologies in the 1920s made possible long-distance pipelines, including seamless steel pipe, improved welding techniques, and reliable and powerful compressors. After the Depression and World

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[15] Carl T. Montgomery, and Michael B. Smith. “Hydraulic Fracturing: History of an Enduring Technology.” *Journal of Petroleum Technology* 62, no. 12 (December 2010): 26–40, 27. For many years oil and gas exploration was based on a combination of limited geological knowledge and luck (thus the romance of wildcatting). The great east Texas oil field was discovered in 1930 by a wildcatter who selected his drilling locations based on “totally incorrect, fabricated” geological information (Daniel Yergin. *The Prize: The Epic Quest for Oil, Money, and Power*. New York: Simon & Schuster, 1991, 218-219, 244-245).

[16] Yergin, *The Prize*, 111-112; William L. Leffler. *Petroleum Refining in Nontechnical Language*. 4th ed. Tulsa, OK: PennWell Books, 2008, 1-3

[17] Alan Barreca, et al. “Coal, Smoke, and Death: Bituminous Coal and American Home Heating.” Cambridge, MA: National Bureau of Economic Research, February 2014, 9.

War II construction of pipelines and underground gas storage facilities (vital for meeting peak winter demand for space heating) vastly expanded the availability of gas in the lower 48 states.[18]

Technology for Using Oil and Gas in Boilers, Homes, and Diesel Engines

As discussed earlier, the physical characteristics of coal require coal boilers to be large, expensive, and supported by a panoply of coal handling and emissions control equipment. Because of their superior combustion characteristics fuel oil and natural gas can produce the same volume of steam as coal in a smaller and cheaper boiler, and with far less handling and storage equipment. Large boilers of all types and all coal boilers must be built on-site ("field erected"). However, since the late 1940s industrial and commercial facilities with limited steam requirements have been able to buy oil and gas "package boilers" that are delivered as completed units from the factory with automated controls.[19] Nothing as convenient or economical is possible with coal technology.

By the 1920s gas and oil burning space heating systems with automatic thermostat controls were available for the commercial and residential markets. These systems were more compact and efficient than coal furnaces and had none of the maintenance and control issues associated with using coal. The coal industry tried to respond with more mechanized home heating systems that would "seldom [have] to be filled with fresh coal more than once a day…. by the man of the house at any time he happens to be home, thus eliminating all trips to the furnace by the housewife."[20] Consumers were unconvinced.

The steam boiler and space heating technologies described above had variants that could use coal. This is not true of the diesel engine. Compared to the gasoline engines used in cars a diesel engine operates at higher pressures and temperatures and uses distillate oil, which has a higher heat content than gasoline. These factors make diesel engines rugged, reliable, and fuel and cost efficient, ideal for heavy duty applications such as marine, locomotive, and truck engines and small-scale power generation.[21]

Elimination of the Non-Power Coal Markets

Railroads

Rail demand for coal peaked in 1920 at 146 million tons, followed by large negative and positive changes during the Depression and World War II. Post-depression demand peaked at 136 million tons in 1944, 21

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[18] Arlon R. Tussing, and Connie C. Barlow. *The Natural Gas Industry: Evolution, Structure, and Economics*. 1st ed. Cambridge, MA: Ballinger Publishing Co., 1984, 29-57; Schurr and Netschert, *Energy in the American Economy*, 126-127.

[19] Kitto and Stultz, *Steam*, Intro-10, 1-1, 19-2.

[20] Joseph A. Pratt. "The Ascent of Oil: The Transition from Coal to Oil in Early Twentieth-Century America." In *Energy Transitions: Long-Term Perspectives*. AAAS Selected Symposia 48. Boulder, CO: Westview Press, 1981, 21; "Mineral Resources of the United States 1927, Part II -- Nonmetals." Washington: Bureau of Mines, 1930, 575-576. For additional insight into the joys of heating a home with coal, see Alonzo Kittrels. "Back in the Day: Heating with Coal Was Reliable but Laborious." The Philadelphia Inquirer, January 6, 2018. t.ly/GMCw.

[21] Rudolf Diesel, the German inventor of the namesake engine, considered using powdered coal as a fuel but this proved unworkable. Lynwood Bryant. "The Development of the Diesel Engine." *Technology and Culture* 17, no. 3 (July 1976): 432–46. 443. Diesel engines used in the United States for utility-scale (i.e., one MW or greater capacity) electricity generation typically run on natural gas.

percent of total coal consumption, after which demand almost immediately collapsed. This was due to the introduction of a technology vastly superior to the steam locomotive, the diesel electric engine.

Although the first patent for a diesel engine was issued in 1892 the technology took decades to mature. Engines suitable for locomotives (which use diesel engines to drive generators and electric motors) were not practical until the 1930s and wide use was delayed by the Depression and the war.[22] After 1945 diesel locomotives rapidly replaced steam engines. In six years (1944 – 1950) rail demand for coal dropped by 50 percent. Demand dropped 91 percent by 1956, just 12 years after the peak, and disappeared entirely by 1961 (Figure 3).

The railroads replaced their coal engines at tremendous speed because diesel-electric technology revolutionized rail operations. Compared to the coal-burning steam engine the diesel locomotive offered lower maintenance cost, better fuel economy, longer runs between refueling stops, less wear on tracks, higher speeds, and greater availability. The costs and nuisance of dealing with coal ash, smoke and dust were also relieved.[23] The coal and steam engine model that had defined the railroads for generations disappeared almost overnight.

Residential and Commercial

Natural gas and oil space heating offered a level of convenience and cleanliness that coal-burning furnaces could not match. In the 1920s consumers began switching to oil and gas even if coal was less costly to avoid the labor, dirt, and aggravation associated with coal heating.[24] However the general adoption of oil and gas space heating was delayed by the Depression and wartime rationing of fuel and materials. Residential and commercial demand for coal peaked in 1944 at 168 million tons, 26 percent of total coal demand.[25]

With the end of fuel rationing and the buildout of the natural gas pipeline network, consumers rapidly abandoned coal heating, either by purchasing new equipment or by converting coal furnaces to use oil or gas.[26] By 1953, nine years after the peak, half the residential and commercial market for coal was gone. Afterwards demand decreased at a slower rate, largely because the commercial sector includes big institutional consumers with central heating plants, such as universities and military bases, with fuel economics and decision-making akin to industrial facilities (discussed below). Nonetheless the combined residential and commercial markets had contracted by 90 percent by 1970, about a quarter-century after the peak (Figure 4).

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[22] Bryant, "The Development of the Diesel Engine," 445-443; Vaclav Smil. "The Two Prime Movers of Globalization: History and Impact of Diesel Engines and Gas Turbines." *Journal of Global History* 2, no. 3 (2007): 373–394, 379.

[23] Maury Klein. "Replacement Technology: The Diesel as a Case Study." *Railroad History* 162 (Spring 1990): 109–20. 112, 113, 115.

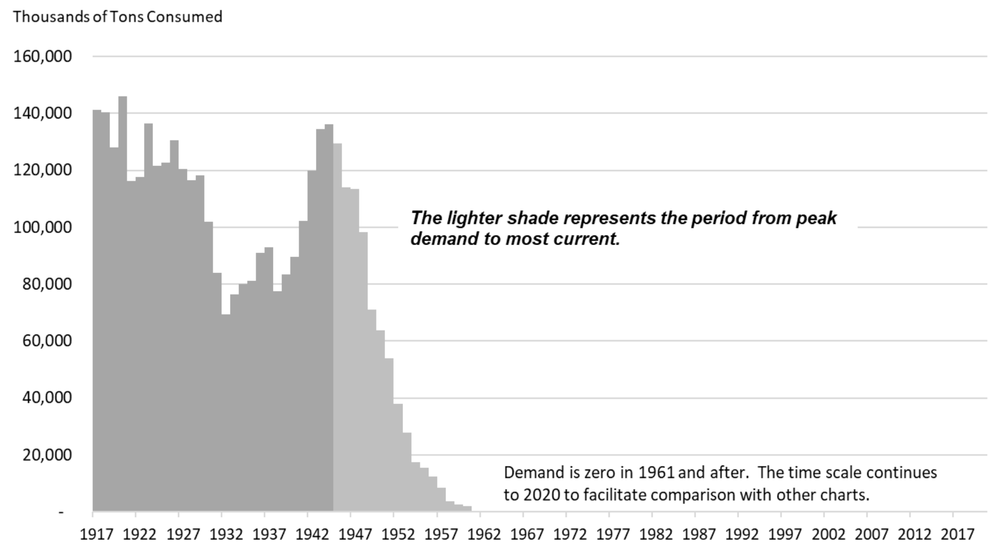
[24] "Mineral Resources of the United States, 1928: Part II -- Nonmetals." Washington: Bureau of Mines, 1930, 575-576.

[25] Separate data series for residential and commercial demand are only available beginning in 1949.

[26] Conversions were economical for many residences. One estimate is that in 1950 it cost an average household about five percent of annual expenditures to convert a coal furnace to burn natural gas and less than two percent for a fuel oil conversion. Barreca, "Coal, Smoke, and Death," 18.

The government stopped collecting data on residential coal use in 2008 after demand fell below 500,000 tons. Commercial demand has recently been about one to two million tons annually, largely for university central heating and cogeneration plants.

Figure 3. The Rail Market for Coal, 1917 to 2020F

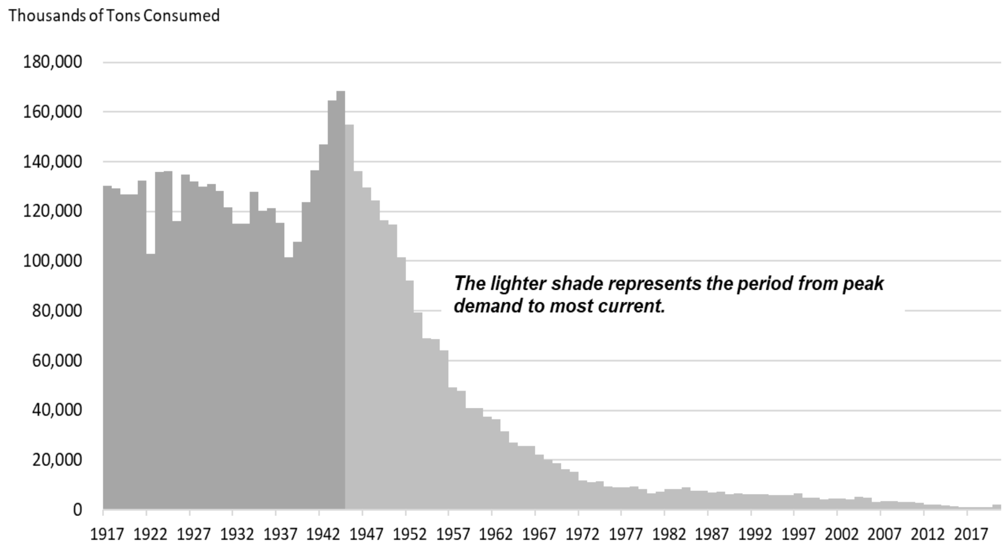


The lighter shade represents the period from peak demand to most current.

Demand is zero in 1961 and after. The time scale continues to 2020 to facilitate comparison with other charts.

Note: Data includes a small amount of vessel bunker fuel. Post-depression demand peaked in 1944. Anthracite consumption for 1932 is estimated. **Sources**: "Minerals Yearbook." Washington: U.S. Bureau of Mines, various years; "Historical Statistics of the United States, Colonial Times to 1970: Part 1." Washington: U.S. Bureau of the Census, 1975, p. 591.

Figure 4. The Residential and Commercial Market for Coal, 1917 to 2020F



The lighter shade represents the period from peak demand to most current.

Notes and Sources: Data are available for 1917 and 1923 from the report "Mineral Resources" (respectively 1917 issue, part 2, 1254, and 1925 issue, part 2, 478. "Mineral Resources" was variously published by the U.S. Geological Survey and the U.S. Bureau of Mines.). Intervening years through 1931 are estimated via linear interpolation. Data from 1932 is forward is from U.S. Bureau of the Census, "Historical Statistics of the United States, Colonial Times to 1970, Part I," p. 591; EIA, Monthly Energy Review data files (Table 6.2.); "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Industrial

Data on industrial coal consumption is first available for 1917, which is also the largest amount on record, 235 million tons. Subsequently industrial coal demand began a century-long decline, interrupted by large gains and losses during the Depression and war (Figure 5). The post-Depression peak was 172 million tons in 1943, after which demand resumed contracting. By 1971 demand had dropped by more than half from 1943, and by 2019 industrial demand was only 29 million tons, an 83% drop from the 1943 peak though still the second largest domestic coal market.

The disappearance of most industrial coal use is attributable to the lower operating and capital costs of natural gas-burning technology and the increased use of electricity as a source of heat and drive power (such as for pumps) in place of fuel combustion. Nonetheless, industrial coal demand has been more resilient than other markets. This is due to three factors, of which one is facility size. As noted above coal utilization is economical mainly in large facilities with the economies of scale, technical expertise, and space required to efficiently operate coal-fired boilers.[27] This category includes large industrial plants.

Second, some industrial and large commercial plants can improve the economics of using coal by operating combined heat and power systems that co-produce steam and electricity. The electricity displaces purchases from the grid or is sold to power companies. Of the 32 million tons of industrial coal consumption in 2018, 11.5 million tons (36 percent) was associated with combined heat and power facilities.[28]

The final factor is that fuel costs are not a primary economic driver for many industrial firms. Firms tend to direct scarce investment capital to projects that are mandatory (regulatory compliance) or related to process and product improvement, such as automation. If a firm is concerned with energy costs investments in energy efficiency may provide a faster payback than conversion from coal to another fuel.[29]

This tendency toward fuel choice inertia has helped to preserve some industrial coal demand. But it also dampened industrial interest in converting to coal in the 1970s and 1980s when oil and gas were sometimes expensive, future shortages were expected, and the federal government promoted conversions. Figure 5 illustrates how industrial coal demand increased only slightly during this period, before resuming its long decline.

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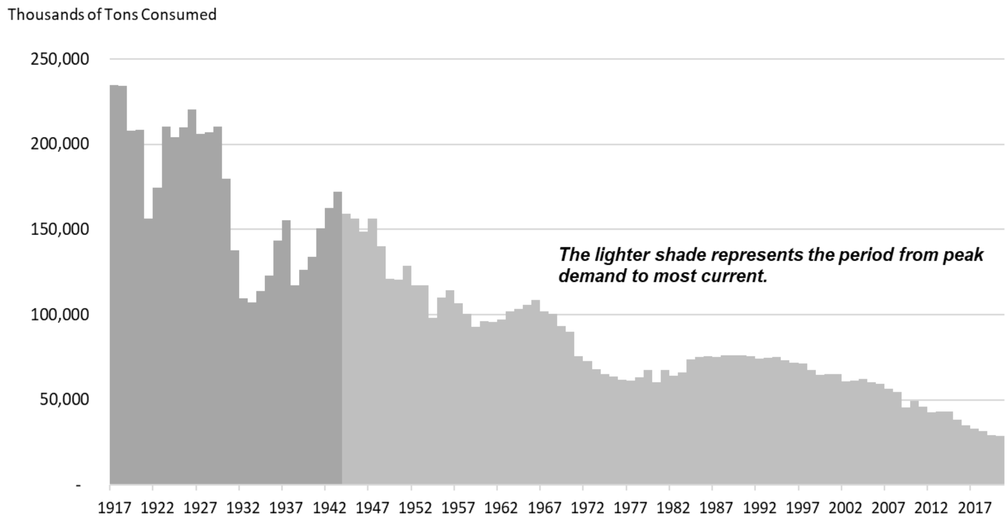
[27] Alvin L. Alm, and Joan P. Curhan. *Coal Myths and Environmental Realities: Industrial Fuel-Use Decisions in a Time of Change*. Boulder, CO: Westview Press, 1984, 11

[28] Calculated from the EIA-923 data file for 2018, https://www.eia.gov/electricity/data/eia923/.

[29] Alm and Curhan, *Coal Myths and Environmental Realities*, 2, 4, 5, 16, 58, 59.

Figure 5. The Industrial Market for Coal, 1917 to 2020F



Notes and Sources: For 1917 through 1932 industrial demand is estimated as total coal consumption minus the sum of residential/commercial + coking coal + rail + electric power demand. See the charts for those sectors for source information. Industrial demand for 1933 to 1948 is from U.S. Bureau of the Census, "Historical Statistics of the United States, Colonial Times to 1970," Part I, p. 591, and U.S. Bureau of Mines, "Minerals Yearbook," various issues. Data from 1949 and forward is from EIA, Monthly Energy Review data files (Table 6.2.); "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Metallurgical

Metallurgical-grade (coking) coal is used to make coke, a high-carbon material produced by heating coal in a low-oxygen atmosphere. Coke is an input to integrated mills that manufacture steel from iron ore and other raw materials. Domestic demand for coking coal peaked in 1951 at 113.7 million tons, 22 percent of total coal demand. By 2019 coking coal demand was only 18 million tons, an 84 percent drop (Figure 6). [30]

The metallurgical coal market was a victim of technological change, but in this case involving the upheaval of an entire industry, not just an energy process. As noted, coke is an input to integrated steel making, which for decades was the primary means for producing steel in the United States. But since the 1960s domestic integrated mills have faced intense competition from low-cost overseas producers. To compete the domestic industry has shifted production to an alternative technology, the electric arc furnace (EAF). Instead of producing steel from iron ore, coke, and other raw materials, an EAF-based "mini-mill" melts scrap to produce steel. Mini-mills are highly productive and require much less capital and labor than integrated steel mills. In part because mini-mills cannot produce the full range of steel products the domestic integrated steel industry has survived, but in a much-truncated form.[31] In 2018

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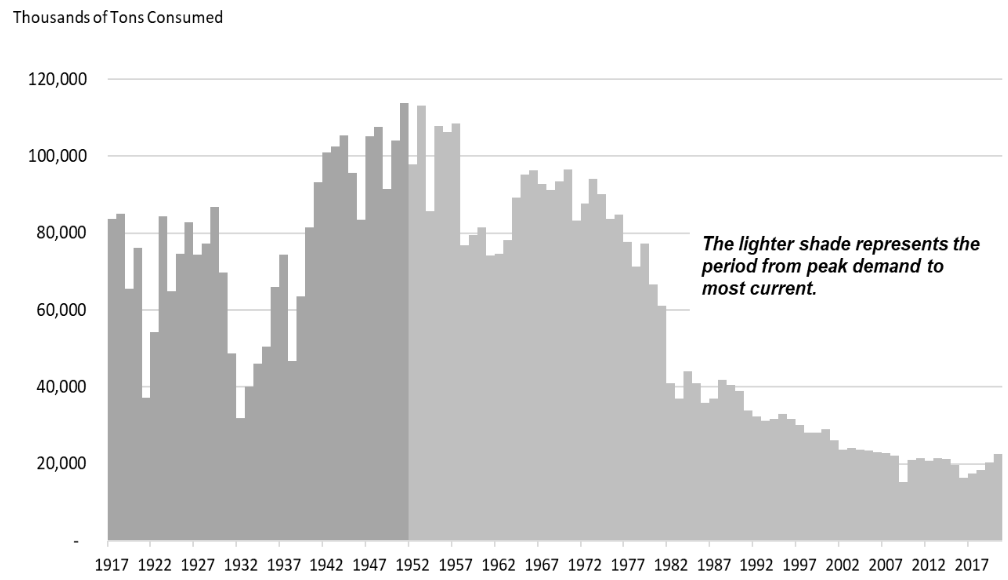
[30] A small portion of the lost demand for coking coal was replaced by coal used directly in integrated steelmaking through a process called Pulverized Coal Injection. This amounts to about one to two million tons of coal annually. "Coal Information 2018." Paris: International Energy Agency, 2018, VI-42.

[31] Allan Collard-Wexler and Jan De Loecker. "Reallocation and Technology: Evidence from the US Steel Industry." *American Economic Review* 105, no. 1 (January 2015): 131–71. 132-133; Christoph Scherrer. "Mini-Mills: A New Growth Path for the U.S. Steel Industry*?" Journal of Economic Issues* 22, no. 4 (December 1988): 1179–1200. 1189-1193.

only a third of American steel production came from integrated mills.[32] Mini-mills are being adapted to produce some of the high quality products that were once the sole province of the integrated steel mill, so a revival of integrated steel production and coking coal demand in the United States is unlikely.[33]

Figure 6. The Metallurgical Market for Coal, 1917 to 2020F



Sources: "Minerals Yearbook." Washington: U.S. Bureau of Mines, 1967, p. 728; U.S. Bureau of the Census, "Historical Statistics of the United States, Colonial Times to 1970," Part I, p. 591; EIA, Monthly Energy Review data files (Table 6.2.); "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Replacing Direct Use of Fuel with Electricity

As the non-power sectors abandoned coal they turned primarily to natural gas and electricity to provide heat and energy. Figures 7 and 8 illustrate how, in terms of absolute volumes and market share, natural gas and electricity came to dominate energy supply to the industrial, residential, and commercial sectors.

In addition to electricity sales the figures also show conversion losses attributable to generating power for these sectors; that is, the quantity fuel input to a power plant lost due to inefficiencies in the generation and transmission processes. Because most thermal power plants are at best only 30 to 40 percent efficient in converting fuel to electricity, conversions losses are large.

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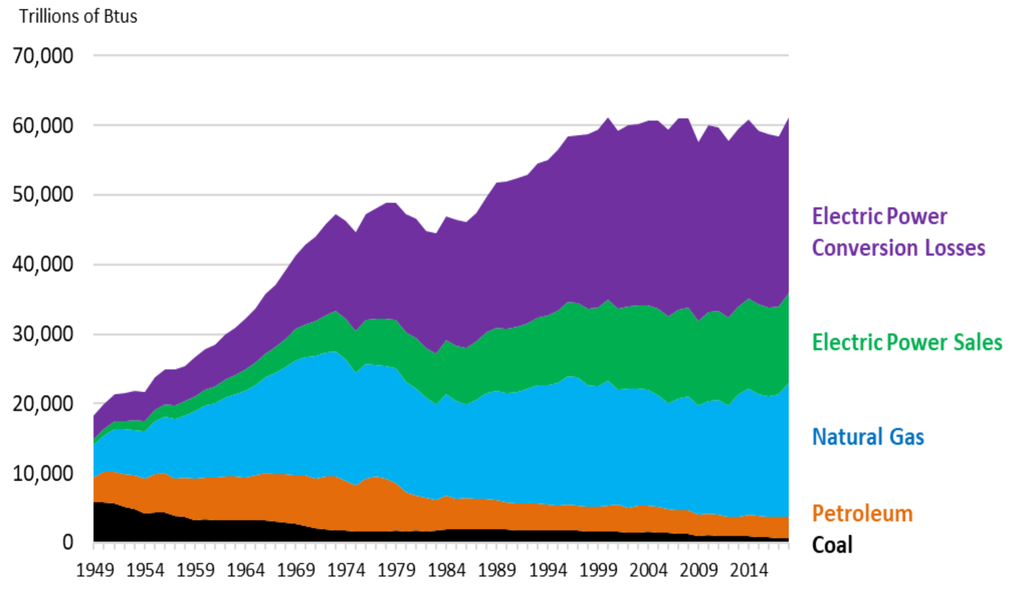
[32] "Mineral Commodity Summaries 2019." Washington: U.S. Geological Survey, February 28, 2019, 82.

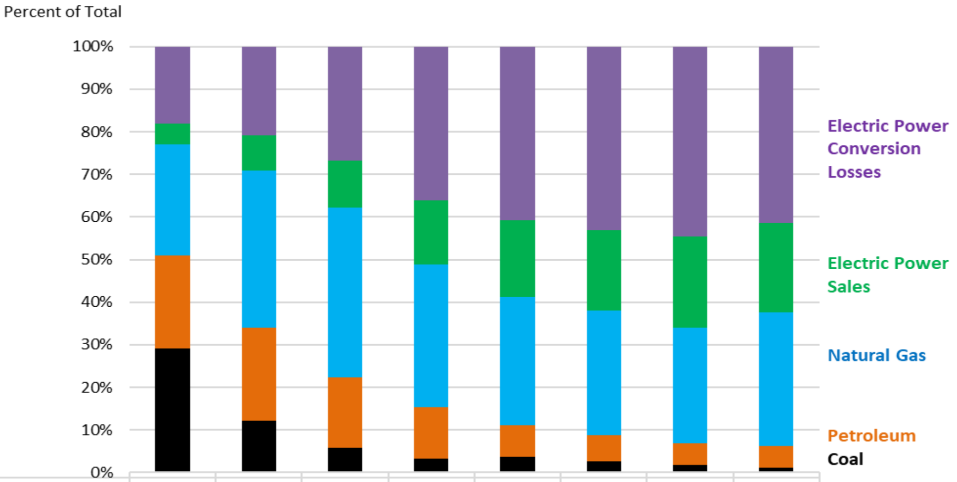
[33] Nicholas Tolomeo, et al. "US Steel Sector Thrives as Mills Move up Quality Ladder." S&P Global Platts Insight, May 9, 2019. https://blogs.platts.com/2019/05/09/us-steel-mills-quality/.

Figure 7. Primary Energy Consumed Including Attributed Electricity Conversion Losses, Industrial, Residential, and Commercial Sectors, 1949-2018



Note: Data is net of the estimated energy value of metallurical coal demand.
Source: EIA, Monthly Energy Review data files (Tables 2.2, 2.3, and 2.4.).

Figure 8. Shares of Primary Energy Consumed Including Attributed Electricity Conversion Losses, Industrial, Residential, and Commercial Sectors, 1949-2018



🟪 Conversion Losses	18%	21%	27%	36%	41%	43%	45%	41%
🟩 Electricity Sales	5%	8%	11%	15%	18%	19%	21%	21%
🟦 Natural Gas	26%	37%	40%	33%	30%	29%	27%	31%
🟧 Petroleum	22%	22%	17%	12%	8%	6%	5%	5%
■ Coal	29%	12%	6%	3%	4%	3%	2%	1%

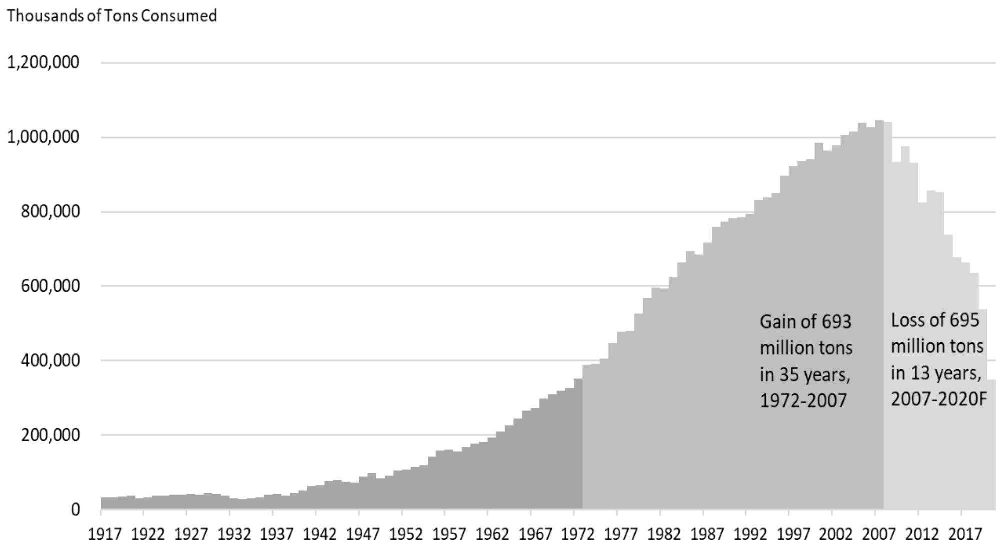
Note: Data is net of the estimated energy value of metallurical coal demand.
Source: EIA, Monthly Energy Review data files (Tables 2.2, 2.3, and 2.4.).

When conversion losses are accounted for electric power is the largest energy source attributable to residential, commercial, and industrial demand (62 percent in 2018). Until recently more than half of the nation's electricity was generated from coal, so from this perspective some of coal's loss of direct sales to these sectors was replaced by coal-fired electricity. However, the switch from direct use of coal to indirect use through the intermediary of electricity created a risk for the coal industry. Electric power can be generated using many fuels and methods. The emergence of electric power as the dominant market for coal made the coal industry vulnerable to fuel substitution, which is precisely what happened when natural gas displaced coal as the primary fossil fuel for power plants. Once the power market weakened the coal industry had no fallback because it had lost its positions in all other markets.

Collapse of the Electric Power Market for Coal

Figure 9 illustrates the post-war growth and rapid decline of electric power demand for coal. Since the electric power market currently accounts for about 90 percent of all domestic coal demand, the collapse of the power part is synonymous with the collapse of coal demand generally.

Figure 9. The Electric Power Market for Coal, 1917 to 2020F



Note: Anthracite consumption for 1932 is estimated.
Sources: "Minerals Yearbook." Washington: U.S. Bureau of Mines, various years; "Historical Statistics of the United States, Colonial Times to 1970: Part 1." Washington: U.S. Bureau of the Census, 1975, p. 591.; EIA, Monthly Energy Review data files (Table 6.2.); "Short-Term Energy Outlook." Washington: EIA, June 2020, Table 6.

Five factors contributed to the decline of the power market for coal, each discussed below:

- Generating technology and efficiency
- Power plant construction costs and construction time

- Industry restructuring and the growth of natural gas generating capacity
- Decreased utilization of coal plants and cost consequences
- Fuel production, distribution, and delivered prices

As the discussion will illustrate, the common thread is the comprehensive technological decline of coal production and utilization relative to natural gas, culminating in natural gas becoming a less expensive source of power.

Generating Technology and Efficiency

Measures of Efficiency

The efficiency of thermal power generation is typically expressed as either the *heat rate*, which is the volume of Btus of energy input required to produce one kilowatt-hour (kWh) of electricity output, or as *thermal efficiency*, which is the percent of the heat input converted into electricity. The heat rate and thermal efficiency are interchangeable. For example, the heat rate of a unit with a thermal efficiency of 33 percent can be calculated as: 3,412 ÷ 33% = 10,339 Btus per kWh, given that a kilowatt-hour contains 3412 Btus.[34]

In this example 67 percent of the thermal input is not converted to electricity. The waste heat goes up the plant stack or is lost elsewhere in the generation process. The "conversion" (or "transformation") loss is a significant economic penalty; two-thirds of all the fuel purchased is in a sense wasted. The history of power generation technology has largely been a search greater efficiency and lower conversion losses.

Steam-Electric Generation and Technological Stasis

As discussed earlier the basic technologies of modern coal-fired power generation – the subcritical water wall boiler, coal pulverization, and the steam turbine generator – were in place by the 1930s. As the technology was refined there were, at first, big gains in efficiency. From 1930 to 1950 the heat rates for the best steam-electric plants in service improved by 27 percent.[35] But subsequently the rate of improvement plateaued (Figure 10). [36] The power industry responded by attempting a leap in the 1950s to more advanced and efficient supercritical steam technology and by building larger units to

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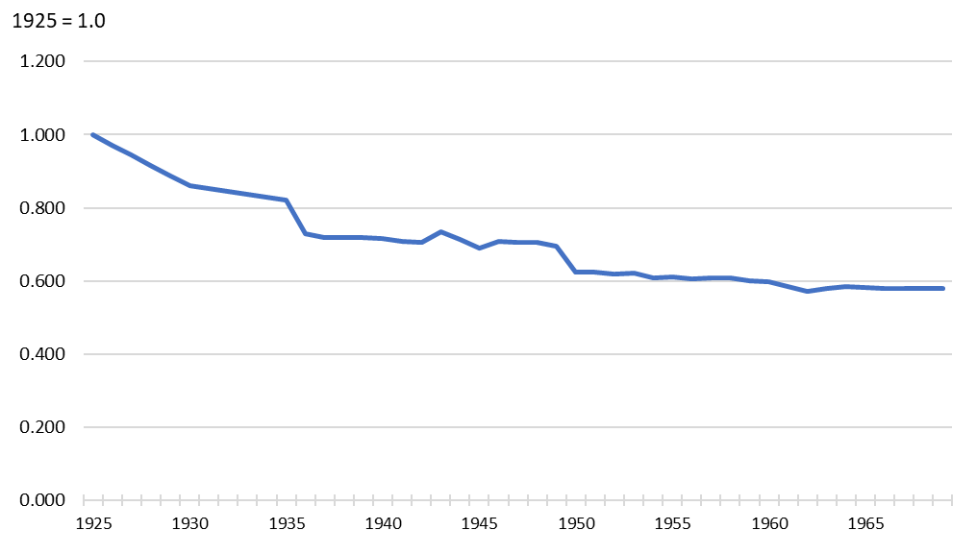
[34] Thermal efficiency and heat rate are usually calculated for the net output of the plant, which is the gross output of the plant's generator minus the electricity the plant itself consumes (which can be significant, particularly for coal plants with flue gas scrubbers). In the United States the heat rate of steam-electric plants is usually calculated using the "higher heating value" of the fuel input, but in the case of combustion turbines and combined cycles the technical and manufacturer literature generally presents a heat rate based on the fuel's "lower heating value." The lower heating value discounts heat released during the combustion process by the vaporization of water that cannot be recovered for power generation. (S. Can Gülen. *Gas Turbine Combined Cycle Power Plants*. New York: CRC Press, 2020, 24.) All heat rates in this paper are on a higher heating value basis. Non-thermal generators such as solar photovoltaic and wind plants do not have heat rates.

[35] Calculated from "National Power Survey: A Report by the Federal Power Commission 1964." Washington: Federal Power Commission, October 1964, 67, Table 24. For a discussion of the technical enhancements that contributed to improved efficiency see Richard Hirsh. *Technology and Transformation in the American Electric Utility Industry*. New York: Cambridge University Press, 1989, 44-46, 89-90, and Tillman*, Coal-Fired Electricity and Emissions Control*, Chapters 4, 5, and 6.

[36] "The 1970 National Power Survey, Part I." Washington: Federal Power Commission, December 1971, I-5-7.

supplement thermal efficiency with financial economies of scale.[37] However, the reliability of the first generation of supercritical units was poor because the higher pressures and temperatures overstressed the available materials. Utilities also found that the large new units, up to 1,300 MW, were less reliable than smaller predecessors.[38]

Figure 10. Heat Rate of the Most Efficient Steam-Electric Generating Stations as an Index, 1925-1969



Note: Data for 1926 to 1929 and 1931 to 1934 estimated via linear interpolation.
Sources: "National Power Survey: A Report by the Federal Power Commission 1964." Washington: Federal Power Commission, October 1964, 67; "The 1970 National Power Survey, Part IV." Washington: Federal Power Commission, December 1971, IV-1-10.

By the early 1980s coal combustion technology had reached what the historian Richard Hirsh characterizes as a point of stasis.[39] Operators responded with technological retrenchment. Although at one time the industry and government envisioned building single generators with a capacity of over 2,000 MW, the typical size for single coal-fired units has been well under 1,000 MW.[40] The power industry also reverted to building subcritical boilers until supercritical technology was proven overseas,

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[37] A supercritical boiler operates above the critical point of 3,200.1 psi at which water becomes steam without the phase change of boiling. Eliminating the phase change makes the unit (which is, strictly speaking, a steam generator and not a boiler since no boiling occurs) more energy efficient and yields about four percent more net electricity. Kitto and Stultz, *Steam*, 2-20, 2-21. An ultra-supercritical plant operates at yet higher pressures and temperatures but there is no formal delineation of the ultra-supercritical threshold.

[38] Hirsh, *Technology and Transformation in the American Electric Utility Industry*, 92-97.

[39] Hirsh, *Technology and Transformation in the American Electric Utility Industry*, 1-11.

[40] On expectations for large units see "The 1970 National Power Survey, Part I," I-5-3. The largest American coal units are Gavin 1 and 2, respectively 1,330 and 1,350 MW, built in Ohio in the early 1970s. There are five other 1,300 MW-class units including the Zimmer plant, also in Ohio, a failed nuclear project converted to use coal.

where the higher cost of coal created incentives for developing the most efficient power plants.[41] Some of the gains that were made in thermal efficiency were negated by new requirements for coal plants to operate an array of pollution control equipment. This equipment, particularly flue gas desulfurization systems ("scrubbers"), consume part of the electrical output from the plant and reduce its net efficiency in producing electricity.

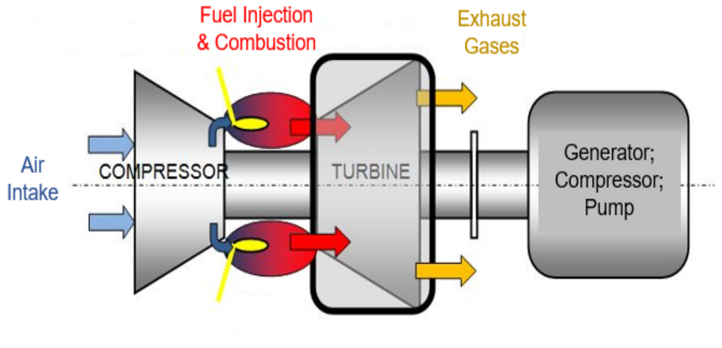
The timing of these developments was important because the vast majority of the American coal-fired generating fleet was constructed before 1990, during this period of technological stagnation.[42] Coal combustion technology has now advanced to "ultra-supercritical" performance but this is essentially irrelevant to the United States where most coal capacity is decades old and new plants are not being built. There is only one ultra-supercritical coal plant in the United States, the Turk station in Arkansas which entered service in 2012.[43]

Even ultra-supercritical technology provides only a limited improvement in efficiency. Much more dramatic improvements in efficiency have been achieved by alternative technologies, the gas turbine and combined cycle, which are incompatible with coal.

Gas Turbines and Combined Cycles

The gas turbine (Figure 11), also referred to as a combustion turbine, applies jet engine technology to ground applications. The gas turbine ingests and compresses air, and then mixes and ignites natural gas or fuel oil with the air in a combustion zone. The resulting stream of hot gases passes through a turbine to rotate a shaft. The shaft drives the compressor stage of the engine and provides mechanical energy to the end-use application, such as a pump or generator. Stand-alone gas turbine generators are typically used as peaking power plants because they can start and reach full load very quickly.

Figure 11. Combustion (Gas) Turbine Schematic



Source: Adapted from Wikimedia Commons: https://commons.wikimedia.org/wiki/File:Turbine_section_gas_turbine.JPG

Analogous to a steam-electric plant, the hot exhaust gases from a stand-alone gas turbine plant are vented to

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[41] Of the coal-fired capacity operating in 2011 (that is, before the wave of retirements began) only 27 percent was supercritical. In 2018 the percentage rose to 35 percent, but this was due to the retirement of subcritical capacity, not because new supercritical capacity was added. Total coal capacity declined by almost a quarter between 2011 and 2018. Calculated from the EIA-860 data files, https://www.eia.gov/electricity/data/eia860/. Excludes industrial and commercial generators.

[42] Of the coal fired capacity operating in 2011, 72 percent was built by 1980 or earlier; 92 percent by 1990 or earlier, and 95 percent by 2000 or earlier. Calculated from the EIA-860 data file for 2011, https://www.eia.gov/electricity/data/eia860/. Excludes industrial and commercial generators.

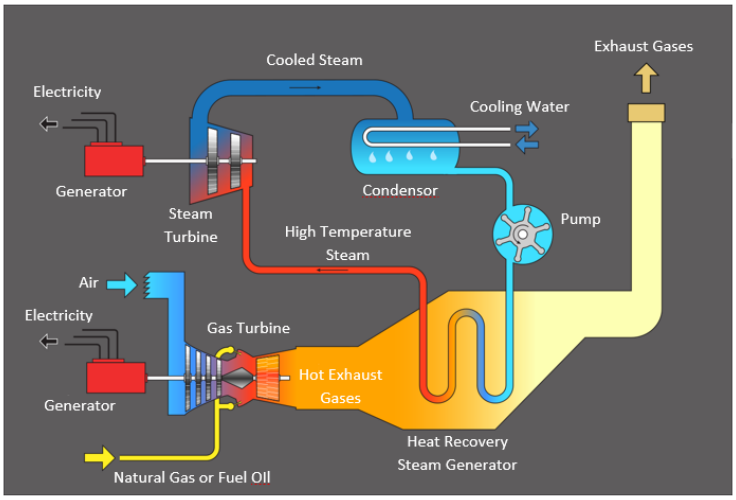
[43] Sonal Patel. "First U.S. Ultrasupercritical Power Plant in Operation." *Power Magazine*, February 1, 2013. https://www.powermag.com/first-u-s-ultrasupercritical-power-plant-in-operation/.

the atmosphere and the energy in the gases is lost. A combined cycle power plant goes the next step and uses a special type of boiler (the heat recovery steam generator or HRSG) to capture the heat from exhaust gases to create steam that powers a second generator (Figure 12). The combined cycle is the most efficient type of fossil fuel-fired power generation system available. As discussed later, modern combined cycles are more than 30 percent more efficient than average coal plants.

Combustion turbines require a high degree of manufacturing and material science sophistication, more than early steam-electric boilers. The first gas turbine for power generation was installed in Neuchâtel, Switzerland in 1939, and the first American unit in Oklahoma City in 1949. These units were inefficient but demonstrated one of the advantages gas turbine technology, high reliability. The Oklahoma unit operated until 1980 and the Swiss unit, amazingly, until 2002.[44]

Another advantage of combustion turbine-based technology is that it is space efficient. The power block is compact and because a natural gas-burning plant does not require equipment or land for storing and handling coal, or need to sequester large quantities of combustion ash, the plant has a relatively small footprint. This reduces project costs and facilitates plant siting.

Figure 12. Schematic of a Natural Gas Combined Cycle Plant



Source: Adapted from Wikimedia Commons: https://commons.wikimedia.org/wiki/File:Prinzip_Gas-und-Dampf-Kombikraftwerk.svg

While steam electric plant efficiency stagnated the efficiency of gas turbines increased dramatically, albeit over a period of decades. The first gas turbines for power generation (circa 1940) had a thermal efficiency of about 15 percent (heat rate of 22,700 Btus per kWh). By the 1960s efficiency had improved to 25 percent (13,648 Btus per kWh).[45] Current units achieve about 34 to 37 percent efficiency (9,900 to 9,100 Btus per kwh),[46] which is more efficient than the average for existing coal units.

Combined cycle efficiencies also improved as the technology for gas turbines and HRSGs advanced. In the mid-1990s the efficiency for a new

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[44] The American Society of Mechanical Engineers. "Neuchâtel Gas Turbine," nd. https://www.asme.org/about-asme/engineering-history/landmarks/135-neuchatel-gas-turbine; American Society of Mechanical Engineers. "3500 KW Gas Turbine at the Schenectady Plant of the General Electric Company," November 8, 1984. t.ly/NxOa.

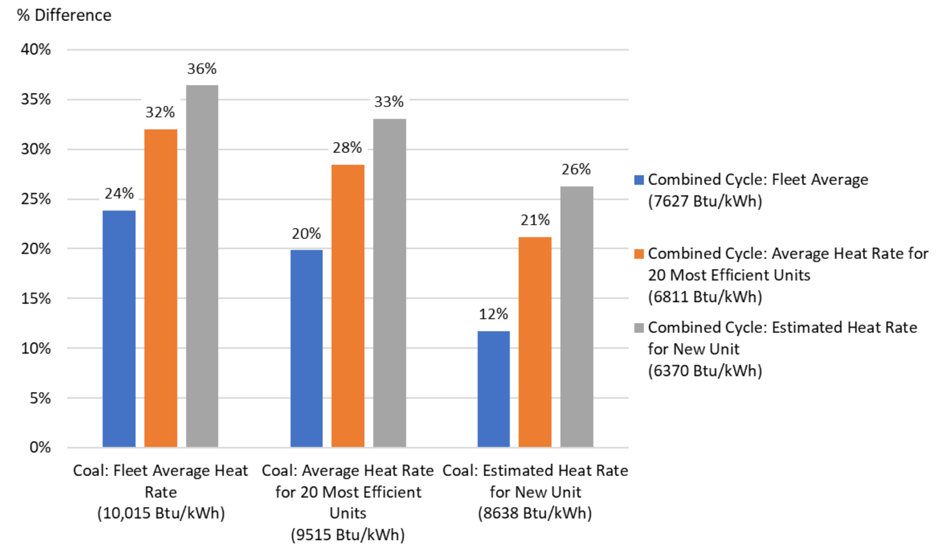
[45] Smil, *Prime Movers of Globalization*, 149-150 including Figure 5.19.

[46] EIA assumes a heat rate of 9,124 Btus per kWh for aeroderivative technology and 9,905 Btus per kWh for an F-class industrial frame unit. The latest HA-class gas turbine has a heat rate of about 9,250 Btus per kWh as a stand-alone generator. "Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies." Washington: EIA, February 2020, 5-3 and 6-3; Samuel A. Newell, et al. "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date." The Brattle Group and Sargent & Lundy, April 19, 2018, 13.

combined cycle was about 43 percent (7,900 Btus per kWh). Efficiency has now advanced to about 54 percent (6,300 Btus per kWh) for the latest technology. There has been no comparable advance in coal combustion technology. The heat rate for a new ultra-supercritical coal plant is estimated by EIA at 8,638 Btus per kWh (40 percent efficiency).[47]

The current coal fleet in the United States has an average heat rate of about 10,015 Btu per kWh. The heat rate for a new ultra-supercritical coal unit is about 14 percent lower. However, this efficiency advantage pales in comparison to the efficiencies achieved by modern combined cycle power plants burning natural gas. A new combined cycle has an efficiency 36 percent better than the coal fleet average, 33 percent better than the most efficient existing coal units, and 26 percent better than a new ultra-supercritical coal plant. Even the fleet average combined cycle heat rate is 12 percent than the most modern coal plant (Figure 13). [48]

Figure 13. Efficiency (Heat Rate) Advantage of Natural Gas Combined Cycles Over Coal



Notes: The new unit values are EIA's estimates for a HA-class multi-shaft combined cycle and an ultra-supercritical coal plant. **Sources**: "Electric Power Annual 2018." Washington: EIA, October 2019, Table 8.2.; "Assumptions to Annual Energy Outlook 2020: Electricity Market Module." Washington: EIA, January 29, 2020, 6; Russell Ray. "Power Plant Performance in 2017." Power Engineering, June 1, 2018. t.ly/nG52.

Power Plant Construction Costs and Construction Time

In addition to being more efficient than steam electric coal plants, combined cycle plants are less expensive to construct and quicker to build. Table 3 presents EIA's estimates of the overnight

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[47] "Assumptions for the Annual Energy Outlook 1996." Washington: EIA, January 1996,48; Newell, et al. "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," 14; EIA, "Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies," 1-6.

[48] Comparisons of new combined cycle plants with new ultra-supercritical coal plants are in any event irrelevant as no large coal units, ultra-supercritical or otherwise, are being built in the United States and none are in offering.

construction costs[49] of combined cycle and coal plants in 2002 (at the time of the turn-of-the-century capacity building boom, discussed below) and in 2019.

Table 3. Estimated Change in New Power Plant Cost and Efficiency, 2002 to 2019

Technology	Metric	2002	2019	Percentage Change
Coal	Overnight Cost, $ per kW of Capacity	$1,389	$3,661	164%
	Construction Lead Time, Years	4	4	0%
	Heat Rate (Btus per kWh)	9,000	8,638	-4%
Natural Gas Combined Cycle	Overnight Cost, $ per kW of Capacity	$618	$954	54%
	Construction Lead Time, Years	2	2	0%
	Heat Rate (Btus per kWh)	7,500	6,370	-15%
Ratio of Coal to Gas	Overnight Cost	2.2	3.8	n/a
	Construction Lead Time	2.0	2.0	n/a
	Heat Rate	1.2	1.4	n/a

Notes: The values shown are estimates for typical units. The costs and performance of actual projects will vary substantially based on factors such as location and specific design. Although not explicitly identified the heat rate of the 2002 coal plant is consistent with supercritical technology. The 2019 coal plant is ultra-supercritical. The heat rate for the 2019 combined cycle is for an HA-class multi-shaft design. The 2002 cost estimate was published in 2001 dollars and adjusted to nominal (2002) dollars using the implicit price deflator.

Sources: “Assumptions to the Annual Energy Outlook 2003.” Washington: EIA, 2003, 73; “Assumptions to Annual Energy Outlook 2020: Electricity Market Module.” Washington: EIA, January 29, 2020, 6.

The table illustrates several points:

- Combined cycles are much less expensive to build than coal plants and the difference has grown over time. The ratio of coal to combined cycle overnight costs increased from 2.2:1 in 2002 to 3.8:1 in 2019.
- Overnight costs understate the capital cost advantage of the combined cycle because this measure does not include financing expense. EIA estimates that a coal plant typically takes two years longer to build than a combined cycle, which means two more years of financing costs. The combined cycle is faster to build because it is compact, does not require extensive bulk materials handling facilities, and major parts of the facility can be shop assembled instead of field erected.
- The efficiency of a new combined cycle improved by 15 percent, compared to only four percent for a new coal plant.

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[49] The overnight construction cost is an estimate of the cost that would be incurred if a project could be constructed instantly, usually expressed in dollars per kilowatt of capacity. It makes no allowance for inflation during the construction period or financing expense.

As these measures indicate the performance and cost advantages of combined cycle technology over coal have increased over time.

Industry Restructuring and the Growth of Natural-Gas Generating Capacity

Prior to 1978 most generating capacity was owned by electric utilities subject to state or local rate regulation. Elements of traditional regulation tended to dampen incentives for cost control and even encouraged investment in high-cost facilities like coal plants. [50] In part to introduce more competitive discipline to the electric power market, the federal and state governments began in the 1980s to encourage the creation of independent power producers (IPPs) free of price regulation. Because IPPs did not have the same near-assurance of cost recovery as traditional utilities they were expected to be more cost-efficient and make better-considered investments.

Facing greater risks and financing costs, the IPPs gravitated toward natural gas-fired combined cycle and gas turbine technology because it was less expensive and quicker to build than coal plants. These factors, plus the development of a bubble market for energy projects due to a misguided fight for market share, led to a building boom for gas-fired plants (Figure 14). From 1999 through 2006 154 GW of natural gas combined cycles and 73 MW of gas turbines were built, increasing the nation's generating capacity by 29 percent in just eight years.[51] This large and overbuilt fleet of new generating units was initially underutilized, but once cheap fracked natural gas became available these plants were available to displace coal-fired generation.

Decreased Utilization of Coal Plants and Cost Consequences

Decreased Utilization of Coal Plants

As discussed above most coal capacity was built before 1990 and the coal fleet consists mainly of older units using obsolete subcritical technology. But although capacity was not added coal burn continued to increase through 2008. This was possible because the coal fleet was overbuilt in the 1970s and early

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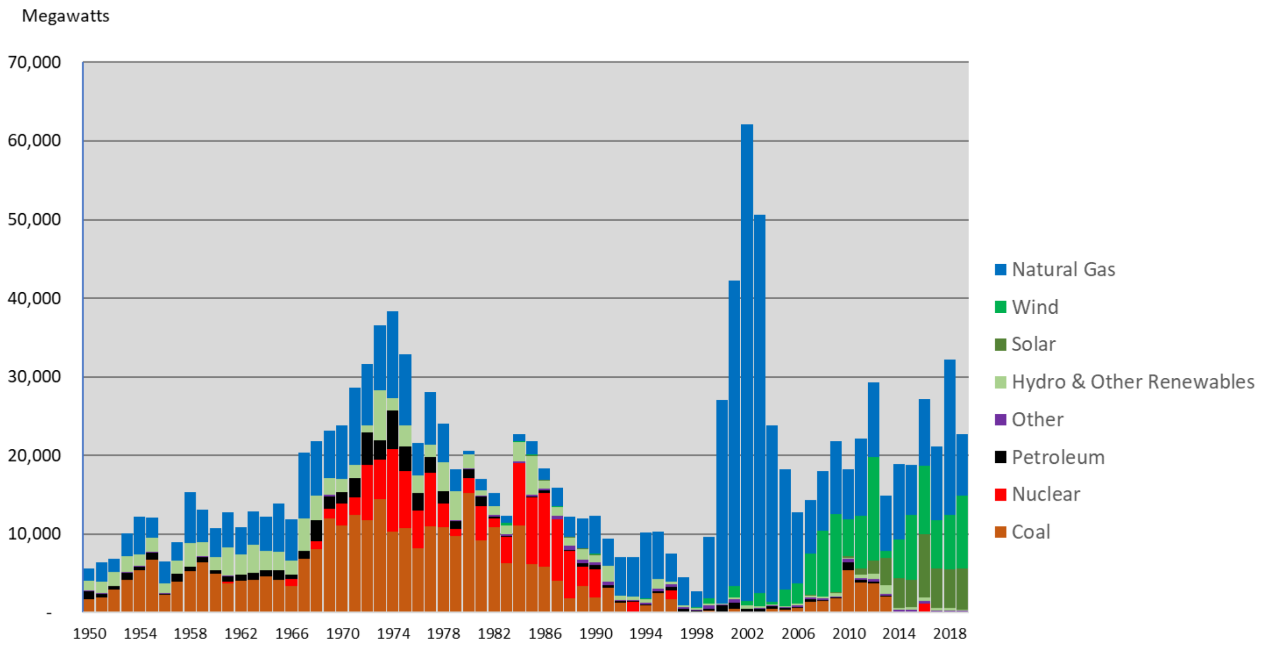
[50] Among the factors that lessened cost discipline: Utility companies have monopoly franchise areas and captive customers; cost of service regulation gives utilities a high assurance, though not absolute certainty, of recovering operating costs; investor-owned utilities receive a return on investment based in part on their amount of invested capital, which creates an incentive to build more expensive facilities; government-owned and cooperative utilities can issue tax-free dept, which lowers their cost of capital and gives them more financial latitude to invest in expensive plants. For an overview of these regulatory concepts see Darryl Tietjen. "Tariff Development I: The Basic Ratemaking Process." nd. https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB. A constraint on investor-owned utility spending is the risk that a regulatory body will find that operations or investments were imprudent and order owners to absorb the cost. In the 1980s some utilities incurred disallowances associated with overbudget or abandoned nuclear and, to a much lesser extent, coal plants. Thomas P. Lyon, and John W. Mayo. "Regulatory Opportunism and Investment Behavior: Evidence from the U.S. Electric Utility Industry." *The RAND Journal of Economics* 36, no. 3 (Autumn 2005).

[51] Calculated from EIA, Preliminary Monthly Electric Generator Inventory data file for January 2020 (https://www.eia.gov/electricity/data/eia860m/) and "Annual Energy Review 2011." Washington: EIA, September 2012, 258, Table 8.11a. Total net summer capacity in 1998 was 775,900 MW.

1980s in anticipation of rapid load growth that did not materialize.[52] To the extent that load did grow after 1980, operators were able to meet demand by running their existing coal units more intensively.

Figure 14. Annual Additions of Generating Capacity, 1950 - 2019



Notes and sources: EIA, Preliminary Monthly Electric Generator Inventory data file for January 2020 (https://www.eia.gov/electricity/data/eia860m/) and unpublished EIA data on units that retired prior to 2002. These data sets are missing some generating units that both entered service and retired during the period 1950 - 2001. This missing capacity is likely to be small.

Post-1980, as construction of new coal plants dried-up, the utilization of the already-built plants generally increased (Figure 15). This trend changed abruptly once low-cost fracked natural gas entered the market in large volumes. Since 2007 coal plant capacity utilization has generally declined. Simultaneously the utilization of combined cycles increased as operators made more use of the plants built during the turn of the century construction boom and added new, even more efficient units.[53]

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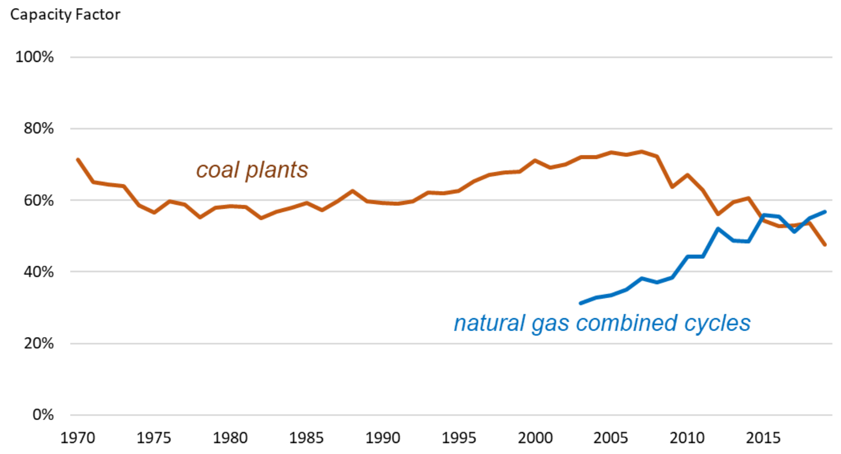
[52] For the decline in load growth in the 1970s see Hirsh, *Technology and Transformation in the American Electric Utility Industry*, 126-130, and Charles R. Nelson, et al. "The NERC Fan in Retrospect and Lessons for the Future." *The Energy Journal* 10, no. 2 (1989): 91–107. 91-93, 105-106. Load shifted into an even slower growth path after the 2008 financial crisis. Lucas Davis. "Evidence of a Decline in Electricity Use by U.S. Households." Berkeley: Energy Institute at Haas, University of California, Berkeley, May 2017; Steven Nadel and Rachel Young. "Why Is Electricity Use No Longer Growing?" Washington: American Council for an Energy-Efficient Economy, February 2014.

[53] The trend toward decreased utilization of coal plants has continued although some utilities are running high cost coal units even when cheaper power is available. The practice, called self-commitment, has recently become controversial. Jeremy Fisher, et al. "Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets." Washington: Sierra Club, October 2019; Catherine Morehouse. "Indiana Regulators Decline to Scrutinize IPL Coal Practices but Continue Duke Review." Utility Dive, June 9, 2020. t.ly/L4en.

Figure 15. Trends in Annual Average Capacity Factors for Coal and Natural Gas Combined Cycle Plants, 1970-2019



Notes and Sources. All data for 2010 – 2019: "Electric Power Annual 2018." Washington: U.S. Energy Information Administration, October 2019, Table 6.07.A. Combined cycles: Estimated for 2003 - 2009 from EIA data files on generation and capacity (respectively at https://www.eia.gov/electricity/data/eia923/ and https://www.eia.gov/electricity/data/eia860/). Generation data specific to combined cycles is unavailable prior to 2003. Coal prior to 2010: Calculated using generation data from EIA, Monthly Energy Review data files (Table 7.2a) and (a) 1970 to 1988, coal capacity from EIA, Preliminary Monthly Electric Generator Inventory data file January 2020 (https://www.eia.gov/electricity/data/eia860m/) and unpublished EIA data on retirements, and (b) 1989 to 2009 capacity from EIA, Annual Energy Review 2011 data files (Table 8.11a.), https://www.eia.gov/totalenergy/data/annual/.

Coal Plant Unit Cycling

Power system generally use "security-constrained economic dispatch" to determine the order in which power plants are brought on-line to serve load. The notion is that the units with the lowest marginal variable costs are operated first with exceptions if the reliability of the grid requires a unit to operate out of merit order (thus "security-constrained"). For decades, the nominal dispatch order on most power systems was:

- Nuclear plants, if any, would dispatch first, because they have the lowest marginal costs of thermal generators.
- Coal units would dispatch second because of their low fuel costs. Coal and nuclear units in combination would meet the constant base level of demand on the power system, leading to their designation as "baseload" units.
- Daily variations in power demand above the baseload level were met using natural gas and oil units that ramped up and down through the day (sometimes referred to as "load following" units) or were briefly operated to meet the highest peak loads. Operating units to follow load or meet peaks is collectively called "cycling" service.

- Hydroelectric power, which has no fuel cost, would be used as available, even ahead of coal and in rare instances nuclear plants.[54]

This is an idealized picture of how power systems traditionally operated. In practice cycling of coal plants was not uncommon, such as on utility systems with excess nuclear capacity or large amounts of low-cost hydroelectric power, or because the utilities were burdened with expensive coal supplies that made the plants uneconomic for baseload operation.[55] Coal plants would also cycle because of low daily or seasonal loads or for technical reasons.[56] Nonetheless, the raison d'être of coal power has been to operate continuously at or near full output, and coal units were designed to provide optimum performance in baseload operation.

The advent of low-cost natural gas fired in efficient combined cycles, and renewable generators with low marginal costs, have flipped the historic dispatch order. In addition to nuclear plants, combined cycles and wind and solar power now dispatch before coal in many power systems. This has forced coal plants out of baseload operation and into a load following role for which they were not designed. It also leads to more plant shutdowns and restarts. This irregular operating mode imposes significant costs on coal units:

- Ramping and stops and starts causes component stress, which translates into increased maintenance and replacement capital costs. Combined cycles also incur higher costs from load following but they are much less (Figure 16).
- Coal units are most efficient operating at high loads. When a plant is forced into load following service its heat rate increases, which increases the fuel cost per MWh and reduces the cost-competitiveness of the station.[57]
- Ramping-related damage to generating units causes a progressive deterioration in efficiency. The impact on coal units is an estimated two to three times greater than for combined cycles.[58]
- Neither combined cycles nor coal plants are ideal for load following service, but coal units are particularly ill-suited. Combined cycles provide better ramping service, especially the most

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[54] Hydroelectric plant dispatch is complex because it must balance multiple factors in addition to meeting power demand, including holding enough water for irrigation and municipal systems, environmental protection such as supporting fish populations, and the unpredictability of precipitation.

[55] For examples of these kinds of effects see "ComEd Reaps Rewards of Cleaning up Its Act," *Megawatt Daily*, May 28, 1999, and "Markets Georgia Shows PRB's Effects at Scherer; Switch Would Hit NS Producers, Plants," *Coal Week*, February 4, 1991.

[56] For example, plants burning western coal with a propensity for slagging on the boiler walls may reduce output in the evening. At lower output, the temperature of the boiler walls drops causing the metal to contract and some slag to break off.

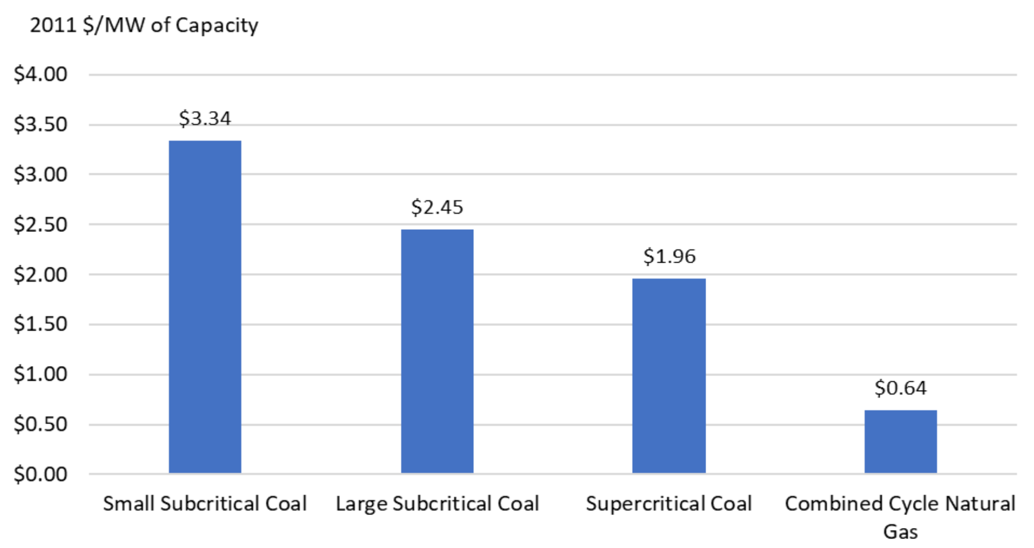
[57] Operating a coal unit at half-load appears to increase the heat rate by three to five percent. See the heat rate curves in D. Lew, et al. "Impacts of Wind and Solar on Fossil-Fueled Generators: Preprint." In IEEE Power and Energy Society General Meeting, 10. 6, and "Managing Large-Scale Penetration of Intermittent Renewables." Cambridge, MA: MIT Energy Initiative, April 20, 2011, 25.

[58] Kumar. "Power Plant Cycling Costs," 31-35

current combined cycle technology compared to the obsolete subcritical units that make up most of the U.S. coal fleet (Figure 17).[59] [60]

Wind and solar power have had a complex and, compared to natural gas, secondary impact on the operation and economics of coal generation. Large amounts of solar and wind capacity have been built since 2000, reflecting the combined impact of federal tax incentives, state renewable portfolio standards, and sharply declining costs for solar photovoltaic plants. Although wind and solar both have

Figure 16. Cost of a Significant Load Following Operation, 2011 $ per Megawatt of Capacity



Note: A significant cycling event is a 15 to 20 percent change in output at a typical ramp rate. Faster ramp rates would increase the cost, but less so for combined cycles. The costs are the median of lower bound estimates for each capacity type.
Source: Nikil Kumar et al., "Power Plant Cycling Costs." Golden, CO: National Renewable Energy Laboratory, July 2012, 11, 13.

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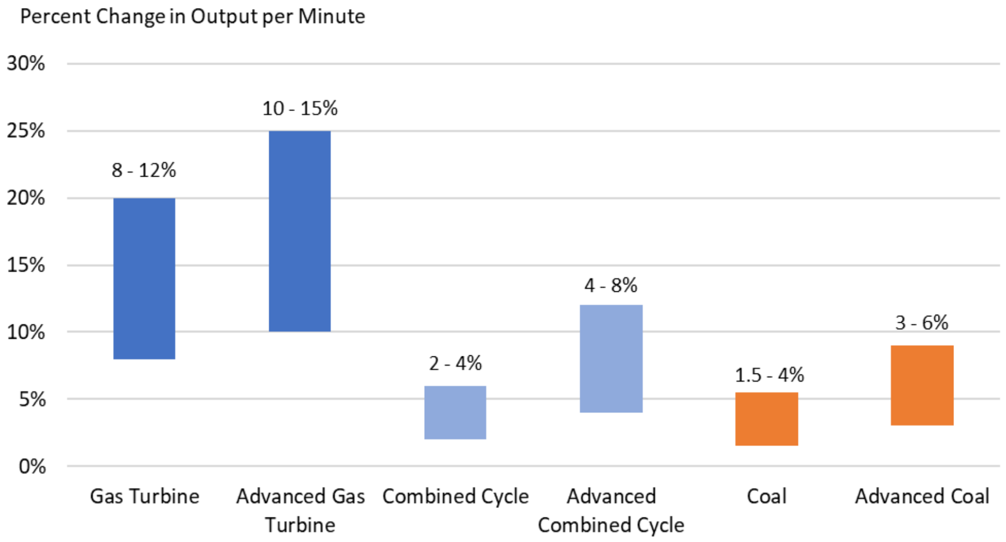
[59] The ramping speed estimates in Figure 16 do not reflect the ability of some combined cycles to operate in a bypass mode that allows the gas turbine to operate independently of the heat recovery steam generator and steam turbine. About 20 percent of the gas turbine capacity that is part of combined cycles in the United States has this capability (30.8 GW out of a total of 120.2 GW in 2018). Calculated from the EIA-860 data file for 2018, https://www.eia.gov/electricity/data/eia860/.

[60] Estimates of ramp rates vary. See "Flexibility in Thermal Power Plants – with a Focus on Existing Coal-Fired Power Plants." Berlin: Agora Energiewende, June 2017, 48 (the source for Figure 16); Andreas Feldmüller. "Flexibility of Coal and Gas Fired Power Plants." Presented at the Advanced Power Plant Flexibility Campaign, Paris, September 18, 2017., 4-8; Lesley Sloss. "Levelling the Intermittency of Renewables with Coal." London: IEA Clean Coal Centre, July 2016, 36.

Figure 17. Indicative Range of Ramp Rates: Percent Change in Output per Minute



Source: "Flexibility in Thermal Power Plants – with a Focus on Existing Coal-Fired Power Plants." Berlin: Agora Energiewende, June 2017, 48

lower capital costs than coal[61] the technologies are not fully comparable. Coal and other thermal plants provide firm capacity and can be dispatched on command. Wind and solar output are dependent on the weather, season, location, and time of day. Wind and solar can provide firm capacity as part of a system that includes storage or backup fossil generation.[62]

Because wind and solar photovoltaic generators have essentially no variable cost they will dispatch before other capacity aside from nuclear plants (which for technical, economic, and regulatory reasons will normally run continuously at maximum output)[63] and units that must operate to maintain system reliability. The low cost of wind and solar power will tend to drive down wholesale power prices and by doing so reduce the revenues available to thermal units. Weak wholesale power prices have been a factor in the retirement of coal and nuclear plants, but the low prices have been primarily due to the low cost of natural gas. Renewables have had less of an impact on wholesale prices, with their greatest

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[61] As shown in Table 3 the overnight cost in 2019 to build a coal unit is $3,661 per kW of capacity. EIA estimates the overnight cost for solar photovoltaic and onshore wind plants at, respectively, $1,331 and $1,319 per kW. "Assumptions to Annual Energy Outlook 2020: Electricity Market Module." Washington: EIA, January 29, 2020, 6.

[62] Overbuilding to meet peak and geographic diversity may also provide means to firm-up solar and wind capacity. Marc Perez, et al. "Overbuilding & Curtailment: The Cost-Effective Enablers of Firm PV Generation." *Solar Energy* 180 (March 2019); Andrew Mills and Ryan Wiser. "Implications of Wide-Area Geographic Diversity for Short- Term Variability of Solar Power." Berkeley: Lawrence Berkeley National Laboratory, September 2010.

[63] Peter Maloney. "How Market Forces Are Pushing Utilities to Operate Nuclear Plants More Flexibly." Utility Dive, October 4, 2016. t.ly/cYe3.

affect in regions where wind and solar power is concentrated such as California and portions of the Midwest.[64]

In summary, the operation of the power grid has evolved and continues to evolve in a manner that puts a premium on flexible operation at high efficiency. This is an environment for which steam-electric coal technology is poorly adapted. Coal units can be modified to improve cycling performance but only at a significant investment cost.[65]

Fuel Production, Distribution, and Delivered Prices

Production

Hydraulic fracturing (fracking) involves injecting water, chemicals, and a "proppant" such as sand into an oil or gas formation to increase the recovery and flow of the hydrocarbons. Fracking was introduced in 1947 and for decades has been central to oil and gas production in the United States. Refinement of the technique combined with other technological advances – including three-dimensional seismology, horizontal drilling, and the drilling of multiple wells from a single pad -- resulted in the fracking breakthrough of the 2000s which allowed low-cost production of oil and gas from shale and other tight formations.[66]

Fracking and complementary technologies have made oil and gas exploration and development more of a predictable mass production process and less of the wildcatting business of legend. Fracked production from tight formations has skyrocketed and now accounts for over 60 percent of domestic gas supply, compared to eight percent in 2007 (Figure 18).[67] Pennsylvania is a striking example of how shale production has upended historic patterns of natural gas production. In 2006 gas production from Pennsylvania was inconsequential; in 2018 Pennsylvania production was over 6 trillion cubic feet, more than any state other than Texas.[68]

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[64] Andrew D. Mills, et al. "Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017." Berkeley: Lawrence Berkeley National Laboratory, November 2019, 23-24, 47-48.

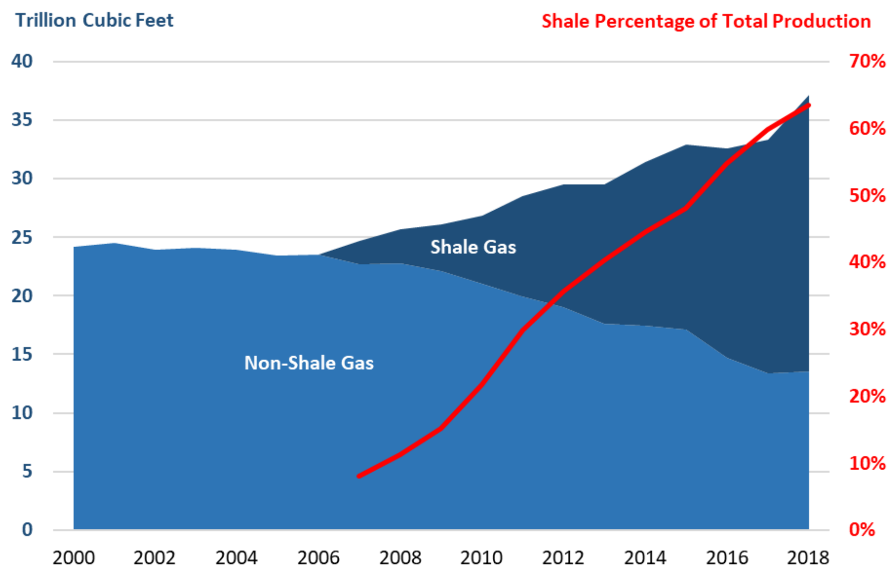
[65] Phillip Graeter and Seth Schwartz. "Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices." Washington: National Association of Regulatory Utility Commissioners, January 2020, 17-19; "Flexibility in Thermal Power Plants – with a Focus on Existing Coal-Fired Power Plants," 57-80, 109.

[66] John M. Golden, and Hannah J. Wiseman. "The Fracking Revolution: Shale Gas as a Case Study in Innovation Policy." *Emory Law Journal* 64, no. 4 (2015): 955–1040, 968-974. For additional background on fracking see Michael Quentin Morton. "Unlocking the Earth - A Short History of Hydraulic Fracturing." GEO ExPro, December 9, 2013. t.ly/RbJn; Carl T. Montgomery and Michael B. Smith. "Hydraulic Fracturing: History of an Enduring Technology." *Journal of Petroleum Technology* 62, no. 12 (December 2010): 26–41.

[67] Data on natural gas production and gross withdrawals downloaded from EIA website, http://www.eia.gov/dnav/ng/ng_prod_sum_dc_nus_mmcf_a.htm

[68] Data on natural gas production and gross withdrawals downloaded from EIA website, https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm

Figure 18. Natural Gas Gross Withdrawals, 2000-2018



Note: Data on shale gas production is unavailable prior to 2007
Source: Data file downloaded from EIA website,
http://www.eia.gov/dnav/ng/ng_prod_sum_dc_nus_mmcf_a.htm

Coal mining technology has also advanced. Innovations include larger and more productive mining equipment, use of information technology to improve mine planning and operations, and the introduction of remote controlled and automated mining equipment that has reduced labor costs. Two overriding developments have been increased production from highly productive surface mines and the increased use in deep mines of efficient "longwall" technology.[69]

But although better technology has improved the cost efficiency and safety of coal mining, these advances have been insufficient to match the impact of the fracking breakthrough on natural gas production costs. Labor productivity (tons of coal produced per employee-hour) is a key measure of coal mining cost efficiency. As shown in Figure 19 after decades of improvement labor productivity trends stalled or went into decline after 2000. Crucially, this decline in has been severe among the western surface mines which are the largest and lowest cost producers.

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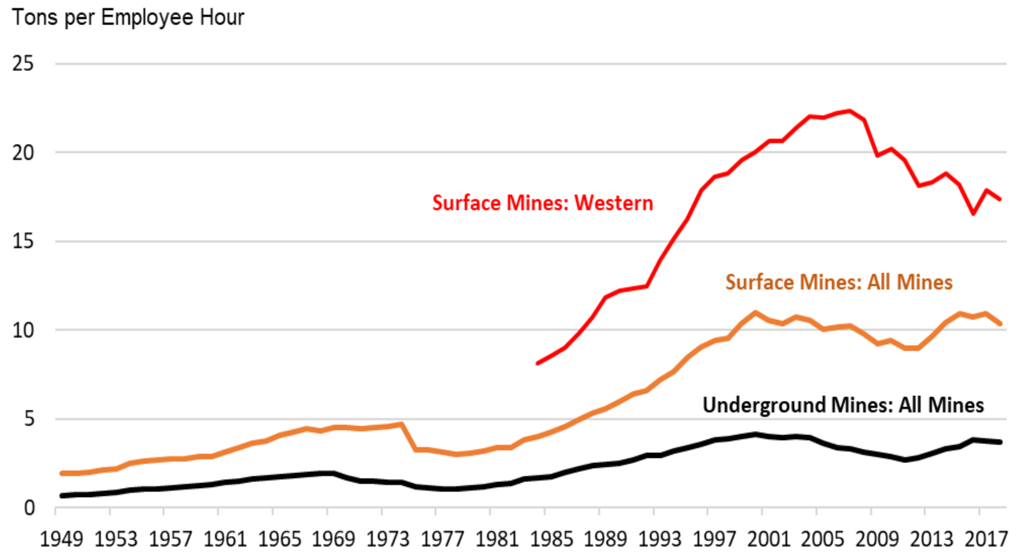
[69] For an overview of coal production methods and technical developments see Dave Osborne. *The Coal Handbook: Towards Cleaner Production: Volume 1: Coal Production*. Philadelphia: Woodhead Publishing, 2013. 193-224. Much older but still useful and in the public domain is "The Direct Use of Coal: Prospects and Problems of Production and Consumption," 64-77.

Figure 19. Trends in Coal Mine Productivity, 1949-2018



Source: "Annual Coal Report 2018." Washington: U.S. Energy Information Administration, October 2019. Table ES2

The stagnation in labor productivity is due in part to the industry reaching saturation levels of surface and longwall mine production. As shown in Figure 20 the percentages of coal from surface and longwall mines plateaued beginning in, respectively, 2008 and 2015. Another factor is the deterioration in mining conditions in some coal fields, most importantly the Wyoming Powder River Basin (WPRB). The WPRB contains the nation's largest and most efficient mines, accounting for 39 percent of total coal output in 2018.[70] However, after years of high-volume production the basin's surface mines are being forced to exploit more deeply buried coal seams, which reduces productivity and increases costs.[71] Deteriorating mining conditions have also increased costs in some Appalachian coal fields.[72]

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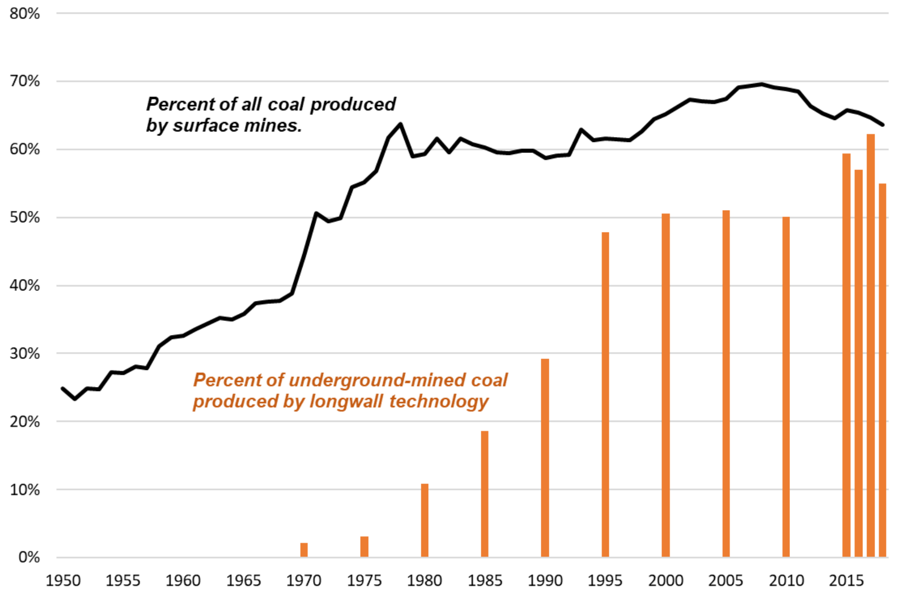
[70] Calculated from "Annual Coal Report 2018." Washington: EIA, October 2019, 3.

[71] The impact of increased overburden (that is, the depth of soil covering a coal seam) is vividly illustrated by the travails of Cloud Peak Energy, which operated three Powder River Basin mines before its 2019 bankruptcy and asset sale. As "CPE's mines…went deeper over the years, [they] were plagued by overburden- removal cost increases, specifically related to diesel fuel prices. The costs would prove to be a factor in the company opting to restructure. With its aging mines running deeper, the company was also locked into 'significant' planned capital expenditures for equipment, surface land holdings, and coal reserve maintenance…. 'Repairs and maintenance increased as a result of running more haul trucks, as well as work done at our rebuild center on various draglines, dozers, dippers and buckets,' CPE reported. 'Explosives increased as a result of an increase in overburden removal. The average cost per ton sold increased primarily due to the lower production and higher strip ratio.'" Jesse Morton. "Desperate Times, Desperate Measures." *Coal Age* 124, no. 7 (September 2019): 16–27, 23-24.

[72] Brett Jordan, et al. "Coal Demand, Market Forces, and US Coal Mine Closures." Washington: Resources for the Future, April 2018; Rory McIlmoil, et al. "The Continuing Decline in Demand for Central Appalachian Coal: Market and Regulatory Influences." Morgantown, WV: Downstream Strategies, LLC, May 14, 2013.

Figure 20. Production of Coal by Mining Method, 1950-2018



Notes: Longwall data is at five-year intervals through 2015, then shown annually. The 1980 longwall percentage is estimated. **Sources**: Surface mine production is from "Annual Coal Report 2018." Washington: U.S. Energy Information Administration, October 2019. Longwall production is from various issues of EIA, "Annual Coal Report" and predecessor publications including Bureau of Mines, "Minerals Yearbook," except for 1985 which is from Thomas M. Barczak. "The History and Future of Longwall Mining in the United States." Washington: Bureau of Mines, 1992, 19.

Distribution

About 70 percent of coal is delivered to consumers by rail.[73] Through much of the last century the railroads were perceived as a sick and financially underperforming industry.[74] In 1980 the railroads, which for decades had been subject to comprehensive economic regulation by the federal government, were largely deregulated by the Staggers Rail Act with the object of reviving the industry.

Since 1980 the freight railroads have used a combination of technical innovation, business restructuring, and management reforms to improve their financial health and cost-efficiency. However, aspects of the new regulatory regime have worked against the interests of the coal and power industries:

- The railroads are given wide latitude to charge higher rates to "captive" customers served by a single railroad and have no feasible alternative for receiving freight. Many coal plants are served by a single railroad and because of the large volumes and long distances that often characterize coal shipments they cannot use other delivery modes. These captive coal plants are, by

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[73] "Annual Coal Distribution Report 2018." Washington: EIA, October 2019, 94.

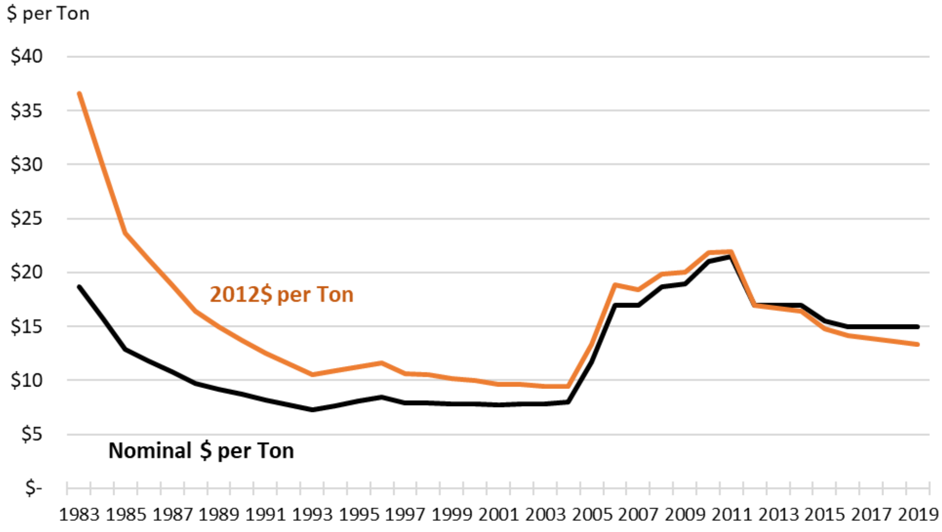
[74] Richard Saunders Jr. *Main Lines: Rebirth of the North American Railroads, 1970-2002*. DeKalb, IL: Northern Illinois University Press, 2003. 3-45.

regulatory design, charged higher rates than otherwise comparable shippers with competitive access to multiple railroads or modes (truck or water delivery).[75]

- One aspect of industry restructuring was consolidation through merger and acquisitions. The result is a highly concentrated industry dominated by four major carriers: the Norfolk Southern Railway and CSX Transportation in the eastern United States and the Union Pacific Railroad and BNSF Railway in the west. These regional duopolies can exercise significant market power, including choosing not to respond to competition from power plants burning cheap natural gas by reducing rail rates to coal plants.[76] By keeping coal rates high the railroads accept that the coal plants will be less competitive, will burn and therefore ship less coal, and may close. The benefit to the railroad is the maintenance of price discipline and the continued profitability of the remaining shipments.

The ability of the railroads to exercise price discipline is illustrated by trends in rates for shipments from the WPRB (Figure 21). As shown in the figure, rates sharply declined when a BNSF monopoly on WPRB shipments was broken by the entrance of a new competitor in the 1980s (a predecessor of today's Union Pacific Railroad). However, by the mid-2000s the BNSF and Union Pacific had reached market share equilibrium, resulting in dampened competition and constant dollar rates stabilizing at a level

Figure 21. Trends in Rail Rates for WPRB Coal to Competitive Destinations, 1,000 Mile Route, 1983-2019



Note: WPRB is Wyoming Powder River Basin. Rates were converted to constant dollars using the GDP implicit price deflator. **Source**: Base data in mills per ton-miles from Jamie Heller, Hellerworx, personal communication.

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[75] "Freight Railroads: Industry Health Has Improved, but Concerns About Competition and Capacity Should Be Addressed." Washington: U.S. Government Accountability Office, October 2006, 3, 7-8; Kelly Eakin, et al. "A Study of Competition in the U.S. Freight Railroad Industry and Analysis of Proposals That Might Enhance Competition: Revised Final Report." Madison, WI: Laurits R. Christensen Associates, Inc., November 2009, 18-16 and 18-17.

[76] Mark Repsher, et al. "The Future of Coal Versus Gas Competition." New York: PA Consulting and Hellerworx, 2017, 32-33.

higher than in the 1990s. The railroads maintained these higher rates even as their cost-efficiency improved.[77]

Natural gas pipeline technology is inherently less costly than shipment of bulk solids by rail, but the interstate pipelines and rail industries also operate under fundamentally different regulatory regimes that effectively magnify the cost advantage of pipelines. Pipelines operate as open access systems that must charge "just and reasonable" and non-discriminatory rates, in most cases determined by competitive forces. Pipelines must interchange with competitors at reasonable rates. Rail operators have no obligation to interchange with other networks at market prices and have explicit authority to charge differential (higher) rates to shippers who lack competitive options. Pipeline capacity shortfalls occur and cause price spikes, especially during high demand periods, but in general the gas pipeline network provides much lower cost and flexible transportation for natural gas than the railroads for coal.

Much as efforts have been made to convert coal into a gaseous or liquid fuel to capture the benefits of oil and gas combustion technology, efforts were also made to adapt coal to pipeline transportation in the form of a coal-water slurry. These efforts ultimately failed due to political, economic, and water supply factors. No coal-slurry pipelines currently operate in the United States.[78]

Delivered Prices

As described above, advances in fuel production technology have benefited natural gas more than coal, and regulatory policy has magnified the inherent advantages of pipeline over rail delivery of fuel. The combined impact of these factors has been to improve the price competitiveness of natural gas relative to coal.

Figures 22 through 24 show the trends in the delivered prices of coal and natural gas to power plants in the East North Central (ENC), East South Central (ESC), and South Atlantic (SA) census divisions for 2007 (the year coal demand peaked) through 2019.[79] These census divisions were selected because they accounted for 66 percent of the coal capacity that has retired after 2011, when the current wave of retirements began.[80] The figures show that in all three regions natural gas delivered prices trended lower while coal prices increased compared to the 2007 base year. Although coal remained less expensive than natural gas (see the data in Appendix B) Figure 25 illustrates how the price advantage has declined over time. As discussed in the next section of the paper, the combination of declining natural gas prices and the superiority of gas-fired combustion technology created an untenable economic situation for many coal plants.

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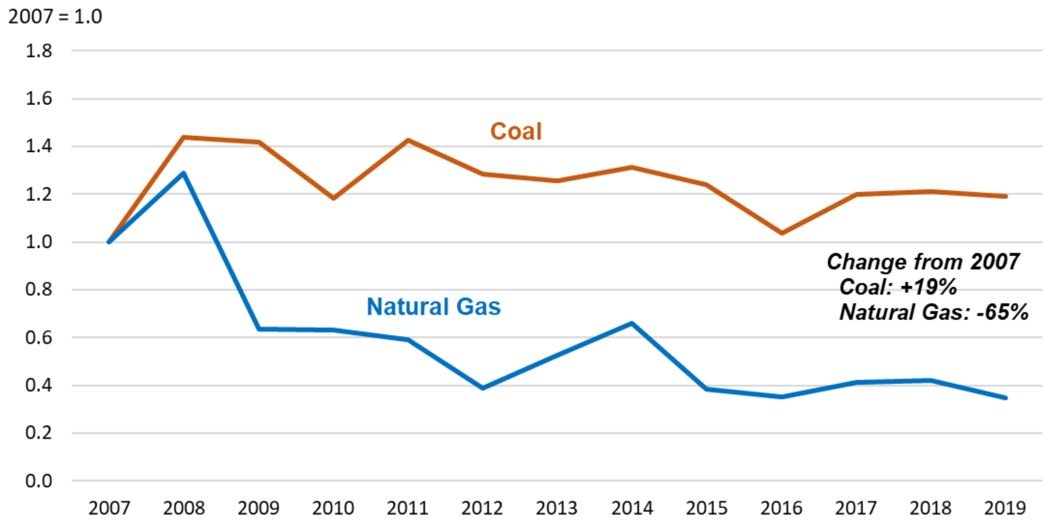
[77] Bill Stephens. "The Cult of the Operating Ratio." *Trains* 77, no. 11 (November 2017): 24–33. Stephens notes that the railroads "gained pricing power starting around 2004" (29).

[78] Dan Whipple. "Coal Slurry: An Idea That Came and Went." WyoHistory.org, November 14, 2014. t.ly/4OBM

[79] The charts present the volume-weighted (MMBtu) regional averages of transactions reported in the EIA-923 data files for deliveries to electric utility plants (https://www.eia.gov/electricity/data/eia923/). Public price data is not available for independent power producers. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal. A census division map is in Appendix C.

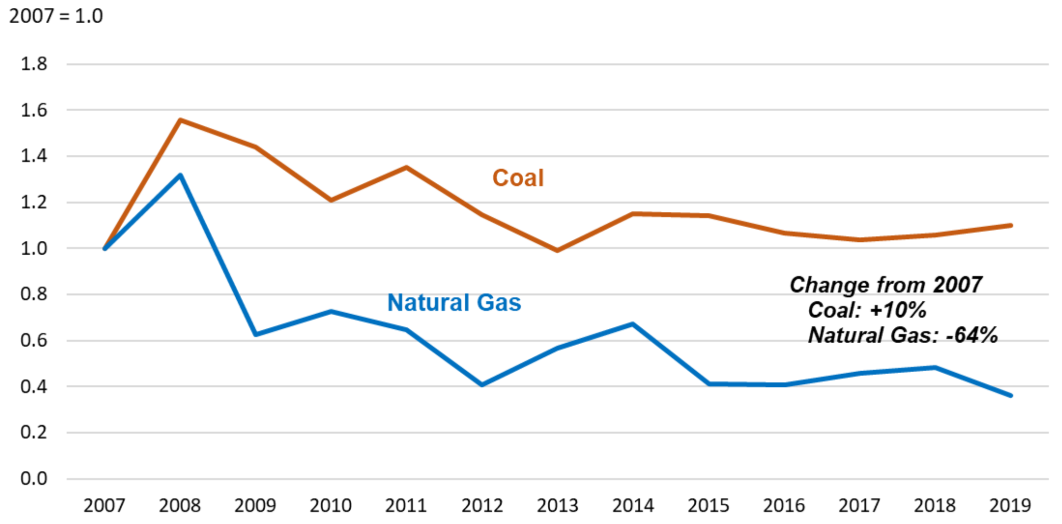
[80] A total of 76,968 MW of coal capacity retired 2012 through January 2020, of which 21,930 MW was in ENC, 16,907 MW in SA, and 12,017 MW in ESC. Calculated from EIA's January 2020 monthly capacity inventory file, https://www.eia.gov/electricity/data/eia860m/.

Figure 22. Trends in the Delivered Price of Coal and Natural Gas: East North Central Census Division, 2007-2019



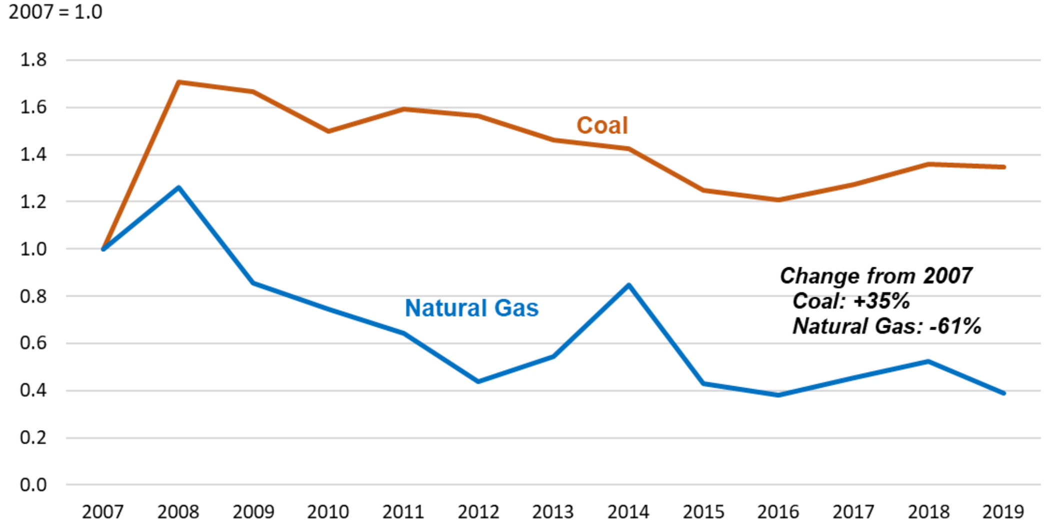
Notes and Sources: Based on the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). Price data for independent power producers are not publicly available. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal.

Figure 23. Trends in the Delivered Price of Coal and Natural Gas: East South Central Census Division, 2007-2019



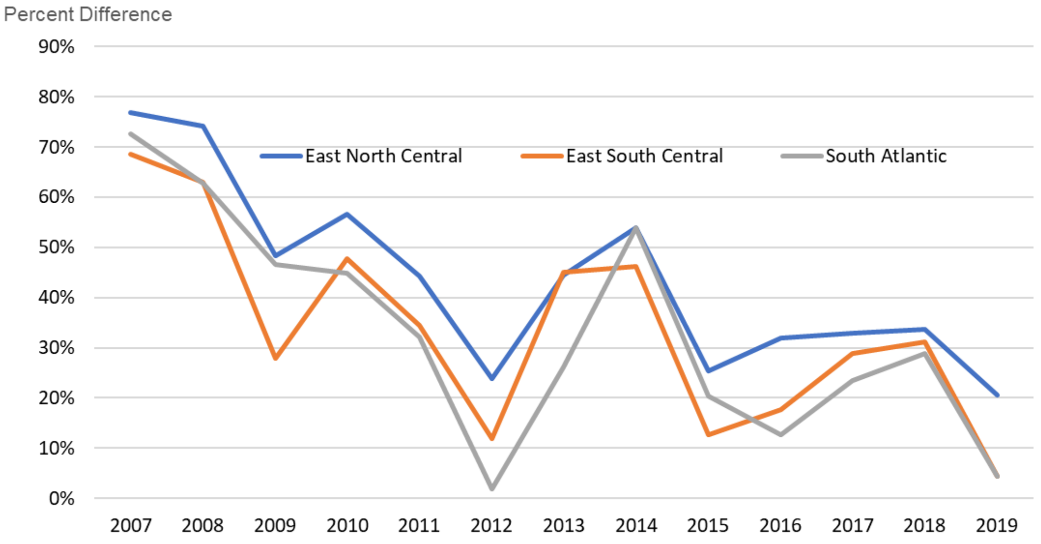
Notes and Sources: The data represent the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). Price data for independent power producers are not publicly available. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal.

Figure 24. Trends in the Delivered Price of Coal and Natural Gas: South Atlantic Census Division, 2007-2019



Notes and Sources: The data represent the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). Price data for independent power producers are not publicly available. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal.

Figure 25. Natural Gas Delivered Price Premium Over Coal, Electric Utility Receipts, 2007-2019



Notes and Sources: Based on the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts data files (https://www.eia.gov/electricity/data/eia923/). Price data for independent power producers are not publicly available. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal.

Culmination: Natural Gas as a Lower Cost Source of Power

The factors discussed above – generation efficiency, plant operations, and delivered fuel price and other operating costs – determine power production costs. Hourly and daily economic dispatch decisions are based on variable operating costs including fuel and operations and maintenance (O&M) expenses that vary directly with plant output. That is:

Variable O&M ($ per MWh) + Fuel Cost ($ per MWh) = Variable Production Cost

The fuel cost per MWh is a function of the delivered price of the fuel and the thermal efficiency with which the plant converts fuel to electricity. The better the thermal efficiency, the lower the fuel cost per MWh.

Figures 26 through 28 provide indicative estimates of the changing competitive position of coal-fired and natural gas combined cycle plants in the ENC, ESC, and SA regions for the period 2007-2019. Detailed information on the cost and operating assumptions are shown in Table 4. In summary:

- Fuel costs are for spot and interruptible supplies, which best represent the marginal fuel prices used in dispatch calculations.
- Variable operations and maintenance (VOM) costs are middle-range estimates.
- Costs are shown for low, national average, and high efficiency coal plants, with heat rates of respectively 12,000, 10,015, and 9,515 Btus/kWh.
- Costs are shown for two types of combined cycles, F-class (6,800 Btus/kWh) and HA-class (6,300 Btus/kWh). F-class turbines have been available since the late 1980s. HA-class and other advanced types (G- and J-class) have predominated since the middle of the last decade.[81]

The figures show comparable patters for the three regions. Beginning in 2009, as fracked supplies cause natural gas prices to fall, the F-class combined cycle became competitive with the low-efficiency coal plant. By the middle of the last decade the F-class plant is generally competitive with or lower cost than even the high-efficiency coal plant. The more advanced HA-class unit, which is first shown in 2015, has a lower production cost than the coal units in every year. This disadvantage in production costs forced many coal units out of baseload service and into load-following operations. Load-following has the knock-on impacts described above – higher heat rates, more wear-and-tear, and higher maintenance costs – which makes the units even more costly to operate. The effect is a kind of death spiral which will only be broken if natural gas prices greatly increase, restoring the economic competitiveness of coal-fired power.

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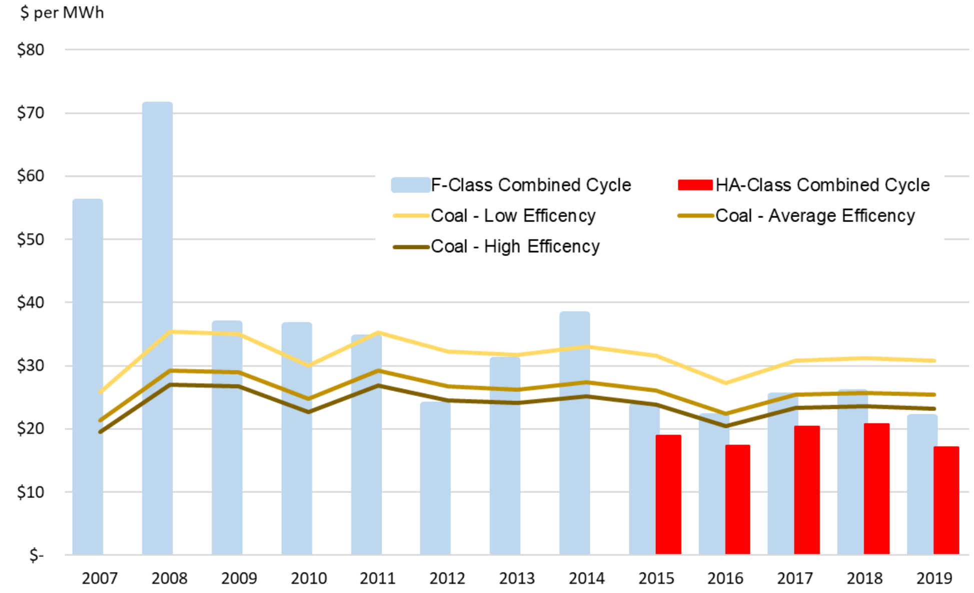
[81] Michael J. Ducker. "The Fall of the F-Class Turbine." Power Engineering, August 21, 2015. https://www.power-eng.com/2015/08/21/the-fall-of-the-f-class-turbine/.

Table 4. Assumed Generating Unit Characteristics for Production Cost Estimates

Characteristic or Cost	Value	Notes	Source (detailed references below)
Delivered Fuel Prices			See Appendix B
Heat Rates: Coal			
• High	12,000 Btus/kWh		Lazard
• National Average	10,015 Btus/kWh	Capacity-weighted tested heat rate for 2018	EIA
• Low	9,515 Btus/kWh	Average of the 20 most efficient units in 2017	Power Engineering
Heat Rates: Combined Cycle			
• F-Class	6,800 Btus/kWh		Brattle 2014
• HA-Class	6,300 Btus/kWh		Brattle 2018
Variable O&M Cost in 2019: Coal			
• High	$5.00/MWh	Pre-2019 values estimated using the GDP implicit price deflator	Lazard
• Medium	$3.88/MWh		Lazard (midpoint of range)
• Low	$2.75/MWh		Lazard
Variable O&M Cost in 2019: Combined Cycle	$3.38/MWh	Pre-2019 values estimated using the GDP implicit price deflator	Lazard (midpoint of range)
Coal Fixed O&M Cost in 2019: Coal	$61.25/kW-year		Lazard (midpoint of range)
Fixed O&M Cost in 2019: Combined Cycle	$12.15/kW-year		Lazard (midpoint of range)

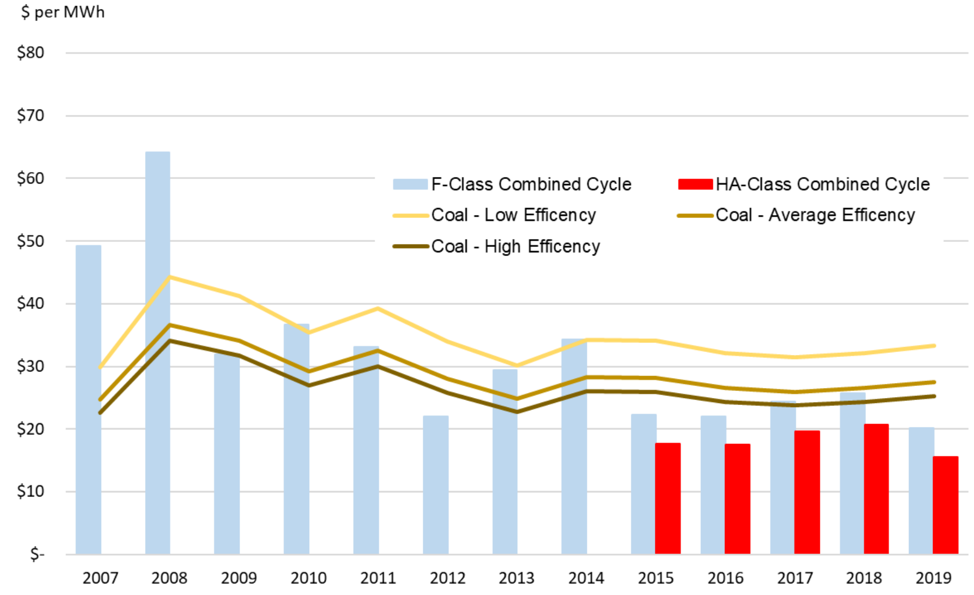
Sources: "Lazard's Levelized Cost of Energy Analysis -- Version 13.0." New York: Lazard Ltd., November 2019, 18; "Electric Power Annual 2018." Washington: EIA, October 2019, Table 8.2; Russell Ray. "Power Plant Performance in 2017." Power Engineering, June 1, 2018. https://www.power-eng.com/articles/print/volume-122/issue-6/features/power-plant-performance-in-2017.html, Table 5; Samuel A. Newell, et al. "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM With June 1, 2018 Online Date." The Brattle Group and Sargent & Lundy, May 15, 2014, 16; Samuel A. Newell, et al. "PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date." The Brattle Group and Sargent & Lundy, April 19, 2018, 14.

Figure 26. Indicative Comparison of Variable Production Costs, Coal and Natural Gas Combined Cycle Plants, East North Central Census Division



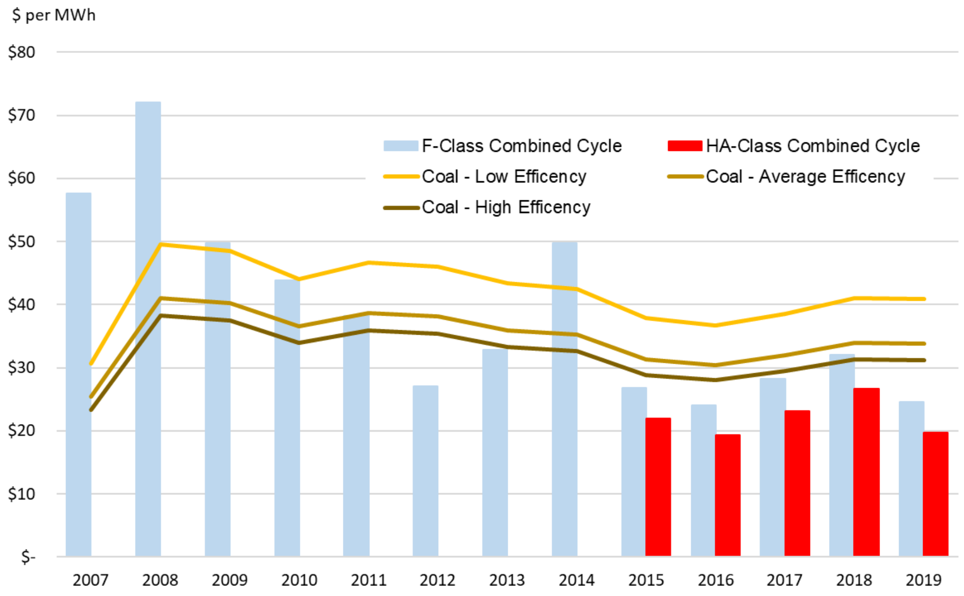
Notes and Sources: The production cost is the sum of the fuel cost and variable operations and maintenance cost expressed in dollars per MWh. The fuel component is based on the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). See the main text and notes to the fuel trend charts for additional information. For other plant characteristics and data sources see the accompanying table.

Figure 27. Indicative Comparison of Variable Production Costs, Coal and Natural Gas Combined Cycle Plants, East South Central Census Division



Notes and Sources: The production cost is the sum of the fuel cost and variable operations and maintenance cost expressed in dollars per MWh. The fuel component is based on the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). See the main text and notes to the fuel trend charts for additional information. For other plant characteristics and data sources see the accompanying table.

Figure 28. Indicative Comparison of Variable Production Costs, Coal and Natural Gas Combined Cycle Plants, South Atlantic Census Division



Notes and Sources: The production cost is the sum of the fuel cost and variable operations and maintenance cost expressed in dollars per MWh. The fuel component is based on the volume (MMBtu) weighted average price for interruptible natural gas and spot coal delivered to electric utility power plants as reported in the EIA fuel receipts and costs data files (https://www.eia.gov/electricity/data/eia923/). See the main text and notes to the fuel trend charts for additional information. For other plant characteristics and data sources see the accompanying table.

The discussion above has focused on variable production costs, but power plants also have fixed O&M (FOM) costs that do not vary with output over the short-term, such as plant staff salaries, routine maintenance, and periodic major maintenance and capital replacement projects. Because they are large, complex, and have extensive ancillary equipment, coal plants have large FOM costs. For example, Lazard estimates the FOM for a coal plant in 2019 at $40.75 to $81.75 per kW-year, which for a 500 MW plant amounts to $20.4 to $40.9 million annually.[82] These fixed costs must be recovered through power sales, but if high variable costs force a coal plant into cycling service fewer MWh will be sold and the FOM charge per unit of power will increase.

Using the middle of the FOM cost range presented above, a coal plant operating at a baseload-type 70 percent capacity factor would need to recover $9.98 per MWh in FOM.[83] But if high variable costs drive the plant into cycling service and the capacity factor is halved to 35%, the FOM cost doubles to almost $20 per MWh. This is equivalent to a 50 percent or greater adder to the 2019 variable production costs

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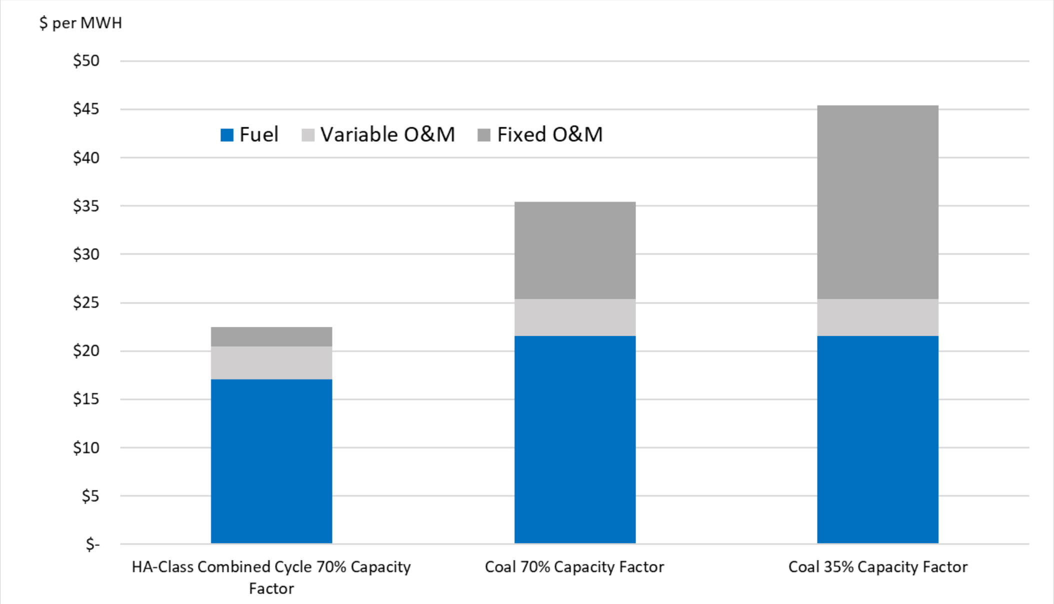
[82] In comparison Lazard's estimated FOM cost for a combined cycle is $11.00 to $13.50 per kW-year. "Lazard's Levelized Cost of Energy Analysis -- Version 13.0." New York: Lazard Ltd., November 2019, 18. EIA provides a point estimate of $40.41 per kW-year for an ultra-supercritical coal plant and $12.15 per kW-year for an HA-class combined cycle (2019 dollars). EIA, "Assumptions to Annual Energy Outlook 2020: Electricity Market Module," 6.

[83] The mid-range of the Lazard FOM cost is $61.25 per kW-year, or $30.6 million annually for a 500 MW (500,000 kW) plant. At a 70 percent capacity factor, the plant produces 3.066 million MWh per year (8,760 hours x 500 MW x 70%). $30.6 million ÷ 3.066 million MWh = $9.98 per MWh.

(see the above production cost charts). An example of the impact of FOM costs is shown in Figure 29 for the ENC census division. If, over the longer term, the plant cannot sell power at a price high enough to recover FOM costs it will be uneconomic to operate and will be forced into retirement.

Figure 29. Comparison of Production Costs ($/MWh) including Fixed O&M, 2019 Fuel Prices, East North Central Census Division



Sources: Assumptions for calculations: See accompanying table. Basis of fuel prices: see main text and notes to delivered fuel price trend charts.

Conclusion

> The coal power industry acknowledges that to play a stable role in future power markets, it needs to modernize, and perhaps even overhaul its long-held status as a “conventional generator.” Could new technology give it the reboot it needs?
>
> — *From Power Magazine, January 2, 2020* [84]

Across all dimensions – fuel production, transportation, combustion -- coal-fired technology has been surpassed by the natural gas combined cycle. Consequently, coal’s role in American power generation is ending and will probably reach irrelevance in ten to 15 years.

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[84] Sonal Patel. “Transformative Coal Power Technologies Take Shape.” Power Magazine, January 1, 2020. https://www.powermag.com/transformative-coal-power-technologies-take-shape/.

EIA projects that electric power demand for coal will fall from 539 million tons in 2019 to 352 million tons in 2020, down 35 percent in a year. This drop is partly due to the economic impact of the COVID-19 crisis, but as noted earlier the pandemic is an accelerant of coal's decline, not the root cause.

EIA expects a partial rebound of coal demand in 2021 (to 425 million tons) but another view is that the lost demand will never return. Moody's Investor Service, for example, expects "minimal future recovery" and that power demand for coal will "fall significantly in the 2020s."[85] Moody's outlook is more realistic because the power market is moving decisively away from coal to newer, more efficient, and less costly technologies. For example, just in May and June 2020, operators in North Dakota, Wisconsin, Maryland, Illinois, Indiana, Colorado, and Florida announced plans to shut coal-fired generators. A few weeks earlier one of the newest and most efficient coal plants in the United States, the Longview station in West Virginia, declared bankruptcy. The driving factors were "long-term pressure from natural gas, a mild winter [which depressed wholesale power prices] and the COVID-19 pandemic."[86]

A primary motivation for coal plant retirements is to cut costs by replacing coal with wind, solar, and natural gas power. For example, the Indiana utility Vectren concluded it could save $320 million over 20 years by retiring coal units and ending an agreement to buy coal-generated power. It would also be able to avoid spending $700 million on pollution control equipment. To replace 730 MW of coal generators Vectren will build up to 1,050 MW of solar capacity, 300 MW of wind power, and two natural gas combustion turbines (480 MW).[87] [88]

To help salvage the coal industry the federal government is researching advanced coal plants with characteristics more like gas-fired generators, such as better cycling performance. But this kind of program will do little to keep America's obsolete fleet of coal plants viable and it is improbable that many new plants will be built. A more fundamental issue is that making coal plants more like gas-fired

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[85] "Coronavirus-Driven Economic Weakness Crushes Demand Outlook for 2020." New York: Moody's Investors Service, May 31, 2020, 2; "Coronavirus-Related Power Demand Reductions Drive Lower Carbon Emissions." New York: Moody's Investors Service, June 30, 2020, 1. The EIA forecasts cited in this and the prior paragraph are from the June 2020 "Short-Term Energy Outlook," Table 6.

[86] But note that the company began preparing its bankruptcy filing in January 2020, prior to the pandemic. Catherine Morehouse. "Manchin Presses FERC to Keep West Virginia Coal Online, as Advocate Questions Identity of New Plant Owners." Utility Dive, June 24, 2020. t.ly/v9WM; Fotios Tsarouhis. "Longview Power Sees Quick Bankruptcy Exit, Plans Gas and Solar Builds." S&P Global Market Intelligence, April 22, 2020. t.ly/Kv8O.

[87] Mark Wilson. "Vectren Plan Focuses on Solar and Wind, Keeps Some Coal, Natural Gas." Evansville Courier & Press, June 16, 2020. t.ly/CfHo; Catherine Morehouse. "Vectren Bucks Indiana Legislature with Plan to Reduce Coal Mix 78% to 12% by 2025." Utility Dive, June 17, 2020. t.ly/hFdF.

[88] For the other retirements announced in May-June 2020 see Jeffrey Tomich. "Midwest Coal Giant Announces Plant Closure." t.ly/J3xu; Catherine Morehouse. "Alliant Energy to Retire 380 Mw Coal-Fired Unit Said to Have Lost Millions with Uneconomic Scheduling." Utility Dive, May 26, 2020. t.ly/FryD; Darrell Proctor. "GenOn Will Close Three Coal-Fired Units." Power Magazine, May 21, 2020. t.ly/Pdxf; Molly Parker. "Southern Illinois Power Co-Op Plans to Shutter Its Largest Coal-Fired Unit This Fall." The Southern Illinoisan, June 8, 2020. t.ly/QzyM; Lauren Irwin. "Larimer County Coal-Fired Power Plant Will Close 16 Years Early as Colorado Speeds Move Toward Renewable Energy." The Colorado Sun, June 16, 2020. t.ly/AEO2; Mark Jaffe. "Colorado Springs Will Shut down Its Two Coal-Fired Plants by 2030. Now It's Time for Xcel to Do the Same, Environmentalists Say." Colorado Sun, June 26, 2020. t.ly/RgPq; Matthew Bandyk. "FPL, JEA to Retire 848 MW Unit of Largest US Coal Plant." Utility Dive, June 29, 2020. t.ly/u5fv.

plants is already several steps behind the technology curve. The cost of wind, solar, and battery power is plunging and is a factor in the displacement of coal and natural gas.[89] The future seems to lie with technologies that supply electricity without combustion.

The government appears to recognize that the future of coal power in the United States is grim. The Department of Energy is seeking to increase coal exports and to expand use of coal as a feedstock to produce “advanced materials, rare earth elements, and critical minerals.” [90] It is difficult to imagine these paths supporting more than a minimal coal industry.

The railroad industry was once one of the largest markets for coal. Writing about the elimination of the steam engine, the historian Maury Klein observed:

> While it is a truism that technology is a catalyst for social change, little attention has been given to the role and repercussions of "replacement” technologies. By this term I mean a technology so superior that it does not merely improve earlier devices but supersedes them entirely. In the process it also brings sweeping changes to the context in which the technology is used. By its nature, the influence of replacement technology spreads rapidly in ways that are neither intended nor predictable….
>
> The diesel locomotive revolutionized the way railroads performed their work; reconfigured the physical landscape of railroads; redefined the role of labor in this most traditional of industries; transformed the structure of labor relations; and consigned to the realm of nostalgia an entire subculture rooted in a shared passion for that dominant symbol of 19th century America, the steam locomotive. What is more remarkable, this entire process took place in only about twenty years despite the intrusion of a major war.[91]

This type of technological revolution is now bringing coal in America to an end.

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[89] For example, the investment bank Morgan Stanley “compared the costs of operating each coal plant against our state-by-state forecasts of renewables costs across 13 stocks [i.e., power companies] and identified [47,000 MW] of coal capacity that will become more expensive than renewables by 2024….[This analysis] follows a December 2019 report in which the research firm forecast that about 70,000 MW to as much as 190,000 MW of coal-fired generation is ‘economically at risk’ from the deployment of a ‘second wave of renewables’ in the U.S. The research firm said these projections exclude about 24,000 MW of coal generation already set to shut down.” Darren Sweeney. “Morgan Stanley: $64B Capex Upside for Utilities Replacing Coal with Renewables.” S&P Global Market Intelligence, February 18, 2020. t.ly/GZ0V. Also see Darren Sweeney. “Morgan Stanley: ‘Second Wave of Renewables’ to Drive 70 GW of Coal Retirements.” S&P Global Market Intelligence, December 20, 2019. t.ly/wW8B.

[90] Steven Winberg. “21st Century Coal.” Presented at the U.S. Department of Energy Future of Coal Roundtable, Washington, March 25, 2020, 4. t.ly/nYvL.

[91] Maury Klein. “Replacement Technology: The Diesel as a Case Study.” *Railroad History* 162 (Spring 1990): 109–20, 109.

Appendix A: Making Coal into Something Else

Business and government have tried for more than 100 years to develop economical processes to convert coal into a gaseous or liquid fuel. This would indirectly give coal the favorable characteristics of oil and gas, including the high energy density of fuel oil, utilization of efficient pipeline transportation, compact storage for liquid fuels, and firing characteristics that would permit the use of diesel and combustion turbine technologies.

Because of cost, technical, and economic uncertainties, national governments have been the leading actors in coal-based synfuel development, by subsidizing research, pilot plants, and commercial-scale facilities. Governments have pursued these projects for several reasons, including:

- Providing a secure source of petroleum where domestic supplies are scarce and reliance on imports considered risky.
- In anticipation of domestic or global depletion of oil and gas.
- To counter high market prices for oil and gas.
- To find new markets for coal; and
- To provide a more environmentally benign way to use coal.

In the United States, all these factors have been in play at one time or another, and all the various conversion efforts have failed or yielded minimal benefits due to the cost and complexity of synfuel technology.

Work on coal gasification and liquefaction dates from German research in 1913. The petroleum-poor pariah states of Nazi Germany and apartheid-era South Africa are perhaps the best known examples of nations making large investments in coal-to-liquids.[92] American interest in synfuels was sporadic because of poor economics and ample conventional supplies, until the triple energy disruptions of the Arab Oil Embargo of 1973, the natural gas shortages of the early to mid-1970s, and the Iranian Oil Crisis of 1979-1980.[93] High prices and physical shortages convinced many policymakers that oil and gas resources would have to be supplemented and perhaps ultimately replaced with synthetic fuels. These circumstances eventually led to the nation's largest synfuel initiative, the creation in 1980 of the Synthetic Fuels Corporation. The SFC was authorized to spend $88 billion on facilities using coal-based and other technologies to produce two million barrels per day of liquid fuel or gaseous fuel equivalent by 1992. In practice the efforts of the SFC came to nothing. Instead of increasing as expected, oil and

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[92] For background on German and South African synfuel efforts see Anthony Stranges. "Germany's Synthetic Fuel Industry, 1927-1945." In *The German Chemical Industry in the Twentieth Century*. Boston: Kluwer Academic Publishers, 2000.; Stephen Sparks. "Between 'Artificial Economics' and the 'Discipline of the Market': Sasol from Parastatal to Privatisation." *Journal of Southern African Studies* 42, no. 4 (July 2016): 711–24.; Bureau of Mines, "Minerals Yearbook 1932-33," 442-447.

[93] Sabrina Willis. "The Synthetic Fuels Corporation as an Organizational Failure in Policy Mobilization." In *The Unfulfilled Promise of Synthetic Fuels: Technological Failure, Policy Immobilism, or Commercial Illusion*. New York: Greenwood Press, 1987, 72-73.

natural gas prices declined in the 1980s, making coal-derived synfuels uneconomic. The SFC was ordered closed in 1985.[94]

Marginally more successful was the Great Plains Coal Gasification Project, intended to convert North Dakota lignite coal into pipeline quality synthetic natural gas. The plant was built by a consortium of gas pipeline companies with about 75 percent of the cost covered by a federal loan guarantee. Although the plant was finished ahead of schedule in 1984 and operated successfully, it was uneconomic even before it opened due to the declining price of natural gas. The consortium defaulted on the federal loan guarantee in 1985 and the government took ownership of the $2.1 billion project. In 1988 the project was sold for $85 million to a subsidiary of Basin Electric Power Cooperative, which continues to operate the plant. To improve its economics Basin Electric has used the facility was to produce chemicals in addition to natural gas. Nonetheless, the finances of the project have deteriorated with the declining price of natural gas and its financial prospects are reportedly poor. A recent lawsuit claims that the plant has lost at least $600 million since 2014. [95]

The SFC and Great Plains Project were aimed at creating central facilities that would sell synthetic oil and gas through commercial networks to multiple buyers.[96] The other model for coal conversion is the integrated gasification combined cycle (IGCC) plant, which converts coal into a gas for use by a single generating facility. In an IGCC plant coal is introduced into a gasifier, where it is converted under high pressure and temperatures into a "synthesis gas" consisting largely of carbon monoxide and hydrogen. The synthesis gas is processed to remove pollutants and then burned in a modified combined cycle.

On paper the IGCC technology has advantages over conventional steam electric coal plants, including pre-combustion removal of pollutants and adapting coal to use modern combined cycle generating technology. In practice the complexity of the IGCC has made it uneconomic in the United States.[97] The only American IGCC plants operating today are the small (250 MW) Polk unit in Florida and the Edwardsport station in Indiana (618 MW), both built with federal government support. Polk was constructed as an experimental pilot plant but Edwardsport was intended from the start to be a

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[94] Peter Z. Grossman. "U.S. Energy Policy and the Presumption of Market Failure." *Cato Journal* 29, no. 2 (Spring/Summer 2009): 295–317. 301-305; Willis, "The Synthetic Fuels Corporation as an Organizational Failure in Policy Mobilization," 71-72.

[95] Arlon R. Tussing, and Bob Tippee. *The Natural Gas Industry: Evolution, Structure, and Economics*. 2nd ed. Tulsa, OK: PennWell Books, 1995, 164-167; Jessica Holdman. "Future Looks Bleak for Great Plains Synfuels Plant." Bismarck Tribune, August 6, 2019. t.ly/OXq6; Amy Sisk. "Power Cooperatives Embroiled in Dispute Stemming from Money Woes at Synfuels Plant." Bismarck Tribune, February 9, 2020. t.ly/S8f3; "Turning Coal into Natural Gas and a Whole Lot More." Minot Daily News, November 25, 2014. t.ly/yzjv.

[96] There has also been work on underground coal gasification; that is, gasifying the buried coal seam in place. This has never been more than an experimental technology in the United States. National Energy Technology Laboratory. "Underground Coal Gasification," nd. https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/underground.

[97] For an overview of IGCC technology see "The Future of Coal." Cambridge, MA: Massachusetts Institute of Technology, 2007, 32-39, 120-125. On the complexity of IGCC technology the study notes that "A detailed analysis of the operating history of the Polk Power Station over the last few years suggests that it is very similar to operating a petroleum refinery, requiring continuous attention to avert, solve and prevent mechanical, equipment and process problems that periodically arise. In this sense, the operation of an IGCC unit is significantly different from the operation of a PC [pulverized coal] unit, and requires a different operational philosophy and strategy." 39.

commercial facility. It entered service in 2013 two years late and $1.5 billion over budget and has had continuing cost and operating problems.[98]

Most recently Southern Company's Kemper County project in Mississippi (582 MW), aimed at building an IGCC with a new gasification technology and partial carbon capture, was a financial and technical fiasco. The original $2.9 billion estimate for project ballooned to $7.5 billion, a cost realm normally inhabited only by nuclear power plants. Southern was ultimately forced to abandon the gasification and carbon capture systems and operates the plant as a conventional natural gas combined cycle.[99] Reportedly the Edwardsport plant would also be cheaper to run if the operator shut down the gasification system and operated the unit as a natural gas combined cycle. [100] There are no plans or prospects for new commercial IGCC plants being built in the United States.[101]

In summary, the many handling and combustion advantages of fuel oil and natural gas have been one motivation for repeated efforts to convert coal into a liquid or gaseous form. These efforts have foundered on the costs and complexities of the technologies and have no current prospect of economic viability in the United States.

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[98] Sonal Patel. "Duke Hit Hard by Exorbitant O&M Costs at Edwardsport IGCC Facility." Power Magazine, June 12, 2018. https://www.powermag.com/duke-hit-hard-by-exorbitant-om-costs-at-edwardsport-igcc-facility/.

[99] Proctor, "Regulators Back Settlement for Costs of Failed Kemper IGCC Project." Kemper is probably the most expensive fossil-fired power plant ever built

[100] According to a news report, "On the Edwardsport plant, [John] Swez [director of generation dispatch at Duke Energy] argues the facility must be designated 'must-run' because it's difficult to cycle off and on, and it doesn't want to lose its specialized work force. And although [Duke's] own analysis has found the plant would save a net $6.1 million by running the plant only through its gas units, Swez says the 'volatility' of natural gas has them wanting to maintain 'the diversity value of coal.' Catherine Morehouse. "Duke, IPL Face Indiana Scrutiny as NGOs Detail Coal Plant Practices Costing Ratepayers Millions." Utility Dive, April 24, 2020. t.ly/1ZpC.

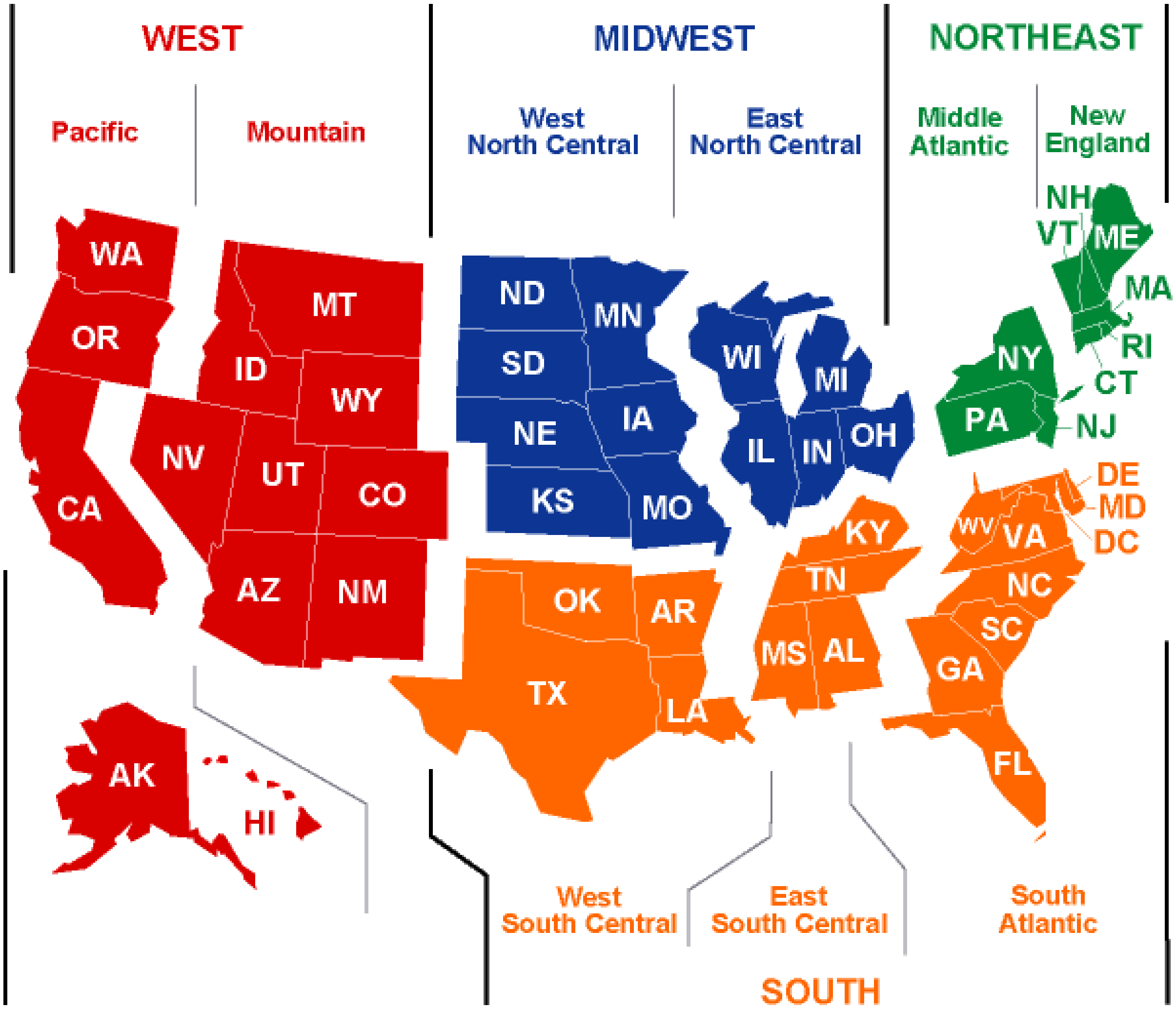
[101] Harry Jaeger. "Once Promising Technology: Is There Still a Case to Be Made for IGCC?" Gas Turbine World (2018 Handbook Edition) 33 (January 2018): 17–24. 17.

Appendix B. Estimated Delivered Fuel Prices, 2007-2019

East North Central Census Division					
	Delivered Price, Nominal $ per MMBtu			Delivered Price Index, 2007 = 1.0	
	Coal	Natural Gas	Coal Price Advantage	Coal	Natural Gas
2007	$1.81	$7.81	-77%	1.00	1.00
2008	$2.60	$10.07	-74%	1.44	1.29
2009	$2.57	$4.97	-48%	1.42	0.64
2010	$2.14	$4.93	-57%	1.18	0.63
2011	$2.58	$4.62	-44%	1.42	0.59
2012	$2.32	$3.05	-24%	1.28	0.39
2013	$2.27	$4.09	-45%	1.25	0.52
2014	$2.37	$5.15	-54%	1.31	0.66
2015	$2.24	$3.00	-25%	1.24	0.38
2016	$1.87	$2.76	-32%	1.04	0.35
2017	$2.17	$3.23	-33%	1.20	0.41
2018	$2.19	$3.30	-34%	1.21	0.42
2019	$2.15	$2.71	-21%	1.19	0.35
East South Central Census Division					
	Delivered Price, Nominal $ per MMBtu			Delivered Price Index, 2007 = 1.0	
	Coal	Natural Gas	Coal Price Advantage	Coal	Natural Gas
2007	$2.14	$6.84	-69%	1.00	1.00
2008	$3.34	$9.01	-63%	1.56	1.32
2009	$3.08	$4.27	-28%	1.44	0.62
2010	$2.59	$4.97	-48%	1.21	0.73
2011	$2.90	$4.43	-35%	1.35	0.65
2012	$2.46	$2.79	-12%	1.14	0.41
2013	$2.13	$3.87	-45%	0.99	0.57
2014	$2.47	$4.58	-46%	1.15	0.67
2015	$2.45	$2.81	-13%	1.14	0.41
2016	$2.28	$2.77	-18%	1.06	0.41
2017	$2.22	$3.12	-29%	1.04	0.46
2018	$2.27	$3.29	-31%	1.06	0.48
2019	$2.36	$2.47	-4%	1.10	0.36
South Atlantic Census Division					
	Delivered Price, $ per MMBtu			Delivered Price Index, 2007 = 1.0	
	Coal	Natural Gas	Coal Price Advantage	Coal	Natural Gas
2007	$2.21	$8.07	-73%	1.00	1.00
2008	$3.78	$10.17	-63%	1.71	1.26
2009	$3.69	$6.90	-47%	1.67	0.86
2010	$3.32	$6.01	-45%	1.50	0.75
2011	$3.52	$5.19	-32%	1.59	0.64
2012	$3.47	$3.53	-2%	1.57	0.44
2013	$3.24	$4.38	-26%	1.46	0.54
2014	$3.16	$6.85	-54%	1.43	0.85
2015	$2.76	$3.48	-20%	1.25	0.43
2016	$2.67	$3.06	-13%	1.21	0.38
2017	$2.82	$3.68	-23%	1.27	0.46
2018	$3.01	$4.22	-29%	1.36	0.52
2019	$2.99	$3.13	-4%	1.35	0.39

Notes and Sources: Volume-weighted (MMBtu) regional averages of transactions reported in the EIA-923 data files for deliveries to electric utility plants (https://www.eia.gov/electricity/data/eia923/). Public price data is unavailable for independent power producers. Outlier records, such as natural gas prices below $0.50 per MMBtu, are excluded. Interruptible natural gas includes deliveries for which the supply and/or transportation contracts are interruptible. Coal data excludes waste coal.

Appendix C. Map of Census Divisions and Regions



Source: https://www.eia.gov/consumption/manufacturing/maps.php