

Power dynamics: Forces shaping the future of coal in the United States

A perspective for investors considering
opportunities in the energy sector



Power dynamics: Forces shaping the future of coal in the United States

Opportunities abound for investors who understand the options available to coal-fired generators as changing regulations, economics and technology reshape the US power sector.

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Coal-fired plants have been the backbone of US power generation for more than a century, and they still account for nearly 40 percent of power generation in the country. But coal's dominance in the United States is waning. It will remain a significant source of fuel for generating power in the future, but natural gas and renewables will account for an increasing share of the nation's fuel mix.

That's because a variety of forces are converging to make coal a less attractive source of fuel. Perhaps the most important factor is that emissions regulations are changing the economics of power generation, rendering coal uneconomical in some areas. At the same time, other resources such as gas and renewables are becoming more economical. And trends such as distributed generation and demand response are reducing demand for power from traditional generators.

Despite these forces, coal is expected to account for about one quarter of the country's generating capacity in 2030. That is a significant piece of a large pie. In July 2015, Moody's published an analysis of the sector concluding that "coal's large share of the US electricity supply means it is here to stay." In fact, power companies added 15 gigawatts (GWs) of coal-fired capacity to the market from 2008 to 2013. The ten largest coal-fired plants built during this period accounted for about half of that capacity—and each of them incorporated controls that enable them to meet current and anticipated emissions regulations.

In coming years, shrewd investors will find many attractive opportunities for returns in the power sector—including opportunities related to coal-fired generation—as the shift to a new fuel dynamic unfolds in the United States. To capture these opportunities, investors will have to understand the difficult choices facing most owners of existing coal-fired assets, who will most likely have to pursue one of three difficult options: retrofit to reduce emissions; convert to natural gas; or retire their coal-fired plants.

FORCES SHAPING THE FUTURE OF COAL

Owners of coal-fired plants face a range of challenges as regulations, fuel economics and attitudes toward power consumption evolve. We focus on the effects of three broad trends that are likely to be most important to coal plants: intensifying emissions regulations; the increasing importance of natural gas and renewables; and falling demand for power from traditional generators.

Emissions regulations threaten coal economics

By 2030, the Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) looks to reduce carbon emissions of US power plants to 32 percent below 2005 levels. The CPP sets deadlines for states to submit plans and achieve interim objectives that will help ensure progress toward the overall 2030 goals, but it leaves it up to states to develop their own plans for how to achieve the CPP's

STATES TO DETERMINE HOW TO MEET CPP GOALS

States are required to submit a carbon reduction plan by September 6, 2016, with options for requesting extensions of up to two years; all state plans must be submitted by September 6, 2018. States may develop their own plans or collaborate with other states on multi-state plans. The plans must indicate how states will meet both interim goals for emissions reductions, which are marked out for the period from 2022 to 2029, as well as the final goal by 2030. The EPA has a year after a state submits its final plan to approve it or send it back for revision. If a state does not submit an adequate plan, the EPA is authorized to impose a federal plan to achieve the necessary reductions.

The CPP gives states the flexibility to create plans for reducing emissions that are best suited to their particular circumstances. The EPA identified four "building blocks" for reducing carbon emissions: improving the heat rate of existing coal-fired power plants; shifting to lower-emitting gas-fired generation; shifting to zero-emitting renewable generation; and increasing use of demand-side efficiency programs. But states are free to meet requirements through other means, such as implementing emissions trading schemes.

goals (see the sidebar "States to determine how to meet CPP goals" for more details on CPP deadlines and requirements).

According to analysis by the US Energy Information Administration (EIA), a previous goal proposed by the CPP to reduce emissions by 30 percent (a goal that is 2 percentage points lower than the current requirement) would bring carbon emissions from the power sector

down to their lowest levels since the 1980s. Chart one shows the EIA's analysis: the "reference case" projects emissions levels without CPP and the CPP case projects emissions under CPP requirements.

The CPP would significantly change the fuel mix used for generating power in the United States, according to the EIA. Chart two shows that coal would account for only 25 percent of the country's generating capacity in 2030, down from 52 percent in 2000. Natural gas would take the lead with 31 percent, and renewables would tie coal for second place at 25 percent. CPP requirements are the same for every state, which puts some states in a better starting position than others for achieving the goals. States such as California and Washington have already taken steps to reduce CO₂ emissions and thus have a head start (see the sidebar "States also regulate emissions" for details.) And some states depend much more heavily on coal than others, as shown in chart three. Fitch Ratings points out that public power and

cooperative utilities operating in states subject to sizable mandated carbon-reduction plans and high carbon-reduction costs will have the most difficulty maintaining margins; these include utilities in Arkansas, Arizona, Florida, Mississippi and West Virginia. Fitch singled out Washington, Idaho and Oregon as states where utilities are least likely to face compliance challenges.

It is important to remember that the final rule issued in August 2015 adopting the CPP has generated significant controversy. Fifteen state attorneys general already filed for emergency stays while the CPP's legality is challenged in the courts. The DC circuit rejected the requests for stays, but questions about whether, when and how to comply with the CPP are likely to continue to roil the power sector for years to come.

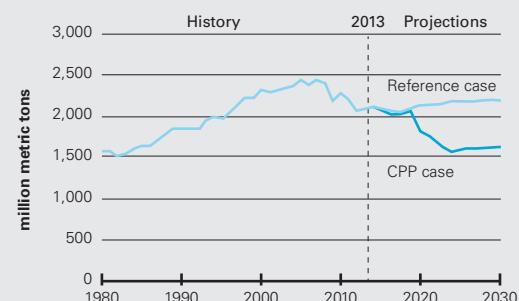
The EPA's Mercury and Air Toxic Standards (MATS), adopted in 2012, require power plants to incorporate the "maximum achievable control technologies" to limit emissions of mercury, acid gases and toxic

metals. About 600 power plants, mostly in the South and upper Midwest, were subject to an April 2015 deadline to meet MATS requirements or be shut down; about 175 of these plants obtained an additional year to comply, giving them until April 2016.

The EPA estimates that MATS will cost owners of coal-fired and oil-fired plants about US\$9.6 billion a year, but the EPA also estimates that MATS will result in savings to the country of at least US\$37 billion in the form of lower healthcare costs, fewer lost work days and a reduction in early deaths.

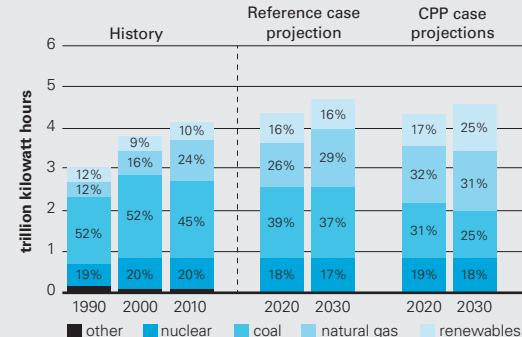
The future of MATS remains uncertain, however. In June 2015, the US Supreme Court rejected the EPA's conclusion that it was not required to consider costs when deciding it was "appropriate and necessary" to regulate air toxic emissions from power plants. While this was a win for industry participants and states that objected to MATS, the Supreme Court holding did not vacate MATS—the case was remanded to a lower court for

CO₂ emissions could fall to 1980s levels



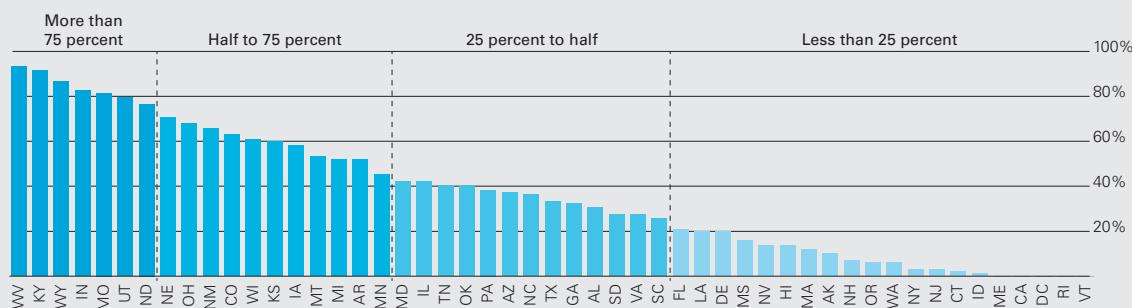
Source: US Energy Information Administration

Coal's market share could fall to 25%



Source: US Energy Information Administration

A third of states generate at least 50% of power from coal



Source: US Energy Information Administration

further consideration. Significantly, the Supreme Court order did not require the EPA "to conduct a formal cost-benefit analysis in which each advantage and disadvantage is assigned a monetary value." Instead "it will be up to the Agency to decide" how best to account for the cost of regulation. It is too soon to tell what the future holds for MATS, but given the EPA's ambitious agenda for emissions reductions, it is unlikely that MATS regulation will disappear in its entirety. The EPA is due to publish its cost analysis in April 2016.

Gas and renewables are becoming increasingly economical

The natural gas revolution in the United States raised the prospect of lower electricity costs, and utilities have expanded gas-fired capacity to seize the opportunity. Indeed, the EIA predicts a 7 percent decrease in total coal consumption in 2015 due mainly to utilities switching from coal to lower-priced natural gas to fuel their plants. In its 2015 annual electric utility industry survey, Black & Veatch found that most respondents expect natural gas to take market share away from nuclear and coal as utilities work to meet CPP emissions goals. And gas is increasingly the fuel of choice for backup generation needed to enable renewable power to flourish.

Renewables are also becoming competitive with coal on a levelized cost of electricity (LCOE) basis, and some forms of renewable power are cheaper than coal even without federal subsidies. Lazard, the investment bank, reported in 2014 that the cost of utility-scale solar energy was as low as 5.6 cents per kilowatt hour (kWh), and the cost of wind was as low as 1.4 cents per kWh (without subsidies, the cost rose to 7.2 cents per kWh for solar and 3.7 cents per kWh for wind). By comparison, the cost for natural gas was 6.1 cents per kWh, and the cost of coal was 6.6 cents per kWh. In July 2015, Austin Energy, a public utility that provides electric power to the city of Austin, Texas, asked for bids for 600 megawatts (MWs) of solar power and was offered record low bids of less than 4 cents per kWh.

The US renewables industry is growing rapidly as a result of these emerging price dynamics. In 2014,

STATES ALSO REGULATE EMISSIONS

A number of states have enacted or proposed laws to reduce greenhouse gas emissions, and others have enacted climate action plans and taken other steps to address emissions in the power sector. California has some of the most stringent carbon emissions standards in the nation. Its global warming law, enacted in 2006, calls for the state to reach 1990 emissions levels by 2020 and to reduce emissions to 80 percent below 1990 levels by 2050. In April 2015, Governor Jerry Brown issued an executive order that accelerates the state's goal, calling for reducing the state's emissions to 40 percent below 1990 levels by 2030. The state of Michigan, which was the lead plaintiff in a lawsuit challenging the EPA's MATS, has a mercury emissions rule in place that requires reductions similar to those required by MATS.

the United States ranked second (after China) in total investment in clean energy. Wind and solar are the fastest-growing renewable technologies in the United States, having more than tripled their capacity from 27 GWs in 2008 to 87 GWs in 2014. According to Accenture, solar will reach grid parity in many states in 2015 (meaning the cost of solar will be equal to or less than the cost of power purchased from the grid).

The renewables market is also emerging as an alternative source of baseload demand—particularly as forecasting and scheduling technologies have improved the responsiveness of intermittent renewable resources, and backup power is more readily available in the form of gas-fired generation and energy storage.

It's important to note that the pace of growth in some renewable resources could depend on continued subsidies. Congress recently extended the production tax credit (PTC) and investment tax credit (ITC) for wind energy to the end of 2016. It has yet to extend the ITC for solar energy. If Congress does not extend the solar ITC before the end of 2016, the 30 percent credit for residential systems will expire, and the credit for commercial systems will drop to 10 percent. But even if the pace slows due to reductions in subsidies, renewables growth is likely to continue. Indeed, about 30 states reportedly have mandates to increase the proportion of electricity from renewables.

Innovations are reducing demand from utilities

Advances in technology are driving rapid growth in the market for distributed energy, enabled by the proliferation of small-scale and modular devices designed to provide electricity in locations close to consumers. These include not only solar arrays and wind turbines but microturbines, fuel cells, combustion turbines, energy storage devices (such as batteries and flywheels), and combined heat and power systems. The market is attracting an increasing number of investors, including companies such as Google, which is putting US\$300 million in a US\$750 million fund that will invest in installing rooftop solar panels. The explosive growth of the distributed market is creating unease among some utilities, which see a threat to their revenue from traditional power generation. In some states, utilities are pushing state utility commissions to impose grid charges on customers using distributed generation, which could make it less attractive to potential customers.

Demand response programs are designed to enable and encourage consumers to voluntarily use less power or switch to renewable sources whenever they choose. This is raising anxiety among traditional generators. The Supreme Court recently heard oral arguments on whether the Federal Energy Regulatory Commission exceeded its authority in 2011 when it issued a rule requiring utilities to compensate consumers that participated in

certain demand response programs at "the market price for energy," which power operators say is too generous. The wholesale power market landscape could shift significantly depending on how the Supreme Court rules on this case.

Energy efficiency programs are already putting pressure on utilities in some states, and many states are likely to increase their emphasis on efficiency due to the CPP. States such as Massachusetts, California and Oregon have led the way in setting, funding and enforcing standards that establish energy savings targets for utilities, and almost half the states have what are known as Energy Efficiency Resource Standards.

THREE MAIN OPTIONS FOR EXISTING COAL-FIRED PLANTS

In light of the above forces and pressures, investors should understand the tradeoffs involved in the three main options available to owners of coal-fired plants: retrofit to reduce emissions; convert to natural gas; or retire their coal assets.

Retrofit to reduce emissions

Some coal-fired generators have the option to retrofit their existing plants with new technology to bring them into compliance with new and anticipated emissions regulations. But doing so is expensive. Options such as installing sulfur dioxide scrubbers, baghouses and electrostatic precipitator upgrades can cost several hundred dollars per kWh, driving up the LCOE for coal-fired assets to a level that may not be economical. The viability of this approach could depend heavily on local dynamics, such as state regulations and the potential for other generation technologies to take hold in the area.

Some promising options for bringing existing coal-fired assets into emissions compliance remain largely unproven in practice. Carbon capture and storage (CCS) technologies involve capturing CO₂ before it is emitted into the atmosphere and then storing it underground in porous rock formations. The federal government and the private sector are actively investing in research and piloting CCS programs, but the technology is still in the early stages of development. One closely watched

project is a clean-coal power plant under construction in Kemper County, Mississippi. The plant is designed to convert coal into a flammable gas that can be used to generate electricity. The CO₂ captured from this process will be sent via pipeline to oilfields in the state. The gas will then be injected into the ground for storage, but in the process it will be used to squeeze more oil out of aging fields in a procedure known as enhanced oil recovery. This is not cheap. The cost of the Kemper County project, originally estimated at US\$2.88 billion, has reportedly soared to US\$6.2 billion. It has thus far been delayed two years and now has an expected in-service date of 2016.

Convert to natural gas

Converting coal-fired plants to natural gas is a practical and sustainable option, particularly given the historically low cost of natural gas in the United States. Gas-fired plants produce about 45 percent less CO₂ than do coal-fired ones, and they produce no sulfur dioxide or mercury. They also require smaller sites to operate, which reduces real-estate costs relative to coal-fired plants (although this may not be a factor for coal-to-gas conversion projects).

But to determine whether conversion is a viable option, owners of coal-fired plants will have to consider a number of factors, including:

Pipeline capacity: Many plants are located in areas that lack pipeline capacity to reliably bring sufficient gas to their facilities. Indeed, the United States faces a shortfall in distribution infrastructure for natural gas, and solutions for expanding capacity have proven difficult to implement.

Price volatility: The price of gas is more volatile than coal, particularly in the winter when surging demand can cause price spikes. And the future price of gas is also uncertain, with the possibility that increasing demand—from domestic power generators and manufacturers as well as rising gas export capacity—will cause the price to rise, particularly if pipeline capacity is not increased.

Complexity: Coal-to-gas conversion is a highly complex process that can also be very expensive. Some plants may be

too old or out of date to justify conversion. When conversion is operationally and economically viable, plant owners must ensure they can marshal the technical expertise to pull it off efficiently without causing severe interruptions to customers in their service area.

Tenor of existing contracts: Long-term take-or-pay coal contracts may limit near-term conversion options for many coal-fired plants.

Retire coal plants

Many owners of coal-fired assets face the prospect of having to close plants, due mainly to pressures stemming from increasing emissions regulations and sustained low gas prices. Estimates about how much coal-fired capacity will be retired vary greatly. The EPA estimates that 9.5 GWs of coal-fired capacity will be retired by the end of 2016, while the EIA estimates that 60 GWs will be retired by then.

Closures also vary significantly by region. For example, retirements of about 20 GWs of capacity have been announced by utilities in the PJM region, but less than 1 GW of retirements have been announced in the ERCOT and NYISO regions. See the sidebar "Three case studies" for details about how some leading generators are approaching plant retirements and navigating other options, such as retrofitting existing coal plants and converting to gas.

States will have to address the challenge of how to ensure power is provided to consumers as companies retire aging coal plants or shift to other fuels. Some industry executives and market operators such as MISO fear that there will be blackouts if new generation is not brought online efficiently.

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The transformation of the US power market is creating new challenges for utilities. The collective pressure to meet these challenges is particularly strong on utilities that depend heavily on coal. There will be winners and losers in coming years, and it is hard to predict today which strategies will help individual power providers to thrive. But one thing is certain: There will be many opportunities for investors to secure attractive returns by helping power companies position themselves for success as this new US power market takes shape. ■

THREE CASE STUDIES

DTE Electric

In 2014, Michigan's largest power utility announced plans to retire a third of its coal-fired generation capacity by 2025. DTE recently projected that its reliance on coal-fired generation would be reduced to about 25 percent in 2030, compared to roughly 60 percent in 2012. DTE will rely more on natural gas and renewables, particularly wind. At the time of the announcement, CEO Gerry Anderson said that the EPA's then-proposed carbon emissions rules would trigger the biggest renewal of Michigan's power industry in decades. He estimated that about US\$15 billion would be spent making changes to Michigan's power infrastructure to meet the EPA rules, with DTE spending about US\$8 billion.

Duke Energy

The largest energy holding company in the United States has retired 15 coal-fired plants with a total capacity of 3,836 MWs since 2011, and it plans to retire five more with a total capacity of about 2,466 MWs over the next few years. In addition, it recently announced plans to retire its Asheville, North Carolina coal plant in four to five years, and it announced that it will build a US\$750 million, 650 MW natural gas plant with solar capacity installed on the site. But coal remains central to Duke's strategy. It operates about 4,500 MWs of coal capacity, including its Gibson baseload plant, one of the largest coal plants in the Midwest. Duke also is building new coal facilities. Among other projects, it recently built a 825 MW advanced clean-coal plant in North Carolina. It also built a 618 MW integrated gasification combined-cycle power plant that converts coal to synthetic gas to generate power.

Dynegy Inc.

Transactions completed in April 2015 made Dynegy the third-largest independent power producer in the United States, enabling it to significantly diversify its geographic reach and fuel mix. It acquired coal and gas plants from Duke Energy and Energy Capital Partners for a total of US\$6.25 billion, doubling its generating capacity to about 26,000 MWs. Dynegy has made significant investments in environmental controls and has set a goal to safely recycle 100 percent of its coal ash byproduct for beneficial reuse by 2020.

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