No country for coal gen

Below 2°C and regulatory risk for US coal power owners

Carbon Tracker Initiative

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About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's financial markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

Introducing our power supply cost curves series

This is Carbon Tracker's first report in a series of power supply cost curves and follows a similar approach to the upstream oil, coal and gas studies previously published that identify uncompetitive assets in the transition to a low carbon economy. These reports provide a tool for the majority of mainstream investors who cannot simply divest, so they can understand their risk and start redirecting capital in a manner that is both economically rational and consistent with the Paris Agreement. Much of the content in this report is directed at a non-specialist audience.

Institutional investors and power analysts can view one-page company summaries of listed US coal owners at:

www.carbontracker.org/report/no-country-for-coal-gen

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Xcel Energy's Sherburne County (Sherco) Generating Station, a coal-fired power plant, near Becker, Minnesota.
Source: Tony Websiter via Wikimedia Commons

Executive Summary

Coal's market share in the US power mix is being diminished at an unprecedented rate due to fierce competition from cheap gas and renewables. Around 30 GW of coal capacity has been retired over the last three years, with coal generation declining by 13% over the same period. The economics of US coal power could not be starker: new coal capacity is not remotely competitive, while in the next few years it will be the exception rather than the rule for the operating cost of existing coal to be lower than the levelized cost of new gas and renewables.

The purpose of this report is threefold:

- provide a tool for investors who have exposure to US coal power to make their portfolio compliant with the Paris Agreement in an economically rational way;
- detail how an outdated regulatory framework is one of the only reasons why uncompetitive coal power continues to operate in the US; and
- highlight how phasing-out coal power could save US citizens money and make the US economy more competitive.

Given the current political backdrop, the assumptions underpinning our analysis are deeply conservative: no Clean Power Plan (CPP) or carbon prices and only well-established environmental regulations, originally drafted in 1970s.

Our modelling approach

Our net present value (NPV) model values units based on their regulatory status. Regulated units are valued based on the revenue requirement approved by regulators, while merchant units are valued based on their cost relative to a new combined cycle gas turbine (CCGT). Our NPV model values every operating unit in the US to generate two separate scenarios:

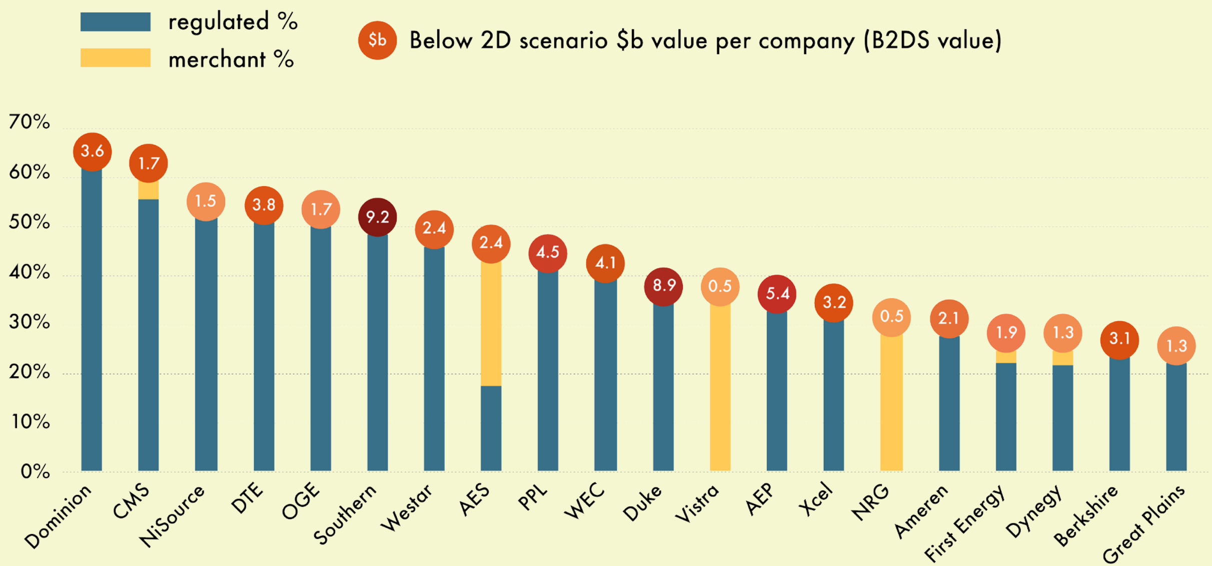
- ***Below 2°C scenario for all units***. Stranded value under the below 2°C scenario is defined as the difference between the IEA "Beyond 2°C Scenario" (B2DS) – which phases-out all unabated coal power by 2035 – and business as usual (BaU) based on company reporting. A 2°C Scenario (2DS) is also included for comparison. Every existing coal unit (both regulated and merchant) is forecasted and ranked to develop a retirement schedule based on its operating cost and system value. The impact on unit valuation from the retirement schedule is aggregated up to the listed coal owner, to provide a tool for investors to comply with the Paris Agreement in way that is economically rational.
- ***Regulatory risk scenario for regulated units.*** Regulatory risk under this scenario is defined as the difference between regulatory and market valuation of all regulated units. Regulated units are valued based on the revenue requirement approved by regulators, while market valuation assumes the unit

has no value if the operating cost is greater than the cost of a new CCGT. The impact on unit valuation from comparing assets with the most competitive dispatchable power technologies is aggregated to highlight the extent uncompetitive coal power is being subsidized by an out of date regulatory framework.

Below 2°C scenario – $104 billion of stranded value for all listed coal owners

We estimate the total stranded value for coal owners in the B2DS for the period to 2035 to be $104 billion. Out of the 20 largest listed coal owners, Dominion has the highest proportion of value at risk under a B2DS scenario with more than 60% of stranded value compared to the BaU scenario. CMS, NiSource and DTE are also at risk with 59%, 52% and 51% of stranded value against the BaU scenario, respectively. Stranded value as a percentage of the BaU scenario is dependent on the regulatory status and operating cost of the unit.

Figure 1. Below 2°C stranded value as a percentage of BaU for 20 largest coal owners



Source: Carbon Tracker analysis

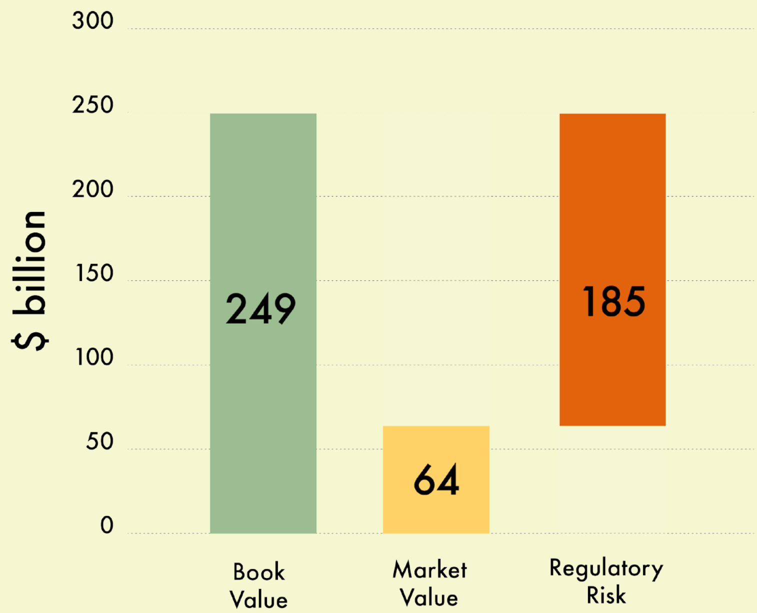
For example, Dominion's units are both high cost and regulated. The materiality of stranded value is contingent on exposure relative to total assets. For instance, Berkshire Hathaway owns a substantial amount of regulated coal capacity, but the stranded value from these units is dwarfed by their market capitalisation resulting from its diversification across many sectors of the economy.

Regulatory risk scenario – $185 billion of regulatory risk for all regulated units

We estimate $185 billion of regulatory risk for all regulated units projected out to 2035. Regulated utilities are mostly protected from competition, charging government-approved prices and receiving guaranteed returns. Merchant utilities are competitive businesses that operate in wholesale power markets. Merchants know first-hand the implications of owning coal capacity: over the past two years listed merchants have lost around half of their market capitalisation. This is in part due to operating high-cost coal units. Despite also holding high-cost coal units, owners of regulated coal units pass on this cost to ratepayers and, as such, have not suffered the same financial consequences. Yet, as cheap gas and renewables expand throughout the country, the cost impact of coal for ratepayers will become harder to ignore.

The difference between book and market value represents the regulatory risk for regulated utilities who – by continuing to operate high cost coal units – are putting their financial interests ahead of the consumers they serve.

Figure 2. Regulatory risk for regulated coal units



Source: Carbon Tracker analysis

Energy transition versus corporate welfare – phasing out unprofitable coal could save $10 billion per year and reduce household electricity bills by up to 10% by 2021

Utilities that own regulated units often have little incentive to retire costly coal power. While merchant units are subject to financial losses through market forces, regulated units pass costs onto customers. The rate base creates a perverse incentive as utilities with regulated capacity are often motivated to continue investing in existing coal units. As mentioned above, an overwhelming proportion of existing coal capacity will soon be economically unviable compared to other new and existing power technologies. However, these coal units could be kept running as owners seek to make ongoing capital investments to earn a return on the remaining undepreciated balances. This form of corporate welfare is stifling the energy transition at the expense of consumers. Phasing-out coal could save the US consumer $10 billion per year by 2021, with Kentucky, Indiana and Michigan households saving on average 10%, 9% and 7%, respectively on their electricity bills. This reality contrasts with recent rhetoric from the Trump Administration about the virtues of continuing to rely on coal power.

Recommendations

Regardless of federal politics, the transition in the US power sector has reached escape velocity: end-user efficiency and onsite generation are crimping load growth, while renewable energy and electric vehicles are going to change power systems in ways previously unimaginable. A below 2˚C pathway would save US power consumers money – and therefore make the US economy more competitive – but this reality will only be realised if regulation catches up with the structural changes that have occurred over the last three years. Our recommendations outline how:

- investors can make their US power investments compliant with the Paris Agreement;
- energy transition obstruction could have a negative impact on regulated coal power; and
- regulators can be harbingers of change.

Investors

As a minimum, investors must require more information on the processes used by listed coal owners to manage energy transition risk. Investors should comprehensively review their future exposure to coal generation assets. This analysis should be based on the cost profile and system value of individual assets. Moreover, investors need to acknowledge regulated coal can no longer be considered a safe asset class, as utilities that keep high-cost regulated units operating are often doing so at their customers' expense. Carbon Tracker's below 2˚C model identifies the stranded value of every operating coal unit based on their regulatory status and their year of retirement.

Coal owners

Regulated investor-owned utilities – don't be another RWE

Since 2008, RWE – one the of the largest utilities in Europe – has lost 80% of its market capitalisation due to a failure to understand policy, technology and business model changes. The 20th century legal framework that underpins regulated utilities in the US is not well suited to the 21st century. As energy efficiency, onsite generation, renewable energy and electric vehicles change the production and consumption of electricity, regulated investor-owned utilities need to put their customers first. Failure to do this could result in a consumer revolt. To reduce the risk of value destruction, regulated utilities need to act in the interests of both shareholders and their customers. This must involve developing a coal phase-out plan consistent with a below 2°C outcome.

Merchant investor-owned utilities – if you're going through hell, keep focusing on capital discipline

Merchant utilities have already incurred significant reductions in market capitalisation due to deteriorating market conditions. The loss in market capitalisation experienced by merchant utilities over the last 2 years have been a reality for over 5 years in Europe. The crisis facing European utilities has resulted in business model changes, as well as significant reductions to the operations and maintenance (O&M) costs of conventional thermal generation assets.

Merchant utilities should focus on capital discipline while also adopting a coal phase-out schedule consistent with a below 2°C outcome.

Conglomerate holding companies – holding regulated coal is no longer low-risk

Holding companies have historically been attracted to regulated utilities that are monopoly franchises with captive customers. However, as noted above, the business model underpinning regulated utilities is coming under sustained pressure. As with regulated utilities, holding companies need to reconcile the tension between shareholder and customer interests. Failure to do so could result in a changing regulatory landscape.

Regulators

Public Utility Commissions (PUCs) around the US are starting to grapple with the reality that rate of return regulation may no longer be viable in the 21st century. Part of this recognition needs to reflect the following realities: (i) even without expensive pollution control and carbon capture and storage (CCS) technologies, coal is often a more expensive option relative to other power technologies; (ii) making coal highly dispatchable to accommodate increased amounts of low-cost variable renewable energy increases O&M costs, exacerbating its economic disadvantage; and (iii) retrofitting existing units with comprehensive pollution control and CCS technologies make coal-fired generation prohibitively expensive relative to other power technologies. For these reasons, PUCs need to work with industry to develop coal phase-out schedules. These schedules should be consistent with a below 2°C outcome and focus on employee retraining and compensation.

Introduction

Throughout the 20th century coal was the dominant fuel source for US power generation, at its peak providing up to half of all generation. The role of coal power in the 21st century looks notably different: end-use efficiency, strong competition from other resources and regulations to improve air quality and reduce environmental damage have reduced coal's economic competitiveness and market share. As energy efficiency, technology costs, gas prices, longstanding regulations and market conditions continue to shine a spotlight on coal's competitive shortcomings, the outstanding question is not if, but when, coal will be phased-out? Despite increasingly being a high-cost way of producing power, coal remains entrenched due to a 20th century regulatory framework that often encourages corporate welfare.

This report highlights the growing risks of regulated coal ownership and illustrates why it makes economic sense for regulators to retire high-cost coal power. It explores how listed US coal owners and their investors can manage and prepare for the transition to a low carbon economy. The report also includes a method for investors to make their US coal investments compliant with the Paris Agreement in an economically rational way.

The report has three main sections. The first section provides a brief introduction to US power markets. US power markets are notably heterogenous due to the many levels of codified and uncodified law. This section outlines the roles and responsibilities of regulatory bodies, as well as the different market arrangements, with specific emphasis on the legal framework which supports regulated power assets. A more comprehensive overview of US power markets from their genesis in the mid-1930s to the present day can be found in Appendix 1.

The second section provides an overview of coal power economics. The economics of power generation assets can be categorised three ways: new on new investments, new on existing investments and existing on existing investments. We review these investment scenarios and provide an overview of the regulatory status of coal units, the markets they operate in and their ownership.

The third and final section contains two separate scenarios: below 2°C and regulatory risk. These scenarios introduce our asset-level below 2°C phase-out model and compare the book value of regulated coal units with their market value to obtain a measure of regulatory risk. The below 2°C phase-out model identifies the stranded value of every operating coal unit based on its regulatory status and its year of retirement.

We conclude with recommendations for investors, listed coal owners and regulators. We demonstrate how phasing-out coal can save the US consumer (and therefore the US economy) money while also reducing the risk of regulated coal ownership for investors.

Section 1

This section provides a brief introduction to US power markets, the roles and responsibilities of regulatory bodies and the different market arrangements for coal-fired power.

US power markets in brief

The US power system consists of over 7,300 plants and around 160,000 miles of high-voltage power lines, serving 145 million customers.[1] Utilities managing generation assets can be investor-owned utilities, municipal-owned utilities, and co-operative utilities. Since the Federal Energy Regulatory Commission (FERC) opened-up the electricity markets in the 1990s, in some regions operators are a mixture of traditional vertically integrated companies that own and operate entire supply chains, independent generators and system operators.

Around 66 balancing authorities (BAs), independent system operators (ISOs) and regional transmission organizations (RTOs) manage wholesale power markets and power transmission across the US. Whether served by an RTO, ISO, or BA, all parts of the US have some form of wholesale market for power under the supervision of FERC.

Market arrangements vary: the California independent system operator (CAISO), Midcontinent (MISO), New England (ISO-NE), New York (NYISO), PJM interconnection, Texas (ERCOT) and Southwest power pool (SPP) operate competitive wholesale markets. The Southeast and Northwest of the US are regulated markets where vertically integrated utilities and federal systems own the generation, transmission and distribution systems.

There is overlap between regulated markets and competitive "unregulated" markets in some regions, while some are more distinct. We will refer to coal units operating under regulated market conditions as "regulated", and units operating in open market conditions as "merchant" units.

A more detailed overview of US power markets is provided in Appendix 1.[2]

Legal framework for regulated utilities

While FERC regulates transmission and wholesale power, state-level regulatory commissions (PUCs) determine and approve revenue requirements, price structures and levels, service quality standards and customer protection requirements of vertically integrated utilities.

1 *EIA, (2016). Today in energy: U.S. electric system is made up of interconnections and balancing authorities. See: https://www.eia.gov/todayinenergy/detail.php?id=27152*

2 *In additional to Appendix 1, for an excellent overview of the US power sector refer to the Regulatory Assistance Project (RAP). See for e.g., RAP, (2016). Electricity Regulation in the US. Available: http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf*

The PUCs also have authority over a regulated utility's choice of power sources through portfolio standards, integrated resource planning, construction authorisation, investment prudence and energy efficiency. In the majority of states, the PUCs are appointed by the governor, although a number of states have elected commissioners. PUCs make three types of rules: procedural, legislative and interpretative rules. Commissions hold rate cases and other proceedings through formal adjudication.

A PUC's approved conditions, terms and prices of utility services are published in a document called a tariff. A utility submits a proposed tariff change to the regulator. The regulator may approve, reject, or set a hearing to consider a tariff change. Since PUC's set rates, they need to determine the costs of supply power (i.e. the cost of generation, transmission, and distribution to consumers) and a reasonable rate of return.

Rates are calculated by determining the revenue requirement utilities would need to provide a safe and reliable service and still allow them to earn an acceptable rate of return. The revenue requirement is made up of three variables: the rate base, the rate of return and operating expenses. The revenue requirement is expressed in the below equation.

Revenue requirement = Rate Base Investment * Rate of Return + Operating Expenses

The rate base investment is the total of all long-life capital investments to serve consumers, minus depreciation and adjustments for taxes (working capital allowances and accumulated deferred taxes). Regulated utilities are entitled to earn a rate of return on the rate base, which tends to incentivise capital investments, as they increase company revenues.

Funding sources for the rate base investment influence the rate of return, which gives the PUC the right to rule on the capital structure to minimise the cost to consumers. Funding sources include common equity, preferred equity and both long-term and short-term debt. According to RAP, PUCs typically grant a rate of return of 6-9%, but the range can be as low as 6% and as high as 16%.[3] Operating expenses are all other costs incurred to serve consumers including depreciation and tax expenses. Accounting for depreciation expense takes two forms: operating expense and reduction to rate base.

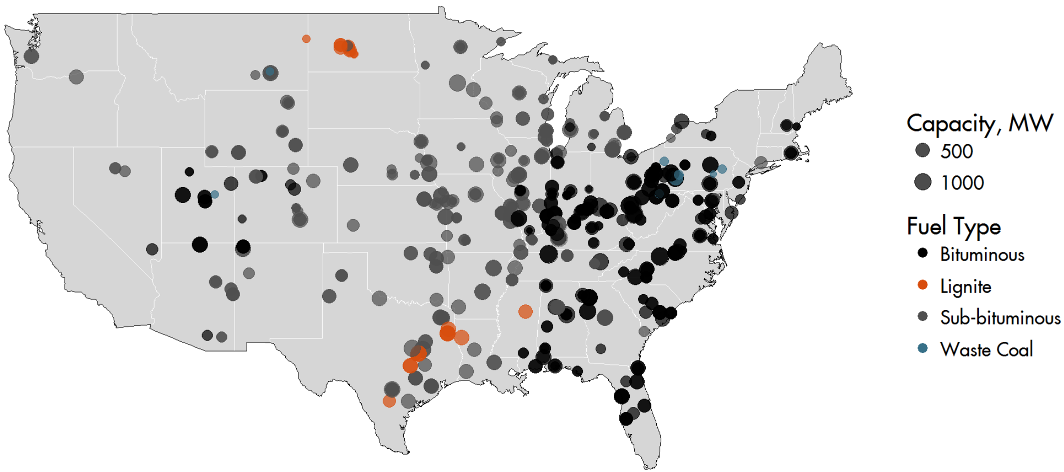
US coal power overview

The US is the second largest producer of power in the world, after China. In 2014, annual production of power in the US was 4,319 TWh, or nearly 20% of the total world output.[4] Power generation represented around approximately 20% of final energy demand in the US in 2014.

3 *RAP, (2016). Electricity Regulation in the US. Available: http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf*
4 *IEA, (2017). Energy Technology Perspectives 2017: Catalysing Energy Technology Transformations. Available: http://www.iea.org/bookshop/758-Energy_Technology_Perspectives_2017*

Coal currently makes up 277 GW, or 24%, of total operating capacity and, in 2016, generated 1,240 TWh; or equivalent to about approximately 30% of total generation.[5]

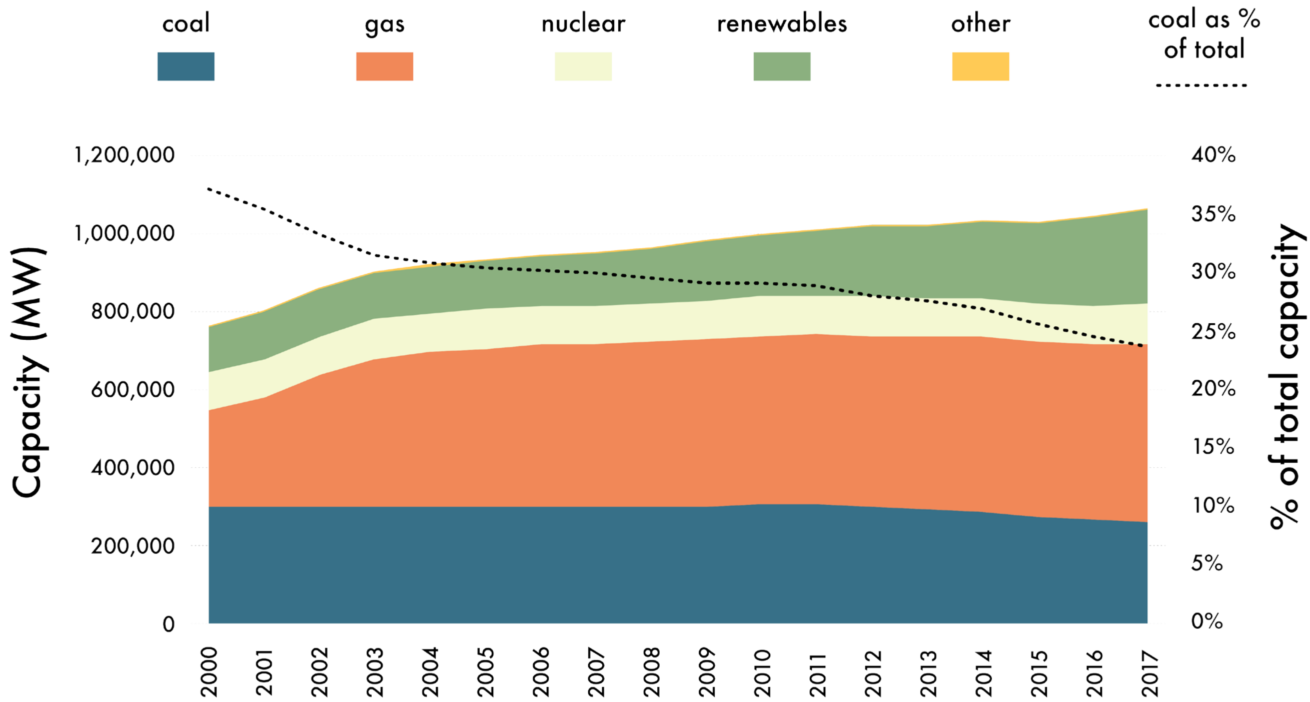
Figure 3. Operating coal units in the US



Source: SNL (2017), Carbon Tracker analysis

5 Carbon Tracker estimates based on SNL data. Our definition of operating capacity includes: nameplate capacity equal or greater than 30 MW; capacity factor greater than 5%; and primary fuel type of bituminous coal, coal, lignite, refined coal, subbituminous coal and waste coal. SNL (2017). SNL platform. Unavailable without subscription.

Figure 4. US power capacity from 2000 to 2017



Source: SNL (2017), Carbon Tracker analysis

Of the 277 GW of operating coal capacity, two thirds are regulated units. Regulated units are not directly subjected to market forces, as their costs are covered by the customers that they serve. Approximately 180 GW of all coal capacity is situated in competitive wholesale markets, of which PJM and MISO are the most exposed to coal. This capacity, both regulated and merchant, must bid into a competitive market to generate power with other generators.

In competitive markets, generation with the lowest marginal cost is bid first while high marginal cost generation is bid last. The primary objective of economic dispatch in power markets is to minimize the total cost of generation, while also honouring the operational constraints of the available generation resources. Thus, dispatchable low marginal cost capacity has higher utilisation rates compared to high marginal cost capacity, which only operates during periods of peak demand.

If regulated utilities are higher up the cost curve of dispatchable capacity than anticipated then their cost-recovery will not match their plan approved by the PUC, and they will lose money.[6] Merchant utilities will lose money in the same way, albeit without a plan signed off by the PUC.

As shown under "Other" in Table 1, 97 GW of coal capacity is situated outside competitive markets and is provided by vertically integrated utilities and federal systems.

Table 1. Breakdown of regulated and merchant units across US power markets (GW)

	MISO	PJM	SPP	ERCOT	NYISO	ISO-NE	Other*	Total
Regulated	62	26	23	5	0	1	70	187
Merchant	12	31	4	15	1	0	27	90
Total	74	57	27	20	1	1	97	277

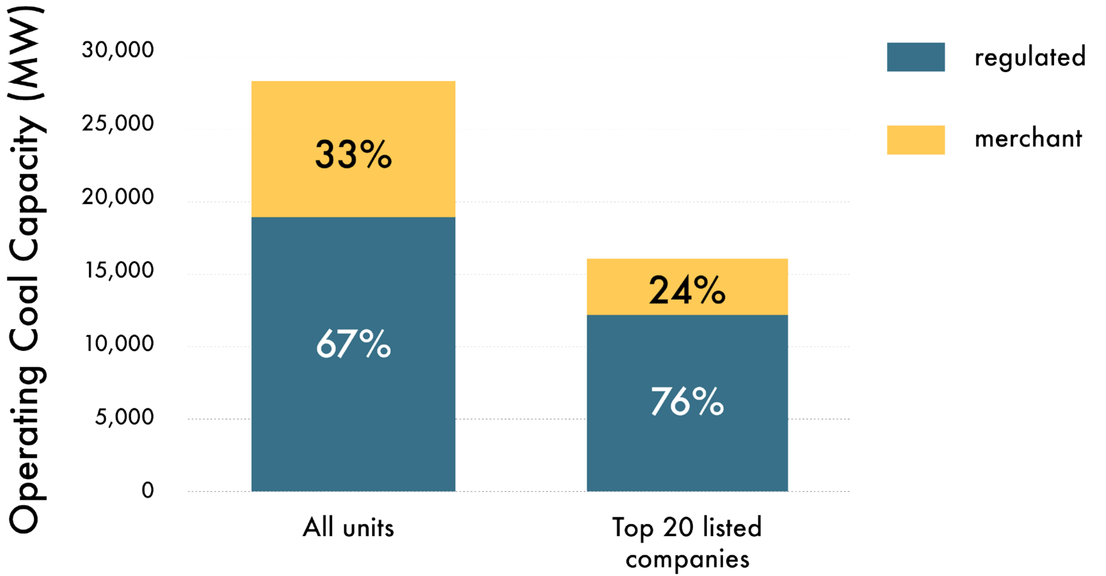
Source SNL (2017), Carbon Tracker analysis

* *Represents all coal capacity outside ISOs (i.e. competitive markets), which is capacity situated in the Southeast and Northeast of the US.*

6 *It should be noted that utilities can apply to the relevant PUC to recover this cost.*

Figure 5 below shows while two thirds of all operating capacity are made up of regulated units, publicly-listed companies have greater exposure to regulated units. Three quarters of coal capacity owned by the 20 largest listed coal owners are regulated units.[7]

Figure 5. Breakdown of regulated and merchant US coal units

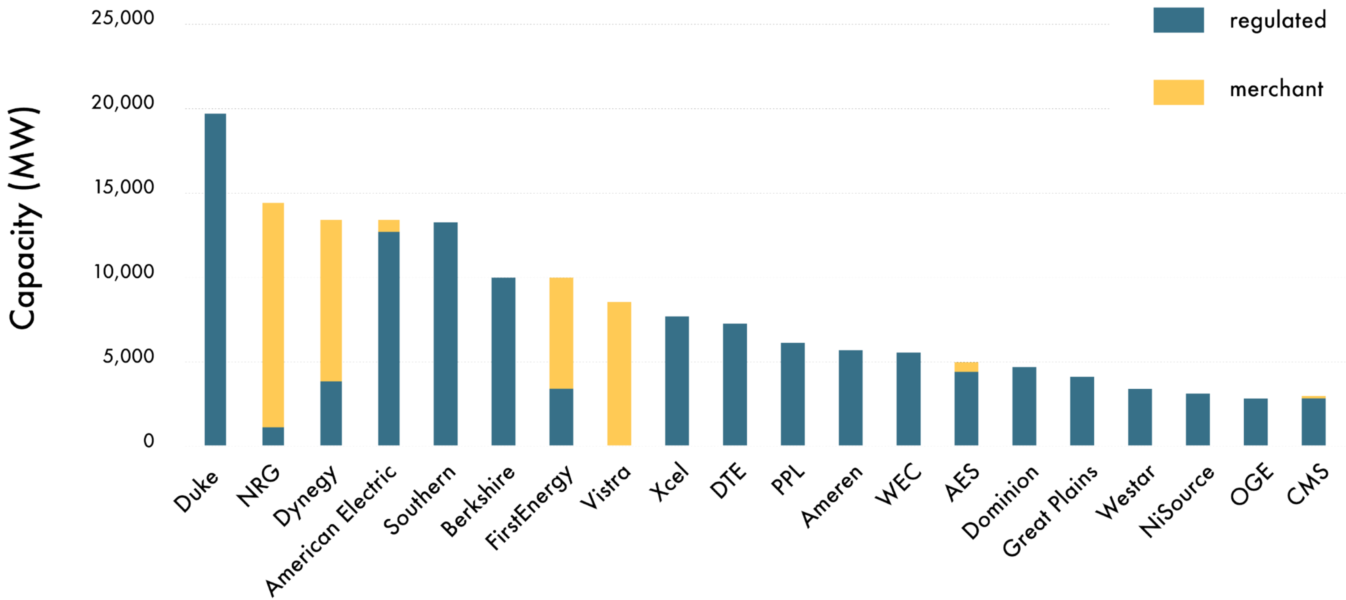


Source SNL (2017), Carbon Tracker analysis

7 *This percentage is based on an aggregation of those units which have multiple owners.*

The 20 largest listed companies in terms of operating coal capacity are shown in Figure 6. NRG, Dynegy and FirstEnergy hold the most merchant coal capacity, while Duke Energy, Southern, American Electric Power and Berkshire Hathaway are the largest owners of regulated capacity. Out of all listed companies with exposure to coal power, the 20 largest represent around 60% of total operating coal capacity.

Figure 6. Largest listed companies by operating coal capacity in the US, 2017



Source SNL (2017), Carbon Tracker analysis

Section 2

This section analyses the economics of coal-fired power and explains why there is still a significant amount of coal capacity in operation in the US today.

Economics of coal-fired power

The economics of power generation assets can be categorised three ways: new on new investments, new on existing investments and existing on existing investments.

New coal investments versus new alternatives

A crude way of determining the economics of new investments typically involves using levelized cost of energy (LCOE) assessments to compare the cost of new plants over their lifetime.[8] Our recent report, 'The end of the load for coal and gas' (2016)[9], concluded that new renewables investments are increasing their competitiveness against new investments in coal and gas power. According to our 2017 LCOE analysis of US power generation technologies, coal and nuclear continue to be challenged by cheap gas and renewables.[10]

While gas continues to be the overall lowest cost option, onshore wind and utility-scale solar PV are quickly reaching cost parity across all regions of the US.[11] Indeed, on average onshore wind is 40% cheaper than conventional coal-fired power. Notably, CCS-equipped coal power is the most expensive form of new generation, with wind, solar, CCS-equipped gas and nuclear costing 74%, 68%, 54% and 42% less, respectively. Several highly-regarded organisations[12] support this conclusion which explains why, as of 2016, only two new investments in coal totalling 1.7 GW are planned[13] compared to 90 GW of gas, 71 GW of onshore wind and 27 GW of solar PV.[14] This reality is reflected in the

8 LCOE analysis provides one way of comparing the costs of power technologies, although it is widely recognized that other factors, such as system value, are also important.

9 Carbon Tracker, (2016). End of the load for coal and gas? Available: http://www.carbontracker.org/wp-content/uploads/2016/09/LCOE-report-v7.pdf

10 To give an empirical understanding of the competitiveness of power technologies, our LCOE analysis reflects market conditions. This involves using realised load factors and carbon prices. See Appendix 2 for a breakdown of the figures.

11 According to a 2015 report by BNEF, Arizona, Texas, New Mexico, Nevada, California, Louisiana, Mississippi, Georgia and Alabama have a lower LCOE than coal and gas. See Bloomberg (2015). Solar and Wind Just Passed Another Big Turning Point. Available: https://www.bloomberg.com/news/articles/2015-10-06/solar-wind-reach-a-big-renewables-turning-point-bnef

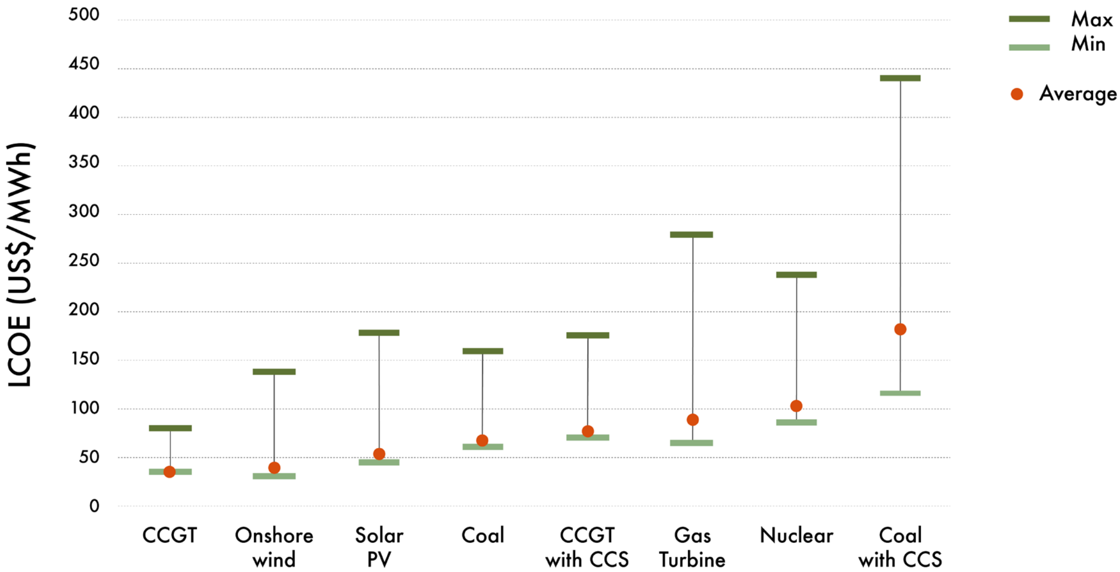
12 LCOE analysis by BNEF and Lazard have similar ranges for US technologies. See BNEF (2017). Country Profiles. Unavailable without subscription. Lazard (2016), Levelized Cost of Energy – Version 10.0. Available: https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

13 A long-planned 895 MW expansion to Holcomb Station in Kansas and the 850 MW Plant Washington.

14 Platts (2017). World Power Plant database. Unavailable without subscription.

number of corporate customers who are increasingly deciding to opt out of utility contracts (and pay the penalty to do so) and seek alternative renewable suppliers.[15]

*Figure 7. Carbon Tracker's 2017 LCOE analysis for US power technologies**



Source SNL (2017), Carbon Tracker analysis
** To give an empirical understanding of the competitiveness of power technologies, our LCOE analysis reflects market conditions. This involves using realised load factors, for example. See Appendix 2 for a breakdown of the assumptions underpinning our LCOE analysis.*

15 See for e.g., Utility Dive (2016). Las Vegas casino set to exit Nevada utility's service with $87M fee. Available: http://www.utilitydive.com/news/las-vegas-casino-set-to-exit-nevada-utilitys-service-with-87m-fee/419644/

Existing coal investments versus new alternative investments

If new coal power investments are uncompetitive with new investments in gas and renewables, then the next step is to consider the economics of existing unit compared to new investments in alternative technologies. This involves analysing the current operating cost of coal and comparing those costs with the LCOE of alternatives. Current operating costs of US coal units can be categorised two ways: current and anticipated operating costs.

For this analysis, current operating costs include: fuel, variable O&M, fixed O&M, and forward-going capital additions. Fuel costs include the expenses incurred from of buying, transporting and preparing the coal. Here we assume EIA's high resource scenario for gas and coal[16].

Anticipated operating costs in this analysis include all current operating costs and future costs from new environmental control retrofits.[17]

The variables in current and anticipated operating cost are detailed in Table 2. Please refer to Appendix 3 for further information on environmental policies.

Table 2. Components of current and anticipated operating costs for coal plant

Operating costs	Detail
Fuel	Cost of buying, transporting and preparing the coal. Assumes EIA's high resource scenario for gas and no CPP for coal.
Variable O&M	Includes: water, waste, purchased power, fees, chemicals for control technologies, lubricants and other supplies.
Fixed O&M	Costs incurred at a power plant that do not vary significantly with generation and include staffing, equipment, general and administrative expenses, maintenance, and operating fees.
Forward-going capital additions	Current annual capital additions required to keep the unit operating.
Anticipated costs	The above costs plus future costs take into account likely new environmental control retrofits.

Source: EIA (2017a), Carbon Tracker analysis

16 Gas and coal prices are forecasted regionally. On a country average the gas and coal price is $4.50/mmbtu and $2.20/mmbtu, respectively. EIA, (2017a). Annual Energy Outlook with projections to 2050. Available: https://www.eia.gov/outlooks/aeo/

17 It is important to note that environmental regulations influence both current costs and anticipated operating costs as, once the control technology is installed, it increases both variable and fixed O&M.

Due to the change in US political leadership, existing and pending environmental regulations and our assumptions as to their phase-in date are detailed in Table 3. To account for recent announcements from the Trump administration, we assume the CPP as previously proposed under the Obama Administration is not implemented. Moreover, we do not apply any carbon pricing. This analysis is therefore not dependent on measures that require support from the current administration.

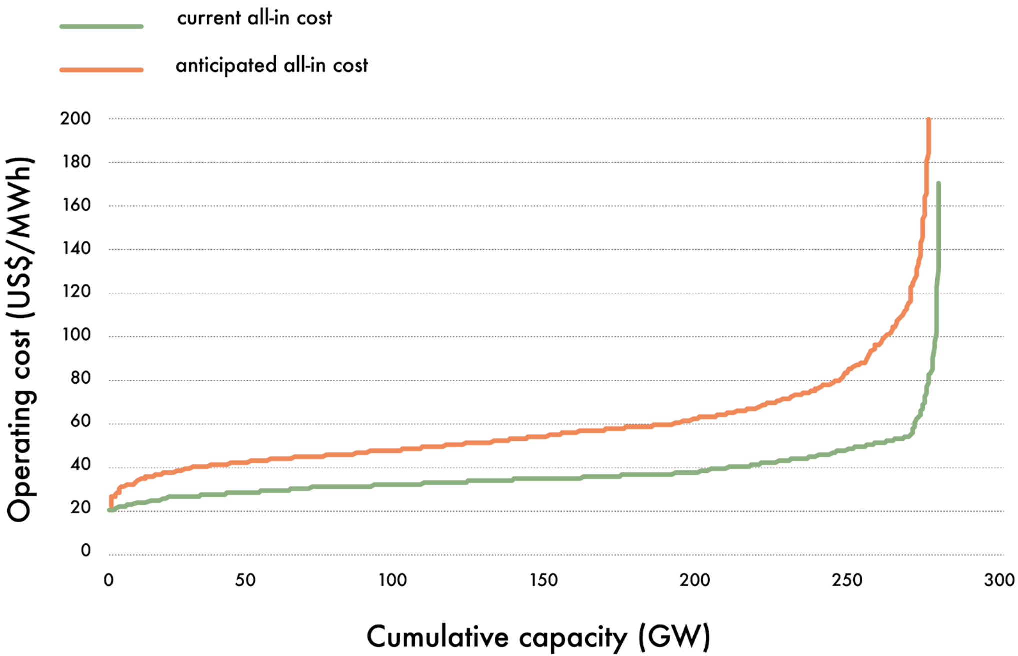
*Table 3. Environmental control technologies considered in this analysis alongside the estimated cost and corresponding legislation**

Control	Phase-in date (year)	Estimated cost range (US$/MWh)	Corresponding regulation
Wet flue-gas desulfurization	Never	10-20	NAAQS, ARP, CSAPR
Dry flue-gas desulfurization	2020	9-16	NAAQS, ARP, CSAPR
Dry sorbent injection	Never	0.7-3	NAAQS, ARP, CSAPR
Selective catalytic reduction	2021	6-10	NAAQS, CSAPR
Selective non-catalytic reduction	Never	0.6-3	NAAQS, CSAPR
Baghouse	2025	5-9	NAAQS, CCR, RH
Activated carbon injection	2016	0.2-0.5	MATS
Cooling	2021	0.4	CWIS
Coal combustion residuals	2019	- **	CCR
Effluent controls	2021	-	ELG

Source: Synapse Energy (2017), SNL (2017), EIA (2017a), Carbon Tracker analysis
** Please refer to Appendix 3 for further information on each control technology.*
*** Our cost ranges are based on actual project costs. No such costs are available for combustion residuals or effluent controls.*

As of 2017, there is 277 GW of coal-fired capacity or approximately 700 units operating in the US. The current cost and all-in cost of every operating coal unit is estimated in Figure 8, which plots units from least to most costly. The current all-in operating cost of units range from US$22 MWh to above US$160 MWh, while the anticipated all-in operating costs vary from US$24 MWh to above US$200 MWh. As set out in Table 3, anticipated costs are introduced between now and 2025; however, 90% of all anticipated costs are realised by 2021.

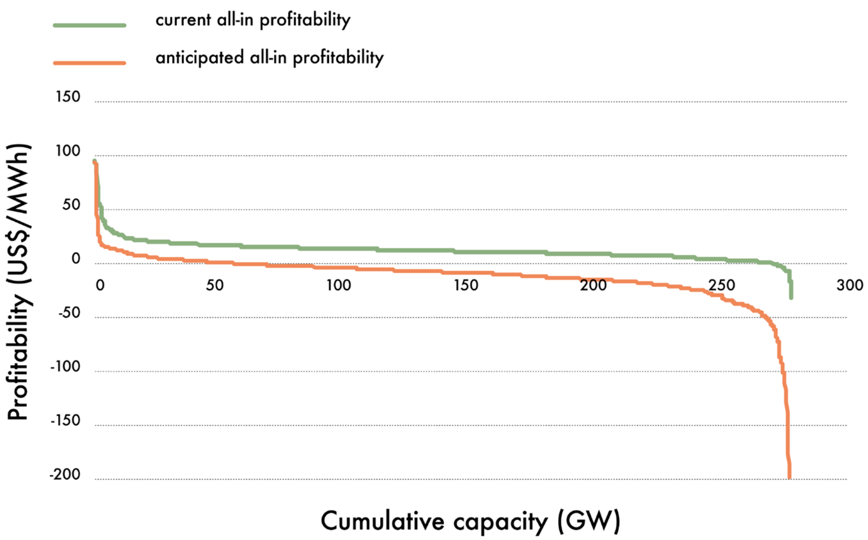
Figure 8. Operating cost of existing coal units



Source: Carbon Tracker analysis

In competitive power markets, the LCOE of alternative power generation technologies will need to get as low as the operating costs of the existing coal units to entirely undermine the economics of coal-fired generation.[18] Figure 9 details the profitability of coal units when compared to the LCOE of a new CCGT. Comparing coal to a CCGT gives a simple comparison which does not require assumptions about renewables costs or deployment rates.[19] For instance, if the operating cost of the coal unit is more than the LCOE of a new CCGT then it is considered unprofitable. As illustrated in Figure 9, 97% of operating coal units are profitable if current all-in costs are compared to the LCOE of CCGTs, but only 22% are profitable when anticipated all-in costs are compared. Importantly, of the units that remain profitable when current-all in costs are considered, 114 GW, or nearly 40%, have profitability of 10 US$/MWh or less, making those units vulnerable to changes in fuel costs.

Figure 9. Profitability of existing coal units compared to new CCGT



Source: Carbon Tracker analysis

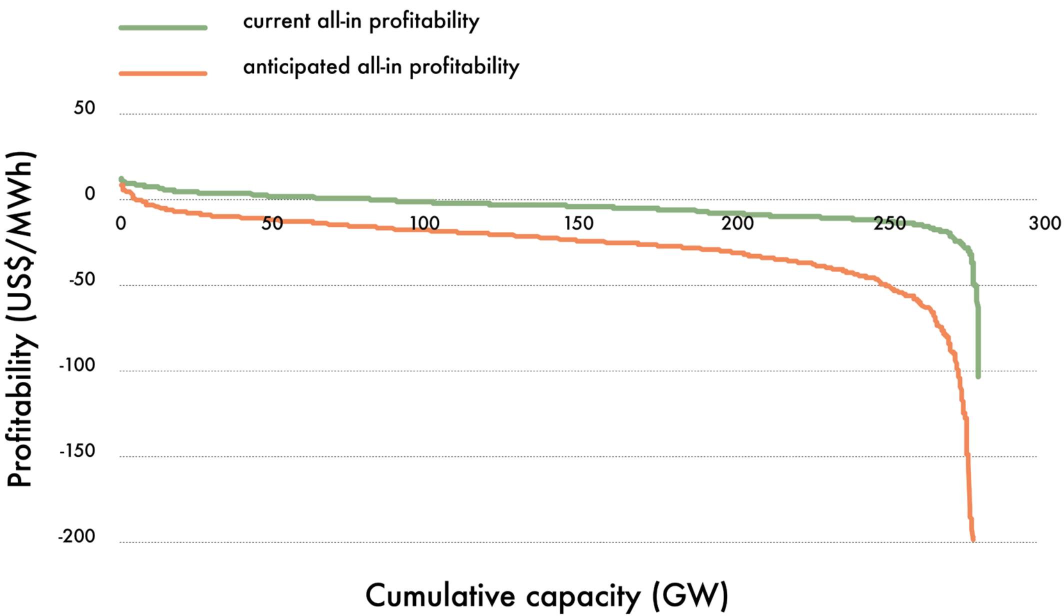
18 *Assuming the absence of out-of-market incentives.*

19 *As detailed in the "Other economic factors" section below, this picture will become increasingly complex as variable renewable energy also undercuts coal in a growing number of states.*

Existing coal investments versus existing alternative investments

Comparing the current and anticipated all-in costs of operating coal units against those costs of operating CCGTs, provides an example of how uncompetitive existing coal investments are relative to existing alternative investments.[20] As illustrated in Figure 10, when current costs are considered, 72% of operating coal units are unprofitable compared to the operating cost of an equivalent CCGT and 98% when the anticipated costs are included.

Figure 10. Profitability of existing coal units compared to existing CCGT units



Source: Carbon Tracker analysis

20 *It is important to note that fuel switching from coal to gas generation is dependent on spare capacity.*

Other economic factors

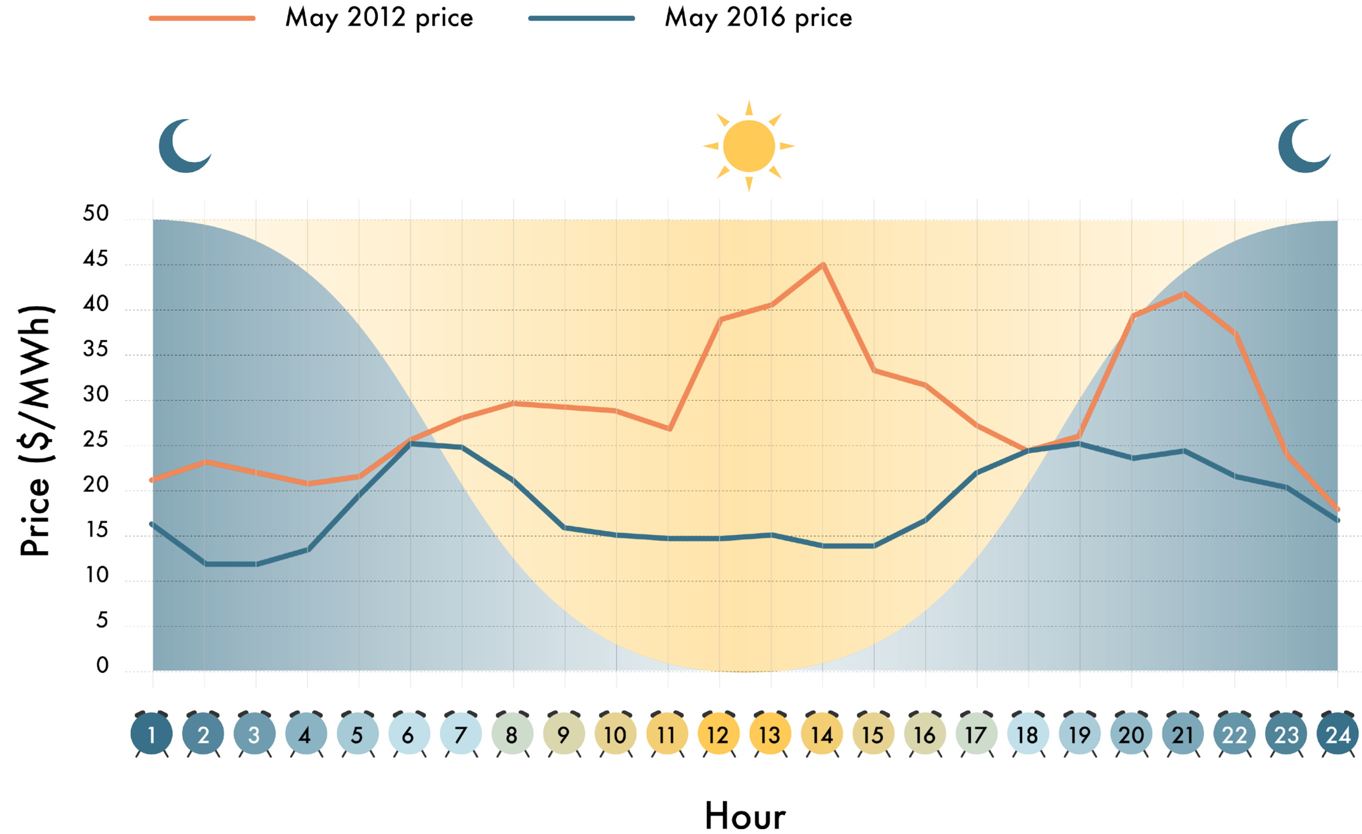
Beyond the declining levelized cost of renewable energy and gas, there are several other factors that have a profound impact on the economics of coal-fired generation. These factors can be categorised two ways: non-fuel expenditures and reduced revenues. As the price of gas declined to reach cost parity with coal on a $/MMBtu basis in many parts of the country, it was relatively low thermal efficiencies, higher transport and fixed O&M costs that made coal-fired capacity uncompetitive in 2016. For example, according to BNEF, rail costs can contribute approximately 65% of delivered fuel costs and 50% of a Texas coal plant's operating cost, assuming $22/st from WY to TX.[21]

Increased production of variable renewable energy tends to increase non-fuel costs and reduce coal generators revenues. Under the old system, power prices spiked during peak hours (the middle of the day and early evening), falling at night as demand subsided. Generators traditionally made a lot of their money during peak periods. However, the middle of the day is when solar generation is strongest. Solar can take a big chunk of peak demand and has competed away the price spike, resulting in lower average intraday prices[22]. As displayed in Figure 11, in 2012 in May intraday power prices averaged $29 MWh. In May 2016, they averaged $19 MWh.

21 *BNEF, (2016). Can Trump resurrect US coal? Unavailable without subscription.*

22 *Moreover, solar and wind can change the load profile to the extent where, under certain conditions, generators pay to produce power as reflected in a price below zero. This occurs when solar and wind electricity surges, conventional plants must be reduced or switched off altogether to avoid the grid overloading and potentially becoming unstable. In the absence of demand response and other flexible resources, this often creates a period of overgeneration, as old coal-fired units are often inflexible and cannot afford to shut down, or are physically unable to turn down or off for just a few hours. These units often take on losses during periods of overgeneration. Gas-fired generators are flexible and can more easily ramp up and down to avoid the unprofitable hours.*

*Figure 11. Average hourly CAISO day-ahead power prices in May 2012 and May 2016**



Source: CAISO (2017)
**This chart shows the price impact of increasing solar PV generation. The authors acknowledge that there is no coal-fired capacity in the CAISO jurisdiction.*

Responding to variable renewable energy is an existential threat for inflexible coal units. In the old system, coal-fired units focused on being available, while now it is increasingly necessary to be responsive to avoid the hours made unprofitable by variable renewable energy. The boilers and steam turbines in old coal plants often lack operational flexibility or incur high start-up and shutdown costs. There are two ways a coal plant can respond to variable renewable energy.

First, the shutting down and restarting of a unit. This includes hot, warm and cold starts, depending on how long the unit has been offline for. According to the IEA Clean Coal Centre (IEA CCC), hot cycles have been offline for less than 24 hours, warm cycles have been offline for 24-120 hours and cold cycles have been offline for more than 120 hours.

Second, coal units can cycle or adjust load between shallow and deep cycles. A shallow cycle reduces load to an economic minimum, while a deep cycle involves lowering the load to an emergency minimum.

The IEA CCC estimated these costs which are detailed in Table 4 in Appendix 3. Hot, warm and cold starting a 500 MW coal unit could cost $94,000, $116,000 and $174,000, respectively. Load cycling a 500 MW coal unit down to 180 MW could cost $13,000.[23] These estimates are likely to be inflated for coal-fired units operating in liberalised markets, as these units would have been forced to restructure O&M costs in response to wholesale price deflation.[24]

23 *IEA CCC, (2016). Levelling the intermittency of renewables with coal. Available: https://www.usea.org/sites/default/files/Leveling%20the%20intermittency%20of%20renewables%20with%20coal%20-%20ccc268-1.pdf*

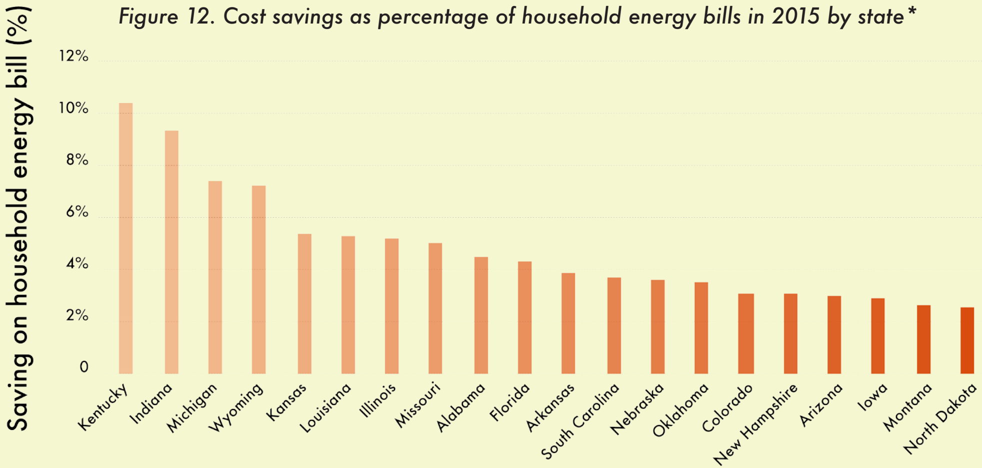
24 *According to CEZ Group, a European utility, O&M costs for their fleet of thermal assets have decreased 40.5% from 2008 to 2015. CEZ Group, (2015). Annual Asset Management Forum 2015. Presentation available on request.*

BOX 1. Corporate welfare

Plants operating in regulated markets can recoup costs according to a rate set by the appropriate PUC, based on the undepreciated value of their generation assets. While merchant units must compete in an open market, the revenues of these regulated plants are protected. Consequently, utilities are often incentivised to continue to invest in existing units that are uncompetitive compared to new alternatives. This perversity occurs at the expense of consumers. A number of regulated coal units could close and be replaced with cheaper alternatives. Utilities could renegotiate an appropriate margin with the PUC, even taking into account a lower rate base, as the plant would be cheaper. While there is no obstacle to this happening, there is also little incentive.

Closing uncompetitive regulated coal units would result in savings for customers of $10bn per year by 2021. Figure 12 shows those savings as a percentage of household energy bills. Any state where regulated coal units are being propped-up will see some saving from their closure. In Kentucky 34% of electricity was used by residential households in 2015, whereas in Wyoming it was only 16%. While impacts on household bills are not always obvious, the more unprofitable coal plants in a state, the larger the savings when they are shuttered.

*Figure 12. Cost savings as percentage of household energy bills in 2015 by state**



Source: EIA (2017b), EIA (2017c), EIA (2017d), Statista (2017), Carbon Tracker analysis
** We have apportioned to the household their state-level proportion of electricity consumption.*

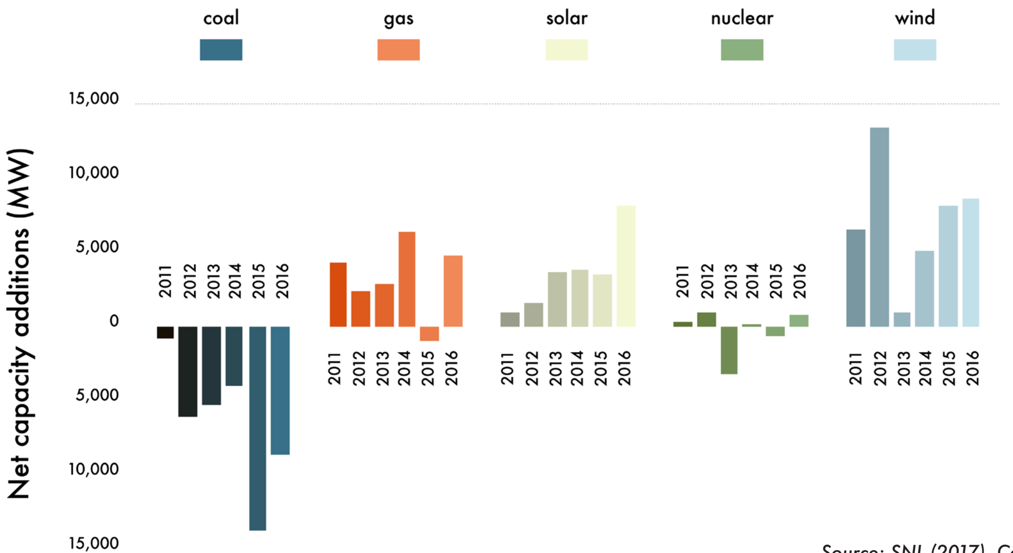
Why does coal power still exist ?

Both new and existing coal-fired power investments in the US are highly undesirable, due to relentless competition from cheap gas and renewables. This reality begs the question: if new coal power investments are all but non-existent and existing assets are highly uncompetitive, why does it still exist today?

Before answering this question, it is important to note that a significant amount of coal-fired capacity has been retired since 2011. Net capacity additions of main power technologies are shown in Figure 13. From 2011 to 2016, 84 GW of wind, solar and gas was built, while around 40 GW of coal was retired over the same period.

Coal capacity has been retired due to cheap renewables and gas taking market share in competitive markets, as well as the prohibitively high cost of both extending the life of old units and retrofitting units with the control technologies needed to meet regulations.

Figure 13. Net capacity additions of main US power technologies 2011-2016



Source: SNL (2017), Carbon Tracker analysis

For this reason, coal-fired generation declined 25% from 2011 to 2016 to a historical low of 30% of the power capacity mix.[25] Nonetheless, as of 2016, 1240 TWh of power is still being generated from coal. There are many reasons why this is occurring, which are detailed below.

Capacity markets favour incumbents over new entrants

Capacity markets are long-term policy responses adopted to operate alongside wholesale markets.[26] These policy mechanisms were prompted by concerns that investors may be unable or unwilling to invest in long-life assets due to insufficient confidence in the volume and price they can expect to receive in the electricity market. There are currently four capacity markets in the US: New England, New York, PJM and MISO. Capacity mechanisms require a multi-year forecast of maximum gross demand, which forms the basis for auctions to quantify the cost and quantity of firm capacity required to meet system requirements.

For instance, PJM's capacity market – the Reliability Pricing Model – procures capacity three years before it is needed through an annual auction. While increased reliance on variable renewable energy changes the calculus for grid operators, capacity markets tend to favour incumbents over new entrants as the capital cost of existing generators is sunk and typically focuses on conventional 'firm' thermal capacity.

Vertically integrated utilities often have little incentive to retire coal plants despite the overwhelming benefit to their consumers

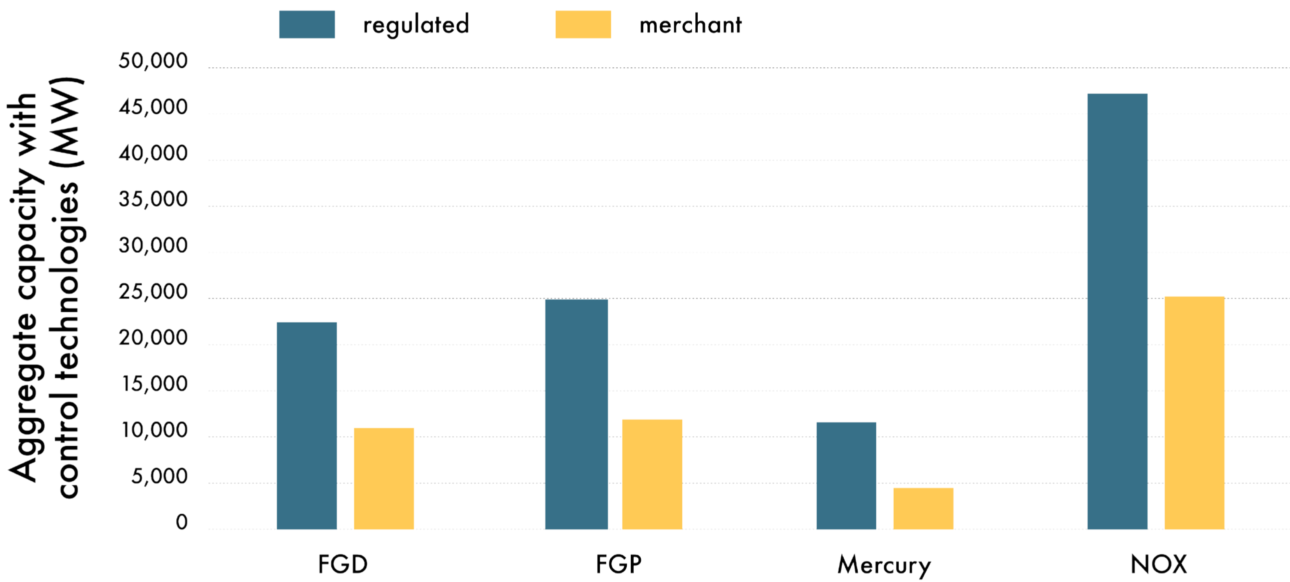
In competitive markets, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. As mentioned above, 67% of coal capacity is regulated.

Regulated utilities are paid by regulators to invest capital, mainly in power plants (transmission and distribution investments typically account for much smaller amounts), which provides them an authorized rate of return on the invested capital. The rate base can often incentivise utilities to continue to invest in operating units, rather than replacing those units with cheaper alternatives. Operating coal units are kept running by repairing damages and adding pollution control equipment to avoid running depreciation schedules to zero, as utilities earn a return on the remaining undepreciated balances.

25 *Coal generation declined 27% in absolute terms, and 25% taking into account an overall decline in energy generation of 6%.*
26 *All competitive power markets have various forms of separate short-term ancillary service mechanisms to incentivise generators to offer dispatchable capacity to system operators.*

As detailed in Figure 14, this is why regulated units typically have greater environmental controls than merchant units. Beyond the lack of economic incentives, there is often pressure from the local community to keep operating uneconomic coal plants to preserve a small number of high paying jobs.

*Figure 14. Aggregate capacity of coal plants with different environmental control technologies**



Source: SNL (2017), Carbon Tracker analysis
** Some plants have up to 5 different control technologies in each category. These are all counted separately. Flue-gas desulfurization (FGD), Flue-gas particulate controls (FGP), Mercury and Nitrous Oxides (NOX) cover different technologies to treat flue gas for various pollutants.*

Listed utilities move uneconomic coal plants from their merchant arm to regulated arm to avoid competition from cheap gas and renewables

Several utilities are moving their resources out of competitive markets into regulated markets to keep their uncompetitive coal plants operating. As detailed in Figure 6 above, the largest listed utilities have significant exposure to regulated coal capacity. While merchant capacity is subject to financial losses through market forces – as competition from cheap gas and renewables pushes coal further up the dispatch curve – regulated coal units can cover their costs through the regulatory process.

Faced with the dilemma of holding loss-making coal capacity, listed utilities have often opted to move uneconomic coal units from the merchant to regulated arm of their business. This accounting practice typically shifts the economic burden from the shareholder to the consumer, with the former often benefiting to the detriment of the latter. While shareholder assets receive government subsidies, the consumer pays for these subsidies through higher power prices. The most recent example is FirstEnergy in Ohio.[27]

Keep portfolio balanced to hedge against changing fuel costs

To a lesser degree, as a hedge against rising gas prices, utilities have some incentive to keep a balanced portfolio achieved by keeping coal capacity online. The increased production from the shale gas "revolution" and ensuing low pricing has driven increased gas demand by, for example, outcompeting coal in the power sector and increasing use in the petrochemical sector.

Moreover, modelling North American supply is complex as it comprises mostly shale gas and several localised markets. The US shale industry, which fully commenced at the end of the last decade, has still not been through a complete cycle of price rise, fall and recovery. Due to the "well by well" rather than "project by project" nature of shale gas production, and the difficulties of estimating the resource potential of large shale deposits, many forecasters expect gas prices to rise (albeit marginally) over the next decade.[28] To mitigate against the risk of gas price rises, utilities have an incentive to keep some coal units online even if they have marginal or negative operating economics.

27 *Power Magazine, (2017). U.S. Electric Markets in Transition. Available: http://www.powermag.com/u-s-electric-markets-transition/?printmode=1*

28 *The 2017 AEO, for example, sees natural gas prices increasing at a compounded annual average growth rate of 0.8% from 2015 to 2050. See, EIA (2017), Annual Energy Outlook. Available: https://www.eia.gov/outlooks/aeo/*

Section 3

In this section, we present a below 2°C scenario for all listed US coal power owners to allow investors to comply with the Paris Agreement; and a regulatory risk scenario for all regulated coal units.

Below 2°C scenario

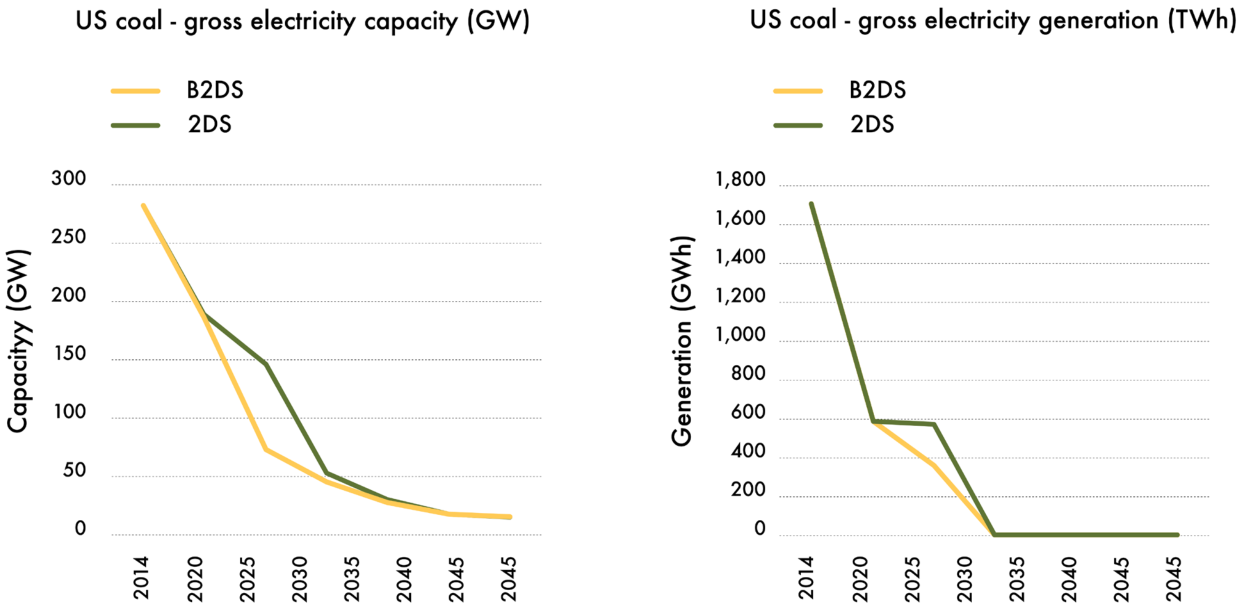
Comparing the capacity requirements under the IEA's B2DS highlights the financial implications of US coal-fired capacity under a below 2°C pathway.

According to the IEA:

> *The B2DS explores how far deployment of technologies that are already available or in the innovation pipeline could take us beyond the 2DS. Technology improvements and deployment are pushed to their maximum practicable limits across the energy system in order to achieve net-zero emissions by 2060 and to stay net zero or below thereafter, without requiring unforeseen technology breakthroughs or limiting economic growth.*
>
> *This "technology push" approach results in cumulative emissions from the energy sector of around 750 GtCO_2 between 2015 and 2100, which is consistent with a 50% chance of limiting average future temperature increases to 1.75°C. Energy sector emissions reach net zero around 2060, supported by negative emissions through deployment of bioenergy with CCS. The B2DS falls within the Paris Agreement range of ambition, but does not purport to define a specific temperature target for "well below 2°C".*

In the IEA's B2DS, unabated (i.e. not CCS-equipped) coal-fired capacity in the US decreases from approximately 281 GW in 2014 to 44 GW in 2035, while actual generation from unabated coal-fired units is completely phased-out by 2035 . The IEA's 2DS also has generation phased-out by 2035.[29] The trajectory of the scenarios and the evolution of capacity and generation of unabated coal-fired units in the B2DS and 2DS are shown in Figure 15. The main divergence between the two scenarios occurs post-2025, which limits the variation in valuation.

Figure 15. Evolution of US coal capacity and generation for B2DS and 2DS

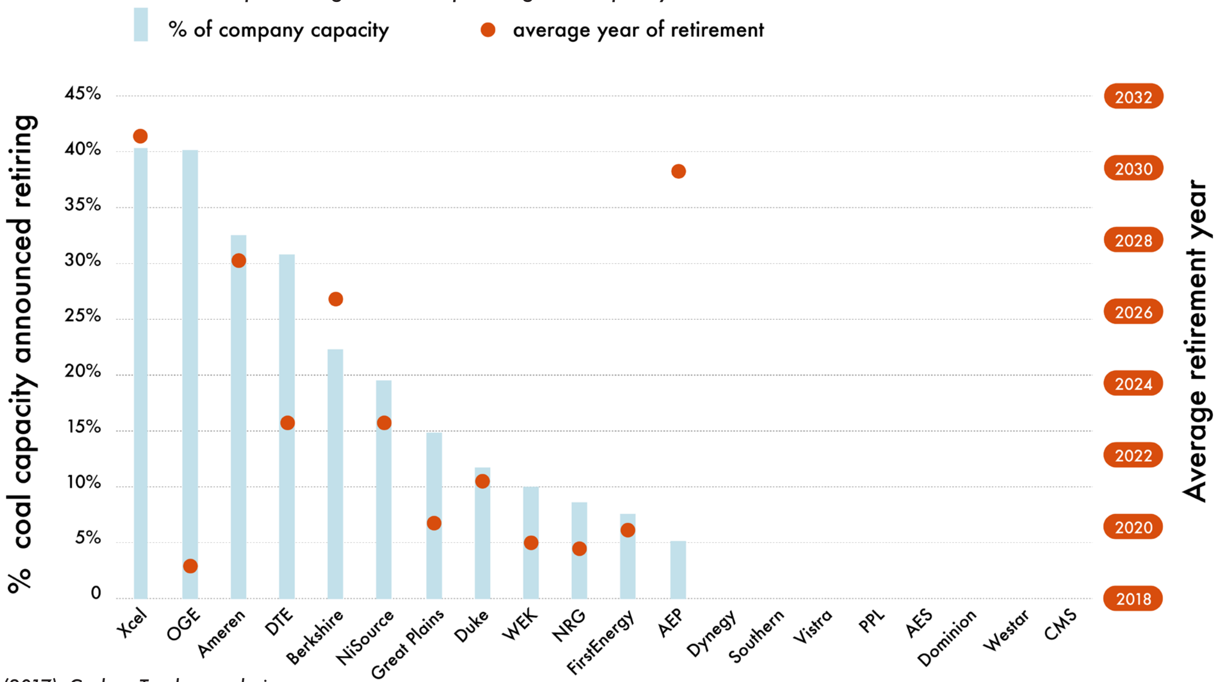


Source: IEA, (2017)

29 IEA (2017). Energy Technology Perspectives 2017: Catalysing Energy Technology Transformations. Available: http://www.iea.org/bookshop/758-Energy_Technology_Perspectives_2017

While cheap gas and renewables are quickly cannibalising the market share of coal; the US power sector remains entirely unprepared for a coal phase-out consistent with a B2DS outcome. For instance, of the 20 largest listed companies in terms of operating coal capacity none have committed to phasing-out coal-fired power in a manner consistent with the B2DS. Figure 16 compares planned retirements with total operating coal capacity. Xcel Energy has the highest amount of planned retirement capacity, which amounts to 40% of its total operating coal capacity. Of the 20 largest listed coal owners by capacity, 8 have no announced retirements, while the total sum of retirements is around 28 GW, or 10% of total operating coal capacity in the US.

Figure 16. Planned retirements as a percentage of total operating coal capacity



Source: SNL (2017), Carbon Tracker analysis

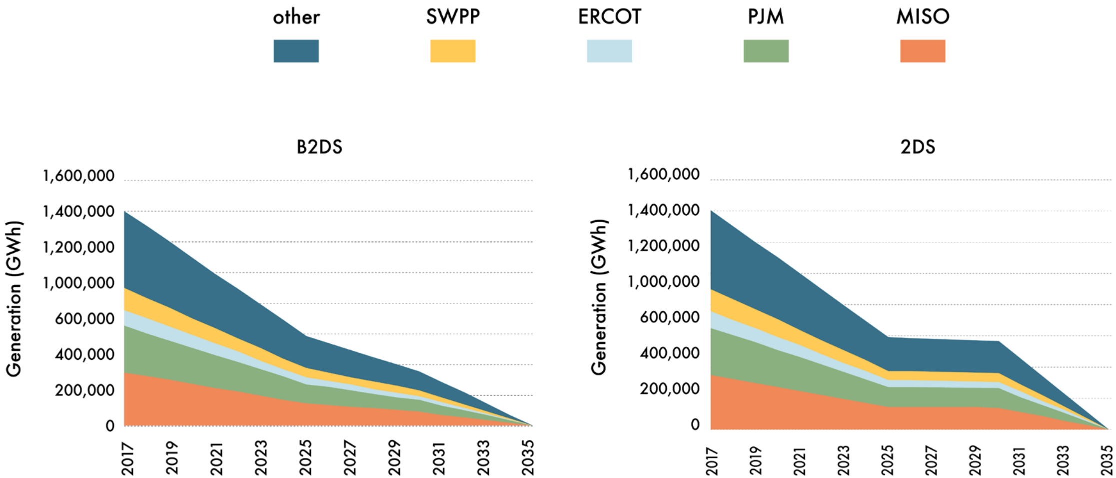
To allow investors to align their portfolio with a B2DS and listed coal owners to prepare for the transition to a low carbon economy, we have developed a below 2˚C model, which aims to phase-out coal-fired units in an economically rational and secure way. To determine a below 2˚C pathway, we used the IEA's B2DS, which gives a breakdown of unabated coal capacity and generation.

To keep unabated coal-fired generation consistent with a below 2˚C pathway, units are retired when generation exceeds the B2DS generation. For example, annually the model keeps retiring units until generation reaches or goes below B2DS generation. The units are ranked by their operating cost, so the highest cost units are phased out first and the lowest cost units are phased out last.

Cost is chosen over profitability as we are interested in reducing the cost to the consumer and maximising the efficiency of the power sector to the US economy. To avoid security of supply concerns, units are phased-out by balancing authority, with each authority being allocated a proportional amount of the carbon budget. Figure 17 illustrates how the phase-out would occur by balancing authority. As the chart shows, there is a plateauing of coal generation from 2025 to 2030 in the 2DS, whereas the decline continues during this period in the B2DS.

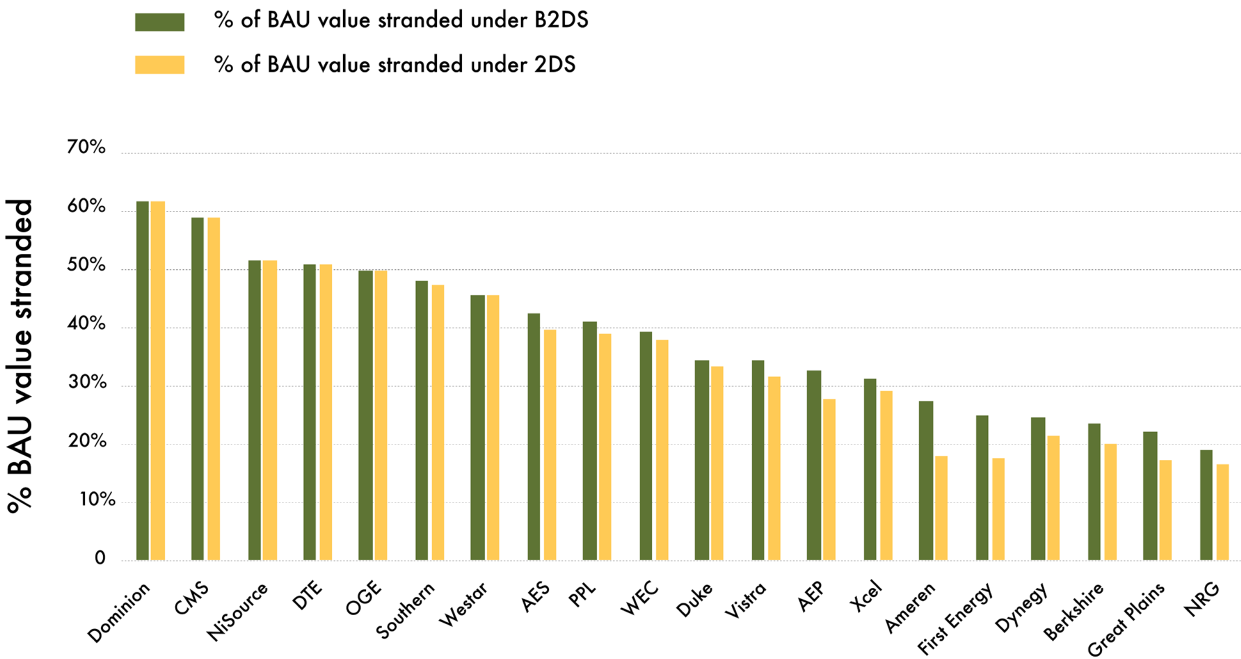
Figure 17. Phasing out coal generation by balancing authority: B2DS versus 2DS

Source: IEA (2017), Carbon Tracker analysis



These units are then aggregated up by ultimate owner to understand the exposure of the 20 largest listed companies in terms of operating coal capacity. Figure 18 compares the stranded value under the B2DS as a percentage of the BaU scenario. Out of the 20 largest listed coal owners, Dominion has the most value at risk under a B2DS scenario with over 60% as a percentage of the BaU scenario. CMS, NiSource and DTE are also at risk with 59%, 52% and 51% of value stranded as a percentage of the BaU scenario, respectively

Figure 18. Below 2°C stranded value as a percentage of BaU value



Source: Carbon Tracker analysis

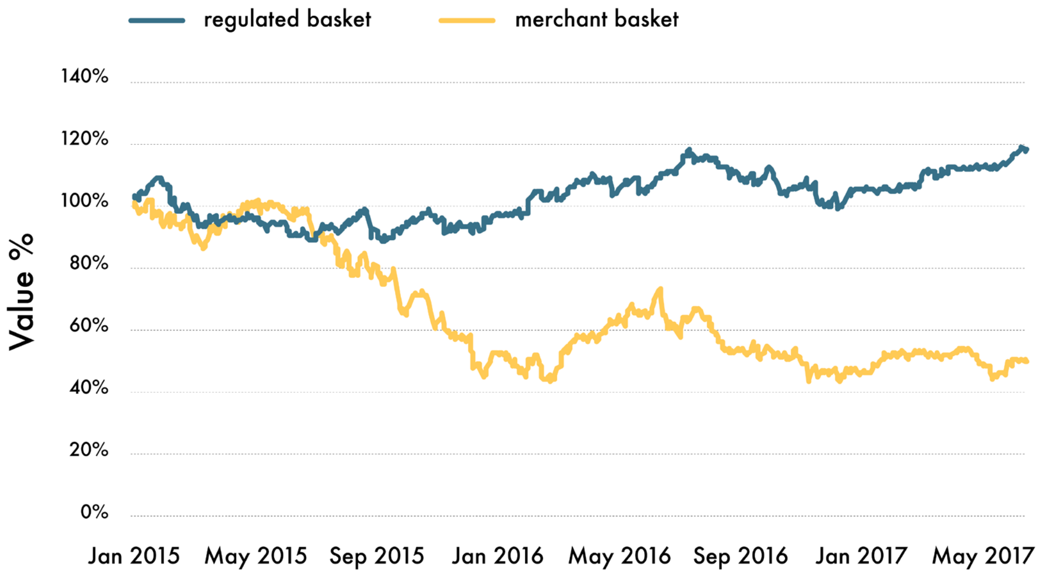
Regulatory risk scenario

Determining the value of US coal capacity depends on its regulatory status. Regulated coal units can cover their costs through the regulatory process, while merchant units are at the mercy of market forces.

The book value of regulatory assets can be estimated through FERC reporting. The FERC Form 1 is a mandatory annual survey of large investor-owned utilities, which makes data on earnings, taxes and depreciation available to the public.

All large investor-owned utilities are subject to the Federal Power Act of 1935 and therefore must submit this survey to FERC. Utilities are required to submit the financial data in accordance with FERC's Uniform System of Accounts Prescribed for Private Utilities and Licensees subject to the Federal Power Act.

*Figure 19. Value over time of basket of regulated and merchant coal asset owners**



Source: Bloomberg, (2017), Carbon Tracker analysis
** Based on unweighted averages.*

As mentioned above, utilities make a rate of return on the invested capital. Of such invested capital, generation makes up a disproportionally high amount compared to transmission and distribution costs. This incentivises utilities to keep reinvesting in operating plants to keep their book values as high as possible. This contrasts to merchant utilities which are valued based on their market value. The market value is typically determined by the NPV of free cashflow, which have been negatively influenced by cheap gas and renewables, as well as energy efficiency and displaced demand from rooftop solar. This reality is clearly demonstrated when comparing the performance of utilities holding merchant units with those holding regulated units (see Figure 19).

One of the reasons regulated utilities have outperformed merchant utilities is due to their ability to hide behind a regulatory framework that passes on the cost to a captive consumer base. As cheap gas and renewables become more prevalent in coal dependent parts of the US, regulators will increasingly be called upon to justify the continued operation of high cost coal units. There are several examples of regulators questioning whether gas and renewable options were properly considered before extending the life of coal-fired units.[30] This sends a clear signal to owners of regulated coal units to carefully consider how they value their coal capacity in light of lower cost alternatives.

Figure 20 illustrates regulatory risk or the difference between book and market value. In this analysis, we value regulated units based on regulatory filings and merchant units based on market conditions. Costs included fuel, variable O&M, fixed O&M and capital costs for existing and anticipated environmental controls, as detailed in Table 3 above. The regulatory risk represents the difference between regulated and market value. Regulatory valuation is based on current free cashflow from operating under existing regulation. The book value calculation considers capital spending on the plant, minus accumulated depreciation declared at a company level which we allocated at the unit level. Market valuation assumes the unit has no value if the operating cost is greater than a new CCGT. As detailed in Figure 20, $185 billion of regulatory risk has been identified for all operating regulated coal units.

30 *See Power Magazine, (2017). U.S. Electric Markets in Transition. Available: http://www.powermag.com/u-s-electric-markets-transition/?printmode=1*

This analysis highlights how listed coal owners with regulated capacity have the most to lose under our below 2°C and regulatory risk scenarios.

The business model of regulated utilities tends to promote capital investments over lowest cost generation, which allows regulated units to be valued arbitrarily higher than merchant units.

Figure 20. Regulatory risk for regulated coal units

Source: Carbon Tracker analysis

This valuation difference means coal owners who have regulated capacity potentially have much more to lose in the transition to a low carbon economy than those owners with merchant capacity. This logic also applies to regulatory risk. As cheap renewables and gas become more prevalent, it will become increasingly difficult for listed coal owners to hide behind a regulatory framework that tends to promote the status quo over the energy transition. Those listed coal owners who fail to provide the lowest cost service risk a regulatory backlash. Since 2015, merchant generators have been devalued in a similar manner to European utilities who operate in liberalised markets. Inflexible coal capacity simply cannot compete in a market increasingly supplied by variable renewable energy, as flexing coal-fired units is often technically difficult or prohibitively expensive compared to gas-fired generation. For these reasons, merchant generators typically have less stranded value.

Recommendations

The technologies and fuels powering the US power sector have changed dramatically over the last five years. The marked decline in the cost of renewable energy is displacing conventional thermal generators and shale gas production has kept gas prices at record lows, which has given gas-fired generation a significant and sustained economic advantage over coal-fired generation. Moreover, efficiency gains have curbed load growth, intensifying competition amongst power generation technologies. These fundamental shifts suggest the US power system is on the cusp of structural change.

However, power markets are political constructs and therefore technological and business model changes can be undermined by the regulatory frameworks which power generators operate in. A below 2˚C pathway would save US power consumers money – and therefore make the US economy more competitive – but this reality will only be realised if regulation catches up with the structural changes which have occurred over the last five years. Obviously, it would not be feasible to wait until a later date and phase out all coal generation at once – hence the transition needs to start now.

Our recommendations are aimed at institutional investors, listed coal owners and regulators. The intention here is to outline how:

- investors can make their US coal ownership investments comply with the Paris Agreement;
- energy transition obstruction could negatively impact regulated coal owners; and
- regulators can act as harbingers for change.

Investors

When confronted with below 2°C divergence, shareholders can divest, engage, or do a combination of both. As a minimum, investors must require more information on the processes used by listed coal owners to manage energy transition risk. Several companies have announced plans to phase-out coal power by 2050.[31] These individual announcements will likely lead to collective failure, as unabated coal-fired generation in the US needs to be completely phased out by 2035 at the latest. Investors should challenge these announcements and assess companies based on the cost profile and system value. This assessment should factor in the differences between regulated and merchant capacity. Regulated utilities have long been considered safe assets.

31 See for e.g., Mid-Western Energy News, (2017). Michigan's two major utilities announce increased commitment to renewables. Available: http://midwestenergynews.com/2017/05/17/michigans-two-major-utilities-announce-increased-commitment-to-renewables/

This can no longer be taken for granted, as investor-owned utilities keep high-cost units operating by using regulation to push additional costs on to consumers.

Coal owners

Our recommendations for coal owners depend on whether they are a utility or an asset manager. Listed coal owners can be broadly categorised three ways: regulated investor-owned utilities, merchant investor-owned utilities and conglomerate holding companies.

Regulated investor-owned utilities – don't be another RWE

Since 2008, RWE – one the of the largest utilities in Europe – has lost 80% of its market capitalisation due to a failure to understand policy, technology cost and business model changes.

The 20th century legal framework that underpins regulated utilities is not well suited to the 21st century. End-user efficiency and onsite generation are stalling load growth, while variable renewable energy and electric vehicles are going to change power systems in ways previously unimaginable. These realities fundamentally challenge the regulated utility business model. Value is shifting down the supply chain from power generation to customer management. Rather than obfuscate the energy transition, regulated utilities should take a leaf out of the book of tech giants who have an intimate understanding of their customer base.

Failure to put the customer first could result in a consumer revolt like Germany's Energiewende. Germany's energy policy has as much to do with the energy democracy as a transition to a low carbon economy. Germans convinced their politicians to pass laws to allow citizens to produce their own energy and phase-out existing nuclear units, even when it hurt utilities to do so. Indeed, an analogous situation is beginning to play-out with California's investor-owned utilities, which are losing their customer base due to access programs, community aggregators and distributed energy resources. According to the California Public Utilities Commission, as much as a quarter of the retail load will be effectively unbundled and served by a source other than an investor-owned utility sometime later this year.[32] Lawmakers in Nevada have also passed a bill which will allow customers to subscribe to an off-site solar project in their community and earn credit on their utility bills.[33]

To reduce the risk of value destruction, regulated utilities need to actively manage the tension between acting in the interests of shareholders and doing good by their customers. A number of utilities are making positive steps with regards to retiring old uncompetitive coal, but action must include a phase-out plan consistent

32 *California Public Utilities Commission, (2017). Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework, Staff White Paper. Available: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf . Sourced from: Green Tech Media, (2017). As California Mulls Retail Electricity Choice, Utilities Are Losing Customers in Droves. Available: https://www.greentechmedia.com/articles/read/california-utilities-are-losing-customers-in-droves*

33 *NELIS, (2017). Revises provisions relating to energy. Available: https://www.leg.state.nv.us/App/NELIS/REL/79th2017/Bill/5450/Overview. Sourced from: Green Tech Media, (2017). Nevada Legislature Boosts Renewables Target to 40% by 2030, Overcoming Casino Opposition. Available: https://www.greentechmedia.com/articles/read/nevada-senate-boosts-renewable-target-to-40-by-2030-overcoming-casino-oppo*

with a below 2°C outcome.[34]

Merchant investor-owned utilities – if you're going through hell, keep focusing on capital discipline

Merchant utilities have already incurred significant devaluations due to deteriorating market conditions. As low wholesale power prices reduce revenues, merchant utilities need to reduce their cost base wherever possible. Market conditions experienced by merchant utilities over the last 2 years have been a reality for more than 5 years in Europe. The existential crisis facing European utilities has resulted in business model changes as well as significant reductions to the O&M costs of conventional thermal generation assets. Merchant utilities should also adopt a coal phase-out schedule consistent with a below 2°C outcome and seek out electricity-as-a-service opportunities in those markets where there is competitive retail pricing.

Conglomerate holding companies – holding regulated coal is no longer low-risk

The modus operandi of holding companies is to allocate capital to high-yield, low-risk businesses. For this reason, holding companies have historically been attracted to regulated utilities which are monopoly franchises with captive customers. Moreover, several conglomerates have minimal exposure relative to the value of all assets under management.[35] However, as noted above, the business model underpinning regulated utilities is coming under sustained pressure from declining electricity demand and increasing onsite generation. As with regulated utilities, holding companies need to reconcile the tension between shareholder and customer interests. Failure to do so could result in a changing regulatory landscape.

Regulators

PUCs around the US are starting to grapple with the reality that rate of return regulation – a policy approach that has worked well for decades – may no longer be viable. Part of this recognition needs to reflect the following realities: (i) even without expensive pollution control and CCS technologies, coal is often a more expensive option relative to other power technologies; (ii) making coal highly dispatchable, to accommodate increased amounts of low-cost variable renewable energy, increases O&M costs, exacerbating its economic disadvantage; and (iii) retrofitting existing units with comprehensive pollution control and CCS technologies make coal-fired generation prohibitively expensive relative to other power technologies. For these reasons, PUCs need to work with industry to develop coal phase-out schedules. These schedules should be consistent with a below 2°C outcome and focus on employee retraining and compensation.

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34 Xcel recently announced it was going phase-out two coal plants in Pueblo, with David Eves, president for Xcel Energy in Colorado stating: "It is really about the economics," and "From the company's perspective, this plan is a response to our customers." See: Denver Post, (2017). Xcel Energy plans to retire two coal-fired plants in Pueblo, increase renewables. Available: http://www.denverpost.com/2017/08/29/xcel-energy-pueblo-coal-plants-retiring/

35 Berkshire Hathaway, for example, is the 4th largest owner of regulated coal units and yet has 0.03% of stranded value as a percentage of market capitalisation.

Conclusions

The US power sector is in transition. Technological developments, fuel costs, business model changes and environmental regulations are marginalising coal-fired generation. Despite these transformational developments, coal remains a significant fuel in the US power mix, due to regulation, which legally protects coal units from competition. This 20th century regulation is fundamentally unsuited to changes occurring to power generation in the 21st century. This report presents an asset-level below 2°C model for investors, listed coal owners and regulators to manage the financial risks associated with coal power.

We recommend:

- investors use our below 2°C scenario model to comply with the Paris Agreement;
- utilities phase-out coal in a manner consistent with a below 2°C outcome to save the US economy, shareholders and consumers money; and
- regulators act in the interest of consumers by demanding coal-fired power is phased-out in a manner consistent with a below 2°C pathway.

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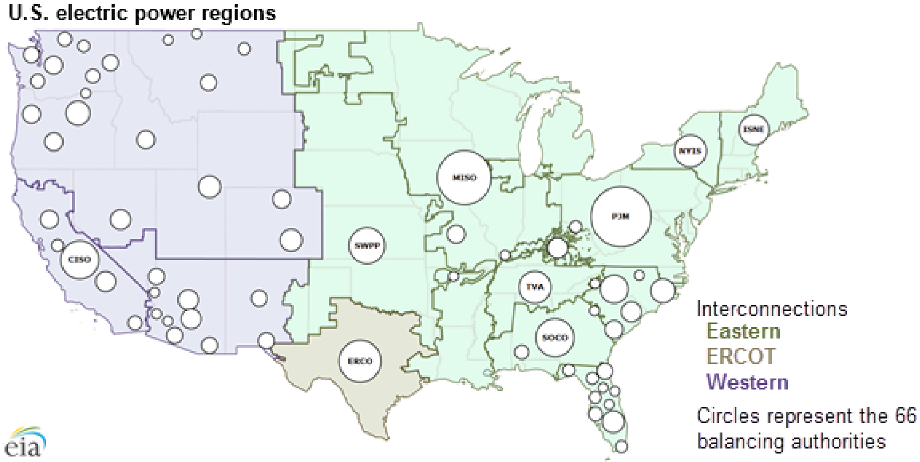
Appendix 1. Overview of US power markets

The US power sector is complicated. The value chain involves the generation, transmission, and distribution of power, as well as grid balancing and customer management. Power generated at plants moves through a complex network of substations, lines, and transformers before it reaches households and businesses. According to the EIA, the US power system consists of over 7,300 plants, approximately 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.[1] A host of technological, regulatory, and economic considerations impact the economic viability of power utilities on a daily basis. In the US, the mix of power generation utilities includes investor owned utilities, municipal-owned utilities, and co-operative utilities.

*Figure 21. US power regions, interconnections and balancing authorities**



Source: EIA (2016)
** The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.*

1 *EIA (2016). Today in energy: U.S. electric system is made up of interconnections and balancing authorities. See: https://www.eia.gov/todayinenergy/detail.php?id=27152*

Local, state, and federal regulation of US power utilities have evolved in several stages, responding to evolving corporate structures, culminating in two major changes during the mid-1930s. The first stage condensed the industry from multiple private company holdings into vertically integrated utilities serving single territories. Vertically integrated utilities operate across the entire power supply chain from the generation of power to its transmission and distribution to customers. Due to high barriers to market entry and economies of scale required to electrify the country, it made economic sense for one entity to own and operate the entire supply chain. These vertically integrated utilities are what economists call natural monopolies.

The next stage saw the creation of rural co-operatives to serve sparsely populated areas and federal power authorities or multi-state utilities owned by the US government during the 1930s. From the 1930s through to the 1990s, power utilities were mainly vertically integrated utilities in the form of municipally-owned utilities and consumer-owned utilities.

The company and market models began to change with the Public Utility Regulatory Policies Act (PURPA) in 1978, which recognized that power generation was not a natural monopoly. In the 1990s, the Federal Energy Regulatory Commission (FERC) acted forcefully to create competitive markets for wholesale electricity and to spur entry into the generation business by new players, as well as requiring vertically integrated utilities to minimise costs through integrated resource planning. These regulatory developments coincided with the advent of the Combined Cycle Gas Turbines (CCGTs) which had lower capital costs and construction times than nuclear and coal plants, and higher voltage transmissions lines that gave power customers more supply choices.

In most regions around the US, both regulated and merchant coal, natural gas, and other power plants provide electricity to consumers. In some areas, these transactions are managed by independent third parties, while in other areas the entity that manages these transactions is a regulated, vertically-integrated utility.[2]

See Figure 22 for a map of independent system operators (ISOs) and regional transmission organizations (RTOs) in North America. The US power system in the lower 48 states is made up of three main interconnections, which mostly operate independently from each other with limited transfers of power between them:

1. The Eastern Interconnect, spanning the entire eastern and central states from the area east of the Rocky Mountains and a portion of northern Texas;

2. The Western Interconnect, spanning the area from Rockies west, pacific and southwestern states; and

3. The Electric Reliability Council of Texas (ERCOT) interconnect which covers most of Texas.

2 *In the Tennessee Valley, a quasi-governmental organization (TVA) acts in this role. Several other cases similar to this exist in the Midwest, the Pacific Northwest, and Alaska.*

The unbundling of generation from electricity services and the move to a competitive market resulted in the establishment of 66 Balancing Authorities (BAs), ISOs and RTOs [3] to (i) manage these wholesale power markets; (ii) reduce the transaction costs of communicating the needs of distribution utilities to generation companies; and (iii) maintain the long-distance transmission grid.[4]

RTOs are independent, membership-based, non-profit organizations that co-ordinate, control and monitor a multi-state power grid. ISOs have the same organisational status and regulatory authority as RTOs. At one time ISOs covered a narrower geographical area, but many ISOs now serve several states. Some grid areas within RTOs and ISOs are managed by individual utilities, mostly large investor-owned ones, and some by the federal power marketing agencies, the BAs.

RTOs, ISOs and BAs also purchase balancing services, and they manage various markets for other grid services. While the dispatch arrangements vary regionally, CAISO, MISO, ISO-NE, NYISO, PJM interconnection and ERCOT all operate competitive wholesale electricity markets. Southeast, Southwest and Northwest are regulated markets where vertically integrated utilities and federal systems own the generation, transmission and distribution systems used to serve electricity consumers.[5] Regulated markets trade power generation through bilateral transactions and power pool agreements.

Unbundling occurred in 17 states before the Californian electricity crisis, caused by market manipulations by Enron, resulted in 7 states suspending unbundling. 27 states remain regulated.[6]

Whether served by an RTO, ISO, or BA; all places have some form of wholesale market for power under the supervision of FERC. ISOs and RTOs typically publish market clearing prices for their regions and sub-regions on an ongoing basis. This data is typically reported as day-ahead locational marginal prices (DA LMP or simply LMP), and is measured in US$ dollars per MWh. Average annual or monthly clearing prices can be used to estimate the revenue that a plant may expect over the short term.

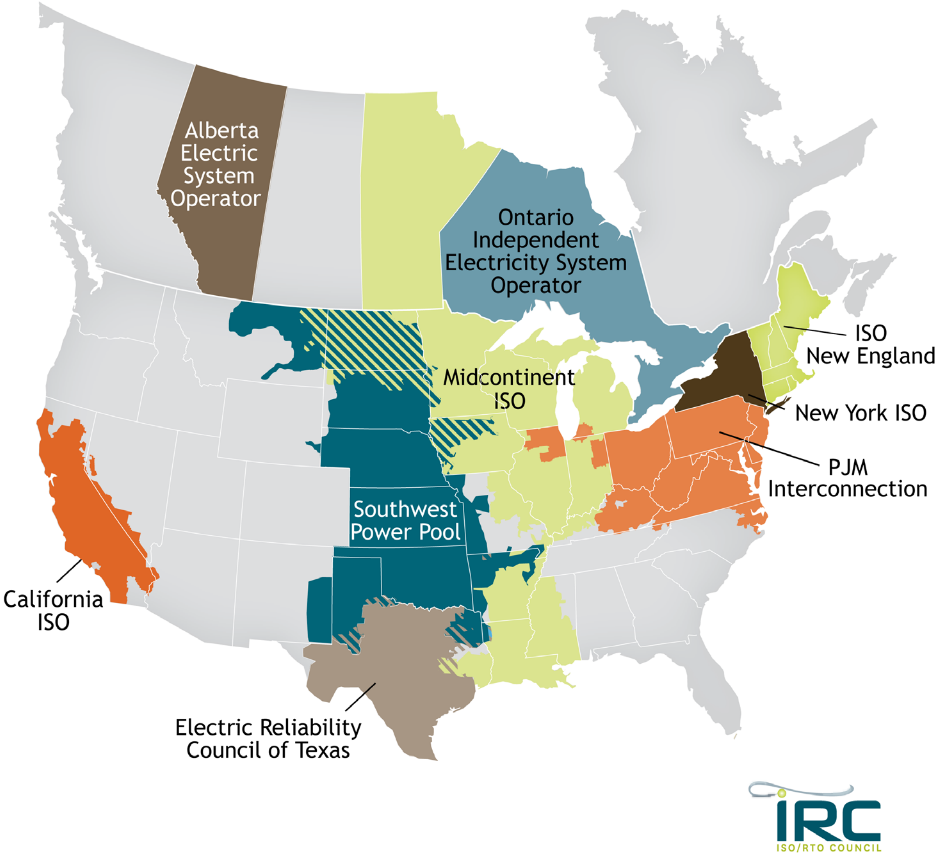
3 *The exact numbers vary as the BAs, ISOs and RTOs change constantly. Frequently some BAs become a component of a larger ISO*

4 *This excludes Canadian and Mexican BAs that are part of the interconnects: https://www.eia.gov/todayinenergy/detail.php?id=27152*

5 *In many areas, the investor-owned utilities are effectively the ISOs/RTOs*

6 *Deregulated states include: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas and Washington DC. Suspended states include: Arizona, Arkansas, California, Nevada, New Mexico, Virginia and Wyoming. Regulated states include: Alabama, Alaska, Idaho, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin.*

Figure 22. ISOs and RTOs of North America



Source: IRC (2017)

Appendix 2. LCOE Assumptions

		Overnight investment costs (US$/kW)	Fixed OM costs (US$/kW)	Technical lifetime (Years)	Capacity factor (%)	Capture rate (%)	Efficiency (%)	Discount rate (%)
Coal		2,600	70	40	40	-	35	5
	Average	2,350	58	40	60	-	40	5
	Min	2,100	45	40	80	-	40	5
Coal – CCS	Max	11,993	220	40	40	90	36	5
	Average	8,797	205	40	60	90	36	5
	Min	5,600	190	40	80	90	36	5
CCGT	Max	1,050	25	35	40	-	57	5
	Average	1,029	25	35	60	-	57	5
	Min	947	25	35	80	-	57	5
OT	Max	956	20	35	5	-	38	5
	Average	950	20	35	15	-	38	5
	Min	950	20	35	30	-	38	5
CCGT – CCS	Max	3,100	100	35	40	90	49	5
	Average	3,100	100	35	60	90	47	5
	Min	3,100	100	35	80	90	47	5
Nuclear	Max	5,800	180	60	40	-	36	5
	Average	5,800	180	60	60	-	36	5
	Min	5,800	180	60	80	-	36	5
Wind	Max	3,440	44	25	30	-	100	5
	Average	1,500	44	25	40	-	100	5
	Min	1,127	44	25	50	-	100	5
PV – Utility	Max	2,240	16	25	15	-	100	5
	Average	1,554	16	25	25	-	100	5
	Min	1,328	16	25	30	-	100	5

Source: Carbon Tracker estimates

Appendix 3. Additional analysis on environmental regulations

Mercury and Air Toxics Standards (MATS)

These rules reduce air pollution from coal-fired power plants in the 1990 Clean Air Act amendments and set technology-based emissions limitation standards for mercury and other toxic air pollutants, reflecting levels achieved by the best-performing sources currently in operation. MATS sets numerical emission limits for mercury, particulate matter and hydrochloric acid requiring all coal fired power plants to install Maximum Achievable Control Technology.

Cooling Water Intake Structures (CWIS)

The CWIS rule sets a mortality standard to protect aquatic life from impingement and entrainment. The rule covers facilities that are designed to withdraw at least 2 million gallons of water per day of cooling water.

National Ambient Air Quality Standards (NAAQS)

The 1990 Clean Air Act requires the EPA to set NAAQS[1] for pollutants considered harmful to public health and the environment. Standards for a number of these pollutants already existed well before this date. However, as detailed in Table 4 below, since the Clean Air Act increasingly stringent limits have been set with great regularity.

1 National Ambient Air Quality Standards (NAAQS) define acceptable levels over an average time for six principal air pollutants. See EPA (2017). NAAQS Table. Available: https://www.epa.gov/criteria-air-pollutants/naaqs-table

Table 4. Outline of existing air quality standards

Pollutant	Primary/secondary	Averaging time		Level	Form	Last revised
Carbon Monoxide (CO)	Primary	8 hours		9 ppm	Not to be exceeded more than once per year	2011
		1 hour		35 ppm		2011
Lead (Pb)	Both	Rolling 3-month average		0.15 µg/m3	Not to be exceeded	2008
Nitrogen Dioxide (NO2)	Primary	1 hour		100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years	2010
	Both	1 year		53 ppb	Annual mean	1971
Ozone (O3)	Primary and secondary	8 hours		0.070 ppb	Annual mean	2015
Particle Pollution (PM)	PM2.5	Primary	1 year	12.0 µg/m3	annual mean, averaged over 3 years	2012
		Secondary	1 year	15.0 µg/m3	Annual mean, averaged over 3 years	1997
		Both	24 hours	35 µg/m3	98th percentile, averaged over 3 years	2006
	PM10	Both	24 hours	150 µg/m3	Not to be exceeded more than once per year on average over 3 years	1987
Sulfur Dioxide (SO2)	Primary	1 hour		75 ppb	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years	2010
	Secondary	3 hour		0.5 ppm	Not to be exceeded more than once per year	1971

Source: EPA and adapted from IEA (2016)

Disposal of Combustion Residuals Rule (CCR)

The CCR rule sets higher standards for the management of ash and other waste by-products of coal burning. This rule targets the structural integrity of landfills and ponds holding non-hazardous coal ash. Those generators with uncompliant landfills or ponds are required to close them and convert to dry-ash removal systems.

Cross-State Air Pollution Rule (CSAPR)

The CSAPR rule addresses SO2, NOx and ozone pollution that can be across state boundaries. The goal can be met through retrofits, retirements or purchasing tradable allowances. It affects coal-fired capacity in the 28 states in which it applies.

Effluent Limitation Guidelines (ELG)

Regulates nitrites, mercury and other heavy metals in wastewater. Those units who have installed wet scrubbers may need to install wastewater treatment upgrades to meet ELG. The ELG requires generators to first reduce wastewater and treat remaining water, with the intention of eradicating liquid discharge.

Acid Rain Program (ARP)

The ARP targets SO2 and sets a permanent cap on the total amount of SO2 that may be emitted by power generators. The program was finalised in 2010 and impacts units with an output capacity greater than 25 MW.

Regional Haze

Targets air pollutants that reduce visibility in national parks and wilderness areas. This program requires states to implement best available technology controls and introduce state implementation plans.

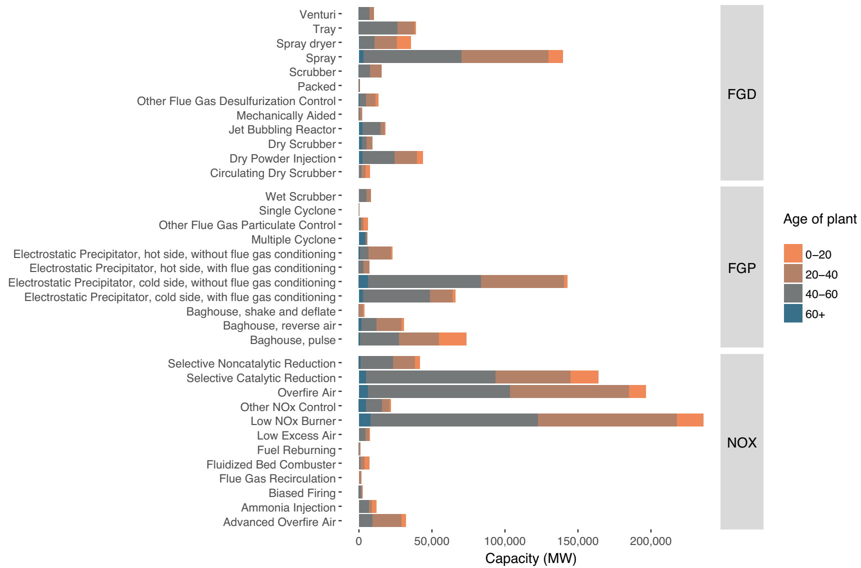
CPP

On 2 June 2014, President Obama announced the proposal to enforce a 30% reduction in carbon dioxide (CO_2) emissions from existing power plants on 2005 levels by 2030. This regulation will have significant health and climate benefits, equal to $55-93 billion in 2030. This is equivalent to 25% below the EPA's forecast of what would happen without the standards. On March 28, President Donald Trump signed an Executive Order calling for a review of the CPP, putting its future status in doubt. However, the EPA is still obligated under a decision from the Supreme Court to regulate CO_2, whether through the CPP or a different proposal.

Regional Greenhouse Gas Initiative (RGGI)

RGGI is a cap and trade system among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO_2 emissions from the power sector.
To meet a number of the above environmental regulations, investments need to be made in control technologies such as scrubbers, ACIs, baghouses, cooling, ash, and effluent controls. Figure 24 below details operating coal units by age and environmental control technologies as of 2017.

Figure 23. Operating coal units by age and environmental control technology



Source: SNL (2017)

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