David Schlissel, Director of Resource Planning Analysis
Dennis Wamsted, Analyst/Editor
April 2020

Institute for Energy Economics and Financial Analysis
IEEFA.org

Public Comments on Rocky Mountain Power's 2019 Integrated Resource Plan

Executive Summary

PacifiCorp's 2019 Integrated Resource Plan (IRP) evaluated the retrofitting of some of the units at its Wyoming coal plants for carbon capture but decided that:

> *"Given the high capital cost of implementing CCS [Carbon Capture and Storage] on coal fired generation (either on a retrofit basis or for new resources) CCS is not considered a viable option before 2025. Factors contributing to this position include capital cost risk uncertainty, the availability of commercial sequestration (non-EOR) sites, uncertainty regarding long-term liabilities for underground sequestration, and the availability of federal funding to support such projects".*[1]

Instead, PacifiCorp identified eight of its coal-fired units in Wyoming for retirement by 2028, with the earliest retirements coming as soon as the end of 2023 and 2025.[2]

However, Wyoming's legislature and governor responded by enacting into law House Bill 200 (HB200) that effectively would force PacifiCorp to retrofit one or more of the units at its coal-fired power plants in the state with carbon capture equipment by establishing a requirement that a "specified percentage" of the utility's generation come from such resources.

Many of the legislation's specifics remain to be worked out by state regulators, but the thrust of the new law is clear: giving PacifiCorp almost carte blanche to charge what it wants to retrofit CCS equipment at one or more of its Wyoming coal units, while completely disregarding the potential cost to the state's ratepayers.

In particular, the legislation would allow PacifiCorp to:

- ask the state utility commission to recover through rates the cost of any carbon capture retrofit, including a higher return on equity, that is "integral or adjacent to a coal-fired generator in Wyoming."[3]

- seek authorization to keep a portion of any revenues from the sale of the captured CO_2 for its shareholders.[4]

---

[1] PacifiCorp 2019 IRP, dated October 18, 2019, at page 158.
[2] Jim Bridger 1 by the end of 2023, Naughton 1&2 by the end of 2025, Jim Bridger 2 by the end of 2028 and Dave Johnston 1-4 by the end of 2027.
[3] Wyoming HB 200 Statute Section 37-18-102(c) (i)
[4] *Ibid. Section* 37-18-102(c) (ii)

- add a surcharge of up to 2% on ratepayers' monthly bills to cover the cost of a proposed carbon capture retrofit even before any funds are spent.[5]

- enable PacifiCorp to ask the commission for additional cost recovery to ensure that it can recover all its prudently incurred costs connected to a CCS retrofit project.[6]

It seems Wyoming legislators assumed that these costs would be spread across all of PacifiCorp's ratepayers in its six-state service territory. This is extremely unlikely, particularly given the language in Section 5.8 of PacifiCorp's Inter-Jurisdictional Allocation Protocol, "State-Specific Initiatives" which states that "Costs and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative." Clearly, HB200 is a Wyoming-specific initiative.

At the same, time, given the mandates to move away from coal generation in Oregon and Washington, those states are not going to be willing to make their ratepayers bear any of the costs resulting from HB200. Thus, Wyoming ratepayers alone will end up bearing all the risks of and paying the bills for this legislation.

One project that is already seeking to benefit from HB200 is a proposal by Glenrock Energy to retrofit at least one of the four units at PacifiCorp's Dave Johnston coal plant. However, there are several flawed assumptions underlying both HB200, in general, and the Glenrock Energy proposal, in particular:

1. It is unlikely that any carbon capture retrofit could be completed before 2026, by which time Dave Johnston 1, the oldest of PacifiCorp's Wyoming coal units, would be 67 years old, while the youngest, Jim Bridger 4, would be 47.

2. By 2037, which is the last year that a retrofitted unit coming online in 2026 would be eligible to earn federal 45Q tax credits, Jim Bridger 4 would be 58 years old while Dave Johnston 1 would be 78 years old. The median age at which currently retired coal units larger than 100MW have been retired has been 53 years old. The average retirement age for U.S. coal plants has been 51.

3. Glenrock Energy's claim that its carbon capture retrofit project would have an operating life of approximately 40 years is preposterous. That would mean Dave Johnston 4 would still be operating until about 2066, when the plant would be 87 years old.

4. Retrofitting any of PacifiCorp's Wyoming coal units will be very expensive. Building the 240MW Petra Nova project near Houston, TX, the only project in the U.S. currently capturing carbon from a power plant, cost $1 billion in 2016 which would be almost $5,000 per kW in 2026 dollars. Even assuming a 30% cost reduction, retrofitting individual PacifiCorp units would range

[5] Wyoming HB 200 Section 37-18-102(c) (iii)
[6] *Ibid.*

from $370 million for the smaller units (Dave Johnston 1&2) to above $1.8 billion for each of its larger units at the Jim Bridger plant

5. Glenrock Energy's claim that it could retrofit Dave Johnston 4 for $480 million is not credible as this would mean a reduction of 70% from the actual cost of building the Petra Nova facility.

6. Capturing 90% of the CO_2 produced at an operating scale coal plant has not been proven over a significant number of years. Petra Nova, which has been in service for only three years, has captured about 83% of the CO_2 it has produced.

7. Tax equity financing, using federal 45Q tax credits, will cover no more than 68% (and perhaps as little as 35%) of the total capital cost of retrofitting PacifiCorp's Wyoming coal units. The specific amount will depend on how many 45Q tax credits PacifiCorp is able to earn, which in turn depends on how much power the unit produces and how many metric tons of CO_2 it produces and captures.

8. Given the expected shortfall in tax credit financing, PacifiCorp likely would have to invest between $141 million and $1.2 billion into retrofitting one of its Wyoming coal units, depending on the unit. These investments would dramatically increase the company's rate base and raise the rates paid by its Wyoming ratepayers.

9. In addition to paying for the projects' capital costs, the company's Wyoming ratepayers would have to foot the bill for the incentives included in HB200 including a higher return on equity from PacifiCorp's carbon capture investments.

10. Ratepayers also would have to pay more for electricity after a carbon capture retrofit because the unit's net generation would decline (with some of the gross generation being used to power the capture equipment), increasing the average cost of electricity to ratepayers.

11. In addition, because the net generation from the retrofitted coal plant would be lower, the company will have to obtain replacement energy from another source – either from another of its own plants or by purchasing from another company. Either way, ratepayers will have to pay for the replacement energy.

12. Capturing CO_2 will entail additional costs beyond those that are regularly incurred when generating electricity at a power plant – additional staff, additional water, etc. Ratepayers will be forced to pay for these additional costs as well.

13. Glenrock Energy's assumptions about the cost benefits associated with using the captured CO_2 for enhanced oil recovery activities are speculative at best, depending on the assumption that a retrofitted coal plant would continue to operate for 40 years after being retrofitted.

We do not believe that HB200 will achieve its aims, as market changes are rapidly pushing the U.S. electricity sector away from coal to cheaper and cleaner renewables and gas.

PacifiCorp is right, CCS is not a viable option.

What HB200 certainly will do is make the price of electricity much more expensive for PacifiCorp's Wyoming ratepayers.

Table of Contents

Table of Figures

Retrofitting Any of the Units at the Dave Johnston, Jim Bridger and Naughton Coal Plants Will Be Expensive and Risky for Ratepayers

The rate impact of retrofitting any of PacifiCorp's Wyoming coal units on the company's ratepayers will depend on several factors:

1. The cost of adding carbon capture to the unit.
2. How long it will take to retrofit one or more of PacifiCorp's Wyoming coal units
3. How much of the cost of adding carbon capture can be financed through the sale of the tax credits available through the federal government's newly expanded 45Q program and how much will have to be paid by Rocky Mountain Power's ratepayers. The 45Q program offers a $35 per ton payment for CO_2 captured and sold for reuse in EOR activities and $50 per ton for geologic storage.
4. How much it will cost to run the carbon capture process at the unit and whether it is feasible to expect that PacifiCorp or Glenrock Energy will be able to recover a significant portion of that cost through the sale of the captured CO_2.
5. The financial feasibility of using captured CO_2 for enhanced oil recovery in Glenrock Energy's oil fields under current and expected future market conditions.

It is Unlikely that Any Carbon Capture Retrofit at PacifiCorp's Wyoming Coal Units Would Be Completed Before 2026

Construction began at Petra Nova in mid-2014, and the project was completed at the end of December 2016. However, design/engineering work began some seven years earlier.

And the importance of completing as much of the project's engineering and design work as possible before construction began has been cited by NRG as one of the key lessons of the project. As David Greeson, the head of the NRG team that developed Petra Nova explained, NRG "probably spent at least twice as much as you would normally spend on engineering and design before we ever put a shovel in the ground."[7]

In fact, it appears that NRG began the design and engineering work for Petra Nova in

[7] E&E News. Carbon Capture Takes "Huge Step" With First U.S. Plant. January 10, 2017.

2009, or about five years before construction began, and completed 90% of the project's conceptual design before it even broke ground.[8,9] As NRG explained to E&E News, this meant that it needed to make few changes after construction began.

Without detailed knowledge of the current state of PacifiCorp or Glenrock's plans for retrofitting any of the company's Wyoming coal plants, it is impossible to know how much pre-planning has been completed. However, given that neither Glenrock nor PacifiCorp appears to even have started a Phase II front-end engineering design (FEED) study, it is hard to see how all of the work involved in completing the engineering and design of the retrofit, ordering and installing the necessary equipment and completing the construction of any new carbon capture facility can be completed before 2025, at the earliest.

For this reason, this analysis assumes that any retrofit won't be online until 2026, at the earliest.

Retrofitting Any of PacifiCorp's Wyoming Coal Units Is Likely to Be Expensive, Costing Far More Than Glenrock Energy Claims

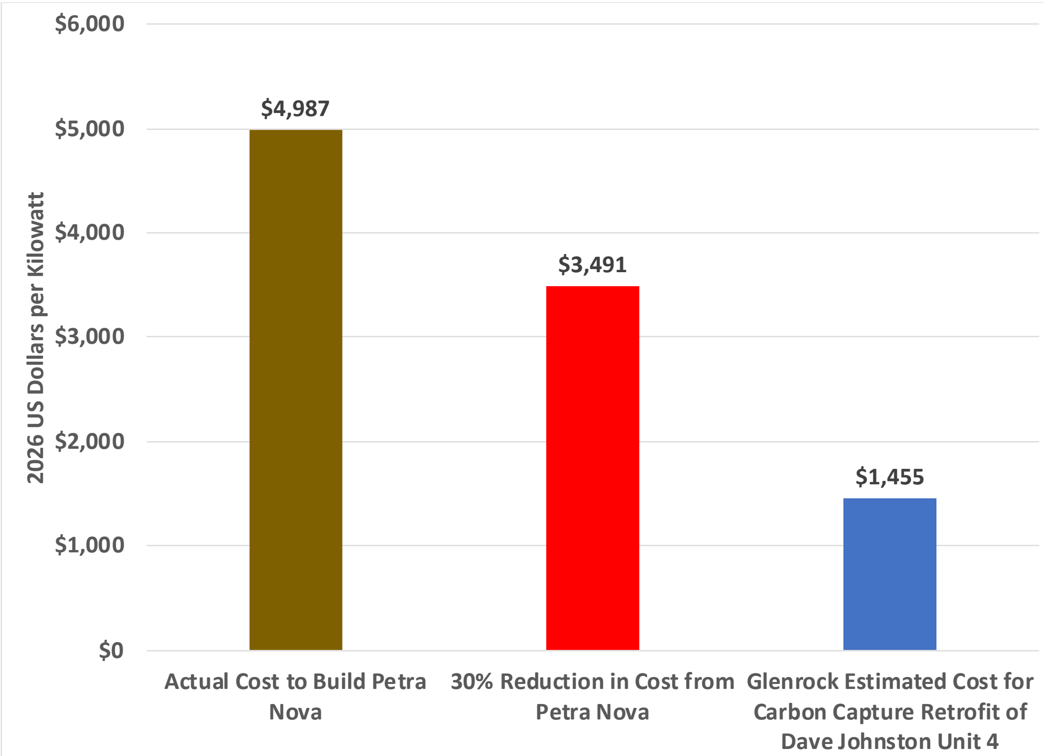
Glenrock claims that the capital cost of retrofitting one of the units at PacifiCorp's Dave Johnston with carbon capture will be $480 million. This claim strains credulity.

The actual capital cost of building the 240MW Petra Nova facility, the only carbon capture facility at an operating coal plant in the U.S., was $1 billion, or $4,166 per kW, in a mix of 2014-2016 dollars.[10] This converts to a cost of nearly $5,000 per kW in 2026 dollars. This is more than triple the capital cost that Glenrock Energy is claiming for the retrofitting of Dave Johnston Unit 4.[11]

---

[8] Presentation on Petra Nova by Petra Nova Parish Holdings LLC, at the June 2019 IEA Clean Coal Conference. Slide No. 3.
[9] In fact, Sargent & Lundy has reported it's involvement in the development and implementation of Petra Nova starting in 2011, or three years before construction began. Sargent & Lundy's San Juan Generating Station CO_2 Capture Pre-Feasibility Study, at page 1-2. July 8, 2019.
[10] EIA, Today in Energy. Petra Nova is one of two carbon capture and sequestration power plants in the world. October 31, 2017.
[11] Argus Media, *PacifiCorp may have buyer for its Dave Johnston plant*, 25 March 2019 and Glenrock Energy IRP Testimony, dated March 31, 2020, at page 2.

Figure 1: Actual Petra Nova Capital Cost vs. Glenrock Estimated Cost for Retrofitting One Unit at Dave Johnston Coal Plant with CO_2 Capture



Source: EIA, Glenrock Energy[12]

In other words, the actual capital cost of designing and building the only existing commercial-scale CO_2 capture project in the U.S. was more than three times as high, on a per kW basis, as Glenrock Energy is claiming for the cost of retrofitting just one of PacifiCorp's units at the Dave Johnston plant.

The theory underlying the development of new technologies, such as carbon capture at commercial-scale power plants, is that, over time, lessons learned from the construction and operation of new plants will drive down the prices for building and running each successive unit.

For example, the cost of installing new utility-scale solar capacity declined by nearly 70% between 2010 and 2018, as a result of the lessons learned in the building and installation of 24.7GW of new solar capacity.[13] Similarly, the price of installing new wind capacity fell by 40% between 2009-2010 and 2018, as a result of the lessons learned during the installation of 56GW of new wind capacity.[14]

[12] Analysis based on costs from EIA Today in Energy, October 31, 2017 and *Glenrock Energy IRP Testimony*.
[13] LBNL. Utility-Scale Solar - Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States, 2019 Edition. December 2019.
[14] U.S. Department of Energy. 2018 Wind Technologies Market Report. August 2019.

However, carbon capture technology is not like solar and wind technology. The decline in solar and wind prices was driven by research and development, robust competition among suppliers, and thousands of new commercial projects. By contrast, there are only two operational carbon capture projects at power plants in the entire world. Unlike with solar and wind, few carbon capture initiatives are in play, meaning costs for the next projects will not go down significantly.

Moreover, instead of assuming that the cost of retrofitting new carbon capture technology to existing coal-fired generators would decline over time, Glenrock assumes that the cost of retrofitting a unit at Dave Johnston with CO_2 capture—making it the very next (or at most, one of the very next) commercial-scale power plants in the U.S. to be retrofitted with carbon capture technology—would immediately be 70% lower (on a dollar per kW basis) than the cost of building the Petra Nova plant in Texas.

It is possible that the cost of retrofitting Dave Johnston Unit 4 with CO_2 capture will achieve some cost savings from (1) lessons learned at Petra Nova, (2) the reuse of facilities at the Dave Johnston plant and (3) some economies of scale. However, it also is quite possible that some unanticipated problems will occur in scaling up the CO_2 capture technology from the 110MW Boundary Dam and the 240MW Petra Nova projects to the larger 330MW Dave Johnston Unit 4.

Nevertheless, other estimates for CO_2 retrofits suggest that the cost of adding carbon capture to one of PacifiCorp's Wyoming coal units will be significantly higher than Glenrock has claimed. The International Energy Agency, an advocate for carbon capture, has estimated that the next generation of power plant carbon capture projects (that is, those after Petra Nova) will achieve 25 to 30 percent reductions in both capital and operating costs.[15] The National Association of Regulatory Utility Commissioners (NARUC) has noted that the International Energy Agency's (IEA's) projected reductions in the next generation of power plant CCS projects, "…support the idea that costs will come down with more facilities."[16]

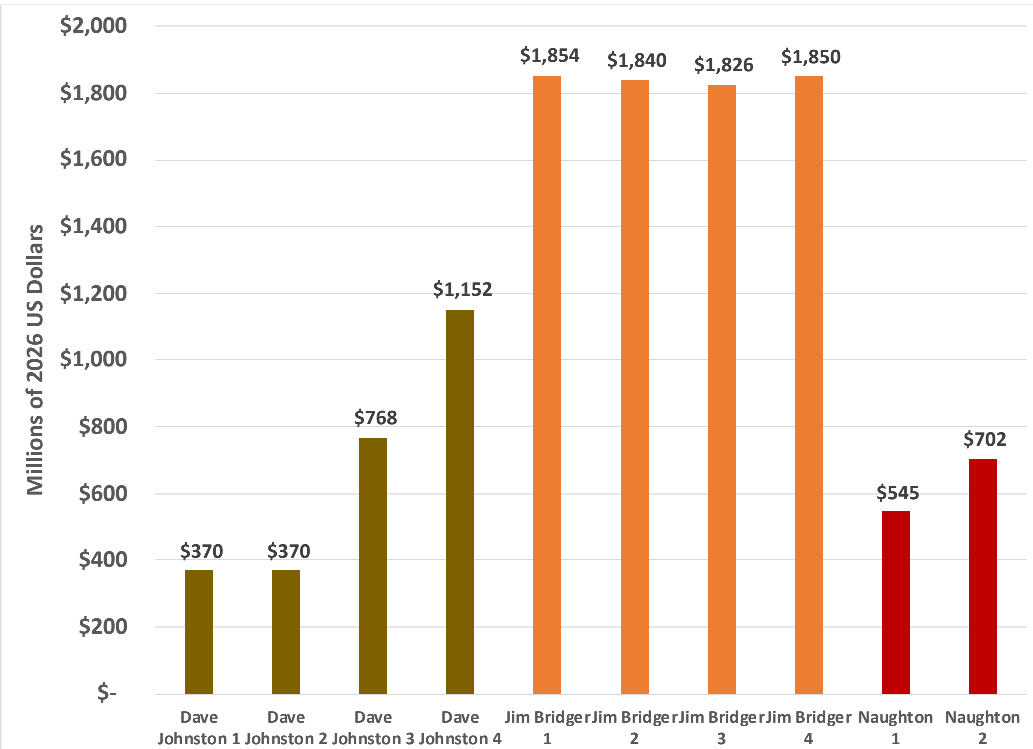
Similarly, the Clean Air Task Force (CATF), also an advocate of CCS, asserts that the capital cost of retrofitting existing coal plants for CCS will come down over time as later retrofits "benefit from the prior experience of the earlier projects."[17] CATF estimates that the capital cost for retrofits will decline to a range of $1,501 to $1,724 per kW by the time a sixth new project is undertaken.[18] However, Glenrock's proposed retrofit project would be only the second or third carbon capture project at a power plant in the U.S., not the sixth. And even CATF's cost estimate for the sixth carbon capture project is higher than the $1,455 per kW that Glenrock assumes.

---

[15] National Association of Regulatory Utility Commissioners (NARUC). Carbon Capture, Utilization, and Storage: Technology and Policy Status and Opportunities. November 2018, page 47.
[16] Ibid.
[17] Clean Air Task Force (CATF). Carbon Capture & Storage in the United States Power Sector: The Impact of 45Q Federal Tax Credits. February 2019, pages 24-25.
[18] Ibid, pages 24-25.

Even if Glenrock, PacifiCorp or some other project developer were able to reduce the cost of retrofitting one or more of the units at Dave Johnston and/or Jim Bridger with carbon capture at 30% below the actual cost of building Petra Nova, these retrofits would still be quite expensive, ranging from a low of $370 million (in 2026$) for Dave Johnston Units 1 or 2 to more than $1.8 billion for each of the units at the Jim Bridger plant.

Figure 2: Estimated Costs of Retrofitting Units at Dave Johnston, Jim Bridger and Naughton Plants with Carbon Capture Assuming 30% Reductions from the Actual Cost of Building Petra Nova



Even if Glenrock were to claim that it had a fixed-price contract for retrofitting the Dave Johnson unit, this would not guarantee that the carbon capture facility would be built for the contracted-for price or that the owners would not bear any of the risk of cost overruns. Some fixed-price contracts have clauses whereby the agreed-upon price can be exceeded if certain enumerated circumstances occur. Sometimes one or all parties to the contract can decide to void it if the estimated cost of finishing the project goes too high.

This is what happened in 2017 at Southern Company's Vogtle plant in Georgia. Southern Company had negotiated a fixed-price contract with Westinghouse to build two new nuclear reactors, which meant that Westinghouse was to bear most of the risk for schedule delays and cost overruns. However, when the estimated cost of building the new reactors doubled, Westinghouse went bankrupt and said it would no longer be involved in new nuclear construction. As a result, the owners of the planned new reactors, and their ratepayers, have had to bear much of the Vogtle cost overruns. Similar schedule delays and cost overruns led to the cancellation of two planned nuclear reactors in South Carolina even though the owners of that project also had fixed-price contracts with Westinghouse.[19]

We are not saying that cost overruns retrofitting Dave Johnston (or Jim Bridger) for carbon capture would be anywhere near the same magnitude as those at the reactors in Georgia and South Carolina, but those examples show that fixed price contracts do not eliminate project risk—a point that government officials, regulators and backers of Wyoming House Bill 200 would be wise to remember.

Retrofitting Dave Johnston or Jim Bridger with Carbon Capture Could Not Be Financed Solely with Federal 45Q Tax Credits – Significant Other Investments Would Be Required

The federal 45Q tax credit program provides a credit of $35 for each metric ton of CO_2 used for enhanced oil recovery (EOR) and $50 for each metric ton of CO_2 permanently sequestered underground. Simply put, the total number of credits that a company will earn will reflect how much CO_2 it produces and how much of the CO_2 it produces is captured. At present, the program allows a plant owner to earn tax credits for the first 12 years after the retrofit goes into service.

The first variable, how much CO_2 the plant produces is, in turn, largely dependent on how much the plant operates. The term "capacity factor" indicates how much power a plant produces in a given period, say a month or a year, versus how much it would have generated if it had operated at 100% power for all the hours of the same period. The higher the capacity factor, the more power is generated by the plant. Conversely, the lower the capacity factor, the lower the amount of power generated by the plant. Similarly, the amount of CO_2 produced by a coal plant goes up as its capacity factor goes up.

The Performance History of the Dave Johnston and Jim Bridger Plants

The first key to the economics of any carbon capture retrofit proposal is the assumption for the retrofitted unit's annual capacity factors for 12 years following the project's start-up.

From 2001-2009, which was before both the fracking revolution that brought huge supplies of low-cost gas into the electricity sector and before the surge in wind and solar generation that is both low-cost and emissions-free, each of the units at the Dave Johnston and Jim Bridger coal plants posted an average capacity factor of 78% or higher – with the average capacity factors of six of the eight units at these plants

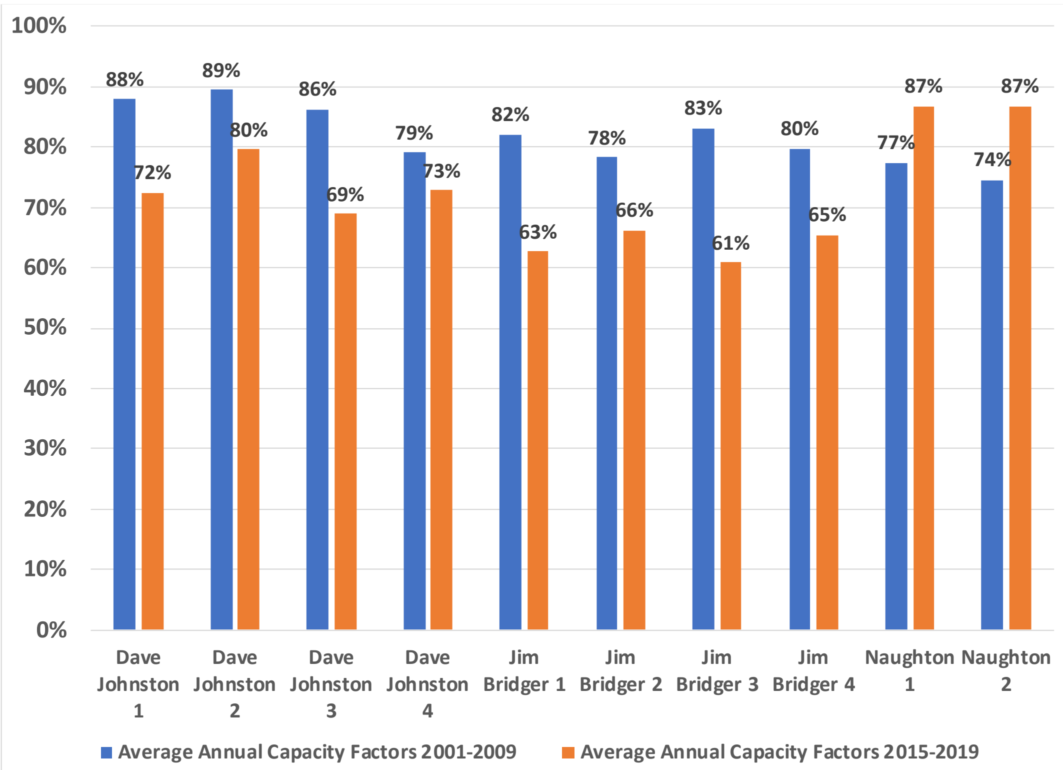
---

[19] For example, see Pittsburgh Post-Gazette. Pushing risk off a cliff: how Westinghouse ended up in bankruptcy. October 23, 2017 and CRS Insight, Westinghouse Bankruptcy Filing Could Put New U.S. Nuclear Projects at Risk. April 19, 2017.

at or above 80%. The average capacity factors of the Naughton Units 1 and 2 were 77% and 74%

Since then, the amount of electricity generated at eight of the ten units has declined, some quite significantly, as shown in Figure 3. Only Naughton Units 1 and 2 have generated more power, on average, in recent years then they did in the period 2001-2009.

Figure 3: Average Dave Johnston and Jim Bridger Unit Annual Capacity Factors in the Years 2001-2009 and 2015-2019

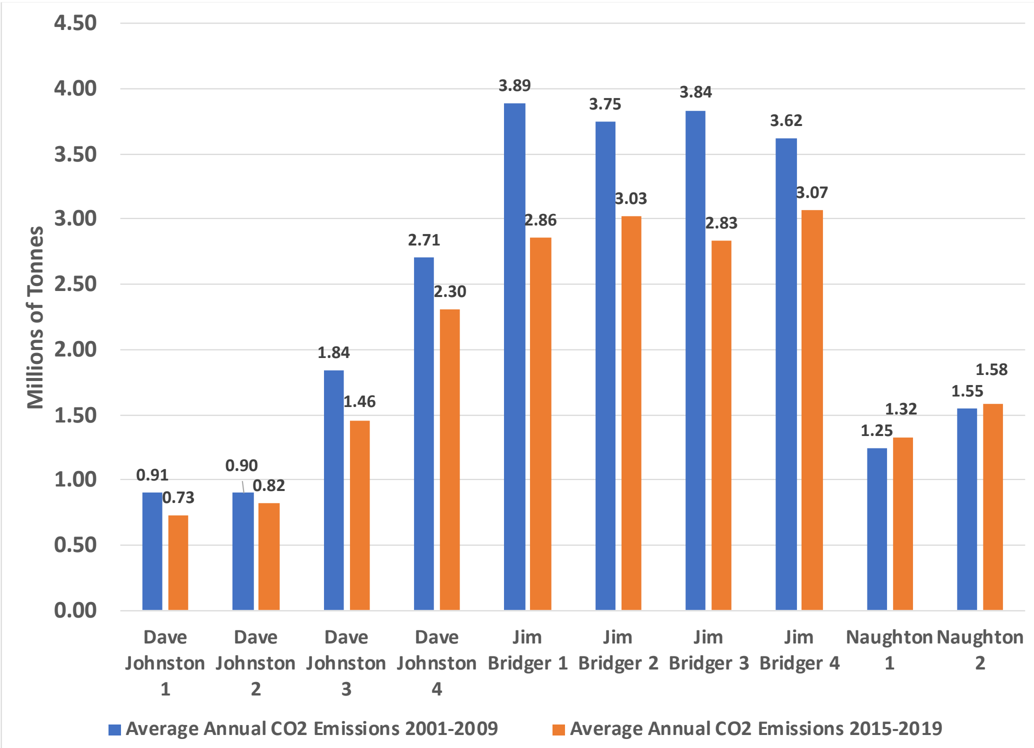


Source: EIA Form 923, S&P Global Market Intelligence

The capacity factor declines at Dave Johnston and Jim Bridger are far from unique. Energy Information Administration statistics show that the average capacity factor for coal plants in the U.S. dropped from 64.2% in 2009 to 53.6% in 2018. Further, in 2019, the average fell to 47.5%, an indicator of growing momentum around change across the U.S. electric sector.

These capacity factor declines are significant for the financial viability of any carbon capture retrofit proposals for the Dave Johnston or Jim Bridger plants because they mean that the units at these plants are producing substantially less CO_2 than could be captured. This, in turn, means that any retrofitted units would be eligible for far fewer 45Q tax credits, thereby further undermining the ability to finance carbon capture retrofits entirely through tax equity financing while avoiding major rate increases for Wyoming ratepayers.

Figure 4: Average Dave Johnston and Jim Bridger Unit CO_2 Emissions in the Years 2001-2009 and 2015-2019



Source: EPA Continuous Emissions Monitoring Systems data, S&P Global Market Intelligence

Glenrock has claimed that the estimated system-wide capacity factor of Wyoming's coal-fueled generation is 77%.[20] However, EIA data suggests that the average capacity factor is lower, at about 70% for the years 2015-2019—and the ongoing transition in the U.S. electricity sector makes it likely this figure will continue to fall in the years ahead.

A Rapidly Changing Market

The capacity factor declines at PacifiCorp's Wyoming coal plants are likely to continue, and probably accelerate, pushed down by a combination of forces roiling the electricity markets in general across the U.S. and a number of plant-specific issues. These factors include:

- The projected continued availability of low-cost gas.
- Growing competition from renewable resources and energy storage.
- Increased integration of the Western power grid.

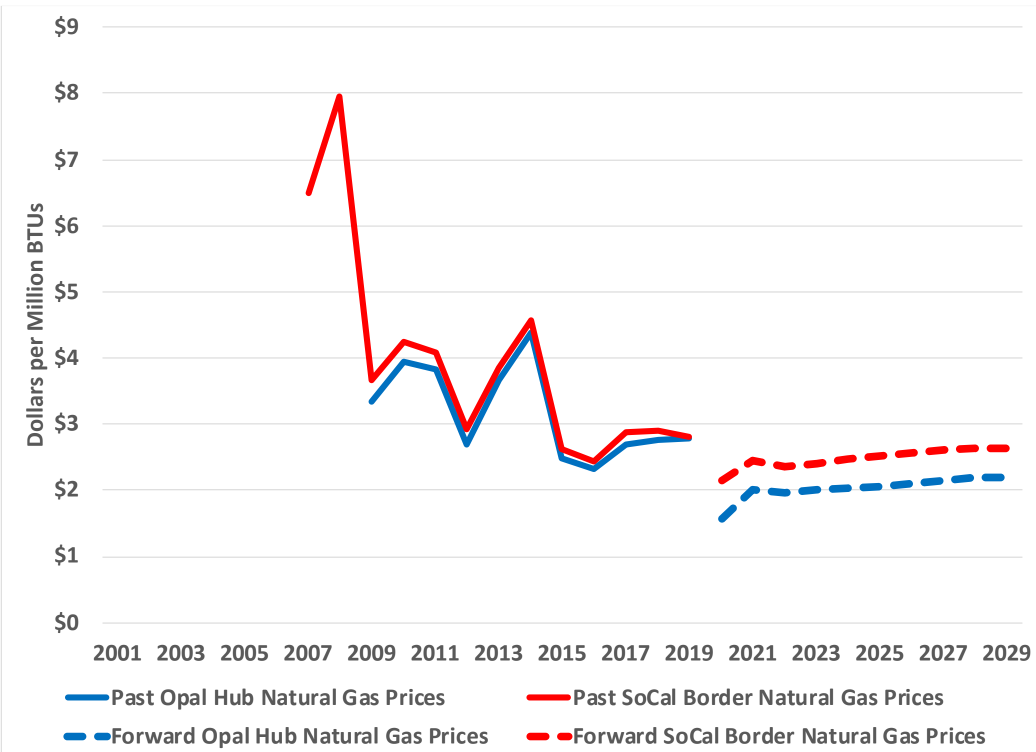
[20] Glenrock Energy IRP Testimony.

- The impact of plant aging.
- The impact of reduced spending on maintenance by the current owners.
- The fact that any retrofitted unit will be much more complicated to operate with carbon capture.

Natural Gas Prices

Similar to what has happened elsewhere in the U.S., gas prices at trading hubs in the West have declined significantly since 2008 and are expected to remain low for the foreseeable future, as can be seen in Figure 5.

Figure 5: Past and Forward Natural Gas Prices in the Western U.S.



Sources: S&P Global Market Intelligence, OTC Global Holdings[21]

These persistently low prices will undermine the financial viability of the proposed retrofit of any coal plants in the West with carbon capture by reducing fuel costs for gas-fired plants with which they would compete. This, in turn, would lead to (a) lower energy market prices and (b) increased generation at gas-fired plants,

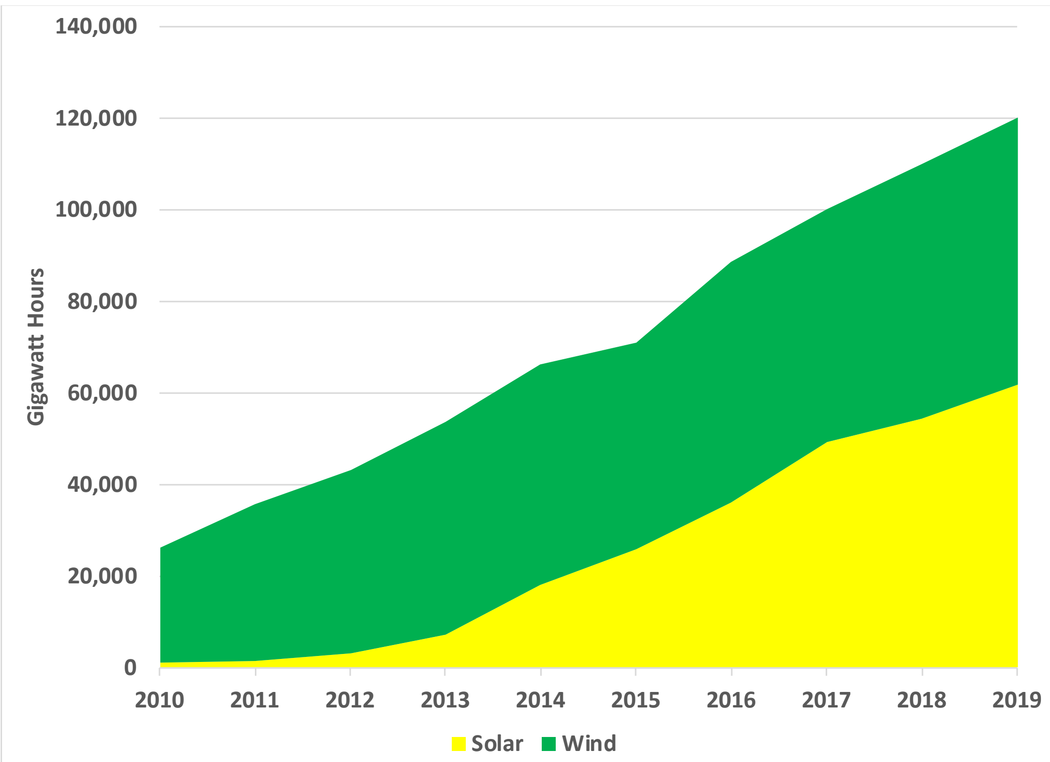
[21] The forward prices in Figure 5 represent the market's view of what future gas prices will be. Past Natural Gas Prices downloaded from S&P Global Market Intelligence on January 24, 2020. Forward prices from OTC Global Holdings, also downloaded from S&P Global Market Intelligence on January 24, 2020.

thereby displacing generation that otherwise would be produced at coal plants, lowering their capacity factors.

Renewable Competition from Wind and Solar Resources

Wind and solar generation have increased almost six-fold in the Western U.S. in the past decade, with dramatic price declines resulting in a doubling in generation between 2010 and 2019.

Figure 6: Rapid Growth in Wind and Solar Generation in the Western United States, 2010 to 2019



Sources: U.S. Energy Information Administration[22]

More renewable generation is on the horizon regionally as states push utilities to boost their renewable generation. California, for example, now mandates that 33% of electricity sales in 2020 and 60% of sales in 2030 come from renewable resources.[23] Elsewhere, Colorado is pushing a "roadmap" to 100% renewable energy in the state by 2040 and Nevada passed legislation last year requiring the state's utilities to meet a 50% renewable energy standard by 2030. New Mexico last year enacted a law that requires utilities to get 50% of their power from renewables by 2030 and 80% by 2040.

[22] U.S. Energy Information Administration (EIA). Electric Power Monthly.
[23] State of California. Renewables Portfolio Standards Program. Stats. 2018, Ch. 312, Sec. 2. (SB 100) (effective January 1, 2019); Cal. Pub. Util. Code § 399.11.

As the amount of installed renewable generation has climbed, the prices of buying power from solar and wind resources have fallen.

Data from Lawrence Berkeley National Laboratory (LBNL) shows that the prices of solar power purchase agreements (PPAs) have fallen dramatically in all regions of the country, declining by more than 80%.[24] Current PPA prices are now commonly below $50/MWh and often significantly less than that. In a review of 38 PPAs signed since 2017, LBNL found that 27 were priced below $40/MWh, with 21 less than $30/MWh and 4 under $20/MWh (all levelized, in 2018 dollars).[25] Significantly, the LBNL survey also found that 23 of these PPAs included battery storage of 4-5 hours and that these projects were not much more expensive than the PPAs from the solar-only projects.[26] And solar PPA prices are expected to continue to decline over time.

For example, in June 2018—in a sign of things to come—NV Energy signed a PPA for power from a solar project with a price of $23.76/MWh, a price that, at the time, was believed to have possibly set a record low.[27] NV Energy subsequently signed a PPA for power from a project that includes 300MW of solar and 135MW of 4-hour storage with a price that averages about $35/MWh.[28]

The same trend of declining PPA prices is evident in the wind industry. Prices for the best wind resources in the Interior region were roughly $60/MWh in 2009-2010; today, PPAs in those same areas are often in the $15-$20/MWh range. Wind prices in the rest of the country have fallen sharply as well, dropping from an average of around $90/MWh in 2010 to less than $30/MWh today.[29]

Utilities in states across the region also are planning to add substantial amounts of new wind and solar resources, as are independent power producers. Many of these resources will compete with PacifiCorp's Wyoming coal plants and displace generation that these plants would otherwise produce, pushing their capacity factors ever lower.

Increasing Integration of the Western Market

As more and more renewable capacity comes online in the West, a major push is under way to better integrate the regional electricity market. This integration is being driven particularly by the Energy Imbalance Market (EIM) created by the California system operator in 2014 as "a real-time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when

[24] Lawrence Berkeley National Laboratory (LBNL). Utility-Scale Solar 2019 Edition. December 2019. Prices cited here are levelized in 2018 U.S. dollars and include any contract escalation clauses.
[25]Ibid.
[26] Ibid.
[27] Utility Dive. NV Energy 2.3 cent solar contract could set new price record. June 13, 2018.
[28] Greentech Media. NV Energy Announces 'Hulkingly Big' Solar Plus Storage Procurement. June 25, 2019.
[29] U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy. 2018 Wind Technologies Market Report. August 8, 2019.

needed."[30] One of its goals is to find and deliver the lowest cost energy to consumers.[31] Another goal—by optimizing resources from a larger and more diverse pool—is to be able to better facilitate the integration of renewable energy that otherwise may be curtailed at certain times of day.

The EIM currently has nine members, including PacifiCorp, the California Independent System Operator (CAISO), and APS and NV Energy in the Southwest, but it is growing. Salt River Project, Public Service Company of New Mexico (PNM) and Tucson Electric Power are scheduled to join by 2022, meaning that participants representing 77 percent of the Western Electricity Coordinating Council's total load will be EIM members.

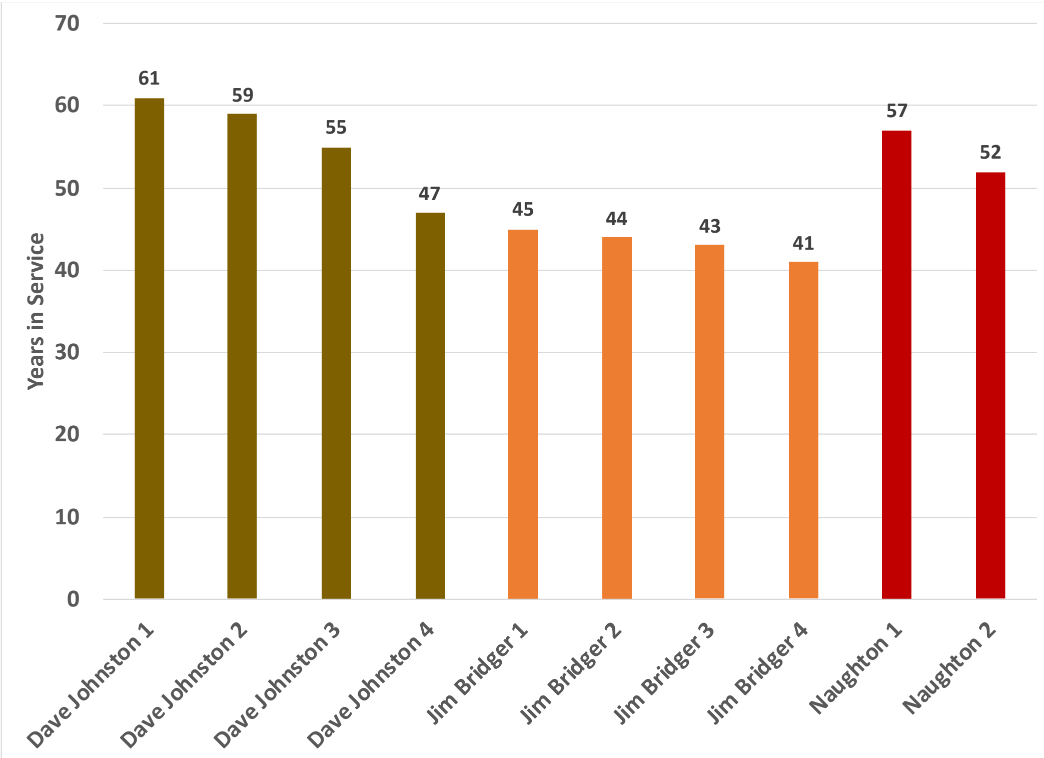
The growth of the EIM amplifies the risk to PacifiCorp's Wyoming coal plants from low-cost renewable resources in California and the rest of the West, as it will mean increased exposure to renewable energy prices that could well be lower than their marginal costs. In turn, as buyers have more opportunity to buy lower cost renewable energy, they are likely to buy less coal-fired generation from PacifiCorp, another factor that will drive the capacity factors of its Wyoming coal plants down.

The Impact of Plant Aging

The ages of the units at Dave Johnston and Jim Bridger range between 41 (Jim Bridger Unit 4) to 61 (Dave Johnston Unit 1).

[30] CAISO Western Energy Imbalance Market.
[31] CAISO Press Release. Western EIM Benefits top $861 million since launching five years ago.

Figure 7: The Current Ages of the Units at the Dave Johnston and Jim Bridger Coal Plants



Source: S&P Global Market Intelligence

By 2026, which is the earliest we anticipate that a carbon capture retrofit would be completed, the age range for the units at Dave Johnston and Jim Bridger would be between 47 and 67. By 2037, the end of the current 12-year period when a retrofit would be eligible for 45Q tax credits, under current legislation, the units would range between 58 and 78 years old.

This is important because older plants, on average, tend to cost more to operate and maintain and are less reliable, according to analyses by the U.S. Department of Energy's Argonne National Laboratory and the National Energy Technology Laboratory, which have found that coal plant heat rates increase with plant age, while plant availability declines.[32] Heat rate is a measure of a power plant's efficiency in generating electricity; a higher heat rate means that a plant is less efficient. And, in general, power plants tend to become less efficient as they age. Plant availability measures the percentage of operating hours in which a plant was actually available to generate power, and plants tend to become less available to generate power as they age, in part because they tend to have more unanticipated problems and unplanned outages.

[32] See, e.g., DOE, Staff Report to the Secretary on Electricity Markets and Reliability. August 2017, page 155.

In other words, even if Glenrock, or PacifiCorp somehow managed to improve the operating performance of the units at Naughton, Dave Johnston and/or Jim Bridger over what they have been in recent years—an extremely unlikely possibility—it will be harder and harder, and increasingly more expensive, to maintain that higher level of performance.

Glenrock claims that its retrofit of one or more of the units at Dave Johnston or Jim Bridger would have a service life of approximately 40 years.[33] This is simply preposterous as it would suggest an overall 86 to 106-year operating life for whichever unit at Dave Johnston or Jim Bridger was retrofitted for carbon capture. The age of the oldest coal-fired unit of more than 100MW operating at this time is 67 years old, and none of the units that are over 65 years old are 200MW or larger.

Given this, and the current market forces that the Dave Johnston and Jim Bridger plants are facing, there is no credible reason to expect that any of their units would have a post retrofit operating life of 40 years.

90% Carbon Capture Has Not Been Proven Over an Extended Number of Years

Proponents of carbon capture, including Glenrock Energy, claim, without any supporting operational evidence, that the technology has been "proven" and that proposed projects will be able to capture 90% of a plant's CO_2 emissions day in and day out over a 12-year period—a prediction that bears no relationship to the performance to date at Petra Nova and Boundary Dam, the only two coal-fired carbon capture power plants in the world.

Petra Nova captures CO_2 from a 240MW equivalent slipstream from the flue gas emitted by the 654MW coal-fired W.A. Parish Unit 8 power plant and Boundary Dam 3 captures the CO_2 from a 110MW plant. Glenrock's proposed retrofit of Dave Johnston Unit 4 would be 330MW, or 38% larger than Petra Nova, while a retrofit of any of the four years at the Jim Bridger plant would be more than twice the size of Petra Nova and almost five times the size of Boundary Dam 3. As the industry has learned through painful experience, serious and expensive problems can occur when scaling up new technologies.

Petra Nova

Petra Nova was originally designed to capture "at least" 90% of the CO_2 from the flue gas in a 240MW slipstream from Parish Unit 8. Put another way, Petra Nova was expected to capture 1.4 million metric tons (1.54 million short U.S. tons), or about 33% of the total emissions from Unit 8, each year.[34]

---

[33] Glenrock Energy IRP Testimony.
[34] DOE Office of Scientific and Technical Information (OSTI). W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Final Public Design Report. February 17, 2017.; EIA, Today in Energy. Petra Nova is one of two carbon capture and sequestration power plants in the world.

The plant's co-owners, NRG Energy and JX Nippon, have not publicly released any detailed information regarding Petra Nova's CO_2 capture performance. However, representatives from the companies and from the U.S. DOE (which supplied $190 million of the $1 billion cost of the project) have made various public presentations in which they made claims about how much CO_2 is captured. For example, the owners have claimed that Petra Nova captured:

- 907,185 metric tons of CO_2 between the start of operations in January 2017 and October 2017;[35]
- 2.18 million metric tons by December 2018; and
- 3.54 million metric tons by December 2019.[36]

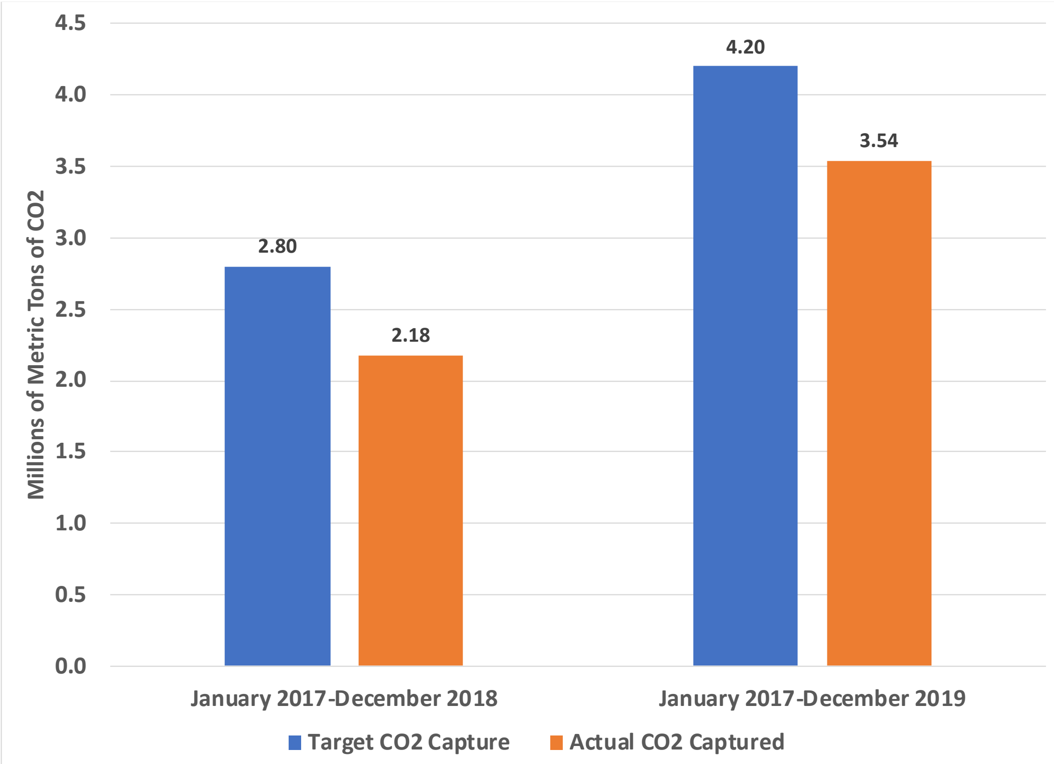
As shown in the figure below, these amounts of captured CO_2 are significantly below what the owners originally projected for the carbon capture facility when it went into service.

October 31, 2017; DOE Office of Fossil Energy, National Energy Technology Laboratory. W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project Summary. September 2012.

[35] DOE Office of Fossil Energy. DOE-Supported Petra Nova Captures More Than 1 Million Tons of CO_2. October 23, 2017

[36] NRG Energy. Testimony of Greg Kennedy, before the U.S. House of Representatives Committee on Science, Space, and Technology, November 22, 2019; and DOE Office of Fossil Energy. Happy Third Operating Anniversary, Petra Nova. January 10, 2020.

Figure 8: Actual vs. Target Amounts of CO_2 Captured at Petra Nova



Sources: NRG, Inc., U.S. Department of Energy

Petra Nova captured 662,000 fewer metric tons of CO_2 during its first three years of operation than projected despite the fact that Parish Unit 8 actually generated more power and, almost certainly, produced more CO_2, than it had in previous years.[37]

Neither of Petra Nova's owners, nor any of the partners in proposed carbon capture retrofit projects, have provided data showing that Petra Nova actually has achieved 90% capture. Instead, carbon capture proponents, merely repeat what the owners of Petra Nova have claimed without providing any supporting evidence.[38]

Consequently, no one outside of Petra Nova's owners knows (a) how much CO_2 the plant actually is capturing, (b) how much of the time Petra Nova is not processing (i.e., capturing) CO_2 due to market conditions, (c) how many equipment problems, outages and deratings have been experienced at Petra Nova and (d) what it actually costs to capture CO_2 at the plant.

---

[37] Parish Unit 8's annual capacity factor rose from 68% in the two years prior to the start of operations at Petra Nova to 72% in the three years since Petra Nova began capturing CO_2.
[38] For example, the Los Alamos National Laboratory's *Preliminary Assessment of Post-combustion Capture of Carbon Dioxide at the San Juan Generating Station* simply observed at pages 9, 10, and 11, that Petra Nova has stated publicly that the facility achieves 90% capture of the processed fuel gas without seeing any actual operational data supporting this claim.

We acknowledge that determining what Petra Nova's actual CO_2 capture rate is difficult, again because of lack of data from the plant's owners. However, we believe a reasonable estimate can be derived from using the continuous emissions monitoring (CEM) data for both W.A. Parish Unit 8 and the dedicated gas-fired combustion turbine built to power the carbon capture equipment. Among other things, the CEM data tracks hourly gross generation and CO_2 emissions; it is publicly available through the EPA's Air Markets Program database.[39]

Using this information, it is possible to estimate Petra Nova's CO_2 capture rate by comparing Unit 8's CO_2 intensity in those hours during which the combustion turbine was generating electricity, beginning with the start of operations of the carbon capture facility in January 2017, with Unit 8's CO_2 intensity in the years prior to 2017.[40]

That analysis shows that Petra Nova achieved an average capture rate of slightly less than 83% between January 1, 2017 and December 30, 2019 during times when the carbon capture equipment was in operation.

However, it is important to remember that the power to operate Petra Nova's carbon capture equipment is provided by a dedicated combustion turbine. When the CO_2 emissions from this combustion turbine are included, Petra Nova's net CO_2 capture rate drops to about 70%.

Failure to capture 90% of the CO_2 emissions at any of PacifiCorp's coal units in Wyoming would have a devastating impact on the already questionable economics of retrofitting the unit(s) with carbon capture.

Boundary Dam 3

The carbon capture system at the 110MW Boundary Dam Unit 3 in Saskatchewan, Canada, began operating in October 2014. It was designed to capture 1 million metric tons a year, a 90% capture rate, but data from the utility shows it has consistently captured far less CO_2 than projected (see figure 9).

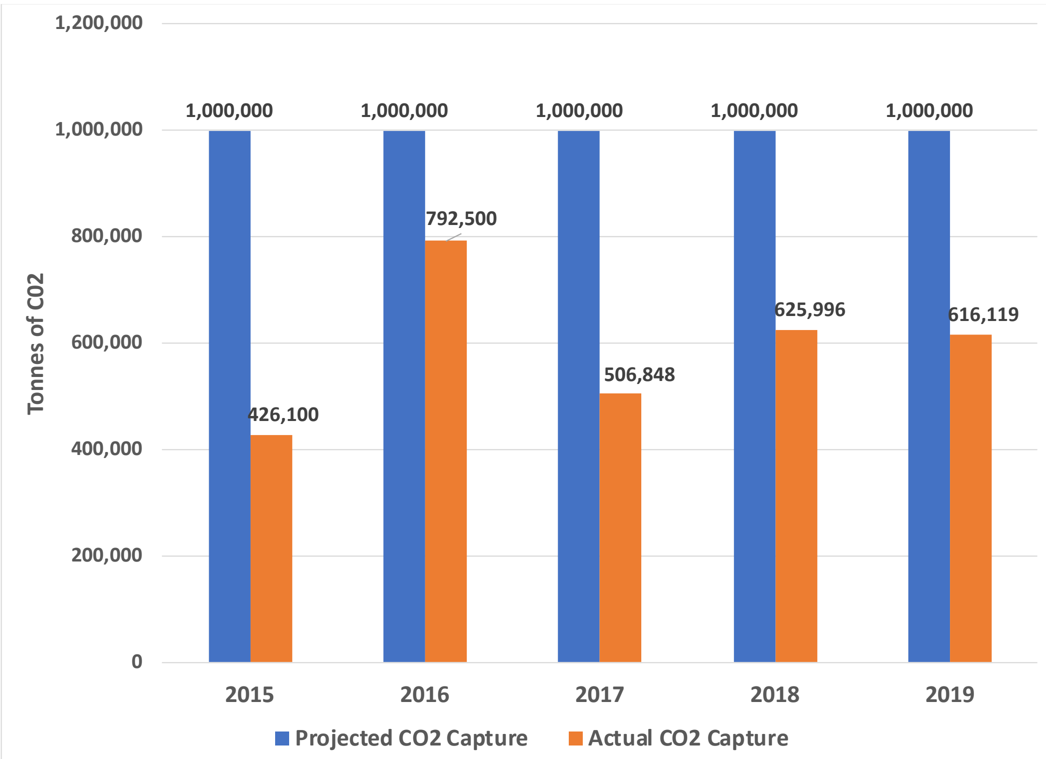
The plant's carbon capture system only operated at its design capacity of 3,200 metric tons per day on three days through early 2018.[41] Consequently, while backers originally projected the facility would capture 3 million metric tons of CO_2

---

[39] U.S. Environmental Protection Agency Air Markets Program Data.
[40] It is possible that the combustion turbine was used to generate power (and not run the CO_2 capture equipment) during some hours of operation. However, the CEM data shows that Unit 8 was operating almost every hour from January 1, 2017-September 30, 2019 during which the turbine was operating and that there were only a few hours when the turbine was running and Unit 8 was not. As such, it is reasonable to use those hours when the combustion turbine was in operation as a proxy for when the carbon capture equipment was operating.
[41] *Boundary Dam 3: Upgrades, updates and performance optimization of the world's first fully integrated CCS plant on coal,* presented by Corwin Bruce from the International CCS Knowledge Centre at the 2019 Clean Coal Technologies Conference on June 5, 2019. The International CCS Knowledge Centre is 50% owned by SaskPower, the owner of Boundary Dam Unit 3.

by November 2017, the plant did not hit that marker until November 4, 2019, two years later than projected.

Figure 9: Boundary Dam Unit 3 Target vs. Actual CO_2 Capture



Sources: SaskPower BD3 Status Updates[42]

The results from Petra Nova and Boundary Dam 3 belie the claims of carbon capture proponents about the future performance of retrofitted coal plants

The amount of CO_2 captured is critical to any coal plant retrofit project's financial feasibility because it affects both the tax credits for which the project would be eligible and the revenue that would be generated from selling the captured CO_2.

Capturing less CO_2 would mean that the retrofit project would generate less revenue from the sale of the CO_2 for enhanced oil recovery (EOR). Similarly, capturing less CO_2 would mean that the project would be eligible for far fewer 45Q tax credits. This, in turn, would mean that additional funds would have to be paid by PacifiCorp, and ultimately its Wyoming ratepayers, to fund the retrofitting. This would raise both the total capital cost of the retrofit and the cost per metric ton of capturing CO_2.

[42] SaskPower. BD3 Status Update: December 2019. January 9, 2020. Previous updates containing information on CO_2 captured in prior years are available at SaskPower's blog.

The Retrofitting of Any of its Wyoming Coal Units for Carbon Capture Will Require Major Rate Base Investments by PacifiCorp

As explained by David Posner in recent testimony to the New Mexico Public Regulation Commission, tax equity financing:

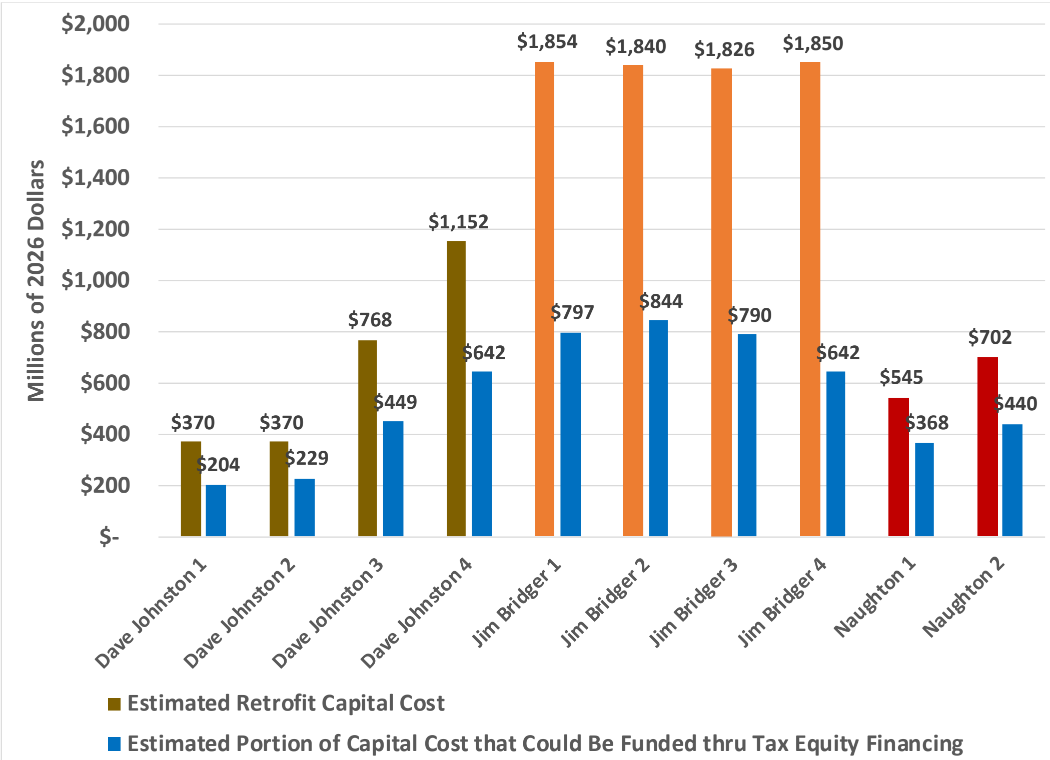
> *Is a transaction in which one party assigns future tax benefits expected to be generated by an eligible physical investment to another party… the assigning party receives funds in exchange for future tax benefits, in effect selling them in exchange for capital that can be used to build the asset.*[43]

Under the current 45Q program, a coal plant owner would receive $35 for each metric ton of CO_2 that it uses for EOR and $50 for each metric ton of CO_2 that is permanently sequestered underground. An owner is eligible for these credits for the first twelve years that the retrofitted unit captures CO_2.

Unfortunately, because of the projected high capital cost of retrofitting any of the units at PacifiCorp's Dave Johnston, Jim Bridger and Naughton coal plants (as shown in Figure 2) and amounts of CO_2 that a retrofitted unit at any of these plants could be expected to capture, the tax credits that PacifiCorp (or Glenrock if it is the whole or part owner of the retrofitted unit) could be expected to receive would fall well short of funding the entire project. This can be seen in Figure 10.

[43] See the Prepared Rebuttal Testimony of David B. Posner in New Mexico Public Regulation Commission Case No. 19-00018-UT.

Figure 10: Expected Value of 45Q Tax Credits vs. Projected Cost of Retrofitting Units at Dave Johnston, Jim Bridger and Naughton



Source: IEEFA analysis

For each unit, the tax credits fall well short of funding the capital cost of the proposed retrofit, meaning that PacifiCorp, or possibly some other entity, would have to come up with the additional money needed to complete and run the project.

The analysis shown in Figure 10 is premised on a set of what we believe are conservative assumptions:

1. The capital cost of any retrofit would be 30% lower than the actual capital cost of the Petra Nova project, as shown in Figure 1 above.

2. Each retrofitted unit would operate at the same capacity factor as it has achieved, on average, in the most recent five calendar years, and would emit the same tonnes of CO_2 each year that it has emitted in this same five-year period as shown in Figure 4. In other words, the operating performance of each unit would not decline in coming years.

3. Each retrofitted unit actually would be able to capture 90% of the CO_2 it produces each year.

4. PacifiCorp (and Glenrock if it is an owner) would receive $50 for each metric ton of CO_2 captured at the retrofitted unit. This would reflect that the

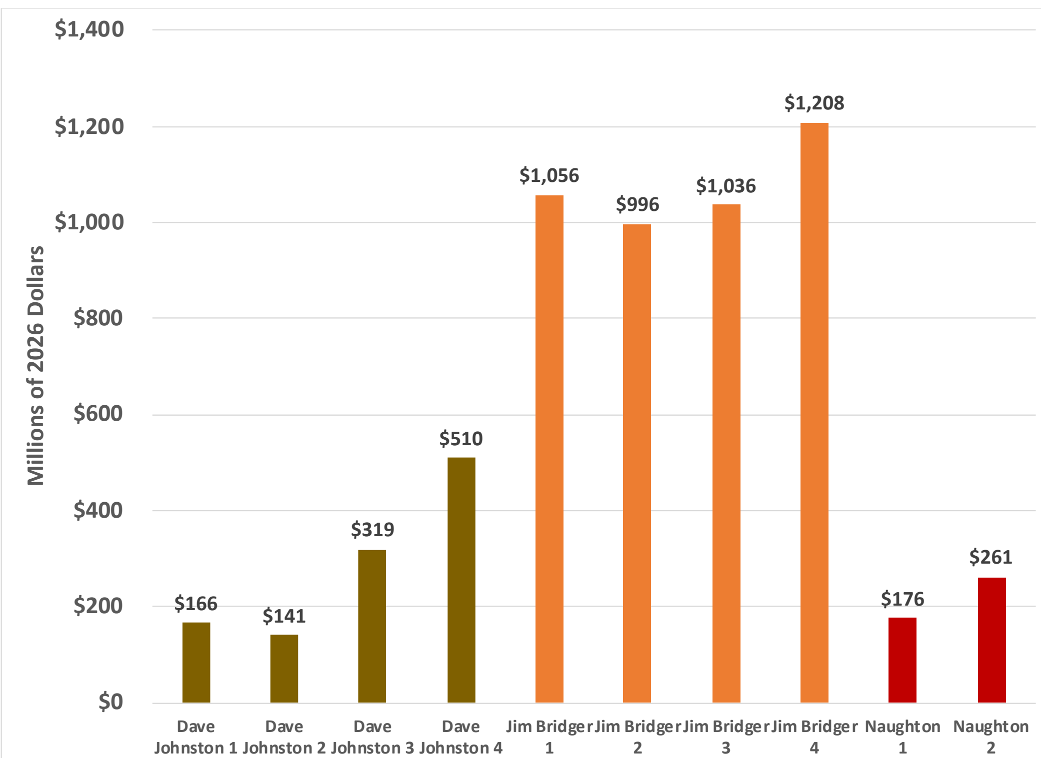
captured CO_2 is permanently sequestered or that the unit owner receives an average of $15 for each metric ton of CO_2 used for EOR.

5. The unit would operate for the entire twelve-year period after it has been retrofitted.

Obviously, there would be an even larger shortfall than shown in Figure 10 if (a) the capital cost of the retrofit is higher than we have assumed; (b) the retrofitted unit's operating performance declines; (c) the retrofitted unit is unable to capture 90% of the CO_2 in any year; (d) it is not financially viable to use the captured CO_2 for EOR or not at a price of $15 per metric ton; or (e) the unit is retired before the end of twelve years.

The gap between the capital cost of a unit's carbon capture retrofit and the tax equity financing that could be raised is likely to be quite significant, as shown in Figure 11.

Figure 11: Estimated Capital that PacifiCorp Would Have to Invest in Each Carbon Capture Retrofit



Source: IEEFA analysis

Section 5.8 of the PacifiCorp Inter-Jurisdictional Allocation Protocol declares that the "Costs and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative." Given that retrofitting for carbon capture would be a state-specific initiative undertaken pursuant to HB200, Rocky Mountain Power's Wyoming ratepayers will almost certainly have to pay for all of the company's investments in any carbon capture retrofit projects at its Wyoming coal plants.

According to PacifiCorp's March 2020 filing, Rocky Mountain Power's Wyoming net rate base for the twelve months ending December 2021 is projected to be $2.349 billion. The retrofitting of even a couple of the company's coal units could easily double the size of its net Wyoming rate base, on their own, without any other non-coal-related investments, creating substantially higher rates for PacifiCorp's Wyoming ratepayers.

Assuming for illustration, that Rocky Mountain Power were to spend $1 billion retrofitting one or several of its aging Wyoming coal units, depending on the requested rate of return, a retrofit could raise rates by more than $80 million a year. And on top of that, HB200 would allow Rocky Mountain Power to see rate recovery for the cost of a carbon capture retrofit that would include a higher return on equity.[44]

Moreover, HB200 actually would allow Rocky Mountain Power to start collecting a 2% surcharge through a rate recovery mechanism to pay for a retrofit of any of its Wyoming coal units before it starts spending money on the project.[45] The company may retain the funds collected through this surcharge to offset future costs. Then, if the amounts collected through this 2% surcharge are inadequate, the Commission is mandated to take "such other actions as necessary…to ensure the public utility is able to recover its prudently incurred incremental costs…"[46]

Finally, as if these bailouts are not enough to entice Rocky Mountain Power to consider retrofitting its aging Wyoming coal units, HB200 would permit the company to retain for its shareholders a portion of the revenues from the sale of the CO_2 captured from a retrofitted unit.

Moreover, the company would, we would expect, be allowed to recover in rates its investments in carbon capture retrofits as part of its depreciation expenses, and can be expected to seek a relatively short depreciable life given the age of units that would be retrofitted.

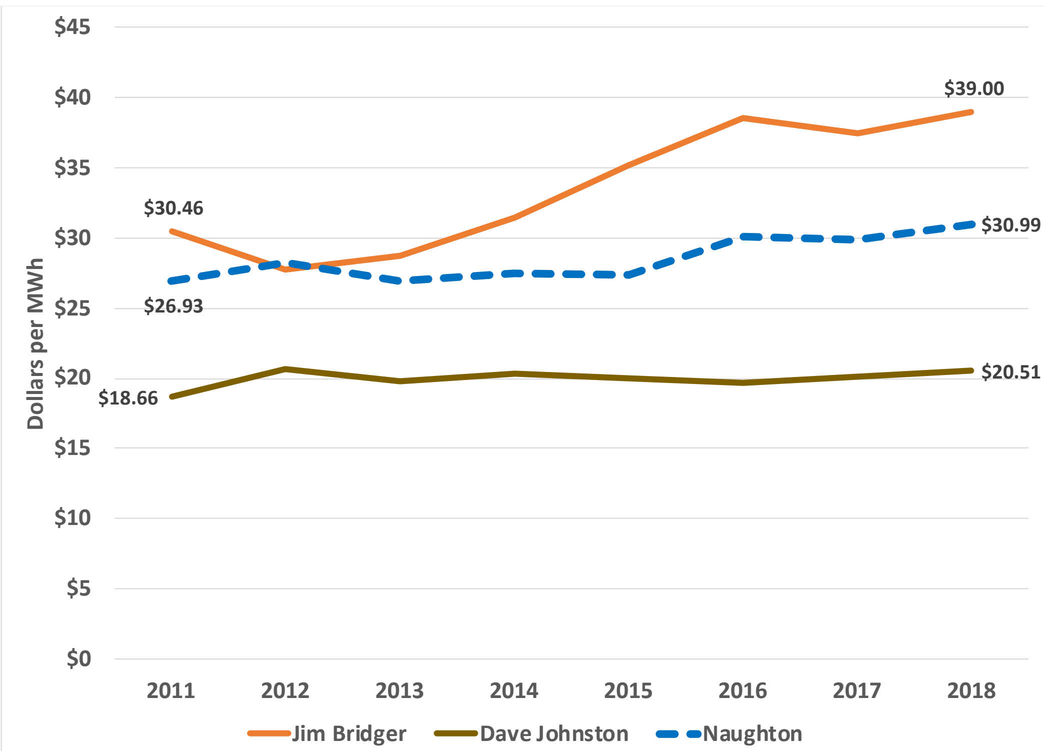
Given the cost of retrofitting any of the units at Dave Johnston, Jim Bridger, and Naughton, and the high likelihood that the full cost of any retrofit will not be obtained through tax equity financing, these provisions of HB200 are likely to lead to a rate disaster for Rocky Mountain Power's Wyoming industrial, commercial and residential customers.

[44] Wyoming HB 200 Statute Section 37018-101(c)(i).
[45] Ibid. 37018-101(c)(iii).
[46] Ibid. 37018-101(c)(ii).

The Cost of Generating Power at Dave Johnston, Jim Bridger and Naughton Would Increase Significantly After Being Retrofitted for Carbon Capture

Glenrock Energy claims that Wyoming's coal-fired power plants are "low-cost generation facilities," with operating costs as low as $0.02 per kilowatt hour ($20 per MWh).[47] Although this may be accurate for the Dave Johnston plant, it clearly is not true for Jim Bridger or Naughton, which have had significantly higher O&M costs in recent years.

Figure 12: Actual Costs of Operating & Maintaining PacifiCorp's Wyoming Coal Plants, 2011-2018



Sources: PacifiCorp Annual FERC Form 1 Filings, S&P Global Market Intelligence

Importantly, the O&M costs in Figure 12 significantly understate the all-in cost of operating and maintaining PacifiCorp's Wyoming coal plants because they do not reflect the capitalized expenditures on maintenance or environmental upgrades.

Moreover, the costs of operating and maintaining any of the units at any of these plants would be significantly higher after they were retrofitted for carbon capture.

[47] Glenrock Energy IRP Testimony, at page 3.

First, there would be additional costs after retrofitting that would be specifically related to the carbon capture process – additional operating, maintenance and administrative staff would be needed; more water would have to be acquired; there would be higher water treatment costs, steam costs, and chemical and disposal costs for the carbon capture facility. These costs would be passed along to ratepayers.

In addition, it is reasonable to expect that capitalized maintenance expenditures will be required during the extended operating lives of the retrofitted coal units, for both the plant's carbon capture-related and its non-carbon capture-related equipment. Such capitalized expenditures most likely would be added to the company's rate base. And ratepayers would have to pay again.

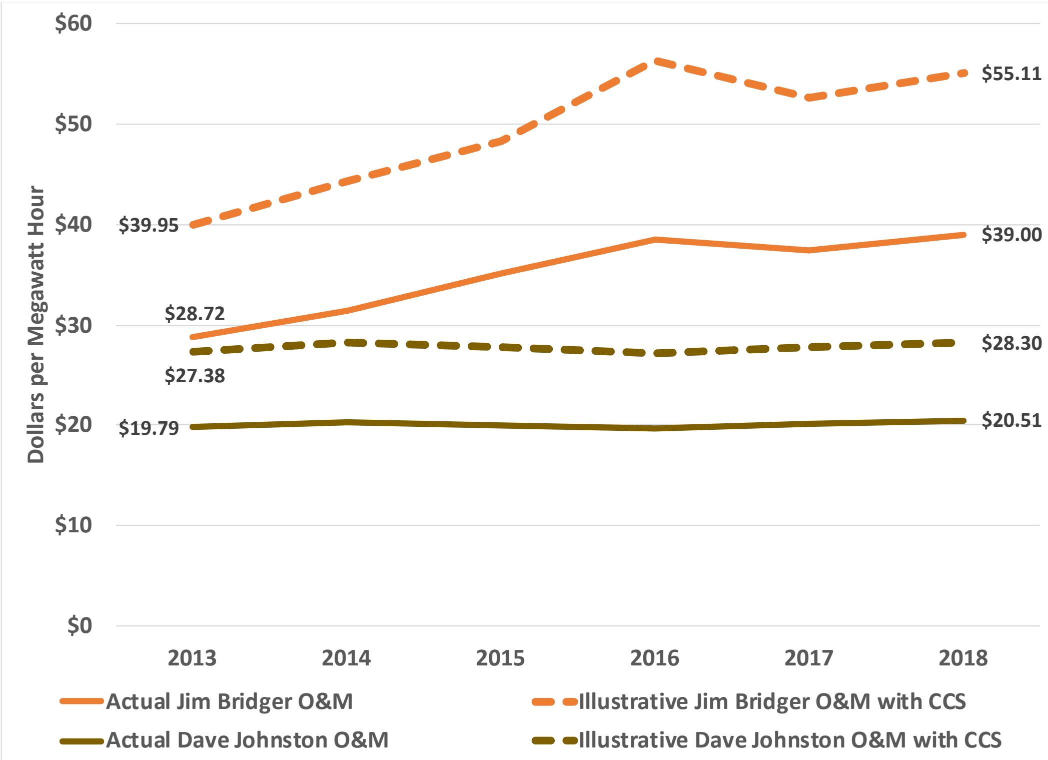
Unfortunately, there is no public information on what it actually costs to capture CO_2 at Petra Nova. However, it can be expected that these costs would certainly fall in the range of millions to tens of millions of dollars, depending on the size of the coal unit retrofitted.

Second, all fossil-fired power plants consume a portion of the power they generate to run necessary on-site equipment. For Dave Johnston and Jim Bridger these "parasitic loads" use between 7% and 10% of the plant's gross generation. The parasitic loads for a retrofitted coal-fired unit are projected to be much higher, somewhere in the range of 30% to 34% of the unit's gross generation.

What this means is that the net generation of a coal-fired unit will be substantially lower after being retrofitted for carbon capture because much more of its gross generation will be consumed onsite, running the carbon capture-related requirement. Indeed, by using a substantial amount of the plant's power, the CO_2 capture equipment at a retrofitted unit will result in its non-carbon capture-related fixed and O&M costs being spread across a smaller number of saleable kilowatt-hours, thus raising the unit's average O&M costs across the board. This means that ratepayers will have to pay more for each MWh of electricity they receive from the retrofitted plant because the same total O&M costs (in dollars) will be spread over fewer net MWhs of output.

Figure 13 provides an illustrative example of the impact that the much higher parasitic loads would have had on the average cost of power received by PacifiCorp's ratepayers by comparing the plant's actual O&M costs in the years 2013 to 2018 with what those costs would have been if the units had 34% parasitic loads as a result of having been retrofitted for carbon capture. Note that this figure only reflects the impact of the higher parasitic loads and does not reflect the additional carbon capture-related costs identified above.

Figure 13: Illustrative Cost Impact of Retrofitting Dave Johnston and Jim Bridger with Carbon Capture on Plant O&M Costs



Source: IEEFA analysis

Thus, the annual per MWh O&M costs at Jim Bridger and Dave Johnston would have been 38% to 41% higher during the years 2013-2018 if either plant had had the higher parasitic loads resulting from being retrofitted for carbon capture.

In addition, because the net generation from the retrofitted unit(s) would be lower due to their having been retrofitted for carbon capture, PacifiCorp would have to obtain replacement power for the missing MWhs (that is, the difference from their net generation without carbon capture and their net generation with carbon capture) either by producing additional generation at its own non-retrofitted units or by purchasing power from other companies.

As noted earlier, Section 5.8 of the PacifiCorp Inter-Jurisdictional Allocation Protocol declares that the "Costs and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative. Given that retrofitting for carbon capture would be a State-specific initiative pursuant to HB200, PacifiCorp's Wyoming ratepayers will almost certainly have to pay for all of these additional post-retrofitting O&M costs in addition to the returns on rate base and the 2% surcharge discussed in the previous section.

There Are Significant Market Risks Associated with the Use of Captured CO_2 for Enhanced Oil Recovery

The speculative economics associated with carbon capture projects at coal-fired power plants all depend on one key element—the ability to either sell the captured CO_2 to oil companies interested in using the gas for enhanced oil recovery projects or to permanently sequester the captured CO_2 underground. The recent crash, which pushed the price of West Texas Intermediate from $53.88 per barrel on Feb. 20 to just $20.31/barrel on April 1, highlights the enormous market risks associated with such a business strategy.

The price collapse can be traced both to the ongoing fight between Saudi Arabia and Russia for oil market share and to the spreading coronavirus, which is pushing global oil demand down significantly. Both are having far-reaching impacts across the U.S. oil sector, forcing substantial cuts in capital spending by producers across the country and pushing smaller companies to the brink of bankruptcy.

In this environment, committing new capital to invest in technologically risky and economically challenged CO_2-based EOR projects would be the height of corporate irresponsibility.

But that is exactly what underlies HB200 and Glenrock Energy's proposed plan to retrofit one of the aging units at the Dave Johnston coal plant with carbon capture and use the captured CO_2 for EOR activities at the nearby Big Muddy field.

Simply stated, the economics associated with EOR activities do not support the Glenrock proposal.

Vello Kuuskraa, an EOR expert who heads up Advanced Resources International, was quoted last year as saying it costs between $55-$60 per barrel to produce oil from conventional U.S. oil fields using EOR.[48] Others estimate that the breakeven point could be even higher for fields with no existing EOR operations, such as Big Muddy.

In contrast, Glenrock's president, Thomas Manning, now says he only needs to realize $39/barrel to make the project economic after saying just a year ago that the breakeven oil price for a retrofit project was $55/$60 per barrel.[49]

That is likely little more than developer optimism, however. A just-released survey by the Kansas City Federal Reserve shows that producers in its region (which includes Wyoming) need prices to be at least $47 per barrel to remain profitable. It is important to note that this survey focuses on conventional producers; adding the capital expenses required for a new EOR project almost certainly would push Glenrock's breakeven costs much closer to the $60 per barrel level than Manning's $39 estimate.

---

[48] E&E News. Big Oil looks to CCS, but will it really help the climate? June 19, 2019
[49] PacifiCorp may have buyer for its Dave Johnston plant, Argus Media, 25 March 2019.

Here it is important to note that NRG assumed oil prices would be at or above $75 per barrel when it planned and built the Petra Nova carbon capture facility in Texas, which at 240 megawatts is the largest existing CO_2 capture facility at a coal-fired power plant in the world. Those estimates proved wildly optimistic, and NRG executives said on numerous occasions well before the current price crash and market uncertainty that they would not be building any additional carbon capture projects because the economics simply didn't pencil out.

As NRG discovered, the risks associated with carbon capture are significant, even for large, well-capitalized companies. Since the project came online at the tail end of 2016 the company has written down $209 million of the $300 million in invested in the project, clearly not a sign of economic success.

The headwinds facing a project in the current economic situation would be significantly stronger. When prices will return even to Manning's low-ball breakeven estimate is highly speculative, how long they will remain at or above that level is even more uncertain. Using a more realistic assessment of breakeven costs, such as NRG's $75 per barrel estimate, only heightens the potential risks.

Beyond the current market upheaval, there is significant uncertainty about the long-term growth potential of the EOR market in general. For example, a November 2018 IEA report noted that there had been an 18 percent decline in oil production from North American EOR between 2014 and 2018.[50] The report pointed to several obstacles that have hindered EOR, pointing in particular to its cost disadvantage versus fracking. The current price crash only accentuates EOR's inability to compete with lower-cost producers.

Another factor that must considered in connection with Glenrock's plan to retrofit a unit at the Dave Johnston plant is the poor financial shape of the current leaders in the EOR sector.

The country's largest EOR operator is Occidental Petroleum, which has extensive operations in the Permian Basin in West Texas. Its stock—like that of oil companies across the board—is under siege, having dropped from $42.97 a share on Feb. 20 to roughly $15 as of April 10. The economic turmoil also prompted the company to slash its dividend to $0.11 a share from $0.79 a share—the first time it has reduced its dividend in 30 years. It also has significantly reduced its capital spending plans for 2020. Despite these moves, the company's debt rating was downgraded to junk bond status by Moody's in March.

Another leading EOR company, Denbury Resources, is facing equally difficult economic problems. The company, which has projects in both the Gulf Coast and Rocky Mountain regions, hired Evercore Inc., an investment bank, in early April to help it figure out how to deal with its $2.3 billion in corporate debt. More than a quarter of that total, $615 million is due in May 2021; according to data from

[50] IEA. Whatever happened to enhanced oil recovery? November 28, 2018

Refinitiv Eikon; that debt is now trading at 18 cents to the dollar, a clear indication that investors doubt Denbury will be able to repay.[51]

To expect Glenrock, a small company with no apparent EOR experience, to be able to escape these sector-wide problems is to rely on wishful thinking instead of sound corporate planning—a sure recipe for financial disaster.

The risks associated with developing carbon capture projects are extensive even during the best of times. These are not the best of times, and the risks are significantly greater now that Glenrock's project will not succeed.

[51] Reuters. U.S. energy firm Denbury Resources hires bank for debt advice -sources. April 8, 2020

About IEEFA

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

About the Authors

David Schlissel

David Schlissel, Director of Resource Planning Analysis for IEEFA, has been a regulatory attorney and consultant on electric utility rate and resource planning issues since 1974. He has testified as an expert witness before regulatory commissions in more than 35 states and before the U.S. Federal Energy Regulatory Commission and Nuclear Regulatory Commission. He also has testified in state and federal court proceedings concerning electric utilities. His clients have included regulatory commissions in Arkansas, Kansas, Arizona, New Mexico and California. He has also consulted for publicly owned utilities, state governments and attorneys general, state consumer advocates, city governments, and national and local environmental organizations. Schlissel has undergraduate and graduate engineering degrees from the Massachusetts Institute of Technology and Stanford University. He has a Juris Doctor degree from Stanford University School of Law.

Dennis Wamsted

An IEEFA analyst and editor, Dennis Wamsted has covered energy and environmental policy and technology issues for 30 years. He is the former editor of The Energy Daily, a Washington, D.C.-based newsletter, and is a graduate of Harvard University.