**BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING**

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| IN THE MATTER OF THE APPLICATION OF )<br>ROCKY MOUNTAIN POWER TO ESTABLISH )<br>INTERMEDIATE LOW-CARBON ENERGY )<br>PORTFOLIO STANDARDS ) | DOCKET No. 20000-616-EA-22<br>(RECORD No. 17032) |

**POWDER RIVER BASIN RESOURCE COUNCIL'S**
**PRE-FILED DIRECT TESTIMONY**

The Powder River Basin Resource Council ("Resource Council" or "PRBRC"), by and through its undersigned counsel, hereby submits to the Parties and Commission its pre-filed direct intervenor testimony, PRBRC Exhibit 600, prepared by witness David Schlissel. Mr. Schlissel will include a signed affidavit with his direct and forthcoming cross-answer testimony as part of the pre-hearing exhibit filing in this docket.

Respectfully submitted this 24th day of August, 2022.

________________________________

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## CERTIFICATE OF SERVICE

I hereby certify that on this 24th day of August, 2022 I served a true and correct copy of the foregoing PRE-FILED DIRECT TESTIMONY on the following parties via electronic mail and the PSC's electronic filing system:

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## Introduction and Summary

**Q. Please state your name and business address.**

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc. My business address is 45 Horace Road, Belmont, MA 02478.

**Q. On whose behalf are you testifying?**

A. I am testifying on behalf of the Powder River Basin Resource Council.

**Q. Please summarize your educational background and recent work experience.**

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford Law School. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983, I have been retained by governmental bodies, publicly owned utilities, and private organizations in 38 states to prepare expert testimony and analyses on engineering, economic and financial issues related to electric utilities. My clients have included state utility commissions, attorneys general, and consumer advocates, publicly owned utilities, and local, national and international environmental and consumer organizations.

I have filed expert testimony before state regulatory commissions in Arizona, Arkansas, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Vermont, Virginia, West Virginia, and Wisconsin; before the U.S. Federal Energy Regulatory Commission and Atomic Energy Commission; and in state and federal court proceedings.

A copy of my current resume is attached as PRBRC Exhibit 601. Additional information about my work is available at www.schlissel-technical.com and www.ieefa.org.

**Q. Have you previously testified before this Commission?**

A. No. However, my colleague Dennis Wamsted and I have submitted Comments and Reply Comments to the Commission in Docket No. 20000-552-EA-19 addressing Wyoming House Bill 200 and Rocky Mountain Power's 2019 Integrated Resource Plan.

**Q. What is the purpose of your testimony in this proceeding?**

A. I have been asked to evaluate the risks associated with the potential retrofitting of Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 for carbon capture and storage or reuse (CCS or CCUS).

**Q. Please summarize your conclusions.**

A. Despite billions of dollars of federal research funds, only one such carbon capture project has been built at a coal-fired electric power facility in the U.S. – the Petra Nova project in Texas which has been indefinitely mothballed in May 2020 after capturing $CO_2$ for just 40 months. A second, smaller carbon capture unit remains in operation in Canada at Boundary Dam Unit 3 as the only coal plant in the world capturing $CO_2$. Both of these projects, as I will show later, have failed to meet their promised performance goals, undercutting assertions by backers of the CCS retrofits in Wyoming, like Glenrock Energy, that they will be using commercially proven technology.

In fact, there is substantial uncertainty about the future technical and financial viability of retrofitting the Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 to capture $CO_2$. Two especially important questions are how well each unit would operate after being retrofitted for carbon capture (that is, their future capacity factors) and how much $CO_2$ they would capture (that is, their future $CO_2$ capture rates). There also is uncertainty about how much it will cost to retrofit each unit and whether PacifiCorp will seek and obtain any federal funding to add carbon capture. It also is unclear how much it will cost to operate the units and to capture $CO_2$ if they are retrofitted and how long and how well they will operate.

For this reason, PacifiCorp should model a wide range of the key assumptions about the units' post-retrofit operating performance and costs, including future capacity factors and $CO_2$ capture rates, was well as retrofit costs. Importantly, the company should include in its analyses all of the costs of capturing, transporting and sequestering the captured $CO_2$. Finally, the provisions of the new Inflation Reduction Act are likely to have a significant impact on the financial viability of future carbon capture retrofits (in both positive and negative ways) and should be included in any modeling analyses.

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. As such, the Commission should thoroughly scrutinize all CCS proposals and ultimately reject any proposals that create unreasonable cost or risk for Wyoming customers.

Such a thorough scrutiny is vital because the expensive investments in adding carbon capture at one or all three of these units could become stranded assets if the carbon capture doesn't work long enough at the coal units, given their ages, or well enough for those investments to be fully recovered. If that happens, PacifiCorp's Wyoming ratepayers alone will have to continue to pay for those stranded assets no longer providing them any capacity or energy.

PacifiCorp was right, CCS is not a viable option.

**Q. What are your key findings?**

A. My key findings are as follows:

1. It is unlikely that any carbon capture retrofit would be completed before 2028, at the earliest, by which time Dave Johnston Unit 4 would be 56, Jim Bridger Unit 3 would be 52 and Jim Bridger Unit 4 would be 48 years old.

2. Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 cannot be relied upon to operate at average 85% capacity factors after being retrofitted for carbon capture.

3. Achieving such high capacity factors would be inconsistent with the units' actual operating history over the past decade. At the same time, dramatic changes are occurring on the western grid as nearly 65,000 megawatts of new solar, wind and battery storage capacity has been added since 2007 and an additional 390,000 megawatts have been proposed.

4. Capturing 90% or more of the $CO_2$ produced at an operating commercial-scale coal plant for a decade or longer has never been proven. Petra Nova, which was in service for only forty months, achieved a capture rate of just 70% of the $CO_2$. The project only achieved a 67% capacity factor, far lower than the planned 85%.

Boundary Dam Unit 3, the only remaining commercial-scale coal plant in the world, has only captured slightly more than half of the $CO_2$ it has produced during its nearly eight years of operation.

5. PacifiCorp has ignored significant costs in its CCUS modeling.

6. It is not reasonable to assume, as PacifiCorp has, that the design, permitting and construction of carbon capture retrofits can be completed in only four years. In-service dates of 2028, at the earliest, for the retrofits being considered at the Dave Johnston and Jim Bridger plants are more likely.

7. The estimated costs of retrofitting Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 can be increased to increase significantly over time.

8. Retrofitting Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 will mean higher costs for PacifiCorp's Wyoming ratepayers and expose them to the risk that they will have to pay for significant stranded costs if the expensive investments in carbon capture retrofits don't work as long or as well as PacifiCorp assumes.

## Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 Cannot Be Relied Upon to Operate at Average 85% Capacity Factors After Being Retrofitted for Carbon Capture

**Q. In its modeling analyses what annual capacity factors has PacifiCorp assumed that Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 would each achieve after being retrofitted for carbon capture?**

A. PacifiCorp has assumed that after being retrofitted for carbon capture each of these units would achieve 85% average annual capacity factors over a period of 10-12 years or longer.

**Q. Is it reasonable to assume that any of these units would achieve an average 85% capacity factor after being retrofitted for carbon capture?**

A. No. Achieving such a high capacity factor would be inconsistent with the actual operating history of each of these units over the past 11 years. In fact, there are a number of factors which suggest that the units' operating performance can be expected to decline further in coming years. First, Dave Johnston Unit 4 is already 50 years old. Jim Bridger Units 3 and 4 are 42 and 46 years old. It is far more reasonable to expect that their operating performance will decline as they continue to age and their operating costs will increase. At the same time, dramatic changes are occurring on the western grid as large amounts of renewable and battery storage resources are being added and regional markets are becoming increasingly integrated, further decreasing the economic viability and dispatch of aging coal units.

**Q. Has PacifiCorp provided any studies, analyses or other evidence to support its assumption that these units would be able to achieve 85% capacity factors after being retrofitted for carbon capture?**

A. No.[1]

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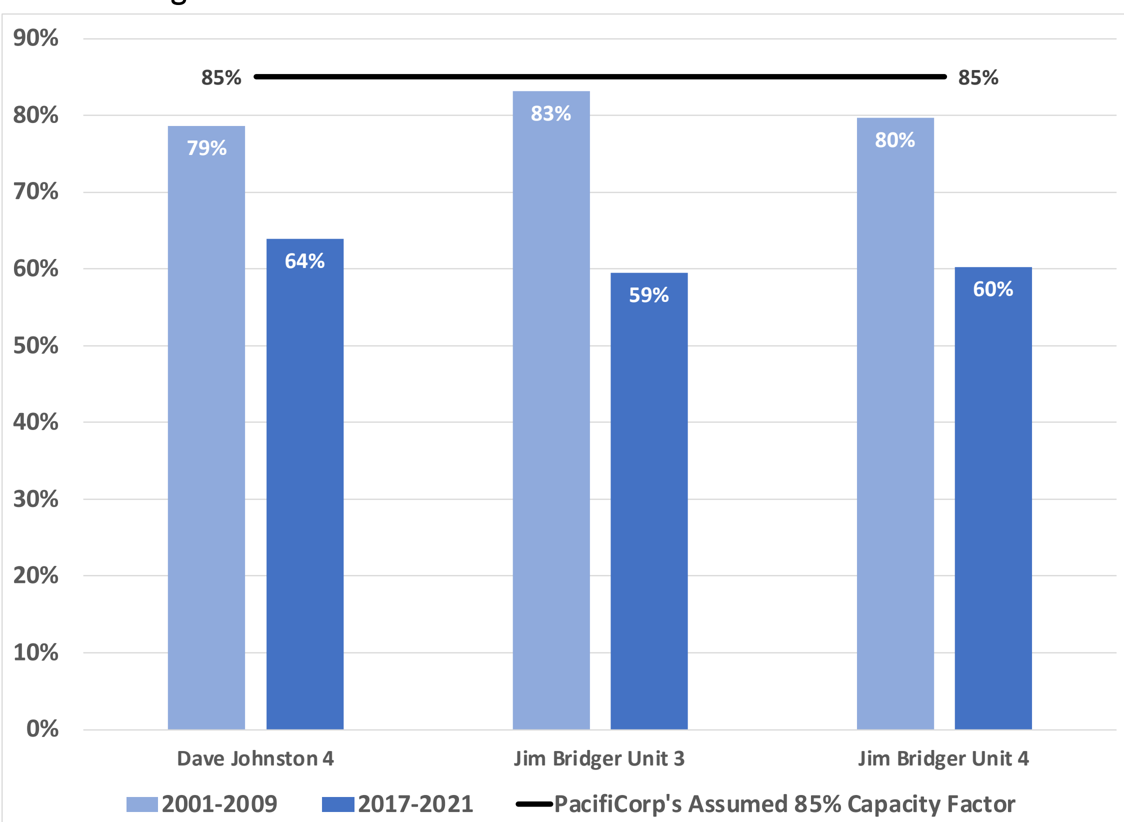
[1] See PacifiCorp's responses to PRBRC Data Requests 1.25, 1.26 and 1.27.

**Q. What has been the operating performance of Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 over the last two decades?**

A. As shown in Figure 1, below, from 2001-2009, Dave Johnston Unit 4 achieved a 79% average capacity factor. Jim Bridger Units 3 and 4 posted average capacity factors during that period of 80% and 83% respectively. These performance figures were recorded when the plants were significantly younger and 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.

Since then, the annual capacity factors of the three units have declined quite significantly, as shown in Figure 1.

Figure 1: Average Annual Capacity Factors of Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 in the Years 2001-2009 and 2017-2021




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

**Q. Are these declines in capacity factors unique to Dave Johnston Unit 4 and Jim Bridger Units 3 and 4?**

A. No. 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 49.3% in 2021. This is an indicator of the growing momentum around change from reliance on fossil fuels to renewable resources across the U.S. electric sector.

**Q. Are these capacity factor declines significant?**

A. Yes, these capacity factors declines are significant for the financial viability of any carbon capture retrofit proposals for the Dave Johnston or Jim Bridger plants for two reasons. First, they mean that the units at these plants are producing substantially less $CO_2$ that could be captured. Second, with lower capacity factors, the average costs of the power from the units are higher as the fixed costs associated with retrofitting and operation of the carbon capture facilities (as well as the fixed balance of plant costs) are spread over fewer MWhs of output.

**Q. How common is it for a coal unit to achieve an 85% or higher capacity factor?**

A. It is not common at all. According to data from EIA Form 923, out of the 405 coal units still operating in the U.S., only four units (1%) had average capacity factors of 85% or higher over the five-year period 2017-2021. Only 15 units (~4%) had average capacity factors of 80% or higher. By way of comparison, 59 units had average capacity factors of 30% or lower. The median coal unit capacity factor over this period was 53.2% and the average was 51%.

**Q. What have been the capacity factors of Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 so far in 2022?**

A. During the first five months of 2022, Dave Johnston Unit 4 posted only a 25.4% capacity factor. Jim Bridger Units 3 and 4 posted 56% and 56.5% capacity factors, respectively.

This is particularly telling given the relatively higher natural gas prices during this time period resulting from factors such as the Russian invasion of Ukraine which would have been expected to lead to increased generation at the coal-fired units.

**Q. What factors have led you to conclude that it is more likely that the operating performance of Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 will continue to decline over the long term rather than jumping up to 85% as PacifiCorp has assumed in the CCUS analyses it presented in its 2021 Integrated Resource Plan?**

A. The age of the units and the dramatic changes that are occurring in the Western grid are combining to push the retirement of fossil-fired generators and accelerate the transition to renewable and battery storage resources.

**Q. What is the significance of plant aging on the operating performance of the Dave Johnston and Jim Bridger units as they get older?**

A. Older fossil-fired 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.[2] 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 possible 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 experience more unanticipated problems and unplanned outages.

[2] *See, e.g.*, U.S. Dep't of Energy Staff Report to the Secretary on Electricity Markets and Reliability at 155 (Aug. 2017), *available at* https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

At the same time, older plants tend to cost more to maintain, as equipment and components degrade or fail and must be repaired or replaced. These factors must be considered by potential plant owners and investors as they decide to participate in retrofit projects at aging coal plants such as Dave Johnston Unit 4 and Jim Bridger Units 3 and 4.

**Q. How old are Dave Johnston Unit 4, Jim Bridger Unit 3, and Jim Bridger Unit 4?**

A. Dave Johnston Unit 4 is already 50 years old. Bridger Unit 3 is 46 years old and Bridger Unit 4 is almost 43 years old.

**Q. How old would these units likely be when they would start capturing $CO_2$ if they are retrofitted?**

A. Given how long it took to build the Petra Nova carbon capture project and the testimony and the Kiewit report submitted by PacifiCorp in this Docket, I think it is reasonable to expect that any carbon capture facilities added at Dave Johnston or Bridger will not be in operation until 2028 or later. At that time Dave Johnston Unit 4 would be 56 years old, Jim Bridger Unit 3 would be 52 and Jim Bridger Unit 4 would be 49.

If these units were then to capture $CO_2$ for twelve years until 2040, they would be 68, 64 and 61 years old, respectively.

**Q. What have been the median and average ages for retired coal units in the U.S.?**

A. The median age at which coal units in the U.S. larger than 100 MW have been retired has been 53 years old. The average retirement age has been 51.

**Q. How many of the coal units still operating in the U.S. are 60 years or older?**

A. Sixty of the remaining coal units in the U.S., 100 megawatts (MW) or larger, are 60 or older. One hundred and forty eight remaining units are 50 or older.

**Q. How many of these units posted 80% or higher average capacity factors over the five-year period 2017-2021?**

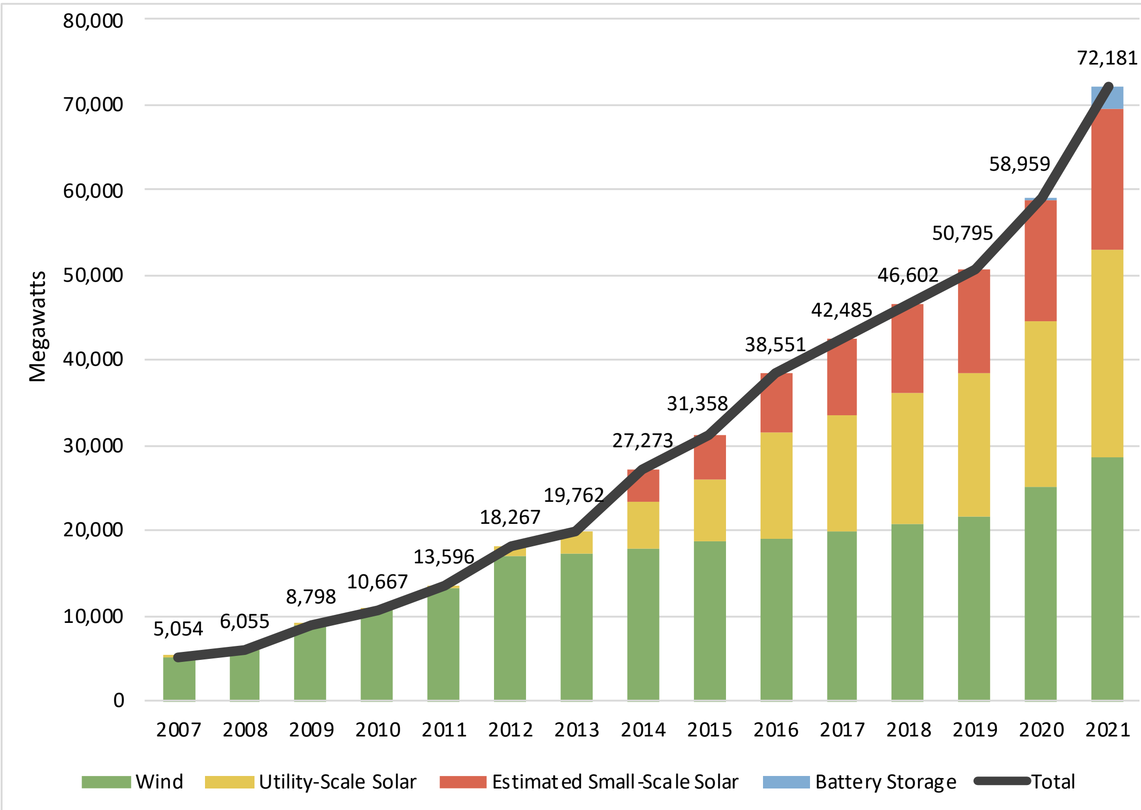
A. None of the 60 remaining coal units that are 60 or older achieved an 80% or higher average capacity factor during the years 2017-2022. Only three of these units achieved capacity factors above 70%.

Only three of the 148 remaining coal units 50 or older had average capacity factors higher than 80% during the years 2017-2021, and only ten had average capacity factors of 70% of higher.

**Q. Have the amounts of installed solar, wind and battery storage capacity grown significantly in the western U.S. in recent years?**

A. Yes. As prices have declined dramatically, the amount of installed renewable capacity generation in the western U.S. electricity grid has increased some 14-fold since 2007. The growth of installed solar capacity has been even more dramatic, climbing from barely any in 2011 to 41,000 MW just 10 years later. More than 2,500 MW of battery storage have been added since 2020.

Figure 2: The Amount of Renewable Capacity and Battery Storage on the Western U.S. Grid Has Skyrocketed in the Last 15 Years




*Source: EIA Electric Power Monthly and data from Lawrence Berkeley Nation Laboratory reports.*

Most importantly, much more is on the way. There are almost 390,000 MW of proposed renewable and storage capacity in the western region's interconnection queues, including:

- 37,727 MW of new stand-alone solar resources
- More than 53,000 MW of new standalone wind, including more than 6,300 MW of offshore wind resources
- 104,707 MW of new stand-alone storage capacity
- More than 181,000 MW of new storage paired with wind or solar resources

- Another 13,423 MW of other new hybrid resources (that is, those that include two or more generator and storage technologies) and new hydro and geothermal capacity.[3]

In addition, the capacity figures listed for the 181,000 MW of new storage paid with wind or solar resources only include the generator capacity, not the storage capacity. If even 20% of this proposed capacity ends up being built in the next five years, the region's renewable and battery storage capacity will double.

Moreover, electricity provided by the new wind, solar and storage capacity can be expected to be increasingly less expensive than power generated at Dave Johnston Unit 4 or Jim Bridger Units 3 and 4. Average solar power purchase agreement (PPA) prices in the California ISO and the non-ISO West declined by 89% and 87% respectively between 2009 and 2021. Average wind PPA prices declined by 69% during the same period.[4] Similarly, average battery storage costs fell by 72% between 2015 and 2019, according to a new analysis by the Energy Information Administration (EIA).[5] More declines are expected in coming years after current supply chain issues are resolved.[6] Additionally, the just enacted Inflation Reduction Act (IRA) provides expanded and extended tax incentives and other provisions that will likely lead to increased renewable energy development in Wyoming and other Western states.

**Q. What is the significance of the increasing integration of western markets for the future operating performance of the Dave Johnston and Bridger units?**

A. 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

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[3] U.S. Department of Energy Berkeley Lab Electric Markets & Policy Group. *U.S. Interconnection Queues 2021*. March 21, 2022.
[4] U.S. Department of Energy Berkeley Lab Electric Markets & Policy Group. Utility-Scale Solar 2021 Edition and Land Based Wind Market Report. October 2021.
[5] Energy Information Administration. Battery Storage in the United States: An Update on Market Trends. August 16, 2021.
[6] Lawrence Berkeley National Laboratory. Levelized cost-based learning analysis of utility-scale wind and solar in the United States. May 2022. Also see: National Renewable Energy Laboratory. Cost Projections for Utility-Scale Battery Storage: 2021 Update. June 2021.

particularly by the Energy Imbalance Market (EIM) created by the California system operator and PacifiCorp in 2014 as “a real-time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when needed.”[7] One of its goals is to find and deliver the lowest cost energy to consumers.[8] 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 the day.

The EIM currently has 18 members, including PacifiCorp, the California Independent System Operator (CAISO), and the Bonneville Power Authority. Two other utilities and the WAPA Desert Southwest Region are scheduled to join in 2023, meaning that participants representing more than 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 Dave Johnston and Bridger 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.

**Q. What impacts would lower capacity factors than PacifiCorp has modeled have on the costs of power from Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 if they were retrofitted for carbon capture?**

A. There would be several significant impacts. First, the fixed capital and operating & maintenance costs associated with the retrofitting and operating of each unit would be spread over fewer MWhs of output and, therefore, would be higher on a per MWh basis. Second, PacifiCorp would have a greater need for replacement power during plant

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

outages and the total cost of generating or acquiring that replacement power could be higher.

**Q. Are there other ways in which the retrofitting Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 would mean higher electricity costs for PacifiCorp's Wyoming customers?**

A. Yes. 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.

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.

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.

Capturing $CO_2$ also will entail additional costs beyond those that are regularly incurred when generating electricity at a power plant – additional staff, additional water, additional pollution controls if not already in place at the coal unit, etc. Ratepayers will be forced to pay for these additional costs as well.

## Commercial-Scale 90% Carbon Capture Has Not Been Proven Over an Extended Number of Years

**Q. What actual experience has there been capturing the $CO_2$ produced by a commercial-scale coal-fired power plant?**

A. There have been two coal-fired units that have captured $CO_2$. The Boundary Dam Unit 3 carbon capture project went into operation in October 2014 and is still in operation. The Petra Nova carbon capture project ran for 40 months from January 2017 through the end of April 2020.

**Q. Does the operational experience at Boundary Dam and Petra Nova demonstrate that carbon capture technology can be relied upon to reduce the CO2 emissions from coal-fired power plants by 90% or more on a consistent day-by-day and year-by-year for more than a decade?**

A. No. Proponents of carbon capture claim, with little or no supporting evidence, that the technology has been "proven" and that proposed projects will be able to capture 90% or more of a plant's $CO_2$ emissions day in and day out over a 12-year period, if not longer—a prediction that bears no relationship to the performance of the Boundary Dam or Petra Nova projects, the only two commercial-scale coal-fired power plants in the world that, to date, have captured $CO_2$.

**Q. Does PacifiCorp have any studies, analyses or other evidence that supports the assumption that Dave Johnston Unit 4 or Jim Bridger Units 3 or 4 would be able to achieve an annual 90% CO2 capture rate after being retrofitted for carbon capture?**

A. No. PacifiCorp seems to be relying on the statements by carbon capture developers that they have the [ability to achieve greater than or equal to 90 percent capture].[9]

**Petra Nova**

[9] PacifiCorp responses to PRBRC Data Requests 1.28, 1.29 and 1.30.

**Q. What was the Petra Nova carbon capture project.**

A. Petra Nova was originally designed to capture "at least" 90% of the $CO_2$ from the flue gas in a 240MW slipstream from NRG's W.A. Parish Unit 8 near Houston, TX.[10] The U.S. DOE supplied $190 million of the $1 billion cost of the project's cost.

**Q. What were the components of Petra Nova?**

A. There was Parish Unit 8, of course, that produced the $CO_2$, and the carbon capture facility. There also was a dedicated combustion turbine that supplied the power to run the carbon capture facility and the equipment needed to pressurize the captured $CO_2$ before it was piped 81 miles. Finally, there was the pipeline and the West Ranch oil field where the $CO_2$ was injected into the ground for use in enhanced oil recovery (EOR).

**Q. For how long did Petra Nova capture $CO_2$?**

A. The project operated during 2017, 2018, 2019 and the first four months of 2020 before it was indefinitely mothballed.[11]

**Q. How much $CO_2$ was Petra Nova expected to capture during its first three years of operation.**

A. Figure 3, below, which includes data from the March 31, 2020 Final Scientific/Technical Report for Petra Nova, shows it was planned that Petra Nova would capture slightly more than 4.64 million tons of $CO_2$ during its first three years of operation.[12]

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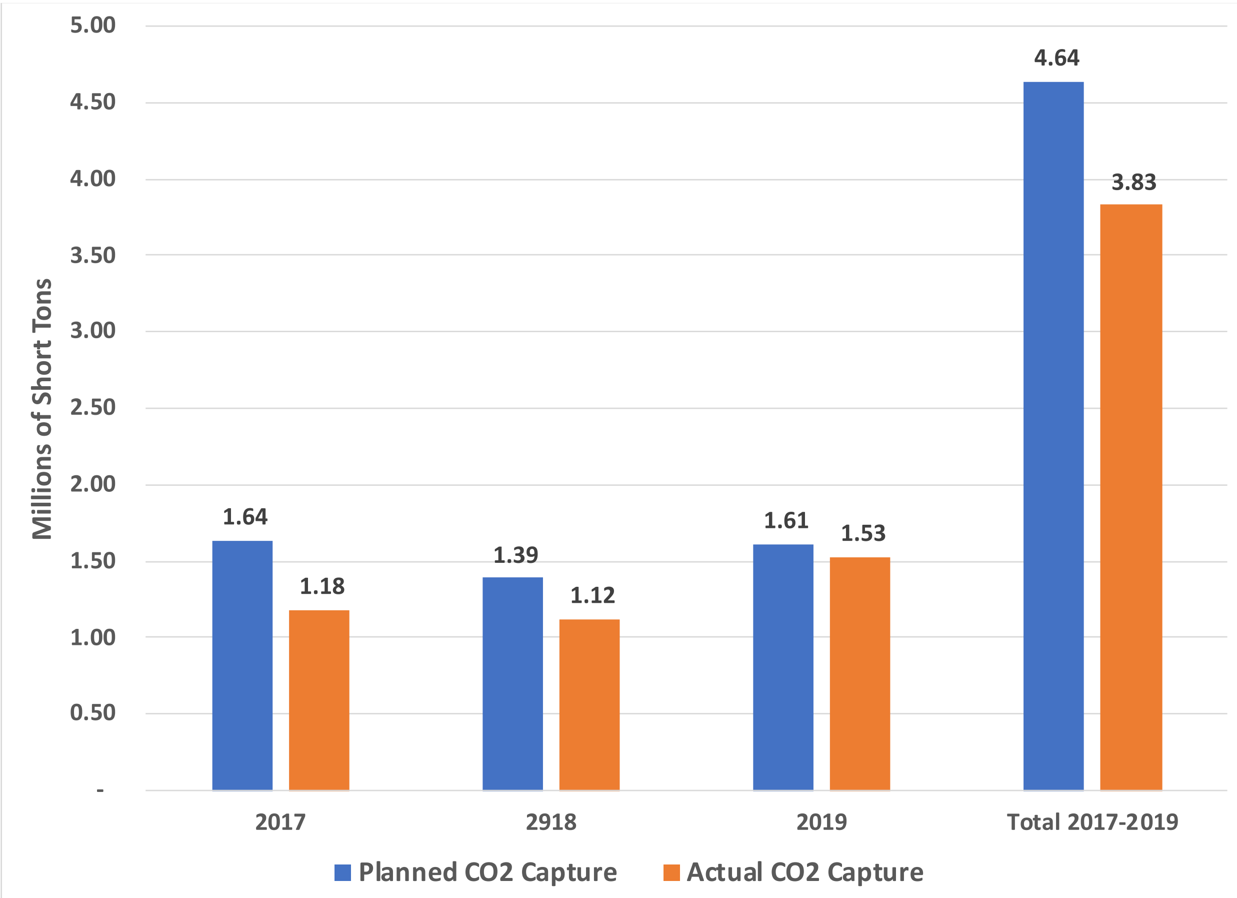
[10] DOE Office of Scientific and Technical Information (OSTI). W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Final Public Design Report. February 17, 2017.; EIA, Today in Energy. Petra Nova is one of two carbon capture and sequestration power plants in the world. October 31, 2017; DOE Office of Fossil Energy, National Energy Technology Laboratory. W.A. Parish Post-Combustion $CO_2$ Capture and Sequestration Project Summary. September 2012.

[11] We have only seen data on how much CO2 was captured at Petra Nova for the years 2017-2019.

[12] W.A. Paris Post-Combustion CO2 Capture and Sequestration Demonstration Project. Final Scientific/Technical Report, at page 47. March 31, 2020.

Figure 3: Planned versus Actual Amounts of $CO_2$ Captured Each Year at the Petra Nova Project




*Source: [W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report](#).*

Figure 3 also shows the project actually captured just 3.83 million tons of $CO_2$ between January 2017 and December 2019. This was 809,000 tons less, or 83%, of the amount of $CO_2$ that had been forecast would be captured in the first three years of operation.

**Q. What was Petra Nova's average $CO_2$ capture rate?**

A. The planned carbon capture amounts in Figure 3 assume an 85% average capture rate. Because the actual amounts of CO2 captured were 83% of what was planned, that would mean that the actual capture rate was 70%. (that's 83% times 85%)

**Q. But haven't proponents of CCS said that Petra Nova achieved a 92.4% carbon capture rate?**

A. Yes. The Petra Nova Final Scientific/Technical Report did say that "When operating at 100%, the carbon capture facility (CC Facility) or carbon capture system, CCS) is capturing the targeted 5,200 tons of $CO_2$ per day."[13] However, the entire carbon capture system (from Parish Unit 8 through the West Ranch where the captured $CO_2$ was used for EOR) experienced a substantial number of problems that reduced the carbon capture facility's ability to operate at 100% and, consequently, to capture $CO_2$ at the targeted rate.

**Q. Isn't it typical for a project using a new technology to experience unexpected problems that are resolved before subsequent projects are built?**

A. Yes. However, there are two points to consider. First, even if all of the unexpected problems experienced at Petra Nova are resolved, the project's three years of operation with a poorer-than-expected average 70% capture rate does not demonstrate that capturing 90% or more of the $CO_2$ produced at other coal plants is proven.

Second, the point of adding carbon capture to a coal plant or any industrial facility should be to capture a high percentage of the produced $CO_2$ on a sustained basis over a long period of years – not just in one year or during limited periods in each year. This sustained high rate of capture is needed not only for CCS to be an effective climate solution, but also to facilitate any business end of the project, such as enhanced oil recovery.

Power plants, especially as they age, experience equipment break-downs and operations disrupted by adverse weather events or conditions. There's no reason to expect that aging units like Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 will avoid these kinds of circumstances which likely would degrade their ability to capture $CO_2$ during certain periods

[13] Id.

At a September 2020 IRP Public Input Meeting on its 2021 IRP, PacifiCorp noted that two of the risks of carbon capture utilization and sequestration were that it was an "immature technology" and "carbon capture forced outage rate."[14] There has been no more operational experience with carbon capture at Petra Nova since September 2020 that should cause PacifiCorp to decide those risks no longer exist and, as I will explain below, the recent carbon capture-related performance of the Boundary Dam 3 project should offer no one any assurance about the technology's ability to achieve capture rates of 90% or higher.

**Q. Why is the 70% average carbon capture rate for Petra Nova lower than the 83% capture rate you included in your April 2020 Public Comments on Rocky Mountain Power's 2019 Integrated Resource Plan?**

A. The 70% capture rate reflects additional data that became available in the Final Scientific/Technical Report for Petra Nova, dated March 31, 2020.

**Q. Does the 70% carbon capture rate reflect all of the Petra Nova-associated CO2 emissions during the years 2017-2019?**

A. No. The dedicated combustion turbine that was used to power the Petra Nova carbon capture facility emitted slightly more than 1.14 million tons of $CO_2$ in the years 2017-2019. If these emissions were included, Petra Nova's net capture rate would be even lower.

**Q. What was the planned capacity factor for the Petra Nova project?**

A. The planned capacity factor was 85%.

**Q. What was Petra Nova's actual capacity factor**

A. Petra Nova achieved an average 67% capacity factor during the three years 2017-2019.

[14] Integrated Resource Plan, 2021 IRP Public Input Meeting, September 17, 2020.

**Boundary Dam 3**

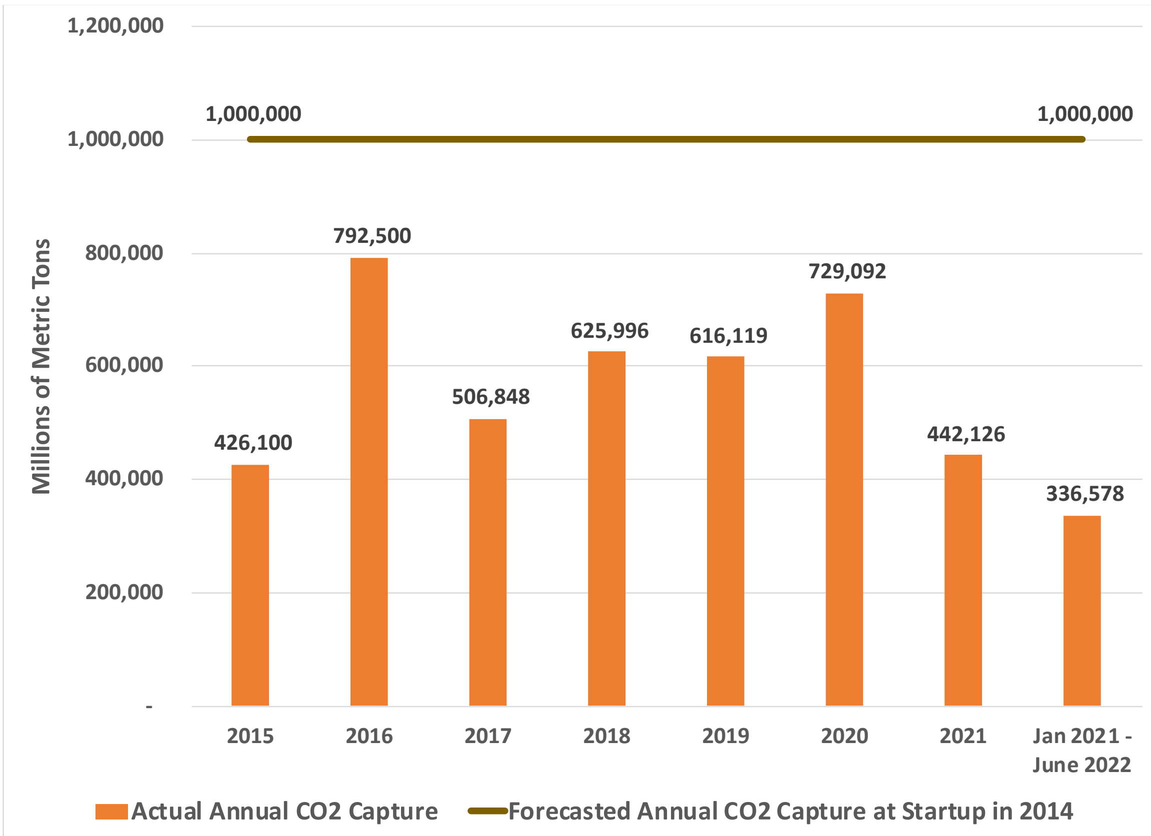
**Q. Has the indefinite mothballing of Petra Nova left Boundary Dam 3 in Canada as the only project capturing $CO_2$ from a coal plant.**

A. Yes.

**Q. When did Boundary Dam 3 begin to capture $CO_2$?**

A. The carbon capture system at the 110MW Boundary Dam 3 began operating in October 2014. It was designed to capture 1 million metric tons a year, a 90% capture rate, but status reports from the plant's owner, SaskPower, show it has barely achieved that goal on any single day and has never done so in any year.

Figure 4: Planned vs. Actual Amounts of $CO_2$ Captured Each Calendar Year at Boundary Dam Unit 3




*Sources: SaskPower Boundary Dam 3 Monthly Status Reports through March 2022 and Quarterly Status Report for 2nd Quarter 2022*

Consequently, it was originally projected the facility would capture eight million metric tons of $CO_2$ by October 2022, the plant is now on schedule to have captured less than five million metric tons by then.

**Q. Is there anything else that stands out in Figure 4?**

A. Yes. The original goal at Boundary Dam 3 was to capture 1 million metric tons a year, a goal they have never reached. However, it has taken the plant nearly 23 months to capture its most recent million metric tons of $CO_2$ – from August 2020 to June 2022. This was due to two unplanned outages of the carbon capture facility that extended into 2022. This is significant because you would expect that by the plant's eighth year of capturing $CO_2$, the operations of the carbon capture facility would be more stable – but clearly it isn't. This should be a flashing red warning sign to anyone considering attempting to retrofit an existing coal unit for carbon capture or funding such a venture. Indeed, SaskPower several years ago abandoned its original target of capturing 90% of the $CO_2$ produced at Boundary Dam – the target is now just 65% capture.

**Q. What has been Boundary Dam 3's average $CO_2$ capture rate since the plant went into service?**

A. Boundary Dam 3's average $CO_2$ capture rate has been 53%.

**Q. What are the reasons for Boundary Dam's failure to capture as much $CO_2$ as SaskPower and other supporters of the project originally claimed and to have such a low capture rate?**

A. There are three possible reasons for Boundary Dam's failure to capture as much $CO_2$ as SaskPower and other supporters of the project originally claimed.

1. The carbon capture technology experienced problems that reduced its capture rate and/or the amount of time it was available to capture $CO_2$.

2. The non-capture portion of the plant experienced problems that reduced its generation and, consequently, the amount of capturable $CO_2$ it was able to produce.[15]

3. Management made a conscious decision not to capture as much $CO_2$ as originally planned because operating the carbon capture facility was either too expensive or uneconomic compared to the revenues that could be obtained from selling or permanently storing the captured $CO_2$.

[15] SaskPower has said that the major outages and availability of the carbon capture facility were aligned with plant outages and that a significant portion of the time in 2018, 2019 and 2020 when the capture facility was not in operation should be attributed to outages of the unit's power island and not the capture island. *Derates and Outages Analysis – A Diagnostic Tool for Performance Monitoring of SaskPower's Boundary Dam Unit 3 Carbon Capture Facility*. While that may be true, failing to capture projected amounts of $CO_2$ due to outages of the non-capture portions of the plant represents a significant risk that SaskPower accepted when it decided to retrofit Boundary Dam 3.

All of these represent serious risks for any project especially those which plan to retrofit unproven carbon capture technology to aging coal-fired generators. Increasing the governmental subsidies or increasing the value of the tax credits given to developers does not eliminate these risks. It merely transfers the risk from developers to the government and its taxpayers.

**Q. Does the actual experience at Petra Nova and Boundary Dam show that carbon capture can be relied upon to capture 90% or more of a coal plant's $CO_2$?**

A. No. The results from Petra Nova and Boundary Dam 3 belie the claims of carbon capture proponents that the capability carbon capture technology to capture 90% or more of a coal plant's $CO_2$ has already been proven.

## PacifiCorp Has Ignored Significant Costs in Its CCUS Modeling

**Q. Has PacifiCorp included all of the costs associated with capturing and sequestering $CO_2$ in its analyses of retrofitting Dave Johnston Unit 4 or Jim Bridger Units 3 or 4?**

A. No. PacifiCorp did not include the cost of transporting the captured $CO_2$ from any of the units to the sites for geological storage or injection for use in EOR.[16] Nor did the company include the costs of injecting, storing and monitoring the captured $CO_2$.[17]

**Q. Is it reasonable to ignore these costs?**

A. No. Although there is significant uncertainty on what the costs of transporting, injecting, storing and monitoring captured $CO_2$ will be, estimates nevertheless should be included in the company's modeling analyses.

[16] PacifiCorp response to PRBRC Data Request 1.16.
[17] PacifiCorp response to PRBRC Data Request 1.18.

## It is Very Unlikely that Carbon Capture Retrofits for Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 Can Be Completed by 2026

**Q. What year did PacifiCorp assume in its modeling analyses for when capturing CO2 would start at Dave Johnston Unit 4 and Jim Bridger Units 3 and 4?**

A. 2026.

**Q. Is it reasonable that the design, permitting, and construction of the carbon capture facilities at any of these units could be completed in only four years?**

A. No.

**Q. Please explain.**

A. 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.

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."[18]

In fact, it appears that NRG began the design and engineering work for Petra Nova in 2009, or about five years before construction began, and completed 90% of the project's conceptual design before it even broke ground.[19,20] As NRG explained to E&E News, this meant that it needed to make few changes after construction began.

[18] E&E News. Carbon Capture Takes "Huge Step" With First U.S. Plant. January 10, 2017.
[19] Presentation on Petra Nova by Petra Nova Parish Holdings LLC, at the June 2019 IEA Clean Coal Conference. Slide No. 3.
[20] In fact, Sargent & Lundy has reported its 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.

Without detailed knowledge of the current state of PacifiCorp's internal plans for carbon capture retrofit, it is impossible to know how much planning has been completed. However, given that PacifiCorp appears to not 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, fabricating and installing the necessary equipment and completing the construction of any new carbon capture facility can be completed before 2028, at the earliest.

## The Estimated Costs of Retrofitting Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 for Carbon Capture Can Be Expected to Increase Over time

**Q. Please explain why you believe that the estimated cost of retrofitting PacifiCorp's units for carbon capture can be expected to increase over time.**

A. Petra Nova has been the only commercial scale carbon capture project built in the U.S. yet it was only designed to capture the $CO_2$ from a 240 MW slipstream from the 600 MW Parish Unit 8 coal plant. Retrofitting will involve the scaling up of the Petra Nova technology to 330 MW at Dave Johnston Unit 4 and 523 MW at Jim Bridger Units 3 and 4. Scaling up immature technologies has proven to be a problem for power plants in the past, resulting in construction cost increases and schedule delays. Current high inflation rates also can be expected to affect construction costs.

**Q. Have the estimated costs of any proposed carbon capture projects risen in recent years?**

A. Yes. The estimated cost of Project Tundra at the Milton R. Young Unit 2 coal plant in North Dakota has increased recently from by forty percent, from $1 billion to $1.4 billion and substantial construction has not yet started.[21]

[21] Project Tundra website and Financing and engineering setbacks plague North Dakota's $1B carbon capture project.

Similarly, the estimated cost of Enchant Energy's proposed retrofit of the San Juan Generating Station in New Mexico has risen grown by more than 17% from $1.2 billion in 2019 to above $1.4 billion even though that project is still years from beginning construction.[22]

**Q. Does this conclude your testimony?**

A. Yes.

[22] Time has all but run out for world's largest carbon capture project.

# David A. Schlissel

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## SUMMARY

I have worked since 1974 as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

## PROFESSIONAL EXPERIENCE

**Electric Resource Planning** - Analyzed the financial and economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the financial, economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

**Coal-fired Generation –** Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

**Power Plant Air Emissions** – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of $NO_x$, $SO_2$ and $CO_2$. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

**Power Plant Water Use** – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

**Electric System Reliability** - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

**Power Plant Repowering** - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

**Power Plant Operations and Economics** - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

**Nuclear Power** – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

**Transmission Line Siting** – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

**Electric Industry Regulation and Markets** - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

**Expert Testimony** - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

**Litigation and Regulatory Support** - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

## TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

**New Mexico Public Regulation Commission (Case No. 19-00195-UT) – January 2020**
Whether retrofitting San Juan Generating Station with a system to capture the plant's $CO_2$ emissions and then selling the captured $CO_2$ for Enhanced Oil Recovery is financially feasible.

**Indiana Utility Regulatory Commission (Cause No. 45253) – December 2019**
Whether continued operation of the Edwardsport facility as an Integrated Gasification Combined Cycle plant is in the economic interest of Duke Energy Indiana's ratepayers.

**New Mexico Public Regulation Commission (Case No. 19-00018-UT) – November 2019**
Whether retrofitting San Juan Generating Station with a system to capture the plant's $CO_2$ emissions and then selling the captured $CO_2$ for Enhanced Oil Recovery is financially feasible.

**Montana Public Service Commission (Docket No. D.2018.2.12) – February 2019**
Whether $303 million represents the current fair market value of Northwestern Energy's 30 percent ownership share of Colstrip Unit 4.

**U.S. Bankruptcy Court, Northern District of Ohio, Eastern Division (Case No. 18-50757) – September 2018**
Whether FirstEnergy Solutions, Inc., will have sufficient assets to properly and completely decommission and environmentally clean up and remediate the sites of three coal plants after they are retired.

**Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 17) – July and October 2018**
The operating performance of the Edwardsport Integrated Gasification Combined Cycle Plant, and the economic impact that the plant has had, and will continue to have, on Duke Energy Indiana's ratepayers.

**West Virginia Public Service Commission (Case No. 17-0296-E-PC) – August 2017**
The reasonableness of Monongahela Power's proposed acquisition of the 1,300 MW Pleasants Power Plant.

**Indiana Utility Regulatory Commission (Cause No. 44794) – October & December 2016**
The economic viability of proposed environmental upgrades at the Petersburg Power Station.

**Montana Public Service Commission (Docket Nos. D2013.5.33 and D2014.5.46) – May 2015**
The circumstances surrounding the extended outage of Colstrip Unit 4 from July 1, 2013 through January 23, 2014.

**Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 12 & 13) – December 2014**
Whether Duke Energy Indiana's Edwardsport IGCC Project was in service between June 7, 2013 and March 31, 2014 and the Project's current operational performance and cost status and future prospects.

**Public Service Commission of West Virginia (Case No. 14-0546-E-PC) – August 2014**
The reasonableness of American Electric Power's proposed transfer of 50 percent of the Mitchell Coal Plant to its regulated affiliates in West Virginia.

**Mississippi Public Service Commission (Docket No. 2013-UN-189) – March and June 2014**
The prudence of Mississippi Power Company's management of the planning for the Kemper County IGCC Plant.

**Indiana Utility Regulatory Commission (Cause Nos. 43114 IGCC 8, 10, and 12) – June 2012, April 2013 and April 2014**
Startup and pre-operational testing delays at Duke Energy Indiana's Edwardsport IGCC Project.

**Public Service Commission of West Virginia (Case No. 12-1655-E-PC) – June 2013 and July 2013**
The reasonableness of Appalachian Power Company's proposed acquisition of 2/3 of Unit 3 of the John E. Amos power plant and ½ of the two unit Mitchell power plant.

**Public Service Commission of West Virginia (Case No. 12-1571-E-PC) – April 2013**
The reasonableness of Monogahela Power Company's proposed acquisition of 80 percent of the Harrison Power Station.

**Virginia State Corporation Commission (Case No. PUE-2012-00128) – March 2013**
Whether Dominion Virginia Power's proposed Brunswick Project natural gas-fired combined cycle power plant is needed and in the public interest.

**Arizona Corporation Commission (Docket No. E-01922A-12-0291 – December 2012**
Reasonableness of Tucson Electric Power's proposed Environmental Compliance Adjustor mechanism.

**U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR and 50-286-LR) – June 2012**
Reply to testimony filed by Entergy Nuclear and NRC Staff concerning the relicensing of Indian Point Units 2 and 3.

**Mississippi Public Service Commission (Docket No. 2009-UA-014) – March 2012**
Petition to Reopen the docket for the Kemper County IGCC Plant based on changed circumstances.

**Mississippi Public Service Commission (Docket No. 2009-UA-279) – February 2012**
The financial and economic risks of retrofitting Mississippi Power Company's Plant Daniel Coal Plant.

**Georgia Public Service Commission (Docket No. 34218) – November 2011**
The reasonableness of Georgia Power Company's proposed fossil plant decertification/retirement plan.

**Missouri Public Service Commission (Case No. EO-2011-0271) – October 2011**
Reasonableness of Ameren Missouri's 2011 Integrated Resource Plan filing.

**Maryland Public Service Commission (Case No. 9271) – October 2011**
The reasonableness of Constellation Energy Group's proposed divestiture of three coal-fired power plants as mitigation for market power concerns arising from its proposed merger with Exelon Corporation.

**Minnesota Public Utilities Commission (Docket No. E017/M-10-1082) – August and September 2011**
Whether the proposed addition of the Big Stone Plant Air Quality Control System is a lower cost alternative for the ratepayers of Otter Tail Power Company than retirement of the Plant and replacement by a natural gas-fired combined cycle unit possibly combined with new wind capacity.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – June, July, and October 2011 and June 2012**
Duke Energy Indiana's imprudence and gross mismanagement of Edwardsport IGCC Project.

**Kansas State Corporation Commission (Docket No. 11-KCPE-581-PRE) – June 2011**
The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

**Arizona Corporation Commission (Docket No. E-01345A-10-0474) – May 2011**
The reasonableness of Arizona Public Service Company's proposed acquisition of Southern California Edison's share of Four Corners Units 4 and 5.

**Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010**
The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July, November and December 2010**
The reasonableness of Duke Energy Indiana's new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

**Oregon Public Utility Commission (Docket LC 48) – May and August 2010**
Comments and Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan.

**South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010**
The reasonableness of Black Hills Power Company's 2007 Integrated Resource Plan and the Company's decision to build the Wygen III coal-fired power plant.

**Michigan Public Service Commission (Docket No. U-16077) – April 2010**
Comments on the City of Holland Board of Public Works' 2010 Power Supply Study.

**Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010**
Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

**North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010**
The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

**Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009**
The costs and risks associated with the proposed Kemper County IGCC power plant.

**Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010**
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

**Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009**
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

**Public Service Commission of Michigan (Docket No. U-15996) – July 2009**
Comments on Consumer Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

**Public Service Commission of Michigan (Docket No. U-16000) – Juy 2009**
Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

**Georgia Public Service Commission (Docket No. 27800-U) – December 2008**
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

**Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008**
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

**Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008**
The estimated cost of Duke Energy Indiana's Edwardsport Project.

**Public Service Commission of Maryland (Case 9127) – July 2008**
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

**Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007**
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

**U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009**
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

**West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007**
Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

**Iowa Utility Board (Docket No. GCU-07-01) – October 2007**
Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

**Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007**
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

**Louisiana Public Service Commission (Docket No. U-30192) – September 2007**
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

**Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007**
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

**North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008**
Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

**Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007**
The appropriate carbon dioxide ("$CO_2$") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

**Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007**
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

**Florida Public Service Commission (Docket No. 070098-EI) – March 2007**
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

**Michigan Public Service Commission (Case No. 14992-U) – December 2006**
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

**Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008**
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

**North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007**
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

**New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006**
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

**Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006**
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

**U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006**
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

**Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006**

**South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006**
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

**Georgia Public Service Commission (Docket No. 22449-U) – May 2006**
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

**California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006**
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

**New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006**
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

**Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005**
The siting of a proposed 230 kV transmission line.

**Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005**
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

**New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005**
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

**Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005**
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

**Maine Public Utilities Commission (Docket No. 2005-17) – July 2005**
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

**Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005**
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

**Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005**
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

**Maine Public Utilities Commission (Docket No. 2004-771) – March 2005**
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

**United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)**
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

**New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005**
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

**Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005**
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

**California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005**
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

**United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004**
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

**California Public Utilities Commission (Application No. AO4-01-009) – August 2004**
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

**Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004**
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

**Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004**
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

**Connecticut Siting Council (Docket No. 272) – May 2004**
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

**Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004**
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

**State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004**
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

**State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003**
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

**Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004**
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

**New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003**
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

**Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003**
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

**Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003**
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

**Arkansas Public Service Commission (Docket 02-248-U) – May 2003**
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

**Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003**
The physical nature of electricity and whether electricity is a tangible product or a service.

**Maine Public Utilities Commission (Docket 2002-665-U) – April 2003**
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

**Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003**
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

**New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003**
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

**New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003**
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

**Arizona Corporation Commission (Docket No. E-01345A-01-0822) – May 2002**
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002**
Repowering NYPA's existing Poletti Station in Queens, New York.

**Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003**
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

**Vermont Public Service Board (Case No. 6545) – January 2002**
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001**
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

**Connecticut Siting Council (Docket No. 208) – October 2001**
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

**New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001**
The market power implications of the proposed merger between Conectiv and Pepco.

**Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001**
Commonwealth Edison Company's management of its distribution and transmission systems.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001**
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001**
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

**New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001**
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000**
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

**Illinois Commerce Commission (Docket 00-0361) - August 2000**
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

**Vermont Public Service Board (Docket 6300) - April 2000**
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

**Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000**
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

**Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000**
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

**Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000**
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999**
Generation, Transmission, and Distribution system reliability.

**Illinois Commerce Commission (Docket 99-0115) - September 1999**
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999**
Standard offer rates for Connecticut Light & Power Company.

**Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999**
Standard offer rates for United Illuminating Company.

**Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999**
Connecticut Light & Power Company stranded costs.

**Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999**
United Illuminating Company stranded costs.

**Maryland Public Service Commission (Docket 8795) - December 1998**
Future operating performance of Delmarva Power Company's nuclear units.

**Maryland Public Service Commission (Dockets 8794/8804) - December 1998**
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

**Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998**
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

**Arkansas Public Service Commission (Docket 98-065-U) - October 1998**
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

**Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998**
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998**
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

**Illinois Commerce Commission (Docket 97-0015) - May 1998**
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998**
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

**Illinois Commerce Commission (Docket 97-0018) - March 1998**
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997**
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

**New Jersey Board of Public Utilities (Docket ER96030257) - August 1996**
Replacement power costs during plant outages.

**Illinois Commerce Commission (Docket 95-0119) - February 1996**
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Utility Commission of Texas (Docket 13170) - December 1994**
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

**Public Utility Commission of Texas (Docket 12820) - October 1994**
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

**Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994**
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

**Public Utility Commission of Texas (Docket 12700) - June 1994**
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

**Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994**
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

**Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994**
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

**Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993**
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

**Public Utility Commission of Texas (Docket 11735) - April and July 1993**
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995**
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

**Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992**
United Illuminating Company off-system capacity sales. [Confidential Testimony]

**Public Utility Commission of Texas (Docket 10894) - August 1992**
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992**
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

**California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993**
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

**Public Utility Commission of Texas (Docket 9945) - June 1991**
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

**Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991**
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

**New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990**
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

**Public Utility Commission of Texas (Docket 9300) - June and July 1990**
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.
**Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989**
Boston Edison's corporate management of the Pilgrim Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989**
United Illuminating Company's off-system capacity sales.

**Kansas State Corporation Commission (Case 164,211-U) - April 1989**
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

**Public Utility Commission of Texas (Docket 8425) - March 1989**
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

**Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989**
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

**New Mexico Public Service Commission (Case 2146, Part II) - October 1988**
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

**United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988**
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

**Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989**
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

**Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988**
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

**Illinois Commerce Commission (Docket 87-0695) - April 1988**
Illinois Power Company's planning for the Clinton Nuclear Station.

**North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988**
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

**Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987**
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

**North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987**
Fuel factor calculations.

**New York State Public Service Commission (Case 29484) - May 1987**
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

**Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987**
The reasonableness of certain terms in a proposed Power Supply Agreement.

**Illinois Commerce Commission (Docket 86-0405) - March 1987**
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

**Indiana Public Service Commission (Case 38045) - November 1986**
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

**Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986**
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

**New York State Public Service Commission (Case 28124) - April 1986 and June 1987**
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

**Arizona Corporation Commission (Docket U-1345-85) - February 1986**
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

**New York State Public Service Commission (Case 29124) – December 1985 and January 1986**
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

**New York State Public Service Commission (Case 28252) - October 1985**
A performance standard for the Shoreham nuclear power plant.

**New York State Public Service Commission (Case 29069) - August 1985**
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

**Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

**Massachusetts Department of Public Utilities (Case 84-152) - January 1985**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

**Maine Public Utilities Commission (Docket 84-113) - September 1984**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

**South Carolina Public Service Commission (Case 84-122-E) - August 1984**
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

**Vermont Public Service Board (Case 4865) - May 1984**
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

**New York State Public Service Commission (Case 28347) -January 1984**
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

**New York State Public Service Commission (Case 28166) - January 1983 and February 1984**
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

**U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983**
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

**REPORTS, ARTICLES, AND PRESENTATIONS**

*How the High Cost of Power from Prairie State is Affecting Bowling Green Municipal Utilities' Customers*. July, 2014.

*Overpriced Power: Why Batavia is Paying So Much for Electricity*. Updated March 2014.

*Huntley Generating Station: Coal Plant's Weak Financial Outlook Calls for Corporate & Community Leadership*. January 2014. Co-authored with Cathy Kunkel and Tom Sanzillo.

*When, Not If: Bridgeport's Future and the Closing of PSEG's Coal Plant*.

*Changing Course: A Clean Energy Investment Plan for Dominion Virginia Power.* Co-authored with Jeff Loiter and Anna Sommer. August 2013.

*Mountain State Maneuver: AEP and FirstEnergy try to stick ratepayers with Risky Coal Plants*. September 2013. Co-authored with Cathy Kunkel.

*Public Utility Regulation without the Public: The Alabama Public Service Commission and Alabama Power*. Co-authored with Anna Sommer. March 2013

*A Texas Electric Capacity Market: The Wrong Tool for a Real Problem*. Co-authored with Anna Sommer. February 2013.

*Dark Days Ahead: Financial Factors Cloud Future Profitability at Dominion's Brayton Point Power Plant*. Co-authored with Tom Sanzillo. February 2013.

*Report on the Kemper IGCC Project: Cost and Schedule Risks.* November 2012.

*The Prairie State Coal Plant: the Reality vs. the Promise*. August 2012.

*The Impact of EPA's Proposed 316(b) Existing Facility Rule on Electric System Reliability*, July 2011.

*The Economics of Existing Coal-Fired Power Plants*, Presentation at EUCI Conference in St. Louis, MO, November 2010.

*Presentation to the Indiana Utility Regulatory Commission on the Need for the Proposed Duke Energy Indiana Edwardsport IGCC Project*, November 2010.

*Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan*, September 2010.

*Presentation to the Oregon Public Utility Commission on Portland General Electric Company's 2009 Integrated Resource Plan,* May 2010.

*Comments on Portland General Electric Company's 2009 Integrated Resource Plan*, May 2010.

*Comments on the Facility Cost Report for Tenaska's Proposed Taylorville IGCC Plant*, April 2010.

*Comments on City of Holland Board of Public Work's 2010 Power Supply Plan*, April 2010.

*Phasing Out Federal Subsidies for Coal*, April 2010.

*Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan*, October 2009.

*The Economic Impact of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia*, August 2009.

*Energy Future: A Green Energy Alternative for Michigan*, report, July 2009.

*Energy Future: A Green Energy Alternative for Michigan,* presentation, July 2009.

*Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan*, June 2009.

*The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station,* April 2009.

*An Assessment of Santee Cooper's 2008 Resource Planning*, April 2009.

*Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead*, Report for the Union of Concerned Scientists, March 2009.

*New Hampshire Senate Bill 152: Merrimack Station Scrubber*, March 2009.

*The Risks of Building and Operating Plant Washington*, Presentation to the Sustainable Atlanta Roundtable, December 2008.

*The Risks of Building and Operating Plant Washington*, Report and Presentation to EMC Board Members, December 2008.

*Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants*, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

*Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants*, Presentation at Georgia Tech University, October 2008.

*Nuclear Power Plant Construction Costs*, Synapse Energy Economics, July 2008.

*Coal-Fired Power Plant Construction Costs,* Synapse Energy Economics, July 2008.

*Synapse 2008 $CO_2$ Price Forecasts*, Synapse Energy Economics, July 2008.

*Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants*, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

*Are There Nukes In Our Future*, Presentation at the NASUCA Summer Meetings, June 2008.

*Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership*, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

*Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants,* Presentation to the New York Society of Securities Analysts, February 26, 2008.

*Don't Get Burned,*Report for the Interfaith Center for Corporate Responsibility, February 2008.

*The Risks of Participating in the AMPGS Coal Plant*, Report for NRDC, February 2008.

*Kansas is Not Alone*, *the New Climate for Coal*, Presentation to members of the Kansas State Legislature, January 22, 2008.

*The Risks of Building New Nuclear Power Plants*, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

*The Risks of Building New Nuclear Power Plants*, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

*The Risks of Building New Nuclear Power Plants*, U.S. Senate and House of Representative Briefings, April 20, 2007.

*Carbon Dioxide Emissions Costs and Electricity Resource Planning,* New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

*The Risks of Building New Nuclear Power Plants*, Presentation to the New York Society of Securities Analysts, June 8, 2006.

*Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs.* Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

*Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities.* Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

*The 2003 Blackout: Solutions that Won't Cost a Fortune*, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

*The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability.* An Analysis for Riverkeeper, Inc. November 3, 2003.

*The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings.* An Analysis for Riverkeeper, Inc. November 3, 2003.

*Entergy's Lost Revenues during Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems.* An Analysis for Riverkeeper, Inc. November 3, 2003.

*Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities*. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants*. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

*Determining the Need for Proposed Overhead Transmission Facilities.* A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

*Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station*. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002.* An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants.* A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

*Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities,* on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

*The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability*. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

*Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line.* A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

*ISO New England's Generating Unit Availability Study: Where's the Beef?* A Presentation at the June 29, 2001 Restructuring Roundtable.

*Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability*. A Synapse Report for the Clean Air Task Force. May 2001.

*Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability*. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

*Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market*, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

*Cost, Grid Reliability Concerns on the Rise Amid Restructuring*, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

*Report on Indian Point 2 Steam Generator Issues*, Schlissel Technical Consulting, Inc., March 10, 2000.

*Preliminary Expert Report in Case 96-016613*, <u>Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company</u>, October 28, 1999.

*Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation*, February 1997.

*Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant*, August 1996.

*Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs*, May, 1996.

*Nuclear Power in the Competitive Environment*, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

*Nuclear Power in the Competitive Environment*, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

*The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations*, a report for the Environmental Law and Policy Center of the Midwest, 1995.

*Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs*, July 15, 1992.

*Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2*, December 1991.

*Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso*, Texas, April 1991.

*Nuclear Power Plant Construction Costs*, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

*Comments on the Final Report of the National Electric Reliability Study*, a report for the New York State Consumer Protection Board, February 27, 1981.

## OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability.  Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

## WORK HISTORY

2012- Director of Resource Planning Analysis, Institute for Energy Economics and Financial Analysis

2010 - President, Schlissel Technical Consulting, Inc.

2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

## EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

## PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981

PRBRC Ex. 602

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84116

July 21, 2022

Shannon Anderson
Staff Attorney
Powder River Basin Resource Council
934 N. Main St.
Sheridan, WY 82801
(307) 672-5809
sanderson@powderriverbasin.org (C)

RE: Wyoming Docket 20000-616-EA-22
PRBRC 1st Set Data Request (1-32)

Please find enclosed Rocky Mountain Power's Responses to PRBRC 1st Set Data Requests 1.3 and 1.5-1.32. The remaining response will be provided separately. Also provided are Attachments PRBRC 1.9, 1.11, and 1.12. Provided via BOX are the Confidential documents. Confidential information is provided subject to Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Wyo. Stat. §16-4-203(a), (b), (d), or (g), until a protective order is issued in this proceeding, and will be made available to non-governmental parties who execute a confidentiality agreement in this proceeding.

If you have any questions, please call me at (307) 632-2677.

Sincerely,

_____/s/______
Stacy Splittstoesser,
Manager, Regulation

Enclosures
C.c. Thorvald A. Nelson/WIEC tnelson@hollandhart.com (C)
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Michelle Brandt King/WIEC mbking@hollandhart.com (C)
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Shelby Hamilton/OCA Shelby.Hamilton1@wyo.gov (C)
Dale W. Cottam/Glenrock dale@performance-law.com (C)
Ronald J. Lopez/Glenrock ronnie@performance-law.com

**PRBRC Data Request 1.3**

Please provide any analyses of the costs of retrofitting Dave Johnston Unit 4, and/or Jim Bridger Units 3 and 4 for carbon capture that have been prepared by or for Rocky Mountain Power or any affiliated company or that are in the possession of Rocky Mountain Power.

**Commercially-Sensitive Confidential Response to PRBRC Data Request 1.3**

PacifiCorp's 2021 Integrated Resource Plan (IRP), Chapter 7 (Resource Options), Table 7.1 (2021 Supply-Side Resource Table (2020$)) on page 168 and 175, and Table 7.2 (Total Resource Cost for Supply-Side Resource Options) on page 180 provides carbon capture, utilization and sequestration (CCUS) capital on a post-CCUS retrofit basis. This information was also provided in Exhibit 1.6 (Percent Portfolio Calculations). The costs are as follows:

- Dave Johnston Unit 4 – $3,877 per kilowatt ($/kW)
- Jim Bridger Unit 3 – $3,873/kW
- Jim Bridger Unit 4 – $3,876/kW

PacifiCorp performed additional modeling on Jim Bridger Unit 3 and Jim Bridger Unit 4 based on updated information, including information PacifiCorp received through the 2021 Request for Expression of Interest (REOI) process. This information is provided with the confidential work papers supporting the Company's Application, specifically commercially-sensitive confidential work paper "Workpaper - Total Resource Cost for Supply-Side Resource Options CCUS (CONF)". Note: this work paper has been designated as commercially sensitive.

The capital cost for the capture unit, on a post-retrofit basis, is as follows:

- Jim Bridger Unit 3 and Jim Bridger Unit 4 – [redacted]

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Confidential information is provided subject to Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Wyo. Stat. §16-4-203(a), (b), (d), or (g), until a protective order is issued in this proceeding, and will be made available to non-governmental parties who execute a confidentiality agreement in this proceeding.

Respondent: Kirsten M. Merrett

Witness: To Be Determined

**PRBRC Data Request 1.5**

Provide any projections or forecasts of short-term or long-term annual future coal costs for Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2020. Provide this information for both the scenario in which each unit is retired as per the current schedule and the scenario in which it is retrofitted for carbon capture.

**Response to PRBRC Data Request 1.5**

The Company interprets this question to be requesting coal fuel costs. The PLEXOS model optimizes thermal resource generation and the associated fuel cost for coal and natural gas. Based on the foregoing interpretation and clarification, the Company responds as follows:

Please refer to Commercially-Sensitive Confidential Attachment PRBRC 1.5.

In addition, please refer to the confidential work papers supporting the Company's Application, folder "Plexos/ST" and, for example, commercially-sensitive confidential work paper "ST Cost Summary -P02-MMGR Prod Port JB34 CCUS 20yr ST 4Blk_Mo - 56792 v23.11.xlsx", tab "Generator", and column K "Fuel cost ($000)". Note: these work papers have also been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Confidential information is provided subject to Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Wyo. Stat. §16-4-203(a), (b), (d), or (g), until a protective order is issued in this proceeding, and will be made available to non-governmental parties who execute a confidentiality agreement in this proceeding.

Respondent: Dan Swan

Witness: To Be Determined

**PRBRC Data Request 1.6**

Provide any projections or forecasts of short-term or long-term future annual non-fuel O&M expenses for Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2020. Provide this information for both the scenario in which each unit is retired as per the current schedule and the scenario in which it is retrofitted for carbon capture.

**Response to PRBRC Data Request 1.6**

Please refer to Commercially-Sensitive Confidential Attachment PRBRC 1.6.

In addition, please refer to the confidential work papers supporting the Company's Application, folder "Inputs/Master Assumptions", specifically commercially-sensitive confidential work paper "JB34 CCUS 20220314.xls" tab "2 – NonCAI O&M (NOM$)". Also, please refer to the confidential work papers supporting the Company's Application, folder "Plexos/ST" and, for example, commercially-sensitive confidential work paper "ST Cost Summary -P02-MMGR Prod Port JB34 CCUS 20yr ST 4Blk_Mo - 56792 v23.11.xlsx", tab "Generator", and column L "VOM cost ($000)". Note: these work papers have been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Confidential information is provided subject to Chapter 2, Section 30 of the Wyoming Public Service Commission's rules and Wyo. Stat. §16-4-203(a), (b), (d), or (g), until a protective order is issued in this proceeding, and will be made available to non-governmental parties who execute a confidentiality agreement in this proceeding.

Respondent: Dan Swan

Witness: To Be Determined

**PRBRC Data Request 1.7**

Provide any projections or forecasts of short-term or long-term annual generation or capacity factors for Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2020. Provide this information for both the scenario in which each unit is retired as per the current schedule and the scenario in which it is retrofitted for carbon capture.

**Response to PRBRC Data Request 1.7**

The PLEXOS model optimizes resource generation and the associated capacity factors (CF), which are therefore model outputs and not inputs. Based on the foregoing clarification, the Company responds as follows:

Please refer to the Company's response to PRBRC Data Request 1.5, specifically Commercially-Sensitive Confidential Attachment PRBRC 1.5.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

In addition, please refer to the confidential exhibits and confidential work papers supporting the Company's Application, specifically Confidential Exhibit 1.2 (Generation Estimate that Qualifies as Dispatchable/Reliable Low-Carbon), and Confidential Exhibit 1.3 (Annual and Forecasted Generation), as well as the associated confidential work paper "Exhibits 1.2-1.6 Application for WY HB200 (CONF)".

Respondent: Dan Swan

Witness: To Be Determined

**PRBRC Data Request 1.8**

Provide any projections or forecasts of short-term or long-term annual capital expenditures or capex for Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2020. Provide this information for both the scenario in which each unit is retired as per the current schedule and the scenario in which it is retrofitted for carbon capture.

**Response to PRBRC Data Request 1.8**

Please refer to the Company's response to PRBRC Data Request 1.6, specifically Commercially-Sensitive Confidential Attachment PRBRC 1.6.

In addition, please refer to the confidential work papers supporting the Company's Application, folder "Inputs/Master Assumptions", specifically commercially-sensitive confidential work paper "JB34 CCUS 20220314.xls", tab "2b – Clean Air Capex", tab 7 "Runrate Plant CapEx", and tab 11 "Mine Capital". Note: this work paper has been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Respondent: Dan Swan

Witness: To Be Determined

**PRBRC Data Request 1.9**

Please provide the annual fuel expenses incurred at Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2017.

**Response to PRBRC Data Request 1.9**

Please refer to Attachment PRBRC 1.9.

Respondent: Dan Moody

Witness: To Be Determined

20000-616-EA-22 / Rocky Mountain Power
July 21, 2022
PRBRC Data Request 1.10

**PRBRC Data Request 1.10**

Provide the annual fuel expenses incurred at Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2017.

**Response to PRBRC Data Request 1.10**

Please refer to the Company's response to PRBRC Data Request 1.9.

Respondent: Dan Moody

Witness: To Be Determined

**PRBRC Data Request 1.11**

Provide the annual non-fuel expenses O&M incurred at Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2017.

**Response to PRBRC Data Request 1.11**

Please refer to Attachment PRBRC 1.11.

Respondent: Dave Dunford

Witness: To Be Determined

**PRBRC Data Request 1.12**

Provide the annual capex incurred at Dave Johnston Unit 4 and/or Jim Bridger Units 3 and 4 that have been prepared by or for Rocky Mountain Power since January 1, 2017.

**Response to PRBRC Data Request 1.12**

Please refer to Attachment PRBRC 1.12 which provides capital costs for Dave Johnston Unit 4, Jim Bridger Unit 3 and Jim Bridger Unit 4. Year-on-year fluctuations in these unit costs are generally due to scheduled major maintenance overhaul costs. Also included is a summary of costs for Dave Johnston and Jim Bridger common locations. These common capital projects are allocable to all units at the plant sites, generally on a megawatt (MW) basis.

Respondent: Karl Mortensen

Witness: To Be Determined

**PRBRC Data Request 1.13**

Provide the following information for Dave Johnston Unit 4 and for Jim Bridger Unit 3 and Unit 4 (separately) for the last five calendar years.

(a) Annual EFOR
(b) Annual EFORd
(c) Annual EAF

**Confidential Response to PRBRC Data Request 1.13**

Please refer to the confidential table provided below:

[redacted]

Note: "EFOR" – equivalent forced outage rate. "EFORd" – equivalent forced outage rate demand. "EAF" – equivalent availability factor.

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Respondent: Gavin Mangelson / Grant Laughter

Witness: To Be Determined

**PRBRC Data Request 1.14**

Specify the parasitic loads (in MW) that Rocky Mountain Power anticipates or projects would be incurred at Dave Johnston Unit 4 and at Jim Bridger Unit 3 and Unit 4 if each of these units were retrofitted for carbon capture.

**Response to PRBRC Data Request 1.14**

Please refer to confidential exhibits accompanying the Company's Application, specifically Confidential Exhibit 1.2 (Generation Estimate that Qualifies as Dispatchable/Reliable Low-Carbon), which provides carbon capture auxiliary load estimates (in megawatts (MW)).

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.15**

Provide copies of any analyses prepared by or for Rocky Mountain Power or any affiliated company that have examined or projected the future parasitic loads and/or change in heat rates at Dave Johnston Unit 4 and at Jim Bridger Unit 3 and Unit 4 if each of these units were retrofitted for carbon capture.

**Response to PRBRC Data Request 1.15**

Please refer to the confidential exhibits accompanying the Company's Application, specifically commercially-sensitive Confidential Exhibit 1.1 (Kiewit CCUS Feasibility Study), page 28 and 29, and Confidential Exhibit 1.2 (Generation Estimate that Qualifies as Dispatchable/Reliable Low-Carbon) which includes the carbon capture auxiliary load assumptions. Note: Confidential Exhibit 1.1 has been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.16**

Please state how much it would cost to transport the CO2 (in dollars per ton or metric ton) captured at Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 from the plant to the site for geological storage or injection for use in enhanced oil recovery.

**Response to PRBRC Data Request 1.16**

A transportation cost analysis was not completed for Dave Johnston Unit 4, Jim Bridger Unit 3 or Jim Bridger Unit 4.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.17**

Provide the copies of the studies or analyses that provide the basis for the cost provided in the response to PRBRC 1.16.

**Response to PRBRC Data Request 1.17**

Please refer to the Company's response to PRBRC Data Request 1.16.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.18**

Please state how much it would cost to inject, store and monitor the $CO_2$ (in dollars per ton or metric ton) captured at Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 in underground geological storage.

**Response to PRBRC Data Request 1.18**

An injection, storage, and monitoring cost analysis was not completed for Dave Johnston Unit 4, Jim Bridger Unit 3, or Jim Bridger Unit 4.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.19**

Provide the copies of the studies or analyses that provide the basis for the cost provided in the response to PRBRC 1.18.

**Response to PRBRC Data Request 1.19**

Please refer to the Company's response to PRBRC Data Request 1.18.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.20**

Please provide any analysis performed by the Company or in possession of the Company that identifies suitable formations for permanent geologic storage in the proximity of the Dave Johnston power plant.

**Response to PRBRC Data Request 1.20**

Please refer to the confidential exhibits accompanying the Company's Application, specifically commercially-sensitive Confidential Exhibit 1.1 (Kiewit CCUS Feasibility Study), pages 30 through 34, which includes the analysis performed to identify storage options and infrastructure proximity. Note: Confidential Exhibit 1.1 has been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.21**

Please list all environmental permits required for a CCUS retrofit at Dave Johnston Unit 4 and/or Jim Bridger Unit 3 and Unit 4, including, but not limited to Clean Air Act PSD & NSR and coal ash landfill permit modifications.

**Response to PRBRC Data Request 1.21**

Please refer to the confidential exhibits accompanying the Company's Application, specifically commercially-sensitive Confidential Exhibit 1.1 (Kiewit CCUS Feasibility Study), pages 29 and 30, which includes the environmental permit/permit modifications that would likely be needed for a carbon capture retrofit. Note: Confidential Exhibit 1.1 has been designated as commercially sensitive.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.22**

Please explain why SCR is not necessary on Dave Johnston Unit 4 to complete a CCUS retrofit.

**Response to PRBRC Data Request 1.22**

Please refer to the confidential exhibits accompanying the Company's Application, specifically commercially-sensitive Confidential Exhibit 1.1 (Kiewit CCUS Feasibility Study), page 26, Table 8 (Air Quality Control System Equipment Comparison) which identifies Dave Johnston Unit 4 as needing selective catalytic reduction (SCR) for amine-based carbon capture. Note: Confidential Exhibit 1.1 has been designated as commercially sensitive.

PacifiCorp plans to issue a carbon capture, utilization and storage (CCUS) request for proposals (RFP). Each bidder will need to perform their own analysis to determine what air quality control technology would be required for their technology.

Note: information designated as "commercially-sensitive confidential" includes commercially sensitive information that could provide an unfair competitive advantage in the Company's proposed Carbon Capture, Utilization and Storage (CCUS) request for proposals (RFP) process. Therefore, intervenors who plan on bidding into the RFP process will not be provided this information.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.23**

Please explain if the Company anticipates a need to upgrade the SO2 scrubbers at Dave Johnston Unit 4 and/or Jim Bridger Unit 3 and Unit 4 to complete a CCUS retrofit.

**Response to PRBRC Data Request 1.23**

PacifiCorp plans to issue a carbon capture, utilization and storage (CCUS) request for proposals (RFP). Each bidder will need to perform their own analysis to determine what air quality control technology would be required for their technology.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.24**

Please disclose if the costs related to the CCUS retrofit permitting, installation, and ongoing O&M are shared with customers outside of WY and if so please explain how that complies with the MSP agreement. Alternatively, if the Company plan is to limit cost recovery to WY customers, please state that.

**Response to PRBRC Data Request 1.24**

The 2021 Integrated Resource Plan (IRP) determined that Carbon Capture, Utilization and Storage (CCUS) was not economical, and it was therefore not a part of the least-cost/risk adjusted preferred portfolio. Accordingly, the costs related to CCUS permitting, installation, and on-going operations and maintenance (O&M) costs are considered incremental costs incurred to serve Wyoming customers to comply with state policy and would be assigned to Wyoming customers.

Respondent: Stacy Splittstoesser

Witness: To Be Determined

20000-616-EA-22 / Rocky Mountain Power
July 21, 2022
PRBRC Data Request 1.25

**PRBRC Data Request 1.25**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Dave Johnston Unit 4 would be able to achieve an annual 85% capacity factor after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.25**

No studies, analyses or evidence collection was performed to determine the capacity factor of Dave Johnston Unit 4 after retrofit of carbon capture.

Respondent: Grant Laughter

Witness: To Be Determined

**PRBRC Data Request 1.26**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Jim Bridger Unit 3 would be able to achieve an annual 85% capacity factor after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.26**

No studies, analyses or evidence collection was performed to determine the capacity factor of Jim Bridger Unit 3 after retrofit of carbon capture.

Respondent: Grant Laughter

Witness: To Be Determined

**PRBRC Data Request 1.27**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Jim Bridger Unit 4 would be able to achieve an annual 85% capacity factor after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.27**

No studies, analyses or evidence collection was performed to determine the capacity factor of Jim Bridger Unit 4 after retrofit of carbon capture.

Respondent: Grant Laughter

Witness: To Be Determined

**PRBRC Data Request 1.28**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Dave Johnston Unit 4 would be able to achieve an annual 90% CO2 capture rate after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.28**

Carbon capture developers have indicated their ability to achieve greater than or equal to 90 percent capture.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.29**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Jim Bridger Unit 3 would be able to achieve an annual 90% CO2 capture rate after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.29**

Please refer to the Company's response to PRBRC Data Request 1.28.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.30**

With reference to page 14 of the Direct Testimony of Kirsten M. Merrett, provide copies of the studies, analyses or other evidence that supports the assumption that Jim Bridger Unit 4 would be able to achieve an annual 90% capture rate after being retrofitted for carbon capture.

**Response to PRBRC Data Request 1.30**

Please refer to the Company's response to PRBRC Data Request 1.28.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett

**PRBRC Data Request 1.31**

Please state whether any of the units Dave Johnston Unit 4, Jim Bridger Unit 3 or Jim Bridger Unit 4 were operated as must-run facilities at any time since January 1, 2017. If the answer is yes, provide the specific hours and days during which each such unit was operated as a must-run facility.

**Response to PRBRC Data Request 1.31**

It is unclear to the Company the intended definition of "must-run" in this data request; the use of that term in this data request is ambiguous. Notwithstanding the foregoing statement, the Company responds as follows:

No, the Company did not operate any of the above referenced units (Dave Johnston Unit 4, Jim Bridger Unit 3 and / or Jim Bridger Unit 4) as must run units. The Company dispatches its resources based on system needs and market economics.

Respondent: Paul Wood

Witness: To Be Determined

**PRBRC Data Request 1.32**

With reference to page 15 of the Direct Testimony of Kirsten M. Merrett, provide each of the updated assumptions that were used in the additional analysis run for the Application and indicate the source of that updated assumption.

**Response to PRBRC Data Request 1.32**

Please refer to the exhibits accompanying the Company's Application, specifically Exhibit 1.0 (PacifiCorp's House Bill (HB) 200 Initial Plan Application), page 25, which includes assumptions for the additional analysis that was performed. The Company updated the carbon capture, utilization and storage (CCUS) operation time from 20 years to 12 years to align with 45Q carbon capture tax credits. Other assumptions came from interest received through the 2021 Request for Expression of Interest (REOI) process.

Respondent: Kirsten M. Merrett

Witness: Kirsten M. Merrett