BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-21-07**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	**Direct Testimony of Robert Van Engelenhoven**
RATES AND CHARGES IN IDAHO	)	**REDACTED**
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Robert Van Engelenhoven and my business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am currently employed as Resource Development Director. I am testifying on behalf of the Company.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science in Civil Engineering from Iowa State University and am a licensed structural engineer in Utah and a licensed professional engineer in Wyoming. I have managed major capital projects for the Company for over 20 years.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my testimony is four-fold: (1) discuss the Pryor Mountain Wind Project, (2) provide an overview of the natural gas conversion of Naughton Unit 3, (3) discuss the Lake Side 2 natural gas plant; and (4) discuss the confidential decommissioning and site reclamation studies attached to my testimony.

First, I explain and support the Company's development and implementation of the Pryor Mountain Wind Project and show that the costs are reasonable. The Pryor Mountain Wind Project, located in Carbon County, Montana, was identified as an opportunity to acquire and implement a late-stage renewables development project to capture 100 percent production tax credits ("PTC") if acted on expeditiously to deliver the project by year-end 2021. In addition to providing PTCs and net power cost benefits, the project also allows the Company to meet a customer need for incremental renewable energy credits ("RECs"), the purchase of which under the Company's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option ("Schedule 272"), further improves the project's economics and associated customer benefits. Mr. Rick T. Link provides the economic analysis demonstrating the net benefits associated with the acquisition of the Pryor Mountain Wind Project.

Second, I give a summary of the natural gas conversion of Naughton Unit 3, which was removed from operation as a coal-fired unit on January 30, 2019, to maintain compliance with certain environmental regulations. Conversion of Naughton Unit 3 to a natural gas fueled resource was facilitated by the design of the unit, which already incorporates natural gas fueling infrastructure for start-up. This underlying infrastructure was readily and economically modified to facilitate generation up to 247 megawatts ("MW") of capacity from the unit within applicable environmental permit limits for periods of peak loads across the Company's system to benefit our customers.

Third, I explain and support the Company's development and construction of the Lake Side 2 natural gas plant and show the costs are reasonable. Placed in service in June 2014, Lake Side 2, which is located just North of Provo in Vineyard, Utah, is a natural gas-fired electric generation facility with a total capacity of 637 MW.

Finally, I provide background regarding the confidential decommissioning and site reclamation studies dated January 15, 2020, and March 13, 2020, (the

"Decommissioning Studies").[1] I discuss the scope of the Decommissioning Studies and the differences from previous plant decommissioning estimates, and summarize the costs estimated in the Decommissioning Studies.

Q. Please summarize your direct testimony.

A. My testimony demonstrates that:

- The acquisition and construction of the Pryor Mountain Wind Project is prudent and in the public interest. The Pryor Mountain Wind Project was acquired and developed in 2019, constructed in 2020 and achieved commercial operation on April 1, 2021, delivering significant net power cost and PTC benefits, as well as incremental customer benefits derived from the associated REC sale.
- Completion of the natural gas conversion of Naughton Unit 3 is prudent and in the public interest. The natural gas conversion project is *de minimis* in scope and facilitates operation of a significant generation resource during periods of peak loads across the Company's system for the benefit of customers.
- The development and construction of Lake Side 2 was prudent and in the public interest. The addition of Lake Side 2 to the Company's gas fleet has generated significant customer benefits and continues to be an important part of the generation fleet.
- The updated decommissioning and remediation costs in the Decommissioning Studies are a reasonable estimate to be included in the revenue requirement.

[1] The Decommissioning Studies were filed in the Company's proceeding to change depreciation rates. *See In the Matter of the Application of Rocky Mountain Power for Authorization to Change Depreciation Rates Applicable to Electric Property,* Case No. PAC-E-18-08.

The estimates were developed by an independent engineering consultant, with review and input by other independent contractors and were prepared and filed consistent with the 2020 Protocol.

III. PRYOR MOUNTAIN WIND PROJECT

Q. Please provide an overview of the Pryor Mountain Wind Project.

A. The Pryor Mountain Wind Project has a nameplate capacity of 240 MW and is located in Carbon County, Montana, approximately 60 miles south of Billings, Montana. The project consists of 57 Vestas Model V110-2.0 MW safe harbor, 16 Vestas Model V110-2.2 MW safe harbor, four General Electric Model 116-2.3 MW safe harbor, and 37 Vestas model V110-2.2 MW follow-on wind turbine generators ("WTGs"). In addition to the wind turbines, there will be a 34.5 kilovolt ("kV") collector system, a collector substation with two 34.5 kV to 230 kV step-up transformers, an operations and maintenance ("O&M") building, and site access roads. A new point of interconnection substation located on the project site in Montana was also constructed. Based on current regulatory practice, the project has been assessed using a depreciable life of 30 years.

Q. Please provide background on the Company's development of the Pryor Mountain Wind Project.

A. The opportunity to capture customer benefits resulting from the acquisition, development, and implementation of the Pryor Mountain Wind Project was identified and evolved over a compressed timeline beginning in October 2018 and ending with final terms on all material agreements (*i.e.*, the engineer, procure, and construct contract and WTG supply agreements) completed by September 30, 2019. In parallel, negotiation of an Oregon Schedule 272 REC purchase agreement for the sale of all RECs associated with the output of the Pryor Mountain Wind Project to Vitesse, LLC began in December 2018 and final terms were reached in late June 2019. The process from initial discussions to negotiation of final terms of the Schedule 272 REC purchase agreement occurred in under six months. The updated cost forecast of the Pryor Mountain Wind Project is [redacted].

Q. Has the COVID-19 pandemic had a material impact on the Company's construction schedule or costs for the Pryor Mountain Wind Project?

A. As a result of the COVID-19 pandemic, the Company received notices from the turbine supply and balance of plant contractors, in which they generally claim delays due to disruption to the global supply chain caused by the COVID-19 pandemic. The Company has and continues to work with these contractors to resolve these claims strictly according to the terms and conditions of their respective contracts. However, this affected both construction schedule and costs of the project.

With respect to construction, final wind turbine equipment deliveries were made the week of November 9, 2020. This allowed erection of all 114 wind turbines to be completed the week of November 16, 2020, prior to high-wind and severe winter conditions that could have shut down the project for the winter and further delayed construction until Spring 2021. Completing wind turbine erection ahead of the high wind season also reduced project cost risk. The Company energized both the Bowler Flats (point of interconnection) substation and the Pryor Mountain (collector) substation the week of November 16, 2020. With the Pryor Mountain substation energized, collector circuits 1 through 4 were energized and proving back feed power to the first 40 wind turbines (80 MW) in December 2020, allowing commissioning of the wind turbines to commence. The remaining collector circuits (5 through 12) were energized in the first quarter 2021. The project achieved commercial operation on April 1, 2021, 90 days later than the originally scheduled December 2020 completion date.

Further, the overall cost of the project increased from an original forecasted cost of [redacted], to the updated forecasted cost of [redacted]. The increase in costs resulted from delays experienced in construction, which were due to a disruption in the worldwide supply chain caused by the COVID-19 pandemic. Specifically, the increase in costs were caused by delayed delivery of the wind turbine components, requiring a shift from rail delivery to the more expensive truck delivery. The delayed component delivery from the turbine supplier delayed the erection of the wind turbines increasing the labor and equipment costs. The delivery and erection delays were compounded by the higher wind speeds experienced during the winter months further delaying construction and increasing costs. During November 2020 there was an onsite COVID-19 outbreak which delayed erection of the wind turbines and the start of commissioning and placing wind turbines in service.

Q. Please describe the time-sensitive nature of the federal PTCs as it pertains to the Pryor Mountain Wind Project.

A. The time sensitive nature of the federal PTCs for the Pryor Mountain Wind Project is similar to the new wind facilities included in the Energy Vision 2020 Projects, which is discussed by Mr. Timothy J. Hemstreet. The time-sensitive nature of the Pryor Mountain Wind Project is primarily driven by the pending phase-out of the federal PTCs for new wind resources. Originally, under prior Internal Revenue Service ("IRS") guidance, PacifiCorp would have captured the full rate (100 percent) of the PTCs if the project's in-service date was before the end of 2020. However due to the COVID-19 pandemic, in May 2020, the Continuity Safe Harbor was extended to five calendar years for projects that began construction in 2016 or 2017.[2] Pryor Mountain has a 2016 start of construction date. Accordingly, the continuity requirement will be met if the project is placed in service by December 31, 2021. With an in-service date of April 1, 2021, the Pryor Mountain Wind Project will capture the full rate (100 percent) of the PTCs. The Pryor Mountain Wind Project deployed safe harbor WTG equipment to achieve PTC eligibility. The Company's acquisition and implementation plan for the Pryor Mountain Wind Project allowed the Company to meet the year-end 2021 in-service schedule and provide customers the full economic benefit of the project.

Q. Does the Pryor Mountain Wind Project meet the IRS start-of-construction criteria?

A. Yes. The Pryor Mountain Wind Project will utilize WTG equipment acquired before December 31, 2016. The WTG equipment acquisition satisfies the safe-harbor requirements under the PTC guidance issued by the IRS.

Q. What approach was taken to secure late-stage development safe harbor WTG equipment and follow-on WTG equipment for the Pryor Mountain Wind Project?

A. The Vestas safe harbor WTG equipment identified above was sourced, acquired, and transferred under an affiliate transaction with Berkshire Hathaway Energy Renewables ("BHER"). The four General Electric safe harbor WTGs described above were directly

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[2] Internal Revenue Service Notice 2020-41 (May 27, 2020). *See*, https://www.irs.gov/pub/irs-drop/n-20-41.pdf.

procured by the Company in 2016. The Company completed a competitive market solicitation for the follow-on WTG equipment required to complete the nominal 240 MW Pryor Mountain Wind Project. By combining the use of safe harbor equipment, the transferred BHER safe harbor equipment, and competitive market engagement for follow-on WTG equipment, the Company addressed a couple of key risk points for the project. Specifically, through this combination of procurement strategies the Company limited its exposure to competitive market constraints and pricing volatility for 2020 delivery of 100 percent PTC projects with the safe harbor equipment already manufactured and awaiting delivery.

Q. What is the current construction status of the Pryor Mountain Wind Project?

A. The Pryor Mountain Wind Project was primarily constructed in 2020, although site activities began in 2019 with completion of geotechnical borings and surveys, other site surveys and detailed engineering, construction of a material laydown area, and installation of approximately five percent of the site access roads before winter weather halted construction. The construction contractor re-mobilized in March 2020 and completed construction in December 2020 with commissioning completed by March 31, 2021. The project was placed in commercial operation on April 1, 2021.

Q. Did the Company perform preliminary evaluations of the wind potential at the Pryor Mountain Wind Project site?

A. Yes. A wind potential study for the Pryor Mountain Wind Project was completed by a third-party wind resource evaluation firm. The wind potential assessments for Pryor Mountain indicate that the site has a favorable wind regime suitable for high performance wind energy generation. The expected capacity factor for the project is [redacted] percent and aligns with the assumptions made in support of the economic evaluation of the project.

Q. Did the Company collaborate with the U.S. Fish and Wildlife Service in developing and implementing the Pryor Mountain Wind Project?

A. Yes. The Company engaged the U.S. Fish and Wildlife Service regarding developing and implementing the Pryor Mountain Wind Project. The Company and the project's previous owner and developers began pre-construction usage surveys for various avian, bat, and wildlife species utilizing recommendations from applicable state and federal guideline documents, including the 2012 Land Based Wind Energy Guidelines. The Company will continue to coordinate with county, state, and federal agencies that have jurisdiction over development, permitting, and operations to ensure appropriate environmental and safety measures are implemented throughout the life of the Pryor Mountain Wind Project. The Company is committed to maintaining development and implementation schedules and protocols that recognize potential environmental impacts and strive to mitigate them.

Q. How did the Company assess the customer benefits provided by the Pryor Mountain Wind Project?

A. Mr. Link provides a detailed description of the Company's customer benefits assessment in his testimony. In general terms, the methodology used to perform the economic analysis of the Pryor Mountain Wind Project is consistent with the methodology used to perform the economic analysis of the Energy Vision 2020 Projects. The Company's economic analysis also reflects the significant benefits from the sale of RECs associated with the Pryor Mountain Wind Project.

Q. How did the Company generate the cost information for construction, operation, and maintenance of the Pryor Mountain Wind Project through its useful life?

A. The Company assessed life cycle costs for the Pryor Mountain Wind Project using information from a variety of sources. For example, initial installation costs and run rate O&M cost projections were developed through competitive market engagements for project construction and WTG supply and long-term O&M contracts. Transmission interconnection costs were confirmed against the Pryor Mountain Wind Project's transmission interconnection studies. The Company's internal project management and administrative costs were estimated based on the Company's experience with construction of past and current wind facilities and other recent generation resource additions. The Company also applied limited funds to the Pryor Mountain Wind Project to account for project uncertainties. O&M cost estimates were developed based on the Company's experience with currently operating wind facility O&M budgets and third-party contracts for the Company's existing wind facilities. Ongoing capital costs were estimated based upon the Company's experience and indicative costs provided by WTG suppliers for critical capital components.

Q. Please describe the exhibit for the 240 MW Pryor Mountain Wind Project.

A. The site plan for the 240 MW Pryor Mountain Wind Project is provided in Exhibit No. 32 which accompanies my testimony.

IV. NAUGHTON UNIT 3 GAS CONVERSION

Q. Please describe why Naughton Unit 3 was converted to natural gas fueling.

A. The Company was required to cease coal-fired operations in Naughton Unit 3 on January 30, 2019, to maintain compliance with certain environmental regulations.

Completion of the natural gas conversion of Naughton Unit 3 increases the unit's generating capacity when fueled by natural gas from 35 MW (utilizing existing start-up fuel infrastructure) to 247 MW.

Q. Please describe the permitting process for Naughton Unit 3.

A. On July 5, 2013, the Wyoming Department of Environmental Quality ("WDEQ") issued Air Permit MD 14506, which establishes natural gas emission and heat input limits for Naughton Unit 3 which would "become effective upon conversion" of Unit 3 to natural gas firing. On November 28, 2017, the WDEQ submitted to the Environmental Protection Agency ("EPA") a Regional Haze State Implementation Plan ("SIP") revision which required Naughton Unit 3 to cease burning coal no later than January 30, 2019; the SIP proposes federally enforceable emission limits for Naughton Unit 3 to fire on natural gas. The EPA issued its proposed approval of WDEQ's SIP revision on November 7, 2018, seeking public comments on the proposal.

On February 4, 2019, the Company filed a notification to the WDEQ that Naughton Unit 3 had ceased coal combustion; the Company designated Naughton Unit 3 as "temporarily 'mothballed' while awaiting final federal action" from the EPA on approval of the WDEQ SIP. The Company clarified in its notification that Naughton Unit 3 remained capable of generating 35 MW when fueled on natural gas, and that the unit could be considered effectively converted following EPA approval of the Wyoming SIP.

On March 21, 2019, the EPA published its approval of the Naughton Unit 3 conversion to natural gas and incorporated by reference the natural gas emission limits from Wyoming state air permits. The Company submitted a notification to WDEQ on

May 24, 2019, for initial startup of Naughton Unit 3 on natural gas and commencement of construction for additional upgrades supporting the full conversion to 247 MW. The Company removed Naughton Unit 3 from designation as 'temporarily mothballed' and committed to completion of all construction relating to natural gas conversion by June 24, 2021.

The Company filed a notification with WDEQ on July 3, 2019, that Naughton Unit 3 was first fired (initial start-up after being temporarily mothballed) on natural gas on July 1, 2019.

The Naughton Unit 3 conversion project was complete and placed into service on July 29, 2020.

Q. What is the cost to complete the full conversion of Naughton Unit 3 to a 247 MW natural gas fired generation resource?

A. The cost of the Naughton Unit 3 gas conversion to 247 MW included in this proceeding is [redacted] million on a total-company basis.

Q. Does the Naughton Unit 3 gas conversion to a 247 MW natural gas fired generation resource provide customer benefits?

A. Yes. As discussed in the testimony of Mr. Link, full conversion of Naughton Unit 3 to a 247 MW gas fueled resource is projected to provide $62 million to $121 million in present-value revenue requirement differential ("PVRR(d)") benefit for customers as analyzed in the 2019 Integrated Resource Plan ("IRP") against early retirement of the unit. As such, the 2019 IRP Preferred Portfolio included Naughton Unit 3 gas conversion as a generation resource available to serve customers going forward.

V. LAKE SIDE 2 NATURAL GAS PLANT

Q. Please describe the Lake Side 2 Power Plant ("Lake Side 2") and its integration into PacifiCorp's System.

A. Lake Side 2 is a natural gas-fired electric generation facility, consisting of a 2x1 configuration, with two Siemens SGT6-5000F combustion turbine generators and a single SST6-5000 steam turbine generator. It is a 548 MW base load with 89 MW of duct firing for a total capacity of 637 MW at average ambient conditions for the site. Each combustion turbine exhausts into its own heat recovery steam generator and, together, they supply a single steam turbine generator. Lake Side 2 is located on a 63.6-acre site in Vineyard, Utah, next to Lake Side 1. The electrical energy generated by Lake Side 2 is delivered to a 345 kV point of interconnection substation where it ties into the PacifiCorp's transmission system.

Q. Please explain why the Company decided to build Lake Side 2.

A. The Company decided to acquire Lake Side 2 based on three IRPs and a competitive request for proposals ("RFP") process. The need for a resource such as Lake Side 2 was recognized as a part of the Commission's acknowledgment of the Company's 2007 and 2009 IRPs.[3] These are the two IRPs that immediately preceded the Company's execution of the Lake Side 2 acquisition agreement in December 2010. Item 2 in the 2011 IRP Revised Action Plan indicated that the Company would: "[a]cquire a combined cycle combustion turbine resource at the Lake Side site in Utah by the

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[3] *PacifiCorp's 2007 Integrated Resource Plan*, Case No. PAC-E-07-11, Acceptance of Filing (Oct. 15, 2007); *PacifiCorp's 2009 Integrated Resource Plan*, Case No. PAC-E-09-06, Acceptance of Filing (Sept. 15, 2017).

summer of 2014."[4] Lake Side 2 was the 2014 combined cycle combustion turbine ("CCCT") proxy resource included in the 2011 IRP preferred portfolio.[5] Further, the Engineer, Procure and Construct ("EPC") contract for Lake Side 2 was awarded to CH2M Hill E&C, Inc. based on a competitive solicitation in the Company's 2010 All Source RFP, which was open to all bidders.[6] The EPC contract provided specific terms and conditions to protect customers and required the 637 MW CCCT resource to be placed in service by June 2014.

Q. Please describe the characteristics of Lake Side 2.

A. Lake Side 2 is located in the Company's control area. Energy from Lake Side 2 is dispatched on a forward, day-ahead basis, with real-time optimization of the plant's usage. Dispatch flexibility gives the Company an additional system resource with the ability to provide operating reserves, load-following reserves, and automatic generation control. This system flexibility provides increased benefit to PacifiCorp as: (1) load grows; (2) PacifiCorp's existing flexible contracts expire; and (3) new wind and solar resources are added to the System.

Q. Is Lake Side 2 in-service providing energy to the Company's customers?

A. Yes. Lake Side 2 was placed in-service in June 2014.

Q. What was the total capital cost of Lake Side 2?

A. The total capital cost for Lake Side 2 was [redacted] million on a total-Company basis.

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[4] *PacifiCorp's 2011 Integrated Resource Plan*, Case No. PAC-E-11-10, 2011 IRP at 14.
[5] *Id.*
[6] *Id.* at 44.

Q. What do you recommend concerning Lake Side 2?

A. The RFP, along with the analysis of the Company and independent evaluators conducted prior to building Lake Side 2, demonstrated that it was in the public interest because it was identified as the best resource to fulfill the need established in the RFP. Lake Side 2 also filled part of the capacity deficit in the Company's system in 2014, identified in the 2008 IRP Update. Lake Side 2 is a valuable part of PacifiCorp's generation resource portfolio. It is used and useful and provides significant benefits to Idaho customers. Therefore, I recommend that the Commission find that the decision to construct Lake Side 2 was prudent and in the public interest and its cost should be included in rate base as a part of this general rate case.

VI. 2020 DECOMMISSIONING STUDIES

Q. What is the purpose of this section of your direct testimony?

A. I provide background regarding the Decommissioning Studies provided in Confidential Exhibit Nos. 33 and 34 that accompany my testimony. I also discuss the scope of the Decommissioning Studies and the differences between previous plant decommissioning estimates, and summarize the costs estimated in the Decommissioning Studies.

Q. Why did PacifiCorp conduct the Decommissioning Studies?

A. Through PacifiCorp's Multi-State Process negotiations, the signatories to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol ("2020 Protocol") agreed that the Company should conduct a thorough study of decommissioning and site reclamation costs for certain coal-fueled generation resources.[7]

Q. Please describe the scope of the Decommissioning Studies.

A. The scope of work for the Decommissioning Studies included the following requirements:

- Provide an owner-informed, overall decommissioning design basis to be used for all generating facilities in the study. The design basis established the fundamental assumptions for the cost estimates provided in the final Decommissioning Studies.
- Provide a Class 3 cost estimate to identify all costs for the decommissioning, demolition, reclamation, and remediation of the Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, Hayden, and Colstrip generating facilities.
- Provide a narrative report describing the entities involved, process used to prepare the report, and assumptions.
- Provide a spreadsheet report incorporating the Association for the Advancement of Cost Engineering ("AACE")[8] Class 3 cost estimates inclusive of certain owner provided Asset Retirement Obligation ("ARO") cost estimates as verified by the third-party study provider.
- Provide cost estimates based on fourth quarter 2019 dollars.

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[7] *In the Matter of Rocky Mountain Power's Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol,* Case No. PAC-E-19-20, Order No. 34649 (Apr. 22, 2020) (2020 Protocol Sections 4.3.1.1-4.3.1.2).

[8] AACE is a 501(c)(3) non-profit professional association founded in 1956 that offers publications, practice guides, education, certification and recommended practices for cost estimating.

Q. Why were PacifiCorp's other coal-fueled generation facilities not included in the Decommissioning Studies?

A. PacifiCorp's owned, but did not operate, Cholla Unit 4 and Craig Units 1 and 2, and so these generating units were not included in the Decommissioning Studies. Those units had common depreciable lives proposed for all states in the most recent depreciation study and common retirement dates in the 2019 IRP.[9]

Q. Who conducted the Decommissioning Studies for the Company?

A. The Decommissioning Studies were performed by independent engineering consultant Kiewit Engineering Group Inc., with input from independent contractors with direct experience decommissioning coal-fueled facilities and site reclamation. The studies included review and input from an independent demolition contractor North American Dismantling Corporation and independent hazardous materials abatement contractors Winter Environmental and ARC Abatement. Two additional independent demolition contractors, Bierlein Companies, Inc. and Brandenburg Industrial Service Company also reviewed the Decommissioning Studies results.

Q. Are you planning to conduct separate decommissioning studies for Cholla Unit 4 and Craig Units 1 and 2?

A. Yes. Arizona Public Service Company, the operator of the Cholla generation facility, retained APTIM Corporation and has completed a study of the decommissioning and demolition costs for the entire Cholla generation facility, including Cholla Unit 4. A decommissioning and demolition study for the Craig facility will be completed by no

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[9] *PacifiCorp's Integrated Resource Plan (IRP) for 2019*, Case No. PAC-E-19-16 (Oct. 18, 2019).

later than 2024 in accordance with the 2020 Protocol.

Q. Please describe the difference between the Decommissioning Studies and previous decommissioning estimates prepared by the Company?

A. The Decommissioning Studies provide an AACE Class 3 estimate for demolition, salvage, and scrap costs for the facilities studied. An AACE Class 3 cost estimate is based on a definition of the scope of work between 10-40 percent and has an expected accuracy of minus 20 percent to plus 30 percent. The typical purpose of a Class 3 estimate is for budget authorization or control.

Previous decommissioning cost estimates were extrapolated from AACE Class 5 estimates for demolition of a limited subset of PacifiCorp's owned and operated coal-fueled facilities. A Class 5 study has an expected accuracy of minus 50 percent to plus 100 percent. The typical purpose of a Class 5 estimate is for concept screening. It should also be noted that the underlying scope and design basis for the previous decommissioning cost estimates was refined and expanded in response to scoping feedback from stakeholders during the Multi-State Process negotiations.

Q. Please describe the major differences between the previous estimates and the current Decommissioning Studies.

A. The differences between the previous estimates and the current Decommissioning Studies are primarily from the definition of the scope of work, the method, estimate class, assumptions for ARO and environmental liabilities, site reclamation, owner's costs and contractor indirect costs applied in the current Decommissioning Studies.

Q. What is the change to the method of estimating decommissioning costs used in the Decommissioning Studies?

A. The previous estimates developed demolition costs and salvage values for three coal-fueled generating facilities that were intended to be generally representative of the broader coal-fueled generating fleet. The cost of demolition and salvage for the generating facilities that were not directly studied were extrapolated to establish estimates using generally comparable generating facilities that had been studied.[10] The current Decommissioning Studies estimate the cost and salvage values for each generating facility individually.

Q. Were there other changes in the scope of the estimate in the Decommissioning Studies compared to the previous study?

A. Yes. The previous estimates were based on 0-2 percent of the scope of the work defined and was focused on three facilities from which the individual generating unit estimates were extrapolated. The previous estimates did not include infrastructure, utilities, or any facilities outside the plant perimeter. The current studies are based on a scope of work defined at 10-40 percent and focused on individual units as well as all common plant facilities, both inside and outside the facility perimeter.

Q. How were ARO addressed in the Decommissioning Studies?

A. During the time between the previous estimates and the current studies, the scope and cost of AROs changed as existing obligations were completed and new obligations were incurred. In addition, the scope of the current studies included reviewing the cost

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[10] *See also,* Case No. PAC-E-18-08, Direct Testimony of Chad A. Teply.

of the Company's ARO estimates. Where the consultant found that the consultant's estimate for an ARO was significantly different than the Company's estimate, the consultant included their estimate for the ARO in the Decommissioning Studies. The net result was a total increase of approximately $15 million.

Q. Did the Decommissioning Studies address site reclamation?

A. Yes. Unlike previous estimates, the current Decommissioning Studies include site reclamation at an estimated average cost of $9.8 million per generating facility. Reclamation scope assumptions include grading to meet permit conditions and match existing terrain as much as reasonably possible, installing topsoil, and seeding for native plants. Topsoil installation and seeding was not estimated for Wyodak, due to its co-location with non-PacifiCorp generation resources in an energy hub.

Q. How did the Decommissioning Studies address owner's costs and contractor indirect costs?

A. The current Decommissioning Studies includes owner's project development and oversight costs. Owner's costs include the cost of preparing the facility for the work, project management, long-lead permitting, and site demolition management. The previous estimates did not include owner's project development and oversight costs or itemized competitive market contractor indirect costs.

Q. Please summarize the results of the Decommissioning Studies.

A. Exhibit No. 35 contains a table showing the results of the Decommissioning Studies excluding certain closure-related costs that may be considered outside of decommissioning costs or require additional steps to refine their accuracy.

Q. What costs were included in the total base decommissioning and demolition costs for each facility?

A. In general terms, the base decommissioning costs include the costs for: (1) developing the decommissioning project including the site investigation; (2) decommissioning the facility, decontaminating activities, and preparing the facility for the demolition contractor; (3) dismantling and demolition of the facility less the offset value of salvage and scrap; (4) completing ARO, site remediation, and site reclamation; and (5) the estimates of competitive market contractor margin and indirect costs.[11] The costs and offsets were adjusted to PacifiCorp ownership values for each facility studied.

Q. Were there any offsets to the estimated base decommissioning and demolition costs?

A. Yes. Demolition costs are offset by the value of salvage and scrap. Estimated salvage value is based on the projected value of equipment, materials, and commodities that could be sold. Estimated scrap value is based on the estimated then-current market prices of steel, titanium, copper-based metals, and other valuable metals.[12]

Q. Do the Decommissioning Studies incorporate other costs in relation to decommissioning?

A. Yes. Other costs incorporated in the Decommissioning Studies that may be considered outside of decommissioning costs include: (1) assets for which cost recovery is accounted for through mechanisms other than depreciation; (2) assets that do not present an immediate hazard, nuisance, or need to decommission and remediate,

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[11] See Confidential Exhibit No. 33 and Confidential Exhibit No. 34.
[12] *Id.*

including asbestos coated piping; (3) coal pile subsurface excavation and remediation and above-ground asbestos remediation costs that have been estimated, but will be further evaluated in the next steps; and (4) material and supply inventory and rolling stock dispensation.[13] As discussed by Mr. Steven R. McDougal, these other costs were not reflected in the revenue requirement request in the proceeding.

Q. Are these the Company's final estimates for decommissioning costs?

A. No. The 2020 Protocol contemplates an update of the Decommissioning Studies in 2024 to address the Craig, Hunter, Huntington, and Wyodak coal-fueled resources. That study will update the estimated decommissioning costs so that depreciation rates for Craig[14] and the longer-lived resources (i.e. Hunter, Huntington, and Wyodak) can be updated to reflect more accurate and contemporaneous decommissioning estimates. Further, as I discussed previously, the operator of Cholla Unit 4 has separately estimated decommissioning and site reclamation costs for that unit.

VII. CONCLUSION AND RECOMMENDATION

Q. Please summarize your testimony.

A. The Company requests the costs for the Pryor Mountain wind facility be included in the approved revenue requirement because it is prudent and benefits Idaho customers. Cost recovery is also appropriate for the Naughton Unit 3 natural gas conversion, which has been prudently analyzed and implemented. The natural gas conversion project is *de minimis* in scope and facilitates operation of a significant (247 MW, post-conversion) generation resource during periods of peak loads across the Company's

[13] *Id.*

[14] PacifiCorp's ownership share is 19 percent of Craig Unit 1 and 19 percent of Craig Unit 2.

system for the benefit of customers. The Company requests that the costs for Lake Side 2 be included in its revenue requirement because it is prudent and benefits customers. Lake Side 2 was built to meet customer needs as identified and filed in the Company's 2008 IRP process. Lake Side 2 resulted from a competitive solicitation in an All Source RFP process as the least-cost adjusted for risk resource. Based on these conclusions, I recommend that the Commission approve these projects for inclusion in rates.

Finally, I recommend that the Commission approve the incremental decommissioning costs as determined by an independent third-party contractor, presented in my testimony, and included in the revenue requirement calculation performed by Mr. McDougal.

Q. Does this conclude your direct testimony?

A. Yes.