BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	)))))	**CASE NO. PAC-E-24-04** **DIRECT TESTIMONY OF RICHARD A. VAIL**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-04

May 2024

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am the Vice President of Transmission at PacifiCorp. I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, capital budgeting for transmission, transmission and distribution project delivery, and administration of the Company's Open Access Transmission Tariff ("OATT").

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science degree with Honors in Electrical Engineering with a focus in electric power systems from Portland State University. I have been Vice President of Transmission for PacifiCorp since December 2012. I was Director of Asset Management from 2007 to 2012. Before that position, I had management responsibility for a number of organizations in PacifiCorp's asset management group including capital planning, maintenance policy, maintenance planning, and investment planning since joining PacifiCorp in 2001.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe PacifiCorp's transmission system and the benefits it provides to Idaho customers, and specifically describe PacifiCorp's major capital investments for new transmission systems included in this rate case. These investments include transmission projects associated with Energy Vision 2024, including Gateway South, Gateway West Segment D.1, Gateway South Supporting projects, and related generation interconnection network upgrades, and a new 14-mile, 345 kilovolt ("kV") transmission line.

My testimony demonstrates that the Company's decisions result in an immediate benefit to PacifiCorp's Idaho customers, and I recommend that the Idaho Public Utilities Commission ("Commission") find these investments are prudent.

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM

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

A. I provide an overview of PacifiCorp's transmission system, transmission reliability requirements, and standards and compliance mechanisms.

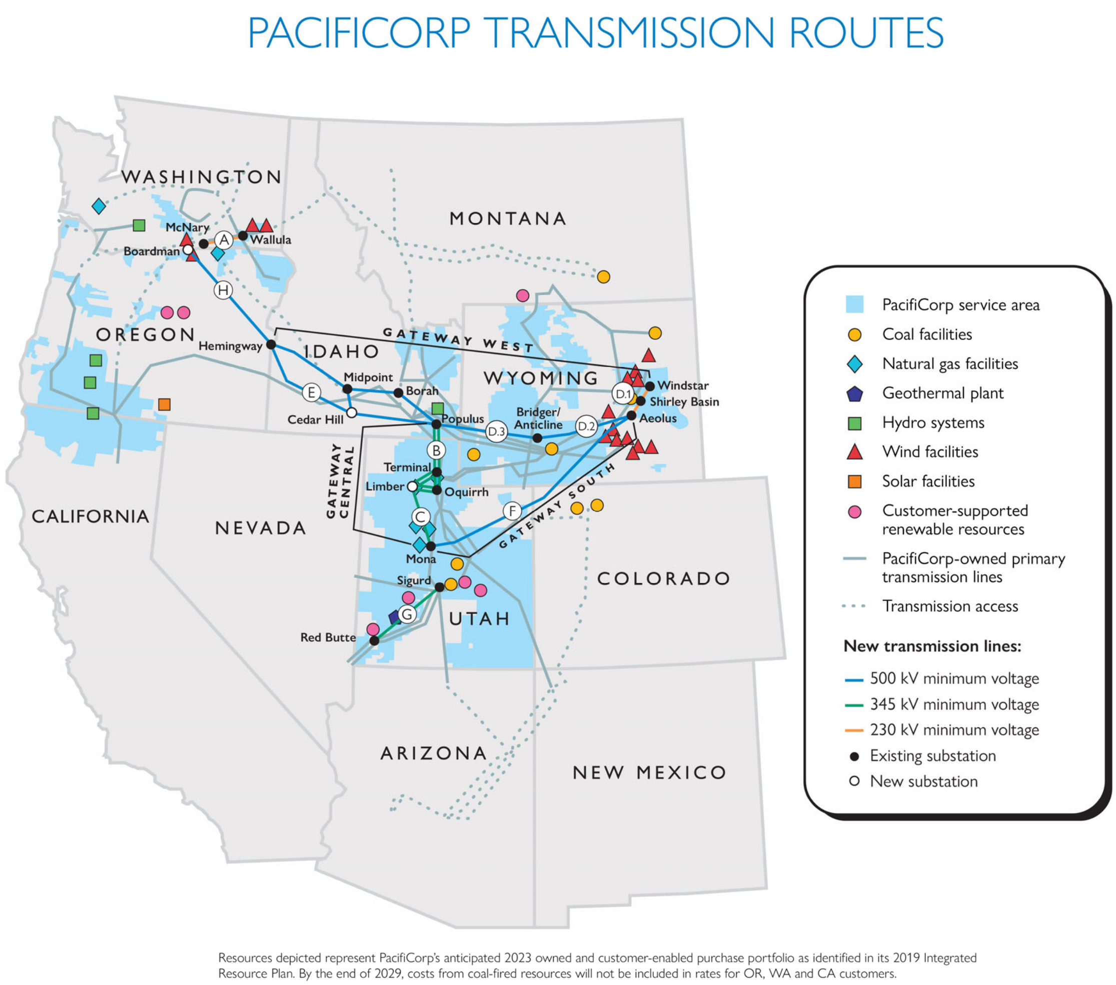
Q. Please provide a brief overview of the purpose of PacifiCorp's transmission system.

A. PacifiCorp's transmission system is designed to reliably transfer affordable electric energy from a broad array of generation resources to loads both within the Company's balancing authority areas ("BAAs") and beyond, including other BAAs that PacifiCorp interconnects with, and participants in the California Independent System Operator's ("CAISO") Western Energy Imbalance Market ("WEIM").

Q. Please briefly describe PacifiCorp's transmission system.

A. As seen in the image below, PacifiCorp owns and operates approximately 17,770 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. PacifiCorp serves nearly two million customers with over 91,000 customers located in Idaho.

Figure 1



Q. What are Balancing Authorities and BAAs?

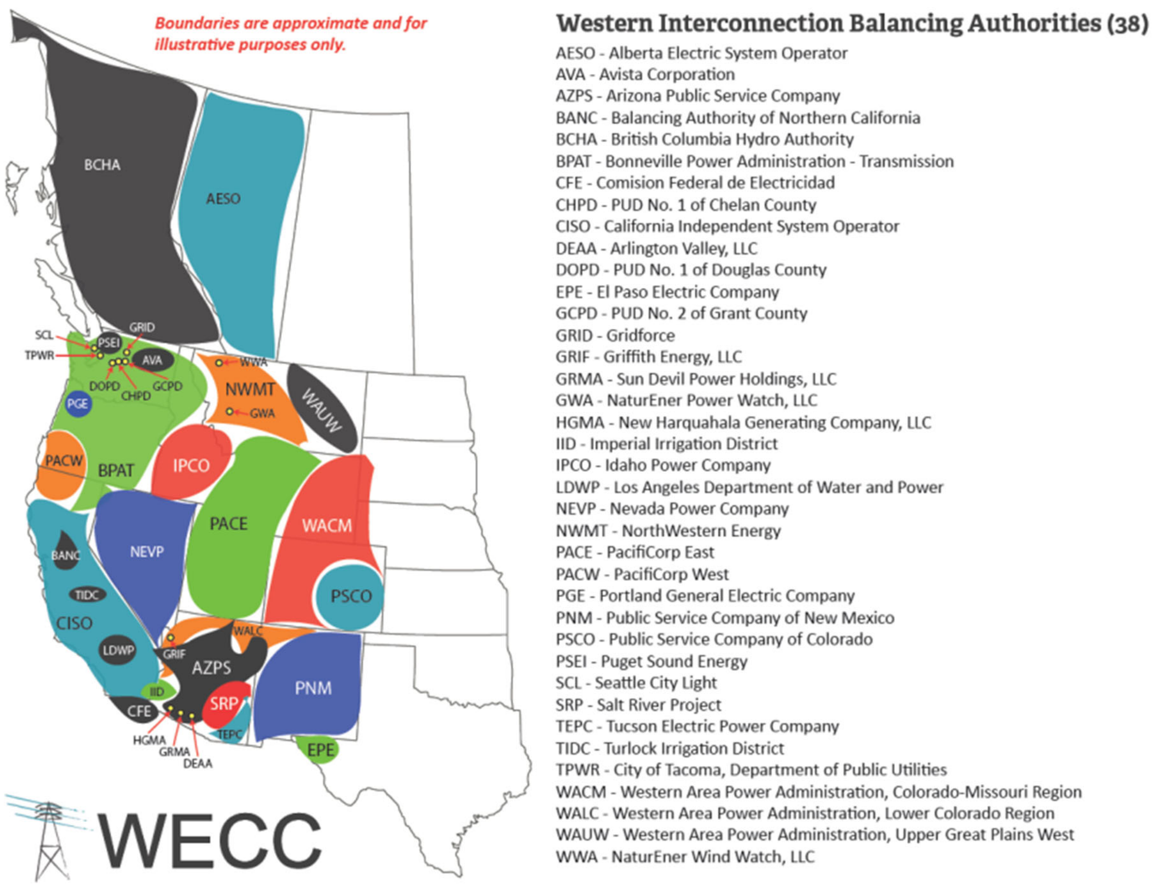
A. A Balancing Authority is the entity responsible for maintaining balance of load, generation, and interchange in a specific BAA, and supports interconnection frequency in real time. BAAs include all the generation, transmission, and loads within a specific metered region.

PacifiCorp is a Balancing Authority and manages two BAAs: PacifiCorp East ("PACE") BAA and PacifiCorp West ("PACW") BAA. The PACE BAA interconnects with utilities in the intermountain west and southwest, and also provides access to the southern portion of the CAISO. The PACE BAA interconnects with utilities in Montana, Idaho, Nevada, Arizona, Colorado, and Wyoming. The PACW BAA includes interconnections with the Bonneville Power Administration ("BPA"), northern points of CAISO, and other utilities in California, Oregon, and Washington.

As a Balancing Authority, PacifiCorp manages the production and consumption of electricity in these areas, by ensuring that there are adequate and available generation resources or electricity transfers from other BAAs to meet load. As seen in the figure below, there are 38 BAAs in the Western Interconnection.[1]

[1] Available at https://www.wecc.org/Administrative/06-Balancing%20Authority%20Overview.pdf.

Figure 2



Q. How does PacifiCorp operate the two BAAs?

A. PacifiCorp separately balances each BAA for energy and load. To optimize dispatch for the benefit of customers, PacifiCorp dispatches generation across both BAAs to serve load across the entire system. Deliveries of energy over PacifiCorp's transmission system are managed and scheduled in accordance with the Federal Energy Regulatory Commission's ("FERC") requirements. The flexibility of PacifiCorp's integrated transmission system provides options for optimizing dispatch to serve load and designating units for holding reserves, and provides for additional reliability during planned or unplanned generation outages. PacifiCorp also provides transmission service across both BAAs, meaning that a transmission customer can purchase transmission service from any point in one BAA to the other BAA, for a single tariff rate.

Q. Please describe PacifiCorp's responsibility for maintaining open access to its transmission system and creating stakeholder transmission planning processes.

A. In 1996, the FERC required transmission system owners like PacifiCorp to provide non-discriminatory access to their transmission systems for all transmission customers.[2] FERC expanded this open-access policy in 2011 by requiring transmission system owners to create regional, inter-regional, and local transmission planning processes.[3]

Under these authorities, the Company is required to provide non-discriminatory and reliable transmission and interconnection service according to the rates, terms, and conditions of PacifiCorp's OATT, and must engage in participant-driven planning processes covering its six-

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[2] *In re Open Access Transmission Services*, Order No. 888, 75 FERC ¶ 61,080 (May 10, 1996).

[3] *In re Transmission Planning and Cost Allocation,* Order No. 1000, 136 FERC ¶ 61,051 (Jul. 21, 2011).

state transmission footprint.[4] These planning processes incorporate economics, reliability, and public policy inputs and requirements to develop comprehensive transmission development strategies.[5]

Where a request for transmission service cannot be reliably provided on the existing system, the Company's OATT and FERC policies require the Company to construct and expand its system to provide FERC-jurisdictional transmission and interconnection service.[6] This obligation to construct transmission facilities in response to transmission or interconnection service requests applies to both newly identified facilities and

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[4] PacifiCorp's Open Access Transmission Tariff Volume No. 11, (updated Apr. 15, 2024) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20240415_OATTMaster.pdf).

[5] *Id.* at Attachment K.; *see, e.g.*, PacifiCorp's Local Transmission System Plan (2022-2023 Biennial Cycle) (Dec. 31, 2023) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf).

[6] PacifiCorp's OATT, §§ 28.2 and 15.4 (reflecting FERC's pro forma tariff and requiring PacifiCorp to construct facilities as necessary to reliably provide requested transmission service); *In re Standardized Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at 767 (2003) (explaining that FERC's pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."); *In re Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at 814 (2007) (explaining that despite certain policy reforms, transmission providers "will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity").

planned system expansions or upgrades.[7]

Q. Please describe PacifiCorp's responsibility for maintaining reliability on its transmission system.

A. In 2005, Congress directed the FERC to establish reliability standards to ensure the safe and reliable operation of the Nation's Bulk Electric System ("BES").[8] The following year, the FERC adopted rules to implement the statute,[9] and delegated these responsibilities to the North American Electric Reliability Corporation ("NERC").[10]

NERC proceeded to establish various reliability standards, including transmission system planning performance requirements ("TPL Standards"). NERC's TPL Standards establish, among other things, "Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable

[7] *In re CAISO Tariff Revision,* 133 FERC ¶ 61,224 (2010) (OATT construction obligations attach to planned facilities identified as necessary to grant interconnection requests, stating that "[t]he fact that CAISO has voluntarily chosen to evaluate a network upgrade in its transmission planning process should not affect the obligation to build these facilities.").

[8] 16 USC § 824o.

[9] *In re Electric Reliability Standards Rulemaking,* 71 FR 8662-01, Docket No. RM05-30-000; Order No. 672 (Feb. 17, 2006).

[10] *In re NERC Certification,* 116 FERC ¶ 61,062 (Jul. 20, 2006), *aff'd Alcoa Inc. v. FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

Contingencies."[11] These TPL Standards, along with regional standards (*i.e.*, established by the Western Electricity Coordinating Council ("WECC")) and utility-specific planning criteria, define the minimum transmission system requirements to safely and reliably serve customers.

Q. How does PacifiCorp ensure compliance with NERC TPL Standards?

A. The Company plans, designs, and operates its transmission system to meet or exceed NERC Standards for the BES, and WECC regional standards and criteria. To ensure compliance with applicable TPL Standards, PacifiCorp conducts an annual system assessment to evaluate the performance of the Company's transmission system and to identify system deficiencies. This annual system assessment is comprised of steady-state, stability, and short circuit analyses to evaluate peak and off-peak load scenarios in the near term (one-, two-, and five- year) and long-term (10-year) planning

[11] Standard TPL-001-5.1 — Transmission System Planning Performance Requirements, at A(3) (available https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf).

horizons.[12] The assessment is performed using power flow base cases maintained by WECC, and is developed in coordination among all transmission planning entities in the Western Interconnection. These base cases include load and resource forecasts, along with planned transmission system changes for each of the future year cases, and are intended to identify future system deficiencies to be mitigated.

As part of these annual system assessments, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission system reinforcement projects or adoption of new operating procedures. In certain instances, operating procedures that change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back or concurrent (N-1-1) transmission system events with allowed system adjustments performed between the two events. However, the use of operating procedure actions has limitations. In particular, actions taken in connection with operating procedures to protect the

[12] Analyses consist of taking a normal system (N-0) and applying events (N-1, N-1-1, N-2, etc.) within each category (P0, P1, P2, P3, etc.) listed within the TPL Standards to identify system deficiencies. For example: An N-1-1 event describes two transmission system elements out of service at the same time, but due to independent causes. An example of an N-1-1 event would be a planned outage of one 230 kilovolt transmission line followed by an unplanned outage of any additional element in the system being used to continue service with the initial element out.

integrity of the larger integrated transmission system in the Western Interconnection can lead to large outages on the occurrence of the second of two back-to-back (N-1-1) events. An effective corrective action plan, one that does not over-rely on operating procedure actions, is critical to ensuring system reliability so that large numbers of customers are not subject to avoidable outage risk.

Q. Is compliance with the reliability standards optional?

A. No. The reliability standards are a federal requirement, subject to oversight and enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1.29 million per day, per violation.

Accordingly, reliability standards are a major driver for the new capital investments in PacifiCorp’s system transmission assets that are identified in and supported by my testimony below.

Q. Are there additional concerns that influence PacifiCorp's distribution and transmission system investment decisions?

A. Yes. Depending on the project, there are several factors that inform whether PacifiCorp will build new distribution and transmission facilities, including increased demand for transmission capacity, requests for transmission service, requests for generation interconnection service, increased demand for distribution capacity, and the age and condition of existing distribution and transmission facilities. The specific concerns for the projects addressed in my testimony are described in more detail below.

IV. CUSTOMER BENEFITS OF PACIFICORP'S TRANSMISSION SYSTEM

Q. Please describe how PacifiCorp's transmission system benefits Idaho customers.

A. PacifiCorp's transmission system is designed to reliably transport electricity from a broad array of generation resources to load across both BAAs, and the Company operates a geographically diverse and expansive transmission system serving retail customers in six western states. This unique geographic footprint, including over 17,770 miles of transmission lines, allows the Company to take advantage of efficiencies and economies from both a planning and operational perspective due to, among other things, retail load characteristics and variable resource diversity. PacifiCorp's transmission system provides over 200 interconnections with adjacent transmission provider BAAs, as well as access to regional energy market hubs in Washington, the California-Oregon Border, Utah, the Four Corners area, and Arizona.

This geographic diversity, access to adjacent transmission providers and BAAs, and access to regional energy market hubs allows PacifiCorp to economically dispatch units across its system and transfer energy from other systems as facilitated by the Company's participation in the WEIM. This expansive footprint ensures that PacifiCorp is uniquely situated to access some of the nation's best wind and most cost-effective solar resources to serve customer load.

PacifiCorp also takes advantage of its transmission system to minimize operation costs related to generation reserve requirements and blackstart capability. The Company is required to carry reserves to ensure system reliability in the event of changes in load or system events. Instead carrying reserves and blackstart capability for each BAA, PacifiCorp can operate its transmission as a collective system and use resources that are geographically remote to meet the system requirements in all areas that PacifiCorp serves. This allows the Company to engage in the most economic dispatch of these resources to lower costs for its customers.

Q. Does PacifiCorp currently carry reserves in each BAA sufficient to meet that BAA's requirements?

A. Not always. While meeting reliability standard reserve requirements is not a transmission function, PacifiCorp's transmission system provides flexibility for PacifiCorp to meet its reserve requirements.

Q. Are investments across the system necessary to maintain PacifiCorp's transmission system?

A. Yes. The ability to flexibly use a diverse set of energy resources depends significantly on the strength and reliability of PacifiCorp's transmission system to connect those resources to PacifiCorp's retail customers in all six states. Transmission system outages and other real-time operation constraints can unnecessarily burden the transmission system when corrective action plans are required to comply with NERC and WECC reliability authorities. Increasing PacifiCorp's transmission system capacity enhances reliability, allows more generation to interconnect to serve customer load, and provides flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

Q. Can the benefits of a reliable system be easily quantified?

A. No. Reliability is, essentially, the absence of system disruptions. It is difficult to quantify the benefit of reliability investments. That said, the access to different regions and redundancy in operations provides reliable service under a variety of conditions that benefits all PacifiCorp's customers.

V. OVERVIEW OF INVESTMENTS

Q. What specific transmission system investments are you addressing in your testimony?

A. My testimony addresses PacifiCorp's major planned transmission system projects that will go in-service during the test period for this rate case. Each of these investments will increase PacifiCorp's load serving capability, enhance reliability, conform with NERC Reliability Standards, improve transfer capability within the existing system, accommodate point-to-point transmission service requests, relieve existing congestion, and interconnect and integrate new wind resources into PacifiCorp's transmission system. These projects include:

- The Gateway South Segment F Aeolus to Mona/Clover 500 kV and Gateway West Segment D.1 Windstar to Aeolus 230 kV Transmission Lines;
- The EV2024 Generation Interconnection Network upgrades;
- The Anticline 345 kV Phase Shifter;
- Gateway South Supporting Projects;
- The Oquirrh Terminal 345 kV Line Project; and
- Path C Transmission Improvements Project.

Q. What are the projected investment costs of these projects and their anticipated in-service dates?

A. Please see the table below for the total-Company costs and in-service dates for each project. These amounts include costs for engineering, project management, materials and equipment, construction, right-of-way, and an allowance for funds used during construction. These costs are detailed in the testimony and exhibits of Company witness Shelley E. McCoy. The in-service dates are based on our current best available information at the time of preparing this case.

TABLE 1

Project	Total-Company Cost (million)	Idaho-Allocated Cost (million)	Final In-Service Date
Gateway South	$2,069.8	$112.1	December 2024
Gateway West Segment D.1	$278.2	$15.1	Various - 2024
EV2024 Network upgrades	$40.1	$2.2	Various - 2024
Anticline 345 kV Phase Shifter	$133.5	$7.2	November 2024
Gateway South Supporting Projects	$20.2	$1.1	December 2024
Oquirrh Terminal 345 kV Line	$75.8	$4.1	November 2024
Path C Transmission Improvements	$31.3	$1.7	May 2024

Q. Will PacifiCorp's OATT transmission customers pay their proportional share of these assets?

A. Yes. Transmission customers pay for transmission and ancillary services through the Company's transmission formula OATT rate.[13] Formula rates are updated by the Company's annual transmission revenue requirement ("ATRR") filing that includes the total cost of providing firm transmission service over the test year.[14] This includes all transmission system investments made

[13] *In re PacifiCorp's Application for Formula Rates*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

[14] *See, e.g.*, PacifiCorp's OATT Volume No. 11, Attachment H: ATRR for Network Integration Transmission Service (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20240415_OATTMaster.pdf).

by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments.[15] Transmission assets, including the capital expenditures described in this rate case, will be included in the Company's annual ATRR filing when each asset is placed in service, weighted by months in service as necessary. This annual filing results in a wholesale customer rate by dividing the total ATRR by firm transmission demand. This rate is then assessed against PacifiCorp's transmission customers.[16]

Q. Do PacifiCorp's Idaho retail customers receive an offsetting revenue credit for a portion of the transmission revenue received under PacifiCorp's OATT?

A. Yes. A portion of PacifiCorp's transmission revenues are credited to the Company's state retail customers. Under this approach, the Company allocates 100 percent of its transmission costs to both state retail and FERC-jurisdictional customers. The FERC, through the

[15] *Id.* at Attachment H-2: Formula Rate Implementation Protocols, at 376-398 (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf); *see also, e.g., In re PacifiCorp's 2024 Transmission Formula Annual Update,* Docket No. ER11-3643 (May 13, 2022) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/2024_Depreciation_Rate_Update_ER24-1612.pdf).

[16] *PacifiCorp's Transmission and Ancillary Services Rates* (effective Jun. 1, 2023) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20230601.pdf).

Company's ATRR filings, determines the appropriate amount to be recovered from PacifiCorp's wholesale customers. This same amount is then credited to PacifiCorp's retail customers. This ensures that PacifiCorp recovers its transmission expenditures, and both wholesale and retail customers only pay their proportional share of the Company's transmission system.

The testimony below provides additional discussion and details for each of transmission investments that the Company seeks rate recovery for in this proceeding.

A. Gateway South and Gateway West Transmission Lines

Q. Please describe the Energy Gateway Transmission Expansion.

A. In 2007, PacifiCorp launched the Energy Gateway Transmission Expansion, a multi-year strategy to add approximately 2,000 miles of new transmission lines across the west.[17] To date, three major segments of Energy Gateway are complete and in service. After over a decade of planning, the Company now proposes to move forward with constructing the Gateway South (Segment F) and a portion of Gateway West lines (Segment D.1).[18] The

[17] *See generally* https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html.

[18] *See, e.g.,* PacifiCorp 2021 Integrated Resource Plan, Vol. 1, Ch. 4 – Transmission, at 83-102 (available 2021 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf).

following graphic provides an overview of the Energy Gateway Transmission Expansion generally, and the Gateway South and Gateway West lines specifically.

Figure 3

This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Q. Please describe the Gateway South Transmission Project.

A. The Gateway South Project includes the following elements:

- A 416-mile, high voltage 500 kV transmission line from the Aeolus substation, near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.

- Rebuilding certain 345 kV transmission facilities in and around the Mona and Clover substations in Utah.

- Two new series compensation stations.

- Expansion of the Aeolus, Anticline, and Clover substations along with modifications to the Mona substation.

- Additional shunt capacitors at Aeolus, Clover, Bonanza (Utah), Riverton and Mustang (Wyoming) substations.

- Additions and modifications to various remedial actions schemes, voltage controllers and control schemes necessary to ensure protection and control of the grid after integration of Gateway South.

Q. Please describe the Gateway West Segment D.1 Transmission Project.

A. Gateway West Segment D.1 includes the following elements:

- A new 59-mile high-voltage, 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock Wyoming.

- Rebuild of the existing Dave Johnston – Amasa – Difficulty – Shirley Basin 230 kV transmission line, which runs approximately 57 miles from the Shirley Basin substation in southeastern Wyoming to the Dave Johnston substation near Glenrock, Wyoming.

- A new 230 kV Heward substation adjacent to the Difficulty substation.

- Additions to the Shirley Basin, Dave Johnston, and Windstar substations.

Q. Please explain why the Gateway South and Gateway West Transmission Projects (collectively, the "Transmission Projects") are needed.

A. The Transmission Projects are an important component of the Company's Energy Gateway Transmission Expansion, and Gateway South has long been recognized as a key transmission segment in the region's long-term transmission planning. These lines will provide substantial customer benefits.

For example, the Company needs additional resources to serve load, and the Transmission Projects enable new, cost-effective Wyoming generation resources to fill this need: these Transmission Projects allow the Company to interconnect up to approximately 2,030 megawatts ("MW") of new resources. These projects will also improve reliability of the transmission system by providing capacity between Gateway West and Gateway Central and relieve transmission congestion on the existing Wyoming 230 kV transmission system.

The addition of Gateway South relieves the stress on the existing 345 kV transmission system that traverses from Wyoming to Southeast Idaho (Populus and Threemile Knoll substations) and through Idaho to the west. The addition of the Gateway South line unloads these 345 kV lines which would otherwise be stressed to serve Wasatch Front load during peak load conditions. The addition of Gateway South and unloading of the existing 345 kV and the underlying 138 kV transmission system enhances the reliability of customers in southeast Idaho and Goshen area and other customers in Idaho. The unloading of these 345 kV lines into Idaho also improves the load serving capability using cost effective resources for customers in Idaho.

Q. Is the increased capacity provided by the Transmission Projects consistent with the Company's obligation to provide transmission service under its OATT?

A. Yes. PacifiCorp adhered to OATT processes when identifying the need for these transmission projects. In response to nearly 2,500 MW of transmission and interconnection service requests, the Company determined that the Transmission Projects were necessary to facilitate the various requests because PacifiCorp lacked adequate transmission capacity. As a result the Transmission Projects have been included in multiple FERC-jurisdictional executed contracts. For example, PacifiCorp has executed 13 contracts with third-party customers that require constructing one or both of the Transmission Projects, including a transmission service agreement that requires construction of Gateway South to reliably provide 500 MW firm point-to-point transmission service beginning by the contract start date of January 1, 2025. The Transmission Projects are lynchpins in PacifiCorp's ability to meet its obligation to grant generator interconnection service and transmission service under the OATT.

The Transmission Projects will also enhance the Company's ability to comply with mandated NERC and WECC reliability and performance standards. Congestion on the current transmission system in eastern Wyoming limits the ability to deliver energy from eastern Wyoming to PacifiCorp load centers in Wyoming, Idaho, Utah, and the Pacific Northwest.

Q. Do the Transmission Projects increase the amount of generation that can be interconnected and delivered across the Company's transmission system?

A. Yes. The Transmission Projects will allow the Company to interconnect an additional 2,030 MW of generation resources in eastern Wyoming, and increase the system transfer capability by approximately 875 MW from the Windstar/Dave Johnston area south to Shirley Basin/Aeolus. This will create approximately 1,700 MW of incremental transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover).

Q. Did the Company consider alternatives to Transmission Projects?

A. Yes. PacifiCorp and Northern Grid (then the Northern Tier Transmission Group, an unincorporated association of entities that promotes coordinated and transparent transmission planning and facilitates compliance with FERC transmission planning and reliability standards for the Pacific Northwest and Intermountain West) evaluated one alternative. This alternative analyzed one 345 kV line with bundled conductors from Aeolus to Anticline (138 miles), and two 345 kV lines with bundled conductors from Anticline to Populus (approximately 198 miles each), along with other supporting mitigation such as transformers and shunt capacitors at different substations.

These analyses indicated that the alternatives were less beneficial compared to the Gateway West and South projects for two reasons. First, these alternative lines would reduce the number of renewable resources that could be interconnected to eastern Wyoming by approximately 1,100 MW compared to Gateway West and South.

Second, this alternative showed additional reliability issues on the transmission system between Rock Springs and Monument, and also between Populus and

Terminal, that would have to be mitigated to comply with relevant reliability standards. This would result in additional cost burdens. Like the Aeolus to Clover line, this alternative does not provide an adequately diverse path for PacifiCorp's network loads.

These two considerations led the Company to conclude that Gateway West and South were more beneficial.

Q. If it did not construct the Transmission Projects, would the Company be able to serve the roughly 2,500 MW of interconnection and transmission service without constructing additional facilities?

A. No, it would not be possible to serve these requests for interconnection and transmission services with PacifiCorp's existing BES. For example, to grant only the 500 MW transmission service request, the Company would be required to construct a 230 kV line at a cost of approximately $1 billion. To grant the transmission and interconnection service requests, consistent with the Company's OATT, would require construction of the functional equivalent of the infrastructure contemplated by the current Transmission Projects.

Q. Has the Company obtained all necessary permits and rights-of-way ("ROW") for the Transmission Projects?

A. Yes. All permits, certificates of public convenience and necessity, and ROW for both Gateway South and Gateway West Segment D.1 have been secured.

Q. Has PacifiCorp begun construction of the Transmission Projects?

A. Yes. Once the Company received necessary permits and ROW, the Company began construction of the Gateway South Project in June 2022, and late September 2022 for Gateway West Segment D.1.

Q. Is the Company confident that the Transmission Projects will be in service by 2024?

A. Yes. To manage construction schedule risk, the Company has structured and managed the projects on firm, date-certain, fixed-price, turnkey contracts. Construction contractors and equipment suppliers will be held to key construction and delivery milestones, guarantees, and development of compressed schedule mitigation plans, if required. The construction remains on-track and on schedule.

Q. Are the Transmission Projects currently on budget?

A. Yes. The project budgets based on contractual provisions require fixed cash flows that are assessed monthly against confirmed construction progress, in addition to identification and mitigation of project risks that could stall or delay completion. To date, almost 2 years from starting construction, both projects remain on budget.

Q. What are the remaining major milestones for the Transmission Projects?

A. Key milestones remaining before the in-service date for these two projects include:

- Complete all wound core device deliveries by August 2024.
- Complete construction of the 500 kV transmission line by October 2024.
- Complete all communications network additions and upgrades by October 2024.
- Complete construction of the 230 kV Windstar to Shirley Basin line by December 2024.
- Complete reconstruction of the 230 kV transmission line by November 2024.
- Complete commissioning and placed in-service in fourth quarter of 2024.

The Transmission Projects are on track to achieve each milestone.

B. <u>EV2024 Generation Interconnection Network Upgrades</u>

Q. What are network upgrades?

A. Network upgrades are the modifications or additions to transmission-related facilities that are integrated with and support PacifiCorp's overall Transmission System for the general benefit of system users.[19]

Q. Please explain how network upgrade costs are allocated under the Company's OATT.

A. When PacifiCorp receives a request for generation interconnection or transmission service, the Company completes various studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request.[20] The studies classify any required additions to support the requested service into two categories: direct assigned or network upgrade. Direct-assigned assets only benefit, or are used solely by, the customer requesting generator interconnection or transmission service. Those costs are directly assigned and paid for by that customer and will not be included in either the Company's ATRR or retail rates. Network upgrades, on the other hand, benefit all customers that use the transmission system. Network upgrade costs can be included in PacifiCorp's ATRR, and ATRR revenues are then credited to PacifiCorp's retail customers in each state.[21]

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[19] PacifiCorp's OATT Volume No. 11, § 1.27 (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20240415_OATTMaster.pdf).
[20] *Id.* §§ 38-43.
[21] *Id.* 47.

Q. Is the Company requesting recovery of any Generation Interconnection Network Upgrades?

A. Yes. There are five generation interconnection projects that were selected from a recent request for proposal to interconnect 1,640 MW of new wind generation to the Company's transmission system in eastern Wyoming that are relevant to the test period in this rate case. The request for proposal process and the resulting resources that were selected are described in the testimony of Company witness Rick T. Link. A separate generation interconnection agreement was negotiated and signed for all five projects, and each will require generation interconnection network upgrades to interconnect and integrate with PacifiCorp's system. These projects include:

- Q0409 Boswell Springs Wind. This project is a 320 MW wind facility that will interconnect to the existing Freezeout 230 kV substation near Aeolus and is planned to be in service by December 31, 2024. This project includes a new breaker at the Freezeout substation, and a new remedial action scheme and communications equipment at Aeolus substation.

- Q0713 Cedar Springs IV Wind. This project is a 350 MW wind facility that will interconnect to the existing Yellowcake 230 kV substation near Windstar, and is planned to be in service on January 15, 2025. This project includes construction of a new line position at the Yellowcake substation, including the installation of three new 230 kV circuit breakers, and requires a new microwave system and approximately 18 miles of fiber optic cable between Yellowcake and Windstar substations.

- Q0785 Anticline Wind. This project is a 100 MW wind facility that will interconnect to a new substation on PacifiCorp's Casper – Claim Jumper 230 kV line and is planned to be in service on December 31, 2024. This project includes a new three breaker ring bus substation on the Casper – Claim Jumper 230 kV line, substation loop in on transmission line, communications upgrade at Casper substation, and Main Grid operations center updates.

- Q0835 Rock Creek Wind 1. This project is a 190 MW wind facility that will interconnect to PacifiCorp's existing Foote Creek 230 kV substation and is planned to be placed in service on December 15, 2024. This project includes expansion of substation, bus, and line position at Foote Creek substation, expansion for new breaker and line positions at Freezeout and Aeolus substations, construction of new approximately 4 miles long 230 kV transmission line between Aeolus and Freezeout substations.

- Q0836 Rock Creek Wind 2. This project is a 400 MW wind facility that will interconnect to PacifiCorp's existing Aeolus 230 kV substation and is planned to be placed in service on December 15, 2024. This project includes a new bay for a 230 kV line terminal at Aeolus substation.

Q. Why are these projects classified as network upgrades, and not directly assigned assets?

A. The interconnection study for each project indicated that these upgrades would provide system-wide benefits. Under PacifiCorp's OATT, this requires the Company to include these costs in the Company's ATRR, as opposed to directly assigning these costs to each project. Accordingly, the network upgrade costs for each of these projects are reflected in their respective Large Generator Interconnection Agreements.

Q. Is the Company confident that it can manage any construction schedule risk and deliver the network upgrades for the new wind facilities by the planned in-service dates?

A. Yes. To manage construction scheduling risk, the Company structured each network upgrade contract on a firm, date-certain, turnkey contract basis. Construction contractors and equipment suppliers are held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required. The Company also established construction contract completion dates and backstopped each with guarantees. To date, the remaining network upgrades remain on track for planned in-service dates.

C. Anticline 345 kV Phase Shifter

Q. Please describe the proposed Anticline 345 kV Phase Shifter Project.

A. The Anticline 345 kV Phase Shifter project will install four 345 kV phase shifting transformers (533.3/597.3 megavolt amperes ("MVA") each (summer normal/4-hour emergency), +40/-40 degrees) at Anticline substation, near Point of Rocks, Wyoming.

Q. Please explain why these projects are needed and beneficial.

A. With the addition of the Gateway South Project, the phase shifters at Anticline are needed to enhance Wyoming transmission utilization and maximize the production of eastern Wyoming wind generation. By utilizing the phase shifters at Anticline, flows on the Aeolus – Bridger/Anticline line can be actively controlled to unload the underlying 230 kV system west of Aeolus, and manage flows on the Aeolus – Clover 500 kV (Gateway South) and the Aeolus-Anticline 500 kV transmission line to within limits depending on system conditions. If the Gateway South transmission path rating limit is exceeded, eastern Wyoming wind generation must be curtailed, and the phase shifters prevent unnecessary curtailment.

Q. Did PacifiCorp consider alternatives to the Anticline 345 kV Phase Shifter project?

A. Yes. Other transmission path power flow control methods, such as multi-segment series capacitors, were previously investigated; however, the installation of phase shifting transformers at Anticline to provide active control flows on the Anticline – Bridger 345 kV line was the most efficient and cost effective as it provides variable flow control using multiple taps on the phase shifter. In addition, adding more than 70 percent series compensation on the transmission line is not preferred, and it would limit the applicability of this proposed alternative.

D. Gateway South Supporting Projects

Q. Please describe the Gateway South Supporting Projects.

A. The Gateway South line requires additional supporting projects to enhance Wyoming transmission utilization and maximize the production of eastern Wyoming wind generation. These additional supporting projects include:

- Install one 41.6 megavolt amperes reactive MVAr shunt capacitor bank at Riverton 230 kV substation, two 30 MVAr shunt capacitor banks at Mustang 230 kV substation, and one 60 MVAr shunt capacitor bank at Bonanza (Deseret Power owned) 138 kV substation. These facilities help maintain flows and voltage reliability at each substation.

- Modification to the Aeolus remedial action scheme ("RAS") to add Gateway South line logic and additional wind projects as part of the wind selection logic.

- Modifications to the Bridger RAS to support additional wind generation and include it in the wind selection logic.

- Implementation of a new fast voltage controller ("FVC") at Aeolus substation to prevent high voltages for the loss of 500kV lines under heavy load scenarios and protect the transmission system under transient conditions (0-15 cycles).

- Modification of the existing Master Grid Controller at Aeolus, to accommodate the addition of the new windfarms and have an appropriate voltage coordination with the added wind farms. The Master Grid Controller is used to maintain the voltage at Aeolus.

- Development of operating procedures to mitigate N-1-1 loss of the two 230 kV paths from Dave Johnston/Windstar area to Aeolus.

- Modifications to the Energy Management System ("EMS") to support monitoring flows on the transmission paths.

Q. Please explain why these projects are needed and beneficial.

A. The shunt capacitor banks will support additional power flows through the Riverton – Wyopo 230 kV and Mustang – Bridger 230 kV lines under outage conditions and will also alleviate low voltage issues. This is because the loss of transmission lines from Dave Johnston/Windstar to the Aeolus area would divert all generation resources in the Dave Johnston/Windstar area towards the Riverton - Wyopo 230 kV and Mustang – Bridger 230 kV lines, and would cause low voltages on the Riverton and Mustang 230 kV buses. Without the shunt capacitor banks, the outage would require significant reductions in wind generation to maintain power flows and voltage reliability at the Mustang and Riverton 230 kV buses. The Bonanza shunt capacitor bank will be owned by Deseret Power, and an agreement has been signed for them to install with PacifiCorp reimbursing their costs.

Modifying the Aeolus RAS is required to add the Gateway South line and the additional wind projects to the Company’s transmission logic, to trip 627 MW of wind generation for the loss of any of the Gateway South elements from Aeolus to Clover. For the Bridger RAS, until the Bridger units are available for tripping, minor system changes might be required, but if the Bridger units are unavailable while keeping the 2400/2200 MW path limit, additional wind generation will have to be included in the Bridger RAS for tripping due to the wind being utilized to load the Bridger West path.

The Aeolus FVC is designed to prevent high voltage at Aeolus 500 kV and Aeolus 230 kV bus for the loss of either 500 kV line under transient conditions immediately after the line has tripped. Because Gateway South requires three new 200 MVAr shunt capacitors on the Aeolus 500 kV and 230 kV substations, planning studies have demonstrated that the loss of either 500 kV line could result in high voltages if the shunt capacitors banks are not tripped quickly. Manually tripping shunt capacitors is a complex task, because it depends on evaluating real-time and anticipated power flow levels, and which 500 kV lines are in-service. It is difficult to implement this logic as part of a comprehensive protection scheme. Instead, the Aeolus FVC is designed to automatically and quickly trip the shunt capacitor banks and prevent high voltages from the loss of 500 kV lines.

Developing an operating procedure for the Windstar area for the N-1-1 loss of the two 230 kV transmission paths from Dave Johnston/Windstar area to Aeolus would require generation curtailment to prevent thermal overloads and low voltage issues in the Casper, Riverton, Thermopolis, and Mustang areas. The operating procedure will identify the list of generators that can be curtailed along with the list of contingencies for which the curtailment may be necessary depending on dispatch scenarios.

Q. Did PacifiCorp consider alternatives to these supporting projects?

A. Yes. Two alternatives were considered instead of installing the shunt capacitors at Mustang and Riverton. The first was additional transmission from the Dave Johnston/Windstar area to Aeolus, similar to Gateway West segment D.1 (Windstar – Shirley Basin), and the second was installing a +/- 100 MVAR Static Var Compensator at Casper. The installation of the shunt capacitors was deemed to be the most efficient and cost-effective option.

The Company also considered alternatives to the Aeolus RAS modification requirements, which would result in additional transmission from Aeolus – Clover. This would be a significant cost compared to modification of the RAS. In addition, without the RAS modification, the amount of renewable resources that could be integrated into the eastern Wyoming system would be reduced by a minimum of 400 MW.

The Company also considered alternatives for the Jim Bridger RAS modification, which would result in additional new transmission between Jim Bridger and Populus (approximately 200 miles of new 345 kV line). Similar to the Aeolus RAS modification, this would require a significant cost as compared to the modification of the RAS. In addition, without the RAS modification PacifiCorp would be unable to achieve the full path rating on Bridger West under different operating conditions such as high wind and low Bridger generation.

E. Oquirrh Terminal 345 kV Line Project

Q. Please describe the Oquirrh Terminal 345 kV Line Projects.

A. This project involves the construction of a new 14-mile double circuit, 345 kV transmission line between the Company's Oquirrh substation in West Jordan, Utah, and

Terminal substation in Salt Lake City, Utah. This transmission line will link together the previously completed Mona to Oquirrh and Populus to Terminal transmission lines, which were both part of the Gateway Central portion of the Energy Gateway Transmission Expansion.

Q. Please explain why this project is needed and beneficial.

A. This project mitigates transmission constraints that currently exist between the Mona area and Wasatch front, and will improve system reliability and operational redundancy allowing for better load serving capability under various system conditions.

For example, the northbound transmission capacity on the Wasatch Front South ("WFS") internal transmission cut plane (a 4,945 MW rating) is currently fully utilized,[22] and transmission planning studies show that new transmission facilities are necessary to meet anticipated network load service, reliability, contractual point-to-point commitments and enhance WEIM benefits. There are also ongoing requests to interconnect additional renewable generation resources

[22] Previous technical studies have determined the current WFS transfer capability to be 4,945 MW, prior to addition of the Oquirrh - Terminal 345 kV line addition and associated companion projects. At 4,945 MW, the WFS path is 100 percent committed (2016), prior to the addition of the Gateway South transmission project.

in southern Utah and transmit the energy north that further exceed the transmission capacity on the WFS path north of Mona/Clover. Additionally, the Company anticipates that future Gateway South transfers into the Mona/Clover area will require additional transmission going north, and will require the Oquirrh-Terminal double circuit line to increase northbound transfers across the WFS transmission path. Finally, NERC TPL-001-4, requirements P1 and P7 mandate increased transmission system reliability and operational redundancy in the area under all expected operating conditions.

The Oquirrh – Terminal double circuit transmission line, in conjunction with the companion projects, addresses each of these issues. It enhances transmission system reliability and operational redundancy within the Wasatch Front by adding additional capacity. This additional transmission capacity also avoids 1,800 MW of curtailment to the WFS cut plane, and also a similar reduction of the equivalent amount of renewable or conventional generators in southern/central Utah, that would otherwise be required to reduce congestion. This increased capacity also avoids the increase stress on the transmission system from Wyoming to the west and northern Utah that otherwise would be used to serve load in the northwest. Additionally, without this new transmission, under system-outage conditions, load shed of up to 1,350 MW may be required to reduce thermal overload below its 30-minute emergency rating.

Q. Did PacifiCorp consider alternatives to the Oquirrh Terminal 345 kV Line?

A. Yes. PacifiCorp took an iterative approach for resolving system limitations to increase transmission capacity on the WFS cut plane. This transmission cut plane helps resources from southern Utah move north to serve load, as well as export power further north and to the northwest. Based on the Wasatch Front South Study Table 6 posted on PacifiCorp's OASIS,[23] PacifiCorp first identified an alternative mitigation to resolve the same system limitation (simultaneous outage of two Oquirrh – Terminal #1 & 2 345 kV lines). This alternative only allowed for a certain amount of capacity increases before the same limitation was observed again, and no other alternative mitigations were available to increase transmission capacity between Oquirrh and Terminal other than adding new transmission. The Company's Oquirrh Terminal 345 kV project adds new transmission, though provides a higher increase in transmission capacity that

[23] Available at https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Wasatch_Front_South_Boundary_Capacity_7_29_2021.pdf.

allows additional resources to move south-to-north compared to the alternative case.

F. <u>Path C Transmission Improvement Project</u>

Q. Please describe the Path C Transmission Improvement Project.

A. The Path C Transmission Improvement project adds a new 345/138 kV source in northern Utah and southeast Idaho by looping the existing Populus - Terminal 345 kV line in and out of the Bridgerland and Ben Lomond substations. The project also includes upgrades at Bridgerland substation, including a 345/138 kV 700 MVA autotransformer; a new 345 kV bus; three 345 kV breakers; and four 138 kV breakers. This new 345/138 kV source will improve the reliability of the 138 kV system, which runs parallel to Path C and will eliminate system limitations on the parallel 138 kV lines. It will also help maintain Path C (southeast Idaho – northern Utah) ratings as well as add operational flexibility under outage conditions at Ben Lomond substation.

Q. Please explain why these projects are needed and beneficial.

A. The Path C Transmission Improvement project resolves N-2 issues that were identified as part of an NERC FAC-013 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon. This assessment was conducted to maintain WECC Path C ratings to 1,600 MW southbound, and 1,250 MW northbound. The project also adds a new 345/138 kV source in northern Utah and southeast Idaho which improves the reliability of the 138 kV system, which runs parallel to Path C and adds operational flexibility under outage conditions at Ben Lomond substation.

Q. Did PacifiCorp consider alternatives to the Path C Transmission Improvement project?

A. Yes. The first alternative considered was to rebuild 6.3 miles of Oneida – Treasureton line, 29.5 miles of the Treasureton – Wheelon 138 kV line, expand the Bridgerland 138 kV substation, and loop in the Honeyville – Wheelon 138 kV line in and out of the substation. However, this alternative only resolves issues related to Path C southbound flows. To resolve northbound issues on Path C, an additional rebuild of 22.6 miles of double circuit line from Ben Lomond – Honeyville and 9 miles of Ben Lomond – White Rock 138 kV line would still be required. These alternatives were higher costs than the Company's primary choice.

VI. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission conclude that the projects described above are prudent.

Q. Does this conclude your direct testimony?

A. Yes.