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 Richard A. Vail**
RATES AND CHARGES IN IDAHO	)	
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

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

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 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. PacifiCorp's transmission system is designed to reliably transfer electric energy from a broad array of generation resources to load.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, all transmission system capacity increases provide benefits to customers by increasing reliability and allowing more generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

I describe the status of PacifiCorp's construction of the Aeolus-to-Bridger/Anticline 500 kilovolts ("kV") Transmission Line and the additional 230 kV network upgrades required to interconnect the Energy Vision 2020 Wind projects ("230 kV Network Upgrades"). I specifically address the current timeline and estimate of costs.

I also describe PacifiCorp's major capital investment projects for new transmission systems included in this rate case, specifically:

- Mona-Oquirrh 345 kV Transmission Line
- Sigurd-Red Butte-Crystal 345 kV Transmission Line
- Wallula to McNary 230 kV Transmission Line
- Snow Goose 500/230 kV Substation
- Vantage to Pomona Heights 230 kV Transmission Line
- Goshen-Sugarmill-Rigby 161 kV Transmission Line
- Goshen #3 345/161 kV 700 Megavolt-Ampere ("MVA") Transformer Installation

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

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND INVESTMENT DRIVERS

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 16,500 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. PacifiCorp serves over 1.9 million customers with approximately 85,000 customers located in Idaho.

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

A. In 1996, the Federal Energy Regulatory Commission ("FERC") issued Order No. 888,[1] which required that transmission system owners provide non-discriminatory access to their transmission systems. PacifiCorp is obligated under its OATT to plan its transmission system for open access to all transmission customers. Through the OATT Attachment K local planning process and the FERC Order 1000 regional and inter-regional planning processes, PacifiCorp participates in open stakeholder planning processes covering its entire transmission footprint. These planning processes result in system plans that incorporate economics, reliability, and public policy inputs and

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[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

requirements. PacifiCorp must also coordinate with other entities in the region for transmission planning purposes as required under FERC Order No. 1000.[2] In addition to these more general requirements, PacifiCorp also must comply with the specific requirements of the mandatory reliability standards approved by FERC.

Q. Who establishes transmission reliability standards?

A. FERC directs the North American Electric Reliability Corporation ("NERC") to develop Reliability Standards to ensure the safe and reliable operation of the Bulk Electric System ("BES") in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards. A subset of the transmission reliability standards are the transmission planning standards ("TPL Standards"). The purpose of the TPL Standards is to "establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[3] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria 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.

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[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g, Order No. 1000-B 141 FERC ¶ 61,044 (2012).
[3] *See* http://www.nerc.com/files/tpl-001-4.pdf.

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

A. The Company plans, designs, and operates its transmission system to meet or exceed NERC Standards for 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. The annual system assessment is comprised of steady-state, stability, and short circuit analyses[4] to evaluate peak and off-peak load seasons in the near-term (one-, two-, and five-year) and long-term (10-year) planning horizons. The assessment is performed using power flow base cases maintained by WECC and 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 the annual system assessment, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission system reinforcement projects or, as applicable, adoption of new operating procedures. In certain instances, operating procedures prescribing action to change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back ("N-1-1") (or concurrent) transmission system events.

[4] 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 in order to identify system deficiencies. Example: An N-1-1 event describes two transmission system elements being 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 kV transmission line followed by an unplanned outage of any element in the system being used to continue service with the initial element out.

However, the use of operating procedure actions does have limitations. In particular, actions taken in connection with operating procedures that are designed to protect the integrity of the larger integrated transmission system in the Western Interconnection of the United States can lead to large numbers of customers being at risk of an outage upon the occurrence of the second of two N-1-1 events. An effective corrective action plan is critical to ensuring system reliability so that large numbers of customers are not subjected 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 other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1 million per day, per violation. Accordingly, and as described more fully later in my testimony, compliance with reliability standards is a major driver for the new capital investments in PacifiCorp's transmission assets identified in and supported by my testimony.

Q. Please identify other drivers that are relevant to the capital investments in PacifiCorp's transmission system described in your testimony.

A. There are several other drivers that inform whether PacifiCorp will build new transmission facilities, including increased demand for transmission capacity, requests for transmission service, and the age and condition of existing transmission facilities. The specific drivers for the projects addressed in my testimony are described in more detail later in my testimony.

IV. OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY

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

A. My testimony addresses PacifiCorp's major new transmission system projects included in this general rate case. Specifically, my testimony addresses the following projects:

1. Aeolus to Bridger/Anticline Line and network upgrades associated with new wind generation interconnections:

The new transmission lines consist of 140 miles of 500 kV transmission line; the new Aeolus (500/230 kV) and Anticline (500-345 kV) substations; a five-mile, 345 kV transmission line from the Anticline substation to the Jim Bridger substation; and a voltage control device at the existing Latham substation, as shown in the map attached in Exhibit No. 24. The 230 kV Network Upgrades are required to accommodate the transmission project and the interconnection of the Energy Vision 2020 New Wind Projects.

2. Mona to Oquirrh 345 kV Transmission Line Project:

The Mona to Oquirrh 345 kV transmission line project involved the construction of a single-circuit 500 kV transmission line, energized at 345 kV, originating from the Clover substation near Mona in Juab County, Utah, extending northward approximately 70 miles to the proposed future Limber substation located in Tooele County, Utah, referred to as the Limber Tap, and continuing from the Limber Tap as a double-circuit 345 kV line for approximately 30 miles to the Oquirrh Substation in South Jordan, Utah, as shown in the map attached in Exhibit No. 25.

3. Sigurd to Red Butte 345 kV Transmission Line Project:

The Sigurd to Red Butte 345 kV transmission line project constructed a new single circuit 345 kV transmission line between Sigurd substation in Sevier County, Utah and Red Butte substation in Washington County, Utah, as shown in the map attached in Exhibit No. 26. The project also included substation and control system upgrades and modifications at both Sigurd and Red Butte substations

4. Wallula to McNary 230 kV Transmission Line:

The Wallula to McNary 230 kV new transmission line extending from Wallula substation located in Wallula, Washington, to McNary substation located near Umatilla, Oregon, as shown in the map attached in Exhibit No. 27.

5. Snow Goose 500/230 kV Substation:

The Snow Goose 500/230 kV substation which is located near Klamath Falls, Oregon, as shown in the map attached in Exhibit No. 28.

6. Vantage to Pomona Heights 230 kV Transmission Line:

The Vantage to Pomona Heights 230 kV new transmission line extending from Vantage substation located northeast of Yakima, Washington, to Pomona Heights substation located in Selah, Washington, as shown in the map attached in Exhibit No. 29.

7. Goshen-Sugarmill-Rigby 161 kV Transmission Line:

The Goshen-Sugarmill-Rigby 161 kV transmission line rebuild of an existing 69 kV line from Goshen substation to Sugarmill substation and then construction of a new 161 kV line from Sugarmill substation to Rigby substation located in the southeast Idaho area, as shown in the map attached in Exhibit No. 30.

8. Goshen #3 345/161 kV 700 MVA Transformer Installation:

The Goshen #3 345/161 kV 700 MVA transformer installation project located in southeast Idaho, as shown in the map attached in Exhibit No. 31.

Q. What are the projected costs associated with these transmission investments and their associated in-service dates?

A. Table 1[5] identifies the specific projects and associated costs and in-service dates.

Table 1

Project	**Total Company**	**In-Service Date**
Aeolus to Bridger/Anticline 500 kV line		
Sequence One (In Service)	$2.1	2017
Sequence Two (In Service)	$4.1	July 2018
Sequence Three (In Service)	$12.7	January 2020
Sequence Four (includes 2021 closeout costs)	$634.0	November 2020
TOTAL 500 kV line	**$652.9**	
230 kV Network Upgrades		
Q707 TB Flats 1 (includes 2021 closeout costs)	$36.8	September 2020
Q712 Cedar Springs Wind 1ts) (includes 2021 closeout costs)	$59.1	November 2020
TOTAL 230 kV Network Upgrades	**$95.9**	
Other Transmission Projects		
Mona to Oquirrh 345 kV Transmission Line (In Service)	$363.9	May 2013
Sigurd-Red Butte 345kV Line		
Sequence One (In Service)	$2.2m	May 2013
Sequence Two (In Service	$349.0m	May 2015
Sequence Four (In Service)	$3.4m	June 2017
Wallula to McNary 230 kV New Transmission Line		
Sequence One (In Service)	$6.4	December 2017
Sequence Two (In Service)	$36.2	January 2019

[5] As discussed later in my testimony, Sequence One of the Aeolus to Bridger/Anticline 500 kV line was placed into service in 2011.

Snow Goose 500-230 kV New Substation Project		
Sequence One (In Service)	$10.3	May 2017
Sequence Two (In Service)	$32.5	November 2017
Vantage to Pomona Heights 230 kV New	$63.8	May 2020
Goshen-Sugarmill-Rigby 161kV Transmission Line Project		
Sequence One (In Service)	$26.0	November 2020
Sequence Two (In Service)	$3.1	February 2021
Sequence Three	$9.2	May 2021
Sequence Four	$1.2	July 2021
Sequence Five	$7.0	Dec 2021
Sequence Six (not included in this case)	N/A	February 2022
Goshen #3 345/161 kV 700 MVA Transformer Install TPL		
Sequence One (In Service)	$21.0	December 2020
Sequence Two	$9.7	June 2021
Sequence Three (not included in this case)	N/A	March 2023

These amounts include costs associated with engineering, project management, materials and equipment, construction, right-of-way, and an allowance for funds used during construction. These costs are also shown in the testimony and exhibits of Mr. Steven R. McDougal. The in-service dates are based on the best available information at the time of preparing this case.

Q. **Please briefly describe the benefits associated with these investments.**

A. The benefits associated with these investments include increased load serving capability, enhanced reliability, conformance with NERC Reliability Standards, improved transfer capability within the existing system, and relief of existing congestion. These benefits will be described more fully below.

Q. Will PacifiCorp's OATT transmission customers pay for some of these assets?

A. Yes, through OATT transmission charges. The Company's current transmission formula rate (included in PacifiCorp's OATT) was approved by FERC in Docket No. ER11-3643.[6] The Company's transmission formula rate is updated annually with the annual transmission revenue requirement ("ATRR") that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments. Transmission assets, including new transmission capital, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing the ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's retail jurisdictions.

Q. Please explain how network upgrade cost allocation works under the OATT.

A. In accordance with its OATT, when PacifiCorp receives a request for generation interconnection or transmission service, the Company completes studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request. The studies identify the facilities and upgrades required and classify the asset additions required to support the service into two categories: direct assigned or network upgrade. Direct assigned assets are those assets that only benefit or are used solely by

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[6] *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

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 rate base. Network upgrades, on the other hand, are those assets that benefit all customers using the transmission system. Costs associated with network upgrades are investments by the transmission provider and are included in PacifiCorp's ATRR[7] and retail rate base.

V. AEOLUS TO BRIDGER/ANTICLINE TRANSMISSION LINE AND NETWORK UPGRADES

Q. Please describe the investment for the Aeolus to Bridger/Anticline transmission line that is included in the Energy Vision 2020.

A. The Aeolus to Bridger/Anticline transmission line was planned to be placed in-service in four sequences. The first sequence was the purchase of property used for the new Aeolus and Anticline substations, which was completed in March 2011. The second sequence was to construct a replacement access bridge over the Medicine Bow River and complete associated upgrades to an existing unpaved county road in July 2018. The third sequence of work, completed in January 2020, was the expansion of the Latham Substation with a new line termination bay to accommodate the installation of a static synchronous compensator voltage control device. Finally, the last sequence of plant in-service, completed in November 2020, included the two 500 kV substations (i.e. Aeolus

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[7] For generation interconnection customers, those customers may be required to pay the initial cost of network upgrades, subject to refund through credits to invoiced charges for transmission service and full refund of any remaining amounts after 20 years. *See* Section 11.4 of PacifiCorp's Standard Large Generator Interconnection Agreement (OATT Attachment N, Appendix 6 and available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20200501_OATTMASTER.pdf); *see also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-B, 109 FERC ¶ 61,287 (Dec. 20, 2004).

and Anticline), the static synchronous compensator voltage control device and the 500 kV transmission line.

Q. Please describe the 230 kV Network Upgrades associated with the Energy Vision 2020 Projects.

A. The generation interconnection projects selected as part of a request for proposal to interconnect 1,150 megawatts ("MW") of new wind generation to the transmission system in eastern Wyoming were fully described in Case No. PAC-E-17-07[8] and are summarized below. Separate generation interconnection agreements were negotiated and signed for each of the projects.

The Ekola Flats network upgrades were placed in-service in August 2020. This work included one 230 kV circuit breaker and one line position with associated switches, which were included in the Aeolus substation scope of work. As such there are no stand-alone network upgrade costs associated with the Ekola Flats project.

The TB Flats I and II network upgrades were placed in-service in November 2020. This project included a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from Shirley Basin substation to Aeolus substation and included modifications at the Shirley Basin substation.

The Cedar Springs network upgrades were placed in-service in December 2020. This project included the reconstruction of four miles of an existing 230 kV transmission line between Aeolus substation and the Freezeout substation, including the modifications required at the Freezeout substation; the reconstruction of 14 miles

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[8] *In the matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities*, Case No. Pac-E-17-07, Order No. 34104 (July 20, 2018).

of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications as required at the Freezeout and Standpipe substations; and the reconstruction of 16 miles of an existing 230 kV transmission line from the Aeolus substation to Shirley Basin substation.

Q. Did the Company implement any contingency options on the project?

A. Yes. PacifiCorp instituted a contingency plan for two components of the 230 kV Network Upgrades. Construction work was hampered during the winter/spring seasons of 2020 on account of severe winter weather. The Bureau of Land Management imposed stringent winter game restrictions that adversely affected construction. The dates affected by the additional Bureau of Land Management restrictions were the May 2020 estimated completion dates for two transmission line segments of the 230 kV Network Upgrades: Aeolus to Shirley Basin and Aeolus to Freezeout.

The only impact from the additional restrictions was an anticipated delay to supplying back-feed power to the Ekola Flats wind project, which was needed by June 15, 2020. The Company, however, implemented a contingency plan that supplied the back-feed power needed, on a temporary basis, by the June 15, 2020 date, until substantial completion the Aeolus to Shirley Basin and Aeolus to Freezeout transmission lines was achieved on November 4, 2020. No other contingency solutions were required.

Q. What were the major milestones to achieve in-service of the Aeolus to Bridger/Anticline transmission line and 230 kV Network Upgrades?

A. Major milestones are identified below:

500 kV Transmission

- Mechanical Completion; September 22, 2020
- Substantial Completion; November 4, 2020

500 kV Substations

- Mechanical Completion Aeolus 230 kV yard; May 27, 2020
- Substantial Completion Aeolus 230 kV yard; June 15, 2020
- Mechanical Completion (all remaining work); October 30, 2020
- Substantial Completion (all remaining work); October 31, 2020

230 kV Network Upgrades

- Aeolus to Shirley Basin Substantial Completion: October 31, 2020[9]
- Aeolus to Freezeout Substantial Completion: October 23, 2020[10]
- Freezeout to Standpipe Substantial Completion: October 13, 2020
- Aeolus to Shirley Basin (rebuild) Substantial Completion: November 5, 2020

Q. Please describe the total cost of the Aeolus to Bridger/Anticline transmission line compared to the amount approved in Case No. PAC-E-17-07.

A. The actual and forecasted costs of the Aeolus to Bridger/Anticline transmission line are $652.9 million, approximately $26 million lower than the $679.2 million approved in Case No. PAC-E-17-07. The entire cost of the Aeolus to Bridger/Anticline transmission line will be incurred by the Company without contribution from any transmission customer projects.

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[9] Changed from May 15, 2020, due to additional restrictions imposed by the Bureau of Land Management.
[10] Changed from May 30, 2020, due to additional restrictions imposed by the Bureau of Land Management.

Q. Please describe the total cost of the 230 kV Network Upgrades compared to the amount approved in Case No. PAC-E-17-07.

A. The 230 kV Network Upgrades actual and forecast cost are $95.9 million, approximately $17.9 million more than the $78.0 million estimate approved by the Commission.[11]

Q. What are the drivers for the cost increase?

A. The increase in cost was due to the competitive bid price received for the transmission line elements of the 230 kV Network Upgrades, which exceeded the initial forecast value. The increase in transmission line costs are attributable to market conditions that changed after the initial cost estimate was prepared in early 2017 and approved by the Commission in Case No PAC-E-17-07. The estimate was prepared using historical metrics to develop a cost plan, which could not have accounted for the rapid expansion of projects in the industry that occurred just prior to the time of the bid, including Pacific Gas & Electric Company's transmission improvement program, initiated in response to extensive wildfires in California. Further increases were caused by extreme weather conditions, birds and nesting environmental concerns, and delays in getting required outages from the Western Area Power Administration.

Q. Did the Company issue a request for proposals for the 230 kV Network Upgrades?

A. Yes. The competitively bid price reflected excess demand on lineman resources as a result of the increased project demand described above. In addition, the increase in projects also created cost impacts on steel and other materials. Several potential bidders

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[11] *In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Rate Making Treatment for New Wind and Transmission Facilities,* Case No. PAC-E-17-07, Order No. 34104 (Jul. 20, 2018).

who had previously done work for PacifiCorp declined to bid, citing lack of resources as their reason. Nevertheless, a subsequent final competitive auction among finalist bidders resulted in an approximate 4.5 percent reduction from the original bid value.

Q. Why was there an increase for the 230 kV Network Upgrades but not for the Aeolus to Bridger/Anticline transmission line?

A. The Company sought bids for the Aeolus to Bridger/Anticline transmission line earlier in the process. The construction requirements in California following the wildfires, however, changed the market conditions when the Company went to bid the 230 kV Network Upgrade projects.

Q. How does the current cost projection for the Aeolus to Bridger/Anticline transmission line and 230 kV Network Upgrades compare to what was filed in Case No. PAC-E-17-07?

A. The current cost projection for the remaining work to complete the Aeolus to Bridger/Anticline transmission line and 230 kV network upgrades is approximately $8 million lower than the amount approved in Case No. PAC-E-17-07.

VI. THE MONA-TO-OQUIRRH 345 KV TRANSMISSION LINE PROJECT

Q. Please describe the Mona-to-Oquirrh Project.

A. This Project was one component of the Company's long range transmission plan and consists of a single-circuit 500 kV transmission line, energized at 345 kV, originating from the Clover substation near Mona in Juab County, Utah, extending northward about 70 miles to the proposed future Limber substation to be located in Tooele County, Utah, referred to as the Limber Tap, and continuing from the Limber Tap as a double-circuit

345 kV line for approximately 30 miles to the Oquirrh Substation in South Jordan, Utah.[12]

To accommodate the Mona-to-Oquirrh transmission lines, the Oquirrh substation was upgraded and modified. In addition, the Company constructed the 500kV/345kV/138kV Clover substation located approximately three miles south of the Mona substation. The Clover substation, that went into service in December 2012, is the southern termination point of the Mona-to-Oquirrh Project and was necessary to provide local 138 kV transmission service to reliably support customers in the local area. The Clover substation will also be the southern termination point for the future Gateway South project, although the upgrades necessary to accommodate Gateway South are not being done at this time, and the costs associated with those upgrades are not included in this proceeding.

Q. What is the status of the Mona-to-Oquirrh Project?

A. Construction on the Mona-to-Oquirrh Project began in March 2011. The 500/345 kV transmission line between the Clover and Oquirrh substations was placed into service in May 2013. Construction of the Clover Substation started in August 2011 and was placed into service in December 2012.

Q. How did the Company ensure that the costs expended to engineer, design, site, and build the Mona-to-Oquirrh Project were the most cost effective for its customers?

A. From a planning perspective, the Company applied prudent industry standards to identify the best transmission route and substation locations in order to balance

[12] See map in Exhibit No. 25.

engineering requirements, environmental impacts, project costs, and impacts to communities during the siting process, while ensuring that the siting criteria requirements were met. This included the completion of project siting and routing feasibility studies by the Company between 2005 and 2007, and the completion of the National Environmental Policy Act Environmental Impact Statement process between January 2007 and February 2011, resulting in an agency "Record of Decision." This process determined the final "preferred" transmission line route and substation locations, which were then incorporated into the Company's competitive bidding process for construction.

Q. Please describe the Company's competitive bidding process for the Mona to Oquirrh 345 kV transmission line project.

A. The Company initiated a competitive bidding process to receive blind sealed bids for the project to be delivered on a turnkey, fixed price, guaranteed completion date basis using an engineer, procure, and construct ("EPC") contract. The competitive bidding process began in July 2009 and provided two separate blind-sealed bidding opportunities. All bid responses were due in October 2009 and again in June 2010 after additional information was provided to bidders allowing a refinement of previously submitted design solutions and terms and conditions, including price. Seven qualified bids were received in October 2009. After extensive evaluations of bidder proposals and review of exceptions to work scope and base terms and conditions from each bid proposal, the final two most qualified bidders were identified. The Company received best and final offers from the final two competing proposals in June 2010. The Company awarded the contract and issued a notice of intent in December 2010, with a notice to proceed issued in February 2011. This process resulted in the Company obtaining the lowest risk evaluated cost for delivery of the Mona-to-Oquirrh Project.

Q. With respect to the construction of the Mona-to-Oquirrh Project, how did the Company ensure that the costs to build the project were controlled?

A. EPC contracts are regarded in the industry as a prudent approach to control costs and manage design, procurement, and construction risks. EPC contracts provide schedule and cost certainty to the benefit of customers and, where possible, cap potential cost escalations upon the occurrence of defined risks. EPC contracts also ensure more timely delivery of needed testing, commissioning, and in-service dates to support system needs and help ensure ongoing transmission system reliability.

The fixed-price EPC contract for the Mona-to-Oquirrh Project has strong provisions to control cost and schedule variances. Where cost and schedule variances were not included in the fixed price for certain contingent aspects of the work scope, these items were identified as risk items and a contingent capped price and schedule allowance were agreed to before contract execution. Contingent risk items were limited to defined occurrences such as weather delays and environmental impacts.

Q. How will the Mona-to-Oquirrh Project benefit the Company's customers?

A. The Mona-to-Oquirrh Project is a key component required for executing the Company's current and future integrated resource plans, which require reliable transport of designated network resources to network loads. Executing those plans is necessary to ensure an adequate, reliable, and low-cost supply of energy is available and benefits our customers. Having adequate long-term transmission system capacity is fundamental in developing and executing those integrated plans.

Q. What analysis has the Company performed to quantify the benefits that the Mona-to-Oquirrh Project provides to the Company's customers?

A. The Mona-to-Oquirrh Project, including its associated costs and benefits, was evaluated on multiple occasions to address changes in the Company's business environment and to ensure the Company continued to meet customer needs and provided desired benefits.

Evaluation of the Mona-to-Oquirrh Project began in early 2007 as part of the overall Energy Gateway analysis, where net power cost calculations were compared against Energy Gateway construction costs and the preferred resource portfolio in the Company's Integrated Resource Plan ("IRP") at the time.

Q. Has additional analysis been performed since 2009 regarding the cost and benefits of the Mona-to-Oquirrh Project?

A. Yes. In August 2010, variable power production cost savings were calculated through the IRP Production and Resource model with and without the entire Energy Gateway project for a 50-year period, discounted back to net present values. The variable production cost inputs used four different combinations of CO_2 taxes per ton and variable future natural gas prices. These results showed a range of expected variable production cost savings benefits between $331 million dollars to $549 million dollars for the Mona-to-Oquirrh Project.

Q. Was the lowest cost alternative selected and constructed to meet the Mona-to-Oquirrh Project requirements and to the benefit of customers?

A. Yes. All customers benefited from the project alternative that was selected and then ultimately constructed by the Company. This alternative selection resulted in an overall reduced capital investment amounting to an estimated $181 million savings over the next best project alternative. This resulted in a lower overall revenue requirement for the Project and ultimately for customers.

Q. Are there other benefits to customers associated with the completion of the Mona-to-Oquirrh Project?

A. Yes. Not only does the project provide new transmission capacity necessary to serve our customers, but it also provides significant system and operational reliability benefits to the existing system that mitigate the risk of customer outages and load curtailments. The Mona-to-Oquirrh Project provides transmission reliability improvements to the existing system between the Mona and Camp Williams substations and between Camp Williams and the Oquirrh substation. The Mona-to-Oquirrh Project provides a parallel and alternative transmission path providing backup capability to the existing system in the event of a system outage.

Specifically, the project provides new transmission capacity between Camp Williams and Oquirrh eliminating the need for capital expenditures estimated at $70 million for construction of a new 345 kV transmission line between the Camp Williams and Oquirrh substations that would otherwise be needed for reliability in the area.

In addition, the Mona-to-Oquirrh Project provides customers with reliability risk reduction benefits on the existing system between Mona and Camp Williams because it reduces the exposure to customer load loss and associated energy curtailments during transmission system outages, both planned and unplanned. The customer load at risk reduction due to the addition of the Mona-to-Oquirrh Project has benefits valued over a range of potential energy replacement costs. Two scenarios analyzed in 2013 estimated benefits between $29 million to $210 million, and the risk reduction benefits continue to grow in 2020 to a range of $214 million to $1,765 million. The Mona-to-Oquirrh Project, by its selection and design, provides the above-stated operational reliability benefits and reduces risk for our customers. These system reliability benefits are not captured in Company net power cost or IRP modeling activities.

Q. Does the Mona-to-Oquirrh Project provide other benefits to the Company's transmission system?

A. Yes. The transmission grid can be affected in its entirety by what happens on an individual transmission line. For example, the transmission path between southern and northern Utah is comprised of several individual transmission lines or line segments. A single outage on any of the individual lines due to storm, fire, or external human interference can and does cause significant reductions in transmission capacity and can negatively affect our ability to serve customers. The Mona-to-Oquirrh Project allows the Company to continue to meet load service obligations in all its states and contractual obligations to third parties under its OATT. The project connects to other existing and future segments of Energy Gateway that interconnect the Company's western and eastern balancing areas, increasing the ability to transport low-cost energy to the benefit of all our customers. The Mona-to-Oquirrh Project also improved the Company's access to energy markets, including the Energy Imbalance Market.

Q. Are there other benefits you see from this Mona-to-Oquirrh Project?

A. Yes. The Mona-to-Oquirrh Project is necessary to maintain the Company's compliance with mandatory reliability standards, while providing the next necessary increment of transmission capacity for our customers. It also supports and can be reliably integrated with other future planned transmission investments that are currently proposed by the Company and other utilities in the WECC region. This project positions the Company to be more strongly interconnected to other regional projects currently being planned and provides options for access to additional future energy resources.

Q. Was the Mona-to-Oquirrh Project included in a Company IRP?

A. Yes. The Company's 2011 IRP included the Mona-to-Oquirrh Project as part of the modeled transmission topology for the purpose of selecting the Company's preferred portfolio of future supply-side and demand-side resources. The 2011 IRP Action Plan, Chapter 9, included a number of actions needed to deliver the plan, one of which was to "Permit and construct a 500 kV line between Mona and Oquirrh." In Chapter 10, Transmission System Action Plan, the Company provided detailed information for the Mona-to-Oquirrh Project. The project was necessary to integrate network generation resources identified in the IRP into the Company's extensive transmission system to meet our customers' energy demands. The Commission accepted the Company's 2011 IRP.[13]

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[13] *In the Matter of the Filing by PacifiCorp dba Rocky Mountain Power of its 2011 Integrated Resource Plan*, Case No. PAC-E-11-10, Order No. 32351 (Sept. 16, 2011).

Q. Was the Mona-to-Oquirrh Project included in previous IRPs?

A. Yes. The Mona-to-Oquirrh Project was evaluated for cost-effectiveness from an integrated system benefits perspective as part of the 2007 IRP filed with the Commission in May 2007. This analysis helped support the decision to include the Mona-to-Oquirrh Project as part of the Company's preferred resource portfolio.

Q. Were alternatives to the Mona-to-Oquirrh Project considered?

A. Yes. Long-term alternatives to constructing a new transmission line are limited; however, alternatives were assessed by the Company during the IRP process. Alternatives considered included: (1) electric load and demand-side management and energy conservation as part of the Company's IRP; (2) the installation of new generation facilities within the Salt Lake City area; and (3) additional capacity to existing transmission lines and alternative transmission technologies. As a result of the resource portfolio modeling conducted for the 2011 IRP, the Company concluded that none of these alternatives met the Company's needs and long-term requirements, and additional transmission transfer capability in Utah presented the lowest overall cost and was the best alternative to meet our customers' demand for electricity.

VII. SIGURD TO RED BUTTE 345 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Sigurd to Red Butte 345 kV Transmission Line Project.

A. This project is a 170-mile single circuit 345 kV line from Sigurd substation in Sevier County, Utah to Red Butte substation in Washington County, Utah, as shown in the map attached in Exhibit No. 26. This project was placed in-service in three sequences. The first sequence, placed in-service in May 2013, was the Three Peaks series capacitor upgrade. The second sequence included all segments of the new 345 kV transmission line, as well as the required upgrades and modifications at Red Butte and Sigurd substations. Sequence three was the completion of the final cultural report required as part of the National Environmental Policy Act permitting process.

Q. Please explain the benefits of this investment in the Sigurd to Red Butte 345 kV line and why it is needed.

A. The Sigurd to Red Butte 345 kV line provides a reliable and adequate supply of electricity to meet existing and future electrical loads. Without the increased transmission capacity provided by the Sigurd to Red Butte 345 kV line, the Company would have faced an increased and unacceptable risk of not being able to meet its load service obligations during peak periods. The Sigurd to Red Butte 345 kV transmission line enhances the Company's ability to provide safe, reliable, and efficient service to all customers. Further, to provide low-cost energy, the Company must have the ability to acquire power from numerous generation sources to negotiate the most competitive pricing.

The addition of the Sigurd to Red Butte 345 kV line is an important piece in strengthening the Western Interconnection transmission infrastructure. The Sigurd to Red Butte 345 kV line has resulted in a stronger interconnection with other parts of the Western Interconnection, providing better transmission system access to the other sources of generation. The Sigurd to Red Butte 345 kV line, especially when complemented with other projects, such as the Populus to Terminal transmission project and the Mona to Oquirrh transmission project, greatly strengthens the Company's transmission capacity and flexibility. This is necessary, based upon the near-term and long-term load growth projections of the Company and its transmission customers, as well as the contingencies and restrictions occurring on the system during outage conditions.

Q. Has the investment in the Sigurd to Red Butte 345 kV line enhanced PacifiCorp's access to wholesale markets?

A. Yes. By adding transmission capacity, the Company has increased its ability and options to obtain power from additional generation sources at competitive pricing. In December 2015, Nevada Energy joined the EIM and established an Energy Transfer System Resource ("ETSR") at Red Butte. The Red Butte ETSR provides PacifiCorp the ability to facilitate intra-hour transfers between NV Energy and the rest of the EIM footprint. Were it not for the investment in the transmission segment, PacifiCorp's EIM transfer capability would likely be 200 MW lower at this ETSR, providing less customer benefits.

Q. Please explain the benefits of the investment in the Three Peaks series capacitor upgrade and why it was needed.

A. To support the additional load flows brought about by the completion of the new Sigurd to Red Butte 345 kV line, the Three Peaks series capacitor needed to be modified to increase the current (ampere) rating. The Three Peaks series capacitor upgrade had to be placed in-service before placing the new transmission line between Sigurd and Red Butte substations in-service. With the completion of the Three Peaks series capacitor project ahead of the Sigurd to Red Butte 345 kV line, the southern Utah transfer capability was increased.

Q. Did PacifiCorp consider alternatives to investing in Sigurd to Red Butte 345 kV Transmission Line Project?

A. The Company took significant steps to identify and implement alternatives that delayed the need for the Sigurd to Red Butte 345 kV Transmission Line Project. These included: (1) completion of interim projects in 2009 which added major equipment to the existing Three Peaks substation, thus improving the 345 kV system operation and increasing reliability for serving the general area; (2) addition of major equipment and devices in 2011 to the existing Red Butte substation, which increased system capacity, improved voltage support, and maintained the reliability of the system in the general area; and (3) the addition of a 345/230 kV 375 MVA transformer, also in 2011, to the Harry Allen substation. These projects, along with special operating procedures, allowed the Company to delay the Sigurd to Red Butte line until the summer of 2015.

PacifiCorp also considered advancing construction of a 345 kV transmission line from Sigurd to St. George, Utah. The 2011 Southwest Utah Joint Study Report, conducted in association with Utah Associated Municipal Power Systems, Deseret Power, and PacifiCorp determined that a future transmission line beyond the proposed Sigurd to Red Butte 345 kV Transmission Line Project will be needed between Sigurd and St. George, Utah, when load and reliability requirements reach a critical point, at the time estimated to be beyond 2025.[14] The planned Sigurd to St. George, Utah 345 kV line would be 185 miles in length, compared to 170 miles for the Sigurd to Red Butte 345 kV line, and would have been more costly and provided fewer system

[14] Updated studies now indicate load and reliability requirements in the area do not require additional action until 2028.

benefits than the enhanced interconnection with a neighboring balancing authority area. Additionally, the future line will connect to four substations instead of the two which the Sigurd to Red Butte 345 kV line connects to.

VII. WALLULA-MCNARY 230 KV NEW TRANSMISSION LINE

Q. Please describe the investment for the Wallula to McNary 230 kV New Transmission Line.

A. The Wallula to McNary 230 kV New Transmission Line project consisted of two sequences of work, the combined costs of which are included in this general rate case. The first work sequence was placed in-service in December 2017 for $6.4 million and included expansion at PacifiCorp's Wallula substation, as well as relay and communications work at the Nine Mile substation. The second sequence of work was the construction of the new 230 kV transmission line that went into service in January 2019, for $36.2 million. A one-line diagram of the Wallula to McNary 230 kV New Transmission Line project is included in Exhibit No. 27.

Q. Please explain why this investment in the Wallula to McNary 230 kV New Transmission Line project was necessary.

A. The Wallula to McNary 230 kV New Transmission Line project was needed to enable PacifiCorp to comply with PacifiCorp's OATT, its transmission service agreements, and FERC's requirements to provide the requested transmission service. Before this line went into service, there were only two MW of available transfer capacity on the existing line between Wallula and McNary, which was insufficient to satisfy the requests for service from providers of generation capacity from renewable resources. The completion of the project now enables PacifiCorp to fulfill such requests in compliance with its OATT requirements and will also increase the Company's access to generation capacity from new resources.

In addition, the project enhances transmission reliability by providing a second connection between the Bonneville Power Administration's ("BPA") McNary substation and PacifiCorp's Wallula substation. With only a single line between Wallula and McNary, line outages (either planned or unplanned), historically caused disruption of service to customers. This disruption resulted in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation. The new second line will provide service reliability in a single line outage condition, and, because it was constructed with lightning protection, the new line reduces lightning-caused voltage sag events in the area.

Q. Did PacifiCorp consider alternatives to investing in the Wallula to McNary 230 kV New Transmission Line project?

A. Yes. In lieu of the selected project, PacifiCorp considered re-building the existing Wallula to McNary 230 kV transmission line to a double circuit line, but this project had an estimated cost of $73.6 million. As a second alternative, PacifiCorp considered re-conductoring the existing Wallula to McNary 230 kV transmission line with high temperature conductor. This alternative would have required the addition of phase shifting transformers to produce increased flow on the line and a new substation to place the equipment at an estimated cost of $53.6 million. Both alternatives were rejected due to cost savings associated with investing in the Wallula to McNary 230 kV New Transmission Line project.

VIII. SNOW GOOSE 500/230 KV NEW SUBSTATION

Q. Please describe the investment for the Snow Goose 500/230 kV New Substation project.

A. This project consisted of constructing a new 500/230 kV substation located near Klamath Falls, Oregon, as shown on the map provided in Exhibit No. 28. The new Snow Goose substation has a 500/230 kV, 650 MVA transformer bank and associated switchgear. In addition, PacifiCorp constructed 0.5 miles of 230 kV transmission line and 1.2 miles of 500 kV transmission line to integrate the substation into the area's 230 kV and 500 kV systems. The 230 kV yard was placed in-service in May 2017, and the 500 kV yard was placed in-service in November 2017, for a total of $42.8 million. A one-line diagram of the Snow Goose 500/230 kV New Substation project is also included in Exhibit No. 28.

Q. Please explain the benefits of this investment in the Snow Goose 500/230 kV New Substation and why it was necessary.

A. The need for the Snow Goose 500/230 kV New Substation project was based on achieving continued compliance with reliability standards mandated by NERC under the TPL Standards. In 2012, PacifiCorp performed TPL Standards screening studies that identified system performance deficiencies following the single contingency loss of PacifiCorp's existing 500/230 kV, 650 MVA transformer bank at Malin substation. Specifically, PacifiCorp determined that during the 2017 projected summer peak load conditions, the loss of the transformer bank would result in the system failing to meet the low voltage limits on the PacifiCorp-owned 230 kV, 115 kV and 69 kV systems and an increase in the load on the Copco-Lone Pine 230 kV line. By 2027, the Copco-

Lone Pine 230 kV line would exceed its rated thermal continuous and emergency capacity during this outage. This outage would also cause a reduction of the power flow on the Alturas-Reno WECC Path 76. As a result, firm scheduled transfers on this line could not continue to be supported without a second 230 kV source.

Construction of the Snow Goose substation provided a second 500 kV to 230 kV transmission tie in the area ensuring that PacifiCorp is able to maintain adequate system voltage and power delivery during a single contingency outage condition, thus maintaining service for customers in southern Oregon and northern California.

Q. Did PacifiCorp consider alternatives to investing in the Snow Goose 500/230 kV New Substation project?

A. Yes. In lieu of the Snow Goose 500/230 kV New Substation project, PacifiCorp considered resolving the deficiencies under the TPL Standards by installing a second transformer at Malin substation and building a second line from Malin to Klamath Falls. This alternative was rejected as the Malin substation could not be readily expanded to accommodate a new 500/230 kV transformer position due to physical site constraints. This alternative was estimated to be $85.0 million.

A second alternative would have involved installing a 500/230 kV, 650 MVA transformer at the BPA-owned Captain Jack substation and building 27 miles of 230 kV line from Captain Jack to Klamath Falls. Adding another transformer at Captain Jack substation would require increasing the size of the substation property and reaching an agreement with BPA. This alternative was estimated to be $90.0 million and was rejected because of insufficient space at the BPA-owned Captain Jack substation, inadequacy of the site in serving as a new source of 69 kV to the Klamath Falls metropolitan area, and additional reinforcement requirements of the 230 kV path between Captain Jack and Klamath Falls substations.

The last alternative considered would have involved installing a 500/230 kV, 650 MVA transformer at the Klamath Co-Gen substation and building a new 230 kV line to tap the Klamath Falls-Boyle 230 kV line. As with the first alternative, this option was rejected due to space and cost limitations. Estimated costs for this alternative were $85.0 million.

IX. VANTAGE TO POMONA HEIGHTS 230 KV NEW TRANSMISSION LINE

Q. Please describe the investment for the Vantage to Pomona Heights 230 kV New Transmission Line.

A. The Vantage to Pomona Heights 230 kV new transmission line consists of a new 41 mile, 230 kV transmission line that extends from BPA's Vantage substation near Vantage, Washington, and ends at PacifiCorp's Pomona Heights substation in Yakima, Washington, as shown on the map attached in Exhibit No. 29. The project consists of two sequences of work. The first work sequence to expand the Pomona Heights substation 230 kV ring bus to provide adequate breaker separation between lines and transformers for breaker failure and bus fault events was placed in-service in November 2015 for $9.4 million. The second sequence of work placed in-service in May 2020 for $63.8 million included the installation of a new 230 kV transmission line connected at BPA's Vantage substation and ending at the Pomona Heights substation. The Company has received full federal permissions to construct this transmission line. The final segment permission was received from the Bureau of Land Management on September

27, 2019. This portion of the project included the installation of breakers, protection and control equipment, and communications equipment at each substation as required to monitor and safely operate the new line. The infrastructure additions at Vantage substation were designed, purchased, installed, and maintained by BPA. A one-line diagram of the Vantage to Pomona 230 kV new transmission line is also included in Exhibit No. 29.

Q. Please explain why this investment in the Vantage to Pomona Heights 230 kV New Transmission Line was necessary.

A. The need for the Vantage to Pomona Heights 230 kV project was identified through internal planning studies and a coordinated Northwest Transmission Assessment Committee study in 2007. NERC screening studies conducted in 2009 and subsequent NERC screening studies additionally identified TPL Standards performance deficiencies following breaker failure and bus fault events on the Pomona Heights 230 kV bus and various N-1-1 outages associated with the Wanapum to Pomona Heights 230 kV line. Breaker failure and bus fault and N-1-1 events on other portions of the Yakima 230 kV and 115 kV systems result in additional TPL Standards performance deficiencies. In total, there are eight contingency combinations that were identified that could give rise to the need to shed Yakima area load. The Yakima area is currently served primarily by two 230 kV transmission sources. The loss of both primary 230 kV sources or loss of one primary 230 kV source and another major element in the underlying system leaves the remaining system unable to provide adequate electric service to all customers in the area.

The addition of a new 230 kV line between Vantage and Pomona Heights substations and providing a third 230 kV source to the area mitigates the identified deficiencies. Specifically, the project eliminates the need to shed Yakima area load for those eight contingency combinations and eliminates overloads in the PacifiCorp and BPA transmission systems with loss of the existing line.

By enabling PacifiCorp to comply with the TPL Standards and increasing the reliability of PacifiCorp's transmission system by eliminating the need to shed Yakima area load under certain outage conditions, this project provides benefits to customers.

Q. Did PacifiCorp consider alternatives to investing in the Vantage to Pomona 230 kV New Substation Project?

A. Yes. In lieu of the selected project, the new 230 kV line from Vantage to Pomona Heights, PacifiCorp considered constructing a new 500/230 kV transformer and bus position at Wautoma substation and a new 230 kV transmission line from Wautoma substation to Pomona Heights substation resulting in an estimated cost of $89.6 million. This alternative was rejected because the costs were higher than the selected project. Another alternative would have involved constructing a second 230 kV transmission line from Midway substation to Union Gap substation. This alternative was rejected because it would have only corrected the identified deficiencies for approximately 10 years before additional transmission reinforcement would be required.

X. GOSHEN-SUGARMILL-RIGBY 161 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Goshen to Sugarmill to Rigby 161 kV Transmission Line project.

A. The Goshen-Sugarmill-Rigby 161 kV Transmission Line project consists of constructing approximately 44 miles of new transmission lines from the Goshen to Sugarmill and Sugarmill to Rigby substations located in southeast Idaho. This includes approximately 22.2 miles of 69 kV line rebuilt to 161 kV and 1.6 miles of new double circuit construction from Sandcreek substation to Sugarmill substation. Substation expansions are required at Goshen, Ammon, Sugarmill, and Rigby substations to accommodate the new 161 kV positions and associated structures and equipment, as shown on the map provided in Exhibit No. 30. In addition to constructing the new transmission line, Ammon substation will be converted from 69 kV to 161 kV which resulted in $6.5m of distribution plant in service in Idaho.

Idaho Falls City had a project to expand their Paine substation and build a 161 kV line to interconnect at PacifiCorp Sugarmill substation. To benefit both stakeholders it was agreed upon to enter into a joint agreement on the construction and ownership of the 12 miles of 161 kV line between Sugarmill substation and Idaho Falls City's Paine substation. The line is being constructed by Idaho Falls City, the Company is funding 49 percent of the construction costs and will be a joint owner of that segment of the line. The Company is continuing construction of the 13-mile 161 kV line from Paine tap to Rigby.

The overall project consists of six sequences of work. The first work sequence, that went into service in November and December 2020 for $26.0 million, included rebuilding 16 miles of 69 kV to 161 kV transmission line between the Goshen and Ammon substations and the required substation construction at both Goshen and Ammon substations to terminate the new transmission line. The second sequence of work that was placed in service in February 2021 for $3.1 million was the required substation work at the Sugarmill substation. The third sequence of work, planned in May 2021 for $9.8 million, is the completion of 9.2 miles of line from Ammon substation to Sugarmill substation. The fourth sequence of work, planned to be placed in service in July 2022 for $1.2 million, is the expansion of the Rigby substation to accommodate the new 161 kV Transmission line. The fifth sequence of work, planned to be placed in service by December 2022 for $7.0 million, is Idaho Falls City construction of the 12-mile transmission line between Sugarmill and Paine substations. The sixth and final sequence of the project, to be placed in service in February 2023, is the 13 miles of transmission line from Paine Tap to Rigby substation as well as the 3.5 miles of reconductor of the existing Sugarmill to Goshen 161 kV transmission line. Work sequences four through six will be completed outside the test period of this case, and none of these costs are included in the filing.

Q. Please explain why the investment in the Goshen to Sugarmill to Rigby 161 kV Transmission Line project is necessary.

A. The need for the Goshen to Sugarmill to Rigby 161 kV line was identified in the 2016 Goshen Area Planning Study to address projected overloads on the Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line, in addition to low voltage at Rigby and Sugarmill substations that manifest under heavy loading conditions. Projected peak summer load conditions in 2021 in the Rigby-Sugarmill area indicate that under normal operating conditions (N-0) the Goshen to Sugarmill 161 kV line is expected to load to 100 percent of its continuous rating of 201 MVA and the Rigby and Sugarmill substations 161 kV bus voltage is expected to reach its minimum limit of 0.95 per unit. Additionally, the projected load growth exacerbates several existing N-1 conditions in the area. Based on 2021 load, loss of the Goshen to Sugarmill 161 kV line causes the Goshen to Rigby 161 kV line to overload to 179 percent of its four-hour emergency rating and can result in excessively low voltage down to 0.68 per unit in the Rigby-Sugarmill area. The loss of the Goshen to Rigby 161 kV line can cause the Goshen to Sugarmill 161 kV line to overload to 111 percent of its four-hour emergency rating of 255 MVA, overload to 102 percent of its 30-minute emergency rating of 279 MVA and can cause low voltage down to 0.88 per unit at Rigby substation. The Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line are operated radially during summer heavy loading periods to mitigate the risk of violating NERC Standard TPL-001-4 category P0 (N-0), P1 (N-1) and P6 (N-1-1) performance requirements due to transmission capacity deficiencies in the area. Operating radially puts approximately 150 MW of load at risk for N-1 loss of either the Goshen to Sugarmill 161 kV line or the Goshen to Rigby 161 kV line and 300 MW at risk for N-1-1 loss of any two transmission lines.

The new Goshen-Sugarmill-Rigby 161 kV line will increase load serving capacity in the Rigby-Sugarmill area by 250 MVA that will allow the transmission lines between Goshen, Sugarmill, and Rigby substations to operate in a normal loop configuration and N-1 thermal overload and low voltage issues on the remaining transmission line and substation. Benefits also include elimination of the N-0 overload risk, improved load service reliability under N-1 conditions, and resolution of most N-1-1 issues present in the area.

Q. Did PacifiCorp consider alternatives to investing in the Goshen to Sugarmill to Rigby 161 kV Transmission Line project?

A. Yes. The first alternative in lieu of the Goshen-Sugarmill-Rigby 161 kV line that PacifiCorp considered was a project to construct a new approximately 35-mile-long Goshen to Rigby 345 kV line with 1272 aluminum conductor steel-reinforced ("ACSR") cable and add a new 450 MVA capacity or larger 345/161 kV transformer at the Rigby substation. This would involve expanding both the Goshen and Rigby substation yards to accommodate the new facilities consisting of at least two 345 kV breakers at Goshen, one 345 kV breaker at Rigby and at least two 161 kV breakers at the Rigby 161 kV substation. This alternative was rejected since the estimated cost of the project was about $17.0 million higher than the chosen project to construct the new Goshen-Sugarmill-Rigby 161 kV transmission line. The alternative was estimated to cost $57.7 million.

A second alternative considered was to construct approximately 61 miles of 161 kV transmission line from Antelope to Rigby with 1272 ACSR cable or larger. This involved expanding both the Antelope and Rigby substation yards to accommodate the new facilities consisting of at least two 161 kV breakers at Antelope and at least two 161 kV breakers at Rigby. A new 161 kV line from Antelope would provide a new source into the Rigby-Sugarmill area apart from Goshen substation; however, planning studies indicated that by adding the Antelope to Rigby 161 kV line, the N-1 loss of the Goshen to Sugarmill 161 kV line would still cause thermal overload and low voltage issues in the area and that load shedding and radialization of the Rigby-Sugarmill area would still be required. This alternative was rejected since the estimated cost of the project was about $8.0 million higher than the new Goshen-Sugarmill-Rigby 161 kV transmission line and that a new Antelope to Rigby 161 kV transmission line does not resolve the loading and voltage issues in the Rigby-Sugarmill area. The alternative was estimated to be $48.0 million.

A third alternative considered was to construct approximately 22.8 miles of 161 kV transmission line from the Meadow Creek wind farm substation to Sugarmill and Rigby substations to create a looped transmission source back to Goshen substation. Work involved constructing approximately 5.9 miles of new single circuit 161 kV transmission line from Meadow Creek to a new tap location, using the existing right-of-way to construct 4.5 miles of double-circuit line from the new tap location to Sugarmill substation, and construct 12.4 miles of new single-circuit 161 kV line from the new tap location to Rigby substation. Work also included converting Meadow Creek's 161 kV substation yard into a new three breaker ring bus, installation of at least two 161 kV breakers at Sugarmill and Rigby substations, rebuilding the Goshen-Wolverine Creek-Jolly Hills-Meadow Creek 161 kV line with 1557 ACSR cable (approximately 32.4 miles), rebuilding the remaining three miles of 795 all-aluminum conductor ("AAC") cable on the Goshen-Sugarmill 161 kV line, and adding a 161 kV bus tie breaker at Rigby to facilitate sectionalizing post N-1. Currently, the Goshen wind farms are radial from the Goshen 161 kV substation. Once looped through the Rigby and Sugarmill substations, a detailed voltage control study would be required to coordinate the wind farms and shunt devices in the area. Since the existing radial wind farm line is owned and operated by third parties, an agreement to use or buy the facilities would need to be negotiated. This alternative was rejected since the estimated cost of the project was about $8.2 million higher than the new Goshen-Sugarmill-Rigby 161 kV transmission line and required significant coordination with third parties to deliver the project. The alternative was estimated to be $48.5 million.

The last alternative considered was to loop the existing Goshen to Jefferson 161 kV transmission line in and out of the Bonneville substation. Work involved converting the Bonneville substation into a 161 kV breaker and one-half configuration, constructing an approximately 27-mile-long 161 kV line from Bonneville to Rigby substation with at least 1557 ACSR cable. Work also involved expanding both the Rigby substation yards to accommodate a new 161 kV line position consisting of at least two 161 kV breakers at the Rigby substation. Adding this new Bonneville to Rigby 161 kV line does not improve N-1 and N-1-1 issues in the area and therefore is not considered as a viable alternative. The estimate for this project was $33.2 million. Additional projects would be required to address the N-1 and N-1-1 issues. These projects include reconductoring 32 miles of Goshen to Rigby 161 kV line, reconductoring 16 miles of Sugarmill to Rigby 161 kV line, and reconductoring 3.5 miles of 795 AAC cable on existing Goshen to Sugarmill 161 kV line. Additionally, a new Goshen-Sugarmill 161 kV line would be required to mitigate the low voltage and voltage swings caused by the loss of the existing Goshen to Sugarmill 161 kV line. The estimate to reconductor these lines was $6.6 million and the estimate to construct a new Goshen to Sugarmill 161 kV line was $13.3 million. This alternative was rejected since the estimate for the new Bonneville to Rigby 161 kV line and supporting projects was about $12.7 million higher than the recommended new Goshen-Sugarmill-Rigby 161 kV transmission line project. The alternative was estimated to be $53.1 million.

XI. GOSHEN #3 345/161 KV 700 MVA TRANSFORMER INSTALLATION PROJECT

Q. Please describe the Goshen #3 345/161 kV 700 MVA transformer project.

A. The Goshen #3 transformer project will install a third 345/161 kV transformer at the Goshen substation, located in southeast Idaho, and expand the 161 kV yard to accommodate a new feed from the 345 kV yard. In addition, various 161 kV lines will be relocated, and the existing Goshen 161 kV dual operate bus will be converted into a breaker and one-half 161 kV scheme. Redundant 161 kV relays will also be installed. The project will use a spare 345/161 kV transformer that was delivered in March 2018 and a spare 345/161kV transformer will be purchased to be located at the Gadsby Plant as required per PacifiCorp's grid resiliency plan. This project is being placed in service in two sequences. The expansion of the 161 kV yard, the conversion of the bus scheme, and the relocation of the 161 kV lines was completed in November 2020 for $20.9 million. The second sequence of work, that is planned to be placed in service in May 2021, is the installation of the 345/161 kV transformer for $9.7 million. The spare replacement transformer is expected to be received in March 2022, which is outside this rate case.

Q. Please explain why the Goshen #3 345/161 kV 700 MVA transformer project is necessary.

A. The Goshen #3 transformer installation project will resolve NERC TPL-001-4 Category P1-3 (N-1) thermal overloading issues on the existing Goshen transformers beginning in 2021. The Goshen substation has two 345/161 kV 450 MVA transformers which serve the load in the area. As loads in the Goshen area increase, the risk of overloading one of the existing Goshen transformers due to the loss of the other increases as well. The 2016 Goshen area studies indicated that by 2021, loss of either one of the Goshen 345/161 kV transformers can overload the remaining Goshen 345/161 kV transformer above its emergency rating. Historical Goshen area load and generation data for the 2013 to 2017 period indicated that the average risk of overloading one of the Goshen 345/161 transformers under an N-1 condition was 10.5 percent each year (915 hours/38 days-the average number hours each year where area generation was below 200 MW and load was in excess of 450 MW). Since a transformer outage is a potential long-term outage (up to 18 months to order and install a new transformer), the risk of overloading one of the Goshen transformers could be present for an extended period, or until the spare can be installed which would take 2 to 3 months.

Q. Did PacifiCorp consider alternatives to investing in the Goshen #3 345/161 kV 700 MVA transformer installation project?

A. Yes. The first alternative considered was to add a new 345/161 kV transformer at the Rigby substation. However, since the Rigby substation does not have a 345 kV source, a new 35-mile-long 345 kV line from the Goshen to Rigby substation would have been required. This alternative would have also required at least two 345 kV breakers at the Goshen substation and one 345 kV breaker and one 161 kV breaker at the Rigby substation. In addition, an expansion of the Rigby substation yard would have been necessary to accommodate the new 345 kV bus, transformer, breakers etc. An estimate of this project is $71 million. This alternative was not selected due to significantly higher cost than the preferred solution.

The second alternative considered was to construct an approximately 61-mile-long 161 kV line from Antelope substation to Rigby substation with at least 1272 ACSR conductor. The un-scoped estimate for this alternative was $48.7 million. Planning studies showed that this alternative line would cause thermal overload and low voltage issues in the area and load shedding and radialization of the Rigby-Sugarmill area would still be required. Due to this and the increased cost for construction this alternative was determined to not be a feasible project to improve service to the Rigby-Sugarmill area.

XII. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission determine that the transmission projects outlined in my testimony: were necessary to ensure the Company maintains compliance with required reliability standards; will serve increased load; will provide benefits to customers; and are therefore prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.