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August 31, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
Request for a General Rate Revision.
Docket No. UE 374

Dear Filing Center:

On June 4, 2020, the Alliance of Western Energy Consumers (“AWEC”) filed the Confidential Opening Testimony and Exhibits of Lance D. Kaufman (AWEC/300-307) in the above-referenced docket. Mr. Kaufman’s testimony reproduced several tables from PacifiCorp’s 2013 Integrated Resource Plan that the Company had originally designated confidential. Accordingly, AWEC designated this material as Protected Information in Mr. Kaufman’s opening testimony.

After the filing of AWEC’s opening testimony, PacifiCorp communicated to AWEC that the Company was re-designating these tables as public information. AWEC is therefore providing the Commission and parties with updated confidential and redacted versions of Mr. Kaufman’s opening testimony (AWEC/300). The affected tables originally appeared in Mr. Kaufman’s testimony as Confidential Figures 4, 5, 6, 7, and 10. With this filing, AWEC has removed the redactions on these figures and has likewise removed the confidentiality designation that appears on page 33, line 3. In addition, AWEC is correcting a calculation error on page 44, line 4, of Mr. Kaufman’s testimony, with the change shown in redline.

Please note that AWEC’s opening testimony contains Protected Information that is being handled in accordance with Order Nos. 20-040. The confidential version of AWEC’s filing has been encrypted with 7-zip software and is being transmitted electronically to the Commission, consistent with Order No. 20-088.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch

Jesse O. Gorsuch

Enclosure

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Revised Confidential Opening Testimony of Lance D. Kaufman** upon the parties shown below by sharing copies by electronic mail, consistent with Order No. 20-088.

Dated this 31st day of August, 2020.

Sincerely,

/s/ Jesse O. Gorsuch

Jesse O. Gorsuch

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UE 374

OPENING TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

June 4, 2020

REDACTED VERSION

(REVISED August 31, 2020)

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EXHIBIT LIST

AWEC/301 – Curriculum Vitae of Lance D. Kaufman

AWEC/302 – PacifiCorp Responses to Data Requests

AWEC/303 – Summary of Cost of Service Study Adjustments

AWEC/304 – Cost of Service Study With All Adjustments

Confidential AWEC/305 – Kiewit Decommissioning Study Adjustments

Confidential AWEC/306 – Jim Bridger and Hunter Pollution Control Analysis

AWEC/307 – AMI Rollout Retired Meter Net Plant Amounts

UE 374 – Opening Testimony of Lance D. Kaufman (REDACTED)

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance Kaufman. I am the principal economist of Aegis Insight. My qualifications are included in Exhibit AWEC/301.

Q. ON WHOSE BEHALF YOU ARE TESTIFYING?

A. I am testifying on behalf of the Alliance of Western Energy Consumers (“AWEC”). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electrical services from PacifiCorp dba Pacific Power (“PacifiCorp” or “Company”) in Oregon.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses cost of service, rate spread, rate design, coal plant decommissioning costs, and the prudence of environmental upgrades at the Jim Bridger Power Plant (“Jim Bridger”).

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I make the following recommendations in my testimony:

1. Use the following on-peak hours for Schedule 48:

a. June to September on-peak from 1 PM to 10 PM

b. Remaining months on-peak from 6 AM to 9 AM and 4 PM to 10 PM

2. Use the coincident peak in December and January to measure demand in the cost of service study.

3. Use the current mix of light technologies rather than all LED when performing the cost of service study.

4. Use the average demand on the hour ending 8 AM PST from December 1 to January 30 to represent lighting demand in December and January.
5. Exclude Schedule 48 customers from the incremental revenue requirement of the AMI rollout.
6. Exclude dedicated substation customers from Schedule 48 Facilities Charges.
7. Adjust line losses to account for dedicated substations.
8. Create a dedicated substation off-set (rate reduction) of 0.086 cents per kWh and \$0.30 per kW.
9. Update PacifiCorp's pricing model in Exhibit PAC/1409 to reflect the proposed changes to the cost of service study.
10. Use the decommissioning and remediation costs originally filed in UM 1968. If the Commission relies on the Kiewit decommissioning study, include AWEC's proposed adjustments.
11. Find the cost of PacifiCorp's Jim Bridger Units 3 and 4 SCR and Hunter Unit 1 Baghouse and SCR investments not prudent. Exclude the associated costs from rates.
12. Apply the Commission's standard rate of return treatment for plant not in service to the undepreciated portion of early meter retirements.

II. RATE DESIGN: TIME OF DAY RATES

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PacifiCorp has proposed to change on-peak hours and the size of the on-off peak energy rate differential for Oregon's Schedule 48 customers. PacifiCorp's proposal changes peak hour definition by season and splits winter peak hours into a morning block and an

1 evening block. PacifiCorp's intention is to encourage conservation and load shifting
2 during the most stressful times on the grid. However, PacifiCorp failed to communicate
3 with Schedule 48 customers about whether they could in fact shift their loads to the
4 newly proposed off-peak periods. In reality, PacifiCorp's proposal will result in limited
5 conservation and shifting because it does not allow for a full 8-hour work shift during
6 off-peak periods in each month of the year. I propose an alternative that allows for a year-
7 round 8-hour off peak work shift, which will more effectively further PacifiCorp's stated
8 goals. I also recommend that the on-off peak rate difference be changed only during a
9 general rate case.

10 **Q. DID PACIFICORP COMMUNICATE WITH SCHEDULE 48 CUSTOMERS**
11 **ABOUT THEIR ABILITY TO SHIFT LOAD?**

12 A. Not substantively. PacifiCorp's communications with customers regarding the on-peak
13 changes were limited to discussions of bill impacts.^{1/} As a result, PacifiCorp's proposal
14 does not align with Schedule 48 production requirements.

15 **Q. WHAT PRODUCTION REQUIREMENTS SHOULD PACIFICORP HAVE**
16 **CONSIDERED?**

17 A. PacifiCorp failed to consider two important factors:

- 18 1. Length of work shifts
- 19 2. Seasonal consistency in work schedules

20 Employees are used to working on shifts of 8, 10, and 12 hours. PacifiCorp's
21 proposal does not allow for a full 8-hour shift off peak. This limits the economic
22 opportunities for Schedule 48 customers to change production schedules to off-peak
23 periods.

^{1/} Exh. AWEC/302 at 8 (PacifiCorp Response to AWEC Data Request ("DR") 46).

Employees also prefer consistent shifts across seasons. While PacifiCorp's winter hours include a 7-hour off peak window from 9 to 4, the summer hours would require the shift to move at least three hours earlier. I recommend that PacifiCorp's hours be modified to allow a full 8-hour shift that is consistent across seasons.

Q. WHAT IS YOUR SPECIFIC PROPOSAL?

A. I recommend the following on-peak hours:

- June to September on-peak from 1 PM to 10 PM.
- Remaining months on-peak from 6 AM to 9 AM and 4 PM to 10 PM.

This proposal changes both the on-peak hours and moves June from the winter hours to the summer hours. It allows an 8-hour off-peak window that is consistent across all months while still capturing the monthly peak prices and the Oregon and System monthly coincident peak loads.^{2/}

Q. YOU ALSO RECOMMEND THAT CHANGES IN THE ON-OFF PEAK RATE SPREAD BE MADE ONLY DURING GENERAL RATE CASES. CAN YOU EXPLAIN THIS RECOMMENDATION?

A. PacifiCorp's current on-off peak rate differential for Schedule 48 appears on both Schedule 200 and Schedule 201. PacifiCorp's proposed rate differential only appears on Schedule 201. This raises a question of whether PacifiCorp intends to update the rate differential as part of its annual power cost update in the Transition Adjustment Mechanism. The on-off peak rate differential is a rate design issue, and as such the size of the differential should not be updated outside of a general rate case.

^{2/} See Exh. AWEC/302 at 11-15 (PacifiCorp Response to AWEC DR 54).

III. COST OF SERVICE STUDY

Q. PLEASE SUMMARIZE THIS ISSUE.

A. A cost of service study (“COSS”) is a basic ratemaking tool that serves two important functions:

1. Assign cost, or revenue requirement, to customer classes or rate schedules. This is also referred to as cost allocation.
2. Inform how costs are recovered within each schedule. This is also referred to as rate design.^{3/}

The COSS has three basic components:

1. Separate costs into primary functions. PacifiCorp identifies production, transmission, distribution, lighting distribution, billing, metering, and customer services as separate functions.
2. For each function, classify costs according to the primary cost driver, such as demand, generation, number of customers, or other driver.
3. Allocate costs based on each schedule’s share of specific cost drivers.

Oregon has a well-established history of using long-term marginal cost to allocate costs to customers. This approach has a sound economic basis because the optimal, or economically efficient, outcome often occurs when prices represent the marginal cost of production.

^{3/} Electric Utility Cost Allocation Manual, NARUC 1992 at 12. The COSS serves additional functions that are less relevant for this testimony.

1 **Q. WHAT IS THE BASIC PRINCIPLE THAT SHOULD UNDERLIE A SOUND**
2 **COSS?**

3 A. The primary principle that should support any COSS is the cost-causation principle.^{4/} The
4 cost-causation principle is that customers responsible for causing costs should be
5 responsible for paying the costs. As the U.S. Court of Appeals for the D.C. Circuit has
6 stated, “all approved rates [must] reflect to some degree the costs actually caused by the
7 customer who must pay them.”^{5/} A corollary to this principle is that customers receiving
8 the benefits of a cost should be responsible for paying the costs – that burden should
9 follow benefit.^{6/}

10 **Q. WHAT ISSUES DO YOU RAISE RELATED TO COST OF SERVICES?**

11 A. I raise several issues related to the COSS:

- 12 a) PacifiCorp’s use of 12-CP to determine demand costs is not consistent with a
13 long-term marginal cost approach to COSS. Instead I recommend the use of a 2-
14 CP approach for allocating costs among the rate classes.
- 15 b) PacifiCorp allocates too few costs to lighting schedules. PacifiCorp models all
16 lights as all LED. I recommend lighting schedules be modeled based on actual
17 lighting technology. Additionally, PacifiCorp excludes lighting schedules from
18 production and transmission demand costs. I recommend including these demand
19 costs for lighting.

^{4/} Electric Cost Allocation for a New Era. Regulatory Assistance Project at 18 (January 2020).

^{5/} KN Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992).

^{6/} See, Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (noting that courts “...evaluate compliance [with cost causation principles] by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party”).

1 c) PacifiCorp allocates the cost of the AMI rollout to all customers, even though
2 some schedules receive no benefit from AMI. I recommend excluding these
3 customers from the allocation of AMI rollout costs.

4 d) PacifiCorp does not distinguish between customers with and without dedicated
5 substations. I recommend accounting for the lower distribution costs and line
6 losses associated with dedicated substations.

7 e) PacifiCorp allocates substantial collection costs to Schedule 48 while these
8 customers have little to no write-offs. I recommend modifying the allocation to
9 reflect the low write-offs for this schedule.

10 The incremental impact of each change on revenue requirement by class is provided
11 in Exhibit AWEC/303

12 **a. Coincident Peak**

13 **Q. PLEASE SUMMARIZE THIS ISSUE.**

14 A. PacifiCorp's cost of service study calculates the cost of meeting both a customer's
15 demand and energy requirements. PacifiCorp evaluates each schedule's demand using the
16 12-month average of the monthly coincident peak ("12-CP"). However, demand in
17 "shoulder" months such as the spring and fall is low relative to summer and winter.
18 Demand during the shoulder months does not drive PacifiCorp's demand-related resource
19 acquisitions. Consequently, I propose that demand costs be based on the coincident peak
20 in December and January only. The proposal better reflects cost causation by increasing
21 the allocation of costs to schedules with relatively high demand during months where the
22 system is at or near capacity and decreasing the allocation of costs to schedules with
23 relatively low demand during these months.

1 **Q. WHY DOES PACIFICORP CURRENTLY USE THE 12-CP FOR DEMAND?**

2 A. PacifiCorp stated at a workshop on its cost of service study that it proposed the 12-CP
3 method because that method is currently used for allocating total system costs to Oregon.
4 System costs are allocated under the 2020 PacifiCorp Inter-Jurisdictional Allocation
5 Protocol (“2020 Protocol”). Previous inter-jurisdictional allocation agreements updated
6 demand-related allocation factors every year. However, the 2020 Protocol transitions the
7 allocation of existing system resources to fixed allocation factors.

8 **Q. WHY DO YOU BELIEVE THE 12-CP METHOD IS NOT APPROPRIATE FOR**
9 **THE COS STUDY?**

10 A. There is no direct relationship between the COS study jurisdictional cost allocations. In
11 fact, the 2020 Protocol specifies that it is not “intended to abrogate any Commission’s
12 right or obligation to ... establish different allocation policies and procedures for
13 purposes of allocating costs and revenues within that State to different customers or
14 customer classes.^{7/} The jurisdictional cost allocations are the result of negotiations with
15 multiple non-Oregon parties and do not reflect the marginal cost principles used in
16 Oregon. Under the 12-CP method, a single customer class can drive all future resource
17 acquisitions, but the cost of these resources can be assigned to all customer classes. This
18 is not consistent with the cost-causer cost-payer principle.

19 Furthermore, most system costs are not allocated using a dynamic, or updated 12-
20 CP factor. Future energy use in the shoulder months will not drive Oregon’s allocation of
21 existing production and transmission costs. This means the demand in shoulder months

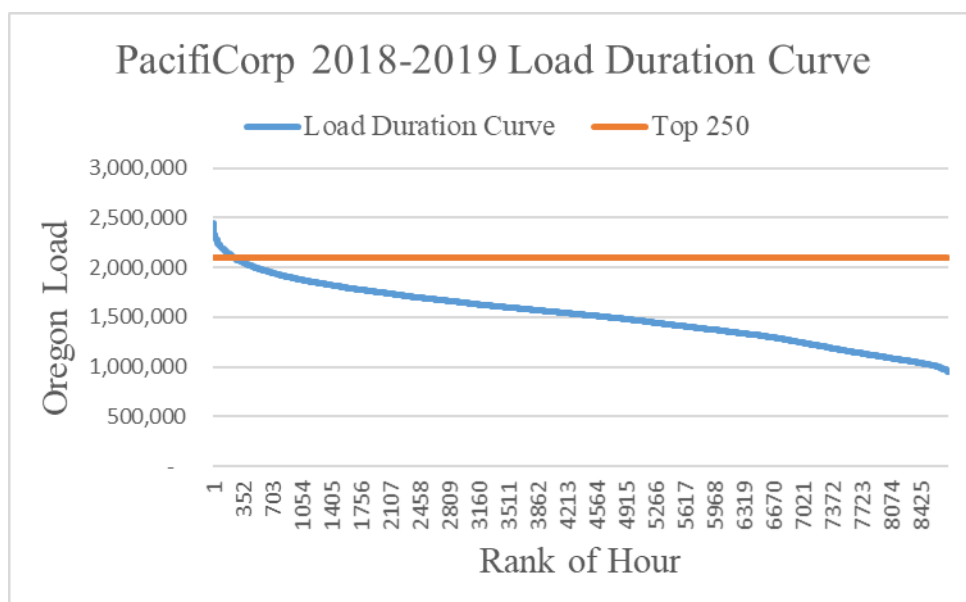
^{7/} 2020 Protocol at 3:48-54.

does not represent a long run marginal capacity cost. As such, the 12 CP is not appropriate for a marginal cost study.

Q. WHAT NUMERIC EVIDENCE IS THERE THAT THE 12-CP DOES NOT REPRESENT PEAK DEMAND?

A. The figure below illustrates the load duration curve for Oregon from July 2018 to June 2019.- The hours within this period are ranked and sorted by descending load size. This technique illustrates how “peaky” Oregon load is. The first hour is appropriately considered to be served by capacity resources. As the curve flattens, the hours are more appropriately considered to be served by energy resources. This concept is also illustrated in NARUC’s cost allocation manual at page 6.^{8/}

Figure 1: Oregon Load Duration Curve



The horizontal line indicates the load of the 250th ranked hour. Note the curve above this line is steep, while the curve below this line is flat. No hour in the top 250 hours occurred in shoulder months of April, May, September, or October. The 12-CP

^{8/} Electric Utility Cost Allocation Manual at 6, NARUC 1992.

places equal weight on demand during shoulder months where even the peak hour is not served by capacity resources. It is not appropriate to consider demand during these months as being served by capacity resources.

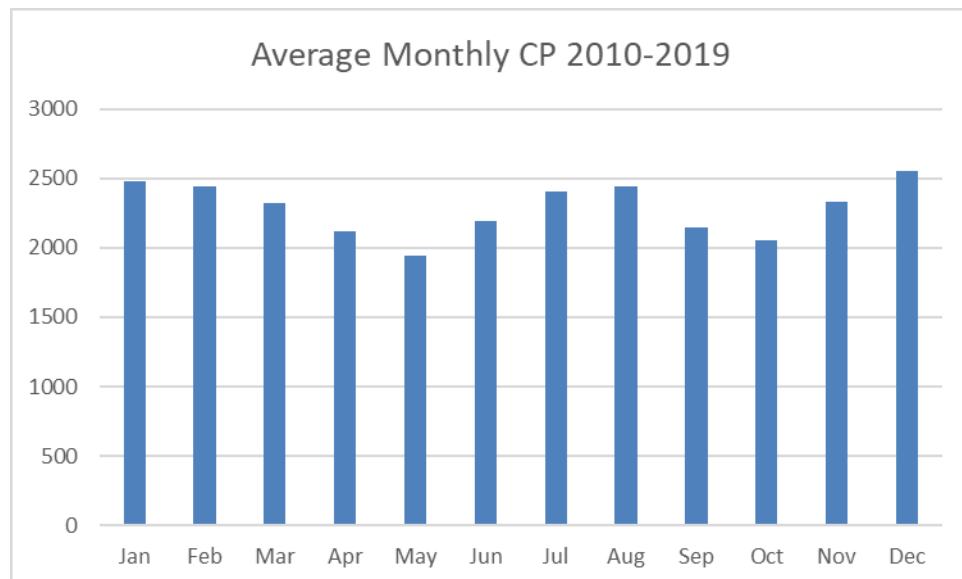
Q. COULD THE WINTER PEAK DRIVE OREGON'S COSTS EVEN IF NO NEW RESOURCES ARE NEEDED?

A. Yes. Oregon's fixed allocation of system resources may not be enough to meet reserve requirements under the current winter load. It is possible that other states will require capacity payments when Oregon relies on non-Oregon shares of resources to meet resource needs.

Q. HOW DOES OREGON'S COINCIDENT PEAK VARY BY MONTH?

A. The figure below illustrates Oregon's average coincident peak by month from 2010 to 2019. January and December are the two highest months. PacifiCorp's system peaks in summer months; however, the growth in solar generation, which is not dispatchable, reduces the net system peak in the summer and the winter peak will likely continue to drive resource acquisitions related to Oregon's load.

Figure 2: Oregon Coincident Peak in MW



1 **Q. WHAT MONTHS DO YOU RECOMMEND BE USED TO CALCULATE**
2 **DEMAND?**

3 A. I recommend using the 2-CP, or two months with highest demand. In the last 10 years,
4 Oregon's 2-CP peak demand has been in January and December.^{9/} 2-CP is preferable to
5 1-CP because Oregon's 1-CP peak switches between January and December, while the 2-
6 CP is consistent across years. This history, combined with expected growth in solar
7 generation, means that January and December demand will likely continue to drive
8 Oregon's capacity needs in the near future.

9 **Q. HOW DOES THE 2-CP ALIGN WITH THE PRINCIPLE OF COST-**
10 **CAUSATION?**

11 A. PacifiCorp's marginal cost study separates the cost of generation into a capacity
12 component and an energy component. The demand component represents the cost of
13 meeting PacifiCorp's capacity needs. Capacity needs are driven by time periods where
14 load is highest. Because only the capacity component of production costs is allocated
15 using the demand factor, the 2-CP is a very targeted and appropriate measure of the cost
16 driver for capacity costs. Demand in May does not cause PacifiCorp to acquire capacity
17 resources. The 2-CP method is more targeted to the months where demand is a driver for
18 capacity costs compared to the 12-CP.

19 **Q. WHY DO YOU INCLUDE NO WEIGHT ON SUMMER DEMAND?**

20 A. Some peak hours occur in the summer. However, these peak load events occur during
21 daylight hours when solar resources are generating. I consider solar resources as energy
22 resources because they have high fixed costs, low marginal costs, and are non-
23 dispatchable. PacifiCorp's capacity resources should be acquired to serve net load, or

^{9/} Exh. AWEC/302 at 12-15 (PacifiCorp Response to AWEC DR 54, Attachment AWEC 54-2).

1 load net of non-dispatchable renewable resources. PacifiCorp's planned solar resources
2 are large enough to diminish the importance of Summer capacity resources for Oregon
3 load.

4 **Q. WHAT IS THE IMPACT OF USING THE 2-CP IN THE COSS?**

5 A. The switch to 2-CP increases cost of service calculations for Residential by five percent
6 and Schedule 23 Primary by ten percent. All other schedules have a reduced cost of
7 service, ranging from a 0.3 percent reduction for lighting to a 25 percent reduction for
8 Irrigation. See Exhibit AWEC/303 for additional detail.

9 **b. Lighting**

10 **Q. PLEASE SUMMARIZE YOUR COSS LIGHTING CONCERNS.**

11 A. I have two concerns with PacifiCorp's treatment of lighting. PacifiCorp models all lights
12 as LEDs. PacifiCorp also excludes light schedules from production and generation
13 demand costs. Both of these modeling choices under-represent the demand and energy
14 costs of light schedules.

15 *i. LED Lighting*

16 **Q. WHY ARE YOU CONCERNED WITH MODELING LIGHTING WITH LEDS?**

17 A. PacifiCorp models the cost of service for lighting schedules under the assumption that all
18 lighting customers use LED lights. In reality, lighting customers use a mix of LED and
19 less efficient lights. PacifiCorp's assumption unfairly benefits lighting customers to the
20 detriment of all other customers. Equivalent treatment of other schedules would require
21 assuming similar conservation measures for all other customers. For example, the
22 residential load could be modeled assuming all households use LED lights, high
23 efficiency heat pumps, and have improved insulation, which is clearly not the case. I

1 propose using the current mix of light technologies when performing the cost of service
2 study.

3 **Q. IS PACIFICORP'S USE OF ALL LED LIGHTS IN THE COSS CONSISTENT**
4 **WITH THE LIGHTING SALES FORECAST?**

5 A. No, the LED hypothetical does not extend to the sales forecast. PacifiCorp's COS shows
6 2.1 million kWh in energy for Schedule 15,^{10/} while the sales forecast shows 8.7 million
7 kWh.^{11/}

8 **Q. WHY DOES ASSUMING ALL LIGHTING CUSTOMERS USE LED LIGHTS**
9 **BENEFIT LIGHTING CUSTOMERS AND HARM OTHER CUSTOMERS?**

10 A. The LED assumption lowers lighting schedules' share of energy and demand. This
11 reduces cost allocations to lighting and increases cost allocations to other schedules.

12 **Q. WHAT IS THE IMPACT OF ASSUMING ALL LIGHTING CUSTOMERS USE**
13 **LED LIGHTS?**

14 A. The cost of lighting customers to the system is underestimated. Adjusting generation and
15 transmission energy costs to reflect actual bulb efficiencies increases lighting cost of
16 service by six percent, or \$270,000.

17 *ii. Lighting Demand*

18 **Q. HOW DOES PACIFICORP TREAT PRODUCTION AND TRANSMISSION**
19 **DEMAND COSTS FOR LIGHTING?**

20 A. PacifiCorp's COS study assumes no demand-related production or transmission costs for
21 lighting. However, dusk-to-dawn lights are often on during Oregon's coincident peak. In
22 addition, many lights are not dusk-to-dawn and remain on during daylight hours. I
23 recommend using the average demand on the hour ending 8 AM PST from December 1
24 to January 30 to represent lighting demand in December and January.

^{10/} Exhibit PAC/1408, Meredith/61, line 6.

^{11/} Exhibit PAC/1409, Meredith/11.

1 **Q. WHAT EVIDENCE IS THERE THAT LIGHTING CONTRIBUTES TO**
2 **OREGON'S COINCIDENT PEAK?**

3 A. PacifiCorp's Oregon winter peaks typically occur at 8 am in January and December.^{12/}
4 PacifiCorp provided lighting demand by schedule and hour. PacifiCorp's data show that
5 lighting customers have significant demand in this time period.^{13/}

6 **Q. HOW DOES ACCOUNTING FOR DEMAND COSTS AFFECT THE COS?**

7 A. Accounting for demand costs increases lighting cost of service by 21 percent, or \$1
8 million. The combined impact of the proposed lighting changes is a \$1.28 million or 28
9 percent increase for lighting and a 0.1 percent decrease for other schedules. Exhibit
10 AWEC/303 provides additional detail.

11 **c. AMI Meters**

12 **Q. WHAT ISSUE DO YOU HAVE WITH PACIFICORP'S TREATMENT OF AMI**
13 **METERS?**

14 A. Between 2017 and 2020 PacifiCorp replaced a large number of existing meters with AMI
15 meters.^{14/} The AMI rollout resulted in \$54 million of early retirements.^{15/} The AMI
16 rollout substantially increased rate base and depreciation expense for all customers. No
17 Schedule 48 customer received a new meter as part of the AMI rollout.^{16/} I recommend
18 two adjustments related to the AMI rollout. First, the undepreciated portion of the retired
19 meters should be treated as plant that is not in service and should earn a reduced rate of
20 return. This return issue is addressed in more detail in Section VII below because it does

^{12/} Exh. AWEC/302 at 12-15 (PacifiCorp Response to AWEC DR 54, Attachment AWEC 54-2).

^{13/} Id. at 16 (PacifiCorp Response to AWEC DR 82).

^{14/} Exh. PAC/1100, Lucas/23.

^{15/} Exh. AWEC/302 at 6-7 (PacifiCorp Response to AWEC DR 28).

^{16/} Id.

1 not relate to cost of service. Second, the incremental costs associated with the AMI
2 investment should not be allocated to Schedule 48 customers in the COS study.

3 **Q. HOW DID THE AMI ROLLOUT INCREASE RATEBASE?**

4 A. The AMI project cost \$112.1 million in capital, with \$79.4 million in meter expenses.^{17/}

5 **Q. WHAT CUSTOMERS RECEIVE THE BENEFITS OF THE AMI PROJECT?**

6 A. Customer classes that received AMI meters receive the benefits of the project. These
7 customers are assigned fewer meter reading costs, have increased access to use data,
8 benefit from remote connects and disconnects, and receive improved customer service.

9 **Q. WHAT CUSTOMERS PAY THE COST OF THE AMI PROJECT?**

10 A. All customers allocated meter costs pay the cost of the AMI project. This includes
11 Schedule 48 customers who do not benefit from AMI. The AMI project increased meter
12 expenses and meter expenses are allocated based on marginal metering costs.

13 **Q. DESCRIBE THE MECHANICS USED TO EXCLUDE SCHEDULE 48**
14 **CUSTOMERS FROM AMI EXPENSES.**

15 A. I split the metering revenue requirement into non-AMI and AMI revenue requirement.
16 Non-AMI revenue requirement is allocated using the Functional Revenue Requirement
17 Allocation Factor for Customer Metering. AMI revenue requirement is allocated using an
18 AMI-metering allocation factor. The AMI-metering allocation factor is equal to the
19 Customer Metering factor scaled up to account for the exclusion of Schedule 48. This
20 factor is presented in Exhibit AWEC/304 at 2.

^{17/} Exh. PAC/1100, Lucas/27.

Q. WHAT IS THE IMPACT OF YOUR PROPOSED ADJUSTMENT?

A. The proposed adjustment reduces cost of service for Schedule 48 by \$310,000 and increases the cost of service for other schedules by the same amount. Additional detail is provided in Exhibit AWEC/303.

d. Dedicated Substations

Q. WHAT ISSUE DO YOU HAVE RELATED TO DEDICATED SUBSTATIONS?

A. Five customers receive service from PacifiCorp under Schedule 48 Primary Service but have dedicated substations. I have two issues related to dedicated facilities:

1. Dedicated substation customers should not pay distribution line expenses.
2. Dedicated substation energy and demand should not be adjusted for distribution line losses.

i. Distribution Line Expense

Q. WHY SHOULD DEDICATED SUBSTATION CUSTOMERS NOT PAY DISTRIBUTION LINE EXPENSES?

A. These customers do not use or benefit from PacifiCorp's distribution lines. However, they contribute to PacifiCorp's revenue requirement for distribution lines through the facilities charge.^{18/} I recommend making the facilities charge applicable only to Schedule 48 customers without dedicated substations.

Q. WHAT COSTS DOES THE FACILITIES CHARGE RECOVER?

A. The Facility Charge recovers "customer costs including billing and metering, plus distribution costs except for distribution substation costs which are recovered through the demand charge."^{19/} However, the distribution component accounts for most of the

^{18/} Exh. AWEC/302 at 17 (PacifiCorp Response to AWEC DR 85, part c).

^{19/} Id.

1 facilities charge.^{20/} Under my proposal, customers with dedicated facilities will continue
2 to pay the cost of metering and billing through the basic charge. This proposal is similar
3 to Avista's "Primary Voltage Discount" in Washington, which reduces rates for
4 customers that use fewer distribution facilities.^{21/} This is also similar to Portland General
5 Electric's treatment of subtransmission customers. PGE Schedule 89 identifies separate
6 rates for subtransmission customers. PGE Schedule 600 differentiates line loss for
7 subtransmission customers from other primary customers.

8 **Q. PLEASE EXPLAIN WHY DEDICATED SUBSTATION CUSTOMERS WILL**
9 **CONTINUE TO PAY METERING COSTS.**

10 A. Dedicated substation customers will continue to pay the basic monthly charge. Dedicated
11 substation customers are all primary service customers greater than 4 MW. The basic
12 charge for these customers is \$1,100 per month. The basic charge typically recovers
13 "customer costs" or costs of service that do not vary with energy use or demand.
14 Metering costs can be included in the basic charge. Exhibit PAC/1408, Meredith/17,
15 lines 21 to 29, identify customer costs. Excluding uncollectable costs on line 28, total
16 customer costs for Schedule 48 Primary service greater than 4MW is \$1,753 or \$148 per
17 month. This amount includes billing and metering costs. The proposed \$1,100 basic
18 charge is more than enough to cover the \$148 of customer costs identified in PacifiCorp's
19 cost of service study for dedicated substation customers.

^{20/} Exhibit PAC/1407, Meredith/1, lines 35 to 37, show total Schedule 48 primary service customer costs of \$236. I argue elsewhere in my testimony that this amount is too high because it includes excessive uncollectable costs. PacifiCorp expects to recover \$4.6 million through the facilities charge from Schedule 48 primary service customers. Even at PacifiCorp's proposed level, customer costs account for only five percent of the facilities charge.

^{21/} See Avista's Washington Electric Tariff for Schedule 25, available here: https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/wa/wa_025.pdf?la=en

1 **Q. HOW DOES YOUR PROPOSAL AFFECT RATES?**

2 A. My proposal will increase the Facility Charge for Schedule 48 Primary service from
3 \$1.10 to \$1.40 under PacifiCorp's filed COSS and revenue requirement. This is because
4 the same amount of distribution costs will be recovered by fewer billable kW.

5 *ii. Distribution Line Loss*

6 **Q. PLEASE SUMMARIZE YOUR CONCERN RELATED TO DISTRIBUTION**
7 **LINE LOSSES.**

8 A. PacifiCorp's COSS estimates each schedule's demand at the generation and distribution
9 level. PacifiCorp uses a loss factor to scale up each schedule's sales to account for system
10 energy loss. Loss occurs on transmission lines, substations, distribution lines, and
11 transformers. Dedicated substation customers do not receive energy on distribution lines;
12 however, in the COSS their sales are grossed up using a loss factor that includes
13 distribution line loss. I recommend modifying the COSS to account for reduced losses
14 associated with dedicated facility customers and I recommend a rate offset to allow
15 dedicated facility customers to capture the incremental impact of this change.

16 **Q. WHAT ARE PACIFICORP'S LOSSES ON DISTRIBUTION LINES?**

17 A. PacifiCorp calculates line loss for demand and energy. Primary distribution line losses
18 expansion factors are 1.02893 for demand and 1.01629 for energy.^{22/} PacifiCorp does not
19 experience these losses from primary customers that have dedicated substations.

20 **Q. HOW DO YOU ACCOUNT FOR THE DECREASED LINE LOSS OF**
21 **DEDICATED FACILITY CUSTOMERS?**

22 A. I modified the cost of service study's generation and distribution level estimates of
23 demand and energy for Schedule 48 Primary Greater than 4 MW by splitting demand and

^{22/} Exh. AWEC/302 at 4-5 (PacifiCorp Response to AWEC DR 23, Attachment AWEC 0023 at 35-36).

energy at the meter into two components: dedicated facility and non-dedicated facility. I use the system loss factor excluding primary distribution line loss to scale up dedicated facility demand and energy. I use the original primary system loss factors to scale up non-dedicated facility components.

Q. WHAT IMPACT DOES YOUR CHANGE HAVE?

A. The change decreases Schedule 48 Primary cost of service by \$167,000 and increases the cost of service for other schedules by an equal amount.

Q. HOW CAN DEDICATED FACILITY CUSTOMERS RECEIVE THE BENEFIT OF THIS CHANGE?

A. I recommend introducing a Dedicated Facility kWh rate offset of 0.086 cents and a kW offset equal to \$0.30. This is the total kWh charge times the energy distribution line loss and the total kW charge times the demand distribution line loss. The table below summarizes this off-set.

	Base Rates	Distribution Line Loss	Ded. Fac. Offset
kWh	5.021 ¢	1.7%	0.086 ¢
kW	\$9.75	3.0%	\$0.30

e. Uncollectables Expense

Q. PLEASE SUMMARIZE THE UNCOLLECTABLES ISSUE.

A. PacifiCorp's COS study assigns too much uncollectable dollars to Schedule 48 customers. PAC assigns \$69,000 in uncollectable costs to Schedule 48; however the five-year average uncollectable amount for all Schedule 48 customers is \$512. PacifiCorp's allocation is based on aggregate uncollectable rates for all commercial and industrial customers. I recommend disaggregating the uncollectable rate to reflect only Schedule 48 customers. This reduces Schedule 48 revenue requirement allocation by approximately

\$23,000. The impact on revenue requirement allocation differs from the impact on uncollectable allocation due to interactions with other marginal cost model mechanisms.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ON HOW YOU MADE YOUR ADJUSTMENT.

A. The COS study starts by calculating five-year average uncollectable amounts by customer class (residential, commercial, industrial, and irrigation). These amounts are then allocated to schedules using schedule share of revenues by customer class. Instead of indirectly assigning uncollectable amounts to schedules through share of customer class revenue I directly assign uncollectables to Schedule 48. The remaining uncollectable dollars are allocated to other schedules using PacifiCorp's original methodology. I similarly update the 903 weighting factor in Exhibit PAC/1408, Meredith/66.

IV. COS: SUMMARY

Q. WHAT IS THE TOTAL IMPACT OF THE RECOMMENDED CHANGES TO THE COS?

A. The impact is summarized in the Exhibit AWEC/303. These impacts are based on PacifiCorp's filed revenue requirement. If the approved revenue requirement is lower, the COSS impacts will also be correspondingly lower. I recommend the cumulative impact of these changes be applied to the cost of service revenues in PacifiCorp's rate design model (Exhibit PAC/1409, pages 1 and 2.)

V. DECOMMISSIONING AND REMEDIATION

a. Overview

Q. PLEASE SUMMARIZE THIS ISSUE.

A. PacifiCorp’s most recent depreciation study included updates to decommissioning and remediation (“D&R”) estimates for generation plant. PacifiCorp’s depreciation study was filed with the Commission in UM 1968 on September 13, 2018. Parties have reached a

1 settlement in principle in that docket. As part of the proposed settlement parties agreed to
2 address decommissioning and remediation in this docket. After the initial filing in UM
3 1968, PacifiCorp filed an update that greatly increased the D&R estimates based on a
4 third-party report (“Kiewit Report”). The Kiewit Report included numerous assumptions
5 and calculations that were not provided to PacifiCorp or other parties. Many of the
6 requested expenses are unsubstantiated and unverifiable. I recommend the Commission
7 rely on the D&R costs of the initial filing. If the Commission chooses to rely on the
8 Kiewit Report, I recommend adjustments to several cost categories.

9 **Q. PLEASE DESCRIBE THE KIEWIT REPORT AND THE CIRCUMSTANCES**
10 **LEADING TO ITS DEVELOPMENT.**

11 A. The Kiewit Report is a third-party decommissioning study of PacifiCorp coal generation
12 facilities. It was filed in UM 1968 on January 16, 2020.^{23/} PacifiCorp filed supplemental
13 testimony related to the Kiewit Report on February 14, 2020. The Kiewit Report was
14 produced as a condition of the 2020 Protocol.^{24/} Accurate D&R estimates are important
15 because of specific provisions in the 2020 Protocol, and PacifiCorp agreed to commission
16 a third-party study on decommissioning costs as part of the 2020 Protocol for this
17 reason.^{25/} The 2020 Protocol also, however, makes clear that “[n]o Party will be bound
18 by the Decommissioning Cost estimates in the Decommissioning Studies ... and final
19 determination of each State’s just and reasonable Decommissioning Cost allocation for
20 each coal-fueled Interim Period Resource will remain exclusively with each Commission
21”^{26/}

^{23/} The initial report addressed all coal plants except Craig, Cholla, and Colstrip. PacifiCorp filed a Kiewit generated decommissioning study for Colstrip on March 16, 2020.

^{24/} Docket No. UM 1968, Exh. PAC/800, Teply/2.

^{25/} 2020 Protocol § 4.3.1.1.

^{26/} Id. § 4.3.1.3.

1 **Q. DO THE DECOMMISSIONING COST ESTIMATES FOR CERTAIN COAL**
2 **PLANTS IN THE KIEWIT REPORT HAVE INCREASED IMPORTANCE FOR**
3 **OREGON CUSTOMERS?**

4 A. Yes. Under the 2020 Protocol, plants with common retirement dates across all states are
5 treated differently than plants with different retirement dates. For example, the retirement
6 date for Dave Johnston is common across all states, while the retirement date for Jim
7 Bridger is earlier in Oregon than in other states. Oregon will be assigned actual costs for
8 plants with common retirement dates. This means there will be an opportunity to true-up,
9 or correct, the depreciation reserve, to account for differences between estimated and
10 actual D&R costs.

11 However, Oregon will not be allocated actual costs for plants without common
12 retirement dates. This means that Oregon will not be liable for over-estimates of D&R for
13 Jim Bridger, but also that Oregon will not receive credit for over-payment of D&R costs
14 for Jim Bridger. Accurate and statistically unbiased estimates of D&R costs are
15 particularly important for plants without common retirement dates because incorrect
16 estimates will either be harmful to Oregon customers, or to PacifiCorp.

17 **Q. PLEASE COMPARE THE KIEWIT REPORT TO PREVIOUS D&R STUDIES.**

18 A. PacifiCorp's filed depreciation study included \$259 million in D&R costs. The Kiewit
19 Report estimates [REDACTED] in D&R. The Kiewit Report separates D&R into two
20 components: a base estimate of [REDACTED] and an "other items" estimate of [REDACTED]
21 [REDACTED] The Kiewit base estimate is adopted by PacifiCorp's witness John Spanos in the
22 calculation of coal plant depreciation rates. Other item expenses appear to be integrated
23 elsewhere in PacifiCorp's testimony. The Kiewit Report expanded the scope of D&R

costs to include Asset Retirement Obligations (“AROs”), grading and topsoil, and owner project costs.

Q. WHY SHOULD THE COMMISSION DISREGARD THE COST ESTIMATES IN THE KIEWIT REPORT?

A. PacifiCorp was unable to provide the assumptions and calculations underlying the Kiewit Report. For example, the report identifies a “reclamation” cost of [REDACTED].^{27/} A number that specific cannot have simply been estimated; it must have been calculated through a model and using certain assumptions. PacifiCorp, however, did not require that Kiewit provide the bases for its calculations or assumptions, and Kiewit has not provided this information.^{28/} Without such data, parties and the Commission cannot fairly evaluate the Kiewit Report. The Kiewit report [REDACTED] percent with minimal discussion of the change or the factors driving this change. PacifiCorp’s incentives are to over-estimate D&R costs because that will limit investor risk, at the expense of ratepayers. As noted below the Kiewit Report contains numerous issues that may overstate D&R expense. Because PacifiCorp bears the burden of proof in this case, it must demonstrate the just and reasonable nature of the costs it proposes to include in customers rates. Without the underlying data and assumptions from the Kiewit report, PacifiCorp cannot satisfy this burden with respect to its D&R costs.

Q. PLEASE DISCUSS THE DECOMMISSIONING COST ESTIMATES PACIFICORP INCLUDED IN ITS ORIGINAL DEPRECIATION STUDY IN UM 1968.

A. PacifiCorp updated its D&R costs in its depreciation filing by identifying plant-specific costs. This compares to the Company’s previous practice of applying a uniform D&R

^{27/} Kiewit Report, Table 10-5.

^{28/} Exh. AWEC/302 at 22 (PacifiCorp Response to AWEC DR 0123).

1 cost assumption of \$40/kW. The updated, plant-specific costs were based on cost
2 updates to decommissioning studies PacifiCorp performed on a selection of its plants.
3 These studies also were performed by a third-party contractor. Because these studies
4 were performed prior to negotiation of the 2020 Protocol, the same incentive for
5 PacifiCorp to over-estimate the costs of D&R for its coal plants did not exist.
6 Consequently, the evidentiary basis for the D&R cost estimates in PacifiCorp's initial
7 depreciation study is stronger and should be relied upon to establish Oregon's D&R cost
8 responsibility for the Company's coal plants in this case.

9 **b. Adjustments to the Kiewit Report**

10 **Q. IF THE COMMISSION DOES CONSIDER THE KIEWIT REPORT, WHAT**
11 **ADJUSTMENTS TO THE COSTS INCLUDED IN THE REPORT SHOULD IT**
12 **CONSIDER?**

13 A. The Kiewit Report contains numerous assumptions and expenses that appear to overstate
14 D&R expense. The Kiewit Report includes:
15 a) Expenses that are part of PacifiCorp's revenue requirement, such as PacifiCorp labor
16 expense.
17 b) Multiple allowances for hazardous material. These allowances appear duplicative.
18 c) Removal of asphalt and concrete to 3 feet below grade. PacifiCorp does not appear to
19 have a legal obligation to remove asphalt or concrete to 3 feet below grade.
20 d) Earthwork for filling ponds and covering structure sites. It is not clear that PacifiCorp
21 will remove ponds or cover structure sites.
22 e) Allowance for demolition contractor indirect expense. It is not clear that PacifiCorp
23 will engage a demolition contractor and if not, these indirect expenses may already be
24 part of PacifiCorp's rates.

- 1 f) Allowance for demolition contractor markup. It is not clear that PacifiCorp will
2 engage a demolition contractor and if not, there is no basis for a markup above cost.
- 3 g) Write-off of materials and supplies, rolling stock, and railcars. PacifiCorp can and
4 likely will repurpose materials and supplies, rolling stock and rail cars.
- 5 h) Coal pile excavation and haul-off. PacifiCorp intends to drill test holes to determine
6 the appropriate depth for excavation. These test results may show less excavation is
7 needed.
- 8 i) Removal of pump house assets. As noted later in this testimony PacifiCorp may be
9 able to transfer or sell water rights associated with closed plants, and pumping assets
10 associated with these water rights could be transferred with the water rights rather
11 than demolished.
- 12 j) The larger of PacifiCorp's and Kiewit's independent estimates of Asset Retirement
13 Obligations were selected without any explanation for why the higher estimate was
14 more accurate. Selecting the maximum value of individual components of different
15 estimates will bias estimates high.

16 In addition to issues with known assumptions and estimates, there are numerous
17 underlying assumptions and calculations that cannot be verified.

18 **Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION?**

19 A. I recommend the Commission adopt PacifiCorp's originally filed D&R costs because
20 PacifiCorp is unable to demonstrate the accuracy of the assumptions and calculations in
21 the Kiewit report. If the Commission chooses to adopt the Kiewit Report estimates, I
22 recommend excluding some or all the costs discussed above. These excluded amounts are
23 discussed below and detail is provided in Confidential Exhibit AWEC/305. The figure

below compares the Kiewit Report with the filed decommissioning costs and with the
AWEC adjusted Kiewit estimates.

Figure 3: Confidential Decommissioning Estimates

	Total Cost (excl. Other Items)	\$/kW
Kiewit Total		
Adjusted Kiewit Total	\$262,604,193	46.53
Filed Total	\$258,615,977	45.83

Q. WHAT EXPENSES DO YOU CONSIDER PART OF PACIFICORP'S REVENUE REQUIREMENT?

A. The Kiewit Report section 5.2.1 and 5.2.2 includes Owner's engineer, staff, and other indirect costs. PacifiCorp's revenue requirement already includes labor costs. As such, collecting these costs as part of D&R is duplicative. AWEC's adjusted Kiewit estimate excludes all costs under these sections.

Q. WHICH ALLOWANCES FOR HAZARDOUS MATERIALS APPEAR DUPLICATIVE?

A. Asbestos waste removal costs are included in both sections 5.4.2 and 5.7.1. Section 5.4.2 appears to be a contingency expense to cover unexpected costs above what PacifiCorp has already estimated for asbestos removal. Contingency costs should not be included because it will bias the estimated D&R costs. AWEC's adjusted Kiewit estimate excludes all costs under these sections.

Q. WHY DO YOU BELIEVE ASPHALT AND CONCRETE MAY NOT NEED TO BE REMOVED?

A. Section 5.4.3 and 5.4.4 include asphalt and concrete removal. PacifiCorp may choose to repower generating facilities as it has with Naughton or to repurpose facilities for non-generating uses. If this occurs, or if PacifiCorp sells the land to a third party, there is no

1 need to remove all asphalt and concrete down to three feet. AWEC's adjusted Kiewit
2 estimate excludes all costs under these sections.

3 **Q. WHY DO YOU BELIEVE EARTHWORK MAY NOT BE NEEDED?**

4 A. Section 5.5.1 and 5.5.2 include earthwork expenses such as removing pond
5 embankments and covering building sites with topsoil. Pond embankments create
6 recreational areas on BLM land.^{29/} Some of these ponds may be retained for ongoing
7 recreation or for repowered facilities. If PacifiCorp repurposes sites, a reduced volume of
8 topsoil will be needed. AWEC's adjusted Kiewit estimate excludes all costs under these
9 sections.

10 **Q. WHY DO YOU THINK PACIFICORP MAY NOT ENGAGE A CONTRACTOR**
11 **FOR ALL WORK IDENTIFIED AS "CONTRACTOR" WORK?**

12 A. Section 5.9 includes indirect expenses, engineering costs, and markup for the demolition
13 contractor. PacifiCorp may choose not to engage contractors for all work identified as
14 "Contractor" work. For example, The Bridger Coal Company performs on-going site
15 remediation equivalent to the earthwork identified in Section 5.5.1 and 5.5.2. PacifiCorp
16 could avoid the indirect expenses, engineering costs, and markup by utilizing BCC assets
17 and expertise for earthwork. AWEC's adjusted Kiewit estimate includes indirect
18 expenses, engineering costs, and markup associated with adjusted contractor costs.

19 **Q. WHY DO YOU THINK THE ALLOWANCE FOR WRITE-OFF OF**
20 **MATERIALS, SUPPLIES, ROLLING STOCK, AND RAILCARS MAY BE**
21 **EXCESSIVE?**

22 A. Section 5.15.1 through 5.15.5 includes write-offs for materials, supplies, rolling stock,
23 and railcars. The Kiewit Report appears to be composed of isolated studies of individual
24 plants without considering the context of the whole of PacifiCorp's operations. It is

^{29/} Kiewit Report at 10.3.2.

1 reasonable to expect that materials, supplies, and rolling stock that are useful at one plant
2 can be used at other plants or elsewhere in PacifiCorp's system. AWEC's adjusted Kiewit
3 estimate excludes all costs under these sections.

4 **Q. HOW ARE MATERIALS, SUPPLIES, ROLLING STOCK, AND RAILCARS**
5 **TREATED FOR PLANTS THAT CONTINUE TO OPERATE AFTER OREGON**
6 **EXITS COAL GENERATION?**

7 A. These goods and assets will presumably continue to be used by non-Oregon states.
8 Oregon should receive the greater of the market value or net plant value when Oregon
9 exits coal generation. It is not clear whether this issue is addressed by the 2020 Protocol.

10 **Q. WHY DO YOU THINK THE COAL PILE EXCAVATION COSTS MAY BE**
11 **EXCESSIVE?**

12 A. Section 5.14.6 includes coal pile excavation and haul off. PacifiCorp has not yet
13 determined the depth of excavation necessary for coal piles. The Kiewit report assumes a
14 depth of 10 feet. PacifiCorp intends to drill test holes to establish the appropriate depth
15 for excavation.^{30/} AWEC's adjusted Kiewit estimate assumes excavation to 5 feet and
16 excludes half the costs under this section.

17 **Q. WHY DO YOU THINK THE REMOVAL OF PUMPING ASSETS MAY NOT BE**
18 **NECESSARY?**

19 A. Sections 5.6 and 5.14.7 include removal of pumping assets. I argue later in this testimony
20 that PacifiCorp may transfer water rights to third parties. If sites are repurposed or water
21 right use continues, these assets may continue to be necessary and may not be
22 demolished. AWEC's adjusted Kiewit estimate excludes cost of removing pumping
23 assets.

^{30/} Docket No. UM 1968, Exh. PAC/800, Teply/10.

1 **Q. WHERE DOES THE KIEWIT REPORT SELECT THE LARGER OF**
2 **PACIFICORP AND KIEWIT ESTIMATES?**

3 A. Assumption 20.b. in Section 3.1 states [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED] A more appropriate approach

9 to combining forecasts is to select the average of the two estimates for all cost items

10 where two estimates were made unless one estimate is believed to be less reliable.

11 AWEC's adjusted Kiewit estimate excludes 25 percent of AROs.

12 **Q. CAN THE VALUES PRESENTED IN THE KIEWIT REPORT BE VERIFIED?**

13 A. No. PacifiCorp declined to provide the workpapers generating the D&R estimates for

14 each cost category. As such, there is no way to identify many of the underlying

15 assumptions of the report, such as dollars, volumes, hours, etc. The largest single line

16 item for most plants is generically called "demolition".^{31/} This line item accounts for

17 [REDACTED] The Kiewit report

18 provides only a generic one paragraph statement regarding the costs in this line item in

19 section 5.4.1. No detail was included for what inputs or assumptions were used. As

20 discussed above, the Commission should disregard the Kiewit report entirely due to this

21 lack of information. However, if the Commission considers the report, I adjust Kiewit's

^{31/} For example, see item 4a under Appendix A through G of the Kiewit Report.

1 estimate to exclude 25 percent expenses under 5.4.1 to account for this lack of
2 transparency and the incentive PacifiCorp has to bias the costs upward.

3 **VI. POLUTION CONTROL INVESTMENTS**

4 **a. Jim Bridger SCR**

5 **Q. PLEASE SUMMARIZE YOUR CONCERNS WTH THE JIM BRIDGER**
6 **POLUTION CONTROL INVESTMENTS.**

7 A. PacifiCorp is requesting selective catalytic reduction (“SCR”) investments at Jim Bridger
8 Units 3 and 4 be included in rate base. PacifiCorp proposed these investments as action
9 items in the 2013 IRP. Staff, Sierra Club, Renewable Northwest, NW Energy Coalition,
10 and the Oregon Citizens’ Utility Board all raised concerns with PacifiCorp’s analysis of
11 the SCRs. The Commission declined to acknowledge action items for these investments,
12 noting deficiencies in PacifiCorp’s analysis. PacifiCorp has not remedied these
13 deficiencies. I recommend that the Commission find the SCR investments not prudent.

14 **Q. WHY DID PACIFICORP CONTINUE WITH THE JIM BRIDGER 3 AND 4 SCR**
15 **INVESTMENTS DESPITE THE COMMISSION’S DECISION NOT TO**
16 **ACKNOWLEDGE THEM?**

17 A. PacifiCorp filed its 2013 IRP with the Commission on April 30, 2013. PacifiCorp’s
18 contract to construct the SCRs was signed with limited notice to proceed on May 31,
19 2013, one month after filing the IRP. PacifiCorp gave its contractors full notice to
20 proceed with the investments December 1, 2013.^{32/} The Commission’s IRP order was
21 issued eight months later on July 2014.^{33/} PacifiCorp simply filed the IRP too late.
22 PacifiCorp was already contractually obligated to proceed with the investment.

^{32/} PAC/800 Teply/33.
^{33/} OPUC Order No. 14-252.

Q. WHAT EFFECT DID BEING CONTRACTUALLY OBLIGATED TO PROCEED WITH THE SCRS HAVE?

A. PacifiCorp's contractual obligation fundamentally changed PacifiCorp's approach to analyzing the investment. Rather than looking for the most economical solution, PacifiCorp sought to justify a decision that had already been made. This meant that PacifiCorp was unable to work cooperatively with parties during the 2013 IRP and instead proceeded with an adversarial approach.

Q. WHAT ANALYSIS DID PACIFICORP PERFORM FOR THE JIM BRIDGER 3 AND 4 SCRS?

A. PacifiCorp compared installing the SCRs with converting to gas. This analysis is summarized in the 2013 IRP Tables V3.8 and V3.9 presented below.

Figure 4

Table V3.8 – Bridger 3 and 4 Emission Control PVRR(d) Analysis Results

System Cost Line Items	Operate as Coal System Costs	Gas Conversion System Costs	PVRR(d) (Benefit)/Cost of SCR Investments (\$m)
Fuel	\$16,539	\$16,858	(\$319)
Variable O&M	\$927	\$939	(\$12)
Emissions	\$3,994	\$3,358	\$336
Net System Balancing	(\$4,218)	(\$3,410)	(\$808)
<i>Total Variable</i>	<i>\$17,242</i>	<i>\$18,044</i>	<i>(\$802)</i>
New Resource Capital/Run-rate	\$2,583	\$2,854	(\$271)
Existing Resource Capital/Run-rate	\$7,328	\$6,431	\$896
Decommissioning/Stranded Cost	\$245	\$229	\$16
Contracts	\$2,639	\$2,639	\$-
Incremental DSM	\$502	\$533	(\$31)
Transmission	\$1,701	\$1,699	\$2
<i>Total Fixed</i>	<i>\$14,997</i>	<i>\$14,385</i>	<i>\$612</i>
<i>Total</i>	<i>\$32,239</i>	<i>\$32,429</i>	<i>(\$190)</i>

Figure 5

Table V3.9 – Bridger 3 and 4 CPCN Emission Control PVRR(d) Analysis Results

Gas Price Scenario	CO ₂ Price Scenario	PVRR(d) (Benefit)/Cost of SCR Investments (\$m)
Base (September 2012)	Base (September 2012)	(\$183)
High with Base CO ₂	Base (September 2012)	(\$755)
Low with Base CO ₂	Base (September 2012)	\$285
Base with High CO ₂	High	(\$51)
High with High CO ₂	High	(\$528)
Low with High CO ₂	High	\$378
Base with Zero CO ₂	Zero	(\$262)
High with Zero CO ₂	Zero	(\$997)
Low with Zero CO ₂	Zero	\$224

Table V3.9 was developed to support PacifiCorp’s Wyoming and Utah certificate of public convenience and necessity (“CPCN”) applications in August 2012 and were not updated for the 2013 IRP.

PacifiCorp also evaluated an alternative compliance scenario where Jim Bridger 3 and 4 retire in exchange for extended operation without SCR investment. This analysis is summarized in Table V3.12 reproduced below.

Figure 6

Table V3.12 – Bridger 3 and 4 Hypothetical Regional Haze Compliance Analysis Results

System Cost Line Items	Operate as Coal System Costs	Hypothetical Retirement	Early	PVRR(d) (Benefit)/Cost of SCR Investments (\$m)
Fuel	\$16,539	\$16,987		(\$448)
Variable O&M	\$927	\$924		\$3
Emissions	\$3,994	\$3,688		\$306
Net System Balancing	(\$4,218)	(\$4,021)		(\$197)
<i>Total Variable</i>	<i>\$17,242</i>	<i>\$17,578</i>		<i>(\$336)</i>
New Resource Capital/Run-rate	\$2,583	\$2,901		(\$318)
Existing Resource Capital/Run-rate	\$7,328	\$6,650		\$677
Decommissioning/Stranded Cost	\$245	\$229		\$16
Contracts	\$2,639	\$2,639		\$-
Incremental DSM	\$502	\$615		(\$113)
Transmission	\$1,701	\$1,700		\$1
<i>Total Fixed</i>	<i>\$14,997</i>	<i>\$15,117</i>		<i>\$120</i>
<i>Total</i>	<i>\$32,239</i>	<i>\$32,413</i>		<i>(\$174)</i>

1 **Q. WHAT EVIDENCE IN PACIFICORP'S 2013 IRP INDICATES THE SCR**
2 **INVESTMENTS WERE OF MARGINAL VALUE?**

3 A. Table V3.9 shows that the investment is highly uneconomic for every low gas price
4 scenario. This demonstrates that the investment is highly sensitive to gas prices. I show
5 below that the investment is also highly sensitive to coal prices and electricity prices.

6 **Q. WHY WERE THESE INVESTMENTS NOT PRUDENT?**

7 A. PacifiCorp failed to place appropriate weight on important factors and variables that
8 were known to PacifiCorp at the time the investments were made:

9 a) Oregon social and political landscape.

10 b) Risk related to coal costs.

11 c) Risk related to market sales.

12 d) Potential economies associated with alternative compliance.

13 e) Potential value of water rights.

14 The failure to place appropriate weight on these factors resulted in insufficient analysis. I
15 explore these factors in more detail below. In addition to failing to place weight on
16 important factors, PacifiCorp failed to update its analysis or to create optionality in its
17 contracting for SCR procurement. If PacifiCorp had placed appropriate weight on the
18 risks associated with the SCR investment, updated its analysis as facts evolved, allowed
19 optionality in procurement contracting, or responded to the Commission's concerns about
20 insufficient analysis, PacifiCorp may have been able to avoid some or all of this costly
21 investment.

Q. HOW DID PACIFICORP FAIL TO PLACE APPROPRIATE WEIGHT ON OREGON'S SOCIAL AND POLITICAL LANDSCAPE.

A. PacifiCorp's 2013 IRP was developed in direct conflict with Oregon's trend away from carbon generating resources. Oregon had stricter renewable generation requirements than PacifiCorp's other states. There was popular support for a cleaner generation fleet. The Commission had already sent a clear signal to PacifiCorp in 2008 that coal generation was unlikely to have a future in Oregon by declining to extend the depreciable lives of PacifiCorp's coal fleet.^{34/} Supporting that decision, the Commission stated: "It is inappropriate to ignore the possibility that increased environmental regulations could reduce the economic lives of coal-fired generation plants."^{35/}

Q. WHAT ANALYSIS DID PACIFICORP FAIL TO PERFORM IN LIGHT OF OREGON'S POLITICAL LANDSCAPE?

A. PacifiCorp failed to perform an analysis consistent with the Oregon depreciable lives of the coal fleet. Oregon's depreciable end of life for Jim Bridger 3 and 4 was 2025. PacifiCorp's analysis of Jim Bridger 3 and 4 assumed operation until 2037. A shorter economic life for Jim Bridger 3 and 4 would have resulted in two significant changes that would have made the investments uneconomic under nearly every possible future scenario.

1. Under a 2037 life the investment in the SCR pushed the need for a replacement resource (i.e., new gas plant) beyond the planning horizon (2013 to 2032).

2. Under a 2037 life the cost of the SCR investment was spread over 22 years rather than 10 years.

^{34/} Docket No. UM 1329, Order No. 08-327 (June 17, 2008).

^{35/} Id. at 4.

Q. WHAT IMPACT DID PUSHING THE JIM BRIDGER REPLACEMENT RESOURCE OUTSIDE THE PLANNING HORIZON HAVE ON THE ECONOMIC ASSESSMENT OF THE SCR INVESTMET?

A. Pushing the replacement resource outside the planning horizon eliminated a large portion of capital costs for new generation. Table V3.12 from the 2013 IRP summarized the base case scenario for the Jim Bridger SCR vs Jim Bridger retirement. This table is reproduced below with additions to illustrate the approximate impact of a 2025 retirement in the “with SCR” scenario. Under a 2025 retirement date the \$174 million dollar benefit from the SCR investment becomes a \$441 million dollar loss. This \$600 million dollar swing exceeds the projected benefit in seven of nine scenarios in Table V3.9.

Figure 7: Jim Bridger IRP Table

Table V3.12 - Bridger 3 and 4 Hypothetical Regional Haze Compliance Anal				
System Cost Line Items	Operate as Coal System Costs	Hypothetical Early Retirement	PVRR(d) (Benefit)/Cost of SCR Investments (\$m)	Adjusted Benefit under "Operate as Coal" and 2025 Retirement
Fuel	\$16,539	\$16,987	(\$448)	-263.5294118
Variable O&M	\$927	\$924	\$3	\$3
Emissions	\$3,994	\$3,688	\$306	180
Net System Balancing	(\$4,218)	(\$4,021)	(\$197)	-115.8823529
<i>Total Variable</i>	<i>\$17,242</i>	<i>\$17,578</i>	<i>(\$336)</i>	<i>-196.4117647</i>
New Resource Capital/Run-rate	\$2,583	\$2,901	(\$318)	
Existing Resource Capital/Run-rate	\$7,328	\$6,650	\$677	\$677
Decommissioning/Stranded Cost	\$245	\$229	\$16	\$16
Contracts	\$2,639	\$2,639	\$-	
Incremental DSM	\$502	\$615	(\$113)	-56.5
Transmission	\$1,701	\$1,700	\$1	\$1
<i>Total Fixed</i>	<i>\$14,997</i>	<i>\$15,117</i>	<i>\$120</i>	<i>637.5</i>
<i>Total</i>	<i>\$32,239</i>	<i>\$32,413</i>	<i>(\$174)</i>	<i>441</i>

Q. PLEASE EXPLAIN HOW YOU ADJUSTED THE BENEFIT UNDER THE 2025 LIFE.

A. Some items were adjusted based on the ratio of Jim Bridger operating years in the IRP relative to operating years under a 2025 retirement. The adjustment ratio is summarized in the figure below.

Figure 8: Adjustment Ratio for Jim Bridger Oregon Retirement Date

Line	Calc		
a		Install Year	2015
b		Planning Horizon	2032
c		Retirement Year	2025
d	(c-a)/(b-a)	Adjustment Ratio	59%

This ratio was applied to the PVRR(d) for fuel, emissions, net system balancing, and incremental DSM. The rationale for this adjustment is that the original benefit or cost was spread over the time from the SCR installation to the end of the planning horizon and grew at the IRP discount rate. Under a 2025 retirement date these benefits would only occur up until 2025 and the adjustment ratio accounts for the benefits or costs stopping after 2025. A second adjustment was to exclude the new resource Capital\Run-rate line. A replacement resource in 2025 would have required substantial capital approximately equal to the original benefit.

Q. HOW DID PACIFICORP FAIL TO PLACE APPROPRIATE WEIGHT ON COAL COSTS?

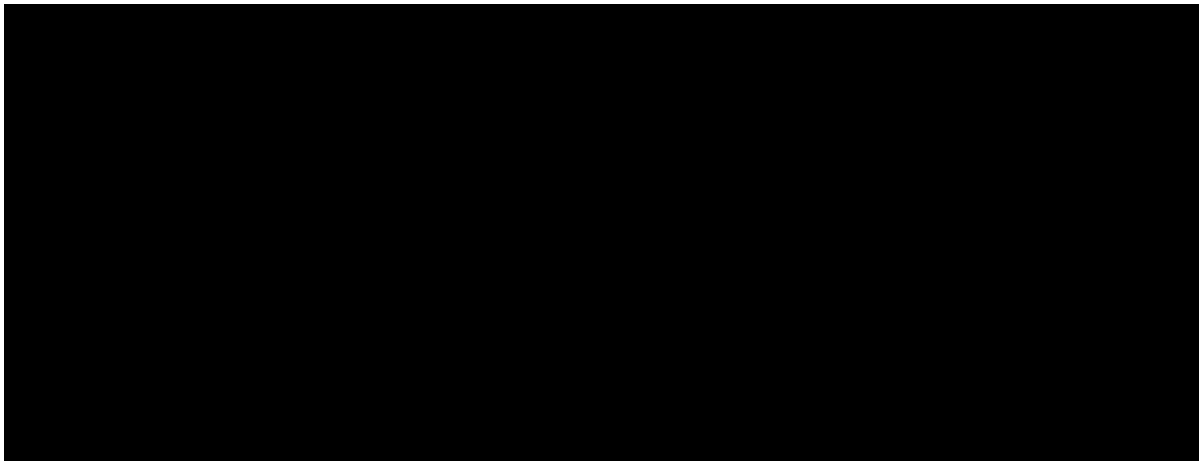
A. One of the primary factors in the viability of thermal generation plants are coal prices. PacifiCorp's coal prices are highly variable. I compared 21 different Bridger Coal Company annual coal cost forecasts with actual coal cost values. Every annual forecast was [REDACTED] actual. On average, actual costs were [REDACTED] [REDACTED] PacifiCorp performed a targeted analysis of Jim Bridger's

1 SCR investments. However, PacifiCorp failed to test the sensitivity of the investments to
2 higher than expected coal prices.

3 **Q. WHAT IS THE IMPACT OF A SCENARIO WITH HIGHER COAL COSTS?**

4 A. Figure 9, below estimates the additional cost for a scenario where Jim Bridger fuel cost is
5 20 percent higher than assumed in the 2013 IRP. The table assumes an 80 percent
6 capacity factor and a heat rate of 10,000 btu/KWh. The annual incremental cost of a 20
7 percent increase in Jim Bridger coal cost is [REDACTED]. The net present value from 2015
8 to 2032 is [REDACTED]. This exceeds the benefit of the base case scenario in Table V3.12
9 from the 2013 IRP and renders six of nine scenarios in Table V3.9 uneconomic.

10 **Figure 9: Confidential Impact of 20% increase in Jim Bridger Coal Cost**



11
12 **Q. HOW DID PACIFICORP FAIL TO ACCOUNT FOR THE RISK OF MARKET**
13 **SALES?**

14 A. PacifiCorp's IRP modeling allows resources to trade in energy markets. Profitable
15 energy sales depend on generation costs and market prices. A portfolio that depends
16 heavily on market transactions to justify profitability is exposed to excessive market risk.
17 The SCR analysis in the 2013 IRP Table V3.8 shows the primary forecasted benefit of
18 the SCR investment was [REDACTED]

[REDACTED]

[REDACTED] PacifiCorp's coal analysis failed to evaluate the economics of the SCR investments under a range of market prices and under a range of generation costs.

Q. WHAT POTENTIAL ECONOMIES EXISTED FOR ALTERNATIVE COMPLIANCE SCENARIOS?

A. PacifiCorp explored only one alternative compliance scenario for Jim Bridger. This scenario is presented in the 2013 IRP Table V3.12. This scenario involved continued coal operation for Jim Bridger 3 and 4 until 2020 and 2021 respectively followed by retirement of the units. In LC 57 Staff requested PacifiCorp perform additional alternative compliance scenarios through Staff DR OPUC 262.³⁶ The Staff scenario extended the operation of Jim Bridger 3 and 4 by two years, to 2022 and 2023. The two additional years of operation in the Staff scenario increased the value of alternative compliance by [REDACTED]. This indicates that an alternate compliance scenario involving a 2024-2025 shutdown could have been economic in PacifiCorp's base case analysis.

Figure 10: LC 57 Alternate Compliance Analysis

LC 57 OPUC 262 Bridger 3 and 4 Early Retirement			
System Cost Line Items	Operate as Coal System Costs (\$m)	Hypothetical Early Retirement (\$m)	PVRR(d) (Benefit)/Cost of SCR investments (\$m)
<i>Total (Retire 2022 and 2023)</i>	\$32,239	\$32,315	(\$77)
<i>Table V3.8 Total (Retire 2020 and 2021)</i>	\$32,239	\$32,413	(\$174)
<i>Impact of 2-year delay</i>			\$97
<i>Impact of 4-year delay</i>			\$195
<i>Total (Retire 2024 and 2025)</i>			\$21

^{36/} Exh. AWEC/302 at 2 (PacifiCorp Supplemental Response to AWEC DR 6).

1 **Q. WAS AN ALTERNATE COMPLIANCE SCENARIO OF 2024-2025 A FEASIBLE**
2 **ALTERNATIVE.**

3 A. Yes. Alternate compliance for regional haze requirements have been applied to several
4 other coal plants in the region. While it is not certain, PacifiCorp could have requested
5 and negotiated for an alternative compliance scenario of 2024 retirement. PacifiCorp's
6 failure to thoroughly analyze and request alternate compliance was not prudent.

7 **Q. WHY IS THE VALUE OF WATER RIGHTS AN IMPORTANT FACTOR IN THE**
8 **SCR INVESTMENT DECISION?**

9 A. PacifiCorp did not consider the value of water rights when evaluating the Jim Bridger
10 SCRs, the sale of which would have increased the value of retiring Jim Bridger.^{37/} Early
11 retirement of Jim Bridger Units 3 and 4 would have made the water used for these plants
12 available 17 years sooner. The value of water for 17 years should have been included as a
13 benefit under early retirement scenarios. PacifiCorp's rationale for not including this
14 value was that water right values are difficult to forecast.^{38/} However, coal prices and gas
15 prices are similarly difficult to forecast. PacifiCorp's 2013 IRP forecasts for gas prices
16 and coal prices were incorrect. There are relatively easy ways to forecast the value of
17 water rights.

18 For example, a forecast can be made by evaluating the incremental value of
19 irrigated farmland versus dry farmland. The value of recent transactions could be used.

20 I used both approaches to estimate the value of water rights for Jim Bridger.
21 Based on my experience with this exercise and IRPs, the modeling performed in the IRP
22 is much more complicated than the task of forecasting the value of water rights. My
23 estimate for the value of water used by Jim Bridger 3 and 4 ranged from \$37 million to

^{37/} Id. at 21 (PacifiCorp Response to AWEC DR 122).

^{38/} Id.

1 \$309 million. The low range of this estimate is high enough to make the SCR investment
2 marginally economic in the Base Gas with High CO2 price scenario of Table V3.9. The
3 high range of this estimate makes the SCR investment uneconomic in six of nine
4 scenarios.

5 **Q. HOW DID YOU ESTIMATE THE VALUE OF JIM BRIDGER 3 AND 4 WATER**
6 **RIGHTS?**

7 A. The low value is based on the incremental value of irrigated Wyoming farmland. I
8 calculated the number of acres of alfalfa that Jim Bridger 3 and 4 water use could irrigate
9 per day, and multiplied that by the incremental value of alfalfa over other Wyoming
10 dryland crops per acre. This calculation, yielding a value of approximately \$37 million,
11 can be found in Exhibit AWEC/306 at 4 to 7.

12 The value of water in industrial uses may be higher than in agriculture uses. For
13 example, the value of water for oil and gas in Cheyenne averaged \$.01 per gallon and
14 ranges as high as \$0.015 per gallon. At this value Jim Bridger 3 and 4 water use is worth
15 piping to Cheyenne.

16 Exhibit AWEC/306 at 4 to 7 models the cashflows of a pipeline with the
17 following assumptions:

- 18 • 24-inch pipe (capacity of 18,000 gpm is sufficient for JB 3 and 4)^{39/}
- 19 • \$2 million per mile (Sacramento Suburban estimates 16-inch pipe costs \$1.1 million
20 per mile, 48-inch pipe costs \$4 million per mile)^{40/}

^{39/} <https://www.hy-techroofdrains.com/water-flow-through-a-pipe/>
^{40/} Water Transmission Main Asset Management Plan August 2011 Sacramento Suburban:
<http://www.sswd.org/home/showdocument?id=1002#:~:text=Rehabilitation%20can%20extend%20the%20service,mile%20for%2048%2Dinch%20piping.>

- 1 • 90-year life^{41/}
- 2 • Maintenance and pumping expense of \$5 million per year
- 3 • Water price of \$0.01 per gallon
- 4 • Maintenance cost and water price growth of 3 percent per year
- 5 • Capital carrying cost of 10 percent per year.

6 With these assumptions the value of Jim Bridger 3 and 4 water from 2015 to 2032 is
7 worth a net present value of \$399 million.

8 **Q. IN ADDITION TO FAILING TO PLACE WEIGHT ON IMPORTANT**
9 **FACTORS, YOU STATE PACIFICORP FAILED TO UPDATE ANALYSIS OR**
10 **MAINTAIN OPTIONALITY. HOW DOES THIS RELATE TO PRUDENCE OF**
11 **THE INVESTMENT?**

12 A. PacifiCorp received clear signals from the Commission and Oregon parties that the SCR
13 investments were of dubious economic value. Given the marginal value of the
14 investments, PacifiCorp should have structured its procurement to maintain options for
15 terminating the investments. PacifiCorp did not complete the SCR on Jim Bridger 4 until
16 2016, four years after performing the CPCN analysis used to support the project. If
17 PacifiCorp had maintained the option to terminate the project, PacifiCorp could have re-
18 evaluated the investment as circumstances changed.^{42/} PacifiCorp did not update the
19 economic analysis of pollution controls at Jim Bridger 3 or 4 after the 2013 IRP.^{43/}

20 **Q. WHAT ARE SOME EXAMPLES OF CHANGING CIRCUMSTANCES THAT**
21 **AFFECTED THE ECONOMICS OF THE PROJECT?**

22 A. I will illustrate with three examples: SB 1547, coal prices, and gas prices.

^{41/} Water Transmission Main Asset Management Plan August 2011 Sacramento Suburban estimates new pipe has a 90-year life.

^{42/} PacifiCorp's final notice to proceed was given three years before the Jim Bridger 4 SCR was placed in service. PAC/800 Teply/32. This is because PacifiCorp selected a structural design that did not allow the option for standalone SCRs. Exh. AWEC/302 at 10 (PacifiCorp Response to AWEC DR 49).

^{43/} Exh. AWEC/302 at 9 (PacifiCorp Response to AWEC DR 48).

Oregon Senate Bill 1547 limits PacifiCorp's ability to have coal generation in Oregon rates beyond 2030. SB 1547 evolved out of Oregon 2015 Initiative Petition numbers 63, 64, 72, and 73. PacifiCorp met with Oregon Commissioners in 2015 to discuss the potential exclusion of coal from rates.^{44/} PacifiCorp became aware of Initiative Petition 63 and Petition 64 in shortly after they were filed on October 5, 2015. PacifiCorp could have re-evaluated the economics of the SCR investments assuming Jim Bridger closures in 2030 after learning of the petitions, but did not.

PacifiCorp's average coal price for the 2013, 2014, and 2015 ten-year business plan are summarized in the table below. As I showed previously, the economics of the SCRs are sensitive to coal costs. PacifiCorp should have re-evaluated the investments as coal price forecasts increased.

Figure 11: Confidential Bridger Coal Company Coal Prices

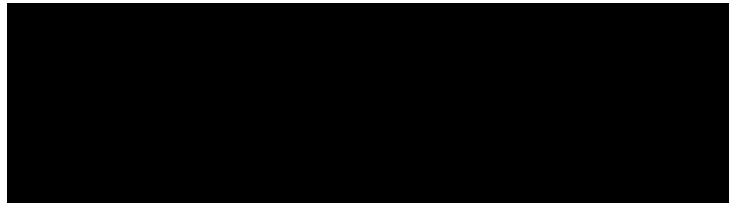


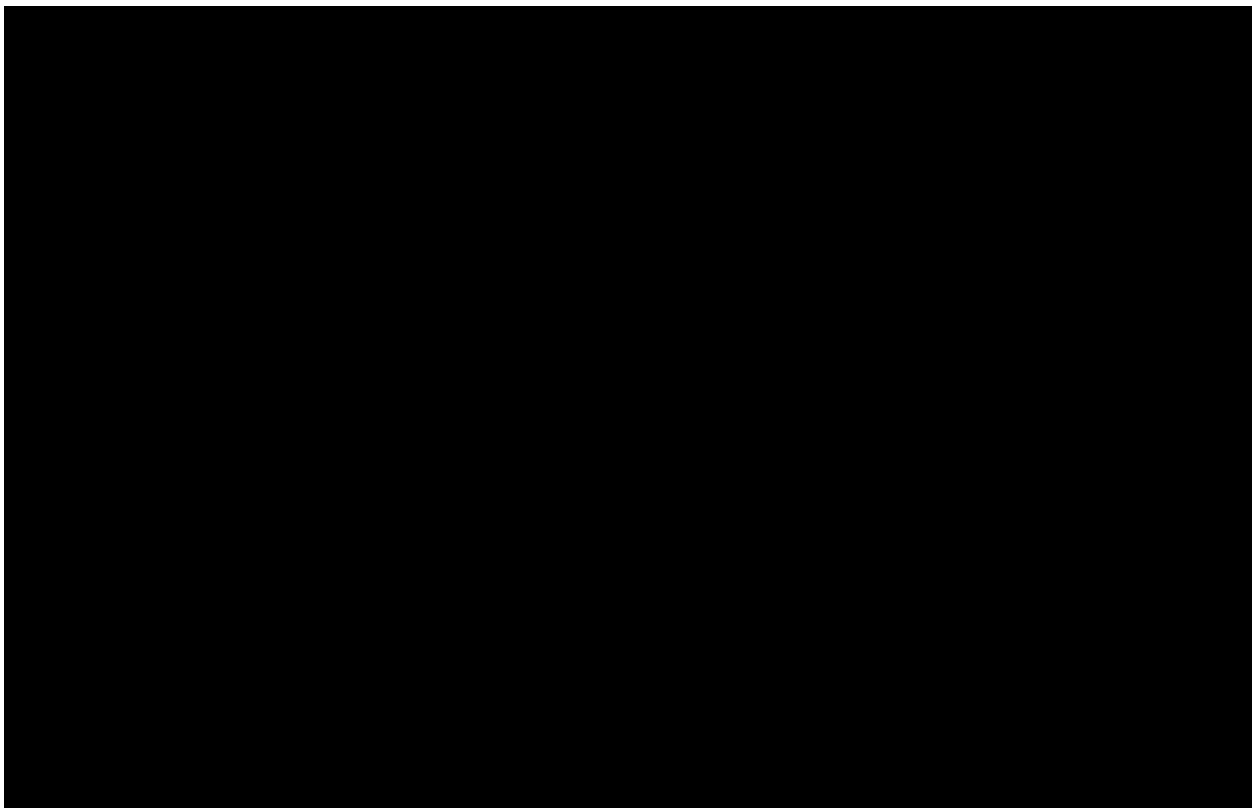
Table V3.9 from the 2013 shows the Jim Bridger 3 and 4 investments were highly sensitive to gas prices. This is seen by comparing the low gas scenarios with the base gas scenarios. All low gas scenarios show the investments are uneconomic. Given this sensitivity to gas prices, PacifiCorp should have been carefully watching gas prices prior to committing to the investment. The figure below illustrates PacifiCorp's 2013 IRP gas price (completed September 2012) with the 2013 through 2015 business plan forecasts and the 2019 IRP (completed September 2018.) The 2013 Business Plan forecast,

^{44/} Exh. AWEC/302 at 1 (PacifiCorp Response to AWEC DR 3).

1 presumably available at the end of 2013, shows gas prices 10 to 15 percent lower than the
2 base case scenario in the 2013 IRP.

3 PacifiCorp's full notice to proceed for both SCRs was given in December 1, 2013
4 despite the reductions in PacifiCorp's forward gas price. PacifiCorp could have re-
5 evaluated the economics of the investment using the most up to date prices but chose not
6 to.

7 **Figure 12: Confidential**



8 **Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE JIM BRIDGER 3 AND 4**
9 **SCR INVESTMENTS.**

10 A. PacifiCorp made the decision to proceed with the SCRs at the beginning of the IRP
11 process, fundamentally changing PacifiCorp's incentives during the IRP. PacifiCorp's
12 IRP showed the investments were uneconomic in all three low gas price scenarios.

1 PacifiCorp's IRP analysis failed to consider five important factors. All five factors
2 independently make the investments uneconomic:

- 3 1. Oregon social and political landscape indicated early closure was likely. Analysis
4 consistent with depreciable life turns the investment into a ~~\$471~~\$441 million loss.
- 5 2. Risk related to coal costs. A 20 percent increase in coal prices renders the investment
6 uneconomic in six of nine scenarios.
- 7 3. Risk related to market sales. The net system sales benefit is four times the base case
8 net benefit, indicating a small change in market prices would make the investment
9 uneconomic.
- 10 4. Potential economies associated with alternative compliance. Staff's analysis from LC
11 57 shows an alternative compliance with retirement in 2024 and 2025 is economic in
12 PacifiCorp's base case.
- 13 5. Potential value of water rights. The potential value of water rights, after accounting
14 for transmission costs, makes early retirement in 2015 and 2016 economic.

15 Additionally, PacifiCorp failed to update its analysis to account for changing
16 circumstances prior to completion of the investment. Oregon 2015 Initiative Petition
17 numbers 63, 64, 72, and 73, increased coal cost forecasts, and increased gas price
18 forecasts are all changing circumstances that decreased the economic value of the
19 investments before they were completed. PacifiCorp's design and contracting choices
20 obligated PacifiCorp to complete the project as early as December 1, 2013. However,
21 even at that time gas prices had sufficiently changed to warrant re-evaluation.

22 I recommend the Commission disallow the Jim Bridger 3 and 4 SCR investments
23 as uneconomic and imprudent investments.

b. Hunter Unit 1 Baghouse and Low NOx Burners

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE HUNTER 1 POLLUTION CONTROL INVESTMENTS.

A. PacifiCorp is requesting investments in Hunter Unit 1 Baghouse and Low NOx Burners be included in ratebase. PacifiCorp failed to bring these investments to the Commission through an IRP process in a timely manner, and the Commission did not acknowledge the investments. PacifiCorp's analysis and procurement of the Hunter 1 investments suffers from the same failures as the Jim Bridger investments. I recommend the Hunter 1 Baghouse and Low NOx investments be disallowed.

Q. HOW DOES HUNTER UNIT 1'S CIRCUMSTANCE DIFFER FROM JIM BRIDGER?

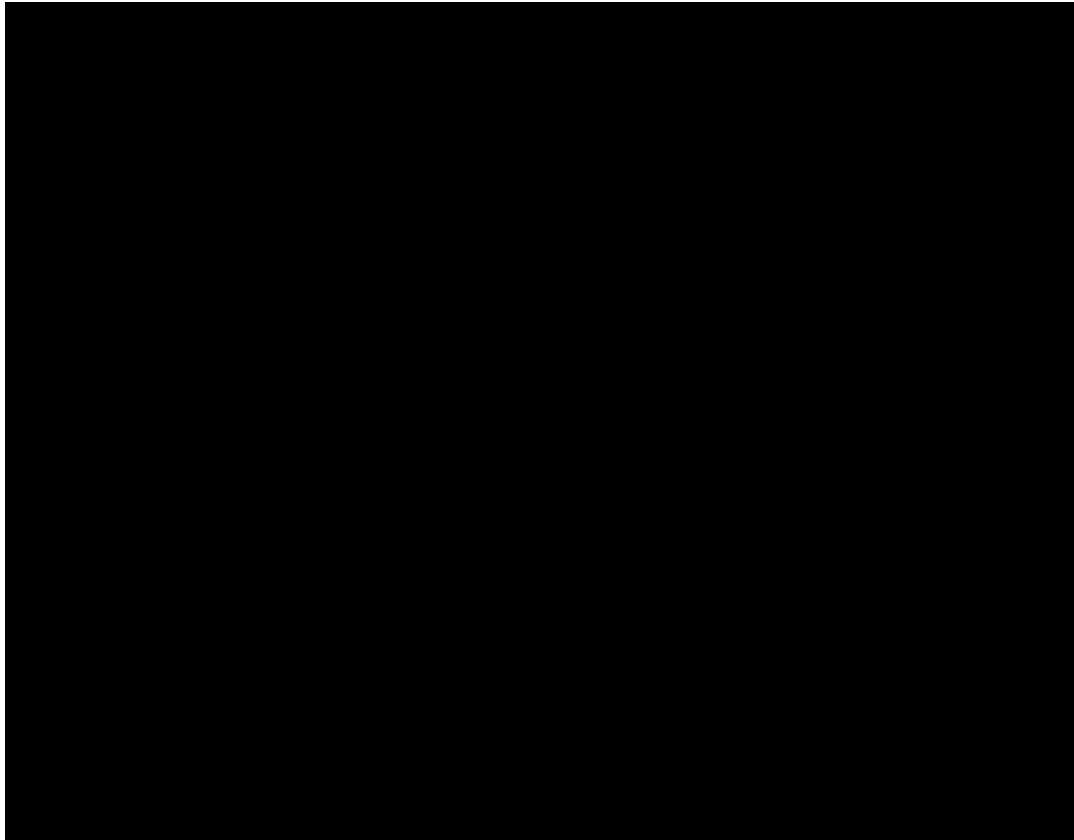
A. Hunter Unit 1 has lower coal costs than Jim Bridger. However, Jim Bridger Units already had baghouses, while Hunter Unit 1 was expected to need a baghouse, low NOx burner, and SCR, resulting in a much higher incremental capital expenditure. Hunter Unit 1's depreciable life was 2029.

Q. WHAT IS THE IMPACT OF USING OREGON'S DEPRECIABLE LIFE AS THE RETIREMENT DATE WHEN EVALUATING THE BAGHOUSE?

A. The Jim Bridger depreciable life analysis is repeated for Hunter below, using the 2029 retirement date. The 2029 retirement date reduces the value of the baghouse by \$620 million. This exceeds the baghouse benefit for every scenario in the 2013 IRP Table V3.5 except high gas base CO₂, which I have reproduced in Figure 12 below with adjustments for a 2029 retirement date.

1

Figure 13: Confidential



2 **Q. IS THE BAGHOUSE INVESTMENT SENSITIVE TO COAL, GAS, AND**
3 **MARKET PRICES?**

4 A. Yes. Like Jim Bridger, the investments are sensitive to coal, gas, and market prices.
5 PacifiCorp did not test coal or market price scenarios. Figure 13 shows the net system
6 balancing benefit of the baghouse exceeds the benefit of the investment, indicating that
7 without economic market transactions the baghouse investment is not economic.

8 **Q. DID PACIFICORP EXPLORE ALTERNATIVE COMPLIANCE SCENARIOS?**

9 A. PacifiCorp did not explore any scenarios that involved tradeoffs across time or across
10 generation units or plants.^{45/} As noted above, such alternative compliance scenarios have
11 been commonly used for coal plants in the West, including several of PacifiCorp's own

^{45/} 2013 IRP Volume 3.

1 plants. PacifiCorp's failure to explore any alternative compliance scenarios was
2 imprudent.

3 **Q. DID PACIFICORP CONSIDER THE VALUE OF WATER RIGHTS WHEN**
4 **ANALYZING THE INVESTMENT?**

5 A. No. Hunter water is drawn from Electric Lake and Huntington Creek. This water directly
6 drains into Lake Powel through the Green River.^{46/} PacifiCorp may be able to monetize
7 these water rights at minimal cost by moving it south through the Green River to Lake
8 Powel.

9 **Q. WHAT IS YOUR RECOMMENDATION FOR THE HUNTER BAGHOUSE AND**
10 **LOW NOX INVESTMENTS?**

11 A. I recommend these investments be excluded from ratebase as uneconomic and imprudent
12 investments.

13 **VII. METER PLANT NOT IN SERVICE**

14 **Q. WHAT METER PLANT IS IN PACIFICORP'S RATES BUT NOT IN SERVICE?**

15 A. As I noted in Section III.c, above, between 2017 and 2020 PacifiCorp replaced a large
16 number of existing meters with AMI meters.^{47/} The AMI rollout resulted in \$54 million
17 of early retirements.^{48/} When PacifiCorp retires plant depreciated with group
18 depreciation PacifiCorp reduces both gross plant and accumulated depreciation by equal
19 amounts and reduces accumulated depreciation by net salvage. This means that the
20 undepreciated portions of the meters retired through the AMI rollout remain in rates.
21 PacifiCorp should have estimated the net plant of the retired meters and removed this
22 amount from ratebase.

^{46/} https://waterrights.utah.gov/asp_apps/viewEditIND/indView.asp?SYSTEM_ID=11095

^{47/} Exh. PAC/1100, Lucas/23.

^{48/} Exh. AWEC/302 at 6 (PAC Response to AWEC DR 28).

1 **Q. WHY SHOULD THE UNDEPRECIATED AMOUNT OF METERS RETIRED IN**
2 **THE AMI ROLLOUT HAVE A DIFFERENT RATE OF RETURN**
3 **TREATMENT?**

4 A. Because they are “not presently used for providing utility service to the customer.”^{49/}
5 Long-standing precedent holds that “property that is not ‘reasonably necessary to and
6 actually providing utility service’ is ineligible for either inclusion in the rate base or for a
7 rate of return payable by utility customers.”^{50/} This is true not only for property that has
8 yet to be placed in service, but also for “property that has *ceased* to be reasonably
9 necessary and actually used.”^{51/}

10 **Q. HOW IS UNDEPRECIATED PLANT BALANCE DETERMINED IN A GROUP**
11 **ACCOUNT?**

12 A. Group accounting does not match depreciation with specific units of assets. This makes
13 quantifying the amount of undepreciated plant associated with the retired meters more
14 difficult to quantify. I estimated the accumulated depreciation assuming PacifiCorp’s
15 current expected life for Oregon meters, 20 years.^{52/} Exhibit AWEC/307 summarizes
16 these calculations. PacifiCorp’s AMI rollout removed \$16,126,628 in net plant from
17 service. I recommend a reduction of PacifiCorp’s ratebase of an equal amount.
18 PacifiCorp should be entitled to recover the remaining unrecovered investment in
19 removed meters through a regulatory asset that earns a return equivalent to the time value
20 of money.^{53/} I recommend recovery of the regulatory asset over a 10-year period with an
21 interest rate equivalent to the current 10-year treasury bond yield, plus 100 basis points.
22 This is equivalent to approximately 1.66%.

^{49/} ORS 757.355(1).

^{50/} *Citizens’ Util. Bd. v. PUC*, 154 Or. App. 702, 710 (1998).

^{51/} *Id.* (emphasis in original).

^{52/} Docket No. UM 1647, Exh. PAC/202, Section III at page 16.

^{53/} *See* Order No. 08-487 at 70-71

VIII. OREGON'S EXIT FROM COAL GENERATION

Q. DID YOUR ANALYSIS RAISE ANY CONCERNS RELATED TO OREGON'S EXIT FROM COAL GENERATION?

A. Yes. Oregon customers should receive fair value for materials and supplies, rolling stock, rail cars, water rights, and land associated with coal plants. Oregon ratepayers will have paid the costs for these items and should receive fair compensation for them. The 2020 Protocol does not address how these assets will be treated in rates following Oregon's exit from a coal plant. While this issue need not be resolved in this case, the Commission should ensure there is a process in place for ensuring customers are fairly compensated for these assets. If PacifiCorp does not transfer these goods and assets to non-Oregon jurisdictions at the higher of cost or market value PacifiCorp should liquidate the assets and flow the proceeds to customers through its property sales balancing account.

Q. DO YOU HAVE ANY SPECIFIC CONCERNS WITH THE TRANSFER VALUE OF WATER RIGHTS FOR COAL PLANTS?

A. Yes. My estimates demonstrate a wide potential range for the value of coal plant water rights. PacifiCorp should provide a transparent and open market process for establishing a value for these rights.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.