BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.

DOCKET UE-152253

REVISED DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1T)

ON BEHALF OF PUBLIC COUNSEL

(RED-LINED)

MARCH 17, 2016

REVISED TESTIMONY OF DONNA M. RAMAS (DMR-1T)
DOCKET UE-152253

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I. INTRODUCTION

Q: Please state your name, occupation and business address.

A: My name is Donna M. Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q: On whose behalf are you testifying?

A: I was retained by the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel) to review Pacific Power & Light Company's (Pacific Power or Company) request for an increase in rates and a two-year rate plan. Accordingly, I am appearing on behalf of Public Counsel.

Q: What is the purpose of your testimony?

A: I present Public Counsel's overall revenue requirement recommendation based on adjustments presented in this testimony. I also discuss the single issue that is driving the vast majority of the Company's requested increase in this case, which is the Company's request to significantly accelerate the recovery of certain coal plant capital costs from Washington ratepayers. I recommend that the Company's requested acceleration of depreciation be rejected at this time. I also show that, absent the requested acceleration, Pacific Power should lower the rates currently being charged to Washington ratepayers, not increase them. Additionally, I address the Company's request for a two-year rate plan and recommend that the requested second year step increase be rejected for the reasons discussed later in this testimony.

Q: **Have you prepared a summary of your qualifications and experience?**

A: Yes. I have attached Exhibit No. DMR-5, which is a summary of my regulatory experience and qualifications.

Q: Have you previously filed testimony before the Washington Utilities and Transportation Commission ("UTC")?

A: Yes. I filed testimony before the UTC in Dockets UE-090205 and UE-140762 (*Consolidated*), both of which involved Pacific Power & Light Company, and Dockets UE-150204 and UG-150205 (*Consolidated*) involving Avista Corporation.

Q: Have you prepared any exhibits in support of your testimony?

A: Yes. I have prepared Exhibit No. DMR-2, which is a summary of my recommended adjustments to Pacific Power's first year rate increase and the resulting revenue requirement, and Exhibit No. DMR-3, which presents the Public Counsel's recommended revenue requirement and the calculations supporting the adjustments sponsored in this testimony.

I also prepared Exhibit No. DMR-4 which presents recommended adjustments to the Company's proposed Year Two incremental step increase, should the Commission choose to adopt a two-year rate plan as proposed by Pacific Power in this case. As explained later in this testimony, I recommend that the Company's proposed second-year increase be rejected by the Commission.

Q: Are you providing any additional exhibits in this proceeding?

A: Yes. I am also attaching various data responses referenced in this testimony and in Exhibit Nos. DMR-2 through DMR-4. These are being provided as Exhibit Nos. DMR-6 through DMR-25. These exhibits are also identified in the Exhibits List at the beginning of this testimony.

Q: Please discuss how Exhibit No. DMR-3 is organized.

A: Exhibit No. DMR-3 consists of pages 1 – 32. Page 1 presents the overall revenue requirement resulting from the adjustments recommended in this testimony. Pages 2 through 7 provide a summary that begins with the Per Company unadjusted per book amounts on a Washington jurisdictional basis, provides all of the adjustments on a Washington jurisdictional basis, and provides the resulting Public Counsel recommended adjusted amounts on a Washington jurisdictional basis.

Adjustments recommended by Public Counsel that were not adjusted by the Company are presented as Adjustments PC-1 through PC-5 on pages 8 through 18. Each of the Company's proposed adjustments that Public Counsel revised are presented on pages 19 through 32. Each of the Company adjustments presented on pages 19 through 32 identifies the Company proposed amounts and the Public Counsel adjusted amounts. The Company proposed adjustments that Public Counsel takes no position on at this time are not included as separate pages in Exhibit No. DMR-3, but are included in the summary of adjustments on pages 2 through 7 at the Company proposed amounts.

Q: Page 1 of Exhibit No. DMR-3 includes three separate columns containing "Per Company" amounts. Can you please explain why there are three different "Per Company" presentations on these schedules?

A: Yes. The Protecting Americans From Tax Hikes Act of 2015, hereinafter referred to as the "PATH Act," was signed into law by President Obama on December 18, 2015. Included in the PATH Act was the extension of bonus depreciation with the 50 percent bonus depreciation provisions being effective retroactively to the beginning of 2015 through 2017, and additional bonus depreciation provisions phasing-down through 2019, as well as other tax provisions. Since the PATH Act was signed into law subsequent to the filing of the Company's application, the impacts of the PATH Act were not incorporated in the Company's filing. Clearly the known and measurable impacts of this new law that became effective less than a month after the Company submitted its filing and impacts the test year should be incorporated in this case.

Additionally, the Company's filing is based on an End of Period ("EOP") rate base approach instead of the Average of Monthly Averages ("AMA") approach recently adopted by the Commission for this Company in its most recent rate case. Later in this testimony, I recommend that the Commission use the AMA approach for determining the appropriate rate base for setting rates for Pacific Power.

For the ease of the Commission in reviewing my testimony and exhibits in this proceeding, and in being able to compare impacts of the EOP and AMA approaches on the individual components of the revenue requirement equation, I have included the three "Per Company" columns on my Revenue Requirement presentation on Exhibit No. DMR-3, page 1 of 32.. The first "Per Company" column presents the amounts contained in the Company's original November 25, 2015, filing which uses an EOP rate base approach. The second column presents the revised EOP rate base approach amounts with the impacts of the PATH Act incorporated. Finally, the third column presents the AMA approach with impacts of the PATH Act incorporated. Both the second and third columns were based on information provided by the Company in response to discovery in this case.[1]

Q: What impacts do the PATH Act and the AMA rate base approach have on the revenue requirements presented in the Company's original filing?

A: As shown on Exhibit No. DMR-3, page 1 of 32, the revenue requirement calculated in the Company's original filing of $10,746,470 declined by $251,092 to $10,495,378 when the impacts of the PATH Act are reflected. As also shown on the above referenced exhibits, the revenue requirement that would result if the PATH Act impacts are reflected and the AMA approach to rate base is used is $9,116,220, which is $1,379,158 lower than the revenue requirement under the EOP approach with the PATH Act impacts reflected. Additionally, as shown on Exhibit No. DMR-4, page 1 at lines 1 through 4, the Year Two step increase calculated in the Company's original filing of $10,550,094 declines by $705,581 to $9,844,513 when the impacts of the PATH Act are reflected.[2]

II. SUMMARY OF TESTIMONY

Q: Based on Public Counsel's analysis of Pacific Power's filing, what is Public Counsel's recommended change to the current level of Washington revenue requirements for Pacific Power?

A: While the Company's initial filing presented revenue requirement calculations resulting in a calculated $10,746,470 increase in rates, and the impacts of the PATH Act reduce that amount to $10,495,378, Pacific Power limited its requested

[1] The Impacts of the PATH Act on the Company's filing was provided in response to Boise Data Request No. 9, provided as Exhibit No. DMR-6. The impacts of reflecting both the AMA rate base approach and the impacts of the PATH Act was provided by the Company in response to Boise Data Request No. 13, provided as Exhibit No. DMR-7.

[2] The impacts of the PATH Act on the Company's requested Year Two step increase were provided in response to Boise Data Request No. 9, provided as Exhibit No. DMR-6.

increase in base rates to $10 million, or 2.99 percent, as a result of its decision to file its case as an Expedited Rate Filing ("ERF").[3] Based on the adjustments proposed in this testimony, the $10 million requested increase should instead be a reduction in current rates of~~$4,512,983~~ ~~$3,396,464~~ $3,389,490. The resulting revenue reduction of ~~$4,512,983~~ ~~$3,396,464~~ $3,389,490 is presented on Exhibit No. DMR-2 and on Exhibit No. DMR-3, page 1 of 32.[4] As shown on each of these exhibits, Public Counsel's recommended revenue requirement is based on the AMA rate base approach with the impacts of the PATH Act incorporated.

It should be noted that adjustments PC-1 through PC-5 recommended in this testimony remain the same if the EOP or the AMA approach is used. Since Exhibit No. DMR-3 begins with the per book amounts (Washington jurisdictional basis) and incorporates each of the Company's adjustments, the Company adjustments that are impacted by the PATH Act and by use of the AMA approach instead of the Company's proposed EOP approach are modified in Exhibit No. DMR-3.

Q: Did you undertake a comprehensive analysis and review of Pacific Power's claimed revenue deficiency for its Washington jurisdictional electric operations?

A: No. My primary focus was on items with larger impacts on customers. Additionally, I did not review or analyze the cost allocation methodology and resulting allocation factors used by Pacific Power and did not review and analyze whether or not the amount of Net Power Costs currently incorporated in current

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[3] The Prehearing Conference Order, Order 03 of this proceeding, at paragraph 14, states, in part, "The Commission does not recognize this filing as an ERF, but to the extent practicable, we have and will continue to expedite the procedural schedule."

[4] There is a $2 rounding difference between the two exhibits.

base rates should be revised. In its filing, the Company has not proposed any changes to the net power costs incorporated in current base rates. While I did review many areas of Pacific Power's filing, I did not conduct a complete or comprehensive review of all issue areas. Public Counsel may subsequently elect to support some of the adjustments of other parties in this proceeding. As a result, the revenue requirements presented above should not be considered a final revenue requirement recommendation on behalf of Public Counsel.

Q: How is the rest of your testimony organized?

A: I first address why the AMA rate base approach should be used in determining the appropriate revenue requirements in this case as opposed to the EOP approach proposed by Pacific Power. I then address the single driver causing the Company's filing to result in an increase in base rates, that being Pacific Power's request to substantially accelerate the recovery of certain coal plant capital expenditures from Washington ratepayers. Next, I present various adjustments to the revenue requirements requested by the Company in this case. In the final section of my testimony, I address the Company's request for a Year Two step increase and recommend that the two-year rate plan approach be rejected by the Commission at this time. As part of that final section, I also present several adjustments to the Company's proposed Year Two step increase should the Commission elect to adopt a two-year rate plan as proposed by the Company.

III. APPROPRIATE RATE BASE APPROACH - EOP OR AMA

Q: In the Commission's decision in the Company's most recent rate case, Docket UE-140762, did the Commission adopt the EOP approach or the AMA approach in determining test year rate base?

A: In Pacific Power's last rate case, the Company requested that rate base be determined on the EOP rate base approach. In Order 08 in Docket UE-140762, issued on March 25, 2015, the Commission explicitly rejected the use of EOP rate base and determined that rate base should be based on its preferred AMA approach.

Q: Why has the AMA approach to rate base been generally preferred over the EOP approach?

A: The AMA approach results in rate base (or investment used to serve customers) being better matched to the test year revenues and expenses. Use of AMA approach avoids the distortion between each of these components of the revenue requirement equation.

Q: In Order 08, in the most recent Pacific Power rate case, did the Commission address the circumstances in which it has found the use of EOP rate base approach to be appropriate?

A: Yes. In addressing the issue at paragraph 145 (page 63 – 64) of the Order, the Commission quoted from several prior orders in which it discussed the limited circumstances in which it has found the EOP rate base approach to be an appropriate regulatory tool:

> The Commission has traditionally required that utility rates be established relying on the measurement of rate base using the AMA approach. The Commission, however, has occasionally recognized that the alternative approach of utilizing end-of-test period rate base may be appropriate in a variety of circumstances. In a 1981 case, *WUTC v. Washington Natural Gas*, the Commission drew on its early experience evaluating the relative merits of the two approaches and drew the following conclusions:
>
> (1) Average rate base is the most favored,

> (2) Year-end rate base is an appropriate regulatory tool under one or more of the following conditions:
>
> (a) Abnormal growth in plant
> (b) Inflation and/or attrition
> (c) As a means to mitigate regulatory lag
> (d) Failure of utility to earn its authorized rate of return over an historical period.[5]

Order 08 went on to find that these circumstances were not present for PacifiCorp. The Commission stated as follows:

> In this case, we have some evidence of capital additions during relevant periods but it does not demonstrate abnormal growth in plant. Inflation remains very low in the current economic environment in the United States. The Company did not present persuasive evidence that it is suffering attrition in earnings. In particular, the Company did not present an attrition study. Moreover, the fact that the Company failed in the past to earn its authorized return cannot justify use of EOP absent a showing that, due to factors beyond the Company's control, the Commission can expect this condition to continue into the future. There is no such evidence in the record of this case.[6]

Q: In this case, has the Company met the criteria for using EOP rate base identified by the Commission in the Company's last rate case?

A: No, it has not. The Company has not demonstrated unusual or abnormal growth in plant. The Company has not indicated that we are in a period of high inflation; in fact, the United States continues to be in a low inflation period. The Company once again has not presented an attrition study. The Company has not demonstrated that it is suffering attrition in earnings. In short, the Company has

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[5] *Petition of Puget Sound Energy and NWEC for Decoupling Authority*, Dockets UE-12167 and UG-121705 (*Consolidated*) and *WUTC v. Puget Sound Energy*, Dockets UE-130037 and UG-130138 (*Consolidated*), Order 07 ¶ 45 (June 25, 2013) (citing *WUTC v. Wash. Nat. Gas Co.,* 44 P.U.R. 4th 435, 438 (Sept. 24, 1981)).
[6] *WUTC v. Pacific Power & Light Co.*, Docket UE-140762 (*Consolidated*), Order 08, ¶ 146 (March 25, 2015).

failed to present evidence demonstrating that it meets the limited conditions under which the Commission has adopted the EOP rate base approach.

Q: Has net rate base grown significantly for the Company since the last rate case?

A: No, it has not. The Company's unadjusted Washington jurisdictional rate base in the prior rate case for the test year ended December 31, 2013, was $788,256,372 on an AMA basis.[7] In the current rate case, the Company's original filing shows an unadjusted Washington jurisdictional rate base for the test year ended June 30, 2015, of $781,321,066[8] on an AMA basis, lower than the unadjusted rate base in the prior case. In the last rate case, the Company made adjustments to reflect EOP plant balances and included certain projected major pro forma plant additions through March 31, 2015. In the original filing in that case the Company requested an adjusted rate base of $849,625,443.[9] In the original filing in this case, the Company made adjustments to reflect EOP plant balances and included an adjustment for certain pro forma major plant additions, resulting in an originally requested rate base of $838,124,164,[10] which is also lower than the rate base requested by the Company in its last rate case.

Q: In the last Pacific Power rate case, did you recommend that the EOP or the AMA approach be used in determining the appropriate revenue requirement for the Company?

A: In my direct testimony in the last Pacific Power rate case, Docket UE-140762 (*Consolidated*), I expressed my understanding that in certain recent cases, Public

[7] Docket UE-140762, Natasha C. Siores, Exhibit No. NCS-3 at 2.2.
[8] Shelley E. McCoy, Exhibit No. SEM-3 at 2.2.
[9] Docket No. UE-140762, Siores, Exhibit No. NCS-3 at 2.2.
[10] McCoy, Exhibit No. SEM-3 at 2.2.

Counsel had recommended the use of EOP rate base as a preferred tool to attrition adjustments to address regulatory lag asserted by utilities and had indicated that it might help reduce the frequency of rate case proceedings. Thus, I indicated that, consistent with Public Counsel's position, I was not challenging Pacific Power's use of EOP rate base.

Although Public Counsel and Staff did not challenge the use of EOP rate base in the last rate case, as discussed, the Commission explicitly rejected the use of the EOP approach. Given the Commission's recent finding on this issue, the Company's failure to demonstrate in this case that it has met the limited criteria identified by the Commission in Order 08, I recommend that rate base be determined based on the AMA approach in this case. Use of the AMA approach assures a better matching of the capital investments used to provide service to customers to the associated revenues and operating expenses in the revenue requirement equation.

IV. ACCELERATED RECOVERY OF CERTAIN COAL PLANT CAPITAL COSTS

Q: Would you please summarize the Company's request with regards to accelerating the recovery from Washington ratepayers of certain coal plant capital costs?

A: In this case, the Company is proposing to significantly shorten the depreciation period over which it recovers from Washington ratepayers the capital costs of the four coal generation units at the Jim Bridger facility and Unit 4 of the Colstrip coal generation plant. It is proposing to shorten the capital recovery period of the Jim Bridger generating plant units from 2037 to 2025, reducing the recovery period by 12 years. It is proposing to shorten the capital recovery period of Colstrip Unit 4 generating plant from 2046 to 2032, reducing the recovery period by 14 years. In other words, recovery of the plant costs will be significantly accelerated from the current Commission approved depreciable lives of the plant assets under the Company's proposal.

Q: What impact does the accelerated recovery of the Jim Bridger and Colstrip coal generating unit assets have on the revenue requirements in this case?

A: The entirety of the Year One rate increase proposed by Pacific Power is driven by the requested accelerated recovery of these coal generating units from Washington ratepayers. Exhibit No. SEM-2 attached to the direct testimony of Company witness Shelley E. McCoy shows that the Company's adjustment to accelerate depreciation on the Jim Bridger and Colstrip plants increases the revenue requirements by $9,907,232.[11] Additionally, the Company's application of the proposed accelerated depreciation rates on the pro forma major plant addition associated with the Jim Bridger Unit 3 Overhaul Project, including the installation of the Selective Catalytic Reduction ("SCR") system, as compared to the existing approved depreciation rates increases the revenue requirements by approximately $1.2 million. Thus, the application of the accelerated depreciation rates on the test year end Jim Bridger and Colstrip Unit 4 plant assets, and the pro forma major plant additions requested in this case, increases the revenue requirements by approximately $11.1 million ($9.9 million + $1.2 million).

Removing only one component from this request, the acceleration of the coal plant asset recovery period from Washington ratepayers, would result in a

[11] McCoy, Exhibit No. SEM-2, at 1:28.

reduction in current rates for the first year of the Company's proposed two-year plan. This is true even with the pro forma major plant additions for the Jim Bridger Unit 3 overhaul and SCR system included in rates. In other words, the impacts of the requested acceleration of the recovery of Jim Bridger and Colstrip plants from Washington ratepayers exceeds the entirety of the requested Year One rate increase in this case. There would be no Pacific Power rate case at this time absent the request for accelerated recovery of coal plant costs from Washington ratepayers!

Q: What reasons or support has the Company offered for its proposed accelerated recovery of the coal plant costs from Washington ratepayers?

A: The Company offered minimal explanation in its original filing in support of its substantial acceleration of the recovery of the Jim Bridger and Colstrip Unit 4 coal generation plant capital costs from Washington ratepayers. In his direct testimony, Company witness R. Bryce Dalley states as follows:

> To provide additional flexibility for compliance with major state and federal environmental initiatives, the Company also proposes to reinstate Washington's previous, shorter depreciation lives for coal plants, similar to Oregon's, the other major state within the west control area. Early implementation of this proposal smooths the associated rate impacts and provides maximum planning benefits.[12]

Mr. Dalley also addresses the issue as follows in his direct testimony:

> …[T]he Company's proposal aligns current depreciation periods between Washington and Oregon, the two states that account for most of the load in the west control area, for the coal-fired resources that serve Washington. The proposed depreciation schedules reflect the shorter depreciation lives Washington used before the Company's 2007 depreciation study. These schedules end in 2025 for all four units at the Jim Bridger generating plant and in 2032 for Unit 4 of the Colstrip generating plant (Colstrip

[12] Direct Testimony of R. Bryce Dalley, Exhibit No. RBD-1T at 3:1 – 6.

> Unit 4). This change will provide greater resource planning flexibility for the Company and its customers as Washington implements state and federal environmental policies described below.[13]

In summary, the reasons identified by the Company for the significant acceleration of recovery of the Jim Bridger and Colstrip Unit 4 coal generating plant costs from Washington ratepayers are: 1) to go back to depreciation lives used prior to the 2007 depreciation study; 2) to match the depreciation period used in Oregon; and 3) to "…provide greater resource planning flexibility to the Company…".

Q: The Company indicates that its proposal reflects shorter depreciation lives used in Washington before its 2007 depreciation study. Why were the depreciation lives extended in the 2007 depreciation study?

A: The depreciation lives were extended based on the anticipated dates the plants would cease to produce electricity and provide service to customers. The lives for depreciation purposes were extended to align them with the anticipated life of the associated plants. In the case addressing the 2007 depreciation study, Docket UE-071794, Company witness Mark C. Mansfield described the term "estimated plant depreciable life" for the steam generating plants as follows:

> For the purpose of determining depreciation, the estimated plant depreciable life of a steam plant is the period of time that begins when the plant is initially placed in service and begins to generate electricity and ends when the plant is finally removed from service and ceases to generate electricity. In other words it is the period of time during which the electric customers benefit from the generation output of the plant.[14]

[13] *Id.* at 4:20 – 5:5.
[14] Docket UE-071795, Direct Testimony of Mark C. Mansfield, Exhibit No. MCM-1T at 2:11-15.

Mr. Mansfield's testimony in that case explained that the estimated steam generation plant depreciable life analysis was prepared by PacifiCorp Energy's engineering staff.

Q: What is depreciation and what is the purpose of depreciation?

A: In general terms, depreciation is a method of recognizing the costs of an asset over the useful life of the asset. In Pacific Power's most recent depreciation case before the WUTC, Docket UE-130052, the direct testimony of Company witness Henry E. Lay contained the following description of depreciation and explanation of the importance of depreciation to an electric utility:

> **Q. Please explain the concept of depreciation.**
>
> A. There are many definitions of depreciation. The following definition was put forth by the American Institute of Certified Public Accountants in its Accounting Research Bulletin #43:
>
> > Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.
>
> The actual payment for an electric utility plant asset occurs in the period in which it is acquired through purchase or construction. <u>Depreciation accounting spreads this cost over the useful life of the property.</u> The fundamental reason for recording depreciation is to provide for accurate measurement of a utility's results of operations. Capital investments in the buildings, plant, and equipment necessary to provide electric service are essentially a prepaid expense, and annual depreciation is the part of that expense applicable to each successive accounting period over the service life of the property. Annual depreciation is an important and essential factor in informing investors and others of a company's periodic income. If it is omitted or distorted, a company's periodic

> income statement is distorted and would not meet required accounting and reporting standards.
>
> **Q. Why is depreciation especially important to an electric utility?**
>
> A. An electric utility is very capital intensive; that is, it requires a tremendous investment in generation, transmission, and distribution equipment with long lives in order to provide electric service to customers. Thus, the annual depreciation of this equipment is a major item of expense to the utility. Regulated electric prices are expected to allow the utility to fully recover its operating costs, earn a fair return on its investment and equitably distribute the cost of the assets to the customers using these facilities. If depreciation rates are established at an unreasonably low or high level for ratemaking purposes, the utility will not recover its operating costs in the appropriate period, which will shift either costs or benefits from current customers to future customers.[15]

In the same docket, Company witness K. Ian Andrews provided the following response in his direct testimony when discussing why it is necessary to estimate the economic life of a generating asset when developing depreciation rates:

> One major component of PacifiCorp's cost of service is the recovery of capital investment. This recovery is accomplished through depreciation expense over the life of each resource. From the standpoint of setting depreciation rates, it is necessary to have a reasonable estimate of the economic life of a resource at the time it is placed into service in order to reasonably calculate the depreciation expense. The estimated plant economic life of a generating asset is the period of time that begins when the asset is placed in service and starts generating electricity and ends when the asset is removed from service. In other words, it is the period of time during which customers benefit from the asset.[16]

Q: What depreciable lives are currently being used in the Company's other regulatory jurisdictions for the Jim Bridger and Colstrip coal generation facilities?

[15] Docket UE-130052, Direct Testimony of Henry E. Lay, Exhibit No. HEL-1T at 4:10 – 5:5 (emphasis added).
[16] Docket UE-130052, Direct Testimony of K. Ian Andrew, Exhibit No. KIA-1T at 3:10-3:18 (emphasis added).

A: The depreciation lives for the Jim Bridger Units are through 2037 in Washington, California, Utah, Wyoming and Idaho.[17] The depreciation lives for the Colstrip Units is currently through 2046 in Washington, California, Utah, Wyoming, and Idaho.[18] Only Oregon is currently using the shorter depreciation period for ratemaking purposes for the Jim Bridger Units (2025) and the Colstrip Units (2032), based on an order entered in August 2008.[19] In that order, the Public Utility Commission of Oregon required the Company to return to life end-dates for 11 coal-fired plants for depreciation purposes based on its prior depreciation case.[20]

Q: You previously indicated that the Company is proposing to shorten the depreciation period for the Jim Bridger generation facilities to 2025 and for the Colstrip Unit 4 generation facility to 2037. Does the Company currently plan to retire or remove the Jim Bridger and Colstrip coal generation facilities from service in 2025 and 2037, respectively?

A: No, it does not. In response to Public Counsel Data Request No. 58, the Company indicated that its "…current best estimate for planning purposes' of the date each of the Jim Bridger units will be retired from service is 2037, which aligns with the currently approved depreciable lives for those resources in the majority of PacifiCorp's states."[21] Similarly, the response to Public Counsel Data Request No. 59 indicated that "…the Company's current best estimate for planning purposes of the date that the Colstrip units will be retired from service is

[17] *See* Response to Public Counsel Data Request No. 13 provided as Exhibit DMR-8.
[18] Ibid.
[19] *PacifiCorp Petition to File Preliminary Depreciation Study*, Docket UM 1329, Order No. 08-427 (P.U.C. of Oregon, August 20, 2008).
[20] *PacifiCorp Application for an Order Authorizing a Change in Depreciation Rates*, Docket UM 1064, Order No. 03-457 (P.U.C. of Oregon, July 24, 2003).
[21] Ramas, Exhibit No. DMR-9.

2046, which aligns with the currently approved depreciable lives for those resources in the majority of PacifiCorp's states." [22]

The Company is currently working on its 2015 Integrated Resource Plan ("IRP") Update, which the Company will file in March 2016. In the 2015 IRP Update, the assumed end of life date for the Jim Bridger Units remains as 2037 and the assumed end of life date for Colstrip Unit 4 remains 2046.[23] Thus, for Integrated Resource Planning purposes, the Company has not shortened the plant lives to the depreciation lives it is requesting in this case. I have seen no information presented by the Company that would indicate that it has plans to remove the Jim Bridger coal generating facilities from service in 2025 or Colstrip Unit 4 from service in 2037.

Q: Under the Company's proposal, will it be using the depreciation rates applicable to the Jim Bridger and Colstrip units that are currently authorized by the Oregon Public Service Commission?

A: No. The Company is proposing to significantly increase the depreciation rates currently authorized in Washington applicable to the Jim Bridger and Colstrip facilities so that the capital costs would be fully recovered by the earlier recovery dates or "depreciation lives" authorized in Oregon. However, since Oregon has been using the shorter recovery life in determining the depreciation rates for a longer period of time, the depreciation rates in Oregon associated with the Jim Bridger and Colstrip facilities are considerably lower than the depreciation rates proposed by Pacific Power in this case.

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[22] Ramas, Exhibit No. DMR-10.
[23] *See* Response to Public Counsel Data Request No. 63, provided as Exhibit No. DMR-11.

Q: If the Company is granted the shorter depreciation lives for the Jim Bridger and Colstrip units, will the Company stop supplying coal generated electricity to Washington ratepayers from the Jim Bridger plants in 2025 and from Colstrip Unit 4 in 2032?

A: No. The Company is simply proposing to recover the costs of the plants over a period shorter than the plants' anticipated service lives, yet still keep the plants in service and use them to generate coal based energy through the longer lives. In response to Public Counsel Data Request No. 60, the Company states, in part, as follows: "Changing depreciable lives, however, would not restrict the Company from using generation from these resources to serve Washington customers after the end of the facilities' depreciable lives, nor would it prevent the Commission from revisiting the depreciable lives in a future proceeding." [24] Similarly, the response to Public Counsel Data Request No. 61 states, in part, that "…adjusting depreciable lives for coal-fueled generation facilities included in Washington rates would not restrict Pacific Power from operating those generation units to serve Washington customers or customers in other states after the end of those depreciable lives." [25]

In response to Public Counsel Data Request No. 12, the Company states that: "Accelerating depreciation on coal-fueled generation facilities in Washington allows Washington customers to preemptively pay down the costs of these plants, to mitigate the risk of simultaneously incurring costs associated with remaining book values and replacement resource costs if state and federal environmental policies and mandates, including carbon emission regulations,

[24] Ramas, Exhibit No. DMR-12.
[25] Ramas, Exhibit No. DMR-13.

force premature shut-down(s) of these facilities."[26] Thus, the Company is apparently offering Washington ratepayers the "opportunity" to pay the Company in advance for coal plant costs just in case the facilities have to be shut down early without yet knowing if early shut-down will in fact occur.

Q: Do you agree that the Company should be permitted in this case to begin to accelerate the recovery of these coal plant costs from Washington ratepayers?

A: No, I do not. Absent plans to actually remove the plants from service earlier, there is no justification for accelerating the recovery of the plant costs from ratepayers at this time. The very purpose of including depreciation expense in rates is to allow the Company to recover the capital costs of the associated assets over the period the assets are used to provide service to customers, i.e., the life of the plant. By allowing the recovery through depreciation over the life of the plant, the customers that receive energy from the plant are paying for the capital cost of the plant that is being used to serve them. If the Company is permitted to accelerate recovery of the plant costs over a period of time that is shorter than the anticipated period in which the plant will be providing service to customers, current ratepayers will be paying for capital costs that will be used to serve future customers. This would result in intergenerational inequity. Under the Company's proposal, the Washington jurisdictional capital costs of the Jim Bridger coal generation units would be fully recovered from Washington ratepayers by 2025, yet those generation units are currently anticipated to continue to providing service to customers through 2037. Thus, Washington ratepayers receiving

[26] Ramas, Exhibit No. DMR-14.

service in the period 2026 through 2037 will not be paying towards the capital costs for the Jim Bridger units that provide service to them; these costs would have been prepaid by other Washington customers between 2016 through 2025.

Q: Is the Pacific Power proposal to accelerate recovery based on a new depreciation study?

A: No, a new depreciation study was not filed as part of this case. It is my understanding that the Company conducts full depreciation studies on approximately five year intervals. It is important to periodically re-evaluate the appropriate depreciation rates through full depreciation studies to ensure that the depreciation rates are still on-track to recover the capital costs over the life of the underlying assets. If the Company determines that the coal generation facilities will be removed from service earlier than the dates currently incorporated in the most recent depreciation study, it can address the changed life of the facilities in its next depreciation study.

Q: How do you respond to Mr. Dalley's concern that state and federal environmental regulations could result in premature shut-down of the coal plants?

A: If information arises that result in it becoming known that any of the coal generation facilities will be removed from service and no longer used to serve customers at a date that is earlier than the depreciation lives incorporated in the most recent depreciation study, and those shorter depreciation lives would have a substantial impact on depreciation expense incorporated in base rates, the Company could conduct a new depreciation study and present that study to the Commission for its consideration. However, it is my opinion that it is not appropriate to substantially change the depreciation rates being applied to the Jim Bridger and Colstrip plants at this time, particularly when the Company does not currently have plans to shorten the actual plant lives from the depreciation lives that were used in determining the depreciation rates currently in place in Washington. As discussed, the Company acknowledges there are no plans to remove the plants from service by the accelerated dates, the plants would continue to provide service to Washington customers, and most other Pacific Power states would not be accelerating their depreciation rates.

Q: Above, you discuss potential *intergenerational* inequities for Washington ratepayers that result from the Company's proposal to accelerate the recovery of the coal generation plant costs. Could there also be *interjurisdictional* inequity issues that result from the request to accelerate recovery of the coal generation plant costs from Washington ratepayers?

A: There could be in certain potential future situations or scenarios. For example, assume that the Company's request in this case is granted and the Jim Bridger units continue to operate after the proposed depreciation life in this case (i.e., after 2025), but the energy generated from those facilities ceases to be utilized in providing electric service to customers in the State of Washington after 2025. In other words, after 2025 the electricity generated from the Jim Bridger plants is only sold to jurisdictions outside of Washington. In this scenario the Washington ratepayers, between 2016 and 2025, would be subsidizing customers in other jurisdictions that continue to receive power from the Jim Bridger units after 2025. This is because the recovery of the coal facility costs in Washington would no longer be aligned with the anticipated service life of the coal facilities.

Q: What adjustments are needed to remove the proposed accelerated recovery of the Jim Bridger and Colstrip capital costs in this case?

A: Two separate adjustments are needed to remove the proposed accelerated recovery of the Jim Bridger and Colstrip coal facility capital costs. The first adjustment, presented in Exhibit No. DMR-3, page 23 of 32, simply removes the Company's proposed adjustment that accelerated the recovery, which was provided in Company Exhibit No. SEM-3 at page 6.4 (Company Adjustment 6.4). In other words, Company Adjustment 6.4 – Accelerated Depreciation on Jim Bridger and Colstrip Plants – should be reflected as $0As shown on Exhibit No. DMR-2, line 27, rejection of this Company adjustment reduces the revenue requirements in this case by $9,907,231.[27]

Q: What is the second adjustment that is needed?

A: In its filing, the Company made a pro forma major plant addition adjustment in which it added certain major plant addition projects associated with the Jim Bridger Unit 3 overhaul and Select Catalytic Reduction (SCR) system that were placed into service in November 2015, which is five months after the end of the test year. The filing included $127.5 million on a total Company basis and $28.6 million on a Washington jurisdictional basis for these post test year Jim Bridger Unit 3 plant additions. In the pro forma major plant addition adjustment, the Company included the associated depreciation expense based on its proposed accelerated depreciation rates. The Company used a depreciation rate of 7.155 percent based on the proposed accelerated recovery period in its adjustment, while the current Commission approved depreciation rate for the applicable account is

[27] Company Exhibit No. SEM-2, page 1 of 3, line 28 shows the same revenue requirement impact from the accelerated depreciation on Jim Bridger and Colstrip of $9,907,232.

2.86 percent. Thus, an adjustment is needed to remove the accelerated recovery of the post test year Jim Bridger Unit 3 plant additions.

As discussed later in this testimony, I am recommending an adjustment to the Company's major pro forma plant addition adjustment (Company Adjustment 8.4) to reflect the actual costs for the projects.[28] As shown on Exhibit No. DMR-3, at page 29 of 32, removing the acceleration of the depreciation on the as-adjusted major plant additions results in a $1,129,621 reduction to depreciation expense and a $764,871 reduction to accumulated depreciation. This adjustment still allows the inclusion of the major post test year plant additions associated with the Jim Bridger Unit 3 overhaul and SCR system in rates based on the actual plant costs with depreciation expense determined based on the depreciation rates currently authorized by this Commission.

Q: Do you have any other comments with regards to the post test year addition of the Jim Bridger Unit 3 SCR system?

A: Yes. In conducting the economic evaluation of whether to proceed with the addition of the SCR System at the Jim Bridger Unit 3 and Unit 4 coal generation facilities, or to either early retire units or convert the units to natural gas generation, the Company assumed the Jim Bridger Unit 3 and Unit 4 retirement dates after installation of the SCR would be December 31, 2037. This is the same retirement date that is incorporated in the current Commission authorized depreciation rates. If the units had been assumed to be retired early in the SCR implementation scenario, such as the 2025 depreciation life date it is proposing in

[28] As discussed later in the testimony, the actual costs of the Jim Bridger Unit 3 overhaul and SCR system capital projects was $117.2 million as compared to the $127.5 million included in the Company's filing for these projects.

this case, the results of the analysis would have differed substantially. In its 1st Supplemental Response to Sierra Club Data Request No. 1.2(f), provided as Exhibit No. DMR-15, the Company indicated that it "…has not performed analysis evaluating the installation of selective catalytic reduction at Jim Bridger Unit 3 and Jim Bridger Unit 4 with the assumption that Jim Bridger would cease operation on or before January 1, 2026."[29] The Company has not demonstrated that the SCR implementation would be the ideal approach with regards to the Jim Bridger Units if the plants are removed from service during or before 2025. If the Company does not currently intend to remove the plants from service in 2025, then there is no justification for accelerating the depreciation of the plants to an assumed 2025 life at this time, particularly at a time when the Company is seeking to recover the substantial Jim Bridger Unit 3 and Unit 4 SCR system plant costs from Washington customers in rates.

Q: If the Commission determines that some form of early or accelerated recovery of coal generation facility costs should begin, do you have any recommendations to offer?

A: Yes. First, I must reiterate that I recommend that the Company's request to accelerate recovery in this case be rejected at this time. If the Company's current plans regarding the dates the coal units used to serve Washington ratepayers will be retired from service changes, then the Company can seek to modify the depreciation lives in the future when the change is known.

However, if the Commission determines that pre-collecting some of the coal generation facility costs from Washington ratepayers is desirable at this time

[29] Ramas, Exhibit No. DMR-15.

to allow for more flexibility for the Commission in addressing the coal generation facilities in the future, then I recommend that a separate regulatory liability be established.

Q: Please explain how the regulatory liability would work.

A: Under this recommendation, the current Commission approved depreciation rates that are based on a full depreciation study and incorporates the current anticipated lives of the Jim Bridger and Colstrip facilities would remain in place until such time as the next depreciation study is conducted by the Company for the Commission's consideration. Rather than modifying the currently approved depreciation rates, a separate coal facility early retirement fund expense could be established in rates by the Commission with the purpose of the expense being to fund a regulatory liability. The Company would increase the regulatory liability account by the amount of coal facility early retirement fund expense collected from customers in base rates and the entries to increase the liability account would occur on a regular basis as the amounts are collected from customers. The regulatory liability collected from customers, which would be reflected as an offset to rate base in future cases, would be used in the future to apply towards prudently incurred, unrecovered coal plant costs should circumstances change and it be determined that one or more coal facilities serving Pacific Power's Washington customers will be removed from service before the currently anticipated plant retirement date(s).

Q: How would this provide the Commission flexibility regarding coal facility costs?

A: This would give the Commission even greater flexibility than that proposed by the Company as the funds collected from customers and set aside in the new regulatory liability account could be directed towards specific prudently incurred unrecovered coal facility costs at the Commission's discretion. Say, for example, it is determined that one or two of the four Jim Bridger units should be retired before the current projected retirement dates, but not all of the Jim Bridger units. The Commission could direct that the funds collected in advance from Washington ratepayers and set aside in the regulatory liability account be used towards the unrecovered costs of the asset(s) that are removed from service early.

Additionally, if it becomes more clear in the future that the units will not be retired early and continue to be used to provide service to customers throughout their currently anticipated life, the Commission could direct that the amounts collected from Washington ratepayers and held in the regulatory liability account be returned to Washington ratepayers.

If the Commission decides to require accelerated cost recovery in this case, this would be preferable to the approach proposed by the Company. It would allow the depreciation rates incorporated in Washington rates to be consistent with the currently anticipated plant lives and aligned with the majority of the jurisdictions that receive service from the Jim Bridger and Colstrip plants. It would also allow more flexibility as the funds collected from Washington ratepayers could be directed towards the early retirement of specific coal generation units in the future.

Q: If the Commission agrees that this alternative approach of establishing a regulatory liability should be implemented, would the amount to be collected

from customers for the new regulatory liability have to be based on the amount of accelerated recovery the Company is seeking in this case?

A: Absolutely not. Again, the accelerated recovery period the Company is requesting in this case is not based on the currently anticipated service lives of the coal units, nor is the accelerated depreciation expense based on the depreciation rates that were authorized by the Oregon Public Utility Commission. Thus, if the Commission does determine that funds should begin to be collected from Washington ratepayers to establish a regulatory liability as I describe, it should not be based on the amount on the depreciation rates the Company has calculated and requested in this case. As previously indicated, $9.1 million of the requested increase in this case is caused by the application of the accelerated depreciation rates on the test year end Jim Bridger and Colstrip Unit 4 plant balances and $1.1 million is caused by the application of the accelerated rates on the Jim Bridger Unit 3 pro forma major plant additions. This is a significant amount the Company proposes to recover from customers that is not based on any known or currently planned early plant retirement dates, nor is it based on any projections of potential unrecovered balances at the time of plant retirement.

I would suggest that if the Commission determines that a regulatory liability should be established to set aside funds for the potential early retirement of coal generation facilities serving Pacific Power customers in Washington, that it do so through a separate proceeding. The Commission could open the proceeding or ask PacifiCorp to file a request to establish a regulatory liability and hold a separate adjudicative proceeding. The proceeding would determine both the appropriate amount of target funding for the regulatory liability account and the appropriate period over which to recover the targeted amount from Washington customers. This would allow for a more thorough vetting of the determination of the appropriate amount of funds to be collected in advance from customers for the potential future early retirement of the coal generation facilities.

Q: Please restate your primary recommendation with regard to depreciation.

A: It is still my recommendation that accelerated recovery not begin at this time and instead be addressed when it becomes known that one or more of the coal generation facilities will actually be removed from service before the currently anticipated plant retirement dates. At that time depreciation rates can be updated based on a new depreciation study.

V. RECOMMENDED ADJUSTMENTS

Q: Are you recommending any revisions to the various test year and pro forma adjustments proposed by Pacific Power?

A: Yes. As previously discussed above, I recommend that the Company's proposed acceleration of the recovery of the Jim Bridger and Colstrip coal plant costs be rejected at this time. Each of the adjustments needed to reflect this recommended rejection of the accelerated recovery have been discussed above. I am recommending several additional adjustments to the Company's filing in this testimony. I will address each of my recommended adjustments below.

Additionally, as addressed previously in this testimony, I recommend that the impacts of the PATH Act be reflected in this case and that the AMA approach be used for rate base instead of the Company's proposed EOP approach. The PATH Act impacts the following Company adjustments: Adjustment 7.1 – Interest True

Up; Adjustment 7.4 – PowerTax ADIT Balance; Adjustment 7.7 – Remove Deferred State Tax Expense & Balance; and Adjustment 8.4 – Pro Forma Major Plant Additions. The use of the AMA approach instead of the Company's proposed EOP approach impacts the following Company adjustments: Adjustment 6.1 – End-of-Period Plant Reserves; Adjustment 6.2 – Annualization of Base Period Depreciation/Amortization Expense; Adjustment 6.3 – Hydro Decommissioning; Adjustment 7.1 – Interest True Up; Adjustment 7.4 – PowerTax ADIT Balance; Adjustment 7.7 – Remove Deferred State Tax Expenses & Balance; Adjustment 8.1 – Jim Bridger Mine Rate Base; Adjustment 8.11 – End-of-Period Plant Balances; and 8.13 – Idaho Asset Exchange. Since I am beginning with the Company per books balances in my presentation, I have included the impacts of the PATH Act and the AMA rate base approach on each of these Company adjustments in Exhibit No. DMR-3.

A. Update Pro Forma Major Plant Additions to Actual.

Q: In its Year One revenue requirement calculations, the Company included a major pro forma plant addition adjustment. Can you briefly discuss what capital additions were included in the pro forma major plant addition adjustment?

A: Yes. The Company's pro forma major plant addition adjustment added the Jim Bridger Unit 3 overhaul and SCR system, which were placed into service in November 2015, to rate base and also included the impacts of the additions on accumulated depreciation, accumulated deferred income taxes and depreciation expense. The total amount added to test year plant in service for the combination of the Jim Bridger Unit 3 overhaul costs and SCR system was $127,544,646 on a total Company basis and $28,617,198 on a Washington jurisdictional basis.

Q: Are you recommending any revisions to the Company's Year One pro forma major plant addition adjustment?

A: Yes. In response to Public Counsel Data Request No. 20, the Company provided the actual amounts placed in service for the Jim Bridger Unit 3 overhaul and SCR system projects.[30] Subsequently, in response to Boise Data Request No. 62, the Company provided a revised version of its pro forma major plant addition adjustment that incorporated the impacts of the actual amounts placed into service for the projects as of December 31, 2015.[31] These responses indicate that the actual amount placed into service for the projects was $117,233,290 on a total Company basis, which is $10.3 million less than the amount incorporated in the Company's filing. As shown on Exhibit No. DMR-3, at page 28 of 32, I recommend that the Company's Adjustment 8.4 - Pro Forma Major Plant Additions be revised to reflect the actual known and measurable project costs instead of the estimated amounts incorporated in the Company's filing. In my recommended revised Adjustment 8.4 – Pro Forma Major Plant Additions on page 28 of 32, I include the impacts of the PATH Act as well as the actual project costs instead of the projected costs included by the Company.

Additionally, as previously discussed in this testimony, I recommend that the proposed accelerated recovery proposed by the Company for the Jim Bridger Unit 3 overhaul and SCR system additions be rejected and the associated

[30] 1st Supplemental Response to Public Counsel Data Request No. 20 and Attachment PC-20 (Redacted version) are provided as Exhibit No. DMR-16.
[31] 1st Supplemental Response to Boise Data Request No. 62 at Attachment Boise 62 (Redacted version) are provided as Exhibit No. DMR-17.

depreciation expense instead by based on the current Commission authorized depreciation rates. This results in an additional $1,129,621 reduction to depreciation expense and a $764,871 reduction to accumulated depreciation based on the actual Jim Bridger Unit 3 overhaul and SCR system plant additions, as shown on Exhibit No. DMR-3, at page 29 of 32.

Q: Did the Jim Bridger Unit 3 Overhaul and SCR project additions cause any existing assets that were included in the test year rate base to be retired from service?

A: Yes. The Jim Bridger Unit 3 overhaul projects resulted in certain existing plant assets being retired. While the retirements would have no impacts on net plant in service as the adjustment to plant in service at retirement would be offset by the adjustment to accumulated depreciation, the retirements do impact depreciation expense. Depreciation expense is impacted because the plant assets being retired are removed from the plant in service balances to which the depreciation rates are applied. In response to Public Counsel Data Request No. 64, the Company indicated that the test year included $69,429 on a Washington jurisdictional basis for the retired assets and agreed that the depreciation expense associated with the retirements related to the installation of the pro forma plant additions should be removed from the test year.[32] As shown on Exhibit No. DMR-3, page 18 of 32, I have presented Adjustment PC-5, which reduces test year depreciation expense by $69,429.

Q: Does the Company's request to apply accelerated depreciation rates to the Jim Bridger generation plant assets impact this adjustment?

[32] Response to Public Counsel Data Request No. 64 and Attachment PC-64, provided as Exhibit No. DMR-18.

A: Yes, if the Commission adopts the Company's proposed accelerated depreciation rates, which I recommend against in this testimony, then my recommended adjustment to depreciation expense would need to be increased from $69,429 to $162,036 as shown on line B.3 of Exhibit No. DMR-3, page 18 of 32 for Adjustment PC-5. The necessary adjustment of $69,429 presented by the Company in its response to Public Counsel Data Request No. 64 is based on the current Commission authorized depreciation rates, not the accelerated recovery rates requested in this case. Since I have already removed the accelerated depreciation of the Jim Bridger coal generation plant assets in another adjustment, I am removing only $69,429 based on the currently authorized rates in my adjustment. However, the Company's proposed adjusted test year would include the depreciation on these retired assets based on the Company's proposed accelerated recovery rates. Thus, if my adjustment to remove the accelerated depreciation is rejected, then the adjustment to remove the depreciation expense associated with the retired assets needs to be increased to $162,036.

Q: Are you opining on the prudence of the Jim Bridger Unit 3 Overhaul and SCR system plant additions included by Pacific Power as a pro forma adjustment in this case?

A: No. It is my understanding that Public Counsel will consider all evidence presented in this proceeding regarding the prudence of the investments and would have the opportunity to address the prudence of the SCR system additions in its brief. My testimony focuses on reflecting the actual project costs in rates and not whether the projects were prudent and should be passed on to Washington ratepayers in this case. As mentioned previously in this testimony, the Company has not provided any analysis demonstrating that the installation of the SCR systems at Jim Bridger Unit 3 and Unit 4 would be cost-effective if the units were retired from service in 2025. While I have not weighed in on the prudence of the installation of the SCR systems at Jim Bridger Units 3 and 4, I do recommend that the Commission take these major projects into consideration in evaluating whether or not the recovery of the associated capital costs should be accelerated to allow for full recovery from Washington ratepayers prior to the end of the projected service life of the projects. The Company's proposed recovery period would result in the Washington jurisdictional portion of SCR system costs being fully recovered from Washington ratepayers by the end of 2025, which is a short 9 ½ year recovery period for such major generation projects.

B. Impact of Current Employee Levels.

Q: In the last Pacific Power rate case, Docket No. UE-140762, the Commission adopted a Public Counsel recommended adjustment to reflect the impacts of the reductions to the employee complement that occurred during the test year and subsequent to the test year. Could you please briefly discuss the adjustment?

A: Yes. The Commission Order 08 in Docket No. UE-140762 (*Consolidated*) addressed the reduction to employees, in part, as follows:

> Elaborating on this last point, Public Counsel states that while Pacific Power's adjusted test year labor costs are based on the average number of employees employed by the Company during the test year ending December 31, 2013, the full time equivalent (FTE) employee count for Pacific Power declined significantly during the test year and continued to decline measurably through October 2014, just prior to the evidentiary hearing in this case (*i.e.*, December 16-19, 2014). Providing details, Public Counsel says that:

> During the test year, PacifiCorp's employee count declined by 115.5 employees. Six months later, by June 2014, the employee count had declined by another 27 FTEs, such that the actual employee level was 66.5 FTE lower, or 1.24% below the average count for the test year upon which Pacific Power based its labor costs. Additional data provided to Public Counsel after the filing of Pacific Power rebuttal shows (sic) that FTE counts continued to decline every month after June 2014, until November, just one month before the hearing.[33]

At page 20 of the same order, the Commission also found that, "The record demonstrates that the reductions in workforce reflect a continuing trend over several years."[34] In the decision, the Commission agreed with Public Counsel's recommended adjustment to reflect the impacts of the test year and post test year actual reduction to the employee complement.

Q: Has the employee complement continued to decline since the last rate case?

A: Yes. In fact, the decline has accelerated. The average test year ended December 31, 2013, full time equivalent (FTE) employee count in the last rate case was 5,375 and the FTE employee count as of June 2014 was 5,308 employees.[35] The adjustment adopted by the Commission in the last rate case was based on the reduction between the average test year employee count and the June 2014 employee count. The FTE employee count has continued to steadily decline since the last rate case. As shown on Exhibit No. DMR-3, Schedule 8, page 2 of 4, the average test year FTE employee count in this case is 5,247. The

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[33] *WUTC v. Pacific Power & Light Co*., Docket UE-140762(*Consolidated*) Order 08, ¶ 36, at 17 (March 25, 2015) (footnote omitted).
[34] *WUTC v. Pacific Power & Light Co*., Docket UE-140762 (*Consolidated*) Order 08, ¶ 42, at 20 (March 25, 2015).
[35] *WUTC v. Pacific Power & Light Co*., Docket UE-140762 (*Consolidated*) Order 08, ¶ 43, at 21 (March 25, 2015).

FTE employee count as of the end of the test year (June 30, 2015) was 5,231.5 employees and the FTE employee count as of December 2015 was 5,128 employees. Thus, the actual FTE employee count as of the most recent date provided by the Company (December 2015) is 180 FTEs lower than the June 2014 level reflected in rates resulting from the last Pacific Power rate case.[36]

Q: Given the continued decline in the employee complement that occurred during the test year and subsequent to date, do you recommend any revisions to the labor costs requested by the Company in this case?

A: Yes. Pacific Power's adjusted test year labor costs are based on the employee complement in place during the test year ended June 30, 2015. In calculating the adjusted test year regular, overtime and premium time labor costs, the Company began with the actual amounts recorded in each month of the test year ended June 30, 2015, and applied various wage escalation factors to the actual recorded monthly amounts in order to annualize the salary and wage increases that went into effect during the test year. Thus, the labor costs included in the adjusted test year are based on the number of employees that were employed by the Company during the test year. As shown on Exhibit No. DMR-3, page 9 of 32 (Adjustment PC-1 at PC-1.2), the FTE employee level declined from 5,280 at the beginning of the test year (July 2014) to 5,231.5 as of the end of the test year (June 2015), and declined even further to 5,128 as of December 2015. The schedule shows that the actual December 2015 employee complement is 119 FTEs or 2.27 percent lower than the average test year employee complement that is incorporated in the Company's adjusted test year labor costs. I recommend that this known and

[36] Calculated as 5,308 FTEs as of June 2014 less 5,128 FTEs as of December 2015 (5,308 – 5,128 = 180).

measurable reduction in employees that occurred both during and subsequent to the test year be reflected in determining the appropriate labor costs to include in rates.

Q: What adjustment is needed to reflect the impact of the significant known and measurable reduction in employees that occurred both during and subsequent to the test year in this case?

A: As indicated above, the actual FTE employee complement as of the most recent month for which the information has been provided (December 2015) is 2.27 percent lower than the average test year employee complement. The labor and incentive costs, employee benefit costs (i.e., medical, dental, vision, 401K, etc.), and payroll tax costs in the Company's labor cost adjustment would all be impacted by the employee level. Exhibit No. DMR-3, page 10 of 32 (Adjustment PC-1 at PC-1.3), identifies the amount of labor costs included in the Company's labor cost adjustment that are impacted by the employee level as $676,492,294. As shown on Adjustment PC-1 at PC-1.1 (Exhibit No. DMR-3 page 9)application of the 2.27 percent FTE employee reduction to the labor costs impacted by the employee level results in a $15,356,375 reduction to labor costs. Thus, I recommend test year labor costs be reduced by $15,356,375. As shown on Adjustment PC-1, after removing the portion that is capitalized and the portion allocated to non-utility, test year expenses should be reduced by $10,457,510 on a total Company basis and by $655,673 on a Washington jurisdictional basis. This adjustment to reflect the actual known and measurable reduction in employee levels is calculated on the same methodology as used in the prior PacifiCorp rate case, which was adopted by the Commission.

C. Pension Expense.

Q: What amount is included in the test year ended June 2015 for pension costs and how was that amount determined?

A: Company Exhibit No. SEM-3, page 4.2.2 identifies the test year pension costs as $24,712,488. The 1st Supplemental Response to Public Counsel Data Request No. 36, Attachment PC 36-1 shows that the $24,712,488 is based on six months of pension costs associated with the pension actuarial reports for 2014 and six months of pension costs associated with the pension actuarial reports for 2015 plus $937,209 of pension administration costs.[37] Thus, the actual recorded test year pension costs are $23,775,279 once the administrative cost is removed and is based on the 2014 and 2015 pension actuarial reports.

Q: Have more recent actuarial reports been completed for the Company?

A: Yes. In response to Public Counsel Data Request No. 52, the Company provided the most recent pension actuarial report for the 2016 plan year.[38] The actuarial assumptions for use in the 2016 plan year would have been selected by the Company in December 2015 and are now known and measurable. These known and measurable actuarial assumptions, as well as the known and measurable impacts of the actual 2015 plan experience, would be incorporated the 2016 actuarial report provided by the Company. The response, at Attachment PC 52-3, shows that the pension expense based on the most recent actuarial report is $21,935,427.[39] As shown on Exhibit No. DMR-3, page 12 of 32 (Adjustment PC-

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[37] Ramas, Exhibit No. DMR-20.

[38] Response to Public Counsel Data Request No. 52 and Attachments PC 52-2 and PC 52-3 are provided as Exhibit No. DMR-21.

[39] Excludes $920,000 of pension administration costs shown on the response, resulting in pension costs excluding administration costs of $21,935,427.

2 at PC-2.1), the most recent known and measurable pension cost is $1,839,852 less than the amount included in the test year.

Q: Do you recommend that this known and measurable reduction to pension costs be reflected in this case?

A: Yes, I do. As shown on Adjustment PC-2, test year pension costs should be reduced from the $23,775,279 contained in the Company's filing to $21,935,427, which is a reduction of $1,839,852. After removing the portion allocated to capital and non-utility, the impact is a reduction to pension expense of $1,252,917 on a total Company basis and $78,556 on a Washington jurisdictional basis.

Q: Did the Commission adopt a similar adjustment in the Company's last rate case?

A: Yes. In Pacific Power's most recent rate case, Docket UE-140672 et. al. (*Consolidated*), I also recommended that the impact of the most recent pension and OPEB actuarial reports be reflected in rates as a known and measurable post test year adjustment. The Commission agreed with my recommendation in its Order 08 in Dockets UE-140762 et al. (*Consolidated*).[40]

D. OPEB Expense.

Q: What amount is included in the test year ended June 2015 for Other Post-Employment Benefits ("OPEB") costs and how was that amount determined?

A: Company Exhibit No. SEM-3, page 4.2.2 identifies the test year OPEB costs as ($4,043,010). The 1st Supplemental Response to Public Counsel Data Request

[40] *WUTC v. Pacific Power & Light Co*., Docket UE-140762 (*Consolidated*) Order 08, ¶ 46, at 22 (March 25, 2015).

No. 37, Attachment PC 37-1 shows that the ($4,043,010) is based on six months of OPEB costs associated with the OPEB actuarial reports for 2014 and six months of OPEB costs associated with the OPEB actuarial reports for 2015.[41] The portion applicable to the six months ended December 31, 2014, is $90,552, while the portion applicable to the six months ended June 30, 2015, is ($4,133,562). Thus, the 2015 OPEB actuarial report included a significant reduction to OPEB costs as compared to the 2014 OPEB actuarial report.

Q: Similar to the pension expense adjustment recommended above, is the most recent expense for OPEBs also available?

A: Yes. In response to Public Counsel Data Request No. 53, the Company provided the OPEB costs based on the actuarial report for the 2016 plan year.[42] This would include the known and measurable actuarial assumptions that were selected in December 2015 as well as the impacts of the actual OPEB plan experience for 2015.

Q: Did the OPEB expense also decline?

A: Yes, the OPEB expense declined fairly substantially as compared to the amount recorded by the Company during the test year. As shown on Exhibit No. DMR-3, page 14 of 32 (Adjustment PC-3 at PC-3.1), the OPEB costs declined from the ($4,043,010) recorded during the test year to ($8,222,739) based on the most recent actuarial report, which is a reduction of $4,179,729.

Q: Do you recommend that the test year OPEB expense be revised to reflect the known and measurable change?

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[41] Ramas, Exhibit No. DMR-22.
[42] Response to Public Counsel Data Request No. 53 with Attachments PC 53-2 and PC 53-3, provided as Exhibit No. DMR-23.

A: Yes. Consistent with the recommendation discussed above regarding pension expense, as well as the Commission's finding in the last Pacific Power rate case, I also recommend that the OPEB expense be updated to reflect the impacts of the known and measurable actuarial assumptions and actual 2015 plan experience reflected in the most recent actuarial report. As shown on Adjustment PC-3, OPEB costs should be reduced by $4,179,729. After removal of the amounts allocated to capital and non-utility, the result is a $2,846,346 reduction to OPEB expense on a total Company basis and a reduction of $178,462 on a Washington jurisdictional basis.

E. Normalize Salary Overhead Costs.

Q: Are you recommending any additional adjustments to the test year labor costs?

A: Yes. Included in the test year labor costs is $1,742,747 for "Other Salary Overheads/Oncosts."[43] This category of costs includes charges from outside vendors that provided services in the labor cost area. The response to Public Counsel Data Request No. 40 shows that the "Other Salary Overheads/Oncosts" have increased from $510,778 in the test year in the Company's last rate case to $1,742,747 in the test year ended June 30, 2015, in this case, which is an increase of $1,231,969.[44] The response to Public Counsel Data Request No. 49, Attachment PC 49-2, shows that the Other Salary Overheads/Oncosts recorded by the Company for calendar year 2014 was $1,437,813 and the expense for calendar

[43] Test year expenses for this category provided in response to Public Counsel Data Request No. 40 and Attachment PC-40, which are provided as Exhibit No. DMR-25.
[44] Response to Public Counsel Data Request No. 40, provided as Exhibit No. DMR-25.

year 2015 was $1,191,391.[45] Based on the significant increase since the last rate case, as well as the fact that the test year expenses are so much higher than the expenses incurred in both calendar years 2014 and 2015, the test year costs do not appear reflective of a normal annual cost level, which could be the result of timing of the charges being recorded on the Company's books. I recommend that the test year costs be normalized to reflect the two-year average of the costs recorded during 2014 and 2015. As shown on Exhibit No. DMR-3, page 16 of 32 (Adjustment PC-4 at PC-4.1), the recommended normalization of the Other Salary Overhead costs results in a $428,145 reduction to the costs recorded during the test year ended June 30, 2015. After removing the portion allocated to capital and non-utility, the impact is a reduction to Other Salary Overhead expense of $291,562 on a total Company basis and $18,281 on a Washington jurisdictional basis.

F. Interest Synchronization Adjustment.

Q: What is the purpose of Company Adjustment 7.1 – Interest True-up shown on you Exhibit No. DMR-3 at page 24 of 32?

A: The interest synchronization or interest true up adjustment allows the adjusted rate base and the weighted cost of debt to coincide with the income tax calculation. Since interest expense is deductible for income tax purposes, any revisions to the rate base or the weighted cost of debt will impact test year income tax expense. The adjusted test year rate base I am recommending differs from the Company proposed rate base. Thus, the resulting interest expense deduction for

[45] Response to Public Counsel Data Request No. 49 and Attachment PC 49-2, provided as Exhibit No. DMR-24.

determining the test year income tax expense will differ from the interest expense deduction used by Pacific Power in its filing.

Adjustment 7.1 – Interest True Up, shown on Exhibit No. DMR-3 at page 24 of 32 presents the calculation of the interest deduction and resulting impact on test year income tax expense based on: 1) the Company's as-filed amounts; 2) the Company's revised amounts based on impacts of the PATH Act; 3) the Company's revised amounts based on impacts of the PATH Act and AMA rate base; and 4) Public Counsel's recommended position in this case.

VI. PROPOSED YEAR TWO STEP INCREASE

Q: Can you please summarize the reasons presented by the Company for requesting a second rate increase to be effective May 1, 2017?

A: Yes. Company witness R. Bryce Dalley addresses the second rate increase starting at page 15 of his direct testimony. He indicates that the Company is "experiencing a ten-year trend of earnings attrition."[46] He goes on to identify four cost drivers in 2016. These include: 1) the Jim Bridger Unit 4 overhaul and SCR system installation anticipated to be complete by December 2016; 2) the expiration of Production Tax Credits available for certain renewable resources beginning in May 2016; 3) the replacement and upgrade of the Supervisory Control and Data Acquisition Energy Management System project in 2016; and 4) placement of the Union Gap Substation Upgrade transmission project into service in 2016. Since the final costs of these 2016 plant additions will not be known before the conclusions of the proceedings in this case, the Company has indicated that it will provide an attestation in late 2016 or early 2017 verifying the final

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[46] Dalley, Exhibit No. RBD-1T, at 15:19.

costs of these investments going into service in 2016. As part of its proposal, the Company also committed not to filing another general rate case or Expedited Rate Filing with a rate effective date prior to April 1, 2018.

Q: Above you indicate that Mr. Dalley claims the Company "is experiencing a ten year-trend of earnings attrition." What is the basis of this Company assertion?

A: At pages 8 and 9 of his direct testimony, Mr. Dalley states that the Company has under earned its authorized return on equity in Washington by an average of 500 basis points since 2006 and that for nine consecutive years through 2014 it did not earn its authorized rate of return in Washington. The failure to achieve its authorized rate of return in Washington is apparently the evidence the Company is relying on, asserting that it has been experiencing earnings attrition. Table 1 presented on page 9 of Mr. Dalley's direct testimony calculates the amount by which the unadjusted per books return on equity in Washington has been below the authorized return on equity, showing an average of actual per books below authorized of 5.49 percent for the nine year period 2006 through 2014. The most recent year presented in the table, 2014, showed the per books return on equity being 2.55 percent less than the authorized return in that year.

Q: Did the Company present a similar analysis in its last Washington rate case?

A: Yes, in the last rate case, Docket UE-140762 et al. (*Consolidated*), Mr. Dalley presented the same table in his testimony with the only apparent difference being that it only included the years 2006 through 2012. That table showed an average by which the unadjusted per books return on equity in Washington has been below the authorized return on equity, showing an average of actual per books below authorized of 6.04 percent for the seven year period 2006 through 2012, which exceeds the nine-year average of 5.49 percent presented in updated table in this case.

Q: Did the Commission agree in the last case that this Company analysis demonstrated that it was experiencing earnings attrition?

A: No, it did not. In fact, in Order 08 in that case, the Commission specifically stated as follows regarding earnings attrition:

> In this case, we have some evidence of capital additions during relevant periods but it does not demonstrate abnormal growth in plant. Inflation remains very low in the current economic environment in the United States. The Company did not present persuasive evidence that it is suffering attrition in earnings. In particular, the Company did not present an attrition study. Moreover, the fact that the Company failed in the past to earn its authorized return cannot justify use of EOP absent a showing that, due to factors beyond the Company's control, the Commission can expect this condition to continue into the future. There is no such evidence in the record of this case.[47]

The Company analysis in this case is essentially identical to that presented in the 2014 docket and is no more persuasive.

Q: Do you agree that the Company has shown in this case that it is experiencing earnings attrition that would justify the allowance of a Year Two rate increase in this case?

A: No, I do not. As indicated previously in this testimony, absent the Company's request to accelerate the recovery of its coal facility capital costs from Washington ratepayers in this case, based on the Company's own numbers there would be no basis to increase in rates for Year One. The impact of the accelerated recovery request exceeds the entire amount of Year One rate increase

[47] *WUTC v. Pacific Power & Light Co*., Docket UE-140762(*Consolidated*) Order 08, ¶ 146, at 64 (March 25, 2015).

being sought by the Company. This is true even if the EOP rate base approach. The EOP approach would reflect the test year capital additions in their entirety and the requested pro forma major plant additions associated with the Jim Bridger Unit 3 overhaul and SCR system would also be included in the test year. Clearly, this is not demonstrative of a company experiencing earnings attrition as current base rates result in revenues that are sufficient to cover operating expenses and the requested return on rate base.

As also previously indicated in this testimony, on a Washington jurisdictional basis the total rate base presented by the Company for the test year in this case (test year ended June 30, 2015) is lower than the total rate base presented by the Company for the test year in its last rate case (test year ended December 31, 2013) on both an adjusted and an unadjusted basis. Again, this is not demonstrative of a company experiencing earnings attrition due to abnormal growth in plant.

Early in this testimony, I also indicated that the Company's employee complement has continued to decline substantially since the last rate case, going from the 2013 test year average at the time of the last rate case of 5,375 FTE employees to an average of 5,247 in the test year in this rate case and 5,128 as of December 31, 2015. In fact, the actual December 31, 2015, FTE employee complement of 5,128 is 247 FTE or 4.6 percent lower than the average 2013 test year FTE employee complement in the prior rate case. This is not consistent with a company experiencing earnings attrition. Rather, the declining employee complement would be more indicative of declining costs.

The table below presents a comparison of certain categories of expense on an unadjusted Washington jurisdictional basis presented in the Company's current rate case filing as compared to the last rate case filing.

	Current Case Unadjusted	Prior Case Unadjusted	Change
Distribution Expense	11,025,297	12,193,373	(1,168,076)
Customer Accounting Expense	5,916,884	6,347,128	(430,244)
Customer Service & Info Expense*	761,054	778,218	(17,164)
Administrative & General Expense	9,604,908	13,226,426	(3,621,518)
Total of Above	27,308,143	32,545,145	(5,237,002)

*Customer Service & Info Expense Excludes the DSM Expense

Similarly, the table below presents a comparison of certain categories of expense on an adjusted Washington jurisdictional basis presented in the Company's current rate case filing as compared to the last rate case filing.

	Current Case Adjusted	Prior Case Adjusted	Change
Distribution Expense	11,115,084	12,252,659	(1,137,575)
Customer Accounting Expense	6,342,566	6,967,383	(624,817)
Customer Service & Info Expense	761,220	790,894	(29,674)
Administrative & General Expense	10,155,481	12,471,080	(2,315,599)
Total of Above	28,374,351	32,482,016	(4,107,665)

Clearly the reduction in various categories of expense between the 2013 test year in the last rate case and the test year ended June 30, 2015, in this rate case, on both an adjusted and unadjusted basis, is not reflective of a company experiencing earnings attrition.

In short, the Company has failed to demonstrate in this case that it is currently experiencing earnings attrition due to abnormal growth in plant or other expense growth beyond the Company's control. In fact, as demonstrated above, rate base, employee levels, and expenses have been declining since the last rate case, not increasing. Based on the Company's failure to demonstrate that it is experiencing earnings attrition, I do not agree that a Year Two rate increase is appropriate or a reasonable outcome in this case.

Q: If the Commission disagrees with your recommendation and determines that a Year Two rate increase should be implemented in this case, are you recommending any revisions to the Year Two rate increase calculations presented by the Company?

A: Yes. The Company's proposed Year Two rate increase is based on certain limited adjustments that were presented on Company Exhibit No. SEM-4 at Tab 1, page 1 of 2, and resulted in total incremental revenue requirements of $10,550,094. The implementation of the PATH Act previously discussed in this testimony reduces the Year Two incremental revenue requirements by $705,582 to $9,844,513. At a minimum, this known and measurable impact should be reflected. The Company's limited adjustments after reflecting the PATH Act impacts along with the associated revenue requirement amounts include: 1) $5,218,907 for the Jim Bridger Unit 4 Overhaul and SCR Installation; 2) $293,404 for the SCADA EMS Replacement & Upgrade project; 3) $523,440 for the Union Gap Transmission Project; 4) $4,234,464 associated with the expiring Production Tax Credits; 5) $7,933 associated with Deferred State tax expense and balance; and 6) ($433,635) for the impact of the previous adjustments on interest synchronization.

Several revisions beyond the reflection of the impacts of the PATH Act need to be made to the above adjustments.

Q: What additional adjustments to you recommend?

A: Consistent with my recommendation that the accelerated depreciation of the coal facility costs be disallowed in this case, I recommend that the Company's application of the proposed accelerated depreciation rates on the Jim Bridger Unit 4 Overhaul and SCR system costs be removed. The $5,218,907 revenue requirement impact of the Jim Bridger Unit 4 Overhaul and SCR system costs identified above includes the application of the accelerated depreciation rates on the projected plant additions. As shown on Exhibit No. DMR-4, page 1 of 2, reflecting the currently approved depreciation rates instead of the accelerated depreciation rates proposed by the Company results in a $1,299,936 reduction to the resulting revenue requirements. The calculation of the needed adjustments, which reduces accumulated depreciation by $1,283,578 and depreciation expense by $1,384,375 on a Washington allocated basis is provided on Exhibit No. DMR-4, page 2 of 2.

Similar to my discussion on the Company's pro forma major plant adjustment for the Jim Bridger Unit 3 SCR system, I am not opining in this testimony on whether or not the Company's decision to install the SCR system on Jim Bridger Unit 4 is appropriate. However, I do recommend that the Commission take the project costs into consideration in its evaluation of whether or not the request to accelerate the recovery of these costs should be approved.

Additionally, I recommend that the additional accumulation of depreciation associated with the Company's proposed first year pro forma major plant addition adjustment be reflected in determining the Year Two incremental revenue requirement. As shown on Exhibit No. DMR-4, page 1 of 2, this results in a $752,220 reduction to accumulated depreciation reducing the Year Two incremental revenue requirement by $88,548. If the Commission disagrees with my recommended removal of the acceleration of the depreciation on the Jim Bridger Unit 3 Overhaul and SCR system additions, then my recommended $752,220 reduction to accumulated depreciation would need to be increased to reflect the impacts of the higher level of depreciation expense on those additions.

Q: What Year Two incremental rate increase results from your recommended adjustments?

A: First, I need to reiterate that I do not recommend that any Year Two incremental rate increase be approved by this Commission for the reasons discussed previously in this testimony. However, if the Commission disagrees with this primary recommendation, then the result of my recommended specific adjustments are presented on Exhibit No. DMR-4. As shown on this exhibit, the Company's proposed Year Two incremental rate increase should be reduced by a minimum of $2,101,970, going from the $10,550,094 presented in the Company's filing to $8,448,125.

Q: Does this conclude your direct testimony?

A: Yes, it does.