Exhibit No. CAC-1CT
Docket UE-152253
Witness: Cindy A. Crane

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-152253

PACIFIC POWER & LIGHT COMPANY

REDACTED SUPPLEMENTAL REBUTTAL TESTIMONY OF
CINDY A. CRANE

May 2016

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position.

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am the President and Chief Executive Officer of Rocky Mountain Power, a division of PacifiCorp.

Q. Have you previously testified in this proceeding on behalf of Pacific Power & Light Company (Pacific Power or Company), a division of PacifiCorp?

A. No, but I am adopting the pre-filed rebuttal testimony and exhibits of Mr. Dana Ralston, which have been identified as Exhibit Nos. DR-1CT, 2C, 3C, and 4C.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990. Since then I have served as Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, Vice President of Strategy and Division Services, and Vice President of Interwest Mining Company and Fuel Resources. My responsibilities in these positions included the management and development of PacifiCorp's 10-year business plan, directing operations of the Energy West Mining and Bridger Coal companies, and coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants. In October 2014, I was appointed to my present position as President and Chief Executive Officer of Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before public utility commissions in all states in which PacifiCorp serves customers, including Washington.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental rebuttal testimony?

A. My testimony responds to the supplemental testimony of Mr. Jeremy B. Twitchell on behalf of Staff of the Washington Utilities and Transportation Commission (Commission) related to the prudence of the Company's decision to install selective catalytic reduction systems (SCRs) on Units 3 and 4 of the Jim Bridger generating plant (Jim Bridger Units 3 and 4). In particular, I respond to Staff's analysis of the coal costs Pacific Power used in its present value revenue requirement differential calculations (PVRR(d)) supporting the decision to install SCRs.

Q. Please summarize your testimony.

A. Pacific Power's decision to install SCRs at Jim Bridger Units 3 and 4 was prudent, and the Company's analysis supporting the decision was based on the best available information at the time the decision was made. Staff accuses the Company of failing to consider increases in coal costs and decreases in natural gas prices when it issued the full notice to proceed (FNTP) on December 1, 2013. Staff bases these accusations on an alleged lack of evidence that these changes were considered, and relies on an analysis of Bridger Coal Company (BCC) coal costs prepared by the Company in fall 2013 as part of its annual budgeting process (the October 2013 mine plan) and selective application of third-party natural gas price forecasts. Staff's accusations are unfounded and untrue.

Mr. Chad A. Teply addresses Staff's assertions that the Company did not consider these changes in December 2013 before issuing the FNTP, and Mr. Rick T. Link addresses the natural gas price forecasts. In this testimony, I address Staff's assertions about estimated coal costs in fall 2013. Although certain costs related to BCC increased in the October 2013 mine plan, other costs decreased, including decreases in capital expenditures and third-party coal costs. The changes in the October 2013 mine plan were not material and did not warrant an update to the Company's long-term fueling plan (what has been called the January 2013 mine plan, but is referred to in the Company's supplemental rebuttal testimony as the January 2013 long-term fueling plan to clarify the intended purposes of the two different types of plans) or its SCR analysis.

OCTOBER 2013 MINE PLAN

Q. Please describe the Company's October 2013 mine plan.

A. As discussed in Mr. Ralston's rebuttal testimony, the October 2013 mine plan was developed by the Company as part of its annual budgeting process.[1] The plan was prepared to forecast BCC coal costs for a 10-year budget horizon. Although the October 2013 mine plan includes forecasts beyond this 10-year horizon, this information is used only to develop reclamation funding inputs for the 10-year budget horizon. In contrast, the Company prepares long-term fueling plans, such as the January 2013 long-term fueling plan, for use in the integrated resource planning process and in analyses of decisions with long-term impacts to the Company and its customers, such as the decision to install SCRs at Jim Bridger Units 3 and 4. Therefore, the nature of the data provided in the two types of plans is different, and different analytical rigor is applied in developing the long-term data included in the plans.

[1] Ralston, Exh. No. DR-1CT 3:8-4:10.

Q. Is the October 2013 mine plan directly comparable to the January 2013 long-term fueling plan?

A. No. As Mr. Ralston previously testified, the plans are not comparable given the major differences in their purpose, scope, and planning horizons. The Company never relied on the October 2013 mine plan as a long-term fueling forecast for the Jim Bridger plant.

Q. Did the BCC coal costs included in the October 2013 Mine Plan increase by [redacted] over the BCC coal costs included in the January 2013 long-term fueling plan, as Staff testified?[2]

A. No. Because the January 2013 and October 2013 plans are not directly comparable, Staff needed to make several assumptions in conducting its analysis. When errors in these assumptions are corrected, the results show that overall coal costs for the Jim Bridger plant increased by only [redacted] during the 10-year budget horizon covered by the October 2013 mine plan. This amount is consistent with the [redacted] increase reflected in the Company's long-term fueling plan for the Jim Bridger plant used for the 2015 Integrated Resource Plan (IRP) for the 2016-2030 period.[3] If the Company had updated costs by this percentage increase in both the two-unit operating scenario (the natural gas conversion alternative) and four-unit operating scenario (the SCR alternative), the SCR benefits would have decreased by approximately [redacted] over the 10-year budget period, as set forth in Exhibit

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[2] Twitchell, Exh. No. JBT-28HCT 18:12-15.
[3] Ralston, Exh. No. DR-1CT 7:16, Exh. No. DR-4C. The long-term fueling costs used in the 2015 IRP were based on the Company's July 22, 2014 BCC mine plan. The Company originally produced a BCC mine plan on July 9, 2014, that it used in its 10-year budget. This plan was updated with only a few changes in the July 22, 2014 mine plan. The long-term fueling plan was finalized in November 2014 after the Company had updated third-party coal costs.

No. CAC-2C. This is a conservative assumption because, as discussed below, the Company's analysis shows that projected cost increases in a two-unit scenario under the October 2013 mine plan would have offset all cost increases in the four-unit scenario.

Q. Before filing its initial or supplemental testimony, was Staff aware that the October 2013 Mine Plan was not directly comparable to the January 2013 long-term fueling plan?

A. Yes. In Mr. Twitchell's initial testimony, he explained that he had reviewed the record from the Company's 2014 Utah rate case to determine how the SCR investments were treated.[4] My testimony in that case explained the differences between the October 2013 mine plan and the January 2013 long-term fueling plan and made clear that they are not directly comparable.[5] Mr. Twitchell's review of the record from the 2014 Utah rate case should have alerted him to the material differences in these two plans. Moreover, Mr. Ralston clearly explained in his rebuttal testimony that these two plans are not directly comparable for the same reasons discussed here.[6]

Q. Please describe the first incorrect assumption made in Staff's new analysis.

A. Staff mistakenly assumes that the long-term data in the October 2013 mine plan is comparable to the long-term data in the January 2013 long-term fueling plan and uses some of this longer-term data from the October 2013 mine plan (data for the period

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[4] Twitchell, Exh. No. JBT-1T 62:1-4. Sierra Club also included a copy of my Utah rebuttal testimony as an exhibit to its testimony in this case. Fisher, Exh. No. JIF-8. The Company's 2014 Utah rate case was docket No. 13-035-184.
[5] *See e.g.* Exh. No. JIF-8 5:72-81.
[6] Ralston, Exh. No. DR-1CT 3:8-23.

2023 through 2030).[7] As I explain above, the long-term cost and revenue assumptions included in the October 2013 mine plan were not developed with the same analytical rigor that the Company uses to develop its long-term fueling plans because this data is used solely to determine appropriate contributions to the reclamation sinking fund during the 10-year budget horizon. This is why, as Staff noted, in the October 2013 mine plan the longer-term capital cost data was kept in a different file than the capital cost data for the 10-year budget horizon.[8]

Q. Please describe the second erroneous assumption in Staff's analysis.

A. Staff's analysis includes a modeling error in BCC's "Mine and Equipment Maintenance" cost component in 2028 that inflates coal costs by [redacted] (Company portion, [redacted]). On a net-present-value basis, correcting this error reduces Staff's calculated coal cost increase by approximately [redacted].

Q. What is the impact of correcting the analysis to account for only the 10-year budget horizon reflected in the October 2013 mine plan and correcting Staff's modeling error?

A. The overall increase in coal costs is only [redacted]. Notably, this increase is consistent with the overall increase between the January 2013 and 2015 IRP long-term fueling plans for the Jim Bridger plant, as I note above. The fact that the long-term cost projections in the 2015 IRP are consistent with the 10-year budget but inconsistent with Staff's 2016 to 2030 analysis highlights the underlying problems in Staff's approach.

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[7] *See e.g.* Twitchell, Exh. No. JBT-28HCT 18:7-9.
[8] Twitchell, Exh. No. JBT-28HCT 17 n. 21.

Q. Are there any other indicators that Staff's analysis was flawed?

A. Yes. The flaws in Staff's revised analysis should have been apparent simply by examining the overall results. In response testimony, Staff claimed that BCC coal costs increased by [redacted], which resulted in a downward adjustment to the SCR benefits of [redacted].[9] Now, Staff claims that coal costs increased by only [redacted], yet the downward SCR adjustment increased to [redacted].[10]

Q. Staff contends that the Company's continued reliance on the January 2013 long-term fueling plan even after the October 2013 mine plan was developed was unreasonable.[11] How do you respond?

A. I disagree. During the budgeting process in fall 2013, the Company recognized that increases in BCC cash costs would be substantially offset by reduced BCC capital spending and third-party fuel costs. Nothing in the October 2013 mine plan signaled that the January 2013 long-term fueling plan was obsolete.

Q. Staff bolsters its long-term analysis by pointing to coal cost increases reported in the Company's 2014 Washington rate case.[12] Is Staff's reliance on rate case coal costs appropriate here?

A. No. Staff claims that if the October 2013 mine plan "created cost increases that were sufficiently known and measurable to support a rate increase, then those costs increases were sufficiently known and measurable to be included in the Company's planning." But as Staff acknowledges, the coal costs included in the Company's rate

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[9] Twitchell, Exh. No. JBT-1T 34:12-14; 9, Figure 1.
[10] Twitchell, Exh. No. JBT-28HCT 18:12-15; 19:20-21.
[11] Twitchell, Exh. No. JBT-28HCT 6:12-19.
[12] Twitchell, Exh. No. JBT-28HCT 7:8-12; 8:1-14; 10:17 – 11:20. The Company's 2014 Washington rate case was Docket UE-140762.

case filings reflect costs expected during the rate year.[13] The analysis used to develop test-period coal costs for a general rate case is fundamentally different from the analysis required to develop long-term fuel plans for a generating plant. Because the October 2013 mine plan updated BCC coal costs for the 10-year budget horizon (a relatively short-term period), the Company reasonably relied on the October 2013 mine plan to establish short-term rates. The fact that the mine plan was used to determine short-term costs does not mean that it is appropriate as a long-term forecast or as a comprehensive life-of-plant fueling plan for the Jim Bridger plant.

THIRD-PARTY FUEL COSTS

Q. Staff acknowledges that the October 2013 Mine Plan did not update third-party coal costs.[14] Staff therefore relied on the third-party coal increases from the 2014 Washington rate case to forecast the change in third-party coal costs over the 2016 to 2030 study period.[15] Is this a valid way to forecast third-party coal costs?

A. No. Staff's reliance on the 2014 Washington rate case produces two fundamental errors in its analysis of third-party coal costs. First, Staff unreasonably assumes an [redacted] annual cost increase for third-party coal. Second, Staff unreasonably assumes that the production ratio between BCC and third-party suppliers reflected in the Company's direct filing in its 2014 Washington rate case will remain constant through 2030. Both of these assumptions are incorrect.

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[13] Twitchell, Exh. No. JBT-28HCT 11: 16-17.
[14] Twitchell, Exh. No. JBT-28HCT 10:5-9.
[15] Twitchell, Exh. No. JBT-28HCT 18:17 – 19: 8.

Q. How did Staff calculate its assumed increase for third-party coal costs?

A. Staff compared the costs of Black Butte coal in the Company's 2013 Washington rate case[16] to the costs of Black Butte coal in the Company's 2014 Washington rate case. Because costs increased by [redacted] between the 2013 and 2014 cases, Staff assumed that costs would continue to increase at [redacted] annually until 2030.[17]

Q. What is wrong with this assumption?

A. First, there were 15 months between the 2013 and 2014 net power cost test years. Therefore, the annual change is only [redacted], not [redacted]. Second, it is unreasonable to assume that third-party coal costs would increase at the same percentage annually through 2030 based on consideration of changes over only one 15-month period. The third-party cost increase between the 2013 and 2014 case represented a price change between two test periods based on contract terms that were expiring in 2015. There is absolutely no basis to assume that the increases in those cases reflect long-term expectations.

Q. How would you correct Staff's assumed third-party cost increase?

A. Based on what the Company knew in fall 2013, during the 10-year budget horizon third-party coal costs were expected to increase by roughly [redacted] annually. When factored into the overall plant fueling costs, third-party costs inclusive of coal inventory changes known in fall 2013 actually *decrease* by [redacted] relative to the third-party costs assumed in the SCR analysis. This decrease further offsets the modest increase in BCC costs reported in the October 2013 mine plan's 10-year budget horizon.

[16] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043.
[17] Twitchell, Exh. No. JBT-28HCT 18:18-22.

Q. Are there any other deficiencies in Staff's analysis?

A. Yes. The Company's direct testimony in the 2014 Washington rate case was filed in May 2014, well after the period of time that Staff concedes is relevant to the prudence determination in this case. Staff claims that it is improper to reference the long-term fueling plan used in the 2015 IRP to validate the absence of major cost increases in the October 2013 mine plan. But Staff attempts to do the same thing by referencing Company testimony filed in May 2014. The testimony on which Staff relies, however, is irrelevant to the long-term coal cost increases at issue in this case.

Q. What is the second error in Staff's analysis?

A. Staff incorrectly assumes that the ratio between BCC and third-party coal reflected in a single year is indicative of the ratio from 2016 through 2030.[18]

Q. How did Staff determine the amount of coal provided by BCC and third-parties from 2016 through 2030?

A. To determine the ratio between BCC and third-party coal over a 17-year period, Staff relies on testimony from the Company's 2014 Washington rate case. In that case, the Company's direct testimony projected that BCC would provide roughly 85 percent of the plant's total coal, with third-party mines providing the remaining 15 percent. The Company's projection in the 2014 rate case, however, was based on expected coal deliveries *during a single year*—April 2015 through March 2016. Staff is incorrect to assume that BCC would provide 85 percent of the plant's total coal until 2030 based on a single year of data.

[18] Twitchell, Exh. No. JBT-28HCT 18:17 – 19:8.

The flaw in Staff's assumption is evident from the record in the 2014 rate case. By the time the Company filed its rebuttal testimony in that case, the proportion of BCC coal decreased to approximately 70 percent of the plant's total coal requirement.[19] This fact undermines Staff's claim that the October 2013 mine plan increased the Company's exposure to market risk because of greater reliance on third-party coal.[20]

TWO-UNIT SCENARIO

Q. Staff contends that if the Company had performed a two-unit scenario analysis in October 2013 it would have shown that coal costs in a two-unit scenario would have decreased, making gas conversion even more attractive.[21] Is Staff's conclusion sound?

A. No. Staff's analysis again relies on incorrect assumptions. First, Staff claims that the surface mine is subject to economies of scale, while implying that the underground mine is not.[22] On the contrary, both the surface and underground mine are subject to economies of scale—as production decreases in either operation the per-unit cost increases. Under a two-unit scenario, production would decrease.

Q. Does Staff's analysis include any other incorrect assumptions?

A. Yes. Staff reasons that under a two-unit scenario based on the October 2013 Mine Plan, the surface mine would continue to operate, which would avoid accelerated reclamation and result in lower costs relative to the two-unit scenario based on the

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[19] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Exh. No. CAC-1CT 6:13-16.
[20] Twitchell, Exh. No. JBT-28HCT 12:10-18.
[21] Twitchell, Exh. No. JBT-28HCT 24:10-13.
[22] Twitchell, Exh. No. JBT-28HCT 23:19 – 24:13.

January 2013 long-term fueling plan.[23] Additionally, Staff states that availability of underground coal through 2023 in the October 2013 mine plan would also lower costs.[24] Relying on these assumptions, Staff concludes that a two-unit scenario based on the October 2013 mine plan would have lower costs than the January 2013 two-unit scenario.

Q. If the Company had developed a two-unit scenario based on the October 2013 Mine Plan, would the costs be less than the January 2013 two-unit scenario?

A. No. Both the January 2013 two-unit scenario and the October 2013 mine plan consider varying levels of underground coal production through 2023. The primary difference between the January 2013 two-unit scenario and a two-unit scenario based on the October 2013 mine plan is that surface mine closure occurs in 2018 in the January 2013 two-unit scenario and the surface mine continues to operate in the October 2013 mine plan.

To quantify the impact of this change using information available in fall 2013, the Company compared BCC surface mine cash costs, BCC surface mine capital costs expressed on a revenue requirement basis, and external coal prices to costs in the January 2013 two-unit scenario. Based on this analysis, the Company estimates that two-unit scenario coal costs would have increased by approximately [redacted] during [redacted] based on changes in the October 2013 mine plan. This is primarily due to higher costs at the surface mine. The cost increases in the two-unit scenario would have entirely offset the cost increases in the four-unit scenario in the Company's PVRR(d) analysis—making the SCR investment become more favorable

[23] Twitchell, Exh. No. JBT-28HCT 23:10-18.
[24] Twitchell, Exh. No. JBT-28HCT 24:8-10.

based on the October 2013 Mine Plan. My analysis is shown in Exhibit No. CAC-3C.

Q. How does this analysis relate to the Company's previous testimony responding to Sierra Club's use of the January 2013 four-unit scenario as a proxy for the October 2013 two-unit scenario?

A. In rebuttal testimony, Mr. Ralston testified that it was reasonable to assume that the two-unit costs increased at the same percentage as the four-unit costs in the Company's 2015 IRP fueling plan. This responded to Sierra Club's claim that the two-unit costs in the 2015 IRP fueling plan would have actually decreased to the level of four-unit costs in January 2013. The Company's updated analysis indicates that its previous estimate of two-unit coal costs in the 2015 IRP fueling plan, which projected only a [redacted] increase, was conservative.[25]

Q. Why didn't the Company update its two-unit scenario coal costs in fall 2013?

A. As I discuss above, nothing in the October 2013 mine plan raised concerns that the January 2013 long-term fueling plan was obsolete or that costs in the two-unit scenario were decreasing relative to costs in the four-unit scenario. Under these circumstances, updating the two-unit scenario was unnecessary.

OTHER ISSUES

Q. Staff testifies that they do not understand why the Company conducted analysis in its rebuttal testimony based on the Company's 2015 IRP fueling plan.[26] Why did the Company include that analysis in its rebuttal testimony?

A. As explained clearly in Mr. Ralston's rebuttal testimony, the Company was responding to Sierra Club's comparison of coal costs between the January 2013 long-

[25] Ralston, Exh. No. DR-1CT 12:10-14.
[26] Twitchell, Exh. No. JBT-28HCT 8:16 – 9:4.

term fueling plan and the long-term fueling plan used in the 2015 IRP.[27]

Q. Staff claims that the long-term fueling plan used in the 2015 IRP is "not relevant in evaluating the prudence of the Company's decision" because "it was prepared several months after Pacific Power issued the full notice to proceed (FNTP) with SCR installation at Bridger."[28] Do you agree?

A. Yes, in part. The Company generally agrees that the prudence standard examines whether a utility's decision was reasonable based on the information it knew or should have known at the time the decision was made. The data used in the 2015 IRP is therefore not relevant to the prudence of the Company's decision to install SCRs at Jim Bridger Units 3 and 4 because the data was developed after the Company made the decision in May 2013 and after it issued the FNTP on December 1, 2013. But in this case, Staff argues that "rising coal costs and falling natural gas costs"[29] between January 2013 and October 2013 demonstrate "obvious trends" that the Company willfully ignored before issuing the FNTP.[30] The analysis of the SCR investments using the 2015 IRP data is therefore relevant to rebut this argument and to verify that there was no significant long-term trend of increasing coal costs.

[27] Ralston, Exh. No. DR-1CT 6:4-9; 7:14 – 10:16.
[28] Twitchell, Exh. No. JBT-28HCT 8:17-19.
[29] Twitchell, Exh. No. JBT-28HCT 33:5-6.
[30] Twitchell, Exh. No. JBT-28HCT 31:18-19.

Q. One of the corrections Staff made in its supplemental testimony is to exclude non-cash operating costs (*i.e.*, depletion, depreciation, and amortization) from its analysis. While acknowledging its previous error, Staff faults the Company for failing to explain that non-cash operating costs were excluded from the SCR analysis.[31] How do you respond to Staff's allegation?

A. Staff's criticism of the Company is unwarranted. On January 20, 2016, Staff received the Company's response to Sierra Club's Data Request No. 11. That request referenced the Company's cash coal costs set forth in Exhibit No. RTL-3C and asked the Company to: "Identify, separately, the elements of Bridger Coal Company's costs which are specifically included and excluded in cash costs." The Company's response clearly indicated that amortization, depreciation, and depletion are excluded from the cash costs used in the Company's SCR analysis. This data response is attached as Exhibit No. CAC-4. Staff had this information well before filing its rebuttal testimony. In addition, my Utah testimony that Mr. Twitchell reviewed before filing his initial testimony,[32] described in detail how the Company removed the non-cash operating costs from its SCR analysis.[33]

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Commission should conclude that the Company's SCR analysis was robust and its decision to install SCR systems on Jim Bridger Units 3 and 4 was prudent. The October 2013 mine plan showed increased operating cash costs, but those increasing

[31] Twitchell, Exh. No. JBT-28HCT 15:16 – 16:3.
[32] Twitchell, Exh. No. JBT-1T 62:1-4.
[33] Fisher, Exh. No. JIF-8 6:107 – 7:116.

costs were substantially offset by decreased capital and third-party costs, and by cost increases in the two-unit scenario. This shows that changes in coal costs during the period the SCR analysis was under review were adequately considered before the FNTP was issued, as demonstrated by the Company in its rebuttal testimony.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes.