SIERRA CLUB

July 24, 2020

Via Electronic Filing

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

Re: Docket No. UE 374 Sierra Club Rebuttal Testimony

Enclosed please for filing in Docket No. UE 374 the following exhibits:

Exhibits 400-414: Fisher
Exhibit 500: Hausman

Confidential version of the documents herein will be served in accordance with OAR 860-001-0070(3) and the Commission's Covid-19 Response outlined in Order 20-088 on all eligible party representatives electronically via encrypted password protected ZIP folders

If you have any questions or require any additional information, please do not hesitate to contact me.

Respectfully submitted,

AMB

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Docket No. UE 374
Exhibit Sierra Club/400
Witness: Jeremy Fisher

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	**UE 374**

Rebuttal Testimony of
Jeremy Fisher, PhD

On Behalf of
Sierra Club

Public Version

July 24, 2020

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1. INTRODUCTION

Q Are you the same Jeremy I. Fisher who provided opening testimony in this docket on behalf of Sierra Club?

A Yes, I am.

Q What is the purpose of your testimony?

A My testimony responds to the reply testimonies of PacifiCorp d.b.a. Pacific Power ("Company") witnesses Rick Link, Dana Ralston, and James Owen. I continue to address the prudence of the Company's decision to proceed with the installation of Selective Catalytic Reduction ("SCR") at Jim Bridger coal power plant units 3 and 4 from 2013 to 2017 (collectively the "Bridger SCR projects"). Specifically, I respond to the following issues:

First, I respond to Mr. Link's testimony that the Company had no reasonable way of perceiving that gas price projections had declined prior to the Company committing monies at the start of the Bridger SCR projects.

Second, I rebut Mr. Ralston's erroneous assertion that I "double counted" various increased coal costs at the Bridger coal mine revealed in October 2013.

Third, I assess Mr. Link's response to Citizen's Utility Board's ("CUB") concern that the Company failed to assess an appropriate later retirement date for Jim Bridger 3 & 4 as an alternative compliance mechanism under the Regional Haze Rule.

Fourth, I address Mr. Link's response to Commission Staff's concern that the retirement of Jim Bridger should have been assessed against avoidable transmission projects of Energy Gateway.

Fifth, I respond to Mr. Owen's testimony asserting that the Company consistently sought to avoid the installation of SCR at Jim Bridger coal plant, and show that the Company made different assertions to different parties, following a long-established investment strategy to install the SCRs.

Sixth, I respond to Mr. Owen's testimony that Sierra Club's stance on the stringency of EPA's environmental requirements is inconsistent with its stance on rate treatment and prudence of pollution controls.

Seventh, I address both Mr. Link and Mr. Owen's attempts to characterize the California Public Utility Commission ("CPUC") recent rate case as an unequivocal affirmation of the prudence of the Bridger SCRs.

Finally, I address Mr. Link and Mr. Ralston's inconsistent characterization of costs and uncertainties with respect to the robustness of the Bridger SCR decision.

The fact that I have not addressed each and every one of PacifiCorp's reply testimonies to my opening testimony does not mean that I agree with the Company's characterization of my assessment.

2. THE COMPANY'S GAS PRICE FORECASTS RELEVANT TO THE BRIDGER SCRS WERE LARGELY GROUNDED IN NEAR-TERM MARKET-BASED FORECASTS

Q According to Mr. Link, "the Company has a long and well-documented history of finalizing its [Official Forward Price Curve] OFPC on the last trading day of each calendar quarter."[1] Please remind us why Mr. Link stresses the schedule on which the Company produces this analysis, and the importance of the OFPC to the Bridger SCR decision.

A The decision to pursue—or not—the Bridger 3 & 4 SCR projects was highly contingent on the Company's forecast of gas prices. Mr. Link testified that the decision to pursue the Bridger SCRs on December 1, 2013 was last evaluated on the basis of gas price forecasts produced in September 2013, in an analysis the Company refers to as its Official Forward Price Curve ("OFPC").[2] At that time, Mr. Link found a benefit of pursuing the SCRs of $130 million,[3] down from the Company's prior "base case" value of $183 million in September, 2012. As I showed in my opening testimony, by the time the Company produced its December 2013 OFPC, the value of the SCRs would have dropped to just $36.7 million, or a reduction of $146 million from its "base case," sending a clear signal that the retrofit was well within the margin of error.[4]

Mr. Link was quite adamant that the production date of the OFPC—always on the last trading day of a quarter—matters because it allowed him to suggest that there

[1] PAC/2300 at Link/23:6-8.
[2] PAC/700 at Link/107:6-8.
[3] *Id.* at Link/107:10-13.
[4] Sierra Club/100 at Fisher/52:12-18.

was no other option other than to wait until the OFPC was produced for the Company. Producing the OFPC on the last trading day placed the problematic December 2013 OFPC 29 days after the "final notice to proceed" ("FNTP") was inked and a done deal.[5]

But as I showed in my opening testimony, Mr. Link was the owner and producer of the OFPC. The forecast, and the process of deriving the forecast is internal, and its production lies entirely in the control of the Company.

Q When did the Company actually have all of the information it used to produce the December 2013 OFPC, according to Mr. Link?

A According to Mr. Link, the gas forecast in the "OFPC is constructed from three components—a forward market component, a blended component, and a fundamentals component."[6] The forward market component is based on "settled forward prices"—effectively commodities market prices.[7] The "fundamentals" forecast is the Company's subjective assessment of forecasts provided by three private vendors.[8] And finally the blended component is simply a combination of both the commodity market prices and Mr. Link's assessment of the private vendor forecast.[9]

The forward market component, of the forecast is fairly straightforward. Gas futures are a commodity traded on the NYMEX market in a very fluid and

[5] PAC/2300 at Link/23:5-9.
[6] *Id.*at Link/23:12-13.
[7] *Id.* at Link/23:15-17.
[8] *Id.* at Link/23:20-/24:9.
[9] *Id.*at Link/23:17-20; PacifiCorp confirms that Mr. Link is responsible for the production of OFPC and gas prices. *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.6(a)-(b).

transparent environment; the market's collective assessment of gas futures is available on-demand.[10] These prices can be accessed at any time, including on November 30 2013, the day before the Company released the FNTP.

PacifiCorp appears to receive expert forecasts on a moderately regular schedule, although not necessarily aligned with the Company's OFPC schedule. Mr. Link admitted that two of three forecasts were in his possession prior to the FNTP.[11] The third forecast became available on December 11, 2013.[12] Therefore, the vast majority of the information needed to make an assessment—even if off-schedule from the Company's normal quarterly OFPC—was in Mr. Link's possession at the time that the Company made the decision to proceed, and the last forecast was close on its heels.

Q Mr. Link stressed that "[t]he Company's long-term resource planning decisions are based on long-term price forecasts because these are the prices that have the most influence on the economic analysis for long-term resource decisions."[13] Is he correct?

A Only in broad strokes. In general, a long-term forecast is important for long-term decisions. But because PacifiCorp uses discounting in its planning, the first few years of a forecast can have a surprisingly large impact. Mr. Link's resource decision on the Bridger SCR project boils down to the nominal levelized cost of

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[10] *See, e.g.*, NYMEX Henry Hub Natural Gas Futures, CME Group, *available at* https://www.cmegroup.com/trading/why-futures/welcome-to-nymex-henry-hub-natural-gas-futures html (last accessed July, 20, 2020).
[11] PAC/2300 at Link/25:4-6.
[12] *Id.* at Link/25:6-7, Link/25:16-17.
[13] *Id.* at Link/27:3-5.

gas from 2016-2030,[14] a factor that he generated from short-term and long-run forecasts.[15] It turns out that the forward market component—i.e. the readily generated commodity trading price—of the OFPC actually accounts for a full 41 percent of the nominal levelized cost of gas.[16] In other words, 41% of the primary information Mr. Link said was unavailable at the time the decision was made, was readily available.

Of the other information, the Company had two of three forecasts in hand on December 1, 2013. I'll address Mr. Link's representation of those forecasts below.

Q According to Mr. Link, the long-term OFPC most informs the Company's gas price forecast, and thus its decision on Bridger. Was he correct?

A Empirically, no. Looking at Mr. Link's construction of the nominal levelized cost of gas—again, the determining factor in his estimation—that factor is <u>almost entirely</u> correlated with short-term market price forecasts. In other words, even though Mr. Link described a relatively intensive process of vetting expert gas forecasts, the key factor underlying the nominal levelized cost of gas is explainable by market fluctuations captured in short-term market projections.

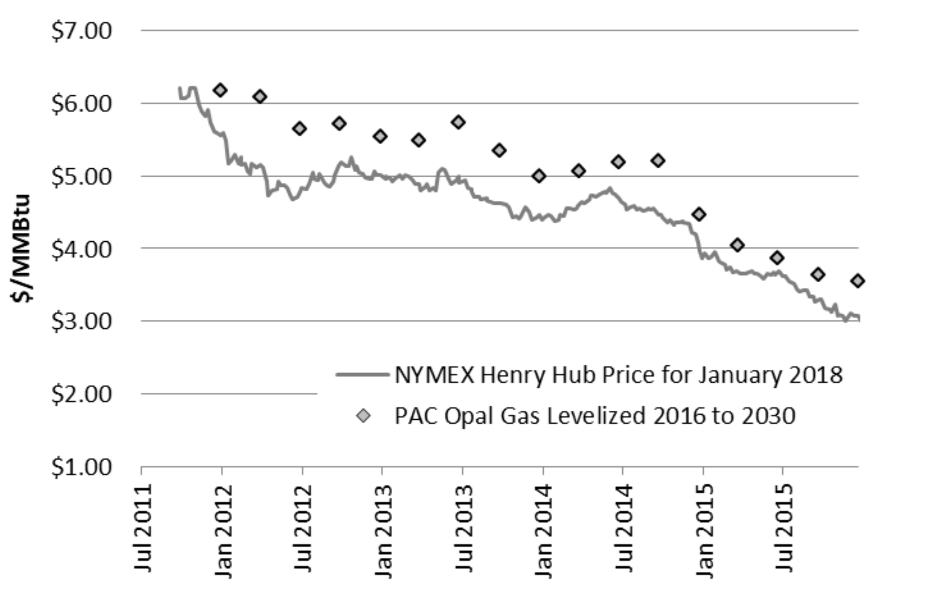
Q Please elaborate.

A PacifiCorp provided seventeen long-run OFPC generated between December 2011 and December 2015. The 2016 Washington general rate case examined the

[14] *Id.* at Link/22:8-13.
[15] *Id.* at Link/23:12-13.
[16] Author's calculation.

Bridger SCR project.[17] For that proceeding, I cited market forward projections of Henry Hub gas prices for January 2018—effectively, what the market thought gas prices would be in January 2018—over that same time period. Plotting the two together, it shows PacifiCorp's levelized Opal gas forecast (2016-2013) actually followed the near-term market projection for gas prices quite closely, with an offset (Figure 1).

Figure 1. PacifiCorp nominal levelized cost of Opal gas (2016-2030) from OFPC between December 2011 and December 2015, and NYMEX market forwards for January 2018.



The relationship between this compressed version of long-term forecasts and the market's projection of 2018 gas prices is remarkably high. In fact, <u>more than 96</u>

[17] *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, a Division of PacifiCorp, Respondent,* Docket No. UE-152253 (Wash. U.T.C.).

percent of the variance in PacifiCorp's "nominal levelized cost of gas" for the years 2016-2030 can be explained by changes in short-term market projections.[18]

While Mr. Link gave the impression that the long-term price forecasts are critical to his ability to determine whether the SCRs at Bridger were actually economic, the fact that a large fraction of the gas price is based on short-term projections, and even the long-run fundamentals closely reflect near-term market price changes shows that he severely overemphasized the importance of a single missing projection on December 1, 2013.

Q Mr. Link noted that for the forecasted period of 2016-2030, "two of th[e] three [long-term] price forecasts are well above the break-even levelized Opal natural gas price" at $4.85/MMBtu.[19] What is your response to Mr. Link's comment?

A Mr. Link's characterization that two of the forecasts were above the break-even point at which the SCRs were no longer in the best interests of customers is disingenuous. What actually matters is the directionality of the forecasts relative to a prior period.

As shown in Confidential Table 1 below, [redacted] forecasts were consistently on the low end, while the [redacted] forecasts were on the high end.[20] When [redacted] released its earlier August 2013 forecast, it was below PAC's breakeven

[18] R-squared factor, based on information shown in Figure 1. Compares nominal levelized cost of gas at Opal hub for period 2016-2030 at every OFPC from January 2012 to December 2015 against two-week average NYMEX Henry Hub around same dates, as projected in January 2018.
[19] PAC/2300 at Link/25:11-12.
[20] Data from Attachments "Attach Sierra Club 7.2-1 PROPRIETARY CONF,," and "Attach Sierra Club 7.2-2 PROPRIETARY CONF" to PacifiCorp Response to Sierra Club Data Request 7. 2.

point. When [redacted] then released its later [redacted] forecast, it remained below PAC's breakeven forecast—and had fallen by [redacted] on a levelized basis. When [redacted] released its May 2013 forecast, it was above PAC's breakeven forecast, as was its October 2013 forecast. And yet it also fell by [redacted] during that window. [redacted] forecasts, which the Company stated it did not have access to until December 11, 2013 (a week and a half after the FNTP)[21] were also consistently on the higher end, but also fell by [redacted] from just September 2013 to October 2013.

Confidential Table 1. Nominal levelized cost of gas at Opal hub (2016-2030) from third-party vendors used to inform OFPC, and PacifiCorp OFPC.

	Sept. 2013 OFPC[22]	Dec. 2013 OFPC[23]	Change
[redacted][24]	$[redacted]	$[redacted]	[redacted]
[redacted][25]	$[redacted]	$[redacted]	[redacted]
[redacted][6]	$[redacted]	$[redacted]	[redacted]
PacifiCorp	$5.35	$5.00	-6.6%

Thus the two forecasts PacifiCorp verifies it had access to by December 1, 2013 showed a downward trend in gas prices, consistent with the short-term commodity market forecasts. This downward trend was clearly apparent to Mr. Link by December 30, 2013—and would have been apparent at the beginning of December as well, despite the absence of the last long-term forecast.

[21] PAC/2300 Link/25:17
[22] Data from Attachments "Attach Sierra Club 7.2-1 PROPRIETARY CONF" to PacifiCorp Response to Sierra Club Data Request 7.2.
[23] Data from Attachments "Attach Sierra Club 7.2-2 PROPRIETARY CONF" to PacifiCorp Response to Sierra Club Data Request 7.2.
[24] Dated August 2013 and November 2013, respectively.
[25] Dated May 2013 and October 2013, respectively.
[26] Dated September 4, 2013 and October 10, 2013

In short, the lack of the third independent long-term gas price forecast should have signaled the need for a new gas price forecast in the days leading up to the Bridger SCR FNTP. Had PacifiCorp elected to create such a forecast, it would have seen that the value of the SCRs had declined substantially from even September 2013.

Q Mr. Link critiqued your assessment that gas price forecasts were dropping steadily from 2011 through the time the Company issued the FNTP to proceed with the Bridger SCRs at the close of 2013, stating "its methodology would show gas prices eventually reaching zero and then becoming negative."[27] Is it your position that PacifiCorp or any other utility should conduct forward looking planning using price forecasts derived on a long-term linear trend?

A No, of course not. I provided the assessment to show that in 2013, PacifiCorp should have approached its forecasts with extraordinary caution. My assessment was, in fact, provided as a direct response to Mr. Link's assertion in his opening testimony that gas prices from 2002 through 2012 were meaningful for assessing forward-looking prices.[28]

An assumption that gas prices would spring back and continue to support coal plant investments had been shown to be a consistently inaccurate assertion, even by the Company's own public statements at the time, as I discussed in my opening testimony.

[27] PAC/2300 at Link/29:1-2.
[28] PAC/700 at Link/104:13-105:3, Figure 14.

Q **Mr. Link critiqued the fact that you did not assess the Company's non-base case gas forecasts, suggesting that you have failed to recognize uncertainty. How do you respond?**

A Mr. Link presented a highly inconsistent view. Sensitivities and uncertainty boundaries are important mechanisms for understanding risk, but at some point the decision becomes binary—a choice is made one way or another. And the Company makes its decisions on the basis of its base forecasts.

Specifically, as Mr. Link noted in his opening testimony, when assessing low gas prices, the outcome was "$285 million unfavorable for the SCR emission control systems" at Bridger 3 & 4.[29] And yet when discussing the <u>actual</u> decision the Company made, Mr. Link was unequivocal: "the Company knew that as long as the natural gas price remained above the breakeven point . . . the SCRs were superior to natural gas conversion."[30] His assertion that base-case conditions were binding is repeated throughout his testimony.[31]

All analysts in the energy industry recognize the uncertainty associated with an increasing number of energy commodities, gas prices among them. But Mr. Link's focus on my lack of discussion around gas price uncertainty is a red herring. The Company's decision was made on the basis of its September 2013 base case forecast.

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[29] *Id.* at Link/100:3-4.
[30] PAC/2300 at Link/29:8-9.
[31] PAC/700 at Link/107:3-8, Link/108:8-11.

3. SIERRA CLUB DID NOT "DOUBLE COUNT" FINAL RECLAMATION CONTRIBUTIONS COSTS AT THE BRIDGER COAL MINE

Q Mr. Ralston accused Sierra Club of "double counting" final reclamation contributions at the Bridger Coal Company, and overstating the extent that a new mine plan, created in October 2013, would have impacted the Company's SCR decision at Jim Bridger.[32] Can you provide some clarity on the issue?

A Yes. As I showed in my opening testimony, the Company acquires a substantial fraction of its coal at Jim Bridger from the adjacent Bridger Mine operated by Bridger Coal Company ("BCC"), an entity entirely owned by PacifiCorp and Bridger co-owner, Idaho Power.[33] I demonstrated that in early 2013, the Company found degraded coal qualities that caused it to re-evaluate the efficacy of the underground portion of that mine,[34] ultimately resulting in a new mine plan, produced in October 2013. The new mine plan abandoned prior plans to expand the newer underground mine, and instead focused on expansion of surface operations. This new mine plan, which post-dated Mr. Link's final September 2013 back-of-the-envelope re-assessment of the Bridger SCRs[35] had two distinct impacts: first, it materially increased the projected cost of coal received at Jim Bridger over at least the next decade; secondly, it reduced the need for an

[32] PAC/2600 at Ralston/4:9-11; Ralston/9:17-18; Ralston/14:9-10.
[33] Sierra Club/100 at Fisher/8:12- 9:4.
[34] *Id.* at Fisher/33:11-34:7, Fisher/37:7-38:17.
[35] PAC/700 at Link/107:6-13.

accelerated surface closure should the Company elect to cease coal operations at Jim Bridger 3 & 4 instead of installing the SCRs

In a prior case before the Washington Utilities and Transport Commission ("WUTC"), Mr. Ralston estimated that the value of the SCRs would have degraded by $31 million due to the October 2013 mining plan at BCC.[36] And despite his attempts to muddy the record and attribute the $31 million modification to Sierra Club,[37] Mr. Ralston generated and testified to that estimate before the WUTC.

In my opening testimony, I testified that the $31 million degradation in the value of the SCRs due to the new mining conditions at BCC represented a floor, not a ceiling. I testified that Mr. Ralston's $31 million degradation likely did not include an adjustment to the final reclamation costs associated with the gas conversion of two Bridger units, an adjustment which would have resulted in an approximate $28.3 million degradation to the value of the Bridger SCR projects, or a total degradation of $59.3 million.[38]

Here I *affirm* that Mr. Ralston's $31 million degradation due to the October 2013 mine plan at BCC did *not* include any adjustment to coal reclamation costs, and thus my initial $28.3 million increment—or a total adjustment of $59.3 million—is warranted.

[36] *See* Exhibit Sierra Club/108 Confidential Rebuttal Testimony of Dana Ralston, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, Respondent*, Docket No. UE-155253, at 8:14-15 (Wash. U.T.C. Apr. 2016).
[37] PAC/2600 at Ralston/10:4-10.
[38] *Id.* at Ralston/4:9-11.

Q How did Mr. Ralston initially arrive at a $31 million increase in the cost of operating four units at Jim Bridger due to the new October 2013 mine plan?

A Mr. Ralston used new variable and capital costs of mining at BCC to estimate a revised cost of operation under the scenario that all four units of Jim Bridger continued burning coal into the indefinite future, the four-unit scenario. In that scenario, he estimated that the cost of providing coal to all four units of Jim Bridger would increase by $[redacted] on a present value basis,[39] or an increase of 2.6 percent.[40] Mr. Ralston then applied this 2.6 percent cost increase to the scenario in which only two units continue coal-fired operations, estimating that in the two-unit scenario, costs might have increased by $[redacted],[41] And since costs increased in both the four-unit scenario and two-unit scenario in Mr. Ralston's estimation, the value of the SCR was only degraded by $31 million.

Q Did Mr. Ralston perform a robust two-unit scenario to assess how the new mine plan impacted the case where two units converted to gas or were retired?

A No. Instead, Mr. Ralston just used a flat multiplier derived from his four-unit analysis modification. I critiqued his lack of a two-unit analysis in my opening testimony.[42]

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[39] Exhibit DR-2C to the Direct Testimony of Dana Ralston in UE-152253 (Wash. U.T.C.) [hereinafter "UE-152253 Exhibit DR-2C") (provided as a confidential attachment to Sierra Club Data Request 1.8(c)) (attached as Exhibit Sierra Club/401).
[40] *Id.*; PAC/2600 at Ralston/14:7-9.
[41] Sierra Club/401, UE-152253 Exhibit DR-2C. *See also* Exhibit DR-3C to the Direct Testimony of Dana Ralston in UE-152253 (Wash. U.T.C.) (provided as a confidential attachment to Sierra Club Data Request 1.8(c)) (attached as Exhibit Sierra Club/402).
[42] Sierra Club/100 at Fisher/42:1-2.

Q What information was missing because the Company never conducted a two-unit scenario?

A Critically, Mr. Ralston failed to assess the value of avoiding accelerated remediation at the surface mine in a revised two-unit scenario. As I noted in my opening testimony, the new mine plan was significant in that it contemplated a total move to surface mining operations[43]—a decision which would have had tremendous impacts on a two-unit scenario. Specifically, the Company had initially assumed that if two Bridger units ceased burning coal, it would seek expedient closure of the surface mine, accelerating surface mine remediation costs. Alternatively, if all four units remained in service, it could defer the remediation costs. The value of this closure deferral alone amounted to $28.3 million in favor of retaining all four Jim Bridger units—and subsequently building the Bridger SCRs.

Mr. Ralston agreed that a revised two-unit analysis should have removed the increased costs associated with accelerated remediation,[44] but implied that his analysis already included such an adjustment.[45] He is incorrect. No such adjustment was made in his $31 million degradation value.

[43] *Id.* at Fisher/39:13-40:2
[44] PAC/2600 at Ralston/13:13-16.
[45] *Id.* at Ralston/13:15-16 ("this cost decrease is only one component of the overall total differential between the two-unit and four-unit analysis").

Q Did Mr. Ralston offer a new adjustment to his coal costs?

A Yes. In reply testimony, Mr. Ralston now seeks to once again re-quantify the difference in coal costs resulting from the October 2013 mine plan, resulting in a $16.7 million differential.[46]

Q Did Mr. Ralston support his re-adjustment through work papers?

A No. Sierra Club requested that Mr. Ralston provide work papers supporting his assertion that I had double-counted mine remediation costs,[47] and work papers supporting his asserted reduced adjustment.[48] Instead, the Company provided a hodgepodge of Excel spreadsheets, which ultimately appear to be the basis of his $31 million adjustment as presented before the WUTC,[49] and a citation to his confidential exhibit PAC/2603, a PDF file with unsourced numbers and no clear relationship to exiting work papers or known data that the Company has prior released on this matter.

The fact that Mr. Ralston has once again re-adjusted his estimate to assert what the Company could have known in late 2013, has provided two conflicting estimates of an adjustment, has completely failed to substantiate a demonstration of double counting, and has provided no evidence for its cost re-adjustment, tells me that the Company is simply seeking to downplay an otherwise important element of Jim Bridger. But the facts are clear: in mid-2013, conditions changed

[46] PAC/2600 at Ralston/13:21-22.
[47] PacifiCorp Response to Sierra Club Data Request 9.1. All public data responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/403.
[48] Sierra Club/403, PacifiCorp Redacted Response to Sierra Club Data Request 9.5(c)).
[49] *See* Attachments "Attach Sierra Club 9.1 CONF" to PacifiCorp Response to Sierra Club Data Request 9.1. Attachment "Bridger Summary Analysis.xlsx, tab "PAC – Summary" is attached as Exhibit Sierra Club/404.

substantially at the Bridger Mine—enough to have lasting impacts on the Company's elections about how it will fuel Bridger in the future—and the Company failed to take these considerations into account when it proceeded in moving forward on the Bridger SCRs.

Q Mr. Ralston testified that "in the fall of 2013 . . . third-party coal costs . . . actually decreased . . . relative to the third-party costs assumed in the SCR analysis."[50] What was the change in third-party costs relative to the change in costs from BCC?

A Costs at BCC increased by anywhere from 2.6 percent[51] to [redacted] percent[52] from January 2013 to October 2013. However, the third-party coal costs only decreased by [redacted] percent[53]—nearly a full order of magnitude less than the cost increase at BCC.

Coal from the third-party (presumably Black Butte) represents only a fraction of the overall coal consumed at Jim Bridger. Thus, the savings realized at the third-party provider were relatively insignificant relative to the cost increase realized at BCC.

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[50] PAC/2600 at Ralston/11:10-12.
[51] *Id.* at Ralston/11:1.
[52] PAC/2603.
[53] *Id.*

4. THE COMPANY DEEPLY MISCHARACTERIZED THE VALUE OF DEFERRED JIM BRIDGER 3 & 4 RETIREMENT IN 2020/2021

Q Mr. Link responded to a critique from CUB that the Company failed to assess a 2023/2024 retirement for Jim Bridger 3 & 4 in lieu of the SCR projects, by claiming that the Company did in fact run similar scenarios. What does Mr. Link claim?

A Mr. Link testified that "the 2013 IRP analysis did consider early retirement [of Jim Bridger 3 & 4] in 2020 and 2021 and the SCRs remained the least cost alternative."[54] He initially followed this statement with the claim that "when the SO model was forced to retire Units 3 and 4 early, the model added a new natural gas resource in 2017, which caused the PVRR(d) to be $588 million in favor of the SCRs."[55] Such testimony was a deep misrepresentation of two entirely separate analyses run by PacifiCorp, neither of which tested CUB's hypothetical.

Mr. Link's testimony implied that in the 2013 IRP—a process by which this Commission has some level of oversight—the Company ran an analysis to assess 2020/2021 retirement of Jim Bridger 3 & 4 as an alternative to building the SCRs, and that the outcome of that analysis was $588 million more expensive than the SCR alternative. This was entirely erroneous.

Q Has Mr. Link since corrected his error?

A Yes. In discovery submitted on June 29, 2020, Sierra Club challenged the Company to identify where the $588 million benefit was identified in 2013 IRP.

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54 PAC/2300 at Link/15:19-21.
55 *Id.* at Link/15:21-16:2.

In response, the Company acknowledged that it had erred, referencing a completely different analysis.[56] The Company acknowledged that the 2013 IRP found that the 2020/2021 retirement of Jim Bridger 3 & 4 was only $174 million more costly than the SCR—on par with the cost of gas conversion.

On July 9, 2020 Mr. Link submitted errata testimony correcting his error.

Q Please explain why Mr. Link's error regarding the cost of later retirement was important in this proceeding.

A The $588 million value first cited by Mr. Link does not appear in the 2013 IRP at all, but was rather presented before the Wyoming Public Service Commission ("WPSC"). The value appeared in Mr. Link's rebuttal to Sierra Club and Wyoming Industrial Energy Consumers ("WIEC") in PacifiCorp's CPCN before that commission,[57] and was provided in confidential testimony just three weeks prior to hearings.[58] In that testimony, Mr. Link briefly testified that "[w]hen Jim Bridger Units 3 and 4 are forced to retire early the SO Model adds a 597 MW combined cycle unit located in Southern Utah in 2017. As compared to an early

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[56] Sierra Club/403, PacifiCorp Response to Sierra Club Data Request 7.3.
[57] *See In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming*, Docket No. 20000-418-EA-12, Rebuttal of Mr. Rick Link on Behalf of Rocky Mountain Power, at 45:1-11 (Wyo. P.S.C. Mar. 2013)2013) [hereinafter "WY CPCN Link Rebuttal"] (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.1(g) (attached as Exhibit Sierra Club/405).
[58] Rebuttal in WPSC 20000-418-EA-12 was filed on March 4, 2013, with confidential testimony arriving by hard copy a few days later. Hearings on 20000-418-EA-12 were held on March 26, 2013. As a practical matter, it is extremely challenging to discover, assess, and provide meaningful cross examination on a new analysis presented fewer than three weeks prior to hearings. Ironically, PacifiCorp witness Mr. Richard Vail raised the same concern with this instant docket, stating that if "new issues [are raised] on rebuttal, other parties to the proceeding will not be able to provide any cross-answering testimony and PacifiCorp will be limited to one round of testimony to respond to new issues." PAC/2800 at Vail/3:3-6. In the Wyoming CPCN, PacifiCorp's new analyses were presented on rebuttal with <u>no</u> opportunity to respond.

retirement alternative, the PVRR(d) is $588 million in favor of the Jim Bridger Units 3 and 4 SCR investments."[59] His Wyoming testimony provided no details, supporting exhibits or work papers. The $588 million benefit found by Mr. Link in the Wyoming CPCN proceeding was for a very different scenario than that requested by CUB, and then portrayed by Mr. Link. Rather than looking at a retirement in 2023/2024 or even 2020/2021 as Mr. Link implied, the Company's $588 million value came from a scenario that looked at the retirement of Jim Bridger 3 & 4 in 2015/2016.

Q Mr. Link corrected his testimony to state that the Company assessed a 2020/2021 retirement in the 2013 IRP as an alternative to the Bridger SCRs. What is notable about Mr. Link's reassessment?

A The most notable item is that the value presented in Mr. Link's reassessment of a later retirement, as presented in the 2013 IRP, is *substantially* lower than the later retirement scenario presented by the Company in the contemporaneous Wyoming CPCN.

The Company presented a scenario in Confidential Volume III of the 2013 IRP which assessed the retirement of Jim Bridger 3 & 4 in 2020 and 2021, respectively, rather that the installation of the SCRs in 2015 and 2016. The outcome of that analysis was that early retirement was only $174 million more expensive than the SCR projects,[60] primarily as a result of a new gas combined

[59] Sierra Club/405, WY CPCN Link Rebuttal at 45:8-11.
[60] PacifiCorp 2013 Integrated Resource Plan, Confidential Volume III, at 10-11, 13, Table V3.12 (Apr. 30, 2013) [hereinafter "2013 IRP Confidential Vol. III"], (provided as discovery in response to Sierra Club 1.2) (attached as Exhibit Sierra Club/406). Note that PacifiCorp renders the $174 million value non-confidential

cycle unit added in 2022.[61] The cost of the alternative retirement schedule here was radically lower than the value testified to by Mr. Link in his direct[62] and pre-correction reply testimonies,[63] and is actually slightly *less* costly than the Company's contemporaneous assessment of converting the units to gas as an alternative form of compliance, at $183 million.[64]

The Wyoming CPCN rebuttal, filed March 3, 2013, and the 2013 IRP, filed April 30, 2013, were effectively contemporaneous, and relied on the same projection of gas prices.[65]

Q What do you conclude from the discrepancy between the value asserted by Mr. Link and the value actually shown in the 2013 IRP?

A The fact that the retirement of the Jim Bridger 3 & 4 units slightly later (2020/2021 vs. 2015 / 2016) resulted in such radically lower costs ($174 million, rather than $588 million)[66] demonstrated that CUB's thesis that a later firm retirement could have been cost competitive was likely valid.

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in response to Sierra Club Data Request 7.3(a), and in errata testimony. *See* ERRATA to PAC/2300 at Link/16:1-3.

[61] Sierra Club/406, 2013 IRP Confidential Vol. III, Appendix V3-D at 34.

[62] PAC/700 at Link/109:16-110:3.

[63] PAC/2300 at Link/15:19-16:2.

[64] PAC/700 at Link/98:8-10; 2013 IRP Confidential Volume III at 9, Table V3.9.

[65] According to Mr. Link's testimony in WPSC 20000-418-EA, the rebuttal assessment relied on the Company's September 2012 OFPC. Sierra Club/405, WY CPCN Link Rebuttal at 2:4-6).The 2013 IRP also relied on the September 2012 OFPC. *See e.g.,* Ex. Sierra Club/406, 2013 IRP Confidential Vol. III at 9 Table V3.9.

[66] Note that both values were made public by Mr. Link in his errata testimony. See ERRATA PAC/2300 at Link/16:1-3.

Q Did the Company assess a 2023/2024 Bridger retirement as an alternative form of compliance, as recommended by CUB?

A No. In the 2013 IRP, the Company claimed that the Jim Bridger 3 & 4 SCRs crossed what it perceived as EPA's [redacted] a window encompassing CUB's recommended timeline. However, the Company also claimed that [redacted][68] offering that it was a "[redacted][69]

Q Do you have an opinion on what the analytical outcome would have been for a 2023/2024 retirement as opposed to a 2020/2021 retirement as alternative compliance?

A Yes. The primary driver of cost in these "retirement" scenarios was the timing of the replacement capacity resource. A 2015/2016 retirement was much more expensive than a 2020/ 2021 retirement because the earlier date required an immediate investment in a large gas-fired power plant, while the later retirement date allowed that same cost to be deferred, thereby reducing the cost of the alternative. By extension, deferring a capacity addition to 2023/2024 would have likely reduced the cost of a later retirement scenario yet further.

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[67] Sierra Club/406, 2013 IRP Confidential Vol. III at 11, Appendix V3-D.
[68] *Id.*at 11.
[69] *Id.* at 11, n.8.

Finally, the cost of alternatives became competitive relative to the SCR projects in the weeks prior to signing the FNTP. I hypothesize that had the Company actually assessed a 2020/2021 alternative compliance pathway in the days leading up to the FNTP, it would have found a substantially lower, or negative, differential, due to the markedly lower gas price forwards in late 2013.

Q Did the Company propose to work with EPA on a 2020/2021 retirement date as a form of alternative compliance?

A No.

Q Did the Company propose to work with EPA on a 2023/2024 retirement as a form of alternative compliance?

A No.

Q In the Wyoming CPCN, Mr. Link testified that "gas conversion, while unfavorable to the SCR investments . . . is . . . favorable to early retirement."[70] Did the Company test any compliance alternative in which the Bridger units were converted to gas at a firm later date?

A No.

5. THE COMPANY FAILED TO SHOW THAT LARGE TRANSMISSION ADDITIONS WERE NOT AVOIDABLE WITH THE RETIREMENT OF JIM BRIDGER 3 & 4

Q Mr. Link responded to Staff's critique that the Company did not assess the value of avoided transmission when reviewing the value of the Bridger 3 & 4

[70] Sierra Club/405, WY CPCN Link Rebuttal at 45:11-13.

SCRs by claiming that the Company did so in response to your testimony in the Wyoming CPCN. First, please provide some background.

A During the Company's request for approval of the Jim Bridger SCRs before the Wyoming and Utah Commissions, Sierra Club raised a concern that certain elements of the proposed Gateway West transmission project, specifically the segment from Bridger to Populus (Idaho), could be largely avoided or deferred if the Company retired some or all of Jim Bridger power plant. In the Wyoming proceeding, I recommended that:

> [I]f one or more units at Jim Bridger are retired in the next few years, this would open several hundred MW of capacity on the existing lines connecting Jim Bridger and Populus, potentially allowing the Company to defer any immediate or impending investments in the segment connecting those two substations, and to points beyond [to the west and south] as well. If replacement generation and capacity is sited closer to the Utah or Oregon load centers, the Company may be able to further relieve other constraints.[71]

I provided evidence that the Company's modeling, which universally assumed that the segment would be built, assessed a cost that was, in theory, avoidable—and in avoiding that segment, customers could still realize the benefits of new wind generation in Wyoming, but not be burdened with the very high costs of new transmission.

Claiming to be responsive to my concern—and that of Wyoming Industrial Energy Consumers ("WIEC")—Mr. Link ran a scenario which he described in

[71] *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming*, Docket No. 20000-418-EA-12, Direct Testimony of Jeremy Fisher on Behalf of Sierra Club, at 21:14-20 (Wyo. P.S.C. Feb. 1, 2013) (redacted version attached as Exhibit Sierra Club/407).

rebuttal testimony in that case, and reiterated here. He testified that "the Company conducted a sensitivity study that removed the Energy Gateway transmission investments and Wyoming wind resources that were able to interconnect because of Energy Gateway from both the SCR and gas conversion alternative model runs," which in turn resulted in a slightly higher value of $230 million favorable to the Bridger SCRs.[72]

Mr. Link used the results of that analysis to claim that avoiding transmission would not provide savings to customers in association with the Bridger SCR projects.

Q Did the Company actually seek to alleviate your concern that transmission from Bridger towards load centers should be considered avoidable in the Wyoming CPCN?

No. In fact, the Company sought to dismiss the concerns out of hand. Mr. Teply, testifying on behalf of the Company flatly denied that the issue had any bearing on the Company's considerations:

> Q. Are the Company's current plans for future Energy Gateway transmission project segments at issue in this case?
>
> A. No.
>
> Q. Is the Jim Bridger Units 3 and 4 SCR Project decision-making process under review in this docket dictated by the future segments of the Energy Gateway transmission project?
>
> A. No.[73]

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[72] PAC/2300 at Link/16:12-17.
[73] *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And*

Q **Was Mr. Link's rebuttal assessment in the Wyoming CPCN in any way responsive to your stated concern in 2013, or Staff's concern today?**

A No. In fact, Mr. Link's response was, and remains, non-responsive. Mr. Link made a substantial lapse in translating our concern to his modeling platform: he modeled both the retrofit and retirement scenarios as if the Gateway West project was not built.[74]

The point of assessing avoidable transmission is that the projects should be avoidable in conjunction with the retirement of Jim Bridger, not in parallel. Specifically, what Mr. Link should have analyzed was whether there were savings associated with avoiding or downscaling certain segments of the transmission line without jeopardizing the relatively low cost wind projects. Table 2 shows the scenarios that PacifiCorp failed to assess.

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4 Located Near Point of Rocks, Wyoming, Docket No. 20000-418-EA-12, Rebuttal Testimony of Mr. Chad Teply on Behalf of Rocky Mountain Power, at 22:6-12 (Wyo. P.S.C. Aug. 2013) (excerpt attached as Exhibit Sierra Club/408).

[74] Sierra Club/403. PacifiCorp Response to Sierra Club Data Request 8.2(c). "Confirm or deny: The avoided Energy Gateway scenario was applied to the base case, which included the Jim Bridger SCR retrofits." "Confirmed."

Table 2. Transmission and wind scenarios examined by PacifiCorp, compared against the scenario not examined by Mr. Link.

	JB 3 & 4 SCRs	**JB 3 & 4 Conversion**	**JB 3 & 4 2020/2021 Retirement**	**Benefit of SCR projects**
Build Wyoming Wind Projects <ins>and</ins> Gateway West, JB gas conversion	Base Case	Base Case		$183 million[75]
Build Wyoming Wind Projects <ins>and</ins> Gateway West, JB retirement	Base Case		2013 IRP	$174 million[76]
Do not build Wyoming Wind Projects <ins>or</ins> Gateway West	Sensitivity in WY CPCN	Sensitivity in WY CPCN		$230 million[77]
Build Wyoming Wind Projects, downscale Gateway West from Bridger to Populus	*NA*	**Not assessed**	**Not assessed**	**Not assessed**

Q Were PacifiCorp to compare the cost of a scenario where Bridger is retired and both the transmission and wind projects were removed, against the Bridger SCR retrofit base case, would you consider that an adequate analysis?

A No because it would still fail to address the question posed here. Sierra Club's and Staff's concerns are whether the transmission project could have been downsized or certain segments avoided—and the associated wind projects—were cost effective. PacifiCorp's modeling has consistently shown that incremental wind is highly cost effective, to the extent that it defrays some of the cost of building additional transmission. As a result, comparing a scenario in which Gateway transmission and the wind projects are avoided <ins>and</ins> Jim Bridger is retired against

[75] PAC/700 at Link/98:9.
[76] ERRATA PAC/2300 at Link/16:1-3 (redline version).
[77] ERRATA PAC/2300 at Link/16:17.15 (clean version).

a scenario in which all of these capital projects go forward is nothing more than an apples and oranges comparison. In short, Mr. Link did not provide a meaningful or transparent response to the critique Sierra Club raised in the Wyoming CPCN, and the critique Staff raised in this case.

Q In 2013, did the Company agree that retirement of the Jim Bridger 3 & 4 units could reduce the need for the Bridger to Populus segment of the Gateway West project?

A Yes, but the Company's response to that testimony was evasive. Asked if the Company could avoid any Gateway West transmission investments with the retirement of Jim Bridger 3 & 4, the Company responded that:

> Retirement of Jim Bridger 3 and 4 would reduce the need to transport thermal resources westward between the proposed Anticline [Bridger] substation and existing Populus substations from Wyoming to the Company's load centers, but it would not avoid the need for more transmission capacity out of Wyoming. The Company's existing transmission system is highly constrained east of Bridger and limits the Company's ability to reliably transport low cost energy including existing and future thermal and renewable energy sources therein. Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West in that regard.[78]

It is worth breaking down this answer. First, the Company acknowledged that the retirement of Jim Bridger 3 & 4 would indeed reduce the need for transmission between Anticline, a proposed substation adjacent to Jim Bridger power plant, and Populus, a substation further west in Idaho. From Populus, PacifiCorp's

[78] Docket No. 20000-418-EA-12, PacifiCorp Response to Wyoming Industrial Energy Consumers Data Request 1.83 (Wyo. P.S.C. Sept. 13, 2012) (originally provided as Sierra Club Exhibit 317 in Docket No. 20000-418-EA-12) (attached as Exhibit Sierra Club/409).

Wyoming generation is sent to the Company's load centers in Utah (south) and Oregon (west).

But then the Company muddles its response by stating that the retirement would not avoid the need for more transmission capacity out of Wyoming, claiming that the system is constrained east of Bridger. But that constraint, east of Jim Bridger, is irrelevant to the potential for avoidable transmission. Finally, the Company's statement that retirements at Jim Bridger would not avoid Gateway West with regard to the constraint to the east of Jim Bridger is uncontested.

Q Why didn't Sierra Club seek additional clarity on the avoided transmission issue in the Wyoming CPCN?

A As I stated earlier, the Company's novel—and confidential—analysis assessing Bridger without Gateway West was provided just under three weeks prior to Wyoming's hearings, and did not represent a reasonable avoidable transmission scenario. The Company did not provide a reasonable avoidable transmission scenario in response to discovery.

Q Did Sierra Club raise a question regarding avoidable transmission from Gateway West within the 2013 IRP?

A Yes. In our final comments on the 2013 IRP in Oregon, Sierra Club commented that it was unable to resolve the issue of avoidable transmission with PacifiCorp in the Wyoming and Utah CPCNs,[79] and agreed with Staff's recommendation that

[79] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan,* Docket No. LC 57, Sierra Club Final Comments, at 5-6 (Ore. P.U.C. Jan. 10, 2014).

the Company be required to rigorously study the "savings of downsizing or avoiding transmission investments due to retirement of coal units."[80]

Q Did the Company present an assessment of the Jim Bridger retrofits or retirement scenario without Gateway West as part of the 2013 IRP?

A No.

Q Did the Company present a refined scenario of downsized transmission were Jim Bridger 3 & 4 retired, rather than retrofit, in the 2013 IRP?

A No, the Company provided no assessment of avoidable transmission in the 2013 IRP or IRP update.

Q How much money is potentially at stake concerning avoided transmission due to the retirement of Jim Bridger 3 & 4?

A In the Company's 2013 System Optimizer model for the Wyoming CPCN, [81] the segments from Jim Bridger to Populus are built in two near-term years ([redacted] and [redacted]), with capacities of [redacted] and [redacted] MW, respectively and at a cost of [redacted] million and [redacted] million, respectively. In comparison, Jim Bridger 3 & 4 are modeled as 345 and 350 MW resources, respectively.[82] At those magnitudes, either of the transmission projects could have been avoidable. Conservatively avoiding the first smaller [redacted] MW line, would have saved [redacted] million in [redacted],

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[80] *Id.*
[81] *See* Confidential Work papers of Mr. Rick Link for JB 3 & 4 SO Inputs and Outputs with Base Gas, Base CO2 (Coal Outputs) "TieBuild-C_M1209_16_OPC.out." Segments are marked "BridgerEast" to "PathCSouth," referencing the northern terminus of "Path C" at the Populus substation.
[82] *Id.* "StaFirmCap-C_M1209_16_OPC.out"

or roughly [redacted] million (excluding financing costs and taxes) on a present value basis in 2013.[83]

As part of the Gateway West project, PacifiCorp's model considered an additional [redacted] segment connecting Populus with Northern Utah.[84] That segment was modeled to carry [redacted] MW of capacity at a cost of [redacted] million, or an incremental [redacted] million in system savings in 2013.

Q Mr. Link testified that Sierra Club "abandoned" the avoided transmission issue, insinuating that you may no longer believe that transmission investments have been avoidable if Bridger were retired. Is that true?

A Not at all. Mr. Link, representing the 11th largest electric utility in the country,[85] is fortunate to have an abundance of staff, computing power, and other resources. Mr. Link may be under the impression that an intervenor's inability to fully scrutinize a complicated issue under a pressing schedule should result in utility commissions resolving the matter in the Company's favor.

In my opinion, PacifiCorp bore the responsibility to demonstrate that the SCRs at Jim Bridger 3 & 4, which functionally extended those units lives, did not preclude the opportunity to avoid large-scale transmission expenditures. And PacifiCorp did not make that showing in Wyoming, Utah, or in response to Staff in this proceeding.

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[83] Assuming a 7.15% discount rate.

[84] *See* Confidential Work papers of Mr. Rick Link for JB 3 & 4 SO Inputs and Outputs with Base Gas, Base CO2 (Coal Outputs) "TieBuild-C_M1209_16_OPC.out." Segments are marked "PathCSouth" to "UtahNorth."

[85] EIA, Annual Electric Power Industry Report, Form EIA-861 (2018) *available at* https://www.eia.gov/electricity/data/eia861/ (revenues from sales to ultimate customers).

6. THE COMPANY MISCHARACTERIZES ITS SUPPORT AND MOTIVATION TO BUILD AND OPERATE SCRS AT JIM BRIDGER

Q Mr. Owen testified that PacifiCorp "consistently opposed" SCRs at Jim Bridger and the Company was not the "source" of these expenditures, do you agree?

A No. For support, Mr. Owen provided a publicly available January 29, 2009 letter the Company sent to Wyoming DEQ stating that the Company was *opposed* to the installation of SCRs; advocating instead for a lower cost alternative for the units, i.e., so-called low NOx burners with overfire air (LNB and OFA).[86] What Mr. Owen omitted was on the [redacted] the exact dates that Mr. Owen testified the Company opposed but were ultimately carried out. To be clear, the Company [redacted]

[86] PAC/2504 at Owen/2.
[87] Letter from PacifiCorp Energy's William K. Lawson to Wyoming DEQ's David Finley, at 1 (Jan. 29, 2009) (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 9.6) (attached as Exhibit Sierra Club/410).
[88] *Id* at 2.

PacifiCorp's intentions to retrofit Bridger with SCRs pre-date the 2009 letters. In fact, in 2003, [redacted] Reviewing the Company's own documents, it is clear the Bridger SCRs were neither a surprise nor unwelcome.

Q Mr. Owen testified that once Wyoming DEQ issued its BART permit in 2009, the Company was under a legal obligation to install the 4 SCRs, do you agree?

A No. I am not a lawyer but Mr. Owen did not point to any Wyoming law specifying that PacifiCorp was legally required to begin planning to install SCRs at units 3 and 4 SCRs before EPA reviewed and acted upon Wyoming's regional haze plan. Instead, Mr. Owen referred to a 2010 settlement agreement as proof that the Company was legally bound. But that document makes clear that EPA's approval of the Wyoming regional haze SIP reflecting the terms of the settlement was a pre-condition of the settlement taking effect.[91] Mr. Owen also claimed

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[89] *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision,* Docket No. UE 246, Confidential Ex. Sierra Club/114, at Fisher/4 (Ore. P.U.C., June 20, 2012) [hereinafter "2003 PacifiCorp Control Report"] (attached as Exhibit Sierra Club/411); *See also*, *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision,* Docket No. UE 246 Confidential Ex. Sierra Club/115 (Ore. P.U.C. June 20, 2012) (attached as Exhibit Sierra Club/412).

[90] 2003 PacifiCorp Control Report at Fisher/4.

[91] PAC/2510 at Owen 4, 6(d)).

Wyoming DEQ refused to grant the Company leeway but that letter simply circled back and said the Company must adhere to the settlement; again, conditioned on EPA's final Regional Haze rule.[92]

Q Mr. Owen testified that you misapplied the BART timing regulations.[93] Was he correct?

A No. Mr. Owen provided an explanation on the difference between two EPA programs under the Regional Haze Rule: Best Available Retrofit Technology and EPA's Long Term Strategy process. Any distinction here is irrelevant. The point I made in my opening testimony was that the Company should not have begun making plans to retrofit Jim Bridger, let alone issue the FNTP, until it had assessed EPA's final federal implementation plan for Wyoming issued on January 30, 2014, irrespective of its details.

Mr. Owen testified that EPA's final Regional Haze determination required it to retrofit Bridger 3 and 4 within two years: in 2015 and 2016.[94] And based on a compressed schedule, it was forced to speculate what EPA might require in its final rule and issue the FNTP. What Mr. Owen failed to explain is why the Company did not request that EPA's impose the normal five-year BART deadline to install those major retrofits.[95] As I understand the process, EPA was acting

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[92] PAC/830.
[93] PAC/2500 at Owen/8:3-13.
[94] *Id.* at Owen/9:1-2.
[95] PacifiCorp filed suit in federal court challenging EPA's Wyoming FIP with regard to SCR requirements for its other units in Wyoming. The Company successfully obtained a stay of the FIP with respect to those other units, but it did not challenge or seek a stay of the EPA's decision to require the Jim Bridger SCRs. *See PacifiCorp v. EPA*, No. 14-9534 (10th Cir.) (filed March 31, 2014). PacifiCorp's motion to stay implementation of the FIP granted September 9, 2014. Implementation of the FIP remains stayed as of this writing.

under its authority to require *BART* controls. Had the Company not supported the 2015/2016 installation dates for units 3 and 4, it would have delayed the need to install SCRs until 2019.

7. SIERRA CLUB'S STANCE ON ROBUST ENVIRONMENTAL REGULATIONS IS ENTIRELY CONSISTENT WITH ITS STANCE ON COST RECOVERY IN THIS CASE

Q Mr. Owen argued that Sierra Club's consistent pressure on environmental regulators for more stringent emission controls[96] and deadlines[97] is inconsistent [98]with its stance that the SCRs should not have been installed on Jim Bridger. Is he correct?

A No. Mr. Owen appeared to be confusing two fundamentally different processes, both of which are important to Sierra Club as an entity representing the public interest: first, air quality agencies must require and enforce stringent pollution limits to protect human health and the environment; and second, utility commissions must ensure ratepayers are not held responsible for a corporation's interest in advancing unnecessary expenditures. These positions are not at odds. However, in PacifiCorp's view, ratepayer savings may only be achieved by degrading environmental protections. I'll explain below.

Sierra Club has a long established—and very public—practice of advocating for stringent environmental regulation at all levels of government. Stringent

[96] PAC/2500 at Owen/5:6-17.
[97] *Id.* at Owen/7:9-8:7.
[98] *Id.* at Owen/7:6-8.

environmental regulations reduce polluting air emissions, water effluent, and safeguard public health in numerous ways.[99]

However, once these safeguards are established, Sierra Club turns to the most cost-effective way to meet the rule of law. Unsurprisingly the most cost-effective way to meet environmental regulations may not entail installing expensive emission controls. The Jim Bridger SCR projects are such a case. Less polluting alternatives than “end of pipe” controls have been, and are, increasingly more cost-effective. It was also the case with hundreds of megawatts of other non-economic coal generation across the country which, when faced with the costs of internalizing decades of free emissions and water pollution, and a declining value of coal energy, elected to close.[100]

Q According to Mr. Owen, Sierra Club’s comments to EPA that SCRs were a cost-effective form of pollution control is inconsistent with its assertion that SCRs are not cost effective for consumers.[101] Can you clarify?

A Yes. Mr. Owen is again confusing two principles: EPA’s own cost effectiveness analysis to evaluate pollution controls to curb regional haze; and the cost effectiveness analysis utility commissions use to protect utility customers. Under the Regional Haze Rule, EPA established a protocol by which it would assess BART requirements for reducing visibility impairment in wilderness areas and

[99] *See, e.g.*, U.S. EPA, Progress Cleaning the Air and Improving People’s Health, *available at* https://www.epa.gov/clean-air-act-overview/progress-cleaning-air-and-improving-peoples-health (last accessed July 21, 2020).
[100] *See, e.g.* U.S. EIA, *Almost all power plants that retired in the past decade were powered by fossil fuels* December(Dec. 19, 2018), *available at* https://www.eia.gov/todayinenergy/detail.php?id=37814;U.S. EIA, *More U.S. coal-fired power plants are decommissioning as retirements continue.* , (July 26, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=40212.
[101] PAC/2500 at Owen/6:1-7:8.

National Parks. EPA evaluated various emission reduction solutions to find a plan that achieved the best visibility improvement while remaining "cost effective" on the basis of dollars per ton of pollution removed—i.e. technologies that could achieve significant visibility improvements at an acceptable cost per ton were considered cost-effective by EPA. Sierra Club's technical assessment using EPA's methodology agreed with EPA that SCRs at Jim Bridger would be cost effective on a dollars per ton basis as calculated under the Clean Air Act.

But even if pollution controls offer a high degree of public health protection for every dollar invested does not mean that pursuing that same outcome is in the best interests of ratepayers, because under utility commission methodology, the question is whether alternatives might provide customers with safe and reliable power but at a lower cost. In this case, it turns out that not installing SCRs and instead closing Jim Bridger would achieve a greater degree of pollution reduction, and reduce costs to consumers. And indeed, EPA has long recognized this type of tradeoff, and explicitly offers the opportunity to realize a near-term (not immediate) retirement in exchange for avoiding compliance costs. Such a tradeoff can be both cost effective for consumers, and achieve the emissions performance goals established by EPA's environmental regulations.[102]

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[102] There are examples of coal units shutting down or switching to gas as an alternative compliance path under the Regional Haze Rule (Apache Unit 2, Arizona (80 Fed. Reg. 19220 (Apr. 10, 2015); Naughton Unit 3, Wyoming (79 Fed. Reg. 5032, 5045 (Jan. 30, 2014)); Muskogee 4 & 5, Oklahoma (76 Fed. Reg. 81727 (Dec. 28, 2011)). And examples where a unit committed to a firm future shut down date in exchange for less expensive near-term controls (PGE Boardman, Oregon (2008 Oregon Regional Haze Plan at 154-156, 76 Fed. Reg. 38997 (July 5, 2011)); Transalta Centralia, Washington (Washington Department of Ecology, Order 6426 (2011).

Q In your opening testimony, you testified that PacifiCorp should have asked EPA for a federally enforceable five-year requirement under the Regional Haze rule,[103] allowing it to install SCR in 2019, rather than in 2015. Isn't Sierra Club's interest in environmental and public health better achieved through the most rapid compliance possible?

A Not always. Rushing to retrofit a coal plant can have adverse effects—both on ratepayers and the environment. In this case, PacifiCorp's rush to install SCRs at Jim Bridger 3 & 4, before EPA's requirements or even trying to work with EPA, meant that ratepayers were left with a large new capital project, and PacifiCorp eschewed an opportunity to eliminate substantial future air pollution through the cost-effective retirement of Jim Bridger 3 & 4. In fact, PacifiCorp now has an interest in protecting Jim Bridger 3 & 4 from earlier (still cost-effective) retirements because early retirement might put at risk its existing expenditures in those SCRs, as well as other capital projects. That interest in maintaining the plant, despite its poor forward-looking economics, is an adverse ratepayer and environmental outcome.

Q In a separate topic of his testimony, Mr. Owen also asserted that PacifiCorp knew by January 2014 that its cost of natural gas conversion for Jim Bridger Units 3 and 4 would have been significantly higher than assessed in 2013.[104] What is your response?

A This testimony appears to be just speculation on his part.

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[103] Sierra Club/100 at Fisher/27:16-18.
[104] PAC/2500 at Owen/16:8-15.

First, Mr. Owen did not work at PacifiCorp in 2014, so any belief by him about what the Company knew at that time would need to be based on some specific historical evidence, evaluation, or other documentation.

Second, when asked in data requests for source documents or calculations to back up his statement, Mr. Owen admitted that none existed.[105] Instead, he claimed that he reviewed bid evaluations for a separate proposal, a gas conversion of Naughton Unit 3, and more or less "guesstimated" a higher cost for gas conversion of the Bridger Units based on the Naughton documents.[106] Mr. Owen even attaches a percentage difference to his guesstimate,[107] despite having never calculated anything or even written anything down. PacifiCorp never solicited bids or evaluated a new cost for the Jim Bridger gas conversion in the time frame he describes, and Mr. Owen apparently did not do any evaluation that he can reproduce for the purpose of review or vetting, in this proceeding or otherwise.

Finally, Mr. Owen testified in response to discovery that "competitive bids [for the Naughton Unit 3 natural gas conversion EPC] were received by the Company in December of 2013."[108] Responses received any time after December 1st, 2013

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105 Sierra Club/403, PacifiCorp Response to Sierra Club Data Request 8.3(c)).
106 Sierra Club/403, PacifiCorp Response to Sierra Club Data Request 8.3(c) – 1st Supplemental
107 In his *post hoc* assessment, Mr. Owen estimates that the Naughton 3 gas conversion may have cost about 30 percent more than PacifiCorp originally anticipated (*see* Sierra Club Data Request 8.3(c) – 1st Supplemental). In testimony (PAC/2500 at Owen/16:14) and discovery response, he erroneously employs the term "order of magnitude" to describe the theoretical cost increase. To avert confusion, the term "order of magnitude" is reserved in both common and technical parlance to mean "ten times different than." To be clear, PacifiCorp did not understand in December 2013 that the costs of gas conversion could ten times higher than anticipated in the Bridger SCR analysis.
108 Sierra Club/403, PacifiCorp response to Sierra Club Data Request 8.3(c) – 1st Supplemental.

could not have informed the Company's decision to sign the FNTP, following the Company's own logic.[109]

Mr. Owen's speculation that the Company would have known that the costs of gas conversion would have been higher than estimated is speculative and unsubstantiated.

8. PACIFICORP'S PASS-THROUGH OF THE COSTS OF THE BRIDGER AND HAYDEN SCRS IN CALIFORNIA DOES NOT REFLECT A POSITIVE FORWARD-LOOKING VIEW OF THE COMPANY'S COAL PLANTS

Q Mr. Link, Mr. Owen, and Mr. Ralston point multiple times to the fact that the California Public Utility Commission ("CPUC") recently allowed the Bridger and Hayden SCRs into rates[110] as a demonstration that the projects were prudent. Can you provide some context?

A Yes. PacifiCorp serves approximately 45,000 customers in California,[111] accounting for just 1.3 percent of PacifiCorp's retail load,[112] and less than one third of one percent (0.3%) of California's retail load.[113] For years, PacifiCorp has

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[109] *See* PAC/2300 at Link/20:20-22 (. . . "is inappropriate because this information was not available to the Company when the FNTP was issued on December 1, 2013."); PAC/2300 at Link/26:19-20 (". . . the Company disputes the relevance of gas price forecasts received after December 1, 2013 . . .").
[110] PAC/2300 at Link/43:7-14; PAC/2500 at Owen/11:16-18; PAC/2600 at Ralston/3:20-Ralston/4:3, Ralston/43:2-7.
[111] *In the Matter of the Application of PACIFICORP (U-901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019,* Docket No. A.18-04-002, Application of PacifiCorp (U-901-E) for an Order Authorizing a General Rate Increase at 1 (Cal. P.U.C. Apr. 12, 2018) [hereinafter "PAC CPUC GRC Application"].
[112] PacifiCorp 2019 SEC Form 10-K, at 2, *available at* https://www.brkenergy.com/assets/upload/financial-filing/BHE%2012.31.19%20Form%2010-K_FINAL.pdf.
[113] EIA, Retail sales of electricity : California : all sectors : annual, *available at* https://www.eia.gov/opendata/qb.php?category=38&sdid=ELEC.SALES.CA-ALL.A (last accessed July 21, 2020).

operated under the radar in California. The last rate case offered by the Company had been filed in 2009,[114] and in the interim time, the Company had offered capital investments into rates in the form of eighteen consecutive and perfunctory "advice letters."[115] In early 2017, on the commission's own motion, the CPUC opened an investigation into PacifiCorp's inter-jurisdictional rates,[116] in preparation for a 2019 test-year rate case. Sierra Club intervened and provided testimony in the investigation, and the subsequent rate case.[117] Sierra Club's purpose in providing testimony was to provide broad context for the CPUC on PacifiCorp's practices, coal units, and (in particular) compliance with California's Emissions Performance Standard ("EPS"). While the Oregon Commission maintains active engagement in PacifiCorp's planning and rate practices, the same cannot be said for the CPUC's historic disengagement with a utility whose presence in California is relatively minor. It should be noted that PacifiCorp's California rate case, requesting a total rate increase of $1.06 million,[118] was presented and considered contemporaneously with Pacific Gas and Electric's

[114] *In the Matter of the Application of PacifiCorp (U-901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, Docket No. A. 09-11-015 (Cal.P.U.C.) (filed Nov. 20, 2009).
[115] To give some context to these advice letters in California, PacifiCorp's investment in Lake Side 2 gas-fired generating station, a $671 million project was described in a single short paragraph of a five-page pro-forma letter to the Commission on July 21, 2014 (Advice Letter 507-E). The Hunter baghouse—an $80 million project described in six pages of Mr. Teply's direct testimony in this case (PAC/800 Teply/37-43)—was described in two cursory paragraphs in that same advice letter. PacifiCorp took the position that these Advice Letters functioned as the sole opportunity to contest additions to rate base (Advice Letter 507-E attached as Exhibit Sierra Club/413).
[116] *Order Instituting Investigation to determine whether PacifiCorp (U901-E) engages in least-cost planning on a control area basis and whether PacifiCorp's Inter-Jurisdictional Cost Allocation Protocol results in just and reasonable rates in California*, Docket No. I.17-04-019 (Cal.P.U.C. Apr. 27, 2017).
[117] *In the Matter of the Application of PacifiCorp (U-901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019*, Docket No. A.18-04-002, (Cal. P.U.C. filed Apr. 12, 2018).
[118] PAC CPUC GRC Application at 1.

("PG&E") multi-billion bankruptcy following the 2017 and 2018 wildfire seasons.

Sierra Club made an assessment that the presentation of broad historical context on PacifiCorp and engagement in the EPS was of far greater consequence, in that case, than electing to follow the intensive analytical steps required to make a prudence argument against specific coal plant retrofits. To give some context, in this docket, Sierra Club has issued—and used— nearly fifty discovery questions, multiple meet-and-confer processes, and even a motion to compel discovery simply to provide a complete picture of the decision-making processes and factors surrounding the Bridger and Hayden SCR projects. Sierra Club is, uniquely, a multi-state intervenor in PacifiCorp's processes, but PacifiCorp has taken—and litigated—the stance that Sierra Club may not use confidential information it learns in one jurisdiction to inform its analytical or assessment processes in other jurisdictions. And since PacifiCorp has deemed much of its decision-making processes around coal retrofits confidential (or even highly confidential), we must generate our assessments of PacifiCorp's decisions from whole cloth each and every time we litigate an issue deemed confidential.

In the California proceeding, PacifiCorp placed Sierra Club in a difficult position: elect to not challenge the coal retrofits, and PacifiCorp would certainly shine a light on Sierra Club's lack of participation (as do Mr. Link and Mr. Ralston here[119]), or seek to inform the Commission about core elements of PacifiCorp's

[119] *See* PAC/2300 at Link/17:9-11 (with respect to certain transmission arguments); PAC/2600 at Ralston/43:2-7 ("Sierra Club subsequently abandoned its challenge to these investments in that proceeding.").

decision-making methods as an educational process, and almost certainly guarantee a loss on the strict grounds typically required for a prudence disallowance, but hope to improve California's oversight for future capital expenditures. Sierra Club took the later route.

Q According to Mr. Link, "Sierra Club's testimony in [the California rate] case was largely the same as here."[120] Is he correct?

A No. In the California rate case, Sierra Club elected to minimize its prudence arguments against the Bridger and Hayden SCRs, in order to center its case on providing the Commission and public information on how PacifiCorp operates. While the core case was similar, we had a limited opportunity to present a complete prudence case.

Instead, Sierra Club focused testimony on PacifiCorp's "alternative compliance" or waiver, under California's Emissions Performance Standard, which resulted in the Company to continuing to invest in coal plants as the state sought to meet rigorous emissions targets.

Q What was the ultimate outcome of the California 2019 rate case?

A As expected, the CPUC granted recovery of past investments. However, the CPUC also took a critically important step and revoked PacifiCorp's waiver of California's EPS, holding that "we consider review of PacifiCorp's investments in

[120] PAC/2300 at Link/43:10-11.

baseload generation necessary going forward and will no longer allow PacifiCorp alternative compliance."[121]

Q What is the impact of the removal of PacifiCorp's waiver of California's Emissions Performance Standard?

A Under California's EPS, investor-owned utilities may not invest in "long-term financial commitments" in baseload electricity generators with emissions over 1,100 lbs. carbon dioxide per MWh, or about a half ton per MWh—the emissions of a gas-fired plant. Also under the EPS, multi-state utilities which serve relatively few customers in California (i.e. PacifiCorp) were allowed "alternative compliance" by which they merely had to demonstrate that another state's commission (*e.g.* Oregon) required the utility to report its emissions in regulatory proceedings (the IRP). When the EPS was adopted, PacifiCorp proposed that it be allowed alternative compliance, and the CPUC effectively waived its participation. The rate case established that PacifiCorp had not been acting in good faith under that EPS in California, marked by the revocation of that waiver.

While the CPUC has yet to consider a request from PacifiCorp for adjustments to rates, under the newly revoked EPS waiver, a lay reading of the EPS "financial commitments" standard suggests that California may no longer allow recovery for either capital investments in coal (including ongoing capital) or multi-year coal supply agreements.

[121] *In the Matter of the Application of PacifiCorp (U-901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2019. And Related Matter*, Docket Nos. A.18-04-002 & 17-04-019, D. 20-02-025, at 51-52 (Cal. P.U.C. Feb. 6, 2020) (provided by PacifiCorp as Exhibit PAC/2515).

While it is unfortunate that Sierra Club did not have the resources to litigate a full prudence case in California, the CPUC's acceptance of past investments should not be construed as that commission's positive outlook on the Company's coal plants. Indeed, the CPUC put a firm end to that state's contributions to PacifiCorp's coal, providing forward-looking protections to California's PacifiCorp ratepayers.

Q Are there any other recent changes of note in other states with respect to the disposition of the Company's coal units?

A Yes. On July 17, 2020, PacifiCorp elected to settle a contemporaneous rate case before the Washington UTC.[122] As part of that stipulation, PacifiCorp agreed to accelerate the depreciation—and then remove from rates—Washington's ratable allocation of PacifiCorp coal by year-end 2023. The stipulation states, in part:

> 2. Accelerated Depreciation
>
> The Parties' stipulated revenue requirement includes the acceleration of depreciation for Colstrip Unit 4 and the Jim Bridger Plant to year-end 2023. Once Colstrip Unit 4 or the Jim Bridger Plant facilities are removed from the Company's revenue requirement, PacifiCorp will not seek to recover additional investments in those facilities in Washington rates.[123]

If approved, the Washington settlement stipulation would remove both Colstrip 4 and the Jim Bridger units from Washington customer rates after 2023. Notably, in the prior California 2019 rate case, PacifiCorp also requested accelerated

[122] *Wash. Util. & Transp. Comm'n v. PacifiCorp*, Dockets UE-191024, UE-190750, UE-190929, UE-190981, UE-180778 (Consolidated), Settlement Stipulation, ¶ 25 (Wash. U.T.C. July 17, 2020) (attached as Exhibit Sierra Club/414).
[123] *Id*. Paragraph 25.

depreciation for various coal units, but made no similar offer to ensure that once depreciated PacifiCorp's coal units would be removed from rates.

9. <u>THE COMPANY'S ASSESSMENT OF "MODEST" OR ROBUST RESULTS ARE SELF-SERVING AND INCONSISTENT</u>

Q How does Mr. Link characterize the Company's confidence in the value of the Bridger SCRs?

A Mr. Link testified that even when the benefit of the SCRs collapsed from a prior [redacted] million benefit in early 2012[124] to a $183 million in September 2012 and $130 million in late 2013, PacifiCorp remained confident that the SCRs were the "most economical environmental compliance option,"[125] and that the results provided a "reasonably sized 'cushion' in the PVRR(d) results."[126] Mr. Link expresses confidence that these results were quite robust.

Q How does Mr. Ralston characterize the erosion of value in the Bridger SCRs due to increasing costs of coal in October 2013?

A Mr. Ralston testified that the erosion in the value of the SCRs by $31 million in October 2013 was a "modest" change,[127] and insisted that it would not change the "substantial customer benefit of the Jim Bridger SCRs."[128]

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[124] *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming* Docket No.20000-418-EA-12, Direct Testimony of Mr. Rick Link, at 2:5. (Wyo. P.S.C. Aug. 2012) (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.1(g)) (refer to Exhibit Sierra Club/103).
[125] PAC/700 at Link/107:10-13.
[126] *Id.* at Link/103:7.
[127] PAC/2600 at Ralston/14:10-12.
[128] *Id.* at Ralston/14:12-13.

Even taking the Company's assessed value of the SCR projects—$130 million in September 2013[129]—a change in value of $31 million, representing a quarter of the value of the project, is not modest. Yet Mr. Ralston twice sought to minimize the $31 million difference as just "1.2 percent of the total $2.5 billion PVRR."[130] And while it is not clear how Mr. Ralston derived his $2.5 billion figure, such a comparison flies in the face of system planning. The overall value of a project is assessed on its own merits. Comparing a project to the overall size of PacifiCorp's multi-billion system[131] would immediately render nearly every capital project—even those of substantial size— "modest."[132]

But equally disturbing is that the Company sought to dismiss or marginalize results that cut against its favor while amplifying results that support its prior decisions. A degradation in the value of the SCRs from $[redacted] when the Company submitted its CPCN to the Wyoming PSC to $130 million just months prior to the decision to proceed is undoubtedly substantial. A further loss of value by $31 million is also substantial.

In late 2013 the Company held enough facts in evidence that undercut the economics of the Bridger SCRs that it should have sought to re-assess its decision in a meaningful process, including searching for other avoidable costs if the units were retired, seeking the opportunity to defer the projects until the federally

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[129] PAC/700 at Link/107:13.
[130] PAC/2600 at Ralston/4:8; *see also* PAC/2600 at Ralston/10:14.
[131] *E.g.*, PacifiCorp's 2019 IRP (OPUC Docket LC 70) indicates a bulk system cost for PacifiCorp's system of around $23 to $24 billion. *See* PacifiCorp, 2019 Integrated Resource Plan, Volume I, at 232, Table 8.4 and 8.5, *available at* https://www.pacificorp.com/energy/integrated-resource-plan.html.
[132] A $500 million project, compared against the present value system cost of PacifiCorp's system would only amount to 2.2% of system cost.

enforceable deadline, or seeking alternative closure dates that would obviate the projects. The Company did none of the above.

Q Does this conclude your reply testimony?

A It does.

Docket No. UE 374
Exhibit Sierra Club/401
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 401

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Exhibit DR-2C to the Direct Testimony of Dana Ralston in UE-152253 (Wash. U.T.C.)

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 402

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Exhibit DR-3C to the Direct Testimony of Dana Ralston in UE-152253 (Wash. U.T.C.)

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/403
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 403

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Selected Public Responses to Sierra Club Data Requests

Exhibit Sierra Club/403

Selected Public Responses to Sierra Club Data Requests

1. PacifiCorp Response to Sierra Club Data Request 7.3
2 PacifiCorp Response to Sierra Club Data Request 8.2
3 PacifiCorp Response to Sierra Club Data Request 8.3
4. PacifiCorp 1st Supplemental Response to Sierra Club Data Request 8.3
5. PacifiCorp Response to Sierra Club Data Request 9.1
6 PacifiCorp Redacted Response to Sierra Club Data Request 9.5

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Sierra Club Data Request 7.3

Sierra Club Data Request 7.3

Refer to the Reply Testimony of Mr. Rick Link, PAC/2300 at Link/15:19 to Link/16:2, with reference to the scenario assessing the early retirement of Bridger 3 & 4.

(a) Confirm or deny: the scenario to which Mr. Link refers is shown in the 2013 IRP, Confidential Volume III at Table V3.12 "Bridger 3 and 4 Hypothetical Regional Haze Compliance Analysis Results." If denied, please state where this scenario is discussed and where the analytical results are shown in the 2013 IRP.

(b) Provide a calculation showing how Mr. Link reached the conclusion that this scenario was $588 million more expensive than the scenario in which the units operate as coal.

(c) Confirm or deny: PacifiCorp did not run a scenario in which Bridger 3 & 4 were converted to gas in 2021 or 2022 as an alternative form of compliance. If denied, please provide the results and underlying work papers of the scenario in which Bridger 3 & 4 are were converted to gas in 2021 or 2022.

(d) If (c) is confirmed, state if PacifiCorp believes that conversion to gas as an alternative form of compliance with the regional haze rule would have met EPA's requirements under that rule.

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(a) The referenced section of reply testimony of Rick T. Link discusses a sensitivity where it was assumed Jim Bridger Unit 3 and Jim Bridger Unit 4 retire in 2020 and 2021 respectively, which is summarized in the 2013 Integrated Resource Plan (IRP), Confidential Volume III at Table V3.12. This table shows that continued coal operation with the installation of selective catalytic reduction (SCR) investments was lower cost than the early retirement case by $174 million. The referenced section of Mr. Link's reply testimony inadvertently referenced the early retirement sensitivity summarized in his direct testimony, where it was assumed Jim Bridger Unit 3 and Jim Bridger Unit 4 retired at the end of 2015 and 2016, respectively. This case showed that continued coal operation with the installation of SCR investments was lower cost than early retirement by $588 million.

(b) Please refer to Confidential Attachment Sierra Club 7.3, specifically the tab "Sensitivity PVRR(d) – Retire," cell I18

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(c) Confirmed.

(d) No.

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Sierra Club Data Request 8.2

Sierra Club Data Request 8.2

Refer to PAC/2300 Link/16:7-18 with respect to the scenarios examining avoided transmission in Energy Gateway.

(a) Mr. Link states that, with respect to the "Utah and Wyoming pre-approval cases," and "…in response to Sierra Club's concern…" Refer to the rebuttal testimony of Mr. Link before the Wyoming Public Service Commission in Docket 20000-418-EA-12, filed March 4, 2013, page 40:4-9, stating "Sierra Club has taken the position that if Jim Bridger 3 and 4 were retired and replaced with a resource located closer to load centers that the need for Energy Gateway transmission investments would be alleviated. Consequently, Sierra Club testifies that deferral of Energy Gateway costs should be considered as a benefit to an early retirement outcome and that this benefit was not captured in the Company's analysis. Explain how the analytical result, shown at PAC/2300 Link/16:12-17 addresses this specific concern.

(b) Confirm or deny: The Company did not present this specific analysis in the 2013 IRP or 2013 IRP Update. If denied, provide a citation to where the analysis was discussed or results indicated.

(c) Confirm or deny: The avoided Energy Gateway scenario was applied to the base case, which included the Jim Bridger SCR retrofits.

(d) Confirm or deny: The avoided Energy Gateway scenario excluded more Energy Gateway segments than just Anticline to Populus.

(e) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were retired in 2015/2016 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(f) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were retired in 2015/2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(g) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2015/2016 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(h) Confirm or deny: PacifiCorp did not assess a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2015/2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of

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Wyoming wind as the base case. If denied, explain.

(i) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were retired in 2020/2021 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(j) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were retired in 2020/2021 2016 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(k) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2020/2021 and the Energy Gateway segment from Anticline to Populus (only) was also avoided. If denied, explain.

(l) Confirm or deny: PacifiCorp did not asses a scenario in which Jim Bridger 3 & 4 units were repowered to gas in 2020/2021 and the Energy Gateway project was resized relative to the base case to carry the same amount of Wyoming wind as the base case. If denied, explain.

(m) Provide the work papers underlying the valuation in PAC/2300 Link/16:12-17 including both scenarios examined to arrive at the difference. Include input and output files from System Optimizer, and any spreadsheets or worksheets used by the Company to process or assess the model outputs from System Optimizer.

Response to Sierra Club Data Request 8.2

(a) Please refer to the rebuttal testimony of Rick T. Link before the Wyoming Public Service Commission in Docket 20000-418-EA-12, filed March 4, 2013, page 40:3-23, pages 41-43, and page 44:1-12.

(b) Confirmed.

(c) Confirmed.

(d) Denied.

(e) Confirmed. Please refer to the Company’s response to subpart (a) above.

(f) Confirmed. Please refer to the Company’s response to subpart (a) above.

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(g) Confirmed. Please refer to the Company's response to subpart (a) above.

(h) Confirmed. Please refer to the Company's response to subpart (a) above.

(i) Confirmed. Please refer to the Company's response to subpart (a) above.

(j) Confirmed. Please refer to the Company's response to subpart (a) above.

(k) Confirmed. Please refer to the Company's response to subpart (a) above.

(l) Confirmed. Please refer to the Company's response to subpart (a) above.

(m) Please refer to the Confidential Attachment Sierra Club 8.2.

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Sierra Club Data Request 8.3

Sierra Club Data Request 8.3

Refer to PAC/2500, Owen/16:8-19, with respect to gas conversion costs.

(a) Provide the Company's estimate of the costs of gas conversion at Naughton 3 as projected in September 2013.

(b) Provide a table of results of EPC contract bids for the gas conversion at Naughton 3 as known in January 2014.

(c) Provide Mr. Owen's work papers estimating the specific change on line 14, from costs "originally anticipated" to "significantly higher."

(d) Provide a definition and citation for the common use of the term "order of magnitude."

(e) Provide Mr. Owens' estimate of the present value of revenue requirements that would have "negatively impacted the competitiveness of the natural gas conversion."

Response to Sierra Club Data Request 8.3

(a) In 2013, PacifiCorp estimated that a natural gas conversion at Naughton Unit 3 would cost between $29 million and $30.4 million.

(b) The requested information is commercially sensitive and highly confidential. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review.

(c) Mr. Owen's statement relates to his review of the evaluations conducted at the time of PacifiCorp decision making, and are not workpapers produced by Mr. Owen or at his direction. Some of the information on which Mr. Owen based this statement is commercially sensitive third-party information and highly confidential. The Company requests special handling. Please contact Matt McVee at (503) 813-5585 to make arrangements for review. Confidential information is provided as Confidential Attachment Sierra Club 8.3.

(d) "Order of magnitude" is commonly used in two ways: (1) to describe a size of value by approximate factors of 10; and / or (2) to mean much bigger or smaller. As used in Exhibit PAC/2500, Owen/14, the term is preceded by the phrase 'were significantly higher' when describing costs, thus, Mr. Owen used the term according to its second common usage.

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Citation: https://www.mathsisfun.com/definitions/order-of-magnitude.html

(e) Mr. Owen's testimony does not state that he calculated an estimate of the present value of revenue requirements. The quoted statement in Mr. Owen's testimony reasonably deduces that the competitiveness of natural gas conversion would be negatively impacted if the estimated cost to implement a natural gas conversion were higher than originally assumed.

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July 23, 2020
Sierra Club Data Request 8.3 – 1st Supplemental

Sierra Club Data Request 8.3

Refer to PAC/2500, Owen/16:8-19, with respect to gas conversion costs.

(a) Provide the Company's estimate of the costs of gas conversion at Naughton 3 as projected in September 2013.

(b) Provide a table of results of EPC contract bids for the gas conversion at Naughton 3 as known in January 2014.

(c) Provide Mr. Owen's work papers estimating the specific change on line 14, from costs "originally anticipated" to "significantly higher."

(d) Provide a definition and citation for the common use of the term "order of magnitude."

(e) Provide Mr. Owens' estimate of the present value of revenue requirements that would have "negatively impacted the competitiveness of the natural gas conversion."

1st Supplemental Response to Sierra Club Data Request 8.3

PacifiCorp provides the following supplemental response to Sierra Club Data Request 8.3:

(c) In the preparation of his testimony in docket UE 374, Mr. James Owen reviewed past testimony provided by the Company. This included testimony from Mr. Chad Teply that stated: "Based on information from the competitive market bids for the Naughton Unit 3 natural gas conversion EPC contract, the Company knew by January 2014 that implementation costs for that project were significantly higher—on an order of magnitude of 30 percent—than originally anticipated".

Mr. Owen conducted a thorough review of the basis for this statement. He reviewed the referenced competitive market bids and found that two competitive bids were received by the Company in December of 2013 in the amounts of $56,300,015 and $48,559,000. Based on discussions with project managers involved in receiving the bids at the time, he understood that the higher bid was not considered plausible, and thus additional consideration was prudent for the lower bid. He also learned that the lower bid (errantly) included a line item valued at $9,422,150 for repair/replacement of FGD bypass ducting, which would not be necessary for the gas conversion as proposed. He subtracted that amount from the bid, and re-calculated the project implementation cost to be $39,136,850.

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To ascertain the Company's anticipated costs for the project in late 2013, Mr. Owen reviewed Progress Review updates from early to mid-2013 and a Budget Calculation Sheet from early 2014. The costs in those documents ranged from $29,000,000 to $30,400,000, with the number $30,200,000 appearing twice. Mr. Owen therefore determined that $30,200,000 was a reasonable number to represent the company's estimate for the project in late 2013. A simple comparison calculation of the two values [($39,136,850-$30,200,000)/($30,200,000) =.2959 ≈30%] shows that the implementation costs for the project were significantly higher—on an order of magnitude of 30 percent—than originally anticipated. Thus, Mr. Owen adopted the statement into his testimony.

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July 17, 2020
Sierra Club Data Request 9.1

Sierra Club Data Request 9.1

Refer to the Reply Testimony of Dana Ralson (PAC/2600) at Ralston /9:17-18. Provide a detailed explanation of the asserted double count of reclamation costs, along with any calculation(s) and work paper(s).

Response to Sierra Club Data Request 9.1

Please refer to the reply testimony of Dana M. Ralston, page 4, lines 9 through 13 which explains Sierra Club's double count of reclamation costs. Please refer to Confidential Attachment Sierra Club 9.1 for the work papers that show calculations with reclamation costs included in Jim Bridger Plant cash coal costs.

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July 17, 2020
Sierra Club Data Request 9.5

Sierra Club Data Request 9.5

Refer to the Reply Testimony of Dana Ralson (PAC/2600) at Ralston/11:10-14 where Mr. Ralston testified that third party coal costs decreased by a certain percentage, offsetting modest increase in BCC coal costs.

(a) Please specify the dollar amount of the final increase in BCC coal costs as a result of the offset.

(b) Related please specify the dollar amount of the overall impact on the project economics.

(c) Provide all calculations and work papers associated with the above cost calculations.

Confidential Response to Sierra Club Data Request 9.5

(a) The dollar amount was a decrease of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Please refer to the reply testimony of Dana M. Ralston, specifically Confidential Exhibit PAC/2603.

(b) Please refer to Mr. Ralston's reply testimony (PAC/2600), page 10, lines 17 through 20, and page 11, lines 1 through 7.

(c) Please refer to Mr. Ralston's Confidential Exhibit PAC/2603.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Docket No. UE 374
Exhibit Sierra Club/404
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 404

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 9.1

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 405

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Confidential Rebuttal Testimony of Rick Link in 20000-418-EA-12 (Wyo. P.S.C.)

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 406

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

2013 PacifiCorp IRP Confidential Volume III

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/407
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 407

Exhibits Accompanying the Rebuttal Testimony of Jeremy Fisher

Redacted Direct Testimony of Jeremy Fisher in 20000-418-EA-12 (Wyo. P.S.C.)

BEFORE THE
WYOMING PUBLIC SERVICE COMMISSION

In the Matter of: The Application of PacifiCorp for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on the Jim Bridger Units 3 and 4	)))))))	**Docket No. 2000-418-EA-12**

Direct Testimony of
Jeremy Fisher, Ph.D.

On Behalf of
Sierra Club

REDACTED VERSION

February 1, 2013

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INTRODUCTION AND PURPOSE OF TESTIMONY

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

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Ave, Suite 2, in Cambridge Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and four years of working within the energy planning sector, including work on integrated resource plans, long-term planning for utilities, states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates (CA DRA), the National Association of State Utility Consumer Advocates (NASUCA), National Rural Electric Cooperative Association (NRECA), the State of Utah Energy Office, the State of Alaska, the State of Arkansas, the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), and Civil Society Institute.

Prior to joining Synapse, I held a post doctorate research position at the University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as Exhibit 301.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified in front of the Wyoming Public Service Commission previously?

A Yes. I submitted testimony in PacifiCorp's 2011 General Rate Case (Docket 20000-384-ER-10) on behalf of Powder River Basin Resource Council.

Q What is the purpose of your testimony?

A In my testimony I evaluate the reasonableness of the assumptions used by Rocky Mountain Power (PacifiCorp or the Company) in the modeling that supports this Application for a Certificate for Public Convenience and Necessity (CPCN) to construct Selective Catalytic Reduction (SCR) systems at Jim Bridger units 3 & 4. Specifically, this testimony:

1. Evaluates the assumptions and validity of the data underlying the range of natural gas and carbon dioxide (CO_2) prices used by the Company;

2. Assesses opportunities to avoid significant and high cost transmission investments in the Gateway West project between Bridger and Populus terminals;

3. Critiques the assumption that the fate of Jim Bridger generating station should be dictated by the need to fund remediation activities of Bridger Coal Company, and proposes that coal prices at Jim Bridger should be evaluated at fair market prices to capture opportunity costs; and,
4. Examines the requirement for the Company to pursue the retrofit at this time in light of delayed EPA requirements.

Q What are your findings?

A It is my opinion that the retrofit of Bridger is **not** in the best interests of ratepayers. The evidence shows a marginal, at best, outcome for ratepayers in a reasonable and updated base case. Further, the Company's refusal to find opportunities to protect ratepayers against inefficient expenditures shows that the investment in SCR is not merely marginal, but a net liability for consumers. Finally, the requirement for the SCR is currently highly uncertain, as the EPA has withdrawn its Regional Haze implementation requirements for the State of Wyoming, and will not re-issue a final rule until September 2013. Therefore, the Company's press to install this equipment by 2015 is premature, and the current proposal may not ultimately reflect the requirements put in place by the EPA.

1. ANALYSIS RELIES ON OUTDATED MODEL AND FORECASTS

Q Does the Company's modeling in this docket reflect the same mechanism as used in the 2011 Integrated Resource Plan?

A Yes. The Company has used precisely the same model, as well as model assumptions, as used in the 2011 Integrated Resource Plan (IRP) update, issued March 20, 2012. The base case commodity price forecast (the "official forward price curve") is from December 2011.

Q Is it appropriate to use the same mechanism here as used in the IRP?

A Yes. Generally, I approve of the Company using a similar modeling framework in the IRP process and for making individual strategic planning decisions, such as in this case. Nevertheless, to formulate a nuanced opinion (i.e. the absolute outcome is not at all definite from the Company's own analysis) requires significant care and attention.

As I will discuss, it appears that the Company has put significant effort into some aspects of future planning, such as evaluating how to fund their coal mine remediation efforts, but has completely neglected significant opportunities to provide ratepayer benefits through the avoidance of potentially unnecessary capital expenses, such as new transmission costs.

Q Is it appropriate to use the same assumptions and inputs as used in the 2011 IRP?

A No. Since the issuance of the 2011 IRP Update, the Company has updated commodity price forecasts (such as natural gas prices),[1] has predicted significantly lower future load requirements,[2] and has terminated the all source request for proposals (RFP) for an anticipated 2016 supply resource included in the modeling for this docket.[3] While not all of this information was available to the Company prior to the filing of this docket, such relevant information should inform updates and revisions to the Company's application as further information is known.

Q Why did the Company not perform updates of its System Optimizer model as new information was made available?

A The Company claims that conducting new System Optimizer runs for the purposes of evaluating the economics of this docket are too onerous, stating that

[1] Direct testimony of Rick Link, page 26 lines 4-8

[2] *See* response to WIEC 22.6: "The Company agrees that the load forecast presented at the September 14, 2012, integrated resource plan (IRP) stakeholder meeting is lower than the forecast used for the GRID and System Optimizer model (SO Model) studies." Also, *see* response to WIEC 23.15: "The Company agrees that the recent load forecast is lower than the prior forecast. The Company has not completed an analysis at this time that isolates the impact of a load forecast update on the analysis of the Jim Bridger…SCR investments."

[3] *See* response to WIEC 22.8: "The All Source request for proposals (RFP) for a 2016 resource, filed with the Public Service Commission of Utah and the Public Utility Commission of Oregon, has been terminated."

"to analyze the Jim Bridger units 3 and 4 investments, both individually and combined, across a range of natural gas and CO_2 cost scenarios, required 42 distinct System Optimizer model (SO Model) 'runs'."[4]

Q Is it onerous to perform a modified System Optimizer run?

A No. Introducing a new load profile, gas price assumptions, and minor changes in assumed resources should be a fairly straightforward and standard process. According to the Company, the actual run time for each of the "42 distinct" runs "generally took three to five hours."[5] I would estimate that the Company could have produced illustrative updated runs for key scenarios in a few days, and a completely new analysis with about a week's worth of dedicated computer time.

Q Is the Company currently conducting modeling for a new IRP?

A Yes. The Company is currently conducting modeling for a 2013 IRP.

Q Is the modeling for the 2013 IRP conducted in the same System Optimizer platform as for this filing?

A No.[6]

Q Has the Company run any of the scenarios described in this filing with the updated 2013 IRP model?

A No.[7]

Q Please describe how PacifiCorp evaluated the benefit of retrofitting Jim Bridger with SCR against alternatives.

A As discussed in Mr. Link's testimony, the Company presents the results of its analysis as the difference between two scenarios:

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[4] Response to WIEC Data Request 1.21
[5] Response to WRA Data Request 2.1 in Utah Docket 12-035-92, January 2, 2013.
[6] Response to Sierra Club Data Request 3.1(c)
[7] Response to Sierra Club Data Request 3.4.

1. The System Optimizer model was allowed to choose freely to invest in the SCR system and continue operation of Bridger 3 and 4, or to convert Bridger 3 and 4 to natural gas, called the "optimized" case; and

2. System Optimizer was restricted from making whichever operational choice (invest in SCR or convert to gas) it deemed optimal, known as the "change case."

The present value of revenue requirements (PVRR) is calculated for each of these scenarios, and the difference between them – called the PVRR(d) – is a final measure of the relative merits of the two scenarios. When the PVRR(d) for a given set of assumptions is negative, the revenue requirements of the SCR retrofit scenario are less than the gas conversion, indicating a preference for the SCR retrofit. When the PVRR(d) is positive, the revenue requirements of the SCR retrofit are greater than the gas conversion, indicating a preference for conversion to natural gas.

Q Please describe how PacifiCorp addressed uncertainty in gas and CO_2 prices.

A The Company presented PVRR(d) results for seven different sets of assumptions that vary in terms of their natural gas and CO_2 allowance prices. The base gas price is the December 2011 Opal official forward price curve (OFPC), which has a nominal levelized value of $6.18/MMBtu; the projection of this base gas price included the assumption that $16/ton CO2 price would be in effect by 2021 and would escalate gradually thereafter.

The Company also runs the System Optimizer model using high and low gas prices, the nominal levelized value of which (with the assumed $16/ton CO2 price) are $8.94/MMBtu and $4.51/MMBtu, respectively.

In addition to high, base, and low gas price assumptions coupled with the Company's base CO_2 price of $16/ton starting in 2021 (and escalating gradually thereafter), PVRR(d) results were estimated using a high ($34/ton starting in 2018, then escalating) and zero ($0/ton in all years) CO_2 price.

For the high and low CO_2 price assumptions the Company chose to adjust the natural gas price, a point that I will discuss more fully below. With the high CO_2 price, the nominal levelized value is $7.25/MMBtu for the base gas price and $5.50/MMBtu for the low gas price. With the zero CO_2 price, the nominal levelized value is $5.62/MMBtu for the base gas price and $8.70/MMBtu for the high gas price.

Table 1 below reports the PVRR(d) values for each of these seven sets of assumptions. The values displayed are taken from Confidential Attachment WIEC 14.3 (Attached as Exhibit 302), which provides results that are corrected for errors found in the Link Testimony. According to the Company's modified findings, SCR is preferred to natural gas conversion for Bridger 3 and 4 in all cases that use the base or high gas prices; gas conversion is preferred in the low gas price cases.

Table 1. Net benefit of retrofitting both Jim Bridger 3 & 4 as presented in initial Company testimony.

(millions 2012$)	Low Gas	Base Gas (Dec.2011)	High Gas
Zero CO_2		[redacted]	[redacted]
PacifiCorp Base CO_2	[redacted]	[redacted]	[redacted]
PacifiCorp High CO_2	[redacted]	[redacted]	

Q What did you conclude from these results?

A According to Mr. Link, the Company's decision to implement SCR appears, on the surface, to be heavily dependent on projections of future gas and CO_2 prices. However, upon closer inspection, it becomes clear that the decision hinges on other questions as well, which I discuss later in this testimony.

The Company does not put an explicit weight on any given option.[8] However, by stating that the results support its position to retrofit the plant, it is clearly putting greater emphasis on the base case, and discounting the risk of low future gas prices and high future CO_2 allowance prices.

Q **Did the Company review how different gas and CO_2 prices would impact the outcome of their analysis?**

A Yes. The Company used a simple linear trend to estimate the breakeven CO_2 price at the base (December 2011) gas price.[9] Their estimated breakeven nominal levelized CO_2 price is [redacted]/ton. They have not reported breakeven CO_2 prices at their high and low gas prices, nor breakeven gas prices for non-base case CO_2 prices.

Q **Did the Company review changes to either gas or CO_2 prices after the time it ran the original System Optimizer model?**

A Yes. According to Mr. Link, the Company used the linear trend to estimate the PVRR(d) with base CO_2 price (assuming $16/ton starting in 2022) and the June 2012 Opal OFPC natural gas price (reported to have a nominal levelized value of $5.65/MMBtu in Mr. Link's testimony). Mr. Link estimates a [redacted] million PVRR(d) for this case.

Q **Did the Company run the System Optimizer model with the updated gas prices?**

A No. Because the Company did not run an updated case, and did not provide ancillary information for this run, or corrections for this run in Confidential Attachments WIEC 14.3, it is not directly comparable to the corrected PVRR(d) results shown above in Table 1.

[8] Response to WIEC 1.115 (Attached as Exhibit 303). "The Company has not assigned weighting to each of the alternatives presented in the application. Rather the Company has provided analyses of a range of input assumption to provide the Commission with a range of information from which to make their determination."
[9] See Confidential Exhibit RMP__(RTL-7)

Q What was the impact of having changed the gas price?

A Using the linear trend with the updated gas price forecast (June 2012), Mr. Link estimates that the uncorrected PVRR(d) results shift from [redacted] million to [redacted] million. Both results are favorable to installation of the SCR system, but the more recent forecast reduces the benefits of SCR installation by [redacted] million. This change shows that the relative value of SCR has dropped with the change in gas price forecasts.

Q At the newer gas price, what is the breakeven CO_2 price?

A Updating assumptions regarding future gas and CO_2 prices would change the Company's PVRR(d) results. To demonstrate this I have essentially followed Mr. Link's theory of a linear relationship between gas prices and PVRR(d), and CO_2 prices and PVRR(d). My analysis does the following:

1. Calculated updated nominal levelized gas prices for the scenarios run by the company. The base gas price is calculated directly from the Company's September 2012 Opal OFPC.[10] High and low gas prices are then calculated as the same percentage change from base as in the Company's original filing. No adjustment has been made to these gas prices to take account of low or high CO_2 prices. The nominal levelized values are $5.57/MMBtu for the base gas price, $8.50/MMBtu for the high gas price, and $4.15/MMBtu for the low gas price.

2. Calculated nominal levelized CO_2 prices for the Synapse low, mid, and high cases (as reported in Exhibit 304). Prices come into effect in 2020 in all three Synapse cases. The 2020 nominal values for the Synapse CO_2 prices are $17/ton, $23/ton, and $35/ton, respectively.[11] The Synapse low, mid, and high

[10] See Confidential Attachment WIEC 11.1 -1
[11] Using the Company's assumed 1.9% inflation rate. Approximated from Confidential Attachment WIEC 1.20 -1.

CO_2 prices have nominal levelized values of $15.41/ton, $23.81/ton, and $37.94/ton.

3. Performed a multiple linear regression using the Company's nominal levelized gas and CO_2 prices as the explanatory variables and its PVRR(d) values as the dependent variable. The results of this regression were then applied to the updated gas prices to identify the breakeven CO_2 price, and to the zero and Synapse low, mid, and high CO_2 prices to identify the breakeven gas price.

Using the updated gas prices, the breakeven nominal levelized CO_2 price is [redacted]/ton for the base gas price.[12] Using the Synapse mid CO_2 price, the breakeven nominal levelized gas price is [redacted]/MMBtu.[13] It is noteworthy to recall that Mr. Link's revised gas price from June 2011 has a nominal levelized value of $5.65/MMBtu, very close to the breakeven value.

The breakeven nominal levelized CO_2 price of [redacted]/ton at the updated base gas price can be compared to the Company's estimated breakeven CO_2 price of [redacted]/ton at the base gas price used in the original filing. Updating the Company's analysis with more recent gas price forecasts therefore shows that SCR becomes unfavorable at a much lower CO2 price than originally found by the Company.

2. <u>Company Base CO_2 Price is Unreasonably Low</u>

Q Does the Company's CO_2 price forecast represent a reasonable forecast range?

A No. The Company's base (December 2011) CO2 forecast is low relative to other industry estimates from the last two years.[14] The high CO2 forecast is closer to what other utilities and parties consider a mid-range price forecast. While the zero

[12] Also [redacted]/ton for the high gas price, and [redacted]/ton for the low gas price.
[13] Also [redacted]/MMBtu for the low Synapse CO_2 price and [redacted]/MMBtu for the high CO_2 price.
[14] Company CO_2 prices presented in Link Direct Testimony, Figure 2 and Confidential Exhibit RMP___(RTL-2).

CO_2 price may provide a useful end number, in my opinion, it is not reasonable to rely on a long-term assumption of no action regarding climate change.

It is my opinion that the Company has been very selective in choosing which forecasts to review and follow, and while the current forecast represents a slight improvement over that used by the Company in 2009 (an increase of about 46% in levelized nominal terms),[15] it is still unreasonably low relative to forecasts from other utilities and industry groups.

Q How do the Company's CO_2 price forecasts compare to forecasts used by other utilities?

A The Company's forecast is lower than those used by other utilities and industry groups. Synapse has reviewed CO_2 price forecasts from approximately 25 publicly available IRP and utility planning dockets filed over the last three years (2009-2012), representing over sixty non-zero price forecasts.[16] In addition, Synapse has reviewed government and other forecasts, as well as the changing policy landscape, and published a set of price forecast series in October, 2012.[17] I show these forecasts as a backdrop (grey lines) against the Company's forecast (red triangles) and the Synapse 2012 price forecast (black circles) in **Figure 1**, below.[18]

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[15] Comparison of base case CO_2 prices as used in Hunter 1 & 2 PVRR(d) analyses for FGD (evaluation in November, 2009) against base case values used in this docket. Nominal levelized cost performed similarly to Company mechanism from 2015-2030.

[16] Attached as Exhibit 305.

[17] Synapse Energy Economics, Inc. October 4, 2012. *2012 Carbon Dioxide Price Forecast*. Attached as Exhibit 304, and available online at http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

[18] Figure 1 is attached as Exhibit 306.

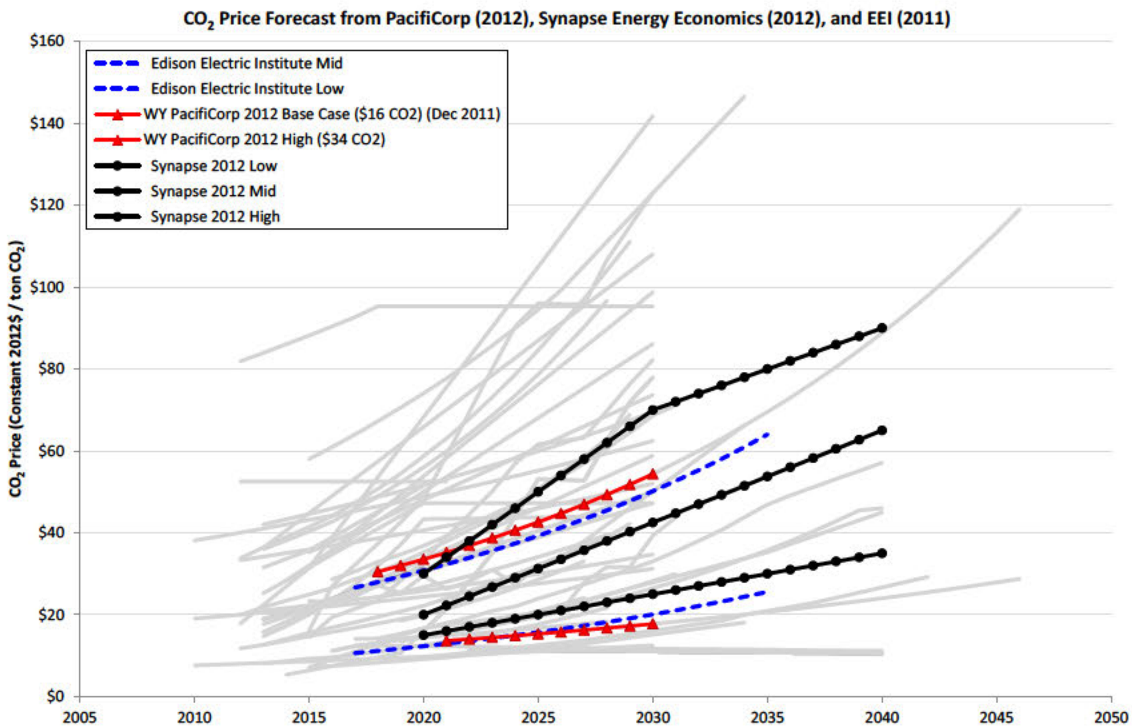

Figure 1. CO_2 Price Forecast. Company (red triangles), Synapse (black circles), and Edison Electric Institute (blue dashes) assumed CO_2 price forecasts against a backdrop of sixty other utility forecasts from 2009 - 2012.

The PacifiCorp Base Case (red triangles) is at the very lowest threshold of prices in this diagram, above only three other forecasts.[19] In all three cases, the other utility forecasts also start earlier than PacifiCorp base case, imposing a greater impact on decisions today.

The PacifiCorp high case (red triangles) starts a few years earlier, and is closer to the middle of the utility forecast spectrum.

Interestingly, the PacifiCorp forecasts fall almost in line with two forecasts produced by the Edison Electric Institute (EEI) in a January 2011 study.[20] I have

[19] American Electric Power (2011), New Mexico Public Service, Low (2012), and NE Omaha, Low (2010).
[20] Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January, 2011. Edison Electric Institute (prepared by ICF International). Attached as Exhibit 307.

also plotted these two forecasts in Figure 1 (blue dashes). However, EEI characterizes the higher forecast as their baseline expectation, and the lower forecast as an “Alternate” low case. The EEI study also explores a zero CO_2 price forecast.

The Synapse CO_2 price forecasts (black circles) bound the PacifiCorp high case. Synapse’s Low, Mid, and High 2012 forecasts start in 2020, at $15, $20, and $30/short ton CO_2 (real 2012$) respectively, and rise over time. The PacifiCorp <u>Base</u> CO_2 price is below the Synapse <u>Low</u>.

Q How did the Company develop their CO_2 price forecasts?

A The Company reviewed 2011 third-party forecasts from three consultancies ([redacted]) as well as older estimates from the U.S. EPA on the expected allowance price under the 2009 American Clean Energy and Security Act (ACES, or Waxman-Markey).[21] Ultimately, the Company appears to have settled on a forecast close to the [redacted] forecast as their base price, and EPA’s estimate of allowances prices from the Waxman-Markey bill (as run in June of 2009) to set their high price.

Q Do the Company’s CO_2 price forecasts cover a reasonable range of risk?

A No. Importantly, EPA did not consider the PacifiCorp high allowance price (taken from the Waxman-Markey bill) to be at the “high” end; rather, this price was the EPA’s base allocation price assumed to be required under the mechanisms proposed in the regulation. A valid mechanism of evaluating the “high” and “low” estimates of the impact of that particular bill would be to look at a range of models and a range of scenarios to determine how that particular bill might impact CO_2 allowance prices. Had the Company looked at EIA’s estimate of the impacts of the Waxman-Markey, it would have found a much wider and higher range than that found by EPA or used by PacifiCorp. I have plotted EIA’s

[21] See Confidential Attachment WIEC 1.35 -2 “ThirdParty_CoalStudy_CO2 CONF.xlsx”.

estimates against the Company's "third-party" estimates from Confidential Exhibit RMP___(RTL-2) in Figure 2, below. EIA includes several cases exploring the impact of international offsets, which has a significant impact on the assumed allowance price. Note that the EIA's estimate in the Waxman-Markey "Basic Case" quickly exceeds PacifiCorp's High, and EIA's estimate for a restricted offset case is about twice PacifiCorp's High case.

[redacted]

Figure 2. Confidential. Company CO_2 price forecasts against third-party estimates from Confidential Exhibit RMP___(RTL-2). Modified to include EIA estimates of Waxman Markey CO_2 allowance prices.

Q Are there other indicators that the High case chosen by PacifiCorp was at the low end of estimates for the Waxman-Markey assumptions?

A Yes. In September 2009, the Electric Power Research Institute (EPRI) ran the National Energy Modeling System (NEMS) model and produced a "Preliminary Analysis of Waxman-Markey (H.R. 2454) Using NEMS for PacifiCorp." This document is found on PacifiCorp's IRP website.[22] The CO_2 prices calculated by the NEMS, shown in Figure 3 (below), ranges from a reference case starting in 2012 and passing about $30 (real 2012$) in 2021, finishing at about $40 in 2030, a similar trajectory to PacifiCorp's High case. The NEMS model also shows several other sensitivities that clearly outpace the Company's base case in this docket.

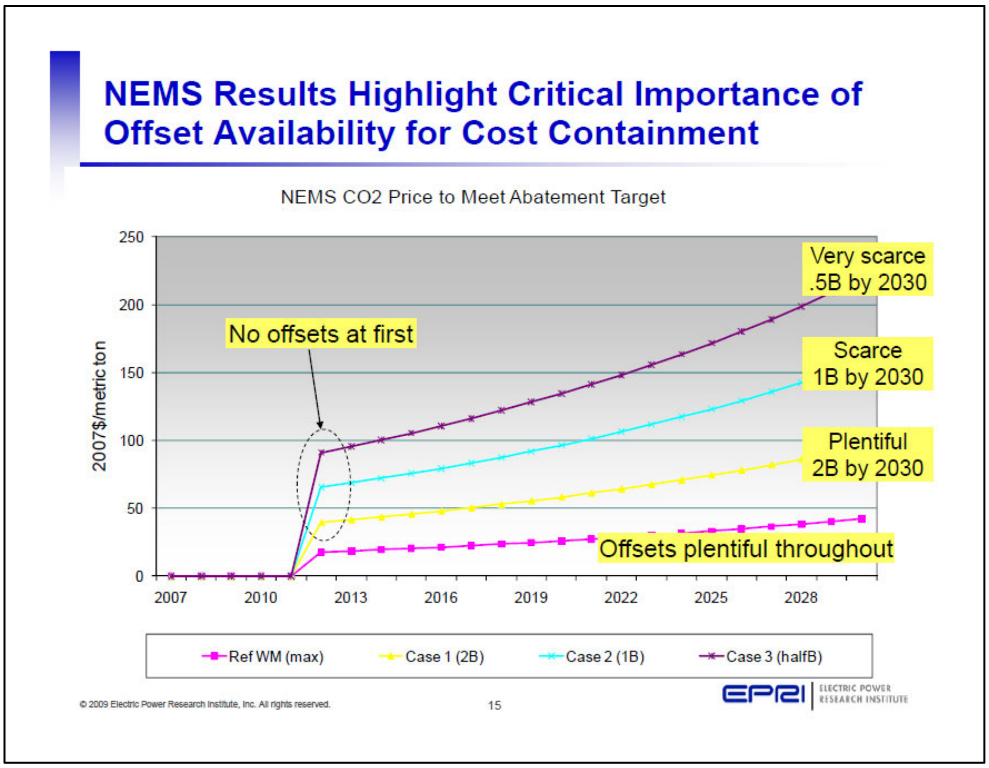

Figure 3. Slide from "Preliminary Analysis of Waxman-Markey (H.R. 2454) Using NEMS for PacifiCorp." September, 2009 (Attached as Exhibit 308).

[22] Preliminary Analysis of Waxman-Markey (H.R.2454) Using NEMS for PacifiCorp. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Environment/WM-NEMS-Roadshow-draft-9-11-09.pdf (Attached as Exhibit 308).

Q What do you recommend for a CO_2 price forecast?

A The Synapse CO2 price forecasts represent a reasonable range of utility, government, and third-party estimates, and provide a reasonable range of sensitivities for use in forward planning cases.

Q Do you have any other concerns about CO_2 pricing as pertains to this case?

A Yes. The Company's CO_2 price forecast for the IRP planning process (upon which this modeling case is based) extends beyond 2030 (the end of the analysis period here), rising over time. It is unclear how the model accounts for future rising CO_2 prices, if at all, in the end period extending to the 2037 retirement of Bridger 3 and 4. Higher future CO_2 prices would reasonably be expected to have an impact on resource decisions today, even if they extend beyond the analysis period.

3. GAS PRICE INCLUDES UNSUPPORTED CO_2 PRICE ADDERS

Q Is the Company gas price forecast reasonable?

A The Company's initial derivation and continued revision of the base gas price forecast appears generally to be reasonable. However, I have significant concerns about the Company's adjustment of gas prices based on forecast CO_2 prices. In the presence of a CO_2 price forecast, the Company assumes that natural gas prices are higher than they would be in the absence of a CO_2 price. In fact, the assumption is that for approximately every $24 of (real 2012$) CO_2 price, the natural gas price is increased by $1/MMBtu.[23] This assumption leads to natural gas prices in the High CO_2 price case that are 15-25% higher than Base Case prices.

[23] The difference between the base case natural gas price at the Company high CO_2 price trajectory ("$34") and the gas price at a zero CO_2 price shows that gas prices increasing as CO_2 prices increase (in real 2012$) (see Confidential Attachment WIEC 14.3). My calculations show that a linear fit (forced to a zero intercept) between the gas price difference and CO_2 price has a slope of 23.5, meaning that for each dollar of gas price increase, CO_2 has increased by about $24.

Q Why does the Company increase natural gas prices in the presence of a CO_2 price?

A Mr. Link describes the basis of this adjustment in a hypothetical (Link Direct, p11, lines 224-231):

> This [adjustment] is primarily driven by the relatively high level of carbon content in coal as compared to natural gas. With rising CO_2 prices, generating resources with lower CO_2 emissions, such as natural gas-fueled resources, begin to displace coal-fueled generation, thereby increasing the demand for natural gas within the electric sector of the U.S. economy. Displacement of coal generation is also influenced by low or zero emitting renewable generation sources; however, not enough to entirely offset increased natural gas demand.

This conclusion by the Company is unsupported. There is currently no definitive evidence that such a link between natural gas prices and CO2 prices would occur, or if it did, that it would have the dramatic impact on natural gas prices Mr. Link assumed. In fact, from the evidence that I have reviewed, integrated system models rarely predict increasing natural gas prices with higher CO_2 prices.[24] In absence of significant evidence, or consistent and definitive modeling results, the supposition that natural gas prices will increase in the presence of a CO_2 price is unsupported and inappropriate.

[24] Review of data from 2009 Energy Modeling Forum #22 (Fawcett, A. A. K. V. Calvin, F.C. de la Chesnaye, J.M. Reilly, and J. P. Weyant. 2009 "Overview of EMF 22 U.S. Transition Scenarios. Energy Economics, Vol. 31, pp. S198-S211. http://emf.stanford.edu/files/res/2369/fawcettOverview22.pdf), US DOE EIA Annual Energy Outlook 2012, EIA NEMS run for "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009" (see http://www.eia.gov/oiaf/servicerpt/hr2454/index html); EPA modeling of Waxman-Markey Discussion Draft (April 2009), EPA modeling of American Clean Energy and Security Act of 2009 (June, 2009), Clean Energy Jobs and American Power Act of 2009 (October 2009), and American Power Act of 2010 in the 111th Congress (June 2010) (see http://www.epa.gov/climatechange/EPAactivities/economics/legislativeanalyses html).

4. REASONABLE RANGE OF CO_2 AND GAS PRICES INCREASES LIABILITY RISK

Q What are the results of modifying the Company's gas and CO_2 price forecasts?

A The results of the multiple linear regression, discussed previously, were also applied to the updated gas prices, and the Synapse low, mid and high CO_2 prices to estimate a PVRR(d) for each set of assumptions. Table 2 displays these results.

Table 2. Net benefit of retrofitting both Jim Bridger 3 & 4 under updated gas price, Synapse CO_2 price forecasts, and Company post-hoc corrections, using simple linear regression. *Low gas and high gas cases deviate from September 2012 forecast.

(millions 2012$)	Low Gas*	Base Gas (Sept.2012)	High Gas*
Synapse Low CO_2	[redacted]	[redacted]	[redacted]
Synapse Mid CO_2	[redacted]	[redacted]	[redacted]
Synapse High CO_2	[redacted]	[redacted]	[redacted]

With low gas prices, neither the low, mid or high CO_2 prices result in a net benefit from the installation of SCR. With base gas prices, only the low CO_2 price assumption favors SCR installation; a mid CO_2 price results in a PVRR(d) of [redacted] million, which I regard as too close to the margin of error to be definitive. High gas prices favor SCR installation regardless of the CO_2 price level.

Q Are Synapse's results the outcome of an optimization or production cost model?

A No. The Synapse results simply review the outcome of the Company's optimization model and test alternative outcomes from very generic changes to input assumptions. It is not clear if the outcome from an optimization or production cost model, appropriately modified, would produce the same results. I expect, however, that without additional modifications to the model structure or inputs, that the order of magnitude would remain the same within these results.

Q You have questioned the avoided transmission costs and incorporating the cost of remediating the Bridger coal mine – do these results address those outstanding questions?

A They do not. I address these issues individually and in turn below. Any modifications resulting from avoided transmission costs, avoidance of the remediation cost of the Bridger coal mine, or any other changes would be in addition to the results shown above.

5. Analysis Does Not Take Into Account Opportunity to Avoid or Defer Gateway Transmission Investments

Q What is the Gateway West Transmission Project?

A The Gateway West Transmission Project is jointly proposed by Idaho Power and Rocky Mountain Power to build and operate approximately 1,100 miles of new high voltage transmission lines between the Windstar Substation in Wyoming and the Hemingway Substation in Idaho (see Figure 4, below). The project would include about 300 miles of 230 kV and 800 miles of 500 kV in new transmission lines and parallel three existing Western Electricity Coordinating Council (WECC) rated Paths. The Gateway West Transmission Project is currently planned in five segments – Windstar to Aeolus, Aeolus to Jim Bridger (at the Anticline substation), Jim Bridger to Populus, Populus to Midpoint and Midpoint to Hemingway. Figure 4 below, shows a map of these major substations and proposed segments.

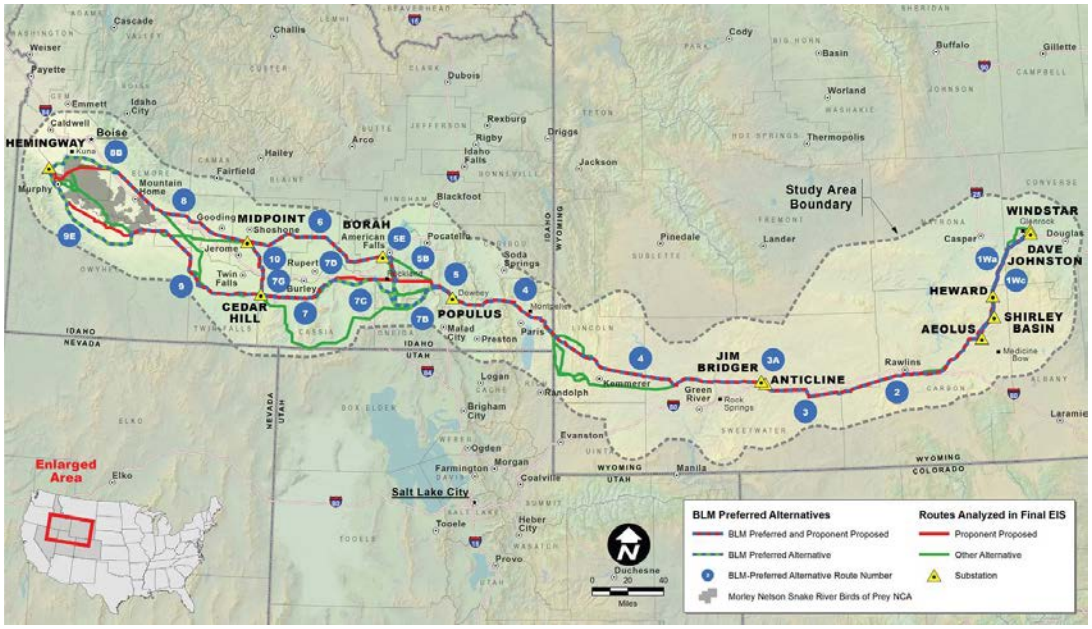

Figure 4. Map of Gateway West project from project website. Windstar is the furthest east point. Hemingway is the furthest west. Source: http://www.gatewaywestproject.com/ (Attached as Exhibit 309).

The dominant flow along the existing lines are from fossil and wind stations in the east (Dave Johnston, Jim Bridger, and Naughton) to load centers in Utah and Oregon via the Populus substation,[25] and the Company modeled them as such in the System Optimizer tool. [26] The Company expects that one of the primary purposes of the Gateway West project will be to carry energy produced from new wind resources in central and northwest Wyoming.[27]

Q How does the Gateway West Transmission Project relate to this case?

A The Gateway West Transmission Project includes a set of proposed transmission capacity expansions that will extend directly through the Jim Bridger Generating Station. If Jim Bridger units 3 & 4 were to be retired and replaced with capacity

[25] *See* WECC Transmission Expansion and Planning Policy Committee, Historical Analysis Work Group. 2009 Western Interconnection Transmission Path Utilization Study. June 24, 2010. Attach WIEC 22.16-1, p64 “Path 19 – Bridger West 2009 Directional Schedules.”
[26] *See* Attach WIEC 1.18 VENTYX CONF\Operates\CapEx_TieCapacity.gms (Attached as Exhibit 324)
[27] See Gateway West website at: http://www.pacificorp.com/tran/tp/eg/gw.html

closer to PacifiCorp's load centers, anticipated transmission expenditures could likely be avoided, deferred or reduced, with system savings in the hundreds of millions of dollars.

The upcoming planned expenditures for certain segments of the Gateway West Transmission Project raise serious questions. It is not clear whether the Company has adequately considered the opportunity to avoid certain transmission expenses by retiring units and replacing them with generation (or demand side management) closer to load centers.

The Gateway West project includes proposed new transmission line segments both to the east and west of the Jim Bridger Generating Station. At issue here is the transmission capacity expansion between Jim Bridger and the Populus substation, which is to the west of Jim Bridger. In System Optimizer, the Company models the segments of concern as in-service in [redacted] and [redacted].[28]

Simply stated, if one or more units at Jim Bridger are retired in the next few years, this would open several hundred MW of capacity on the existing lines connecting Jim Bridger and Populus, potentially allowing the Company to defer any immediate or impending investments in the segment connecting those two substations, and to points beyond as well. If replacement generation and capacity is sited closer to the Utah or Oregon load centers, the Company may be able to further relieve other constraints.

The Company expresses concerns about the ability to move energy through their system. According to recent 2013 IRP documents provided to stakeholders, "Energy Gateway is the result of robust local and regional transmission planning efforts… [and] studies that have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers

[28] *See* Attach WIEC 1.18 VENTYX CONF\Operates\CapEx_TransmissionOptions.gms (Attached as Exhibit 323)

throughout the West. (emphasis in original)"[29] This same document indicates that Gateway was announced in 2007 and has undergone extensive review. Building new transmission is an extended process, with "seven to 10 years required to site, permit and build. (emphasis in original)" Therefore, the process leading up to these segments is clearly under planning consideration today.

Q Has the Company considered how early retirement of the Jim Bridger 3 & 4 units could impact Gateway transmission planning or costs?

A No. According to the Company "the impact of Bridger 3 and 4 retirements at any point in the (2015-2020) timeframe and associated impacts to Company's proposed Gateway expansion west of Bridger have not been analyzed or studied,"[30] and "there have not been any specific studies performed regarding impact of the retirement or gas conversions of Bridger Units 3 and 4 on the need for the Company's Energy Gateway projects."[31]

Q Why has the Company not considered how early retirement of Jim Bridger 3 & 4 could impact Gateway planning transmission or costs?

A The Company explains that "it is not practical to determine with any certainty the change in need, modifications or delays in various Energy Gateway segments due to Bridger Unit 3 and 4 retirements, until the timing, location, type and size of the resources that replace the units has been determined."[32]

Q Is there an appropriate forum by which the Company could have evaluated the "timing, location, type and size of resources that replace" Jim Bridger 3 & 4?

A Yes. The analysis for this docket or the preceding 2011 IRP would have been the correct forum for this analysis. The Company's logic is circular. By neglecting to

[29] 2013 IRP Stakeholder Materials. "Transmission Planning and Investment". October 29, 2012. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP-TransmissionPlanning-Investment-DRAFTWhtppr_11-5-12.pdf
[30] Response to WIEC Data Request 22.15
[31] Response to WIEC Data Request 23.13
[32] Response to WIEC Data Request 8.28

to review the "change in need" for Gateway due to Bridger Unit 3 and 4 retirements in this docket, which is ostensibly about the economics of retrofitting versus retiring these same units, the Company denies ratepayers the opportunity to avoid unnecessary and non-useful infrastructure and costs, and biases this analysis against a retirement decision.

Q How has the Company framed the requirement for Gateway West in light of the potential retirement of Jim Bridger 3 & 4?

A The Company provided a confusing and contradictory assessment. In response to discovery, the Company stated that:

> Retirement of Jim Bridger 3 & 4 would reduce the need to transport thermal resources westward between the proposed Anticline substation and existing Populus substations from Wyoming to the Company's load centers, but it would not avoid the need for more transmission capacity out of Wyoming. The Company's transmission system is highly constrained east of Bridger and limits the Company's ability to reliably transport low cost energy including existing and future thermal and renewable energy sources therein. Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West in that regard.[33]

The retirement of Jim Bridger 3 & 4 would reduce the requirement on the Anticline (at Bridger) to Populus link. However, the Populus substation is in Idaho, and therefore "out of Wyoming," so these statements are contradictory. Further, the assertion that the "transmission system is highly constrained <u>east</u> of Bridger" is irrelevant, as the links of concern are west, not east, of Bridger.

[33] Response to WIEC Data Request 1.83.

Q **Is the Company's transmission system constrained west of Bridger?**

A No. Asked almost precisely this same question, the Company responded that the path[34] between Jim Bridger and the Populus terminal (Path 19) "was one of the most congested WECC paths in 2010 according to the 2009 WECC Path Utilization Study released in 2010."[35] The terms "congested" and "constrained" should not be confused in this circumstance.

The current transmission system, <u>west</u> of the Jim Bridger Generating Station is also referred to as the Bridger West Path or WECC Path #19. It is comprised of the three 345 kV lines originating at the Jim Bridger Generation Station, as shown in Table 3, below. The Bridger West Path has an East to West rating of 2,200 MW with no established rating West to East.

Table 3. Current Bridger West Path segments and rating. Source: 2011 WECC Path Rating Catalog.

Bridger West Path Segments (Existing)	WECC Path Rating
Jim Bridger – Borah 345 kV	2200 MW (East to West)
Jim Bridger – Kinport 345 kV	
Jim Bridger – Goshen 345 kV	

The Company referred to the 2009 WECC Path Utilization Study, which indeed shows that the path maintained a high usage in 2009.[36] However, the utilization of this path does not indicate an actual constraint. Path 19 was designed to serve as a generation outlet for Jim Bridger, and carry generation from Dave Johnston, and Wyodak plants, as well as other resources in Wyoming and points east.

Where transmission lines are designed to serve as a generation outlet, the utilization metrics such as U75 or U90, which indicate loading of the transmission line over 75% and 90% of its rating, need to be viewed in light of the load they

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[34] A "path" is generally a system of transmission lines that connect two (or more) major susbstations, terminals, load centers, or regions. A path may be a single line, or a group of lines that collectively connect two areas.

[35] Response to WIEC 22.16.

[36] Presumably the Company meant to state that the line was congested in 2009, as the study reviews 2009 vintage data, and was released before 2010 was complete.

are designed to carry. Specifically, a high U75 metric for a transmission line solely serving as outlet from a non-intermittent generating resource should not be viewed as an indicator of transmission congestion.

Q How well is the Bridger West Path utilized at its current capability?

A Based on studies and analyses for the years 2007 to 2009, the Bridger West Path is highly utilized and as of 2009, had zero available transfer capability (ATC) for 95% of the year.[37] The path is, however, designed to be highly utilized to this level to accommodate the output of the Jim Bridger Generation Station, and therefore, such utilization is expected and appropriate.

Q What is the configuration of the proposed segment of the Gateway West Transmission Project on the western side of Jim Bridger?

A The proposed plan relevant to the transmission system west of the Jim Bridger Generating Station (Segment 4: Jim Bridger-Populus) is to add the Populus 500 kV & 345 kV buses, the 3 Mile Knoll 345 kV bus, and two Bridger-Populus 500 kV transmission lines to the existing transmission system.[38]

Q How does this change the Bridger West Path and what capability will be achieved after these additions are in service?

A As a consequence of Gateway West transmission additions, the enhanced Bridger West Path will be as shown in Table 4, below.

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[37] WECC Path Reports, 10-Year Regional Transmission Plan, Western Electricity Coordinating Council, September 2011 (Attached as Exhibit 310).

[38] Gateway West Comprehensive Progress Report, Idaho Power Company, Submitted to WECC, November 2008 (Attached as Exhibit 311).

Table 4. Current Bridger West Path segments and rating. Source: 2011 WECC Path Rating Catalog.

Bridger West Path Segments (Existing and Proposed)	WECC Path Rating
Jim Bridger - 3 Mile Knoll 345 kV	5,200 MW
Jim Bridger - Populus #1 345 kV	
Jim Bridger - Populus #2 345 kV	
Jim Bridger - Populus #1 500 kV	
Jim Bridger - Populus #2 500 kV	

The new path rating for the Bridger West Path will be 5,200 MW, by adding 3,000 MW of capability to the existing path rating of 2,200 MW.[39] In some documents[40] the project appears to be divided into two phases: The first phase may entail the installation of the first 500 kV line, and the second phase entails the installation of the second.

Q What are the expected in-service dates of the Gateway West Transmission Project?

A The proponents of the project, Idaho Power and Rocky Mountain Power, anticipate that the project will be brought online in phases between 2016 and 2021. According to the Company, two phases of the segment from Bridger to Populus will be brought online in [redacted].[41]

The link is modeled in [redacted] in the GRID model.[42] In System Optimizer, the link occurs in two additions, in [redacted].[43]

[39] Gateway West Transmission Line DRAFT EIS, US Bureau of Land Management, Chapter 1, Table 1.3-1, Neglecting additional 200 MW path rating not in presently in service, Published 2011 (Attached as Exhibit 312).
[40] Attach WIEC 1.4-1 CONF (Attached as Exhibit 313).
[41] Attach WIEC 1.4-1 CONF (Attached as Exhibit 313). See Jim Bridger to IPC East transmission segment.

[42] Attach WIEC 1.4-2 CONF (Attached as Exhibit 314). In-Service date [redacted].
[43] *See* Confidential Attachment WIEC 1.18 VENTYX CONF\Operates\CapEx_TransmissionOptions.gms (Attached as Exhibit 323), Tie Option-I Bridger E-PathCS and Tie Option I Bridger E-PathCS2.

Q How much will the Gateway West Transmission Project cost?

A According to the Company, the segments between Windstar and Populus will cost about $1.8 billion.[44] The individual segments between Windstar and Populus are shown in Table 5, below.

Table 5. Cost of Windstar to Populus transmission line segments

Transmission Line Segments	Cost ($ millions)
Windstar – Aeolus	$287.5
Aeolus – Bridger	$748.2
Bridger – Populus	$768.8
Total	**$1,804.5**

It is not at all clear whether these costs are for the entirety of the Gateway West project, or for the first phase of the project only. The evidence indicates that, based on a rough per-mile cost, that the cost of the Bridger – Populus segment may represent the cost of the first phase only (i.e. a single 500 kV line).

Q How much will the segment from Jim Bridger (Anticline) to Populus cost, according to the Company's model?

A The Company models the costs of each link explicitly in System Optimizer. A [redacted] MW link in [redacted] from Jim Bridger in an east-bound direction (to "Path C(N)") is modeled at [redacted] million, while an [redacted] MW link in [redacted] (at the same location) is modeled at [redacted] million.[45]

Q Are there other planned links that may be avoidable if Jim Bridger 3 and 4 are retired and replaced with capacity closer to the load centers?

A Yes. The Company has also modeled a link from the equivalent node of Populus ("Path C(N)") to the Utah North load center.[46] This [redacted] MW link, built in [redacted] is modeled at [redacted] million in the System Optimizer model.

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[44] Attach WIEC 13.2 (Attached as Exhibit 315).
[45] *See* Confidential Attachment WIEC 1.18 VENTYX CONF\Operates\CapEx_TransmissionOptions.gms (Attached as Exhibit 323), Tie Option-I Bridger E-PathCS and Tie Option I Bridger E-PathCS2.
[46] *See* System Optimizer Topology in Attach WIEC 1.22-1 CONF (Attached as Exhibit 325)

Q Do the materials provided by the company as justifications for any planned transmission capacity expansions west of Jim Bridger clearly demonstrate the need for this new transmission for reliability purposes or to relieve current constraints?

A No. The company provided two study reports, namely, (a) '2011 Loads & Resource Study for PacifiCorp's Eastern Control Area (PACE)' ("2011 Loads and Resources Study") and (b) '2011 PacifiCorp East TPL Summary Assessment' ("2011 TPL Assessment") in response to WIEC Data Request 22.16-2 ,to serve as justifications for planned transmission capacity expansion west of Jim Bridger.

For the 2011 Loads and Resources Study, the entire PACE area was divided into 11 'load bubbles' as regional demarcations that share similar geography or other characteristics such as transmission (see map in Figure 5). Each of the 11 bubbles was examined with respect to existing and planned generation for determining required transmission capability into each of the bubble (area).

The study refers to the Energy Gateway transmission improvements as projects that will eliminate transmission constraints in the region to the east of Bridger,[47] and will enhance the ability to move generation resources, including new wind resources to other areas to serve network load. The document indicates, however, that <u>none</u> of the 11 load bubbles are expected to be deficient in meeting projected load due to any transmission constraints and specifically, are not dependent on any transmission expansion west of Bridger to meet projected load.

One segment of the Energy Gateway West project would connect Jim Bridger Generating Station to the Populus substation. However, neither the Bridger Generating Station nor the Populus substation appear to be considered as a generation resource and load in any of the 11 load bubbles. Therefore, there is no justification for the need of this project in the aforementioned report

[47] Specifically, relieving a "nomogram" of two paths of transmission leading from eastern Wyoming to the center of the state.

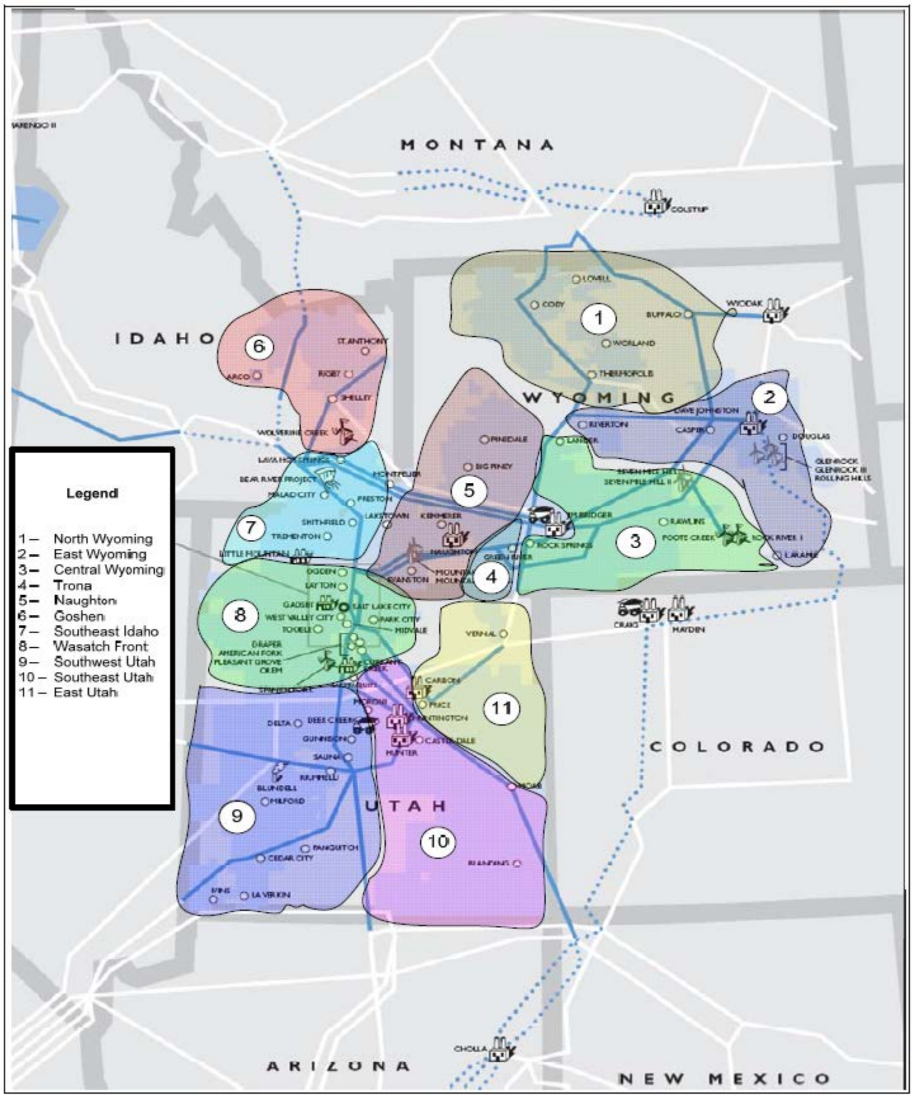

Figure 5. Resource bubbles in 2011 Loads and Resource Study.[48]

The 2011 TPL assessment is essentially a transmission reliability study that studies the company's transmission system for North American Electric Reliability Corporation (NERC) Transmission Planning Standards. The study involves evaluating the transmission system for reliability under normal and contingency events such as outage of one or more transmission lines. In case of this study, the company developed 2012 heavy summer, 2012-2013 light winter

[48] *See* Attachment to WIEC 22.16 -2, page 10.

and 2016 heavy summer base cases to study near term and a 2021 heavy summer base case to study long term load periods. However, it is not clear as to which base cases specifically contain the Gateway West Transmission Projects (new transmission lines west of Bridger). In this assessment, the company has formulated a list of required facilities for mitigation of reliability concerns to meet applicable NERC standards. However, it appears that none of the required facilities are associated directly with the Gateway West Transmission project, and specifically, none are associated with the links west of Bridger.

Q How will the enhanced Bridger West Path be utilized in the future?

A From a forward looking congestion analysis based on production cost model runs of 2019 and 2020 data sets, the Bridger West Path would not be heavily utilized or congested in 2020. In this expected future case, the Bridger West Path operated above 75% utilization for only 2.71% of the year.[49] This study assumed that only Phase 1 of the Gateway West transmission project was in service with a 3,700 MW rating for the Bridger West Path.

Q Please summarize why these planning and reliability studies matter in the context of avoiding transmission expenses with the retirement of Bridger 3 and 4.

A Very simply, the Company has not demonstrated that the links in the Gateway West project westward of Jim Bridger are unavoidable. The proposed links do not relieve current constraints and do not address specific reliability concerns. It is my opinion that many of the links to the west side of Jim Bridger could be avoided, deferred, or reduced if Jim Bridger 3 and 4 are retired.

Q What is the opportunity to avoid transmission expenditures?

A The Bridger 3 & 4 units currently have a combined capacity of about 700 MW. If the [redacted] transmission line from Bridger to Populus no longer had to carry this

[49] WECC Path Reports, 10-Year Regional Transmission Plan, Western Electricity Coordinating Council, September 2011 (Attached as Exhibit 310).

load, the existing infrastructure could carry an additional 700 MW of capacity from other locations (i.e. wind further upstream, as suggested by the Company).[50]

The Company has clearly not taken this potential into account. Were the Company to defer or avoid the cost of a 500 kV line by putting a replacement capacity resource at a different location (i.e. not at Bridger), the savings would be in the hundreds of millions of dollars.[51] Referring to the Company's inputs to the System Optimizer model, the [redacted] link from Jim Bridger to the Populus location ("Path C(S)") could be avoided completely for a net savings of [redacted] million in the retirement scenario.[52] In addition, the Company modeled the transmission path from Wyoming to Utah and Oregon as effectively uni-directional streams.[53] Therefore, the new proposed links from Path C down to Utah could likely be deferred or avoided as well. The proposed [redacted] link from Path C(S) to Utah could be avoided for a net savings of [redacted] million in the retirement scenario.[54] In total, I estimate the Company could avoid about [redacted] million in planned transmission.

Q **Could the Company use their existing System Optimizer model to explore the opportunities to avoid transmission investments with the retirement of Jim Bridger?**

A Yes. For evaluation purposes, the Company could have simply de-activated these extraneous "transmission options" in the model scenario where Jim Bridger is retired, and evaluated the total cost without these links.

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[50] See WIEC Data Request 13.4 (Attached as Exhibit 316).

[51] For example, generic costs for a single kV circuit with a 1,500 MW capacity are approximately $1.8 million per mille (see Generation & Transmission Model Methodology & Assumptions, Western Renewable Energy Zones, Black & Veatch, June 2009, Attached as Exhibit 318). At 200 miles, avoiding a single circuit line could avoid around $360 million.

[52] *See* Confidential Attachment WIEC 1.18 VENTYX CONF\Operates\CapEx_TransmissionOptions.gms. Tie Option-I Bridger E-PathCS. (Attached as Exhibit 323)

[53] Wyoming to Utah: [redacted]. Return flow allowed only through [redacted] MW pipe. Wyoming to Oregon: [redacted] to points west.

[54] *See* Confidential Attachment WIEC 1.18 VENTYX CONF\Operates\CapEx_TransmissionOptions.gms. Tie Option-I_PathCSouth-UtahN2.

6. ANALYSIS DEPENDENT ON RECOVERY OF COSTS FOR SEPARATE ENTITY COAL COMPANY

Q What is the Company's planning proposal for the Bridger Coal mine if Bridger 3 or 4 are retired?

A According to Mr. Link, "the analysis takes into consideration how the fueling plan for the Jim Bridger plant would change if Jim Bridger Unit 3 and/or Unit 4 were to stop burning coal."[55] According to the Company, "there would be insufficient generation demand at the Jim Bridger plant to support the continued operation of the Bridger Coal surface operation in either the two-unit or three-unit operation,"[56] and therefore the Company would immediately begin the reclamation and closure of the surface mining operation. The Company claims that it would be required by Wyoming rules to begin immediate remediation of the coal mine under Wyoming statute.[57] To support the expensive (and near-term) closure process, the Company claims it would need to collect additional fees from Bridger 1 & 2 in the form of a higher coal cost in the near term.

The overall impact of this claim on the CPCN analysis is that the Company inappropriately burdens the decision to close Bridger 3 and/or 4 with significantly higher costs for coal at Jim Bridger, and additional capital costs for the coal mine incorporated into the gas conversion case.

Q What impact does this higher coal cost have on the analysis results?

A In the Company's base case, the difference due to the adjustment in fuel and capital costs at the Bridger mine amount to about [redacted] million in favor of retaining coal generation at the Bridger 3 & 4 units.[58] This difference in outcome

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55 Direct Testimony of Rick T. Link. Page 15, lines 300-302
56 Response to WIEC Data Request 6.7(b). September 26, 2012.
57 Company cites to Wyoming Statutes Title 35 – Public Health and Safety, Chapter 11 – Environmental Quality, Article 4- Land Quality, 35- 11-402 Establishment of Standards (a) (iii) in response to WIEC Data Request 6.8, September 26, 2012 (Attached as Exhibit 319)
58 See response to Data Request WIEC 14.3 (Attached as Exhibit 320), November 2 2012. In WIEC Attach 14.3 CONF. In case where JB3&4 are coal, adjustment to coal cost is [redacted] [Coal Adjustments D126] and to fixed costs are [redacted] [Mine Capital Adjustments D20]; in retirement case, adjustment to fuel is

amounts to nearly half of the Company estimated total [redacted] million benefit of maintaining coal generation at Bridger 3 & 4 under the Company's base gas (December 2011) and base CO_2 ($16/ton in 2021).[59]

Q What is the problem with the adjustment for the cost of coal at Jim Bridger?

A There are two issues with the attachment of the outcome of this analysis to the fate of the Bridger coal mine:

1. The sheer scale of the adjustment, nearly half of the favorable outcome of maintaining Bridger, shows that the Company has tied the fate of Jim Bridger generating unit to the profitability of the Bridger Coal Company. The Company would literally be operating a generating station just so that it could pay off the remediation costs of a mining interest.

2. Bridger Coal Company could feasibly sell coal to other facilities, maintaining surface operations and offsetting remediation costs, and therefore not burden the Bridger unit with the costs of an accelerated remediation process.

Q Why is the impact of remediation a problem for the analysis outcome?

A Maintaining the profitability of a coal mine is an inappropriate reason to build an expensive environmental retrofit required for the continued operation of an electric generating unit. The conclusion that cases in which PVRR(d) results fall between [redacted] million and the breakeven point in favor of SCR installation, therefore, are questionable and strongly dependent on a requirement that ratepayers assume responsibility for Bridger Coal Company's profitability. This category of questionable cases includes the updated base gas price (September 2012) at the mid and low Synapse CO_2 prices as well as the updated low gas price at the zero CO_2 price.

[redacted] [Coal Adjustments D280] and to capital cost is [redacted] [Mine Capital Adjustments D79]. Total difference is [redacted].

[59] Company re-adjusted figures in response to WIEC 14.3 and supplied revised values in worksheet dated 11/2/2012.

Q Did the Company calculate potential savings from sales of Bridger coal to other entities?

A No. The Company claims that it would be unable to sell Bridger coal. According to the Company, "Bridger Coal Company is located in southwest Wyoming, a relatively small niche market. The vast majority of the coal produced in this region is consumed locally either by the "trona" patch companies or power plants."[60] The Company goes on to describe the lack of demand for this particular brand of coal, and that "the lack of competitive transportation alternatives undermines the ability of Southwest Wyoming coals to economically compete with coals from other production basins." There is no evidence that the Company has issued any form of market exploration to see if such sales could or should be pursued.

Q Is there any evidence showing that Bridger coal could be sold economically?

A Yes. Company information shows that Bridger coal could competitively supply at least [redacted] PacifiCorp coal plants in the case that Jim Bridger 3 & 4 are taken out of service.

[60] Response to WIEC Data Request 8.25 (Attached as Exhibit 321)

[redacted]

Figure 6. Confidential. Delivered Cost of Coal to PacifiCorp Plants.[61]

Figure 6, above, shows the delivered cost of coal as assumed by the Company in this analysis (excluding Cholla). The expected long-run cost of coal at [redacted] are all more expensive than the expected cost of Bridger coal from 2020 through most of the analysis period, and both [redacted] coals are over a dollar per MMBtu more expensive than Bridger after 2016. Accordingly, purchasing Bridger coal could represent a cost savings to these [redacted] plants.

Without additional information about the potential transportation costs from Bridger to other generators, or about the potential capital costs required to enable significant export from Bridger mine, I cannot definitively state the expected cost

[61] Source: Master Assumptions (10 - Coal Fuel Cost No Refuel) and PVRR_Tables_Final_JB3+4 (Coal Adjustments)

of transporting the coal from Bridger mine to other PacifiCorp sites. However, Black Butte mine, which delivered approximately 42% of Jim Bridger's coal supply in 2011,[62] also delivers coal to North Valmy station in northern Nevada, about 500 (road) miles distant. In 2011, Black Butte delivered coal to Jim Bridger at an average price of $1.87/MMBtu, and to Valmy at $2.87/MMBtu.[63] If the differential here of approximately $1/MMBtu is due to transportation costs alone, evidence indicates that Bridger mine coal could be delivered to other PacifiCorp locations at a competitive price to their anticipated supply costs.

Q How would selling Bridger mine coal benefit the economics of the decision to install SCR at Jim Bridger?

A The Company has assumed that the Jim Bridger unit alone should bear the cost of an accelerated mine closure, and has tied the fate of the Jim Bridger coal unit to that of the mine. If these costs can be decoupled, i.e. if the Company can find a reasonable strategy such that it could still recover costs for the Bridger mine closure, then the Company would not need to make this inverted decision – that of choosing to maintain a plant simply to recover mine remediation costs. Selling Bridger mine coal to third parties, or other PacifiCorp generating units, could provide such an opportunity. Under this assumption, even if continuing the mine operation is not optimal from the mine's standpoint, if the overall burden to ratepayers is reduced then the solution is an improvement.

Q What is your recommendation for this analysis regarding coal prices?

A The Company has not shown that Bridger Coal Company can only sell coal to the Bridger Plant or that the Bridger Plant can only purchase coal from the Bridger Coal Company. If the Bridger Coal Company can sell its coal, then it should be projected to do so at the market price. If the Bridger Plant can purchase coal, then it should be projected to do so at the market price. Unless the Bridger Coal

[62] US DOE EIA. Form 923. 2011. Schedule 5.
[63] US DOE EIA. Form 923. 2011. Schedule 5. Simple average for 2011 reported data.

Company and Bridger Plant are in fact a single business entity, the appropriate way to evaluate the impact of future coal prices on Bridger Plant operations is to use the <u>opportunity cost</u> of coal at the market price.

It is my opinion that if the market price for coal is higher than the price currently charged by Bridger Coal Company to Bridger Plant, that higher price should be used in the analysis. On the other hand, if the market price for coal is lower than the projected price that will be charged by Bridger Coal Company to Bridger Plant in the event of accelerated surface mine reclamation due to Bridger 3 & 4 retirement, then that lower market price should be used in the analysis. As in any forward looking planning, decisions regarding the future operating strategy for Bridger 3 & 4 should be based on an analysis using the future market prices for coal and not the Bridger Coal Company price.

7. <u>REQUIREMENT FOR SCR NOT ENFORCEABLE UNTIL 2018</u>

Q Does the Company need to move forward with construction of SCR on Jim Bridger 3 & 4?

A No. As my testimony above shows, moving forward with construction of SCR is not in the best interests of ratepayers. However, even if you set aside all of my previous testimony regarding the lack of economic merit for the proposed construction, there is no reason for the Company to move forward with the proposed construction right <u>now</u>.

The Company proposes to complete the projects at Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. The Company filed its application with the Commission based in part on its requirement to comply with the Environmental Protection Agency's ("EPA") final BART determination for all four of the Jim Bridger coal-fired power plant units.[64] When the Company initiated this proceeding, EPA had already issued a <u>proposed</u> BART

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[64] Direct Testimony of Chad A. Teply, p. 41.

determination accelerating the requirement to install SCR on Units 1 and 2 (i.e. December 2015 and 2016, respectively).[65] The Company believed that EPA would issue a final BART determination for the Jim Bridger facility by mid-October of 2012, which would have allowed sufficient time to incorporate EPA's final rule into the evidentiary record of this proceeding, and presumably would have allowed the Company and the Commission to consider any additional economic impacts that would result from accelerating the installation of SCR on Units 1 and 2. However, in December 2012, EPA requested and received an extension to a court-ordered deadline to issue a final BART determination for Jim Bridger and the other Wyoming BART-eligible facilities (the "Consent Decree").

Q Please briefly describe the recent revisions to the Consent Decree governing the schedule under which EPA is required to issue a final rulemaking with respect to BART determinations for Wyoming BART-eligible facilities.

A On December 13, 2012, EPA notified the public that it was delaying its final BART determination for the Jim Bridger facility. Rather than issuing a final decision in October 2012, EPA will now issue a new proposed BART determination for Jim Bridger by March 29, 2013, with a final rule to follow by September 27, 2013. All four of the Jim Bridger units are BART eligible; therefore, EPA's final BART determination will affect the entire plant. EPA's proposed rule, now withdrawn, had proposed to approve the state's submittal on timing and configuration to install SCR at Jim Bridger units 3 and 4, but rejected the state's plan for units 1 and 2 and accelerated the requirement to install SCR on those units.[66] The fact that EPA has withdrawn its prior draft rule and will issue a new draft rule addressing BART-eligible facilities in Wyoming makes it reasonable to assume that EPA intends to significantly revise its prior proposal.

[65] 77 Fed. Reg. 33036. June 4, 2012.
[66] 77 Fed. Reg. 33053. June 4, 2012.

Q What impact does the EPA delay have on the Company's timeline for compliance with the Regional Haze Rule?

A With the delay in issuing the final BART determination and the withdrawal of EPA's previous proposal to approve the timing of installation of SCRs as BART for Bridger Units 3 and 4, the Company's compliance obligations with regard to the Regional Haze Rule are uncertain. Even assuming EPA does ultimately approve the SCRs as BART, it is quite possible that the final rule could impose a more stringent emission limit, which in turn could cost more money. PacifiCorp acknowledged that it has not factored in these potential cost increases into its analysis of the proposed SCR projects.[67]

In addition, the anticipated federal compliance deadline that the Company previously relied upon to justify installation of SCRs by the end of 2015 and 2016 will certainly not materialize. Under the Visibility Protection section of the Clean Air Act, the Company has a maximum of five years from the date of approval of a plan revision (or, in this case, of promulgation of a plan revision by EPA) to procure, install, and operate the best available retrofit technology. 42 U.S.C. 7491(b)(2)(A). If the final promulgation of EPA's BART determination for the Jim Bridger facility will take place on September 27, 2013, assuming the determination is published immediately, then the new compliance deadline for the installation and operation of BART controls in Wyoming would be no earlier than September 27, 2018. This timeframe gives the Company nearly 3 additional years before controls must be in place, or in the alternative, before replacement capacity must be procured.

[67] Rocky Mountain Power's Mem. in Opp'n to Sierra Club's Mot. for a Stay or Continuance Pending Final Action, January 10, 2013 at fn 5.

Q What about the Company's claim that it must install the SCRs on units 3 and 4 by the ends of 2015 and 2016, respectively, in order to comply with the 2010 BART Settlement Agreement and the Wyoming Environmental Quality Council's subsequent order incorporating the terms of the Settlement Agreement?

A The Company's claim refers to the 2010 BART Settlement Agreement with the Wyoming Department of Environmental Quality ("WDEQ") and the subsequent Environmental Quality Council Order that included deadlines for the company to install SCRs on Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. I agree that if the Company were to take no action, those state-based deadlines would remain in place. However, given EPA's recent action to delay its final BART determination, it is very likely that PacifiCorp and WDEQ could reach an agreement to modify the applicable deadlines.

Section 7 of the Settlement Agreement states that the Agreement may be modified "if future changes in either: (i) federal or state requirements or (ii) technology would materially alter the emissions controls and rates that otherwise are required hereunder."

With the delay in EPA's issuance of its final BART determination for Bridger units 3 and 4, the actual emissions control requirements for these units have been delayed until at least September 27, 2018. With this date as the new backstop for compliance with the Federal Regional Haze Rule, the Company should, for the benefit of its ratepayers, seek to amend the Settlement Agreement and the Environmental Quality Council Order to delay installation of the SCRs at Bridger units 3 and 4, in accordance with the new EPA compliance deadline.

Q Is there any indication that WDEQ and the Environmental Quality Council would be amenable to a request to modify of the BART Settlement Agreement?

A Yes. In fact, PacifiCorp is currently pursuing this exact request with respect to its Naughton 3 facility. In Docket No. 20000-400-EA-11, Rocky Mountain Power witness Mr. Chad Teply explained in rebuttal testimony that the Company was pursuing a delayed timeframe to implement the Regional Haze Rule requirements at Naughton 3: "The Company does plan to pursue an extended regional haze compliance timeframe with the state of Wyoming Department of Environmental Quality and the EPA."[68] Ms. Cathy Woollums, the senior vice president of environmental services and chief environmental counsel for PacifiCorp's parent company, MidAmerican Energy Holdings Company, later appeared before the Environmental Quality Council on January 10, 2013 to update the council on the Company's plans to modify the BART Settlement Agreement and related permits with respect to Naughton Unit 3. These actions by the Company show that it very possible – and according to the Company, potentially beneficial for ratepayers – to work with WDEQ to request a modification to the BART Settlement Agreement as circumstances change.

It is also my understanding that at the January 10, 2013 Environmental Quality Council meeting,[69] the Environmental Quality Council indicated that it would be amenable to considering a request to change the Jim Bridger compliance dates in the Order and the Settlement Agreement to reflect EPA's revised timeframe if WDEQ or the Company asked for it. To my knowledge, however, the Company has not made any request to either WDEQ or the Environmental Quality Council seeking an extension of the state deadlines.

Q Should PacifiCorp seek a delay in the state Regional Haze compliance deadlines for Jim Bridger?

A Yes. PacifiCorp's apparent refusal to even request an extension is irrational. As I have shown in my testimony above, the relative economic benefit or liability of the proposed SCRs at Jim Bridger units 3 and 4 is highly dependent on changes to natural gas prices and CO_2 prices. Table 2 above shows that under the Synapse Mid CO_2 price and the September 2012 base gas price (i.e. the "mid-mid

[68] Docket No. 20000-400-EA-11, Rebuttal Testimony of Chad A. Teply, April 2012, p. 9.
[69] Environmental Quality Council Meeting cited by Ms. Woollums in response to WPSC Data Request 4.2

scenario"), the decision to install SCR is essentially a wash.[70] Given that the Company will not face a federal requirement to install SCR controls until September 2018 at the earliest, it would be beneficial for ratepayers for the Company to take the extra time to evaluate whether changes in either the gas market or the cost of CO_2 become clearer in the coming months or years. Rushing the decision now puts the risk on ratepayers that circumstances will change in such a way that makes the SCR expenses even more unfavorable.

Waiting for more certainty from EPA would also allow the Company to consider any potential changes in the economics of the project if EPA imposes stricter emission limits on 3 and 4, and it would allow the Company to fully consider the economic impact of SCR at all four of the Jim Bridger units instead of considering only units 3 and 4 independently in the current proceeding.

8. CONCLUSIONS AND RECOMMENDATIONS

Q What are your firm conclusions on the outcome of this analysis?

A From the three major areas I have discussed here, (a) gas and CO_2 prices, (b) the opportunity to avoid transmission investments, and (c) the assumption Jim Bridger generating station must make whole Bridger Coal Company, it is my opinion that there is sufficient evidence to show that the retrofit of Bridger is not in the best interests of ratepayers. At best, the analysis shows a marginal outcome for ratepayers if the analysis is adjusted to reflect a reasonable and updated base case. Further, the Company's continued inability to find opportunities to protect ratepayers against inefficient investments shows that the investment is not merely marginal, but a net liability for consumers. Finally, this entire docket is premature because the Company should pursue an extension of the date to install SCR on Jim Bridger units 3 and 4 given EPA's decision to delay its final BART determination.

[70] The decision is 50/50 only before considering the avoidable transmission costs and before removing costs related to the Jim Bridger coal mine.

Docket No. UE 374
Exhibit Sierra Club/408
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 408

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Redacted Rebuttal Testimony of Chad Teply in 20000-418-EA-12 (Wyo. P.S.C.) (excerpt)

REDACTED
Docket No. 20000-418-EA-12
Witness: Chad A. Teply

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Rebuttal Testimony of Chad A. Teply

March 2013

transmission expenditures, particularly as those opportunities may be impacted by the installation of the Jim Bridger SCR Project.

2) Sierra Club asserts that the retirement and replacement of Jim Bridger Units 3 and 4 with capacity closer to PacifiCorp's load centers would likely allow avoided or deferred transmission system expenditures.

Q. Are the Company's current plans for future Energy Gateway transmission project segments at issue in this case?

A. No.

Q. Is the Jim Bridger Units 3 and 4 SCR Project decision-making process under review in this docket dictated by the future segments of the Energy Gateway transmission project?

A. No.

Q. Has the Company incorporated reasonable assumptions regarding the Energy Gateway segment scenarios into its System Optimizer analyses supporting this docket?

A. Yes. The System Optimizer Model analyses used to support this docket assume the Energy Gateway project is implemented and includes Energy Gateway West transmission investments (Windstar to Populus and Populus to Hemmingway).

Q. Did WIEC witness Mr. Falkenberg's analyses of the impacts of potential future Energy Gateway transmission project segments identify any material impacts on the Jim Bridger Units 3 and 4 SCR Project investment decision?

A. No. Mr. Falkenberg's testimony surmises:

> Consequently, the Gateway project does not, by itself, enhance the value of continued coal operation of Bridger Units 3 and 4, nor

Docket No. UE 374
Exhibit Sierra Club/409
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 409

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

PacifiCorp Response to Wyoming Industrial Energy Consumers Data Request 1.83 in 20000-418-EA-12 (Wyo. P.S.C.)

20000-418-EA-12/Rocky Mountain Power
September 13, 2012
WIEC 1st Data Request 1.83

WIEC Data Request 1.83

Would early retirement of Bridger Units 3 and 4 enable the deferral or avoidance of any of the Gateway transmission links? If so, please identify which links and over what period of time. If not, please explain all reasons why not.

Response to WIEC Data Request 1.83

Retirement of Jim Bridger 3 and 4 would reduce the need to transport thermal resources westward between the proposed Anticline substation and existing Populus substations from Wyoming to the Company's load centers but, it would not avoid the need for more transmission capacity out of Wyoming. The Company's existing transmission system in Wyoming is highly constrained east of Bridger and limits the Company's ability to reliably transport low cost energy including existing and future thermal and renewable energy sources therein. Retirement of Bridger Units 3 and 4 would not avoid the need for Gateway West in that regard.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 410

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Confidential Letter from PacifiCorp Energy's William K. Lawson to Wyoming DEQ's David Finley (Jan. 29, 2009)

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 411

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

UE 246: Ex. Sierra Club/114, 2003 PacifiCorp Control Report

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 412

CONFIDENTIAL

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

UE 246: Ex. Sierra Club/115, Air Quality Reference Case Investments

2005

This exhibit is confidential pursuant to Protective Order 20-040 and is provided under separate cover.

Docket No. UE 374
Exhibit Sierra Club/413
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 413

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Cal. P.U.C Advice Letter 507-E (July 21, 2014)

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 21, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

California Public Utilities Commission
Energy Division
Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, CA 94102
Email: edtariffunit@cpuc.ca.gov

Re: PacifiCorp (U 901-E) Advice Letter No. 507-E
Post Test Year Adjustment Mechanism—Major Capital Addition—Change PacifiCorp Rates on August 22, 2014

PURPOSE

PacifiCorp, d/b/a Pacific Power (PacifiCorp), hereby submits an original and one copy of Advice Letter No. 507-E to request authority to increase rates under the Post Test Year Adjustment Mechanism (PTAM) for Major Capital Additions authorized as part of PacifiCorp's most recent general rate case, Application No. (A.) 09-11-015, in Decision No. (D.) 10-09-010.

The affected schedules, attached to this letter as Exhibit A, are as follows:

Cal. P.U.C. Sheet No.	Title of Sheet No.	Canceling Cal. P.U.C. Sheet No.
3862-E	Table of Contents	3853-E
3863-E	Table of Contents – Rate Schedules	3854-E
3864-E	Schedule A-25 General Service	3829-E
3865-E	Schedule A-32 General Service	3830-E
3866-E	Schedule A-36 Large General Service	3831-E
3867-E	Schedule AT-48 Large General Service Metered Time of Use	3832-E
3868-E	Schedule D Residential Service	3833-E
3869-E	Schedule DL-6 Residential CARE	3834-E
3870-E	Schedule LS-51 Street and Highway Lighting	3835-E
3871-E	Schedule LS-52 Street and Highway Lighting	3836-E
3872-E	Schedule LS-53.1 Street and Highway Lighting	3859-E
3873-E	Schedule LS-53.2 Street and Highway Lighting	3838-E
3874-E	Schedule LS-58 Street and Highway Lighting	3839-E
3875-E	Schedule OL-15 Outdoor Area Lighting	3840-E
3876-E	Schedule OL-42 Airway and Athletic Field Lighting	3841-E
3877-E	Schedule PA-20.1 Agricultural Pumping	3842-E
3878-E	Schedule PA-20.2 Agricultural Pumping	3843-E

BACKGROUND

The PTAM for major capital additions was initially approved in PacifiCorp's 2005 general rate case, A.05-11-022 and D.06-12-011. In 2010, the Commission authorized the continuation of the PTAM for major capital additions when it issued its decision in PacifiCorp's 2009 general rate case, A.09-11-015, D.10-09-010.

In this advice letter, PacifiCorp requests authority to increase rates based on the PTAM for major capital additions consistent with the provisions of A.09-11-015 and D.10-09-010, PacifiCorp's 2009 General Rate Case, and the All-Party Joint Motion for Commission Approval and Adoption of Settlement Agreement (Settlement Agreement) approved by the Commission in that proceeding. As stated in the Settlement Agreement, Section 14, pages 6 and 7, "The Parties agree that Post Test Year Adjustment Mechanism (PTAM) capital additions and the ECAC mechanism will continue in accordance with D.06-12-011."

DISCUSSION

After consultation with the Office of Ratepayer Advocates, PacifiCorp submits this advice letter to request authority to adjust rates for costs associated with two major capital additions: Lake Side 2 Generating Facility and the Hunter emissions reduction project. Each of these capital additions exceeds $50.0 million on a total-company basis. The projects, described in more detail below, will allow the Company to continue to reliably serve customers with an adequate supply of low cost power.

Major Capital Additions
($000's)

Major Plant Addition	Total Capital Investment	Total Company Revenue Requirement*	California Allocated Revenue Requirement**
Lake Side 2	$670,585	$96,254	$1,718
Hunter Emissions Reduction Project	$75,356	$11,356	$203
Total			$1,921

*Includes O&M, depreciation, property taxes, and production tax credits.
**California's share of PacifiCorp's system-wide revenue requirement was determined based on the Revised Protocol Allocation Methodology that was approved in the most recent general rate case, A.09-11-015, D.10-09-010.

Lake Side 2 is a nominally rated 645 megawatt (MW) natural gas fired resource located adjacent to PacifiCorp's existing Lake Side 1 plant. It will provide cost-effective, natural gas-fueled generation for PacifiCorp's customers. The Lake Side 2 project is a "2x1" combined cycle facility consisting of two "F" class natural gas-fired combustion turbine-generators, two heat recovery steam generators equipped with nitrogen oxide emissions control systems and carbon monoxide oxidation catalysts, one steam turbine-generator, and the associated ancillary and support facilities. The facility is equipped with duct firing capability. The project includes a new 345 kilovolt (kV) switchyard and an interconnection to the new 345 kV Steel Mill Substation that connects with the Hunter-Camp Williams 345 kV transmission line.

The Hunter emissions reduction project is the conversion of the Hunter Unit 1 electrostatic precipitator to a pulse jet fabric filter baghouse. The installation of the baghouse is required for compliant operation under the Regional Haze Rules, the State of Utah's § 309 (g) Implementation Plan, the State of Utah's best available retrofit technology (BART) review process, and the state of Utah's Approval Order for Hunter Unit 1 (DAQE-AN0102370012-08) dated March 2008.

This filing will result in a proposed rate increase of approximately $1.9 million or 1.6 percent. A typical California residential customer using 900 kWh per month will see an increase of $2.23 per month. Exhibit B provides a breakdown of the effects of the proposed rate change by rate schedule. This proposed PTAM was calculated in accordance with the settlement agreement in PacifiCorp's 2005 general rate case A.05-11-022, Section 2.3.2, reaffirmed in A.09-11-015/D.10-09-010, and consistent with prior PTAM rate changes. Exhibit C shows the billing determinants and the present and proposed rates.

The proposed increase will result in the following changes by customer segment:

Customer Segment	**Increase**	**Increase (%)**
Residential	$1,001,000	1.6%
Commercial and Industrial	$690,000	1.5%
Irrigation	$214,000	1.5%
Streetlighting	$16,000	1.8%

PROTESTS

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, by facsimile or electronically, any of which must be received no later than August 11, 2014. [1]

Energy Division
Tariff Unit, 4th Floor
505 Van Ness Avenue
San Francisco, CA 94102
Email: edtariffunit@cpuc.ca.gov

[1] The 20-day protest period ends on a weekend so PacifiCorp is moving the date to the following business day.

Copies of protests should also be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above. In addition, the protest should be sent via U.S. mail (and electronically, if possible) to PacifiCorp at the address shown below on the same date it is mailed or delivered to the Commission.

Cathie Allen
Regulatory Affairs Manager
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
Telephone: (503) 813-5934
E-mail: californiadockets@pacificorp.com

With a copy to:

Sarah Wallace
Assistant General Counsel
Pacific Power
825 NE Multnomah, Suite 1800
Portland, OR 97232
Telephone: (503) 813-5865
Facsimile: (503) 813-7262
E-mail: sarah.wallace@pacificorp.com

There are no restrictions on who may file a protest, but the protest must set forth specifically the grounds upon which it is based and be submitted expeditiously.

EFFECTIVE DATE

This advice letter filing is submitted as a Tier 2 filing in compliance with General Order (GO) 96-B. PacifiCorp requests that this advice filing become effective on August 22, 2014.

NOTICE

In accordance with General Order 96-B, Section 4, a copy of this Advice Letter will be served electronically or via U.S. mail to parties shown on the GO 96-B service list and on the service list for PacifiCorp's most recent general rate case (A.09-11-015), copies of which are attached. A request for change of address in the GO 96-B service list should be directed by electronic mail to californiadockets@pacificorp.com. Advice letter filings may also be accessed electronically at www.pacificpower.net/regulation.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to (with a copy to the Company's counsel):

By email (**preferred**): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Please direct any informal questions to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

R. Bryce Dalley /ca

R. Bryce Dalley
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE
CA Advice Distribution List

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have on this 21st of July, 2014, at Portland, OR, provided via email or US mail, a true and correct copy of PacifiCorp's Advice filing No. 507-E to the following:

CA Advice Distribution List

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Amy Eissler
Coordinator, Regulatory Operations

Certificate of Service

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have provided via electronic mail or US Mail if an E-mail address has not been provided, a true and correct copy of **PacifiCorp (U 901-E) Advice Letter No. 507-E Post Test Year Adjustment Mechanism—Major Capital Addition—Change PacifiCorp Rates on August 22, 2014**to the following parties:

Service List
A.09-11-015

PARTIES

Cleveland Lee
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OR 97232
datarequest@pacificorp.com

Dated July 21, 2014.

Amy Eissler
Coordinator, Regulatory Operations

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. PacifiCorp dba Pacific Power (U 901 E)

Utility type:	Contact Person: Cathie Allen
✓ ELC ☐ GAS	Phone #: (503) 813-5934
☐ PLC ☐ HEAT ☐ WATER	E-mail: californiadockets@pacificorp.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: 507-E Tier [2]

Subject of AL: **PacifiCorp (U 901-E) Advice Letter No. 507-E Post Test Year Adjustment Mechanism – Major Capital Addition – Change PacifiCorp Rates on August 22, 2014**

Keywords (choose from CPUC listing): Electric Rate Schedule

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ✓ One-Time Other ______

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.10-09-010

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL N/A

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Resolution Required? ☐Yes ✓ No

Requested effective date: August 22, 2014 No. of tariff sheets: 15 plus table of contents

Estimated system annual revenue effect: (%): $1.9 million

Estimated system average rate effect (%): 1.6%

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: A-25, A-32, A-36, AT-48, D, DL-6, LS-51, LS-52, LS-53, LS-58, OL-15, OL-42, PA-20

Service affected and changes proposed[1]: N/A refer to advice letter for summary of filing

Pending advice letters that revise the same tariff sheets: N/A

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
edtariffunit@cpuc.ca.gov

Utility Info (including e-mail)
Cathie Allen
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
E-mail: californiadockets@pacificorp.com

3219/003/X87117.v1

[1] Discuss in AL if more space is needed.

Exhibit A

Proposed Tariff Schedules

TABLE OF CONTENTS

(Continued)

TABLE OF CONTENTS (Continued)

RATE SCHEDULES (Continued)

CONTRACTS AND DEVIATIONS

RULES

(Continued)

Schedule No. A-25

GENERAL SERVICE
LESS THAN 20 KW

APPLICABILITY

Applicable to single-phase or three-phase alternating current electric service, at such voltage as the Utility may have available at the Customer's premises, for all electric service loads which have not registered 20 kW or more, more than once in any consecutive 18 month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this Schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94, Schedule GHG-92 and Schedule GHG-93.

	Distrib.	FERC Trans.	Calif. Trans.	Gener-Ation	Public Purpose	Total Rate	
Basic Charge							
Single-Phase/Month	$12.64					$12.64	(I)
Three-Phase/Month	$17.35					$17.35	(I)
Energy Charge/kWh for all kWh	5.584¢	0.457¢	0.703¢	4.393¢	1.019¢	12.156¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

Minimum Monthly Charge

The monthly Minimum Charge shall be the Basic Charge for the current month. A higher minimum may be required under contract to cover special conditions.

(Continued)

Schedule No. A-32

GENERAL SERVICE
20 kW AND OVER

APPLICABILITY

Applicable to single-phase or three-phase alternating current electric service, at such voltage as the Utility may have available at the Customer's premises, for electric service loads which have ever registered 20 kW or more, more than once in any consecutive 18 month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Distribution Demand, Generation and Transmission Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All monthly billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Basic Charge							
Single-Phase/Month	$12.53					$12.53	(I)
Three-Phase/Month	$17.21					$17.21	(I)
Distribution Demand Charge/kW	$1.57					$1.57	(I)
Generation & Transmission Demand Charge/kW		$1.45	$1.11	($0.87)		$1.69	(I)
Reactive Power Charge/kVar				60.000¢		60.000¢	
Energy Charge/kWh for all kWh	3.763¢			4.472¢	0.952¢	9.187¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

(Continued)

Schedule No. A-36

LARGE GENERAL SERVICE - Optional
100 KW AND OVER

APPLICABILITY

Applicable to electric service loads which have not registered less than 20 kW or more than 500 kW more than once in a consecutive 18-month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this Schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for Customer's electric generation or other energy sources.

Non-profit group living facilities taking service under this Schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Distribution Demand, Generation and Transmission Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94, and Schedule GHG-92.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Generation**	**Public Purpose**	**Total Rate**	
Basic Charge	$225.31					$225.31	(I)
Distribution Demand Charge/kW	$2.87					$2.87	(I)
Generation & Transmission Demand Charge/kW		$1.45	$2.08	$0.88		$4.41	(I)
Reactive Power Charge/kVar				60.000¢		60.000¢	
Energy Charge/kWh for all kWh	2.370¢			3.096¢	0.881¢	6.347¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

(Continued)

Schedule No. AT-48

LARGE GENERAL SERVICE - METERED TIME OF USE
500 KW AND OVER

APPLICABILITY

This Schedule is applicable to electric service loads which have registered 500 kW or more, more than once in a consecutive 18-month period. This schedule will remain applicable until Customer fails to equal or exceed 500 kW for a period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads will be provided only by special contract for such service.

Partial requirements service for loads of 500 kW and over will be provided only by application of the provisions of Schedule AT-47.

Non-profit group living facilities taking service under this schedule may be eligible for a twenty percent (20%) low-income rate discount on their monthly bill, if such facilities qualify to receive service under the terms and conditions of Schedule No. AL-6.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Distribution Demand, Generation and Transmission Demand, Energy, and Reactive Power Charges; plus Metering and Delivery Adjustments.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Basic Charge	$451.55					$451.55	(I)
Distribution Demand Charge/kW	$1.93					$1.93	(I)
Generation and Transmission Demand Charge/kW - Summer**		$1.45	$2.30	($0.40)		$3.35	(I)
Generation and Transmission Demand Charge/kW - Winter**		$1.45	$2.30	$0.74		$4.49	(I)
Reactive Power Charge/kVar				60.000¢		60.000¢	
Energy Charge/kWh for all kWh	0.941¢			3.270¢	0.807¢	5.018¢	(I)

On-Peak Period Demand
(Monday through Friday: 6:00 a.m. to 10:00 p.m.)

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

**Note:

If the meter reading date is:	The charge is:
January 1 through April 30	Winter
May 1 through October 31	Summer
November 1 through December 31	Winter

(Continued)

Schedule No. D

RESIDENTIAL SERVICE

APPLICABILITY

Applicable to single-phase alternating current electric service for residential purposes in single-family dwellings and as specified under Special Conditions of this Schedule, to multiple dwelling units in which each of the single-family dwellings receive service directly from the Utility through separate meters. The rates specified herein will be designated for each service in accordance with the energy uses qualified and elected by the Customer. The Basic Residential Use and Electric Water Heating allowance will apply unless baseline allowances available for electric space heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All monthly billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92. Billings shall be adjusted in accordance with Schedule GHG-93.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Generation**	**Public Purpose**	**Total Rate**	
Basic Charge	$6.85					$6.85	(I)
Energy Charge:							
All Baseline kWh	5.061¢	0.457¢	0.509¢	3.074¢	0.946¢	10.047¢	(I)
All Non-Baseline kWh	6.556¢	0.457¢	0.509¢	3.420¢	0.946¢	11.888¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

Minimum Monthly Charge

The monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

SPECIAL CONDITIONS

1. No motor load shall exceed a total of 7 1/2 horsepower connected at one time.

2. All electric space heaters larger than 1,650 watts rated capacity shall be designed and connected for operation at 240 volts, and each space heating unit having a rated capacity of two (2) kilowatts or larger shall be thermostatically controlled by automatic devices of a type which will cause a minimum of radio interference. Space heaters served under this schedule shall be of types and characteristics approved by the Utility. Individual heaters shall not exceed a capacity of five (5) kilowatts.

3. Service under this schedule may be furnished to multiple family dwellings such as apartments, complexes, condominiums and mobile home parks in which the single-family dwellings receive service directly from the Utility through separate meters.

(Continued)

Schedule No. DL-6

RESIDENTIAL SERVICE
CALIFORNIA ALTERNATIVE RATES FOR ENERGY (CARE)
OPTIONAL FOR QUALIFYING CUSTOMERS

APPLICABILITY

Applicable to residential low income households in single-family dwellings and as specified further under special conditions of this Schedule, and Residential Service Schedule No. D, and for multiple dwelling units in which each of the single-family dwellings receive service directly from the utility through separate meters, and to multi-family accommodations which are separately submetered.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92. Billings shall be adjusted in accordance with Schedule GHG-93.

	Distrib.	FERC Trans.	Calif. Trans.	Gener-ation	Public Purpose	Total Rate	
Basic Charge	$6.85				($1.37)	$5.48	(I)
Energy Charge:							
All Baseline kWh	5.061¢	0.457¢	0.509¢	3.074¢	(2.409¢)	6.692¢	(I)
All Non-Baseline kWh	6.556¢	0.457¢	0.509¢	3.420¢	(2.777¢)	8.165¢	(I)

Adjustments:

The above Total Rate includes adjustments for Schedule S-99, Schedule S-191, Schedule S-192, and the CARE Adjustment which is equal to twenty percent (20%) of the Residential Service Schedule No. D Basic Charge and twenty percent (20%) of the Residential Service Schedule No. D Energy Charge Total Rate minus the Schedule S-100 surcharge.

Minimum Charge:

The monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

SPECIAL CONDITIONS

1. Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

(Continued)

Schedule No. LS-51

STREET AND HIGHWAY LIGHTING SERVICE
UTILITY-OWNED SYSTEM

APPLICABILITY

To un-metered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control.

AVAILABLE

Within the entire territory in California served by Utility.

MONTHLY BILLING

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

High Pressure Sodium Vapor
Functional

Nominal Lumen Rating	Watts	Monthly kWh	Rate Per Lamp Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
5,800*	70	31	$7.24	$0.14	$0.58	$1.87	$0.27	$10.10	(I)
9,500	100	44	$7.94	$0.20	$0.04	$2.35	$0.38	$10.91	(I)
16,000	150	64	$10.56	$0.29	$0.29	$3.41	$0.55	$15.10	(I)
22,000*	200	85	$13.17	$0.39	$0.18	$4.28	$0.73	$18.75	(I)
27,500	250	115	$17.02	$0.53	$0.58	$6.11	$1.00	$25.24	(I)
50,000	400	176	$24.99	$0.80	$0.53	$8.56	$1.52	$36.40	(I)

High Pressure Sodium Vapor
Decorative Series 1

Nominal Lumen Rating	Watts	Monthly kWh	Rate Per Lamp Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
9,500	100	44	$29.21	$0.20	$0.04	$2.35	$0.38	$32.18	(I)
16,000	150	64	$29.21	$0.29	$0.29	$3.41	$0.55	$33.75	(I)

High Pressure Sodium Vapor
Decorative Series 2

Nominal Lumen Rating	Watts	Monthly kWh	Rate Per Lamp Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
9,500	100	44	$23.25	$0.20	$0.04	$2.35	$0.38	$26.22	(I)
16,000	150	64	$23.45	$0.29	$0.29	$3.41	$0.55	$27.99	(I)

* - Existing fixtures only. Service is not available under this schedule to new 5,800 or 22,000 lumen High Pressure Sodium Vapor fixtures.

(Continued)

Schedule No. LS-52

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE
UTILITY-OWNED SYSTEM
NO NEW SERVICE

APPLICABILITY

To service furnished, by means of Utility-owned installations, for the dusk-to-dawn illumination of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. Utility may not be required to furnish service hereunder to other than municipal Customers. This schedule is closed to new customers as of January 1, 2010.

TERRITORY

Within the entire territory in California served by Utility.

MONTHLY BILLING

A flat rate equal to the monthly cost for operation, maintenance, fixed charges, depreciation and energy costs.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

High Pressure Sodium Vapor		Rate per Lamp						
Nominal Lumen Rating	**kWh per Month**	**Distrib.**	**FERC Trans.**	**Calif Trans.**	**Gener-Ation**	**Public Purpose**	**Total Rate**	
5,800	31	$30.45	$0.14	$9.74	$4.81	$0.99	$46.13	(I)
9,500	44	$31.53	$0.20	$9.19	$5.34	$1.40	$47.66	(I)
22,000	85	$39.28	$0.39	$9.19	$7.57	$2.71	$59.14	(I)
50,000	176	$54.33	$0.80	$8.55	$12.26	$5.60	$81.54	(I)

Adjustments

The above Total Rate includes adjustments as follows:

Nominal Lumen Rating	Schedule S-99	Schedule S-191	Schedule S-192
5,800	$0.01	$0.71	$0.26
9,500	$0.01	$1.01	$0.37
22,000	$0.02	$1.95	$0.72
50,000	$0.04	$4.03	$1.49

Energy Charge

The above rates include an energy charge as follows:

Base Rate	Schedule S-99	Schedule S-191	Schedule S-192	Net Rate	
11.995¢	0.024¢	2.290¢	0.845	15.154¢ per kWh for all kWh	(I)

TERM OF CONTRACT

Not less than five years for service from an overhead, or ten years from an underground, system by written contract.

(Continued)

Schedule No. LS-53

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE
CUSTOMER-OWNED SYSTEM
ENERGY ONLY SERVICE

APPLICABILITY

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of customer owned street lighting systems controlled by a photoelectric control or time switch.

TERRITORY

Within the entire territory in California served by Utility.

MONTHLY BILLING

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

High Pressure Sodium Vapor

Nominal Lumen Rating	Watts	Monthly kWh	Distrib.	FERC Trans.	Calif Trans.	Generation	Public Purpose	Total Rate	
			Rate Per Lamp						
5,800	70	31	$2.11	$0.14	$0.27	$1.22	$0.16	$3.90	(I)
9,500	100	44	$3.00	$0.20	$0.39	$1.73	$0.21	$5.53	(I)
16,000	150	64	$4.36	$0.29	$0.57	$2.52	$0.31	$8.05	(I)
22,000	200	85	$5.79	$0.39	$0.75	$3.35	$0.41	$10.69	(I)
27,500	250	115	$7.83	$1.53	$1.02	$4.53	$0.56	$14.47	(I)
50,000	400	176	$11.98	$0.80	$1.56	$6.94	$0.85	$22.13	(I)

Adjustments

The above Total Rate includes adjustments as follows:

Nominal Lumen Rating	Schedule S-99	Schedule S-191	Schedule S-192
5,800	$0.01	$0.10	$0.04
9,500	$0.01	$0.14	$0.05
16,000	$0.02	$0.20	$0.08
22,000	$0.02	$0.27	$0.10
27,500	$0.03	$0.36	$0.14
50,000	$0.04	$0.56	$0.21

(Continued)

Schedule No. LS-53

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE
CUSTOMER-OWNED SYSTEM
ENERGY ONLY SERVICE
(Continued)

MONTHLY BILLING (Continued)

For non-listed luminaires, the cost will be calculated for 3,940 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire

Base Rate	Schedule S-99	Schedule S-191	Schedule S-192	Net Rate	
12.113¢	0.024¢	0.316¢	0.121	12.574¢ per kWh for all kWh	(I)

TERM OF CONTRACT:
Not less than five (5) years for both new and replacement fixtures.

SPECIAL CONDITIONS

1. The Company will not maintain new Customer owned street lights when mounted on Customer owned poles. Such maintenance will be the responsibility of the Customer; however the Company may install pole identification tags for the purposes of tracking unmetered Customer owned lights.
2. Customer owned lights, mounted to Company owned distribution poles, shall be installed, maintained, transferred or removed only by qualified personnel. If qualified personnel are not available, the Company may maintain these at the Customer's expense. Appurtenances or other alterations to the Company's standard will not be supported by, or become the responsibility of, the Company. Following notification by the Customer, inoperable lights under this provision will be repaired as soon as possible, during regular business hours or as allowed by Company's operating schedule and requirements. Costs described in this provision will be invoiced to the Customer upon completion of the work.
3. The entire system, including the design of facilities, installation of fixtures on Customer poles, and wiring suitable for connection to Company's system, will be furnished by the Customer.
4. The Customer must notify the Company in writing of any changes to the street lighting system which would affect billing, including new installations, removals or wattage changes. Standard notification procedure will be through online forms at www.pacificpower.net/streetlights.
5. All new underground-fed lights on this schedule will require a Customer installed means of disconnect acceptable to both the Company and the local electrical inspecting authority.
6. Temporary disconnection and subsequent reconnection of electrical service requested by the Customer shall be at the Customer's expense.
7. Where approved by the Company, all pole mounted outlets used for holiday or other decorations as well as traffic or other signal systems, will be supplied with service on a metered General Service rate schedule via a Customer-installed meter base.

Schedule No. LS-58

STREET AND HIGHWAY LIGHTING SERVICE
CUSTOMER-OWNED SYSTEM
NO NEW SERVICE

APPLICABILITY

Applicable to lighting for public streets, roads, highways and other public outdoor lighting service.

TERRITORY

Within the entire territory in California served by the Utility.

MONTHLY BILLING PER LIGHT

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

	Nominal Lumen Rating	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Class A								
Incandescent								
	1,000	$3.15	$0.17	$0.28	$1.54	$0.20	$5.34	(I)
	2,500	$6.21	$0.33	$0.55	$3.03	$0.40	$10.52	(I)
	4,000	$10.12	$0.54	$0.89	$4.94	$0.64	$17.13	(I)
	6,000	$13.86	$0.74	$1.22	$6.76	$0.88	$23.46	(I)
Mercury Vapor								
	7,000	$6.46	$0.35	$0.57	$3.15	$0.41	$10.94	(I)
	21,000	$14.62	$0.79	$1.28	$7.14	$0.92	$24.75	(I)
	55,000	$35.02	$1.88	$3.08	$17.10	$2.20	$59.28	(I)
Fluorescent								
	21,400	$13.77	$0.74	$1.21	$6.72	$0.87	$23.31	(I)
Class B								
Incandescent								
	1,000	$4.73	$0.17	$0.28	$1.54	$0.20	$6.92	(I)
	2,500	$7.87	$0.33	$0.55	$3.03	$0.40	$12.18	(I)
	4,000	$11.82	$0.54	$0.89	$4.94	$0.64	$18.83	(I)
	6,000	$15.66	$0.74	$1.22	$6.76	$0.88	$25.26	(I)
Mercury Vapor								
	7,000	$7.43	$0.35	$0.57	$3.15	$0.41	$11.91	(I)
	21,000	$15.69	$0.79	$1.28	$7.14	$0.92	$25.82	(I)
	55,000	$36.47	$1.88	$3.08	$17.10	$2.20	$60.73	(I)
Fluorescent								
	21,400	$16.44	$0.74	$1.21	$6.72	$0.87	$25.98	

(Continued)

Schedule No. OL-15

OUTDOOR AREA LIGHTING SERVICE
NO NEW SERVICE

APPLICABILITY

To all Customers for lighting outdoor areas other than public streets, roads and highways. Lighting service will be furnished from dusk to dawn by Utility-owned luminaires which may be served by secondary voltage circuits from Utility's existing overhead distribution system. Luminaires will be mounted on Utility's wood poles and served in accordance with Utility's specifications as to equipment and installation.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

Nominal Lumen Rating	Rate per Luminaire: Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Mercury Vapor							
7,000	$10.81	$0.35	$0.22	$ 3.67	$0.59	$15.64	(I)
21,000	$21.37	$0.79	$0.77	$ 8.00	$1.31	$32.24	(I)
55,000	$45.96	$1.88	$2.53	$18.47	$3.15	$71.99	(I)
High Pressure Sodium Vapor							
5,800	$12.22	$0.14	$2.61	$2.51	$0.24	$17.72	(I)
22,000	$19.24	$0.39	$1.25	$5.05	$0.65	$26.58	(I)
50,000	$31.84	$0.80	$0.07	$9.44	$1.34	$43.49	(I)

Adjustments

The above Total Rate includes adjustments as follows:

Type of Luminaire	Nominal Lamp Rating	Rate Per Luminaire: Schedule S-99	Schedule S-191	Schedule S-192
Mercury Vapor	7,000 lumens	$0.02	$0.39	$0.16
" "	21,000 "	0.04	0.88	0.35
" "	55,000 "	0.10	2.12	0.84
High Pressure Sodium	5,800 "	$0.01	$0.16	$0.06
" " "	22,000 "	0.02	0.44	0.17
" " "	50,000 "	0.04	0.90	0.36

Pole Charge:

Above rates include installation of one wood pole, if required. A monthly charge of $1.00 per pole will be made for each additional pole required in excess of the number of luminaires installed.

(Continued)

Schedule No. OL-42

AIRWAY AND ATHLETIC FIELD LIGHTING SERVICE

APPLICABILITY

Applicable to service for airway beacons, the lighting of airfields, the lighting of publicly owned and operated outdoor athletic fields, and for incidental use therewith.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92.

	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Basic Charge							
Single-Phase/Month	$10.18					$10.18	(I)
Three-Phase/Month	$13.95					$13.95	(I)
Energy Charge/per kWh for all kWh	7.818¢	0.457¢	0.623¢	4.467¢	1.109¢	14.474¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

Minimum Charge:

The minimum monthly charge shall be the Basic Charge.

SPECIAL CONDITIONS

1. Delivery to be made at one central point. The Customer shall install and maintain the distribution system.
2. Extensions to supply service under this Schedule will be made in accordance with the established rule of the utility governing extensions.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Customer from minimum monthly charges.

Schedule No. PA-20

AGRICULTURAL PUMPING SERVICE

APPLICABILITY

This Schedule is applicable to customers desiring seasonal service for irrigation and soil drainage pumping installations only. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

TERRITORY

In all territory served by the Utility in the State of California.

MONTHLY CHARGE

The Monthly Billing shall be the sum of the applicable Generation and Transmission Demand, Energy Charges and Reactive Power Charges. The Annual Charge will be included in the bill for the November billing month.

Direct Access Customers shall have their Monthly Billing modified in accordance with Schedule No. EC-1 and Schedule No. TC-1. All Monthly Billings shall be adjusted in accordance with Schedule ECAC-94 and Schedule GHG-92. Qualified billings shall be adjusted in accordance with Schedule GHG-93.

	Distrib.	**FERC Trans.**	**Calif. Trans.**	**Generation**	**Public Purpose**	**Total Rate**	
Generation & Transmission Demand Charge/kW		$1.45	$1.29	($0.80)		$1.94	(I)
Reactive Power Charge/kVar				60.000¢		60.000¢	
Energy Charge/per kWh for all kWh	3.585¢			3.641¢	0.921¢	8.147¢	(I)

Adjustments

The above Total Rate includes adjustments for Schedule S-99, Schedule S-100, Schedule S-191, and Schedule S-192.

REACTIVE POWER CHARGE:

The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 40% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60 cents per kvar of such excess reactive demand.

(Continued)

Schedule No. PA-20

AGRICULTURAL PUMPING SERVICE
(Continued)

ANNUAL CHARGE (collected in November Billing Period)*

If Load Size is: Annual Charge is:

	Distrib.	FERC Trans.	Calif. Trans.	Generation	Public Purpose	Total Rate	
Annual Load Size:							
Single Phase Customers	$71.60					$71.60	(I)
plus Distribution Demand/kW	$15.48					$15.48	(I)
Three Phase Customers:							
50 kW or less demand	$71.60					$71.60	(I)
plus Distribution Demand/kW	$15.48					$15.48	(I)
51-300 kW of demand	$147.90					$147.90	(I)
plus Distribution Demand/kW	$15.48					$15.48	(I)
over 300 kW of demand	$147.90					$147.90	(I)
plus Distribution Demand/kW	$15.48					$15.48	(I)

*Note: Customer may pay monthly installments on their annual charge based on the estimate shown on their monthly bill.

DISTRIBUTION DEMAND

The Distribution Demand shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

GENERATION AND TRANSMISSION DEMAND

The measured kW shown by or computed from the readings of Utility's demand meter, or by appropriate test, for the 15-minute period of Customer's greatest use during the billing month, but not less than two kW; provided, however, that for motors not over 10 hp, the demand may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

2 HP or less		2 kW
From 2.1 through 3	HP	3 kW
From 3.1 through 5	HP	5 kW
From 5.1 through 7.5	HP	7 kW
From 7.6 through 10	HP	9 kW

SPECIAL CONDITIONS

When a monthly billing computes at less than $3.00, the consumption will instead be carried forward to the succeeding month.

Exhibit B

Effects of Proposed Rate Change
Distributed by Rate Schedule

PACIFICORP
STATE OF CALIFORNIA
EFFECTS OF PROPOSED RATE CHANGE
DISTRIBUTED BY RATE SCHEDULE
Forecast 12 Months Ending December 2011

					Present Revenues					Proposed Revenues					Proposed Change		Net Proposed Change		
Line No.	Description	Soh.	No of Customers	KWH	Base Revenue	ECAC	Base with ECAC	Adders[1]	Net Revenue	Base Revenue	ECAC	Base with ECAC	Adders[1]	Net Revenue	Revenue	Percent	Revenue	Percent	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	
							(5)+(6)		(7)+(8)			(10)+(11)		(12)+(13)	(12)-(7)	(15)/(7)	(14) (9)	(17)/(9)	
	Residential																		
1	Resident al Service	D	27,591	294,743 543	$30 382,667	$8 850,973	$39,233,640	$6,602 126	$45,835 766	$31,128 880	$8,850 973	$39 979 853	$6 602,126	$46 581 979	$746 213	1 9%	$746 213	1 6%	1
2	Res dent al Service CARE	DL 6	8,941	100 067 340	$10 223,512	$3,005 022	$13,228 534	$2 084 402	$15 312 936	$10,474.482	$3 005 022	$13,479 504	$2 084 402	$15,563 906	$250 970	1 9%	$250 970	1.6%	2
3	Multi Family Master Metered	DM 9	8	255,208	$25,025	$7,664	$32 689	$5,717	$38 406	$25 640	$7,664	$33 304	$5,717	$39,021	$615	1 9%	$615	1 6%	3
4	Multi Family - Submetered	DS 8	14	1,336,216	$104,774	$40,127	$144,901	$29,094	$173 995	$107 757	$40 127	$147 884	$29,094	$176 978	$2,983	2.1%	$2 983	1.7%	4
5	**Total Residential**		36,554	396,402,307	$40,735 978	$11 903,786	$52 639,764	$8 721 339	$61 361,103	$41 736 759	$11,903 786	$53 640,545	$8 721 339	$62,361,884	$1 000 781	1 9%	$1,000 781	1 6%	5
	Commercial & Industrial																		
6	General Serv ce - < 20 kW	A 25	7,208	61,935,978	$7,876 655	$1,857 998	$9,734,653	$1,617,003	$11 351,656	$8 073 051	$1 857,998	$9 931,049	$1,617 003	$11,548,052	$196 396	2 0%	$196 396	1 7%	6
7	General Serv ce 20 kW & Over	A 32	893	52 718,752	$5 585,254	$1,580 128	$7 165 382	$1 204 670	$8,370 052	$5 719,223	$1 580,128	$7 299,351	$1 204 670	$8 504,021	$133,969	1 9%	$133 969	1 6%	7
8	General Serv ce 100 kW & Over	A 36	290	104,693 175	$8,433 884	$3 142 021	$11 575,905	$1 989 189	$13 565,094	$8 639.089	$3,142,021	$11,781 110	$1,989 189	$13,770 299	$205 205	1 8%	$205 205	1 5%	8
9	Large General Service 500 kW & Over	AT-48	17	113 573,565	$6 379,845	$3,406 972	$9,786 817	$1 733 245	$11,520 062	$6,534 212	$3 406 972	$9,941 184	$1,733 245	$11 674 429	$154,367	1 6%	$154 367	1.3%	9
10	Agricultural Pumping Service	PA 20	2,027	95 186 258	$8 956 838	$2,853,662	$11 810,500	$2,007 971	$13,818,471	$9,170 847	$2,853 662	$12,024 508	$2 007.971	$14,032,479	$214,008	1.8%	$214 008	1.5%	10
11	**Total Commercial & Industrial**		10 435	428,107 728	$37,232 476	$12 840 781	$50,073,257	$8 552 077	$58 625 334	$38,136,421	$12,840,781	$50,977,202	$8,552 077	$59,529 279	$903,945	1.8%	$903,945	1.5%	11
	Lighting																		
12	Outdoor Area Lighting Service	OL 15	926	1077 000	$227,273	$32 310	$259,583	$41,939	$301,522	$233 005	$32,310	$265 315	$41 939	$307 254	$5 732	2 2%	$5,732	1 9%	12
13	Airway & Athletic Light ng	OL 42	40	202 965	$31 864	$6 089	$37 953	$6 226	$44,179	$32 664	$6,089	$38 753	$6,226	$44,979	$800	2 1%	$800	1.8%	13
14	Street Lighting Service	LS 51	74	694 980	$168,356	$20 851	$189 207	$30 371	$219 578	$172 586	$20 851	$193 437	$30,371	$223,808	$4 230	2 2%	$4,230	1.9%	14
15	Street Lighting Service	LS 52	5	7 772	$8 108	$233	$8,341	$1 283	$9 624	$8 316	$233	$8 549	$1 283	$9 832	$208	2 5%	$208	2 2%	15
16	Street Light ng Service	LS 53	118	1 531 797	$181,073	$45 952	$227,025	$37 934	$264,959	$185,537	$45 952	$231,489	$37 934	$269 423	$4,464	2 0%	$4 464	1 7%	16
17	Street Lighting Service	LS 58	23	245 451	$33,225	$7,362	$40,587	$6 719	$47,306	$34,064	$7 362	$41 426	$6,719	$48,145	$839	2.1%	$839	1.8%	17
18	**Total Lighting**		1,186	3,759 965	$649,899	$112,797	$762,696	$124 472	$887 168	$666 172	$112,797	$778,969	$124,472	$903 441	$16 273	2 1%	$16 273	1 8%	18
19	**Total Sales to Ultimate Consumers**		48,174	828 270,000	$78618,353	$24857,364	$103,475,716	$17,397,888	$120,873,605	$80,539 352	$24857,364	$105,396,716	$17,397,888	$122,794604	$1 920,999	1 9%	$1,920,999	1.6%	19
20	**Total AGA**				$156 069		$156,069		$156 069	$156,069		$156 069		$156,069	$0	0 0%	$0	0 0%	20
21	**Total Employee Discount**				($39 149)	($11,511)	($50,660)	($8 586)	($59 246)	($40 110)	($11 511)	($51 621)	($8 586)	($60 207)	($961)	1.9%	($961)	1 6%	21
22	**Total Sales** (inc. AGA and Employee Discount)		48,174	828 270,000	$78,735,273	$24,845,853	$103,581, 125	$17,389,302	$120,970,428	$80,655,311	$24,845853	$105,501,164	$17,389,302	$122,890,466	$1,920039	1.9%	$1,920,039	1.6%	22

Notes:

1 Total effects of Schedule S 190 Surcharge to Fund Solar Incentive Program Schedule S 191 Surcharge to Fund Public Purpose Programs, Schedule S 192 Surcharge to Fund Energy Savings Assistance Program, Schedule ECAC 94 Deferred ECAC and GHG 92 Carbon Pollut on Permit Cost Surcharge. Excludes the effect of Schedules S 99 CPUC Surcharge, S 100 CARE Surcharge CARE D scounts S 199 Klamath Dam Removal Surcharge and GHG 93 California Climate Credit.

Exhibit C

Billing Determinants and
Present and Proposed Rates

Present Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Present Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	ACTUAL Jun 09	FORECAST Dec 11	Distrib ution Price	Distribution Charges	FERC Transm ission Price	FERC Transm ission Charges	California Transm ission Price	California Transm ission Charges	Gener ation Price	Generation Charge	Gener ation Franchise Fee	Gener ation Franchise Charges	w/o ECAC Subtotal Price	w/o ECAC Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Present Price	Forecast Present Revenue Dollars
ScheduleNo. D																		
Residential Service																		
Non CARE																		
Composite																		
Customer Charge	323,019	331,092	$6 68	$2,211,695									$668	$2,211,695			**$6.68**	**$2,211,695**
All Baseline kWh	186,648,648	187,624 104	4 934 ¢	$9,257,373	0 457 ¢	$857,442	0 496 ¢	$930,616	2 997 ¢	$5 623,094	0 022 ¢	$41,277	8 906 ¢	$16,709,802	3 003 ¢	$5,634,352	**11.909 ¢**	**$22,344,154**
All Non Baseline kWh	106,562 526	107,119,439	6 391 ¢	$6.846003	0 457 ¢	$489,536	0 496 ¢	$531,312	3.334 ¢	$3,571,362	0 022 ¢	$23 566	10.700 ¢	$11,461,779	3 003 ¢	$3,216,797	**13.703 ¢**	**$14,678,576**
Subtotal	293,211,174	294,743,543		$18,315,071		$1,346,978		$1,461,928		$9,194,456		$64,843		$30,383,276		$8,851,149		**$39,234,425**
Employee Discount			25%															
Customer Charge	1,141	1,170	($1.67)	($1,954)									($1.67)	($1,954)			**($1.67)**	**($1,954)**
All Baseline kWh	847,024	851,451	(1.234) ¢	($10,503)	(0 114) ¢	($973)	(0.124) ¢	($1,056)	(0 749) ¢	($6,379)	(0 006) ¢	($47)	(2.227) ¢	($18,958)	(0.751) ¢	($6,392)	**(2.977) ¢**	**($25,350)**
All Non Baseline kWh	678,242	681,787	(1.598) ¢	($10,893)	(0 114) ¢	($779)	(0.124) ¢	($845)	(0 834) ¢	($5,683)	(0 006) ¢	($37)	(2.675) ¢	($18,237)	(0.751) ¢	($5,119)	**(3.426) ¢**	**($23,356)**
Subtotal	1,525,266	1,533,238		($23,350)		($1,752)		($1,901)		($12,062)		($84)		($39,149)		($11,511)		**($50,660)**
Easement Discount			50%															
Customer Charge	24	25	($3.34)	($82)									($3.34)	($82)			**($3.34)**	**($82)**
All Baseline kWh	11,488	11,548	(2.467) ¢	($285)	(0.229) ¢	($26)	(0 248) ¢	($29)	(1.499) ¢	($173)	(0.011) ¢	($1)	(4.453) ¢	($514)	(1.502) ¢	($173)	**(5.955) ¢**	**($687)**
All Non Baseline kWh	219	220	(3.196) ¢	($7)	(0.229) ¢	($1)	(0 248) ¢	($1)	(1.667) ¢	($4)	(0.011) ¢	$0	(5.350) ¢	($13)	(1.502) ¢	($3)	**(6.852) ¢**	**($16)**
Subtotal	11,707	11,768		($374)		($27)		($30)		($177)		($1)		($609)		($176)		**($785)**
Total Sch D	293,211,174	294,743,543		$18,291,347		$1,345,199		$1,459,997		$9,182,217		$64,758		$30,343,518		$8,839,462		**$39,182,980**
ScheduleNo. DL 6																		
Residential Service																		
CARE																		
Customer Charge	106,255	107,293	$6.68	$716,717									$6 68	$716,717			**$6.68**	**$716,717**
All Baseline kWh	64,767,192	66,912,490	4.934 ¢	$3,301,462	0.457 ¢	$305,790	0.496 ¢	$331,886	2.997 ¢	$2,005,367	0 022 ¢	$14,721	8.906 ¢	$5,959,226	3.003 ¢	$2,009,382	**11.909 ¢**	**$7,968,608**
All Non Baseline kWh	32,091,864	33,154,850	6.391 ¢	$2,118,926	0.457 ¢	$151,518	0.496 ¢	$164,448	3.334 ¢	$1,105,383	0 022 ¢	$7,294	10.700 ¢	$3,547,569	3.003 ¢	$995,640	**13.703 ¢**	**$4,543,209**
Total	96,859,056	100,067,340		$6,137,105		$457,308		$496,334		$3,110,750		$22,015		$10,223,512		$3,005,022		**$13,228,534**
Schedule No. DM 9																		
Multi Family Residential Service																		
Master Metered																		
Customer Charge	96	96	$668	$641									$6 68	$641			**$6.68**	**$641**
All Baseline kWh	162,374	162,965	4.934 ¢	$8,041	0 457 ¢	$745	0 496 ¢	$808	2 997 ¢	$4,884	0 022 ¢	$36	8 906 ¢	$14,514	3.003 ¢	$4,894	**11.909 ¢**	**$19,408**
All Non Baseline kWh	91,909	92,243	6.391 ¢	$5,895	0 457 ¢	$422	0 496 ¢	$458	3 334 ¢	$3,075	0 022 ¢	$20	10 700 ¢	$9,870	3.003 ¢	$2,770	**13.703 ¢**	**$12,640**
Total	254,283	255,208		$14,577		$1,167		$1,266		$7,959		$56		$25,025		$7,664		**$32,689**
Schedule No. DS 8																		
Multi-Family Residential Service																		
Sub- Metered																		
Customer Charge	113	121	$6 68	$808									$6 68	$808			**$6.68**	**$808**
Discount (Submeter-Days)	74,885	80,187	($0.218)	($17,481)									($0.218) ¢	($17,481)			**($0.218)**	**($17,481)**
All Baseline kWh	639,730	686,087	4.934 ¢	$33,852	0 457 ¢	$3,135	0 496 ¢	$3,403	2 997 ¢	$20,562	0 022 ¢	$151	8.906 ¢	$61,103	3 003 ¢	$20,603	**11.909 ¢**	**$81,706**
All Non Baseline kWh	108,361	116,213	6 391 ¢	$7 427	0 457 ¢	$531	0 496 ¢	$576	3 334 ¢	$3,875	0.022 ¢	$26	10 700 ¢	$12 435	3.003 ¢	$3 490	**13.703 ¢**	**$15,925**
CARE Customers																		
Customer Charge	44	47	$6 68	$314									$6 68	$314			**$6.68**	**$314**
All Baseline kWh	495,638	531,554	4.934 ¢	$26,227	0.457 ¢	$2,429	0 496 ¢	$2,637	2.997 ¢	$15,931	0.022 ¢	$117	8.906 ¢	$47,341	3.003 ¢	$15,963	**11.909 ¢**	**$63,304**
All Non Baseline kWh	2,202	2,362	6.391 ¢	$151	0.457 ¢	$11	0 496 ¢	$12	3 334 ¢	$79	0.022 ¢	$1	10.700 ¢	$254	3.003 ¢	$71	**13.703 ¢**	**$325**
Total	1,245,931	1,336,216		$51,298		$6,106		$6,628		$40,447		$295		$104,774		$40,127		**$144,901**

Present Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Present Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	ACTUAL Jun 09	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	w/o ECAC Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Present Price	Forecast Present Revenue Dollars
Schedule No. A 25																		
General Service																		
Less than 20 kW																		
Customer Charge	86,745	86,193																
Single Phase	74,190	73,718	$12 32	$908,206									$12 32	$908,206			**$12.32**	**$908,206**
Three Phase	12,555	12,475	$16 91	$210,952									$16 91	$210,952			**$16.91**	**$210,952**
All kWh	63,381 494	61,759,727	5.443 ¢	$3,361,582	0 457 ¢	$282 242	0.685 ¢	$423,054	4 282 ¢	$2,644,552	0 022 ¢	$13,587	10.889 ¢	$6,725,017	3.000 ¢	$1,852,792	**13.889 ¢**	**$8,577,809**
CARE Discount																		
Customer Charge	84	83															**$0.00**	**$0**
Single-Phase kWh	40,176	38,961															**0.000 ¢**	**$0**
Metering Discount																		
High Voltage Charge	165	164	$60.00	$9,840									$60.00	$9,840			**$60.00**	**$9,840**
All kWh	127,048	124,286	(0.054) ¢	($68)	(0 005) ¢	($6)	(0.007) ¢	($9)	(0.043) ¢	($53)	(0.000) ¢	$0	(0 109) ¢	($136)	(0 030) ¢	($37)	**(0.139) ¢**	**($173)**
Special Discounts																		
Customer Bills	12	12	($6.16)	($74)									($6.16)	($74)			**($6.16)**	**($74)**
kWhs	3,096	3,002	(2 722) ¢	($82)	(0 229) ¢	($7)	(0 343) ¢	($10)	(2 141) ¢	($64)	(0.011) ¢	$0	(5 445) ¢	($163)	(1.500) ¢	($45)	**(6.945) ¢**	**($208)**
Total	63,381,494	61,759,727		$4,490,356		$282,229		$423,035		$2,644,435		$13,587		$7,853,642		$1,852,710		**$9,706,352**
Schedule No. A 32																		
General Service																		
20 kW and over																		
Customer Charge	10 128	10,715																
Single Phase	3 827	4 059	$12.21	$49,560									$12 21	$49,560			**$12.21**	**$49,560**
Three Phase	6,301	6,656	$16 78	$111,688									$16.78	$111,688			**$16.78**	**$111,688**
Distribution Demand	463 066	429 070	$1 53	$656,477									$1 53	$656,477			**$1.53**	**$656,477**
Generation & Transmission	324,296	300 489			$1 45	$435,709	$1 08	$324,528	($0.85)	($255,416)			$1 68	$504,821	$0 39	$117,191	**$2.07**	**$622,012**
kVar	34,199	31,969							60.000 ¢	$19,181			60.000 ¢	$19,181			**60.000 ¢**	**$19,181**
All kWh	56,957,757	52,718,752	3 668 ¢	$1,933,724					4 359 ¢	$2 2[illegible]8,010	0 022 ¢	$11,598	8.049 ¢	$4,243,332	2.775 ¢	$1,462,945	**10.824 ¢**	**$5,706,278**
Discount Meter & Delivery																		
Distribution Demand	1,174	1,098	($0.46)	($504)									($0 46)	($504)			**($0.46)**	**($504)**
All kWh	30,000	28,600	(0.037) ¢	($10)					(0.044) ¢	($12)	(0 000) ¢	$0	(0 080) ¢	($22)	(0 028) ¢	($8)	**(0.108) ¢**	**($30)**
High Voltage Charge	12	12	$60.00	$720									$60 00	$720			**$60.00**	**$720**
Total	56,957,757	52,718,752		$2,751,655		$435,709		$324,528		$2,061,764		$11 598		$5,585,254		$1,580,128		**$7,165,382**
Schedule No. A 36																		
General Service																		
100 kW and over																		
Customer Charge	3,485	3,479	$219 63	$764,093									$219.63	$764,093			**$219.63**	**$764,093**
Distribution Demand	340,256	319,040	$2 80	$893,312									$2 80	$893 312			**$2.80**	**$893,312**
Generation & Transmission	286,590	268,533			$1.45	$389,373	$2 03	$545,122	$0.86	$230,938			$4 34	$1,165,433	$0 88	$236,309	**$5.22**	**$1,401,742**
kVar	25,013	22,617							60 000 ¢	$13,570			60 000 ¢	$13,570			**60.000 ¢**	**$13,570**
All kWh	111,613,489	104,693,175	2 310 ¢	$2,418,412					3.018 ¢	$3,159,640	0.022 ¢	$23,032	5 350 ¢	$5 601 084	2 776 ¢	$2,906,283	**8.126 ¢**	**$8,507,367**
Discount Meter & Delivery																		
Distribution Demand	7,057	6,414	($0.84)	($5,388)									($0 84)	($5,388)			**($0.84)**	**($5,388)**
All kWh	2,267,922	2,055,922	(0.023) ¢	($475)					(0 030) ¢	($620)	(0.000) ¢	($5)	(0 054) ¢	($1,100)	(0 028) ¢	($571)	**(0.081) ¢**	**($1,671)**
High Voltage Charge	48	48	$60.00	$2,880									$60.00	$2,880			**$60.00**	**$2,880**
Total	111,613,489	104,693,175		$4,072,834		$389,373		$545,122		$3,403,528		$23,027		$8,433,884		$3,142,021		**$11,575,905**

Present Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Present Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	ACTUAL Jun 09	FORECAST Dec 11	Distribution Price	Distribntion Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	w/o ECAC Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Present Price	Forecast Present Revenue Dollars
Schedule No. AT 48																		
General Service																		
500 kW and over																		
Customer Charge	191	192	$440 18	$84,515									$440.18	$84,515			**$440.18**	**$84,515**
Distribution Demand	303,779	295,643	$1.88	$555 809									$1 88	$555,809			**$1.88**	**$555,809**
Gen & Tran Smnmer	138,802	135,232			$1 45	$196,086	$2 24	$302,920	($0.39)	($52,740)			$3 30	$446,266	$0 95	$128,470	**$4.25**	**$574,736**
Gen & Tran Wmter	130,601	127,419			$1 45	$184,758	$224	$285,419	$0.72	$91,742			$4 41	$561,919	$0 95	$121 048	**$5.36**	**$682,967**
kVar	51,482	51,852							60 000 ¢	$31,111			60 000 ¢	$31 111			**60.000 ¢**	**$31,111**
All kWh	113 370 360	110,629 823	0 917 ¢	$1,014,475					3 188 ¢	$3,526,879	0 022 ¢	$24,339	4 127 ¢	$4,565,693	2 783 ¢	$3 078 828	**6.910 ¢**	**$7,644,521**
Discount Meter & Delivery																		
Distribution Demand	82,265	81,521	($0.56)	($45,978)									($0.56)	($45,978)			**($0.56)**	**($45,978)**
All kWh	34,219,800	33,610,082	(0.009) ¢	($3,082)					(0 032) ¢	($10,715)	(0.000) ¢	($74)	(0.041) ¢	($13,871)	(0.028) ¢	($9,354)	**(0.069) ¢**	**($23,225)**
High Voltage Charge	36	36	$60.00	$2,160									$60.00	$2,160			**$60.00**	**$2,160**
Total	113,370,360	110,629,823		$1,607,899		$380,844		$588,339		$3,586,277		$24,265		$6,187,624		$3,318,992		**$9,506,616**
Schedule No. PA 20																		
Agricultural Pumping																		
Annual Load Size Charge:																		
Single-Phase Customers	113	113	$69 80	$7,887									$69 80	$7,887			**$69.80**	**$7,887**
Three-Phase Customers:																		
50 kw or less demand	943	940	$6980	$65,612									$69 80	$65,612			**$69.80**	**$65,612**
51 300 kw demand	270	269	$144 17	$38,782									$144 17	$38,782			**$144.17**	**$38,782**
over 300 kw demand	5	5	$144.17	$721									$144.17	$721			**$144.17**	**$721**
Distribution Demand:																		
Single-Phase	578	599	$15 09	$9,039									$15 09	$9,039			**$15.09**	**$9,039**
Three-Phase:																		
50kw or less demand	20,337	21,066	$15 09	$317,886									$15.09	$317,886			**$15.09**	**$317,886**
51 300 kwdemand	24,557	25,437	$15.09	$383,844									$15.09	$383,844			**$15.09**	**$383,844**
over 300 kw demand	1,913	1,982	$15.09	$29,908									$15.09	$29,908			**$15.09**	**$29,908**
Generation & Transmission	241,196	249,842			$1.45	$362,271	$1.26	$314,801	($0.78)	($194,877)			$1.93	$482,195	$0.54	$134,915	**$2.47**	**$617,110**
kVar	35,928	37,216							60.000 ¢	$22,330			$60.00	$22,330			**60.000 ¢**	**$22,330**
All kWh	68,097,612	70,538,712	3.495 ¢	$2,465,328					3.549 ¢	$2,503,419	0.022 ¢	$15,519	7.066 ¢	$4,984,266	2.775 ¢	$1,957,449	**9.841 ¢**	**$6,941,715**
Total	68,097,612	70,538,712		$3,319,007		$362,271		$314,801		$2,330,872		$15,519		$6,342,470		$2,092,364		**$8,434,833**
Total Bills	16,224	16,177																
Avg Customers	1,352	1,348																
Annual Bills	1,331	1,327																

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	ACTUAL Jun 09	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	w/o ECAC Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Present Price	Forecast Present Revenue Dollars
Schedule No. PA 20 (former Sch PA 40)																		
Agricultural Pumping																		
(Klamath Irrigation)																		
Annual Load Size Charge:																		
Single Phase Customers	12	12	$6980	$838									$69.80	$838			**$69.80**	**$838**
Three Phase Customers:																		
50 kw or less demand	357	360	$69 80	$25,128									$69 80	$25,128			**$69.80**	**$25,128**
51 300 kw demand	302	304	$144 17	$43,828									$144.17	$43,828			**$144.17**	**$43,828**
over 300 kw demand	2	2	$144 17	$288									$144.17	$288			**$144.17**	**$288**
Distribntion Demand:																		
Single-Phase	23	0	$15 09										$15.09	$0			**$15.09**	**$0**
Three-Phase:																		
50kwor lessdemand	10,168	9,846	$15 09	$148,576									$15 09	$148,576			**$15.09**	**$148,576**
51 300 kw demand	23,386	22,646	$15 09	$341,728									$15 09	$341,728			**$15.09**	**$341,728**
over 300 kw demand	777	752	$15 09	$11,348									$15 09	$11,348			**$15.09**	**$11,348**
Generation & Transmission	147,885	143,202			$1 45	$207,643	$1.26	$180,435	($0.78)	($111,698)			$1 93	$276,380	$0 54	$77,329	**$2.47**	**$353,709**
kVar	42,443	41,099							60.000 ¢	$24,659			60 000 ¢	$24,659			**60.000 ¢**	**$24,659**
All kWh	25,453,502	24 647 546	3 495 ¢	$861,432					3 549 ¢	$874,741	0 022 ¢	$5,422	7.066 ¢	$1 741,595	2775 ¢	$683,969	**9.841 ¢**	**$2,425,564**
Subtotal	25,453,502	24 647 546		$1,433,166		$207.643		$180,435		$787,703		$5,422		$2,614,368		$761,298		**$3,375,666**
Schedule No. AT 48 (former Sch. PA 40)																		
Customer Charge	12	12	$440 18	$5,282									$440 18	$5,282			**$440.18**	**$5,282**
Distribution Demand	22,912	22,187	$1.88	$41,712									$1 88	$41,712			**$1.88**	**$41,712**
Gen & Tran Summer	4,074	3,945			$1 45	$5,720	$2 24	$8,837	($0.39)	($1,539)			$3.30	$13,018	$0.95	$3,748	**$4.25**	**$16,766**
Gen & Tran - Winter	2,508	2,429			$1 45	$3,522	$2 24	$5,441	$0.72	$1,749			$4.41	$10,712	$0.95	$2,308	**$5.36**	**$13,020**
kVar	15	15							60.000 ¢	$9			60.000 ¢	$9			**60.000 ¢**	**$9**
All kWh	3,040,000	2,943,742	0.917 ¢	$26,994					3.188 ¢	$93,846	0.022 ¢	$648	4.127 ¢	$121,488	2.783 ¢	$81,924	**6.910 ¢**	**$203,412**
Subtotal	3,040,000	2,943,742		$73,988		$9,242		$14,278		$94,065		$648		$192,221		$87,979		**$280,200**
Total	28,493,502	27,591,288		$1,507,154		$216,885		$194,713		$881,768		$6,[illegible]7[illegible]		2,806,589		$849,277		**3,655,867**
Total **Bills**	8,100	8,157																
Avg Customers	675	680																
Annual Bills	674	679																
Schedule No. A 25 (former Sch. AWH 31)																		
General Service																		
Less than 20 kW																		
Customer Charge	330	302																
Single-Phase	306	280	$12 32	$3,450									$12 32	$3,450			**$12.32**	**$3,450**
Three-Phase	24	22	$16 91	$372									$16 91	$372			**$16.91**	**$372**
All kWh	206,501	176,251	5 443 ¢	$9,593	0 457 ¢	$805	0 685 ¢	$1,207	4.282 ¢	$7,547	0 022 ¢	$39	10 889 ¢	$19,191	3 000 ¢	$5,288	**13.889 ¢**	**$24,479**
Total	206,501	176,251		$13,415		$805		$1,207		$7,547		$39		$23,013		$5,288		**$28,301**
Schedule No. OL 42																		
Airway & Athletic Lighting																		
Commercial, Rate Code 42																		
Customer Charge	464	480																
Single-Phase	308	319	$992	$3,164									$9.92	$3,164			**$9.92**	**$3,164**
Three-Phase	156	161	$13 60	$2,190									$13.60	$2,190			**$13.60**	**$2,190**
All kWh	201,423	202,965	7.621 ¢	$15,468	0.457 ¢	$928	0 607 ¢	$1,232	4 354 ¢	$8,837	0.022 ¢	$45	13.061 ¢	$26,510	3.000 ¢	$6,089	**16.061 ¢**	**$32,599**
Total	201,423	202,965		$20,822		$928		$1,232		$8,837		$45		$31,864		$6,089		**$37,953**

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Schedule No. LS 51																		
Street Lighting																		
Total Bills	876	886																
High Pressure Sodium Vapor Wood Overhead																		
5,800 Lumen	4,920	5,056	$7 06	$35,695	$0.14	$708	$0 57	$2,882	$1 82	$9,202	$0 01	$51	$9 60	$48,538	$0 93	$4,702	**$10.53**	**$53,240**
9,500 Lumen	7,006	7,200	$7.74	$55,728	$0 20	$1,440	$0 04	$288	$2 29	$16,488	$0 01	$72	$10 28	$74,016	$1 32	$9,504	**$11.60**	**$83,520**
16 000 Lumen	0	0	$10 29		$0 29		$0 28		$3 32		$0 01		$14.19		$1.92		**$16.11**	
22,000 Lumen	2,485	2,554	$12.84	$32,793	$0.39	$996	$0 18	$460	$4 17	$10,650	$0 02	$51	$17 60	$44,950	$2 55	$6,513	**$20.15**	**$51,463**
27,500 Lumen	0	0	$16 59		$0 53		$0 57		$5 96		$0 03		$23 68		$3 45		**$27.13**	
50,000 Lumen	24	25	$24 36	$609	$0.80	$20	$0 52	$13	$8 34	$209	$0 04	$1	$34 06	$852	$5 28	$132	**$39.34**	**$984**
High Pressure Sodium Vapor - Decorative Series 1																		
9,500 Lumen	0	0	$28 47		$0 20		$0 04		$2 29		$0 01		$31 01		$1 32		**$32.33**	
16,000 Lumen	0	0	$28 47		$0 29		$0 28		$3 32		$0 01		$32 37		$1.92		**$34.29**	
High Pressure Sodium Vapor - Decorative Series 2																		
9,500 Lumen	0	0	$22 66		$0 20		$0 04		$2 29		$0 01		$25 20		$1 32		**$26.52**	
16,000 Lumen	0	0	$22 86		$0 29		$0 28		$3.32		$0 01		$26 76		$1 92		**$28.68**	
All kWh	676,222	694,980	17 961 ¢		0 457 ¢		0 524 ¢		5 259 ¢		0 022 ¢		24 223 ¢		3 000 ¢		**27.223 ¢**	
Total	676,222	694,980		$124,825		$3,164		$3,643		$36,549		$175		$168,356		$20,851		**$189,207**
Schedule No. LS 52																		
Street Lighting																		
Total Bills	60	60																
High Pressure Sodium Vapor																		
5,800 Lumen	12	12	$29 68	$356	$0 14	$2	$9 49	$114	$4 69	$56	$0 01	$0	$44 01	$528	$0 93	$11	**$44.94**	**$539**
9,500 Lumen	168	168	$30 74	$5 164	$0 20	$34	$8 96	$1,505	$5 21	$875	$0 01	$2	$45 12	$7,580	$1 32	$222	**$46.44**	**$7,802**
22,000 Lumen	0	0	$38 29	$0	$0 39	$0	$8 96	$0	$7 38	$0	$0 02	$0	$55 04	$0	$2.55	$0	**$57.59**	**$0**
50,000 Lumen	0	0	$52 96	$0	$0 80	$0	$8 33	$0	$11.95	$0	$0 04	$0	$74.08	$0	$5 28	$0	**$79.36**	**$0**
All Energy													11.695				**14.695 ¢**	
All kWh	7,764	7,772	71.024 ¢		0.457 ¢		20.831 ¢		11.979 ¢		0.022 ¢		104.313 ¢		3.000 ¢		**107.313 ¢**	
Total	7,764	7,772		$5,520		$36		$1,619		$931		$2		$8,108		$233		**$8,341**
Schedule No. LS 53																		
Street Lighting																		
Total Bills	1412	1,417																
High Pressure Sodium Vapor																		
Option A																		
5,800 Lumen	4,056	4,307	$2 06	$8 872	$0.14	$603	$0 27	$1,163	$1 19	$5,125	$0 01	$43	$3 67	$15,806	$0 93	$4,006	**$4.60**	**$19,812**
9,500 Lumen	12 456	13,228	$2 92	$38,626	$0 20	$2,646	$0 38	$5,027	$1 69	$22,355	$0 01	$132	$5 20	$68,786	$1 32	$17,461	**$6.52**	**$86,247**
16,000 Lumen	0	0	$4 25		$0 29		$0 55		$2 46		$0 01		$7 56		$1.92		**$9.48**	
22,000 Lmnen	2,532	2,799	$5 64	$15,786	$0 39	$1,092	$0 73	$2,043	$3 27	$9,153	$0 02	$56	$10 05	$28,130	$2 55	$7,137	**$12.60**	**$35,267**
27,500 Lumen	0	0	$7 63		$0 53		$0 99		$4 42		$0 03		$13 60		$3 45		**$17.05**	
50,000 Lumen	36	38	$11 68	$444	$0 80	$30	$1 52	$58	$6.76	$257	$0 04	$2	$20 80	$791	$5 28	$201	**$26.08**	**$992**
Custom																		
16,000 Lum A 55 kWh	673	715	$3 65	$2 610	$0 25	$179	$0 48	$343	$2 11	$1,509	$0 01	$7	$3.19	$122	$1.65	$1,180	**$8.15**	**$5,828**
16,000 Lumen A	1,020	1,083	$4 25	$4,603	$0 29	$314	$0 55	$596	$2 46	$2,664	$0 01	$11	$7 56	$8,188	$1 92	$2,079	**$9.48**	**$10,267**
10,700 Lumen - A	120	127	$7.17	$911	$0 49	$62	$0 93	$118	$4 15	$527	$0 02	$3	$6.50	$4,648	$3 24	$411	**$16.00**	**$2,032**
27,500 Lumen - A	1 418	1,506	$7 63	$11,491	$0 53	$798	$0 99	$1,491	$4 42	$6,657	$0 03	$45	$24 20	$0	$3 45	$5,196	**$17.05**	**$25,678**
37,000 Lumen - A	1,811	1,923	$9 49	$18,249	$0 65	$1,250	$1.24	$2,385	$5 49	$10,557	$0 03	$58	$13 60	$20,482	$4 29	$8,250	**$21.19**	**$40,749**
37,000 Lumen - B	0	0	$17 28	$0	$0 65	$0	$1.24	$0	$5 49	$0	$0 03	$0	$16 90	$32,499	$4 29	$0	**$28.98**	**$0**
22,000 Lumen B CSTM	104	0	$19.79	$0	$0 39	$0	$0 73	$0	$3 27	$0	$0 02	$0	$24 69	$0	$2 55	$0	**$26.75**	**$0**
5,800 Lum - A 27 kWh	36	38	$1.79	$68	$0 12	$5	$0 23	$9	$1 04	$40	$0.01	$0	$12 76	$1,621	$0 81	$31	**$4.00**	**$153**
All Energy													0 000				**0.000 #**	
All kWh	1,442,368	1,531,797	6 636 ¢		0 457 ¢		0 864 ¢		3 842 ¢		0 022 ¢		11 821 ¢		3 000 ¢		**14.821 ¢**	
Total	1,442,368	1,531,797		$101,660		$6,979		$13,233		$58,844		$357		$181,073		$45,952		**$227,025**

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Schedule No. LS 58																		
Street Lighting																		
Total Bills	276	276																
Class A																		
Incandescent																		
1,000 Lumen	0	0	$3 07	$0	$0 17	$0	$0 27	$0	$1 50	$0	$0.01	$0	$5 02	$0	$1 11	$0	**$6.13**	**$0**
2,500 Lumen	84	85	$6 05	$514	$0 33	$28	$0.53	$45	$2 95	$251	$0.02	$2	$9 88	$840	$2 19	$186	**$12.07**	**$1,026**
4,000 Lumen	0	0	$9 86	$0	$0 54	$0	$0 87	$0	$4 81	$0	$0.03	$0	$16 11	$0	$3 57	$0	**$19.68**	**$0**
6,000 Lumen	0	0	$13 51	$0	$0 74	$0	$1 19	$0	$6 59	$0	$0.[illegible]4	$0	$22 07	$0	$4 89	$0	**$26.96**	**$0**
Mercury Vapor																		
7,000 Lumen	1,940	1,959	$6.30	$12,342	$0 35	$686	$0 55	$1,077	$3.07	$6,014	$0 02	$39	$10 29	$20,158	$2 28	$4,467	**$12.57**	**$24,625**
21,000 Lumen	520	525	$14 25	$7,481	$0 79	$415	$1 25	$656	$6 96	$3,654	$0.04	$21	$23 29	$12,227	$5.16	$2,709	**$28.45**	**$14,936**
55,000 Lumen	0	0	$34.14	$0	$1.88	$0	$3 00	$0	$16 67	$0	$0 09	$0	$55 78	$0	$12 36	$0	**$68.14**	**$0**
Fluorescent																		
21,400 Lumen	0	0	$13 42	$0	$0 74	$0	$1 18	$0	$6 55	$0	$0 04	$0	$21.93	$0	$4 86	$0	**$26.79**	**$0**
Class B																		
Incandescent																		
1,000 Lumen	0	0	$4 61	$0	$0.17	$0	$0 27	$0	$1 50	$0	$0 01	$0	$6 56	$0	$1.11	$0	**$7.67**	**$0**
2,500 Lumen	0	0	$7 67	$0	$0 33	$0	$0 53	$0	$2 95	$0	$0 02	$0	$11 50	$0	$2 19	$0	**$13.69**	**$0**
4,000 Lumen	0	0	$11 52	$0	$0 54	$0	$0 87	$0	$4 81	$0	$0 03	$0	$17 77	$0	$3 57	$0	**$21.34**	**$0**
6,000 Lumen	0	0	$15.27	$0	$0 74	$0	$1 19	$0	$6 59	$0	$0 04	$0	$23 83	$0	$4 89	$0	**$28.72**	**$0**
Mercury Vapor																		
7,000 Lumen	0	0	$7 24	$0	$0 35	$0	$0 55	$0	$3.07	$0	$0 02	$0	$11 23	$0	$2 28	$0	**$13.51**	**$0**
21,000 Lumen	0	0	$15 29	$0	$0 79	$0	$1 25	$0	$6 96	$0	$0 04	$0	$24 33	$0	$5 16	$0	**$29.49**	**$0**
55,000 Lumen	0	0	$35.55	$0	$1 88	$0	$3 00	$0	$16 67	$0	$0 09	$0	$57 19	$0	$12 36	$0	**$69.55**	**$0**
Fluorescent																		
21,400 Lumen	0	0	$16 03	$0	$0 74	$0	$1.18	$0	$6 55	$0	$0 04	$0	$24.54	$0	$4 86	$0	**$29.40**	**$0**
All kWh	243,012	245,451	8.287 ¢		0.457 ¢		0.728 ¢		4.045 ¢		0.022 ¢		13.539 ¢		3.000 ¢		**16.539 ¢**	
Total	243,012	245,451		$20,337		$1,129		$1,778		$9,919		$62		$33,225		$7,362		**$40,587**
Schedule No. OL-15																		
Street Lighting																		
Composite																		
Total Bills	11,133	11,110																
Mercury Vapor																		
7,000 Lumen	10 898	10 466	$10.54	$110,312	$0 35	$3,663	$0 21	$2,198	$3 58	$37,468	$0 02	$209	$14.70	$153,850	$2 28	$23,862	**$16.98**	**$177,712**
21,000 Lumen	917	931	$20 83	$19,393	$0 79	$735	$0 75	$698	$7 80	$7,262	$0 04	$37	$30 21	$28,125	$5 16	$4,804	**$35.37**	**$32,929**
55,000 Lumen	72	73	$44 80	$3,270	$1.88	$137	$2 47	$180	$18 00	$1,314	$0 09	$7	$67 24	$4,908	$12 36	$902	**$79.60**	**$5,810**
High Pressure Sodium Vapor																		
5,800 Lumen	1,724	1,691	$11 91	$20,140	$0 14	$237	$2.54	$4,295	$2 45	$4,143	$0 01	$17	$17.05	$28,832	$0 93	$1,573	**$17.98**	**$30,405**
22,000 Lumen	390	392	$18 76	$7,354	$0 39	$153	$1.22	$478	$4 92	$1,929	$0 02	$8	$25 31	$9,922	$2 55	$1,000	**$27.86**	**$10,922**
50,000 Lumen	31	32	$31 04	$993	$0 80	$26	$0.07	$2	$9 20	$294	$0 04	$1	$41 15	$1 316	$5 28	$169	**$46.43**	**$1,485**
All kWh	1,107,565	1,077,000	14.992 ¢		0.457 ¢		0.729 ¢		4 866 ¢		0 022 ¢		21 066 ¢		3.000 ¢		**24.066 ¢**	
Additional Wood Poles	324	320	$1 00	$320									$1 00	$320			**$1.00**	**$320**
Total	1,107,565	1,077,[illegible]		$161,782		$4,951		$7,851		$52,410		$279		$227,273		$32,310		**$259,583**

Present Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Present Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

ACTUAL Jun-09	FORECAST Dec 11	Distrib ution Price	Distribution Charges	FERC Transm ission Price	FERC Transm ission Charges	California Transm- ission Price	California Transm ission Charges	Gener ation Price	Generation Charge	Gener ation Franchise Fee	Gener ation Franchise Charges	w/o ECAC Subtotal Price	w/o ECAC Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Present Price	Forecast Present Revenue Dollars

SUMMARY

	ACTUAL Total KWH	Forecast Total KWH	Distribution Charges (1)	FERC Transmission Charges (2)	California Transmission Charges (3)	Generation Charge (4)	Generation Franchise Charge (5)	w/o ECAC Subtotal Revenue (6) (1)+(2)+(3)+(4)+(5)	Base ECAC Charges (7)	Forecast Present Revenue (8) (6)+(7)
(1) Total*	837,369,514	828,270,000	$42,714,943	$3,896,835	$4,387,227	$27,437,115	$182.233	$78,618,353	$24,857,364	$103,475,716
(2) Average Price (mills/kwh)			51 57	4 70	5.30	33.13	0 22	94.92	30 01	124.93
(3) Employee Discount			($23,350)	($1,752)	($1,901)	($12,062)	($84)	($39,149)	($11,511)	($50,660)
(4) Total (Including Employee Discount)			$42,691,593	$3,895,083	$4,385,326	$27,425,053	$182,149	$78,579,204	$24,845,853	$103,425,057
(5) Bills	548,166	578,093								
(6) Customers	45,680	48,174								
(7) AGA										
Residential								$202		$202
Commercial								$109,431		$109,431
Industrial								$1,541		$1,541
Irrigation								$44,896		$44,896
Public Street & Highway Lighting								$0		$0
Total								$156,069		$156,069
(8) Total	837,369,514	828,270,000						$78,735,273		$103,581,125

Notes:
Line (1) = Sum of all schedules excluding Employee Discount
Line (2) = Line (1) / Total Forecast KWH in Line (1)
Line (4) = Line (1) + Line (3)
Line (8) = Line (4) + Line (7)
* Before discount

Proposed Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Proposed Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No. D																	
Residential Service																	
Non CARE																	
Composite																	
Customer Charge	331,092	$6 85	$2,267,980									$6 85	$2,267,980			**$6.85**	**$2,267,980**
All Baseline kWh	187,624,104	5.061 ¢	$9,495,656	0.457 ¢	$857,442	0.509 ¢	$955,007	3 074 ¢	$5,767,565	0 022 ¢	$41,277	9 123 ¢	$17,116,947	3 003 ¢	$5,634,352	**12.126 ¢**	**$22,751,299**
All Non Baseline kWh	107,119,439	6.556 ¢	$7,022,750	0 457 ¢	$489,536	0 509 ¢	$545,238	3 420 ¢	$3,663,485	0 022 ¢	$23,566	10 964 ¢	$11,744,575	3 003 ¢	$3,216,797	**13.967 ¢**	**$14,961,372**
Subtotal	294,743,543		$18,786,386		$1,346,978		$1,500,245		$9,431,050		$64,843		$31,129,502		$8,851,149		**$39,980,651**
Employee Discount		25%															
Customer Charge	1,170	($1.71)	($2,004)									($1.71)	($2,004)			**($1.71)**	**($2,004)**
All Baseline kWh	851,451	(1 265) ¢	($10,773)	(0 114) ¢	($973)	(0.127) ¢	($1,083)	(0 769) ¢	($6,543)	(0 006) ¢	($47)	(2.281) ¢	($19,419)	(0 751) ¢	($6,392)	**(3.032) ¢**	**($25,811)**
All Non Baseline kWh	681,787	(1.639) ¢	($11,174)	(0.114) ¢	($779)	(0.127) ¢	($868)	(0 855) ¢	($5,829)	(0 006) ¢	($37)	(2.741) ¢	($18,687)	(0 751) ¢	($5,119)	**(3.492) ¢**	**($23,806)**
Subtotal	1,533,238		($23,951)		($1,752)		($1,951)		($12,372)		($84)		($40,110)		($11,511)		**($51,621)**
Easement Discount		50%															
Customer Charge	25	($3.43)	($84)									($3.43)	($84)			**($3.43)**	**($84)**
All Baseline kWh	11,548	(2.531) ¢	($292)	(0.229) ¢	($26)	(0.255) ¢	($29)	(1.537) ¢	($177)	(0.011) ¢	($1)	(4.562) ¢	($525)	(1.502) ¢	($173)	**(6.063) ¢**	**($698)**
All Non Baseline kWh	220	(3.278) ¢	($7)	(0.229) ¢	($1)	(0.255) ¢	($1)	(1.710) ¢	($4)	(0.011) ¢	$0	(5.482) ¢	($13)	(1.502) ¢	($3)	**(6.984) ¢**	**($16)**
Subtotal	11,768		($383)		($27)		($30)		($181)		($1)		($622)		($176)		**($798)**
Total Sch D	294,743,543		$18,762,052		$1,345,199		$1,498,264		$9,418,497		$64,758		$31,088,770		$8,839,462		**$39,928,232**
Schedule No. DL-6																	
Residential Service																	
CARE																	
Customer Charge	107,293	$6 85	$734,957									$6 85	$734,957			**$6.85**	**$734,957**
All Baseline kWh	66,912,490	5 061 ¢	$3,386,441	0.457 ¢	$305,790	0.509 ¢	$340,585	3 074 ¢	$2,056,890	0 022 ¢	$14,721	9.123 ¢	$6,104,427	3.003 ¢	$2,009,382	**12.126 ¢**	**$8,113,809**
All Non Baseline kWh	33,154,850	6 556 ¢	$2,173,632	0.457 ¢	$151,518	0 509 ¢	$168,758	3 420 ¢	$1,133,896	0 022 ¢	$7,294	10.964 ¢	$3,635,098	3 003 ¢	$995,640	**13.967 ¢**	**$4,630,738**
Total	100,067,340		$6,295,030		$457,308		$509,343		$3,190,786		$22,015		$10,474,482		$3,005,022		**$13,479,504**
Schedule No. DM 9																	
Multi Family Residential Service																	
Master Metered																	
Customer Charge	96	$685	$658									$6 85	$658			**$6.85**	**$658**
All Baseline kWh	162,965	5.061 ¢	$8,248	0 457 ¢	$745	0.509 ¢	$829	3.074 ¢	$5,010	0.022 ¢	$36	9 123 ¢	$14,868	3.003 ¢	$4,894	**12.126 ¢**	**$19,762**
All Non Baseline kWh	92,243	6 556 ¢	$6 047	0 457 ¢	$422	0 509 ¢	$470	3 420 ¢	$3,155	0 022 ¢	$20	10 964 ¢	$10,114	3 003 ¢	$2,770	**13.967 ¢**	**$12,884**
Total	255,208		$14,953		$1,167		$1,299		$8,165		$56		$25,640		$7,664		**$33,304**
Schedule No. DS 8																	
Multi-Family Residential Service																	
Sub- Metered																	
Customer Charge	121	$6 85	$829									$6 85	$829			**$6.85**	**$829**
Discount (Submeter-Days)	80,187	($0 218)	($17,481)									($0.218)	($17,481)			**($0.218)**	**($17,481)**
All Baseline kWh	686,087	5 061 ¢	$34,723	0 457 ¢	$3,135	0 509 ¢	$3,492	3 074 ¢	$21,090	0022 ¢	$151	9.123 ¢	$62,591	3 003 ¢	$20,603	**12.126 ¢**	**$83,194**
All Non Baseline kWh	116,213	6 556 ¢	$7,619	0 457 ¢	$531	0 509 ¢	$592	3 420 ¢	$3,974	0 022 ¢	$26	10 964 ¢	$12,742	3 003 ¢	$3,490	**13.967 ¢**	**$16,232**
CARE Customers																	
Customer Charge	47	$6 85	$322									$6 85	$322			**$6.85**	**$322**
All Baseline kWh	531,554	5 061 ¢	$26,902	0 457 ¢	$2,429	0 509 ¢	$2,706	3 074 ¢	$16,340	0 022 ¢	$117	9 123 ¢	$48,494	3.003 ¢	$15,963	**12.126 ¢**	**$64,457**
All Non Baseline kWh	2 362	6.556 ¢	$155	0.457 ¢	$11	0 509 ¢	$12	3 420 ¢	$81	0.022 ¢	$1	10 964 ¢	$260	3 003 ¢	$71	**13.967 ¢**	**$331**
Total	1,336,216		$53,069		$6,106		$6,802		$41,485		$295		$107 757		$40,127		**$147,884**

Proposed Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Proposed Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No A 25																	
General Service																	
Less than 20 kW																	
Customer Charge	86,193																
Single-Phase	73,718	$12 64	$931,796									$12 64	$931,796			**$12.64**	**$931,796**
Three-Phase	12,475	$17 35	$216,441									$17 35	$216,441			**$17.35**	**$216,441**
All kWh	61,759,727	5.584 ¢	$3,448,663	0.457 ¢	$282,242	0 703 ¢	$434,171	4.393 ¢	$2,713,105	0.022 ¢	$13,587	11 159 ¢	$6,891,768	3.000 ¢	$1,852,792	**14.159 ¢**	**$8,744,560**
CARE Discount																	
Customer Charge	83											$0 00	$0			**$0.00**	**$0**
Single-Phase kWh	38,961											0 000 ¢	$0			**0.000 ¢**	**$0**
Metering Discount																	
High Voltage Charge	164	$60 00	$9,840									$60 00	$9,840			**$60.00**	**$9,840**
All kWh	124,286	(0056) ¢	($69)	(0.005) ¢	($6)	(0 007) ¢	($9)	(0 044) ¢	($55)	(0 000) ¢	$0	(0 112) ¢	($139)	(0 030) ¢	($37)	**(0.142) ¢**	**($176)**
Special Discounts																	
Customer Bills	12	($6.32)	($76)									($6.32)	($76)			**($6.32)**	**($76)**
kWhs	3,002	(2.792) ¢	($84)	(0.229) ¢	($7)	(0.352) ¢	($11)	(2.197) ¢	($66)	(0 011) ¢	$0	(5 580) ¢	($168)	(1 500) ¢	($45)	**(7.080) ¢**	**($213)**
Total	61,759,727		$4,606,511		$282,229		$434,151		$2,712,984		$13,587		$8,049,462		$1,852,710		**$9,902,172**
Schedule No. A 32																	
General Service																	
20 kW and over																	
Customer Charge	10,715																
Single-Phase	4,059	$12 53	$50,859									$12 53	$50,859			**$12.53**	**$50,859**
Three-Phase	6,656	$17.21	$114,550									$17 21	$114,550			**$17.21**	**$114,550**
Distribution Demand	429,070	$1 57	$673,640									$1 57	$673 640			**$1.57**	**$673,640**
Generation & Transmission	300,489			$1 45	$435,709	$1 11	$333,543	($0 87)	($261,425)			$1.69	$507,826	$0 39	$117,191	**$2.08**	**$625,017**
kVar	31,969							60.000 ¢	$19,181			60 000 ¢	$19,181			**60.000 ¢**	**$19,181**
All kWh	52,718,752	3 763 ¢	$1,983,807					4.472 ¢	$2,357,583	0.022 ¢	$11,598	8 257 ¢	$4,352,987	2 775 ¢	$1,462,945	**11.032 ¢**	**$5,815,933**
Discount Meter & Delivery																	
Distribution Demand	1,098	($0.47)	($517)									($0.47)	($517)			**($0.47)**	**($517)**
All kWh	28,600	(0.038) ¢	($11)					(0.045) ¢	($13)	(0.000) ¢	$0	(0.083) ¢	($24)	(0.028) ¢	($8)	**(0.110) ¢**	**($32)**
High Voltage Charge	12	$60.00	$720									$60.00	$720			**$60.00**	**$720**
Total	52,718,752		$2,823,048		$435,709		$333,543		$2,115,325		$11,598		$5,719,223		$1,580,128		**$7,299,351**
Schedule No. A 36																	
General Service																	
100 kW and over																	
0																	
Customer Charge	3,479	$225 31	$783,853									$225 31	$783,853			**$225.31**	**$783,853**
Distribution Demand	319,040	$2 87	$915,645									$2 87	$915,645			**$2.87**	**$915,645**
Generation & Transmission	268,533			$1 45	$389,373	$2 08	$558,549	$088	$236 309			$4 41	$1,184,231	$0 88	$236,309	**$5.29**	**$1,420,540**
kVar	22,617							60 000 ¢	$13,570			60 000 ¢	$13,570			**60.000 ¢**	**$13,570**
All kWh	104,693,175	2 370 ¢	$2,481,228					3 096 ¢	$3,241,301	0 022 ¢	$23,032	5 488 ¢	$5,745,561	2 776 ¢	$2,906,283	**8.264 ¢**	**$8,651,844**
Discount Meter & Delivery																	
Distribution Demand	6,414	($0.86)	($5,522)									($0.86)	($5,522)			**($0.86)**	**($5,522)**
All kWh	2,055,922	(0 024) ¢	($487)					(0 031) ¢	($637)	(0.000) ¢	($5)	(0.055) ¢	($1,129)	(0.028) ¢	($571)	**(0.083) ¢**	**($1,700)**
High Voltage Charge	48	$60 00	$2,880									$60.00	$2,880			**$60.00**	**$2,880**
Total	104,693,175		$4,177,597		$389,373		$558,549		$3,490,543		$23,027		$8,639,089		$3,142,021		**$11,781,110**

Proposed Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Proposed Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No AT 48																	
General Service																	
500 kW and over																	
0																	
Customer Charge	192	$451 55	$86,698									$451 55	$86,698			**$451.55**	**$86,698**
Distribution Demand	295,643	$1 93	$570,591									$1 93	$570,591			**$1.93**	**$570,591**
Gen & Tran Summer	135,232			$1 45	$196,086	$2 30	$311,034	($0.40)	($54,093)			$3 35	$453,027	$0 95	$128,470	**$4.30**	**$581,497**
Gen & Tran Winter	127,419			$1 45	$184,758	$2 30	$293,064	$0.74	$94,290			$4 49	$572,112	$0 95	$121,048	**$5.44**	**$693,160**
kVar	51,852							60 000 ¢	$31,111			60 000 ¢	$31,111			**60.000 ¢**	**$31,111**
All kWh	110,629,823	0.941 ¢	$1,041,027					3.270 ¢	$3,617,595	0 022 ¢	$24,339	4 233 ¢	$4,682,961	2 783 ¢	$3,078,828	**7.016 ¢**	**$7,761,789**
Discount - Meter & Delivery																	
Distribution Demand	81,521	($0.58)	($47,201)									($0.58)	($47,201)			**($0.58)**	**($47,201)**
All kWh	33,610,082	(0.009) ¢	($3,163)					(0 033) ¢	($10,990)	(0 000) ¢	($74)	(0.042) ¢	($14,227)	(0 028) ¢	($9,354)	**(0.070) ¢**	**($23,581)**
High Voltage Charge	36	$60.00	$2,160									$60.00	$2,160			**$60.00**	**$2,160**
Total	110,629,823		$1,650,112		$380,844		$604,098		$3,677,913		$24,265		$6,337,232		$3,318,992		**$9,656,224**
Schedule No. PA-20																	
Agricultural Pumping																	
Annual Load Size Charge:																	
Single-Phase Customers	113	$71 60	$8,091									$71.60	$8,091			**$71.60**	**$8,091**
Three-Phase Customers:																	
50 kw or less demand	940	$71.60	$67,304									$71 60	$67,304			**$71.60**	**$67,304**
51 300 kw demand	269	$147 90	$39,785									$147 90	$39,785			**$147.90**	**$39,785**
over300 kwdemand	5	$147 90	$740									$147 90	$740			**$147.90**	**$740**
Distribution Demand:																	
Single-Phase	599	$15 48	$9,273									$15 48	$9,273			**$15.48**	**$9,273**
Three-Phase:																	
50 kw or less demand	21,066	$15 48	$326,102									$15 48	$326,102			**$15.48**	**$326,102**
51 300kw demand	25,437	$15 48	$393,765									$15 48	$393,765			**$15.48**	**$393,765**
over 300 kw demand	1,982	$15 48	$30,681									$15.48	$30,681			**$15.48**	**$30,681**
Generation & Transmission	249,842			$1.45	$362,271	$1.29	$322,296	($0.80)	($199,874)			$1 94	$484,694	$0 54	$134,915	**$2.48**	**$619,608**
kVar	37,216							60.000 ¢	$22,330			60 000	$22,330			**60.000 ¢**	**$22,330**
All kWh	70,538,712	3.585 ¢	$2,528,813					3.641 ¢	$2,568,315	0 022 ¢	$15,519	7.248 ¢	$5,112,647	2 775 ¢	$1,957,449	**10.023 ¢**	**$7,070,096**
Total	70,538,712		$3,404,554		$362,271		$322,296		$2,390,771		$15,519		$6,495,411		$2,092,364		**$8,587,775**
Total Bills	16,177																
Avg Customers	1,348																
Annual Bills	1,327																

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	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No. PA-20 (former Sch. PA-40)																	
Agricultural Pumping																	
(Klamath Irrigation)																	
Annual Load Size Charge:																	
Single Phase Customers	12	$71 60	$859									$71 60	$859			**$71.60**	**$859**
Three Phase Customers:																	
50 kw or less demand	360	$71 60	$25,776									$71 60	$25,776			**$71.60**	**$25,776**
51 300 kw demand	304	$147 90	$44 962									$147 90	$44,962			**$147.90**	**$44,962**
over 300 kw demand	2	$147.90	$296									$147.90	$296			**$147.90**	**$296**
Distribution Demand:																	
Single Phase	0	$15 48	$0									$15 48	$0			**$15.48**	**$0**
Three Phase:																	
50 kw or less demand	9,846	$15 48	$152,416									$15 48	$152,416			**$15.48**	**$152,416**
51-300 kw demand	22,646	$15 48	$350,560									$15 48	$350,560			**$15.48**	**$350,560**
over 300 kw demand	752	$15 48	$11,641									$15 48	$11,641			**$15.48**	**$11,641**
Generation & Transmission	143,202			$1 45	$207,643	$1 29	$184,731	($0.80)	($114,562)			$1 94	$277,812	$0 54	$77,329	**$2.48**	**$355,141**
kVar	41,099							60.000 ¢	$24,659			60.000 ¢	$24,659			**60.000 ¢**	**$24,659**
All kWh	24,647,546	3.585 ¢	$883,615					3.641 ¢	$897,417	0.022 ¢	$5,422	7.248 ¢	$1,786,454	2.775 ¢	$683,969	**10.023 ¢**	**$2,470,423**
Subtotal	24,647,546		$1,470,125		$207,643		$184,731		$807,515		$5,422		$2,675,435		$761,298		**$3,436,733**
Schedule No. AT-48 (former Sch. PA 40)																	
Customer Charge	12	$451 55	$5,419									$451.55	$5,419			**$451.55**	**$5,419**
Distribution Demand	22,187	$1 93	$42,821									$1.93	$42,821			**$1.93**	**$42,821**
Gen & Tran - Sununer	3,945			$1.45	$5,720	$2.30	$9,074	($0.40)	($1,578)			$3 35	$13,216	$0 95	$3,748	**$4.30**	**$16,964**
Gen & Tran - Winter	2,429			$1.45	$3,522	$230	$5,587	$0.74	$1,797			$4 49	$10,906	$0.95	$2,308	**$5.44**	**$13,214**
kVar	15							60.000 ¢	$9			60.000 ¢	$9			**60.000 ¢**	**$9**
All kWh	2,943,742	0.941	$27,701					3.270 ¢	$96,260	0.022 ¢	$648	4.233 ¢	$124,609	2.783 ¢	$81,924	**7.016 ¢**	**$206,533**
Subtotal	2,943,742		$75,941		$9,242		$14,661		$96,488		$648		$196,980		$87,979		**$284,959**
Total	$27,591,288		$1,546,066		$216,885		$199,392		$904,003		$6,070		$2,872,415		$849,277		**$3,721,693**
Total Bills	8,157																
Avg Customers	680																
Annual Bills	679																
Schedule No. A 25 (former Sch. AWH 31)																	
General Service																	
Less than 20 kW																	
Customer Charge	302																
Single-Phase	280	$12 64	$3,539									$12.64	$3,539			**$12.64**	**$3,539**
Three-Phase	22	$17 35	$382									$17.35	$382			**$17.35**	**$382**
All kWh	176,251	5 584 ¢	$9,842	0 457 ¢	$805	0 703 ¢	$1,239	4 393 ¢	$7,743	0.022 ¢	$39	11.159 ¢	$19,668	3.000 ¢	$5,288	**14.159 ¢**	**$24,956**
Total	176,251		$13,763		$805		$1,239		$7,743		$39		$23,589		$5,288		**$28,877**
Schedule No. OL-42																	
Airway & Athletic Lighting																	
Commercial, Rate Code 42																	
Customer Charge	480																
Single-Phase	319	$10 18	$3,247									$10 18	$3,247			**$10.18**	**$3,247**
Three-Phase	161	$13 95	$2,246									$13 95	$2,246			**$13.95**	**$2,246**
All kWh	202,965	7 818 ¢	$15,868	0 457 ¢	$928	0 623 ¢	$1,264	4 467 ¢	$9,066	0.022 ¢	$45	13 387 ¢	$27,171	3 000 ¢	$6,089	**16.387 ¢**	**$33,260**
Total	202,965		$21,361		$928		$1,264		$9,066		$45		$32,664		$6,089		**$38,753**

Proposed Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Proposed Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No. LS 51																	
Street Lighting																	
Total Bills	886																
High Pressure Sodium Vapor Wood Overhead																	
5,800 Lumen	5,056	$7 24	$36 605	$0 14	$708	$0.58	$2,932	$1 87	$9,455	$0 01	$51	$9 84	$49,751	$0 93	$4,702	**$10.77**	**$54,453**
9,500 Lumen	7,200	$7 94	$57,168	$0 20	$1,440	$0.04	$288	$2 35	$16,920	$0 01	$72	$10.54	$75,888	$1 32	$9,504	**$11.86**	**$85,392**
16,000 Lumen	0	$10 56		$0 29		$0 29		$3.41		$0 01		$14 56		$1 92		**$16.48**	
22,000 Lumen	2,554	$13 17	$33,636	$0 39	$996	$0.18	$460	$4 28	$10,931	$0 02	$51	$18 04	$46,074	$2 55	$6,513	**$20.59**	**$52,587**
27,500 Lumen	0	$17.02		$0 53		$0 58		$6 11		$0 03		$24 27		$3 45		**$27.72**	
50,000 Lumen	25	$24.99	$625	$0.80	$20	$0 53	$13	$8 56	$214	$0 04	$1	$34 92	$873	$5 28	$132	**$40.20**	**$1,005**
High Pressure Sodium Vapor - Decorative Series 1																	
9,500 Lumen	0	$29.21		$0 20		$0 04		$2 35		$0 01		$31 81		$1.32		**$33.13**	
16,000 Lumen	0	$29 21		$0 29		$0 29		$3.41		$0 01		$33 21		$1.92		**$35.13**	
High Pressure Sodium Vapor - Decorative Series 2																	
9,500 Lumen	0	$23 25		$0 20		$0 04		$2 35		$0 01		$25 85		$1 32		**$27.17**	
16,000 Lumen	0	$23 45		$0 29		$0 29		$3 41		$0 01		$27 45		$1.92		**$29.37**	
All kWh	694,980	18 423 ¢		0 457 ¢		0 531 ¢		5 399 ¢		0 022 ¢		24.832 ¢		3 000 ¢		**27.832 ¢**	
Total	694,980		$128,034		$3,164		$3,693		$37,520		$175		$172,586		$20,851		$193,437
Schedule No. LS 52																	
Street Lighting																	
Total Bills	60																
High Pressure Sodium Vapor																	
5,800 Lumen	12	$30 45	$365	$0 14	$2	$9 74	$117	$4 81	$58	$0 01	$0	$45 15	$542	$0 93	$11	**$46.08**	**$553**
9,500 Lumen	168	$31.53	$5,297	$0 20	$34	$9 19	$1,544	$5 34	$897	$0 01	$2	$46 27	$7,774	$1.32	$222	**$47.59**	**$7,996**
22,000 Lumen	0	$39 28	$0	$0 39	$0	$9 19	$0	$7 57	$0	$0 02	$0	$56 45	$0	$2.55	$0	**$59.00**	**$0**
50,000 Lumen	0	$54 33	$0	$0.80	$0	$8.55	$0	$12 26	$0	$0.04	$0	$75 98	$0	$5 28	$0	**$81.26**	**$0**
All Energy												11 .995				**14.995 ¢**	
All kWh	7,772	72 851 ¢		0 457 ¢		21.372 ¢		12 288 ¢		0.022 ¢		106 990 ¢		3 000 ¢		**109 990 ¢**	
Total	7,772		$5,662		$36		$1,661		$955		$2		$8,316		$233		$8,549
Schedule No. LS 53																	
Street Lighting																	
Total Bills	1,417																
High Pressure Sodium Vapor																	
Option A																	
5,800 Lumen	4,307	$2 11	$9,088	$0 14	$603	$0 27	$1,163	$1 22	$5,255	$0 01	$43	$3 75	$16,152	$0 93	$4,006	**$4.68**	**$20,158**
9,500 Lumen	13,228	$3 00	$39,684	$0 20	$2 646	$0 39	$5,159	$1.73	$22,884	$0 01	$132	$5.33	$70,505	$1 32	$17,461	**$6.65**	**$87,966**
16,000 Lumen	0	$4 36		$0 29		$0 57		$2 52		$0 01		$7 75		$1 92		**$9.67**	
22,000 Lumen	2,799	$5 79	$16,206	$0.39	$1,092	$0 75	$2,099	$3 35	$9,377	$0 02	$56	$10 30	$28,830	$2 55	$7,137	**$12.85**	**$35,967**
27,500 Lumen	0	$7 83		$0.53		$1 02		$4 53		$0 03		$13.94		$3 45		**$17.39**	
50,000 Lumen	38	$11 98	$455	$0.80	$30	$1 56	$59	$6.94	$264	$0 04	$2	$21 32	$810	$5 28	$201	**$26.60**	**$1,011**
Custom																	
16,000 Lum A 55 kWh	715	$3 74	$2,674	$0.25	$179	$0 49	$350	$2 17	$1,552	$0 01	$7	$6 66	$4,762	$1 65	$1,180	**$8.31**	**$5,942**
16,000 Lumen A	1,083	$4.36	$4,722	$0 29	$314	$0 57	$617	$2 52	$2,729	$0 01	$11	$7 75	$8,393	$1 92	$2,079	**$9.67**	**$10,472**
10,700 Lumen A	127	$7.35	$933	$0 49	$62	$0 96	$122	$4 26	$541	$0 02	$3	$13 08	$1,661	$3 24	$411	**$16.32**	**$2,072**
27,500 Lumen A	1,506	$7.83	$11,792	$0 53	$798	$1 02	$1,536	$4 53	$6,822	$0 03	$45	$13 94	$20,993	$3 45	$5,196	**$17.39**	**$26,189**
37,000 Lumen - A	1,923	$9.73	$18,711	$0 65	$1,250	$1 27	$2,442	$5 64	$10,846	$0 03	$58	$17 32	$33,307	$4 29	$8,250	**$21.61**	**$41,557**
37,000 Lumen - B	0	$17.73	$0	$0 65	$0	$1.27	$0	$5 64	$0	$0 03	$0	$25 32	$0	$4 29	$0	**$29.61**	**$0**
22,000 Lumen - B CSTM	0	$20.3[illegible]	$0	$0 39	$0	$0 75	$0	$3 35	$0	$0.02	$0	$24 81	$0	$2 55	$0	**$27.36**	**$0**
5,800 Lum - A 27 kWh	38	$1 84	$70	$0.12	$5	$0.24	$9	$1 06	$40	$0.01	$0	$3 27	$124	$0 81	$31	**$4.08**	$155
All kWh	1,531,797	6 807 ¢		0 457 ¢		0 886 ¢		3.941 ¢		0 022 ¢		12.113 ¢		3 000 ¢		**15.113 ¢**	
Total	1,531,797		$104,335		$6,979		$13,556		$60,310		$357		$185,537		$45 952		$231,489

Proposed Revenues and Rates
PACIFICORP
State of California
Billing Determinants for Proposed Prices
Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

	FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transmission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/o ECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars
Schedule No. LS 58																	
Street Lighting																	
Total Bills	276																
Class A																	
Incandescent																	
1,000 Lumen	0	$3 15	$0	$0 17	$0	$0 28	$0	$1.54	$0	$0 01	$0	$5 15	$0	$1.11	$0	**$6.26**	**$0**
2,500 Lumen	85	$6 21	$528	$0 33	$28	$0 55	$47	$3 03	$258	$002	$2	$10 14	$863	$2.19	$186	**$12.33**	**$1,049**
4,000 Lumen	0	$10 12	$0	$054	$0	$089	$0	$4.94	$0	$0 03	$0	$16 52	$0	$3.57	$0	**$20.09**	**$0**
6,000 Lumen	0	$13 86	$0	$0 74	$0	$1.22	$0	$6 76	$0	$004	$0	$22 62	$0	$4 89	$0	**$27.51**	**$0**
Mercury Vapor																	
7,000 Lumen	1,959	$646	$12,655	$0 35	$686	$0 57	$1,117	$3 15	$6,171	$0 02	$39	$10.55	$20,668	$2 28	$4,467	**$12.83**	**$25,135**
21,000 Lumen	525	$14 62	$7,676	$0 79	$415	$1 28	$672	$7 14	$3,749	$0 04	$21	$23 87	$12,533	$5 16	$2,709	**$29.03**	**$15,242**
55,000 Lumen	0	$3502	$0	$1 88	$0	$3 08	$0	$17 10	$0	$009	$0	$57.17	$0	$12 36	$0	**$69.53**	**$0**
Fluorescent																	
21,400 Lumen	0	$13.77	$0	$0 74	$0	$1 21	$0	$6 72	$0	$0 04	$0	$22 48	$0	$486	$0	**$27.34**	**$0**
Class B																	
Incandescent																	
1,000 Lumen	0	$473	$0	$0.17	$0	$0.28	$0	$1 54	$0	$0.01	$0	$6 73	$0	$1.11	$0	**$7 84**	**$0**
2,500 Lumen	0	$787	$0	$0.33	$0	$0.55	$0	$3.03	$0	$0.02	$0	$11 80	$0	$2.19	$0	**$13.99**	**$0**
4,000 Lumen	0	$11.82	$0	$0.54	$0	$0 89	$0	$4.94	$0	$0.03	$0	$18.22	$0	$3 57	$0	**$21.79**	**$0**
6,000 Lumen	0	$15 66	$0	$0.74	$0	$1 22	$0	$6.76	$0	$0.04	$0	$24 42	$0	$4 89	$0	**$29.31**	**$0**
Mercury Vapor																	
7,000 Lumen	0	$7.43	$0	$0.35	$0	$0.57	$0	$3 15	$0	$0.02	$0	$11 52	$0	$2 28	$0	**$13.80**	**$0**
21,000 Lumen	0	$15.69	$0	$0.79	$0	$1 28	$0	$7.14	$0	$0.04	$0	$24 94	$0	$5 16	$0	**$30.10**	**$0**
55,000 Lumen	0	$36.47	$0	$1.88	$0	$3.08	$0	$17 10	$0	$0.09	$0	$58 62	$0	$12 36	$0	**$70.98**	**$0**
Fluorescent																	
21,400 Lumen	0	$16 44	$0	$0.74	$0	$1.21	$0	$6.72	$0	$0.04	$0	$25.15	$0	$4 86	$0	**$30.01**	**$0**
All kWh	245,451	8 501 ¢		0 457 ¢		0 747 ¢		4 150 ¢		0 022 ¢		13 877 ¢		3 000 ¢		**16.877 ¢**	
Total	245,451		$20,859		$1,129		$1,836		$10,178		$62		$34,064		$7,362		**$41,426**
Schedule No. OL-15																	
Street Lighting																	
Composite																	
Total Bills	11,110																
Mercury Vapor																	
7,000 Lumen	10,466	$10 81	$113,137	$0 35	$3,663	$022	$2,303	$3.67	$38,410	$0 02	$209	$15 07	$157,722	$2 28	$23,862	**$17.35**	**$181,584**
21,000 Lumen	931	$21.37	$19,895	$0 79	$735	$0 77	$717	$800	$7,448	$0 04	$37	$30 97	$28,832	$5 16	$4,804	**$36.13**	**$33,636**
55,000 Lumen	73	$45 96	$3,355	$1.88	$137	$2 53	$185	$18.47	$1,348	$0 09	$7	$68.93	$5,032	$12 36	$902	**$81.29**	**$5,934**
High Pressure Sodium Vapor																	
5,800 Lumen	1,691	$12 22	$20,664	$0.14	$237	$2 61	$4,414	$2 51	$4,244	$0 01	$17	$17 49	$29,576	$0 93	$1,573	**$18.42**	**$31,149**
22,000 Lumen	392	$19.24	$7,542	$039	$153	$1 25	$490	$505	$1,980	$0 02	$8	$25 95	$10,173	$2 55	$1,000	**$28.50**	**$11,173**
50,000 Lumen	32	$31 84	$1,019	$0.80	$26	$007	$2	$9 44	$302	$004	$1	$42 19	$1,350	$5 28	$169	**$47.47**	**$1,519**
All kWh	1,077,000	15 377 ¢		0 457 ¢		0 753 ¢		4 989 ¢		0 022 ¢		21 598 ¢		3 000 ¢		**24.598 ¢**	
Additional Wood Poles	320	$1.00	$320									$1.00	$320			**$1.00**	**$320**
Total	1,077,000		$165,932		$4,951		$8,111		$53,732		$279		$233,005		$32,310		**$265,315**

Proposed Revenues and Rates
PACIFICORP
State of California
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Historic 12 Months Ended June 2009
Forecast 12 Months Ending December 2011

FORECAST Dec 11	Distribution Price	Distribution Charges	FERC Transmission Price	FERC Transmission Charges	California Transm-ission Price	California Transmission Charges	Generation Price	Generation Charge	Generation Franchise Fee	Generation Franchise Charges	w/oECAC Subtotal Price	Subtotal Revenue Dollars	Proj. (Base) ECAC Price	Projected (Base) ECAC Charges	Proposed Price	Proposed Revenue Dollars

SUMMARY

	FORECAST Total KWH	Distribution Charges	FERC Transmission Charges	California Transmission Charges	Generation Charge	Generation Franchise Charge	w/oECAC Subtotal Revenue	Base ECAC Charges	Proposed Revenue
		(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							(9)+(10)+(11)+(12)+(13)		(14)+(15)
(1) Total*	828,270,000	$43,816,888	$3,896,835	$4,501,048	$28,142 348	$182,233	$80,539,352	$24,857 364	$105,396,716
(2) Average Price (mills/kwh)		5290	4 70	5.43	33 98	0 22	97 24	30 01	127.25
(3) Employee Discount		($23,951)	($1,752)	($1,951)	($12,372)	($84)	($40,110)	($11,511)	($51,621)
(4) Total (Including Employee Discount)		$43,792,938	$3,895,083	$4,499,097	$28,129,976	$182,149	$80,499,242	$24,845,853	$105,345,095
(5) Bills	578,093								
(6) Customers	48,174								
(7) AGA									
Residential							$202		$202
Commercial							$109,431		$109,431
Industrial							$1,541		$1,541
Irrigation							$44 896		$44,896
Public Street & Highway Lighting							$0		$0
Total							$156,069		$156,069
(8) Total	828,270,000						$80,655,311		$105,501,164

Notes:
Line (1) = Sum of all schedules excluding Employee Discount
Line (2) = Line (1) / Total Forecast KWH in Line (1)
Line (4) = Line (1) + Line (3)
Line (8) = Line (4) + Line (7)
* Before discount

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

SIERRA CLUB EXHIBIT 414

Exhibit Accompanying the Rebuttal Testimony of Jeremy Fisher

Docket No. UE-191024 et al. Settlement Stipulation (Wash. U.T.C)

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-191024, UE-190750, UE-190929, UE-190981, UE-180778 (Consolidated) **SETTLEMENT STIPULATION**

1 PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company); Staff of the Washington Utilities and Transportation Commission (Staff); Packaging Corporation of America (PCA), the Public Counsel Unit of the Attorney General's Office (Public Counsel), The Energy Project (TEP), and Walmart, Inc. (Walmart) submit this Settlement stipulation for PacifiCorp's General Rate Case for approval from the Washington Utilities and Transportation Commission (Commission). The parties to this proceeding, PacifiCorp, Staff, Public Counsel, PCA, TEP, and Walmart (collectively, the "Parties," and individually "Party") have reached a Settlement Stipulation (Stipulation) resolving all the issues in this proceeding.

2 This Stipulation is being filed with the Commission as a full settlement of the issues in this consolidated proceeding in accordance with WAC 480-07-730(1), with the exception of Docket UE-180778, which is the subject of a separate settlement stipulation.[1] The Stipulation consists of this document, entitled "Settlement Stipulation".

[1] The settlement for that proceeding is filed separately.

The Parties understand that the Stipulation is not binding on the Commission or any Party unless the Commission approves it.[2]

I. RECITALS

3 On December 13, 2019, PacifiCorp filed a general rate case with the Commission requesting an increase in revenues of approximately $3.1 million from Washington operations, offset by the approximately $7.1 million proposed amortization of certain tax reform benefits, resulting in an overall price reduction of approximately 1.1 percent, or $4.0 million.

4 The filing was based on an historical twelve-month period ended June 30, 2019, adjusted for known and measurable changes. In particular, net power costs reflected the normalized pro forma costs for the 12-month period ending December 31, 2021, the rate effective period in this case, scaled back to the historical test period using the production factor.[3]

5 On January 9, 2020, the Commission issued an order suspending PacifiCorp's tariffs and allowing parties to conduct discovery consistent with the Commission's procedural rules.[4] On February 3, 2020, the Commission issued a Pre-Hearing Conference Order that set a procedural schedule, which allowed for the filing of Supplemental Testimony updating PacifiCorp's revenue requirement on April 1, 2020, based on decommissioning studies that were currently ongoing at the time.[5] The Pre-Hearing Conference Order also approved the interventions of PCA, TEP, and Walmart,

[2] The exception is that before the Commission's approval of the Stipulation, the Parties agree to support approval of the Stipulation by the Commission.
[3] The production factor is the ratio of the loads in the historical test period to the loads in the forecast period.
[4] Order 01 (Jan. 9, 2020).
[5] Order 03 at Appendix B (Feb. 3, 2020).

and granted consolidation of Dockets UE-190750, UE-190929, UE-190981, and UE-180778.

6 On March 13, 2020, the Commission issued an order that among other rulings, directed PacifiCorp to file supplemental testimony on the Colstrip coal supply agreement, also on April 1, 2020.[6] PacifiCorp filed supplemental testimony on April 1, 2020. This supplemental testimony identified an increase in revenues of approximately $29.8 million from Washington operations, offset by approximately $18.8 million proposed amortization of certain tax reform benefits, resulting in an overall price increase of approximately 3.2 percent, or $11.0 million.

7 The Parties have conducted extensive discovery in this proceeding. The Parties held an initial settlement conference on April 30, 2020, and held subsequent meetings on May 18, 2020, and May 28, 2020. The Parties presented proposals and counter-proposals which culminated in this settlement. Staff notified the administrative law judge on May 29, 2020, that an agreement had been reached.

8 This settlement is a comprehensive resolution of this consolidated proceeding, except for the issues in Docket UE-180778, which are addressed in a separate stipulation. The terms of the settlement are set forth in the following Stipulation, which the Parties have entered into voluntarily to resolve matters in dispute in the interests of expediting the orderly disposition of this proceeding. The Parties intend to file the Stipulation with the Commission and request Commission approval of the Stipulation.

[6] Order 05 at ¶11 (Mar. 13, 2020).

II. AGREEMENT

A. Rate Decrease and Rate Effective Date

9 The Parties agree that PacifiCorp shall be authorized to implement rate changes based on a revenue requirement decrease of $5.61 million, netted against a transmission adjustment of $5.4 million, for a total decrease of PacifiCorp's annual revenues from Washington customers of $0.21 million (or a 0.06 percent rate decrease). This amount also includes an approximate $1.48 million revenue requirement reduction resulting from modifications to PacifiCorp's depreciation rates, as agreed to in the separate stipulation filed in Docket UE-180778. Under Schedule 197, the Stipulation provides for a five-year amortization of the remaining tax credit balances, which is an $11.94 million tax credit annually.[7] Offset by the expiration on January 1, 2021, of the approximate $8 million currently being passed back to customers through Schedule 197, this results in a total decrease of $4.15 million for customers (1.18 percent rate decrease) in 2021 and no rate change in 2022 and 2023, subject to the results of the updates and additional proceedings agreed to in this Stipulation. Appendix A reflects the calculation of this rate change. The Parties agree that the rate change identified herein will be effective with service on and
10 after January 1, 2021. The suspension period in this case ends on December 31, 2020.

As shown in Appendix A and detailed below, the Parties agree that the proposed $4.15 million rate decrease reflects specific updates and adjustments to the Company's filed case, as well as an additional non-specific adjustment related to a compromise of issues on which resolution could not be reached.

[7] Schedule 197 currently credits approximately $8 million to customers. This credit expires on January 1, 2021.

B. Rate Plan

11 PacifiCorp accepts a 3-year rate plan from 2021 to 2023, with no base rate changes through 2023, except as specifically provided for in this Stipulation. To implement the rate plan, the Company agrees not to file a general rate case for rates that would be effective before January 1, 2024. However, consistent with Section II.(E) below, PacifiCorp will file a Power Cost Only Rate Case (PCORC) in 2021 to update its net power cost (NPC) baseline to reflect the day-ahead dispatch expected to occur beginning January 2021.

12 The base rates resulting from the settlement, effective January 1, 2021, include production related plant that will be in service during the latter half of 2020. The intent of this settlement and the rate plan is to provide rate stability, through a rate decrease in 2021, and no change in base rates in years 2022 and 2023, subject to the results of the updates and additional proceedings agreed to in this Stipulation. Nothing in this settlement precludes PacifiCorp or other parties from seeking deferred accounting for unanticipated costs or revenues during the rate plan period; PacifiCorp may also seek deferred accounting as appropriate under Washington's emissions performance standard, RCW 80.80.060(6) during the rate plan period. No party waives its rights to substantively object to any such deferred accounting filing.

C. Rate of Return

13 For purposes of this settlement and rate plan, the Parties agree to maintain the current authorized capital structure and cost of equity that were previously approved for

PacifiCorp in Docket UE-152253, which supports a rate of return of 7.17 percent.[8] The Parties agree to update the cost of long-term debt to 4.92 percent.

D. Pro Forma Major Capital Additions

14 The Parties agree to a limited-issue rate filing in 2021 for review of the major capital additions included in this case that are placed in service after May 1, 2020.[9] Rates based on the costs and benefits of the following assets are subject to refund pending review in the limited-issue filing:

- Ekola Wind Project
- TB Flats Wind Project
- Cedar Spring I Wind Project
- Cedar Springs III Wind Project
- Pryor Mountain Wind Project
- Dunlap Wind Repowering Project
- Foote Creek I Wind Repowering Project
- Aeolus to Bridger/Anticline 500kv Transmission Line Sequence 4
- Associated 230kv network upgrades

15 In the limited-issue filing, the Company will demonstrate the prudency and actual costs of major production and transmission related assets placed in service between May 2020 and the filing in 2021. The Commission will set final rates based on its review of prudence and actual project costs, which may be higher or lower than what was filed in this case. The Parties agree to support a procedural schedule that will provide for issuance of a decision by the Commission in no less than 6 months and no more than 7 months following the filing.

[8] PacifiCorp's previously authorized return on equity was 9.5 percent, with an authorized capital structure of Long-Term Debt at 50.88 percent, Common Stock Equity at 49.10 percent, and Preferred Stock at 0.02 percent.
[9] Consistent with this Stipulation's general provision on "No Precedent", the Parties specifically agree that the handling of pro forma capital additions as specified in this stipulation is non-precedential, and that this stipulation does not bind any party to a specific position on how proforma capital additions should be handled in any future rate proceeding.

16 The Parties agree there will be no further incorporation of capital additions into rates through 2023. PacifiCorp may include in the limited-issue filing in 2021 any unanticipated capital additions placed into service prior to the filing, which if found prudent by the Commission, will be recovered in rates as a part of the Company's next general rate case. Any such unanticipated capital additions will be excluded from the calculation of the Company's baseline NPC in the PCORC specified below, unless the Company is allowed to defer the revenue requirement associated with unanticipated capital additions until its next rate case, in which case the associated benefits will be included in baseline NPC.

E. Net Power Costs

17 Parties agree that the NPC baseline will be updated based on a nodal dispatch through a PCORC filed in 2021. The only effect from this PCORC on rates will be a change in the NPC baseline which could be higher or lower. The prudence of any costs associated with nodal dispatch and modeling nodal dispatch will also be subject to review in the PCORC. For the purposes of NPC baseline until the baseline is revised in the PCORC in 2021, the parties agree to the following provisions below.

1. Energy Imbalance Market

18 Energy Imbalance Market (EIM) forecast costs (normally included in NPC) and benefits will be included in base NPC and actual EIM costs and benefits will flow through PacifiCorp's power cost adjustment mechanism (PCAM). Non-NPC EIM costs will be moved to base rates as per the Commission's final order in Docket UE-152253.[10] The Parties agree not to oppose a Staff or Generic Commission investigation into the

[10] *WUTC v. Pacific Power & Light Co., a division of PacifiCorp*, Docket No. UE-152253, Order 12 at ¶14 (Sept. 1, 2016).

modeling of EIM benefits. This agreement does not bind any party to a specific approach, calculation, or method for determining or modeling EIM benefits.

2. Production Tax Credits

19 Production tax credits (PTCs) will be credited to customers in a manner that matches the costs in the PCAM without running through the mechanism; differences between the actual and projected PTCs will not flow through the PCAM deferral account. Instead, these amounts will receive separate accounting treatment and be trued up on an annual basis. In accordance with the Parties' intent to align costs and benefits, PTCs associated with the pro forma capital additions identified in Section II.(D) are subject to refund. The Parties agree that this settlement does not foreclose any Party from taking any position on expiring PTCs.

3. Baseline

20 The revenue requirement in this Settlement Stipulation includes a NPC baseline of approximately $102 million, representing an approximate $10.5 million reduction from the baseline included in PacifiCorp's April 1, 2020 filing. The NPC baseline will be updated on October 15, 2020 (October Update). Except as explicitly stated below, the October Update will be calculated in the same manner as the baseline that was used to derive the revenue requirement in this settlement. The October Update must be based on the most recent Official Forward Price Curve (OFPC) available (September 2020 OFPC) and treat EIM costs consistent with Section II.(E)(1) above. This update will also include: a black box adjustment reducing NPC by $1,357,952, line loss savings of 11.5 aMW, and reliability cost savings of 36.5 aMW for the Energy Vision 2020 additions (Ekola, TB Flats, and Cedar Springs), if beneficial to Washington customers.

21 If necessary and to the extent possible, deviations in the positive direction (increase in rates) from the NPC baseline estimated in this settlement as a result of the October Update will be offset by the balance in the deferral account for the PCAM.

4. Colstrip Unit 4

22 The Parties support deferred accounting treatment for major maintenance expenses at Colstrip Unit 4 through 2020 and early 2021. This deferral can be reviewed for prudency as a part of the 2021 PCORC and prudent expenses can be recovered in rates as part of the Company's next general rate case, notwithstanding the limitations specified above.

F. WIJAM MOU & 2020 Protocol

23 The Parties support the implementation of the Washington Interjurisdictional Allocation Methodology Memorandum of Understanding (WIJAM MOU)[11] and 2020 Protocol[12] according to their relevant terms and conditions.

1. Transmission Adjustment

24 The WIJAM MOU originally outlined a three-year phase-in approach to including these costs in Washington's rates through a combination of an update to the revenue requirement in this case and a separate tariff rider, the System Transmission Adjustment. However, this settlement eliminates the three-year phase-in and provides for an allocation of PacifiCorp's System Transmission costs in base rates on January 1, 2021.Consistent with the WIJAM MOU, before December 31, 2023, the Company will need to present a method for excluding the costs and benefits of all transmission-voltage, radial lines

[11] Wilding, Exh. MGW-2.
[12] Lockey, Exh. EL-3.

connecting resources not otherwise included in Washington rates to PacifiCorp's interconnected, network transmission system.[13]

2. Accelerated Depreciation

25 The Parties' stipulated revenue requirement includes the acceleration of depreciation for Colstrip Unit 4 and the Jim Bridger Plant to year-end 2023. Once Colstrip Unit 4 or the Jim Bridger Plant facilities are removed from the Company's revenue requirement, PacifiCorp will not seek to recover additional investments in those facilities in Washington rates.

3. Decommissioning and Remediation

26 The Parties' stipulated revenue requirement includes the recovery of additional Decommissioning & Remediation (D&R) costs[14] over 10 years (2021 through 2030) in the amount of $10,867,247 (total company) and other plant-related closure costs in the amount of $6,283,189 (total company) per year for Colstrip Unit 4 and the Jim Bridger Plant. Parties agree to the decommissioning balancing account as proposed in Exhibit MGW-1CT, where Washington's share of the costs are recorded in a balancing account that is reflected as a reduction to rate base. Parties agree to use the D&R cost estimates provided in PacifiCorp's April 1, 2020 supplemental filing for purposes of setting rates in this proceeding only, but take no position on the accuracy of this estimate overall or of the individual D&R components. Parties further agree that these estimates are not precedential in any way, and reserve all rights to challenge future decommissioning cost

[13] WIJAM MOU at 4.1.3.1. Staff anticipates this process being collaborative. However, if it need be it can be subject to adjudication as a part of the compliance with this docket or in a future general rate case.

[14] The additional decommissioning and remediation is based on the Decommissioning Studies issued in January and March 2020 as compared to the level of decommissioning and remediation originally included in the Company's 2018 Depreciation Study.

estimates in subsequent general rate cases or other proceedings in which such costs are at issue.

4. Bridger Coal Company

27 The Company's current baseline NPC include $18,753,699 (total company) of contributions to the Bridger Coal Company (BCC) Reclamation Trust Fund through fuels costs for the Jim Bridger Plant. The Parties' stipulated revenue requirement also includes recovery of additional, incremental reclamation and depreciation over 10 years (2021 through 2030) in the amount of $11,815,290 per year (total company), for Bridger Mine reclamation and depreciation costs beyond 2023. As with the D&R costs above, Washington's share of these costs will be recorded in a balancing account that will be part of rate base.

28 PacifiCorp agrees to hold a workshop during the fall of 2020 on BCC costs, which will include, but not be limited to: (1) customers' historical contribution to BCC costs; (2) how BCC costs are reflected in Washington rates and in what amount; and (3) the estimated remaining contribution of Washington customers to these costs. PacifiCorp agrees to provide presentation materials and work papers relevant to the workshop at least two weeks prior to the workshop. PacifiCorp further agrees to track customers' contribution to BCC costs over the period of the rate plan in a manner that allows Parties to review these contributions in PacifiCorp's next general rate case.

G. Rate Spread

29 The Parties agree that the rate decrease under this settlement will be spread to all rate schedules, other than street lighting, on an equal percentage of revenue basis. Street lighting schedules will be set at their cost of service as specified in the initial application.

Appendix B to this Stipulation shows the results of the agreed rate spread by rate schedule.

H. Rate Design

30 Appendix B demonstrates the Parties' agreed upon rate design, shows the monthly impact of the rate change on residential customers, and contains the workpapers reflecting the rates designed to collect the revenue requirement specified in this settlement. Appendix C contains the proposed tariff schedules designed to collect this revenue requirement.

1. Residential Rate Design

31 The Parties agree that the Company's residential basic charge will be set at $7.75 and the inclining block tiered energy charge rate structure will be flattened by 25 percent.

2. Non-Residential Rate Design

32 All of the Company's changes for non-residential rate design proposed in the Company's initial filing are implemented, except that the relationship between the first and second block energy charges on Schedule 36 are maintained and the billing determinants used to set rates for Schedule 48T – Dedicated Facilities are re-calculated to be based upon calendar year 2019 information.

3. Pilot Programs

33 The Parties support the Company's proposed pilot programs identified in its December 13, 2019 filing. As part of PacifiCorp's pilot program to remove fees associated with payment methods, all paystation fees will be eliminated. Staff and interested Parties will work with the Company over the next few months to develop a Monitoring and Reporting plan for these pilot programs. At a minimum, the Monitoring

and Reporting plan will include the impacts on low-income and other vulnerable customers. The Company will host a regional meeting by June 30, 2021, on emerging technologies that may help it meet its future resource adequacy needs.

I. Low Income Programs

34 The Parties agree to the formation of an Advisory Group for the LIBA Program consisting of PacifiCorp, The Energy Project, Public Counsel, Commission Staff, NW Energy Coalition, and agency representatives and other interested stakeholders. The first meeting will be held within 60 days of the final order adopting this Stipulation, with quarterly meetings thereafter. The Advisory Group will have the following goals:

- Keep customers connected to electric service;
- Provide assistance to more customers than are currently served;
- Lower the energy burden of LIBA Program participants;
- Collect data necessary to assess LIBA Program effectiveness;
- Inform ongoing policy discussions.

35 The LIBA Advisory Group will specifically review: (1) the sufficiency of funding levels and other mechanisms to expand access to bill assistance, and (2) the possibility of increasing the size of the first energy block to 800 or 1000 kWh in order to create an initial "lifeline" block.

36 The Parties agree that the LIBA Advisory Group will use best efforts to develop a bill discount proposal for the LIBA program with equitable impacts across usage levels, with the Advisory Group process to be completed within one year of the final order adopting this Stipulation.

37 The Company agrees to file annual reports of the LIBA program status with the Commission, with content comparable to the PSE HELP and Avista LIRAP annual reports where applicable. The first report will be filed one year after the final order adopting this Stipulation, with subsequent reports due 120 days after the end of the program year. The Company agrees to provide a draft report to the LIBA Advisory Group for comment before filing the first annual report.

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J. Disconnection Practices

1. Disconnection Data Reporting

38 PacifiCorp agrees to continue to provide its current monthly State of Washington Low-income Data Tracking report and to include the following information on disconnections, credit, and collection data, in the LIBA program annual report:

- Total disconnections for all purposes
- Total disconnections of residential customers for non-payment
- Total disconnections of LIBA and LIHEAP participants for non-payment
- Total remote disconnection, if any, for non-payment
- Total remote disconnection of LIBA and LIHEAP customers for non-payment if any
- Total disconnections of customers with a medical emergency verified at the premises within the previous two years
- Number of payments, amount received, and mode of payment (cash, check, electronic, etc.) received during a field/premise visit to the service address, made by the customer to prevent disconnection
- Number of free and fee-paid pay stations
- Number and nature of customer complaints related to disconnection
- Number of deferred payment plans and the amount deferred
- Arrearage amounts

2. Disconnection Reduction Plan

39 In consultation with the LIBA Advisory Group, PacifiCorp agrees to develop a Disconnection Reduction Plan and to file the Plan with the Commission within one year of the final order adopting this Stipulation.

3. Premise Visits

40 Consistent with Commission regulations, PacifiCorp agrees to continue premise visits to residential service addresses to disconnect service for non-payment. PacifiCorp

will accept payment, including cash payment, at the service address during the premise visit to allow the residential customer to avoid disconnection.

K. Additional Provisions

1. Renewable Energy Credits

41 The Parties agree with the Company's proposed treatment for Renewable Energy Credits (RECs).[15] However, the $300,000 REC one-time purchase should be amortized and tracked for true-up in the existing mechanism over three years.

2. Decoupling

42 The Parties agree to the proposed changes to the decoupling mechanism as specified in PacifiCorp's initial filing.[16]

3. Idaho Asset Exchange

43 The Parties agree that the investments related to the Idaho Asset Exchange[17] are prudent and deem the requirements from Docket UE-152253 to have been satisfied.

4. Investor Supplied Working Capital

44 Work papers related to Investor Supplied Working Capital (ISWC) in future rate cases will use the format provided in the Company's 2nd Supplemental Response to UTC Data Request No. 81.[18] Specifically, ISWC will reflect AMA account balances, by subaccount, in one of the following categories: current assets, current liabilities, average invested capital, and investments. The ISWC presentation will then categorize the investment AMA amounts as Washington, Other States, or Non-Operating/Other. Then,

[15] Lockey, Exh. EL-1T at 34-36.
[16] Meredith, Exh. RMM-1T at 61-64.
[17] Vail, Exh. RAV-1T at 11-15.
[18] Attached as Appendix D.

it will multiply ISWC by the percentage of the total investment representing Washington, to calculate ISWC for Washington.

5. Tax Normalization

45 Parties agree that the Company will use a normalized method of accounting for all temporary book-tax differences, with the exception of equity AFUDC, on a prospective basis beginning January 1, 2021.

L. General Provisions

46 Comprehensive Settlement**.** The agreement above includes specific items reflected in the Company's revenue requirement. This Stipulation resolves all the disputed issues in this proceeding and acts as a modification to PacifiCorp's proposed filing on the issues included in this Stipulation. While certain adjustments were specifically addressed in the settlement, they are being accepted only as part of a comprehensive settlement stipulation that resolves all issues associated with the Company's initial filing. As such, they should be viewed in the broader context of the total settlement stipulation.

47 Discovery. The Parties agree to suspend all discovery in this proceeding pending filing and consideration of this Stipulation. In the event the case resumes, the Parties agree to work cooperatively to develop a new schedule taking into consideration the delay associated with this settlement.

48 Public Interest. The Parties agree that this Stipulation is in the public interest and will produce rates for the Company that are fair, just, reasonable, and sufficient.

49 Binding on Parties. The Parties agree to support this Stipulation as a settlement of the contested issues between them in this consolidated proceeding, except for the issues

raised in Docket UE-180778, which are the subject of a separate settlement stipulation. The Parties understand that this Stipulation is not binding on the Commission or any Party unless the Commission approves it.[19] If approved by the Commission, the Parties shall take all actions necessary, as appropriate, to carry out this Stipulation.

50 Integrated Agreement. The Parties agree that this Stipulation represents the entire agreement of the Parties, and supersedes all prior oral and written agreements on the issues addressed. The Parties have negotiated this Stipulation as an integrated document to be effective upon execution and Commission approval. Accordingly, the Parties recommend that the Commission adopt this Stipulation in its entirety.

51 Procedure for Supporting Stipulation. The Parties shall cooperate in submitting this Stipulation promptly to the Commission for acceptance, and cooperate in supporting this Stipulation throughout the Commission's consideration of this Stipulation. In particular, each Party shall cooperate in developing testimony and offering to present one or more witnesses to testify in support of the Stipulation, , as described in WAC 480-07-740(2)(a) and (3)(a)-(b). If necessary, each Party will provide a witness to sponsor and support this Stipulation at a Commission hearing. If the Commission decides to hold such a hearing, each Party will recommend that the Commission issue an order adopting the Stipulation. No Party to this Stipulation or their agents, employees, consultants, or attorneys will engage in advocacy contrary to the Commission's adoption of this Stipulation.

52 Reservation of Rights. If the Commission accepts the Stipulation with new conditions, or approves the resolution of this proceeding through provisions that are

[19] The exception is that prior to the Commission's approval of the Stipulation, the Parties agree to support the Stipulation before the Commission.

different than recommended in this Stipulation, WAC 480-07-750(2)(b) shall apply. Consistent with WAC 480-07-750(2)(b)(ii), each Party reserves the right, upon written notice to the Commission and all Parties within seven (7) days of the Commission's order, to state its rejection of the conditions. Otherwise, pursuant to WAC 480-07-750(2)(b)(i), each Party will notify the Commission within seven (7) days of the Commission's order that it accepts the conditions. If the Commission rejects this Stipulation, WAC 480-07-750(2)(c) shall apply. In the event that the Commission rejects this Stipulation or if any Party rejects a proposed new condition, the Parties will: (1) request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case consistent with WAC 480-07-750(2)(c); and (2) cooperate in the development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

53 Advance Review of News Releases. The Parties agree: (1) to provide each other the right to review in advance of publication any and all announcements or news releases that any Party intends to make about the Stipulation (with the right of review to include a reasonable opportunity to request changes to the text of such announcements), and (2) to include in any news release or announcement a statement that the Staff's recommendation to approve the settlement is not binding on the Commission itself.

54 No Precedent. The Parties have entered into the Stipulation to avoid further expense, inconvenience, uncertainty, and delay of continuing litigation. The Parties recognize that the Stipulation represents a compromise of the Parties' positions. As such, conduct, statements, and documents disclosed during negotiations of the Stipulation shall not be admissible as evidence in this or any other proceeding. By executing this Stipulation, no Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

55 Execution. The Parties may execute the Stipulation in counterparts and as executed shall constitute one agreement. Copies sent by facsimile or electronic mail are as effective as original documents.

56 Effective date. The effective date of the Stipulation is the date of the Commission order approving it.

This STIPULATION is entered into by each Party as of the date entered below.
DATED: July 17, 2020.

ROBERT W. FERGUSON
Attorney General

Jennifer Cameron-Rulkowski
Assistant Attorney General
Counsel for the Washington Utilities and Transportation Commission Staff

Dated: ________________, 2020

PACIFICORP

Etta Lockey
Vice President, Regulation
Pacific Power

Dated: ________________, 2020

ROBERT W. FERGUSON
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Nina Suetake
Assistant Attorney General
Public Counsel Unit of the Attorney General's Office

Dated: ________________, 2020

PACKAGING CORPORATION OF AMERICA

Tyler Pepple
Davison Van Cleve
Counsel for Packaging Corporation of America

Dated: ________________, 2020

THE ENERGY PROJECT

Simon ffitch
Counsel for The Energy Project

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Vicki Baldwin
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Counsel for Walmart

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Vicki Baldwin
Parsons Behle & Latimer
Counsel for Walmart

Dated: ____________________, 2020

Docket No. UE 374
Exhibit Sierra Club/500
Witness: Ezra D. Hausman, Ph.D.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	**UE 374**

Rebuttal Testimony of
Ezra D. Hausman, Ph.D.

On Behalf of
Sierra Club

July 24, 2020

TABLE OF CONTENTS

I. Identification of Witness

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

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. Are you the same Ezra D. Hausman, Ph.D. who submitted opening testimony in this proceeding?

A. Yes.

II. Purpose of Rebuttal Testimony

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the reply testimony of PacifiCorp witnesses Michael G. Wilding, and Rick T. Link. I address the extraordinary implications of the testimony of Witnesses Wilding and Link that the Commission should ignore not only Governor Brown's Executive Order (EO) 20-04 but also the Commission's own report on EO 20-04 in deciding this case, among other statements.

III. BASIS FOR SIERRA CLUB'S INTERVENTION

Q. PacifiCorp witness Mr. Wilding claims that Sierra Club's intervention in this case "continues its practice of intervening in any PacifiCorp proceeding before the state commissions that regulate the Company to object to the Company's continued use of coal-fired generation."[1] Do you agree?

A. I agree that Sierra Club has intervened in numerous cases, in Oregon and elsewhere, to represent its members' interests in clean, affordable energy, in prudent planning, and to prevent continued life-extending investments in uneconomic coal generation that has no place in a climate-constrained future. This important role has been recognized by utility commissions, including the Oregon PUC, by granting Sierra Club intervener status in each of the proceedings to which Mr. Wilding refers.

Q. In your experience, has Sierra Club's practice of repeatedly intervening in utility commission cases in Oregon and elsewhere benefitted ratepayers?

A. Very much so. Sierra Club has raised important issues on behalf of its ratepayer-members not addressed by any other party, allowing regulatory commissions to have a more comprehensive and informative record on which to base their decisions. As a result, Sierra Club's interventions have contributed to billions of dollars of avoided investments in uneconomic coal plants in the U.S. These interventions have effectively supported earlier retirements of approximately 100

[1] PAC/2000 at Wilding/34:13-16.

gigawatts of uneconomic coal generation in the U.S. since 2006, resulting in vast ratepayer savings, cleaner air, countless avoided illnesses and deaths, and reductions in global-warming pollution.

In my opinion, Sierra Club's interventions and other activities have also contributed to the growing recognition of the need to take more aggressive action to dramatically reduce greenhouse gas ("GHG") emissions by state legislatures and governors, including in Oregon. Sierra Club's engagement has also led to important changes in state policies that have transformed the energy planning landscape to be more protective of the environment and the climate. Once such policy drivers are in place, they provide direction and a mandate for utility commissions and the utilities they regulate to incorporate specific GHG emission goals in their planning practices. EO 20-04 is such a mandate, and the Commission has clearly recognized that the planning framework in Oregon must evolve accordingly, and without delay.

Q. Mr. Wilding cites the Oregon Global Warming Commission's report as stating that "[f]rom 2014 to 2016, emissions from electricity use decreased from 30% to 26% of the state's total emissions."[2] Is this in any way related to Sierra Club's interventions?

A. Yes. There are, of course, a number of factors that have led to a decrease in utility-related emissions in Oregon; however, in my experience and opinion, Sierra Club's participation in a variety of proceedings before the Oregon

[2] *Id.* at Wilding/37:18-20.

Commission, including Integrated Resource Plans ("IRP"), rate cases, and Transition Adjustment Mechanism ("TAM") proceedings, has played an important role in the transition to cleaner energy sources that have helped to reduce the state's total emissions.

Q. PacifiCorp witness Mr. Link states that Sierra Club "simply repeats arguments Sierra Club has been making for years, in IRPs, TAMs, and rate cases."[3] How do you respond?

A. Just as PacifiCorp often touches on similar issues from one rate case to the next, I have raised certain issues in this case that have also been raised by myself and other witnesses sponsored by Sierra Club when they were germane to various other proceedings before this and other regulatory commissions. The testimony I filed in the current matter is responsive to the specific issues raised by the Company in this case, grounded in the regulatory environment in Oregon, and on specific standards that have been articulated by this Commission regarding its intended regulatory principles and practices.

Q. Can you provide specific examples of these regulatory principles and practices?

A. Yes. One such principle, articulated in EO 20-04 and quoted by the Commission, is that "[i]t is in the interest of utility customers and the public generally for the utility sector to take actions that result in the rapid reductions of GHG emissions,

[3] PAC/2300 at Link/72:10-11.

at reasonable costs, to levels consistent with the GHG emission goals set forth in [EO 20-04], including transitioning to clean energy resources and expanding low carbon transportation choices for Oregonians."[4]

Q. Does Mr. Wilding address this principle in his reply testimony?

A. Yes. However, he emphasizes only that this quote from EO 20-04 contains the words "at reasonable costs"[5] and ignores the directive to achieve certain aggressive GHG emissions mitigation goals. In writing the referenced sentence, I do not believe the Commission intended for cost to be its sole consideration, as Mr. Wilding appears to imply. Moreover, the term "reasonable costs" implies Commission judgement. In this case there is ample evidence–including through PacifiCorp's own studies and analyses[6]–that current coal plant operations are either marginal or uneconomic, and that continuing to invest in and operate them may harm Oregon ratepayers.

Q. Is there another principle or practice to which you refer?

A. Yes. In the Commission's May 15, 2020 report on EO 20-04, wherein the Commission stated that "[t]he PUC can explore pathways to *enhance and refine* our existing least-cost, least-risk framework to ensure energy utilities are focusing their system-wide resource strategies on making rapid progress to GHG reduction

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[4] Ore. Pub. Util. Comm'n, Report on Executive Order 20-04 at 3 (May 15, 2020), *available at* https://www.oregon.gov/puc/utilities/Documents/EO20-04PUC-Report.docx.pdf [hereinafter "OPUC Report on EO 20-04"].

[5] PAC/2000 at Wilding/35:10-13.

[6] *See* PacifiCorp, *2019 Integrated Resource Plan*, Volume II, Appendix R (Oct. 18, 2019), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html [hereinafter "PAC 2019 IRP"].

goals."[7]

Q. Does Mr. Wilding address this sentence in his rebuttal testimony?

A. Once again, Mr. Wilding quotes this sentence but ignores its plain meaning. He emphasizes the words "least-cost, least-risk"[8] but ignores that the intention is to *enhance and refine* the Commission's existing practice–which implies a change from its previous practice–"to ensure energy utilities are focusing their system-wide resource strategies on making rapid progress to GHG reduction goals." It has always been and remains the Commission's mandate to focus on least-cost, least-risk resource planning solutions, but to do so within the context of the full suite of reliability, environmental, and other constraints imposed by physics and by law.

What the Commission is addressing, but Mr. Wilding chooses to ignore, is that these constraints have evolved due to the Governor's directive, and in response to the pressing need to reduce greenhouse gas emissions from Oregon's electric supply resources; hence the need to "enhance and refine" the Commission's framework.

[7] OPUC Report on EO 20-04 at 5 (emphasis added).
[8] PAC/2000 at Wilding/35:15-17.

Q. PacifiCorp witness Mr. Link argues that the sort of analysis you recommended in your opening testimony, weighting resource lifetimes against certainty in decommissioning and remediation liability, is more properly the domain of an IRP, not a rate case.[9] Do you agree?

A. I agree that this would generally be the case. In this particular case, however, the Company is specifically asking for Exit Orders from the Commission, each of which is associated with an Exit Date, so it is appropriate to ask the Company to fully justify its choices of proposed Exit Dates with analysis of the type I recommend. Further, PacifiCorp witness Ms. Lockey describes just such an analysis of the Jim Bridger Units 2-4, as I quote and discuss on Page 26 of my opening testimony.[10] PacifiCorp cannot have it both ways: if the current rate case is an appropriate forum for its requested Exit Orders and weighing of costs and risks for certain coal plants, then it is an appropriate forum for the very similar, if broader analysis, that I recommend.

Nevertheless, should the Commission choose to not issue 2025 Exit Orders for the units in this case as I recommend in my opening testimony, it should direct the Company to perform an updated, comprehensive coal retirement analysis as a component of its 2021 IRP.

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[9] PAC/2300 at Link/76:13-19.
[10] Sierra Club/300 at Hausman/26:1-23.

IV. IMPACT OF EO 20-04

Q. PacifiCorp witness Mr. Wilding states that your assertion that EO 20-04 represents a new legal circumstance is "in error as Executive Order 20-04 supports the Exit Dates and Exit Orders in the 2020 Protocol."[11] Do you agree?

A. No. The Governor also directed "the utility sector to take actions that result in rapid reductions of GHG emissions."[12] The Commission must execute the mandate to achieve rapid reductions in GHG emissions while ensuring just and reasonable rates. Mr. Wilding's interpretation of EO 20-04 would result in no modification of the Commission's review of utility planning and rates, despite the directives laid out in the Executive Order.

Q. Mr. Wilding further claims that you do not "analyze the impact on customer rates if the Commission were to adopt [your] recommendation."[13] What is your response?

A. Sierra Club and other public interest organizations participate in proceedings such as the current matter, and audit the Company's processes and proposals, in order to protect the public interest. In my opening testimony, I discussed reasons that in my judgement the overall impact of my recommendations on revenue requirements would be modest, and could result in customer savings over the long

[11] PAC/2000 at Wilding/34:19-35:1.
[12] Sierra Club/302, Order No. 20-04, *Directing State Agencies to Take Action to Reduce and Regulate Greenhouse Gas Emissions* at Ordering ¶ 5(A) (Mar. 20, 2020) [hereinafter "EO 20-04"].
[13] PAC/2000 at Wilding/36:7-8.

term. However, it is PacifiCorp's ultimate responsibility to evaluate options for implementing the Governor's GHG mitigation goals and to provide a full accounting of associated costs, for comparison with the costs of its proposed plan, to the Commission. The Commission can only apply its judgement as to the reasonableness of costs if it is presented with such an accounting.

V. RELEVANCE OF PRE-MSP DOCUMENTS

Q. Mr. Wilding notes that you cite a 2018 Report to the Oregon Legislature by the Oregon Global Warming Commission, noting that this document "appears to have been in existence at the time Sierra Club signed the 2020 Protocol."[14] Is this true?

A. Yes.

Q. Mr. Wilding further asserts that the costs and risks associated with continued reliance on coal on pages 20-27 of your opening testimony do not represent "changed or unforeseen circumstances"[15] since the signing of the 2020 Protocol. Do you agree?

A. Yes.

[14] *Id.* at Wilding/36:15-18.
[15] *Id.* at Wilding/38:15

Q. Given that neither of these represents changed or unforeseen circumstances, why do you cite them in your testimony as support for earlier Exit Dates than the Company has proposed for some of its coal-fired resources?

A. As I made clear in my opening testimony, and as Mr. Wilding is clearly aware,[16] the changed and unforeseen circumstances on which I base my recommendation are (1) the change in legal circumstance represented by EO 20-04 and the Commission's report on the same, and (2) the change in factual circumstances represented by the emergence of COVID-19 and the significant, long-term impact this is likely to have on the load the Company serves. I did not claim that the Oregon Global Warming Commission report was a changed or unforeseen circumstance; I certainly did not imply that the economic, environmental, and regulatory risks of continued reliance on coal have emerged only in the last few months.

I raised these issues in my testimony because I believe that, while not new, they must be viewed in a new light given the mandates of EO 20-04 and the Commission's report. They represent evidence that must be weighed by the Commission as it considers how to carry out its revised responsibility. In my opinion, the Oregon Global Warming Commission report strongly supports the need for increasing the pace of eliminating high-emissions resources from Oregon's supply mix, which can be achieved through the issuance of Exit Orders. The review of risks associated with continued reliance on coal that I presented

[16] *See id.* at Wilding/33:13-17.

suggests that there will be other economic and environmental benefits for Oregonians by eliminating these resources from their supply mix as expeditiously as possible.

VI. ECONOMIC VIABILITY OF PACIFICORP COAL PLANTS

Q. PacifiCorp witness Mr. Link "disagree[s] with Sierra Club's claim that the 2019 IRP showed that the Company's coal units were already uneconomic on their own."[17] Can you explain your claim further?

A. Yes. This statement was based on Table R.4 of Appendix R of the Company's 2019 IRP, which showed a negative PVRR impact (i.e., savings for ratepayers) of retiring most of PacifiCorp's coal units individually, including the Hunter, Huntington, and Wyodak units. This table supports my statement that "the Company's IRP analysis showed that retiring any of the Hunter or Huntington units individually in 2022 would produce a net benefit for ratepayers under the Company's base case (medium gas price, medium CO_2 emissions cost) scenario."[18]

I fully recognize that this table does not demonstrate the costs or benefits that any particular *combination* of early retirements in any particular year, and I am mindful of the numerous caveats in the associated text. Nonetheless, the results were a stark reminder of the precarious economic position of the Company's coal fleet even before the changes in factual circumstances I discussed in my opening

[17] PAC/2300 at Link/74:13-14.
[18] Sierra Club/300 at Hausman/26:24-27 (citing PAC 2019 IRP, Volume II, Appendix R, at 598, Table R.4).

testimony–that is, lower energy prices and a decreased demand outlook due to COVID-19–further impaired the viability of these units. These combined circumstances strongly suggest that the Company might reasonably retire more units early or remove them from Oregon's resource mix and significantly reduce GHG emissions, at minimal cost to ratepayers. However, the Company has not performed this analysis.

Q. Regarding the impact of COVID-19, Mr. Link states that "[t]he fact that COVID-19 is likely to have an impact on demand and market prices for 18 months does not mean that the Company should necessarily revisit long-term resource decisions, such as the coal unit retirement dates established in the 2019 IRP."[19] How do you respond?

A. First, the reports I cite–both of which were released in April 2020, only three weeks into the first COVID-related lockdowns in the US–concluded that power markets would be disrupted for *at least* 18 months. Even at the time, one of the reports raised the potential for losses running through 2023.[20] We now know that such "worst-case" scenarios from April now appear more than likely, and long-term damage to the economy appears all but inevitable.

Under these circumstances, the Company should unquestionably "revisit long-term resource decisions," especially at a time when Oregon ratepayers can least

[19] PAC/2300 at Link/73:2-5.
[20] As described in the Wood Mackenzie brochure describing the reports, *Coronavirus will disrupt North America power markets for at least 18 months: North America power and renewables March 2020 STO* (Apr. 6, 2020), *available at* https://www.woodmac.com/our-expertise/focus/Power--Renewables/short-term-outlook-march2020-naps/.

afford wasteful spending on potentially unneeded and uneconomic resources.

VII. <u>RECOMMENDATIONS AND CONCLUSION</u>

Q. Having reviewed the Company's rebuttal testimony, have your recommendations for the Commission in this matter changed?

A. No. I recommend that the Commission issue Exit Orders in this case for all of PacifiCorp's coal units, with Exit Dates no later than December 31, 2025, regardless of the depreciable lives used by the Company. If the Commission elects not to issue such Exit Orders at this time, I recommend that it direct PacifiCorp to update its IRP analysis using current load, electricity price, and gas price expectations, along with updated renewable and storage resource costs, to determine whether retaining its coal-fired units beyond December 31, 2025 is in Oregon ratepayers' interest. I recommend that this updated analysis incorporate the social cost of carbon as indicated in the Commission's report on EO 20-04.

Q. Does this conclude your rebuttal testimony?

A. Yes.