Exhibit No. JIF-1CT
Docket UE-152253
Witness: Jeremy I. Fisher

BEFORE THE
Washington Utilities and Transportation Commission

In the Matter of PACIFIC POWER AND LIGHT COMPANY Petition For a Rate Increase Based on a Modified Commission Basis Report, Two-Year Rate Plan, and Decoupling Mechanism.	UE-152253

Corrected
Response Testimony of
Jeremy I. Fisher, PhD

On Behalf of
Sierra Club

REDACTED

~~March 17~~ April 13, 2016

Table of Contents

Table of Figures

Exhibit List

Exhibit No. JIF-~~1~~ 2	Curriculum vitae of Jeremy Fisher
Exhibit No. JIF-~~2~~ 3C	Confidential Attachment Sierra Club 1.3 1st Supplemental
Exhibit No. JIF-~~3~~ 4C	Confidential WUTC Data Request 161, 1st Supplemental
Exhibit No. JIF-~~4~~ 5	Response to WUTC 11
Exhibit No. JIF-~~5~~ 6	Response to SC 4.9 in Utah Docket 13-035-184, April 15, 2014
Exhibit No. JIF-~~6~~ 7C	Strategic Planning Review of Jim Bridger Plant, provided as Confidential Attachment to Sierra Club 2.27
Exhibit No.JIF-~~7~~ 8	Rebuttal Testimony of Ms. Cindy Crane in 13-035-184
Exhibit No. JIF-~~8~~ 9	PacifiCorp. 2013. Public Presentation - RFP Process Improvement Workshop (10-29-2013)
Exhibit No. JIF-~~9~~ 10	December 2013 OFPC provided to Sierra Club in non-confidential discovery in Wyoming Docket 20000-446-ER-14 (2014 General Rate Case) as SC 11.6
Exhibit No. JIF-~~10~~ 11	Response to WUTC DR 92
Exhibit No. JIF-~~11~~12C	Confidential Communication between Mr. Rick Link and associates, September 23, 2013
Exhibit No. JIF-~~12~~ 13	Response to Public Council DR 9
Exhibit No. JIF-~~13~~ 14	Response to Public Council DR 7
Exhibit No. JIF-~~14~~15C	Confidential Company Response to Public Council DR 15
Exhibit No. JIF-~~15~~16C	Confidential attachment response to WUTC DR 165, “Midas Inputs P0913B04.”

1. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, 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 and policies for electricity sector issues, including fossil generation, efficiency, renewable energy, ratemaking and rate design, restructuring and market power issues, and environmental regulations.

Q Please summarize your work experience and educational background.

A I've worked in electricity system energy planning for a decade, evaluating and helping to shape integrated resource plans, performing planning on behalf of states and municipalities, and helping regulators navigate environmental rules.

I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the states of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General ("TVA OIG"), the California Division of Ratepayer Advocates ("CADRA"), the California Energy Commission ("CEC"), the Regulatory Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), and other organizations.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oklahoma, Oregon, Nevada, New Mexico, Utah, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit JIF-~~1~~ 2.

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 Washington Utilities and Transportation Commission previously?

A No, I have not.

Q Have you testified in other states with regards to planning by PacifiCorp?

A Yes. I submitted testimony in PacifiCorp 2011 general rate case ("GRC") in Oregon UE-246.

I have provided testimony in PacifiCorp (d.b.a Pacific Power in Washington, or the "Company") rate cases and pre-approval dockets in multiple jurisdictions, including the 2010 general rate cases ("GRC") in Wyoming and Utah (WY 20000-384-ER-10, UT 10-035-124), the 2011 GRC in Oregon (UE-246), the 2013 GRCs in Wyoming and Utah (WY 20000-446-ER-14, and UT 13-035-184).

Relevant to this case, I provided testimony on the 2012 Certificate of Public Convenience and Necessity ("CPCN") docket to install Selective Catalytic Reduction ("SCR") at Jim Bridger units 3 &4 (WY 20000-418-EA-12) and a Utah docket seeking pre-approval of those expenses (UT 12-035-92) when the plan was first submitted for approval.

I have also submitted comments in multiple PacifiCorp states on behalf of Sierra Club in the Company's 2011, 2013, and 2015 Integrated Resource Plans ("IRP").

Q What is the purpose of your testimony?

A I reviewed the prudence analysis conducted by PacifiCorp as part of its decision to move forward with the installation SCRs at Jim Bridger units 3 and 4 to comply with the Regional Haze Rule in Wyoming. I also reviewed and analyzed critical information that was in the Company's possession at the time the final decision was made to install SCR at Bridger 3 & 4, but which the Company did not include in its economic analysis supporting that decision. I also reviewed the Company's western control area sub-analysis, and reject it as a basis for a prudence decision in Washington or any other state. Finally, I reviewed and support the Company's request to accelerate the depreciation schedule of Jim Bridger to 2025.

Q What are your conclusions regarding the Company's economic analysis that led to the decision to install the SCRs at Jim Bridger 3 & 4?

A The Company's analysis significantly overestimated the relative value of continuing to operate Bridger 3 & 4 as a coal plant. Based on a review of the data available to the Company at the time that it released contractors to begin work on the SCRs, PacifiCorp should have concluded that the SCRs were non-economic compared to an alternate compliance plan of converting Bridger 3&4 to run on natural gas. My adjustments to the Company's analysis indicate that natural gas fuel conversion of Bridger 3 & 4 would have saved customers approximately [redacted] over the study period compared to the decision to install SCRs.

Q What are your adjustments to the Company's SCR analysis?

A The Company's analysis, presented by Mr. Link, concluded that the installation of SCR at Bridger 3 & 4 would result in a benefit of [redacted].[1] However, this analysis, which the Company conducted in early 2013,[2] relied on data and information that was both overly optimistic and significantly out of date by the

[1] Direct Testimony of Mr. Rick Link (RTL-1CT) page 2 at line 8.
[2] The Company's early 2013 analysis presented in this docket is the same analysis it originally presented in two separate pre-construction dockets: Wyoming PSC Docket 20000-418-EA-12 and Utah PSC Docket 12-035-92. Those dockets concluded in May 2013.

time the Company released its contractors to begin substantial work on the project in December 2013.[3] In the intervening period, significant new information was available to the Company that should have indicated the decision to retrofit was not the least cost alternative available to the Company.

My adjustments to the Company's assessment are as follows:

1. **Coal prices at Bridger mine:** In mid-2013, PacifiCorp discovered problems at the Bridger coal mine, and by late 2013 had adjusted its expectations for the mine and anticipated significantly higher costs for delivery. To account for these higher costs in the base case, I adjusted the benefit of the SCR down by [redacted]
2. **Natural gas prices:** Gas price forecasts fell sharply through 2013, significantly reducing the benefit of the retrofit. Following a methodology propounded by Mr. Link, and contemporaneous gas price forecasts provided and used by the Company, I adjusted the benefit of the SCR down by [redacted]

Taken together and as illustrated in the table below, these adjustments show that the overall impact to ratepayers from the SCR installation at Bridger 3 & 4 will not result in a benefit, but instead will result in a [redacted] cost to customers (2012$).

[redacted]	PacifiCorp PVRR(d)
	Coal cost adjustment
	Gas price adjustment
	Adjusted PVRR(d) (2012$)

These adjustments are described in more detail in my testimony below.

Q What are your recommendations to this Commission?

A I recommend the following:

[3] Direct Testimony of Mr. Rick Link (RTL-1CT) page 20 at line 12.

- That the Commission determine that the Company's decision to install SCR at Bridger 3 & 4 was imprudent based on the information that the Company knew, or should have known, at the time it committed to spend over [redacted] on the projects.[4] Rather than providing a benefit to ratepayers, the SCRs will result in an estimated loss of [redacted] for ratepayers, relative to the lower cost option of converting the units to operate on natural gas.

- That the Commission disallow a portion of the costs of the SCRs that PacifiCorp has requested to be put in rate base. I recommend that the Commission calculate the disallowance for the SCRs by taking into account information known today, including the substantially lower gas prices compared to 2013. I roughly estimate that the decision to install SCRs will cost ratepayers between $132 and $194 million on a system-wide basis,[5] or roughly $30 to $43 million on a Washington-allocated basis.[6] Therefore, I recommend that this Commission disallow $35 million of the Company's request to add [redacted][7] to Washington rate base for the SCRs at Bridger 3 & 4.

- Finally, I recommend approval of the Company's request to accelerate depreciation of the existing plant balance for Jim Bridger to 2025 in recognition of the risks entailed in the continued operation of the Jim Bridger plant and the likelihood that it will not be economic to operate the plant to the currently scheduled depreciation date of 2037.

2. SUMMARY OF COMPANY'S ANALYSIS AND SUBSEQUENT ADJUSTMENTS

Q Please describe the Jim Bridger plant.

A The Jim Bridger power plant is a 2,100 MW coal-fired plant made up of four units (Jim Bridger units 1, 2, 3, and 4). PacifiCorp owns two-thirds of each unit and Idaho Power Company owns the remaining one-third. Jim Bridger is located in southwest Wyoming and contributes to haze pollution in several national parks and wilderness areas: Yellowstone National Park, Grand Teton National Park, Rocky Mountain National Park, Teton Wilderness Area, Bridger Wilderness

[4] CAT-7C
[5] See Section 9 below for a full description of this range.
[6] In the alternative, the Commission could require the Company to run its model from a 2013 standpoint with updated data (i.e. known today) to calculate the total harm to ratepayers.
[7] CAT-1CT at 15, line 3 and 24, line 1.

Area, Fitzpatrick Wilderness Area, Mt Zirkel Wilderness Area, Rawah Wilderness Area, and Washakie Wilderness Area. [8]

Jim Bridger is a mine-mouth plant, which means that it receives the bulk of its coal fuel from a mine that is adjacent to (or at least near) the plant. The majority of Jim Bridger plant ("Bridger plant") is supplied by the Bridger coal mine ("Bridger mine"), which like the power plant is jointly owned by PacifiCorp and Idaho Power Company. The Bridger coal mine consists of both a surface mine and an underground mine.

Q What led PacifiCorp to install SCR at Jim Bridger 3 & 4?

A Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances and color. The main haze-forming pollutants are sulfur dioxide (SO_2), nitrogen oxides (NO_X) and fine particulate matter (PM). These air pollutants contribute to the deterioration of air quality and reduced visibility in our national parks and wilderness areas, designated as Class 1 areas.

In 1977, Congress declared as the nation's goal, the "prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[9] In order to meet this goal, states are required to design implementation plans ("SIP") to reduce, and ultimately eliminate, haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that state's boundaries.

The Clean Air Act imposes a legal obligation on both states and EPA to abate haze pollution in our Class 1 areas.[10] One of the Clean Air Act's mechanisms for achieving this goal is the requirement for certain haze-causing sources, like coal

[8] 79 FR 5031, 5041 (Jan. 30, 2014).
[9] 42 U.S.C. §7491(a)(1).
[10] Id.

plants, to install "best available retrofit technology" ("BART").[11] Bridger units 3 & 4 are subject to BART.

In 2011, Wyoming submitted to EPA its state implementation plan to comply with the BART provisions of the Regional Haze Rule. After several years of back and forth, EPA disapproved several elements of Wyoming's plan, which triggered EPA's obligation to promulgate a federal implementation plan ("FIP") to replace these disapproved elements.[12]

On January 30, 2014, EPA issued its FIP and upheld the portion of Wyoming's state plan that required the installation of SCR at Jim Bridger Units 1 & 2 by 2021 and 2022, respectively, and SCR at Jim Bridger Units 3 & 4 by 2015 and 2016, respectively. EPA's regional final haze rule required SCR on six units of PacifiCorp's Wyoming coal fleet.

The current question before this Commission is whether PacifiCorp's decision to retrofit Jim Bridger 3 & 4 with expensive SCRs, as opposed to an alternative compliance path, was prudent.

Q Were alternative compliance paths available to the Company?

A Yes. The Regional Haze Rule's requirements are based on both a control technology and an emissions limit at each unit. PacifiCorp could therefore comply with the rule either by installing the required pollution controls necessary to meet that limit, or by shutting down or converting Jim Bridger units to run on natural gas. There are several examples of coal plants shutting down or switching to natural gas fuel as an alternative compliance path under the Regional Haze Rule,[13] and examples wherein a unit committed to a firm future shut down date in exchange for less expensive near-term controls.[14]

[11] Id. § 7491(a), (b)(2).
[12] 42 U.S.C. § 7410(c)(1)(A).
[13] Apache Unit 2, Arizona (80 FR 19220); Naughton Unit 3, Wyoming (79 FR 5045); Muskogee 4 & 5, Oklahoma.
[14] PGE Boardman, Oregon (2008 Oregon Regional Haze Plan p154-156, and 76 FR 38997); Transalta Centralia, Washington (Washington Department of Ecology, Order 6426, 2011)

Q When did the requirement to install SCRs at Bridger 3 &4 become final?

A As described above, EPA did not issue its final BART determination for Wyoming until January 30, 2014. EPA generally provides up to five years to install BART retrofits.[15] In this case, however, PacifiCorp appears to have supported the proposed 2015/2016 installation dates from the Wyoming plan, which EPA approved as within the five year requirement.[16]

Q When did the Company make the decision to proceed with the SCRs at Bridger 3 & 4?

A The Company appears to have decided to move forward with the SCRs long before EPA issued its final Regional Haze FIP. As early as August 7, 2012, PacifiCorp filed an application in Wyoming for a certificate of public convenience and necessity ("CPCN") and on August 24, 2012, PacifiCorp sought a voluntary preapproval decision in Utah to install the SCRs at Bridger 3 & 4.[17] PacifiCorp did not execute an engineering, procurement and construction ("EPC") contract until May 31, 2013, after the Wyoming and Utah dockets had closed.

The Company did not issue a Full Notice to Proceed (FNTP) until December 2, 2013.[18] Prior to this date, the Company had spent less than [redacted] percent of the total cost of the project for various engineering and scoping work and could have exited the contract without incurring substantial contractual penalties.[19] Therefore, the Company could have and should have continued to update its analysis of the SCR expenditures until at least December 2, 2013.

[15] 40 CFR 51.308(e)(iv).
[16] 79 FR 5031, 5046 (Jan. 30, 2014).
[17] These proceedings included an analysis of the SCRs at Jim Bridger that are substantially similar to the analysis presented by Mr. Link in this docket.
[18] Ex. JIF-~~2~~ 3C, Confidential Attachment Sierra Club 1.3 1st Supplemental.
[19] Ex. JIF-~~3~~ 4C, Confidential WUTC Data Request 161, 1st Supplemental.

Q Why did the Company contractually commit to the SCR projects prior to EPA issuing the final Regional Haze FIP?

A I do not know. Arguably, the Company should have left open the opportunity to adjust its plans pending issuance of the final Regional Haze FIP by EPA, which ultimately occurred on January 30, 2014.[20] At a minimum, the Company should have allowed itself an off-ramp in the EPC contract that would have allowed it to continue to evaluate whether the SCR was in the best interests of ratepayers at the time that EPA issued the FIP.[21]

Notably, the Company's issuance of the FNTP on December 2, 2013 came nearly two months before EPA issued its final Regional Haze FIP that required the installation of SCRs on Bridger 3 & 4. Irrespective of the approvals provided by Utah and Wyoming earlier in the year, the Company still had an obligation to test, and re-test, its assumptions. This is particularly true because the case for the Bridger SCR retrofits became increasingly marginal leading up to the issuance of the Wyoming Regional Haze FIP.

It is also not clear why the Company appeared to support a deadline to install SCR in 2015 and 2016 when the EPA allows up to five years to install the controls once a final decision is made, which would have delayed the need to install SCRs until 2019.[22]

[20] PacifiCorp filed suit challenging EPA's Wyoming FIP with regard to SCR requirements for 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. United States Environmental Protection Agency, Case 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.

[21] Even after it issued the FNTP, the Company still could have terminated the project with minimal costs. The termination schedule in the EPC contract indicates that by January 2014, less than [redacted] of the costs were committed, and by February 2014, less than [redacted] of the costs were committed.

[22] 40 CFR 51.308(e)(iv).

Q Please summarize the Company's analysis process to determine if the SCRs should be built at Bridger 3 & 4.

A Since 2012, PacifiCorp has used the System Optimizer model, its primary forward planning and integrated resource planning platform, to determine if large capital investments were economic at existing coal-fired units. This model structure is able to test the costs of two alternative worlds: one in which the retrofit is pursued, the other in which the plant is retired or, as in this case, repowered. Since both paths have implications beyond the units in question, the method can theoretically reveal the replacement value of the decision. To the extent that the decision to retrofit is lower cost than the next best alternative, the value of the decision, and thus the value of the unit(s), is positive.

This methodology, like all other models, is highly sensitive to inputs and the quality of the data used in the model. Specifically, the value of the unit(s) can change substantially as the market shifts, and decisions need to be evaluated using the very best information available up to the moment the decision is finalized, and even beyond.

The Company's initial filing in this case was a CPCN submitted to the Wyoming Public Service Commission on August 1, 2012, based on an analysis conducted using December 2011 data.[23] In that initial analysis, the Company argued that the Bridger 3 & 4 SCRs had a value of [redacted], 40% higher than the results from the analysis in the instant docket. Intervenors pointed out that, amongst other flaws, the analysis used outdated data. On rebuttal, the Company provided an updated analysis, populated with September 2012 data, showing a [redacted] value - the results of this revised analysis are before this commission today.[24] The Wyoming Commission docket was concluded in May 2013.

[23] Direct Testimony of Mr. Rick Link in Utah Docket 12-035-92, page 10 at 209
[24] Direct Testimony of Mr. Rick Link, RTL-1CT, page 9 at 5

Q How has the Company's analysis of the Bridger 3 & 4 SCRs changed?

A Since the conclusion of the pre-construction dockets in Utah and Wyoming, the value of the decision to install SCRs has continued to fall substantially. In this docket, Mr. Link testified that the Company re-assessed the decision prior to executing the FNTP in December 2013, and found that the margin had shrunk another 30% to [redacted] using September 2013 gas price data.[25]

However, the updated analysis provided by Mr. Link is still deficient because it relied on inadequate and stale data when there was substantial evidence that the decision to install SCR continued to rapidly lose value. In fact, by the time PacifiCorp executed the FNTP on December 2, 2013, the SCR projects had become a substantial liability. The originally purported benefit of the SCRs had declined so far as to indicate an overall harm to ratepayers of [redacted] (see Confidential Figure 1, below).

[redacted]

[25] Direct Testimony of Mr. Rick Link, RTL-1CT, pate 20 at 17-21.

3. ADJUSTMENT #1: NEW INFORMATION AT BRIDGER COAL COMPANY MINE DRIVES HIGHER COST OF COAL OPERATION

Q Please describe the first adjustment you made to the Company's analysis.

A The first adjustment accounts for substantially higher costs at the Bridger coal mine, which reduces the relative value of maintaining Bridger 3&4 as a coal plant compared to conversion to natural gas. This adjustment modifies the cost-effectiveness of the SCR decision on the basis of new information, or new decisions, made about the long-term future of the Bridger coal mine. Based on these higher coal costs, I adjusted the value of the SCR decision for Bridger 3 & 4 decision down by [redacted].

Q How does the Bridger mine affect the Jim Bridger power plant?

A The Jim Bridger power plant is a mine mouth plant that receives most of its coal fuel from the adjacent Bridger mine, operated by the Bridger Coal Company which is in turn owned by PacifiCorp and Idaho Power Company. The Bridger Coal Company operates both a surface mine and an underground mine. [redacted]

PacifiCorp's analysis of the SCRs in this case assumes that the Bridger mine plans have a significant impact on the economics of the decision to install SCR because the SCR decision determines whether Jim Bridger operates as a two-unit versus four-unit scenario. Under Mr. Link's analysis, coal prices at the Bridger mine [redacted] under a scenario where two units of the power plant stop burning coal (i.e. gas conversion alternative). These [redacted] are premised on the assumption that the surface mine at Bridger would be closed if Bridger 3 & 4 were converted to gas.[27] When the initial analysis for

[26] "Cash cost" is a term used by PacifiCorp to refer to effectively variable costs of production, excluding amortized capital and new capital at the mine.
[27] Direct Testimony of Mr. Rick Link, page 6 line 19 through page 7 line 5

the SCRs was conducted, PacifiCorp assumed that the best future coal resources would come from the underground mine, while the surface mine would be closed under a two-unit operation scenario. Under a four-unit operation scenario (i.e. the SCR retrofit goes forward), the Company assumed that it would keep mining both the surface and underground mines, with the majority of the coal coming from the underground mine.

Q Why is the cost of coal different between the two-unit and four-unit operation scenarios in the Company's analysis?

A In the case where Bridger 3&4 are converted to gas or retired, the Company's mine plans and remediation plans changed to a "two-unit" scenario that account for a lower demand for coal. Under the Company's analysis, this two-unit scenario increased coal costs because it assumed that the surface mine would close and that remediation costs would therefore accelerate. In contrast, the Company's analysis of the SCR installation assumed that if the SCR were installed, then the mine would continue to operate under a "four-unit" scenario where the surface mine would remain open and the remediation costs would be delayed.[28]

Q Has the expected cost of coal from Bridger mine changed compared to the assumptions in the Company's analysis?

A Yes. In mid-2013, the Company changed its previous plans and determined that the Bridger surface mine would [redacted], and the [redacted]. This shift in assumptions had two effects on the SCR analysis. First, it increased the cost of coal to be delivered to Bridger in the base case. Second, the fact that the Bridger [redacted] largely eliminated the relative cost differentials between the two and four-unit operation scenarios that the Company

[28] Direct Testimony of Mr. Rick Link, page 6 line 19 through page 7 line 5

had previously relied on to support the SCR retrofit.[29] For example, the large near-term increase in costs assumed in a two-unit scenario compared to the four-unit scenario were no longer applicable because the Company's mine remediation plans would likely be similar under both the two-unit and four-unit scenarios.

Q Did you calculate the magnitude of the Bridger mine's impact on the SCR analysis?

A Yes. In late 2013, the Company filed rate cases in Utah and Wyoming seeking to recover increased costs of operation at Bridger due to lower coal quality than expected at the underground mine.[30] The long-run cash cost of coal from Bridger mine presented in that case were substantially higher than the costs used in the SCR analysis,[31] but those costs were consistent with the cash cost of coal from Bridger mine in the recent 2015 IRP.[32] Because the Company did not provide an "all source"[33] long-term coal fueling plan for Bridger vintage late 2013, I used the 2015 IRP as a proxy for the 4-unit scenario. Substituting in those cash coal costs for the Bridger plant, I estimated that the four-unit scenario (i.e. installing SCR) would have increased cost by about [redacted]. Separately, I roughly estimated that the two unit scenario (i.e. gas conversion or retirement) would have increased cost by about [redacted]. In total, these changes mean that the relative cost of installing the SCRs would have increased by [redacted] relative to Mr. Link's assessment shown in this case.[34]

[29] The Company prepared two 2013 Mine Plans. One in January 2013, which was incorporated into this case, and another in October 2013, which was not incorporated into this case. In response to WUTC Data Request 11, the Company responded that "there were no significant increases between [the 2013 Mine Plan] and the time of the September 2013 official forward price curve (OFPC)." This response failed to disclose that the Company was preparing a new mine plan that did, in fact, have substantial increases in coal cost. Ex. JIF-~~4~~ 5. WUTC 11.
[30] Direct Testimony of Ms. Cindy Crane, Utah Docket 13-035-184, page 22.
[31] Approximately 9% higher on a nominal levelized cost basis 2014-2030.
[32] Approximately 2% difference, nominal levelized cost 2014-2030.
[33] "All source" in this case means coal both from the Bridger mine, as well as third-party sources.
[34] Difference due to rounding.

4. EVIDENCE FOR ADJUSTMENT #1 – RISING COSTS AT BRIDGER COAL MINE

Q Please explain how you arrived at the [redacted] increase for the four-unit scenario where Bridger 3 & 4 are retrofit with SCRs.

A I substituted the cash cost of coal delivered to Jim Bridger plant as provided in the 2015 IRP[35] for the cash cost for four-unit operations as provided in this case,[36] assuming no change in the amount of fuel consumed.[37] The difference between these two scenarios, holding all other elements constant, is an increase of [redacted] (2012$), net present value 2014-2030.

Q Why did you rely on the 2015 IRP for coal costs at Bridger in this case?

A I believe that the 2015 IRP costs for coal at Bridger are a reasonable proxy for the information that would have been known by the Company by December 2, 2013, the date the FNTP was executed.

The mine plan that PacifiCorp relied on to support the application before this Commission was developed in January of 2013, prior to the Company's rebuttal testimony in the Utah pre-approval docket for the Bridger 3 & 4 SCRs.[38] However, by the time the Company committed to proceed with the installation of the SCRs, that mine plan had changed substantially.

Q Please describe the different mine plans that you reviewed for your analysis.

A Overall, I will discuss three different plans, of which I am aware, for the Bridger mine. I will refer to several plans throughout my testimony, labeled as follows:

---

[35] REF

[36] RTL-3C, Column "4-unit Coal Operation"

[37] See confidential workpapers submitted by Mr. Link: SO Inputs and Outputs, CONF\Base Gas, Base CO2 (Coal Outputs) CONF\StaMoFuel-C_M1209_16_OPC.out, sum of MMBtus consumed at all four Bridger units.

[38] See Rebuttal Testimony of Ms. Cindy Crane in Utah Docket 12-035-92 page 3, lines 65-67. "Subsequent to the original filing, Bridger Coal Company completed extensive life 65 of mine planning and cost analysis, and as a result, the Company has more current 66 and detailed mine plans to rely on as part of this analysis."

- **January 2013 mine plan:** The plan used to support the coal costs in the present docket. Plan includes 2 and 4-unit costs for coal provided from both Bridger mine and other sources.
- **October 2013 mine plan**: A later plan provided in a Utah General Rate Case, but prior to the FNTP. Plan includes only 4-unit costs for coal provided from Bridger mine.
- **July 2014 mine plan**: The plan used to support the coal cost of Bridger in the 2015 IRP. Plan includes only 4-unit costs for coal provided from both Bridger mine and other sources.

In March/April of 2013, Bridger mine conducted drilling that resulted in a finding that a panel in the underground mine had excessive ash content,[39] a finding that led to a substantial change in mining operations and ultimately contributed to a rate increase request before the Utah Public Service Commission. That January 2014 Utah rate case presented new costs associated with the Bridger mine. [40] The workpapers supporting those new costs were prepared in early October 2013, two months before the FNTP.[41,42]

The October 2013 four-unit mine plan shows that the Company had significantly changed its expectations for the Bridger mine since January of 2013. While the January 2013 mine plan (for four-unit operation) assumed that both the surface and underground mines would be utilized through [redacted], the October 2013 mine plan indicated that the Bridger [redacted] only through the end of the analysis period.

[39] See response to SC 4.9 in Utah Docket 13-035-184, April 15, 2014. Attached as Exhibit JIF-~~5~~ 6.
[40] Utah Docket 13-035-184, filed January 3, 2014.
[41] See public rebuttal testimony of Ms. Cindy Crane in Utah Docket 13-035-184, page 9 lines 198-202. "In this test period, based on drilling in March/April 2013, Bridger Coal personnel spent several months re-engineering the mine plan to bypass the 12th right longwall panel. This re-engineered plan is the basis of the 2014 Bridger Coal Business Plan produced in October 2013."
[42] Bridger workpapers for Utah Docket 13-035-184 available through attachment to Sierra Club 1.6 1st SUPP CONF\C.8 f Conf

Q How did you use the October 2013 mine plan in your analysis?

A The October 2013 mine plan shows that the Company had, in fact, changed strategies for the long-term procurement of coal at Bridger mine by mid-2013, a strategy which remained consistent through the analysis of the 2015 IRP. However, the October 2013 mine plan did not specifically include "all-in" coal price forecasts.

During the Utah rate case, the Company claimed that the changed mine plan was not significant for the SCR decision, and instead asserted that "[t]he Company's workpapers serve[d] to support test period costs solely – not a life-of-plant fueling strategy."[43] The Company pointed out that it had not provided a long-term "all in" coal price forecast for Jim Bridger in that case. Nonetheless, the workpapers contained significant information about the Company's expectations of coal supplied from the mine as of October 2013.

In the 2015 IRP, the Company provided a long-term coal price and fueling plan for Jim Bridger dated July 9, 2014.[44] While the Company claims that the October 2013 mine plan was not a "fueling strategy,"[45] the use and cost of Bridger mine coal under the October 2013 plan remained consistent with the July 2014 fueling strategy. Because the October 2013 plan does not provide an all-in cost of coal at Bridger plant, but the July 2014 plan does, I have used July 2014 data (from the 2015 IRP) as a proxy for information that should have reasonably been known by the Company in late 2013 at the time the FNTP was executed.

Q How consistent are the October 2013 and July 2014 Bridger mine plans and costs?

A The October 2013 and July 2014 Bridger mine plans are very consistent. But both of those plans are *inconsistent* with the January 2013 plan used to support the Bridger 3 & 4 SCRs.

[43] Rebuttal Testimony of Ms. Cindy Crane, Utah Docket 13-035-184 page 7 lines 154-157.
[44] Attachment to Sierra Club DR 3.13
[45] Rebuttal Testimony of Ms. Cindy Crane, Utah Docket 13-035-184 page 4 lines 72-81

The striking difference from the earlier plan is the amount of coal the Company anticipated it would procure from [redacted]. The January 2013 plan anticipated that the [redacted] operations through 2037. In contrast, the October 2013 and July 2014 plans anticipated the [redacted], respectfully. Both of these later plans anticipated roughly the same amount of coal to be procured from [redacted],[46] as shown in [redacted], below.

[redacted]

The cash costs of coal procured from the Bridger mine are also substantially different between the January 2013 and October 2013 mine plans,[47] but consistent between the October 2013 and July 2014 plans,[48] as shown in [redacted], below.

[46] [redacted] tons, respectively, or within 4%.
[47] An increase of over 11% from January 2013 to October 2013 on a nominal levelized basis (2014-2030),
[48] A decrease of less than 2% from October 2013 to July 2014 on a nominal levelized basis (2014-2030).

[redacted]

Finally, the Company's strategic planning review of the Jim Bridger Plant, drafted in mid-2014 and finalized at the end of the year, [redacted].[49]

Overall, even through PacifiCorp previously claimed that the October 2013 plan was meant only to serve as the business plan for the Bridger Coal Company,[50] a comparison of the various mine plans shows that the October 2013 plan was substantially different from the January 2013 plan in its estimates of near term and long-term costs. Moreover, PacifiCorp relied on the key elements of this plan to support a top line item in its Utah rate case, and the elements of the October

[49] Strategic Planning Review of Jim Bridger Plant, provided as Confidential Attachment to Sierra Club 2.27. Attached as Exhibit JIF-~~6~~ 7C. [redacted]

[50] See Rebuttal Testimony of Ms. Cindy Crane in 13-035-184, lines 154-157. Attached as Exhibit JIF-~~7~~ 8. Ms. Crane testified that the "Inclusion of the 2014 Bridger Coal Company Business Plan was necessary to demonstrate appropriate funding levels for the final reclamation trust." However, reclamation trust contributions are highly dependent on the Company's anticipated long-term future use of the surface mine, and thus should represent the Company's best estimate of coal procurement strategies from the Bridger mine complex.

2013 plan were later included in the default strategic planning documents that persisted through the recent 2015 IRP.

The July 2014 mine plan (2015 IRP) also adds an important layer of information to the coal price forecast for Bridger that was not made available in the October 2013 forecast – coal from third-parties. [redacted][51] [redacted][52] [redacted]. I use the July 2014 mine plan as a proxy for the all-in cost of coal at Bridger, known in late 2013.

Q Was PacifiCorp aware of these changing coal costs when it considered the SCRs at Bridger 3 & 4?

A Yes. In October 2013, two months prior to the execution of the FNTP, PacifiCorp was aware, or should have been aware, that the cost of four-unit operation at the Bridger Plant would be approximately [redacted] more expensive than it had previously anticipated in January 2013. This increase in the cost of coal substantially diminished the relative value of installing the SCR at Bridger 3&4 compared to the gas conversion alternative.

Q Please explain how you arrived at the [redacted] increase for the two-unit scenario where Bridger 3 & 4 are repowered to natural gas.

A When the Company's plans for the Bridger mine changed in October 2013, the fueling plan for two-unit operation should have changed as well. In particular, the

[51] See Jim Bridger Plant 2014 Strategic Planning Review_DRAFT. Provided in response to SC DR 2.27. Attached as Exhibit JIF-~~6~~ 7C.
[52] Provided as discovery response to SC 2.3-2 in Oregon LC 62, 2015 Integrated Resource Plan. See file "Bridger.xlsx"

two-unit operation plan as of January 2013 assumed the closure of the Bridger surface operations.[53] PacifiCorp did not prepare a new two-unit operation cost in October 2013 (or indeed anytime after January 2013)[54] so we are left in a position of either assuming that the plan for two units would have stayed the same, in contrast to the four-unit scenario, or that the plan would have changed to adapt to the assumption that [redacted][55]

Assuming the plan would have (likely) changed, it was necessary to develop a reasonable proxy for a two-unit coal cost in the absence of information from the Company. Ultimately, the proxy I chose for consistency and simplicity was the cash cost of coal for the four-unit scenario, vintage January 2013 This was a reasonable proxy because the costs were developed at a time when the Company still planned [redacted]

To arrive at an estimate of the coal costs in the two-unit scenario, I substituted in the January 2013 four-unit coal cost at Bridger for the two-unit coal cost at Bridger through the end of the analysis period, assuming the same amount of coal is consumed. This substitution raised the cost of the two-unit scenario by [redacted] on a net present value basis.

Q Why did you use the January 2013 four-unit coal cash cost as a proxy for the cash cost of a two-unit scenario in October 2013?

A The January 2013 four-unit coal cash cost is based on a mix of Bridger mine surface and underground coal, as well as third-party sources, through the analysis period. I assessed that at the consumption rate of a two-unit scenario, balanced with surface consumption and expected third-party sources, the current tract [redacted]

[53] See Direct Testimony of Mr. Rick Link, RTL-1C page 7, lines 2-4
[54] See Company response to Sierra Club 3-30(d). Question asked "did PacifiCorp ever evaluate, as of the time that the workpapers for UT Docket 13-035-184 were created, a two-unit operation [coal cost assessment] at Bridger?" PacifiCorp responded that "the analysis has already been provided in this proceeding."
[55] Note that the [redacted] assumes four-unit operation.

[redacted] I surmised that although the Company was planning, as of October 2013, to [redacted].[56]

This blend of coal sources produces a cash cost roughly in line with the four-unit cash cost from January 2013. I assumed that [redacted] coal would be procured from the surface and from third party providers, in line with the cash cost of coal in the updated mine plan, July 2014.

Q What was the impact of your revised two-unit scenario cost on the analysis?

A Assuming that the amount of coal used at Bridger is consistent with Mr. Link's analysis, this new stream of coal cash costs raises the price of the two-unit scenario by [redacted] on a net present value basis (2014-2030).

Q Are capital expenditures at the coal mine taken into account in the "cash cost" of coal delivered to Bridger?

A No. PacifiCorp holds the capital expenses incurred at Bridger coal mine separate from the "cash cost" of coal paid by the Bridger plant, so in effect Bridger plant pays for Bridger mine coal at well under the full cost of the coal. Ratepayers see the capital expenses from Bridger mine through rate base, rather than fuel costs. I discuss this disconnect between the mine and plant in more depth later in my testimony.

[56] Another option that I did not assess here is that the Company could [redacted] providing the bulk of the coal required by the two units. After such time the Company would presumably switch back to the surface mine, or procure coal from a different source. I extrapolated that this cost, on a per MMBtu basis, would be approximately the same as maintaining a blend over the period of the analysis.

Q Does the fact that capital expenses are excluded from cash costs change your assessment of either the two or four-unit scenario cost updates to October 2013?

A No. Based on the information available, it is reasonable to conclude that the majority of the capital cost changes from January 2013 to October 2013 would be approximately the same from the two-unit scenario to the four-unit scenario. However, as I showed earlier, the Company never created an updated two-unit scenario in October 2013, so this estimate is based on the best information available to me. The data I do have indicates that the change from January 2013 to October 2013 should be consistent from a four-unit and two-unit scenario, meaning that it is reasonable to disregard these costs in my comparative analysis.

Q Is there evidence that the change in capital spending at Bridger mine is likely consistent from January 2013 to October 2013 in both the two and four unit scenarios?

A Yes. The October 2013 mine plan, which is implicitly a four-unit scenario, includes [redacted] at the underground mine despite the fact the mine is planned to be used to depletion. [57] I expect this to be the case for two-unit operation as well. In January 2013, the Company forecasted approximately [redacted] [58] of capital expenditures at the underground mine for the two-unit scenario, and [redacted] [59] for the four-unit scenario (2016-2030, NPV).

As of October 2013, the capital costs associated with the underground mine under the implicit four-unit scenario are reported as zero over the same time period, suggesting a savings of [redacted] in the four-unit scenario. I would have no reason to believe that there would be capital expenses incurred in a two-unit

[57] Company response to Sierra Club 1-6
[58] NPV (2013 – 2030) of cash flow-adjusted capital expenditures at the underground mine under two-unit operation (sum of lines 247 through 249 on "OPEX" sheet in BCC Production-Operating Cost Schedules (2 unit).xlsx as provided in Company response to Sierra Club 1-8(a))
[59] NPV (2013 – 2030) of cash flow-adjusted capital expenditures at the underground mine under two-unit operation (sum of lines 247 through 249 on "OPEX" sheet in BCC Production-Operating Cost Schedules (2 unit).xlsx as provided in Company response to Sierra Club 1-8(a))

scenario that are not seen in the four-unit scenario, and so I treat the level of savings at the underground mine as approximately the same [redacted]).

Similarly, the January 2013 mine plan predicts [redacted] in capital expenditures at the surface mine, and close to zero for two-unit operation (as the surface mine is closed). The October 2013 mine plan predicts only [redacted] in capital expenditures at the surface (implicit four-unit operations) despite a similar coal delivery schedule as January 2013. I would not expect reduced extraction at the surface from two-unit operations to result in any higher capital costs than the four-unit option (i.e. [redacted]), and likely significantly lower.

In sum, I therefore believe that it is appropriate to exclude capital cost changes from my assessment of the updated costs at Bridger mine from January to October 2013.

Q What is the overall impact of your coal price adjustment?

A Had the Company assessed the value of the Bridger 3 & 4 decision using the updated October 2013 mine plan, it would have found that the four-unit scenario was approximately [redacted] more expensive than previously anticipated, and the two-unit scenario was [redacted] more expensive than previously anticipated. Overall, this would have reduced the value of the decision to install SCR by about [redacted], on a net present value basis. This adjustment, by itself, reduced the expected benefit of the SCR from [redacted] down to only [redacted]. Combined with the adjustment to gas prices discussed below, the coal price and gas price adjustments cumulatively change the value of the decision to install SCR to a [redacted] liability.

5. ADJUSTMENT #2: FALLING GAS PRICES IN LATE 2013 NEGATE BRIDGER BENEFIT

Q Please describe the second adjustment you have made to the Company's analysis.

A Using the December 2013 OFPC, I adjusted the value of the Bridger 3 & 4 decision down from [redacted] to [redacted], an adjustment of [redacted] million, to account for rapidly falling gas price forecasts.

The second adjustment is based on the fact that gas prices and gas forwards had been declining continuously through much of 2013. Gas prices are highly influential in this analysis because changing gas prices impact the cost of providing energy from a re-powered Bridger[60] and the cost of replacement energy.[61] As Mr. Link demonstrates in RTL-9C, there is a direct correlation between gas prices and value of the decision to retrofit Bridger 3 & 4.

Mr. Link testified that he can use this relationship between gas prices and the value of the decision to evaluate the economic merit of the decision under different gas prices.[62] Mr. Link concluded that, while the value had fallen substantially (30% by September 2013), the Company's decision was still economic when using the September 2013 Official Forward Price Curve ("OFPC").[63]

I used the levelized cost of gas in the Company's December 2013 OFPC using the same mathematical relationship established by Mr. Link to test the economic merit of the SCRs at the time the FNTP was executed. Below, I have put these results in the same figure type as shown by Mr. Link in Exhibit RTL-9C.

[60] i.e. Bridger as powered by natural gas, as a peaking unit.
[61] i.e. the energy that Bridger as a coal-fired unit would have produced either for customers or for sale off-system.
[62] Direct Testimony of Mr. Rick Link, RTL-1CT, pate 20 at 17-21.
[63] Id.

[redacted]

Confidential Figure 4 shows that, as Mr. Link indicated, the value of the Bridger retrofit decision had shrunk from September 2012 to November 2013, and then rapidly fell again by December 2013, when nominal levelized gas prices at [redacted] MMBtu where nearly as low as the breakeven price of [redacted] MMBtu.

Following Mr. Link's methodology, I estimate that the value of the decision to retrofit (the "PVRR(d)") had fallen from a [redacted] benefit in September 2012 to [redacted] in September 2013, and finally to [redacted] three months later in December 2013. This falling value due to gas prices is independent of the changes due to the new Bridger mine plan, which means that the adjustments are cumulative.

At the time the FNTP was executed in early December, the Company had, or should have had, sufficient information to indicate that the Bridger decision was

non-economic, and as a result the Company should have stopped the project. I discuss the timing and evidence for this conclusion later in my testimony.

6. EVIDENCE FOR ADJUSTMENT #2 – FALLING GAS PRICE FORECAST

Q Please describe the basis of your natural gas price adjustment.

A The middle of 2013 saw a realignment of expectations about the future of domestic natural gas supply, and subsequent expectations of long-term pricing. The forward price of natural gas fell almost continuously through 2013, a fact not lost on PacifiCorp, and evidenced through both publicly available forecasts, short-term commodity trading prices, and the proprietary gas price forecasts used by PacifiCorp. The Company states that it had re-assessed the economic viability of the Bridger SCRs with updated gas price forecasts prior to signing the FNTP,[64] but this analysis was superficial and missed both a clear trend and equally clear data showing that the Bridger SCRs were rapidly becoming only marginally cost effective (at best), and could readily be rendered non-economic with only small shifts in gas prices. Had the Company performed a slightly deeper dive prior to signing the FNTP, it would have found that the Bridger 3 & 4 SCRs barely broke even on the basis of gas prices alone, much less the updated coal mine plan.

Q Did the Company re-assess the economic merit of the Bridger SCRs prior to executing the FNTP?

Yes. Mr. Link briefly described this process.[65] He reviewed the relationship between levelized natural gas prices and PVRR(d) (as shown in my Confidential Figure 4 and RTL-9C), and noted that the September 2013 OFPC Opal gas price was [redacted], above his "breakeven" price of [redacted] He therefore he concluded that the decision was still economic.

There are three problems with Mr. Link's argument.

[64] Direct Testimony of Mr. Rick Link, page 20 lines 14-21.
[65] Direct Testimony of Mr. Rick Link, page 20 lines 14-21.

1. Mr. Link's September 2013 assessment alone would have indicated that the SCR decision had lost about 30% of its value (over [redacted]) since its justification before the Utah and Wyoming commissions just a few months previously. This rapid deterioration in relative value should have provided a clear signal to the Company to reevaluate the decision very carefully, or to at least to seek holding off on a decision to allow for additional information to develop.[66]
2. From September 2013 (the date of the OFPC used by Mr. Link) to December 2, 2013 (the date the FNTP was signed), gas price forwards continued to fall. During that period, PacifiCorp would have had access to public data, including NYMEX pricing and EIA's Short Term Energy Outlook indicating a rapid change in forward pricing signals. In addition, it would have likely received data from one of its vendors indicating falling prices,[67] and were only ten days out from receiving data from another vendor showing dramatically lower prices.[68]
3. Mr. Link's September 2013 assessment set up a clear conflict of interest between the Company's prospects for recovery of the SCR costs in Wyoming and Utah, where it had already received pre-approval of those costs, and its other state jurisdictions, where the decision to proceed with the SCRs had yet to be considered. PacifiCorp had recently completed proceedings before two state commissions justifying the proposed decision, and even a slightly lower price forecast could have eliminated the economic value of the Bridger SCRs completely, negating two years of preparation and justification in Wyoming and Utah.

[66] This is especially true given the Company had no legal obligation to begin planning for the SCR retrofits until January 2014, when EPA issued its final decision.

[67] [redacted] as provided in WUTC DR 92 or [redacted] as provided in WUTC DR 165 file IPM_Assumptions_Results_P0913B04.pptx, slide 43.

[68] [redacted] Provided in WUTC DR 92.

Q Which gas price forecast did you use in your analysis?

A The Company's December 2013 OFPC forms an appropriate basis from which to assess the best known or knowable gas price forecasts at the time the FNTP was signed. The December 2013 OFPC was released at the end of December, but it was based on information available before the FNTP and within a week and a half of executing the FNTP. The December 2013 OFPC is therefore the most appropriate forecast to use because it reflected the rapidly falling gas price forecasts in common use at the end of 2013.

Q What other information would have been available to PacifiCorp about falling gas price forecasts at the end of 2013?

A There are at least two publicly available short-term forecast options. The US Energy Information Administration (EIA) produces a monthly short-term energy outlook (STEO) that looks forward two calendar years, also gas futures at the Henry Hub trade on the New York Mercantile Exchange (NYMEX), and are readily tracked, with reasonable trading volumes 4-5 years ahead.

STEO prices for 2014 were at $4.00/MMBtu in September 2013. By November 2013, forwards for 2014 had dropped by 2%, which while small, would still have trimmed another [redacted] from the SCR decision. More importantly, EIA was reporting that production was at record levels near the end of 2013, with production high enough to displace international imports. The November 2013 STEO specifically calls out the rapid growth in shale gas production.[69]

According to NYMEX records 2018 Henry Hub forwards were trading at anywhere from $4.6 to $5.1/MMBtu (nominal) between July and September, 2013. In the next quarter, prices had fallen to between $4.3 to $4.5/MMbtu before December 1, 2013, as shown in Figure 6, below.

[69] November 2013 STEO: "This month's STEO raises the projection for marketed natural gas production by 0.4% in 2013 and 0.9% in 2014 from the previous STEO. In the past several months, natural gas production has hit record high levels, even as prices declined this summer. The Marcellus Shale has been the main driver of growth…" http://www.eia.gov/forecasts/steo/archives/nov13.pdf

Figure 5. NYMEX Futures for 2018 HH, 2012-2016, indicating fall in forecast during 2013.

Retrieved from CME Group, March 15, 2016. January 2018 Henry Hub gas futures with one-week average open, high, low, close.

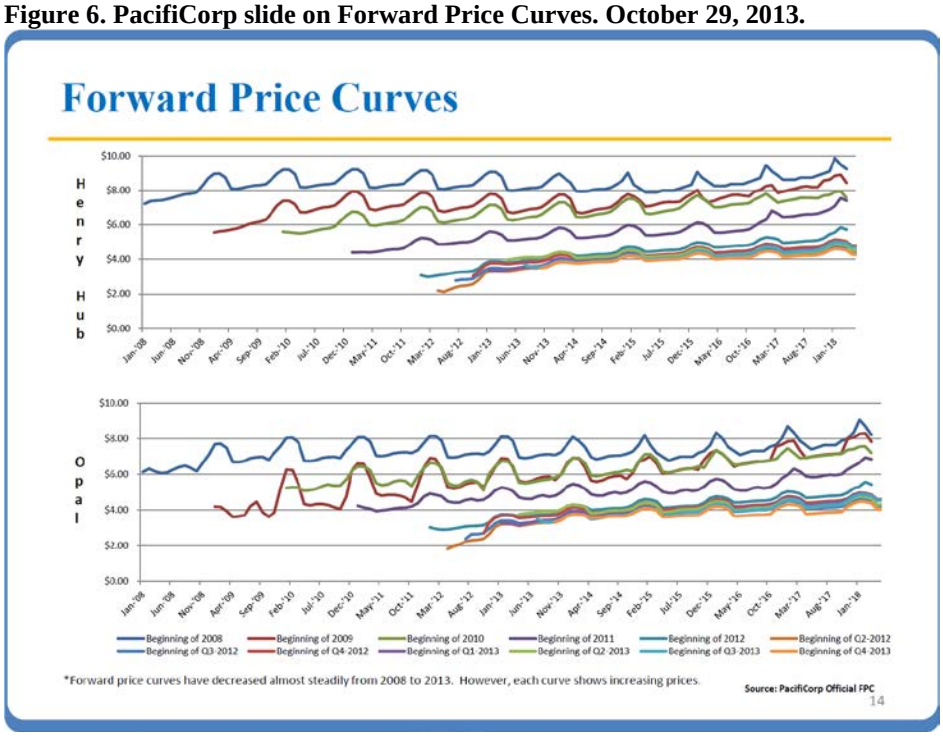
This three month drop of about 6-10% was consistent across years projected in the NYMEX market (i.e. 2014-2020). If this trend were true for longer-term forecasts, it should have effectively signaled that the SCRs were no longer economic (a loss in value of between [redacted]).

Q Did PacifiCorp recognize that gas prices were dropping rapidly through 2013?

A Yes. In an October 29, 2013 workshop on a natural gas RFP process, PacifiCorp developed a slide with series of then-recent OFPCs, dropping from 2008 through

the September 2013 OFPC.[70] The slide, shown below in Figure 6, indicates that "forward price curves have decreased almost steadily from 2008 to 2013." The curves show that the Company, in fact, had revised gas price futures downwards in recent OFPCs as well, and was therefore aware of the trend.

Figure 6. PacifiCorp slide on Forward Price Curves. October 29, 2013.



Q Please summarize your gas price adjustment.

A The Company's December 2013 OFPC is the correct forecast to use for this evaluation because it is largely based on information that was available to the Company prior to the FNTP, and reflects trends that would have been known to the Company around the time the FNTP was signed.

As discussed above, using Mr. Link's method of levelizing nominal gas prices, the gas prices from the December 2013 OFPC would have been approximately

[70] PacifiCorp. 2013. Public Presentation - RFP Process Improvement Workshop (10-29-2013). http://www.pacificorp.com/content/dam/pacificorp/doc/Suppliers/RFPs/RFP_NaturalGas2012/PacifiCorp-2013NaturalGasRFP-ProcessImprovement_10-29-13.pdf Attached as Exhibit JIF-~~8~~ 9.

$5.00/MMBtu,[71] or just $0.14/MMBtu shy of Mr. Link's "breakeven" price. This change should have alerted the Company to the deteriorating relative value of the SCR decision before the Company had substantially committed resources to that decision.

The December 2013 OFPC resulted in a downward adjustment of [redacted] million compared to the Company's initial estimate of a [redacted] benefit from installing the SCRs at Bridger 3 & 4. Based on the gas adjustment alone, the value of the Bridger 3 & 4 decision dropped to only [redacted]. Combined with the increased coal prices discussed earlier, the cumulative change to the SCR analysis resulted in a net liability of [redacted].

Q Do you have any other concerns regarding Mr. Link's assessment of the valuation of the SCRs that he conducted prior to the execution of the FNTP?

A Yes. Mr. Link bases his "last minute" assessment on the September 2013 OFPC, which is implied to be a fully third-party forecast, and thus completely external to any decision making process dependent on said forecast. In fact, PacifiCorp develops its own forward price curves for natural gas.[72] While these forecasts are based on information gleaned from third-party forecasts, they are – as is any forecast – partially subjective, and Mr. Link is central to the creation and derivation of the gas price forecasts.[73]

In fact, Mr. Link recognized that the September 2013 OFPC would not reflect even the most up-to-date information he had in his possession at the time. In an email to an associate, he wrote that one of the vendors had recently updated their projections, yet he was recommending against incorporating this newer information [redacted] As

[71] December 2013 OFPC provided to Sierra Club in non-confidential discovery in Wyoming Docket 20000-446-ER-14 (2014 General Rate Case) as SC 11.6. Attached as Exhibit JIF-~~9~~ 10.
[72] See Response to WUTC DR 92. Attached as Exhibit JIF-~~10~~ 11.
[73] See communication between Mr. Rick Link and associates, September 23, 2013, wherein Mr. Link provides a direct recommendation of forward gas prices to be used in the September OFPC. Provided in WUTC 165 1st Supplement. Attached as Exhibit JIF-~~11~~ 12.

such, he recommended maintaining the long-term price curve, effectively ensuring that the September forecast was not up to date.[74]

7. WESTERN CONTROL AREA ANALYSIS DOES NOT AFFECT PRUDENCE DETERMINATION

Q Have you reviewed the west control area analysis of the decision performed by the Company?

A Yes. Mr. Link discusses a west control area analysis in which the decision to retrofit Bridger 3 & 4 is cast from a Washington state rate policy specific basis.[75] I understand that Mr. Link has used the same System Optimizer runs that were utilized in the full-system Bridger SCR analysis, and extracted the specific costs and benefits accrued to the west control area (Washington, Oregon, and California).

Q What is your opinion on the west control area analysis performed by the Company?

A The results of the west control area analysis are immaterial to the prudence decision before this Commission. The case before this Commission with regards to the Bridger SCRs asks a brightline question: was the decision to install SCRs at Jim Bridger units 3 & 4 reasonable based on information the Company knew or should have known at the time that it was required to make the decision? The installation of the SCRs was a binary decision: install or choose an alternate course of action. The Company must take into account the benefit of ratepayers when making the decision, but the Company does not, and should not, make decisions to retrofit the Bridger plant on the basis of Washington's allocation scheme alone. Therefore, while Washington's allocation scheme influences recovery of costs, the allocation methodology does not dictate the results of the prudence decision.

[74] Id.
[75] Direct Testimony of Mr. Rick Link, pages 14 - 18

The west control area analysis may separately provide guidance in fashioning a remedy based on the harm that PacifiCorp's imprudent decision caused to Washington ratepayers. For example, should this Commission find that the decision to retrofit was imprudent, it would be reasonable for the Commission to use the west control area analysis to determine the costs that the imprudent decision imposed on Washington ratepayers. The Commission should also consider other current information that shows the extent to which PacifiCorp's imprudent decision harmed ratepayers, including information on current gas and coal prices and price forecasts.

8. ACCELERATED DEPRECIATION AT JIM BRIDGER

Q Have your reviewed the Company's proposal to accelerate depreciation at the Jim Bridger plant to 2025?

A Yes. The Company states that "this change will provide greater resource planning flexibility for the Company and its customers as Washington implements state and federal environmental policies,"[76] "including the Clean Power Plan, in alignment with reasonably anticipated implementation timelines."[77] The Company further states that it is seeking to "realign depreciable schedules for west control area coal-fueled generation resources included in Washington rates with the lives used in Oregon, the largest jurisdiction in the west control area."[78]

Q Do you support the Company's request to accelerate depreciation at Jim Bridger Plant?

A Yes. Accelerating depreciation at Bridger accomplishes several goals.

1. Accelerated depreciation provides a clear signal to the Company that the State of Washington is interested in PacifiCorp making rational, least cost

[76] Direct Testimony of R. Bryce Dalley, page 5, lines 3-5
[77] Response to Public Council DR 9, Attached as Exhibit JIF-~~12~~ 13.
[78] Response to Public Council DR 7. Attached as Exhibit JIF-~~13~~ 14.

planning decisions, even if such decisions require the retirement of existing resources;

2. Given the increasing likelihood that Jim Bridger and other coal plants will retire sooner than their current depreciation schedule in Washington, accelerated depreciation protects the interests of Company shareholders by allowing recovery of plant assets during the life of the plant.

3. Accelerated depreciation protects ratepayers by minimizing the risk of intertemporal cost shifting between current ratepayers who are continuing to receive power from the plant, and future ratepayers who may otherwise be required to pay off undepreciated assets after the plant has stopped providing power;

4. Changing the depreciation schedule now allows nine years to mitigate ratepayer impacts from accelerated depreciation, whereas waiting to accelerate depreciation will only increase rate shock in the future;

5. Accelerated depreciation aligns with the Company's expected [redacted]

Q Does the Company's justification for the accelerated depreciation schedule cause any concern for you?

A Yes, in part. While I support the end goal of setting a clear, near-term date at which Bridger assets will be fully depreciated in Washington, Mr. Dalley's justification for the schedule is either unfortunately phrased, or indicative of a problematic outlook by the Company.

According to Mr. Daley, the accelerated depreciation schedule "will provide greater resource planning flexibility for the Company and its customers as

Washington implements state and federal environmental policies."[79] This assertion is repeated as the primary response to Public Council DR 60 and Staff DR 29, both of which state that the change in depreciable life "provide[s] greater resource planning flexibility for the Company and its customers as Washington implements state and federal environmental policies."

I'm concerned that the Company links the accelerated depreciation schedule specifically to planning. As the Company would no doubt agree, existing plant balance and other sunk costs are necessarily excluded from forward-going planning. The Company's existing asset base is not, nor should be, at issue when considering forward planning. The Company's rationale for accelerating depreciation indicates that in the absence of accelerating depreciation, the Company may choose to avoid making near-term retirement decisions, even where that is the least-cost decision, if it would result in stranded assets. The Company's forward planning should in no way be influenced by its perception of the ability to recover stranded assets, an all-too-common motivation in utility resource planning.

While the shorter depreciation schedule does change how new capital is recovered, and thus influences planning decisions, the recovery of new capital does not *a priori* "provide greater resource planning flexibility."

Q What is the impact of the Company's proposal to accelerate depreciation on the decision to retrofit Bridger 3 & 4 with SCRs?

A As with the west control area analysis, the accelerated depreciation schedule at Jim Bridger for Washington should not substantially change the analysis of PacifiCorp's decision process unless the Company knew at the time that there was a significant risk that Jim Bridger 3 & 4 would become non-economic to operate or retain on a going-forward basis after 2025 as coal-fueled resources.

[79] Direct Testimony of Mr. R. Bryce Dalley, page 5 at 3-5

If the Company knew that it was likely that Bridger 3 & 4 would not be operated as a coal plant post-2025, then the Company should have assessed the value of the SCRs based on an assumption that a replacement resource for Bridger 3 & 4 would be required in 2025 in the SCR scenario. This assessment would likely have added significant costs to the SCR alternative compared to a gas conversion alternative.

Overall, however, the request for accelerated depreciation is subordinate to the economic decision as a whole, and like the western control area analysis, would not guide the Company's decision-making process unless the Company knew that it was likely to stop operating Bridger 3 &4 as a coal resource in 2025 at the time that it made the decision to install SCR.

Q Why would the accelerated depreciation request be meaningful to the decision to retrofit if PacifiCorp were aware that there was a significant risk that the coal fired units would become non-economic in or around 2025?

A If PacifiCorp was aware that Jim Bridger 3 & 4 were likely to become non-economic on a going-forward basis (i.e. after the SCRs were installed) in or around 2025, then the entire analysis should have been constructed around alternative resources coming online after the retirement of Bridger 3 & 4. I assume that the most significant reason that Bridger 3 & 4 would become non-economic in 2025 would be due to the narrowing margin between gas and coal, and carbon regulations. Therefore, any such analysis determining that Bridger 3 & 4 might be non-economic after 2025 should be applied only to the case where the units are coal-fired, not as gas-fired resources.

The Company performed an assessment similar to this issue in response to a discovery request from Public Council,[80] and demonstrated that the economic value of the Bridger 3 & 4 SCR decision was significantly reduced by the accelerated depreciation schedule. The value shrinks from [redacted] (as shown

[80] Company Response to Public Council DR 15.

by Mr. Link) to [redacted],[81] using the September 2012 gas price forecast. Updating the analysis to September 2013 gas prices as used by Mr. Link in testimony and following his extrapolation methodology, the relative value declines to just [redacted] – a significant degradation from the Company's application. Including my own changes based on either the October 2013 coal price adjustment or the December 2013 gas price adjustment further impacts the analysis, with each adjustment on its own rendering the decision to install the SCRs a significant liability for ratepayer (over $[redacted] million for each adjustment separately).

In short, if the Company was aware at any time prior to the execution of the FNTP that Bridger 3 & 4 were likely to be non-economic as coal units on a going-forward basis in or around 2025, the Company should have modeled replacement power and would likely have found that the decision to install SCRs in 2015 and 2016 was highly non-economic and imprudent.

Q What conclusions can you draw about the request for accelerated depreciation?

A I support the Company's petition to accelerate its remaining assets towards a depreciable life in 2025 for the reasons stated above. This does not alter my assessment that the decision to retrofit Bridger 3 & 4 was imprudent, and in fact the potential that Bridger 3 & 4 may stop burning coal in 2025 makes the decision to install SCRs even less favorable.

For purposes of determining whether the decision to install SCR was prudent, I believe that the accelerated depreciation schedule has minimal bearing on the decision to move forward on the SCR retrofits unless the Company knew at the time that it was likely to stop burning coal at Bridger 3 & 4 in 2025. This conclusion is consistent with my conclusion that the western control area analysis

[81] Company Response to Public Council DR 15. Table 1: 2025 Depreciable Life for Coal-Fueled Operation Case (SYSTEM). Attach PC 15 -1 1st Supp CONF.xlsx Attached as Exhibit JIF-~~14~~ 15.

should have no bearing on evaluating the prudent of the Company's SCR decision.

However, like the western control area analysis, the accelerated depreciation analysis could be considered a useful tool in assessing the harm to ratepayers caused by the Company's imprudent action to retrofit Bridger 3 & 4. Looking forward, the Commission should assess harm to Washington ratepayers from the perspective of both the western control area analysis (i.e. the burden carried by Washington ratepayers) *and* the accelerated depreciation analysis. PacifiCorp has provided a starting point in response to Public Council data request 15 in an analysis combining both of those elements in Table 3. Again, it is critical to stress that the results shown here should not be used to assess prudence, but instead to determine the level of harm incurred in Washington.

9. OTHER KEY ISSUES

Q Do you have any other concerns that are relevant to the analysis at hand?

A Yes. I have three specific concerns regarding the Company's analysis and input assumptions. These are deeply embedded in the Company's methodology, but may individually and collectively bias the outcome of the Company's assessment, both here and in other similar cases.

First, the Company treats the Jim Bridger mine, for all intents and purposes, as a completely separate regulated entity with oversight and planning that is separate from the Jim Bridger plant. This is a concern because the two entities are inextricably tied to each other. As a consequence, planning at the mine does not adequately take into account avoidable opportunities at the plant, and vice versa. This disconnect means that the plant receives coal at a lower cost than is reasonable because capital costs are incurred through the mine, not the plant. Ratepayers, however, still ultimately pay for higher costs because they support the mine.

If the mine were operated and owned by a third party, we would expect that all costs incurred for coal, except for liquidated damages, would be incurred as a variable cost. At Bridger mine, capital costs are put directly into rate base and are not included as "cash costs" for coal received at Bridger plant. The equivalent type of arrangement for a market participant might be a long term contract for coal procurement with a very large, irrevocable, fixed charge component. However, when a utility signs a very large, irrevocable, fixed charge mine contract, it must subject that contract to rigorous economic review, similar to the way that large capital expenditures are reviewed at plants today (e.g. the instant case with regards to the SCRs). Such a review is necessary because, if a contract is going to be signed that contains a significant commitment (such as a take or pay contract), there is a substantial burden of economic review to ensure that optionality and least cost procurement are maintained.

PacifiCorp does not exercise either of these principles at Bridger in the current arrangement, or at least not through any demonstrable mechanism. The mine planning is based on an assumed procurement of coal on a year by year basis, with no clear tie in to plant operations, and PacifiCorp simply assumes that it will operate through the end of the plant's depreciable life. Therefore, there is no mechanism by which PacifiCorp vets capital expenses against economic efficiency, and there is no way for the Company, or ratepayers, to know if the combination of the mine and plant are actually economically justifiable. Capital expenses at the mine are simply incurred.

Similarly, the variable cost of coal provided to the Bridger plant is far lower than would be demanded under market circumstances because many of the costs are simply siphoned into rate base and are not paid for by the plant. This combination results in the obtuse result that the plant may simply operate under some circumstances to consume the coal produced at the mine, not because it is an economic resource.

Second, the Company's forward modeling in System Optimizer treats all operating and maintenance (O&M) costs at Jim Bridger (and other coal units) as fixed,[82] which significantly underestimates the variable cost of production and potentially overestimates dispatch as the units become increasingly marginal under low gas price forecasts. This is a simple and expansive error in assumption. While it may be the case, historically, that Bridger was so inexpensive on a variable cost basis that the difference of a variable O&M cost was irrelevant, it is clearly not the case now. As the units become more marginal on an operating basis, the inclusion of the variable O&M costs as avoidable (i.e. variable) costs is increasingly important. Failing to include these costs means that the plant dispatches at a higher rate than it should economically, which biases the outcome of the analysis towards the selection of the SCRs.

Third, the model used by the Company to assess the market cost of energy for forward planning appears to assume that three of the four Jim Bridger units retire in 2017.[83] If this is in fact the case, it would artificially raise the market cost of energy where Bridger continues to operate, therefore enhancing the off-system sales benefit of maintaining all four units. This enhancement would bias the selection of the Bridger retrofits over the gas replacement option, which results in fewer off-system sales. This inconsistency would also likely persist through the Company's other coal and resource planning initiatives.

10. REMEDY ASSESSMENT

Q How should this Commission assess the impact of the Company's imprudent decision to retrofit Bridger 3 & 4 with SCRs?

A I recommend that the Commission disallow a portion of the SCR expense based on the harm that PacifiCorp's imprudent decision caused to Washington

[82] See response to Sierra Club DR 1-13(a). The referenced file "CAPEX_VOM.gms" is the input file that holds capital expenditures and variable operation and maintenance (O&M) costs for existing thermal resources, including Jim Bridger. Gas plants in this file are populated with variable O&M, but coal units are not.

[83] See attachment response to WUTC DR 165, "Midas Inputs P0913B04." Attached as Exhibit JIF-~~15~~ 16.

ratepayers. As discussed in more detail below, I recommend that the Commission disallow $35 million of the [redacted][84] that PacifiCorp has requested to be put into Washington rate base for the SCRs at Bridger 3 & 4.

Q Is your recommended disallowance based on information that the Company knew or should have known at the time it made the decision to install SCR?

A No, I based the calculation of the disallowance on current information as opposed to information that the Company knew or should have known at the time is made the decision to move forward with the SCRs. When the Company decided to execute the FNTP on December 2, 2013, it committed ratepayers to a twenty-three year investment, one that had been rapidly declining in value and increasing in risk. It is appropriate to assess the prudence of that decision based on information available to the Company at the time it made that decision, but the calculation of harm or damage to ratepayers that occurred as a result of that imprudent decision is a separate question that must consider current information.

My testimony above shows that by the time the decision to install the SCR was made in December 2013, it was clear that installing the SCRs would be a significant liability for PacifiCorp's ratepayers. This Commission is now faced with deciding how to assess a remedy to protect ratepayers against the Company's poor management and decision making.

Q Have other public utility commissions penalized PacifiCorp for imprudent decision making related to its coal plants?

A Yes. The Oregon Public Utilities Commission considered a similar circumstance in PacifiCorp's 2012 rate case concerning imprudent decisions to make large capital expenditures at several coal plants in or around 2008. The Oregon Commission stated that "we agree that new analysis to model the impact on ratepayers would provide us additional information to determine a disallowance, [but] requiring the additional analysis would take more time than we are allotted."

[84] CAT-1CT at 15, line 3 and 24, line 1.

Ultimately, that Commission opted for a simplified fractional approach, and disallowed a $17 million portion of the capital recovery sought by the Company.[85]

Q How should the Commission calculate a disallowance in this proceeding?

A In this docket, the Company's assessment provides a layer of analysis that was not available in the Oregon proceeding. Here, the Company already assessed an alternative, lower-cost compliance option that it could have pursued if it had properly rejected the SCR installation. The difference between the Company's chosen course of action and the lower-cost alternative provides a basis from which this Commission can assess the harm incurred as a result of the imprudent decision. The lower-cost course of action, as analyzed by PacifiCorp, would have been to convert Bridger 3 & 4 to operate on natural gas. The Commission therefore has the necessary information available to determine the difference in costs between the SCR scenario and the gas alternative would have played out through today and into the future based on a current estimate of fuel prices.

The Company's System Optimizer model, recently updated for the 2015 IRP, and used to assess other decisions as well, can also be rapidly modified to assess harm to ratepayers incurred by this decision. The Commission could require PacifiCorp to make a compliance filing that re-runs System Optimizer to calculate the level of harm that Washington ratepayers will suffer based on information that is know today. Lacking that information, I propose two alternative options to assess harm. The first takes the perspective of the overall Company. The latter is more specific to Washington, taking into account both the request for accelerated depreciation as well as the western control area analysis.

[85] Oregon Public Service Commission, Order 12-493 in Docket UE-246. Page 32.

Q Please describe your calculation of the harm to ratepayers on a system-wide basis.

A In order to determine the harm to Washington ratepayers, I first assessed the system-wide harm to ratepayers that resulted from PacifiCorp's decision to install SCR. I started with a baseline of the Company's analysis that assumed a benefit of the SCR retrofits on a system-wide basis (at [redacted]) and adjusted from there. As Mr. Teply testified, the ultimate cost of the SCR contract decreased by [redacted].[86] However, during the same time period, gas price forwards fell substantially, even below the forecasts in December 2013. Based on the Company's assessment of gas price forwards at Opal in late 2014,[87] the relative value of the SCR decision has dropped by [redacted] from the Company's initial estimate based on 2012 gas prices. Adjusting coal prices to the October 2013 mine plan (and consistent with the recent 2015 IRP), the relative value of the SCR dropped another [redacted] as a result of higher coal costs incurred under the four-unit scenario. Without the benefit of another run through System Optimizer with contemporary capital, coal, gas and energy prices, I estimated that the decision to install SCRs will result in costs to ratepayers of approximately $194 million on a system-wide basis, or roughly $43 million on a Washington-allocated basis. The following is a summary of the estimated system-wide harm to ratepayers:

[redacted] million	Company's estimated benefit
[redacted] million	Reduced cost of SCRs in final EPC contract
[redacted] million	Adjustment to late 2014 gas prices
[redacted] million	Adjustment of coal prices at Bridger to October 2013
[redacted] million	Total Costs (2012$), Company-wide analysis

[86] Direct Testimony of Chad Teply, page 15 line 8 and page 24 line 5, also Exhibits CAT-7C and 13C
[87] OFPC from 12/2014, provided as non-confidential response to discovery in Oregon Docket 1712, SC 2.13

Q Please describe your assessment of the harm to Washington ratepayers.

A From the perspective of Washington ratepayers, I calculated harm to ratepayers based on the Company's analysis of the benefit of the SCRs, but included both the accelerated depreciation schedule and the western control area analysis, provided in supplemental responses to Public Council data request 15. Table 3 of the Company's supplemental attachment to Public Council Data Request 15 shows a net benefit of the retrofit (after these two adjustments) of [redacted] for the western states.[88] Again accounting for the savings in the final SCR cost, updated gas prices,[89] and the revised coal prices, I calculated a total cost to ratepayers of $132 million, or approximately $30 million on a Washington-allocated basis.

[redacted] million	Company's estimated benefit
[redacted] million	Reduced cost of SCRs in final EPC contract
[redacted] million	Adjustment to late 2014 gas prices
[redacted] million	Adjustment of coal prices at Bridger to October 2013
[redacted] million	Total Damages (2012$), Washington-specific analysis

The calculation of harm to Washington ratepayers is likely a more accurate prediction of the costs that PacifiCorp's imprudent decision will impose on customers in the state. However, the system wide damage assessment is also a reasonable alternative to calculate harm to ratepayers. Therefore, I recommend that this Commission consider a disallowance of $35 million, which falls between the two estimates of $30 million and $43 million.

In the alternative, the Commission could require the Company to run its model from a 2013 standpoint with updated contemporary coal and gas prices (i.e. known today) to provide a more accurate calculation of harm to ratepayers.

[88] Ex. JIF ~~14~~ 15, Attach PC 15 -1 1st Supp CONF.xlsx

[89] This assessment is imperfect as gas prices may have a slightly different impact in a west control area assessment than in the region as a whole. However, PacifiCorp did not provide bounding data on gas price impacts, and therefore this is a rough estimate.

Q Do you have any closing thoughts?

A Yes. The Company's mechanism for assessing individual unit decisions has improved markedly since my first engagement on such issues with PacifiCorp in 2012. The Company now uses a state of the art model to maintain a database of unit costs and operations and tests viable alternatives. Despite this improvement, the Company's system is not without flaws. In particularly, the assumptions that the Company uses to populate its modeling assumptions continue to be flawed and are based on decisions that are completely external to the modeling.

The ultimate decision to retrofit Bridger 3 & 4 was made at a time when the energy economy was undergoing significant and rapid change; changes that catalyzed new planning efforts and radically different decisions in utilities across the country. Lower gas and energy prices along with new environmental regulations drove many utilities to re-imagine their portfolios. The Company was not blind to these changes, and it bore a responsibility to assess – and reassess up to the moment final moment and beyond – decisions that could extend the lives of its aging coal plants.

The Company had an opportunity to avoid significant expenditures at Bridger 3 & 4, and yet willfully ignored substantial changes occurring at its own coal mine, as well as clear trends in gas and energy prices – trends that would assuredly have indicated that the decision was moving towards, and then beyond, a threshold of cost effectiveness. Nonetheless, the Company failed to pull together these pieces, and as a result, PacifiCorp committed substantial capital expenditures to a coal plant that the Company now perceives as a risk and seeks to depreciate in just ten years.

This Commission must hold PacifiCorp responsible and accountable for its planning decisions. Running a complex model only to ignore clear data trends or discard unfavorable results is imprudent, and Washington's ratepayers should not have to pay for PacifiCorp's complacency. I recommend that this Commission determine that the Bridger 3 & 4 SCR retrofits were imprudent. I further recommend that the Commission make Washington ratepayers whole by

disallowing $35 million from the total cost of the SCRs that the Company is requesting to put in rate base.

Finally, the Commission should move to accelerate the recovery of remaining plant balance at Jim Bridger so that it can disentangle Washington ratepayers from future harm incurred at this plant and mine.