SIERRA CLUB
FOUNDED 1892

August 13, 2012

Via Electronic Filing and USPS

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308-2148

Re: OR Docket No. UE-246 - Sierra Club Surrebuttal Testimony and Exhibit of Jeremy Fisher

Please find enclosed the original and five (5) copies of Sierra Club's Surrebuttal Testimony and Exhibit of Jeremy Fisher in the above-referenced docket.

Confidential versions of the documents herein will be served in accordance with OAR 860-001-0070(3) upon all eligible party representatives on the official service list for this proceeding via U.S. Mail.

Please let me know if you require any additional documents or if you have any questions. Thank you.

Sincerely,

/s/ Derek Nelson
Derek Nelson
Program Assistant
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105
(415) 977-5595
derek.nelson@sierraclub.org

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 13th day of August, 2012, I caused to be served the foregoing Sierra Club Surrebuttal Testimony of Jeremy Fisher on all party representatives on the official service list for this proceeding via electronic mail. I caused to be served confidential versions of the aforementioned documents on all eligible party representatives on the official service list for this proceeding via U.S. Mail.

William Ganong
514 Walnut Ave.
Klamath Falls, OR 97601
wganong@aol.com

Boehm Kurtz & Lowry
Kurt J. Boehm
36 E. Seventh St., Ste. 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com

Boehm Kurtz & Lowry
Jody Kyler
215 South State St., Ste. 1510
Cincinnati, OH 45202
jkyler@bkllawfirm.com

Citizens' Utility Board Of Oregon
OPUC Dockets
Robert Jenks
G. Catriona McCracken
610 SW Broadway, Ste. 400
Portland, OR 97205
dockets@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org

Davison Van Cleve
Irion A Sanger
Melinda J. Davison
333 SW Taylor, Ste. 400
Portland, OR 97204
mail@dvclaw.com
ias@dvclaw.com
mjd@dvclaw.com

Energy Strategies LLC
Kevin Higgins
215 State St., Ste. 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Esler Stephens & Buckley
John W. Stephens
888 SW Fifth Ave., Ste. 700
Portland, OR 97204-2021
stephens@eslerstephens.com
mec@eslerstephens.com

Klamath Water and Power Agency
Hollie Cannon
735 Commercial St., Ste. 4000
Klamath Falls, OR 97601
hollie.cannon@kwapa.org

NW Energy Coalition
Wendy Gerlitz
1205 SE Flavel
Portland, OR 97202
wendy@nwenergy.org

PacifiCorp d/b/a Pacific Power
Oregon Dockets
R. Bryce Dalley
825 NE Multnomah St., Ste. 2000
Portland, OR 97232-2149
oregondockets@pacificorp.com
bryce.dalley@pacificorp.com

PacifiCorp d/b/a Pacific Power
Sarah Wallace
825 NE Multnomah St., Ste. 1800
Portland, OR 97232-2149
sarah.wallace@pacificorp.com

Portland General Electric
Randy Dahlgren
121 SW Salmon St., 1WTC0702
Portland, OR 97204
pge.opuc.filings@pgn.com

Portland General Electric
Douglas C. Tingey
121 SW Salmon St., 1WTC13
Portland, OR 97204
doug.tingey@pgn.com

Public Utility Commission of Oregon
Deborah Garcia
PO Box 2148
Salem, OR 97308-2148
deborah.garcia@state.or.us

PUC Staff – Department of Justice
Michael T. Weirich
Business Activities Section
1162 Court St., NE
Salem, OR 97301-4096
michael.weirich@doj.state.or.us

Regulatory & Cogeneration Services Inc.
Donald W. Schoenbeck
900 Washington St., Ste. 780
Vancouver, WA 98660-3455
dws@r-c-s-inc.com

Renewable Northwest Project
Megan Walseth Decker
Jimmy Lindsay
421 SW 6th Ave., #1125
Portland, OR 97204-1629
megan@rnp.org
jimmy@rnp.org

Robertson-Bryan, Inc.
Stuart Robertson
9888 Kent St.
Elk Grove, CA 95624
stuart@robertson-bryan.com

Parks Law Offices LLC
Kevin Parks
310 SW 4th Ave., Ste. 806
Portland, OR 97204
kevin@parks-law-offices.com

PUC Staff - Department of Justice
Johanna Riemenschneider
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4796
mailto:johanna.riemenschneider@doj.state.or.us

Dated this 13th day of August, 2012 at San Francisco, CA.

/s/ *Derek Nelson*

Derek Nelson
Program Assistant
Sierra Club
85 Second St., 2nd Fl.
San Francisco, CA 94105
(415) 977-5595
derek.nelson@sierraclub.org

STATE OF OREGON

Public Utility Commission

In the Matter of PacifiCorp's Filing of Revised Tariff Schedules for Electric Service in Oregon	Docket No. UE 246

Surrebuttal Testimony of Jeremy Fisher, Ph.D.

On Behalf of Sierra Club

Public Version

August 13, 2012

Table of Contents

Table of Figures

Table of Tables

INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address and position.

A My name is Jeremy Fisher, and I am a scientist with Synapse Energy Economics (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts 02139.

Q Are you the same Jeremy Fisher who submitted direct testimony in this proceeding on behalf of Sierra Club?

A Yes.

Q On whose behalf are you submitting this surrebuttal testimony?

A I am testifying on behalf of Sierra Club.

Q What is the purpose of your testimony?

A The purpose of my testimony is to respond to points raised by PacifiCorp (“Company”) witnesses Mr. Chad Teply and Ms. Cathy Woolums.

In this rebuttal testimony, I address my objections to retrofits at the Naughton plant. I have had insufficient opportunity to review the Company’s new evidence with regards to the Hunter plant. However, the concerns at the Hunter plant are of a similar nature.

Q Which retrofits are you contesting at the Naughton plant?

A In my direct testimony, I questioned the requirement and economic justification for five projects at Naughton for which the Company is requesting rate recovery. These include flue gas desulfurization (FGD) at Naughton 1 & 2 for the control of sulfur dioxide (SO_2), low-NOx burners (LNB) at Naughton 1 & 2 for the control of oxides of nitrogen (NOx), and an FGD reagent loadout facility. In total, these projects would add approximately $297 million to the Company’s rate base.

Q Please summarize the basis of your objection.

A My objection is two-fold. First, the retrofits were permitted and implemented prematurely, prior to a legal requirement, and were ultimately insufficient to mitigate pollution at Naughton. Due to this premature action, the plant will continue to incur environmental obligations and costs that could have more appropriately been avoided through the retirement of the plant. Second, the economic justification performed for the retrofits at the plant were insufficient and erroneous. Finally, a reasonable Company would have reviewed the outcomes of a properly executed analysis and decided that the economic outcome was so dubious that the retrofits should deferred, or the plant considered for retirement.

Mr. Teply and Ms. Woolums provided testimony regarding the regulatory requirements facing the Company. Generally, although the Company does, in fact, face numerous, complicated and overlapping environmental compliance obligations, most of the justification provided by Mr. Teply and Ms. Woolums appears to be backfill – *post-hoc* rationalizations to justify investments in environmental controls, some of which may be well founded, others that are not. In my direct testimony, I documented "that the Company decided to move forward on a number of capital investments without regard to particular regulatory requirements."

The explanations provided by Ms. Woolums are complicated, but rebuttable. It has taken me the larger part of two years and three rate cases (Wyoming, Utah, and Oregon) to piece together how the Company's actions related to known regulatory requirements, and I still do not have a complete story. The Company's actions are, in some cases, simply inexplicable. Overall, however, the conclusion is the same. If the Company had worked through the regulatory process as intended and expected by the EPA and state regulatory mechanisms, negotiated openly , and had then invested in appropriate controls after rigorously (and preferably transparently) scrutinizing their own actions, this case would likely be uncontested. Instead, the Company made a series of ill-timed and unsupported investments that are ultimately insufficient to mitigate the harm caused by pollution at their plants. At worst, the Company worked to preempt proper regulatory authority, invested just enough to meet only the most immediate regulatory requirements, and made piecemeal investments across the entire fleet.

1. Requirement for Retrofits

Q Did the Company provide a justification for the Naughton environmental retrofits?

A Yes. In Company witness Chad Teply's direct testimony, he describes that the FGD are installed "to control emissions of criteria pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation Plan, and the State of Wyoming's permit (MD-5156) dated May 2009." [PAC/500 Teply/41 at 16] In addition, the LNB are installed "in response to Regional Haze Rules, the state of Wyoming's § 309(g) Implementation Plan, and the State of Wyoming's BART review, decision and permit (MD-6042) dated December 2009, and the state of Wyoming's permit (MD-5156) dated May 2009." [PAC/500 Teply/41 at 23]

Q Did you contest these regulatory requirements?

A Yes. I stated that "at the time that the Company sought the attainment of the air and construction permits for the FGD retrofits at Naughton, there were no federally enforceable requirements compelling the installation of these controls." [Fisher Direct, page 19 at 4]. I further explained that:

- the Company had not shown that the SO_2 reductions at Naughton were necessary by 2012 to meet regional SO_2 milestones under the 309 provisions of Wyoming's regional haze program; and
- the retrofits were implemented before BART (Best Available Retrofit Technology) provisions for the regional haze program in Wyoming were either established or finalized;
- there were no NAAQS violations on the federal record that would have impacted the Naughton unit directly for either SO_2 or NOx;
- the permit MD-5156 was apparently sought voluntarily by the Company;

- the permit MD-6042 only directed the addition of NOx and PM emissions controls, not the high-cost FGD.

Q Would you summarize the Company's rebuttal position on your explanation?

A According to Company witness Ms. Cathy Woolums, given PacifiCorp's large contribution to western SO_2 emissions,

- the Company was compelled to participate in the backstop trading program to meet impending milestones,
- the BART retrofits needed to be installed as expeditiously as practicable, and
- most disconcertingly, the FGD controls were "installed largely to address nonattainment of the SO_2 NAAQS."

Q Did the Company demonstrate that SO_2 reductions at Naughton were fundamental to the region not exceeding the SO2 milestones under the 309 provisions of Wyoming's regional haze program?

A Critically, the Company did not provide any evidence that FGD at Naughton was in any way necessary to meet the milestones program, had it been in force in 2008 or 2009. Amongst the Company's large fleet and significant contribution to western pollution, there may have been alternative economically optimal mechanisms to meet obligations, rather than simply installing nearly $280 million dollars of new retrofits on some of the least viable units in the fleet. [See Fisher Direct, Table 16 on page 64]

Despite this lack of sound planning and lack of regulatory requirement, the Company had the intent to pursue an FGD at the Naughton unit prior to the release of the 2008 version of the SIP. Early contract work apparently began in [redacted] with appropriation requests for early work on the SO_2 and particulate matter (PM) emissions controls.[1]

Q Was the Company required to start implementing BART controls as soon as the state adopted its 2008 state implementation plan (SIP)?

A No. Below I show that:

- First, around or before the time that the Company released contractors to work in May 2009, it would have known that the EPA was not prepared to accept the 2008 Wyoming BART SIP.
- Second, the Company had chosen which emissions controls it was going to install long before Wyoming issued its BART findings.
- Third, the Company successfully fought to ensure that the state's BART findings aligned largely with its predetermined direction.

It is worth noting that the SO_2 backstop trading program is only now, in 2012, proposed to be approved by the EPA as an acceptable mechanism of meeting regional haze goals, which means that up until today, there has been no formal federal recognition of the program. In fact, the 2008 § 309 SIP to which Ms. Woolums implies the Company had to respond was effectively withdrawn by the State of Wyoming about a year after it was issued and revised in January 2011. Just days after the Wyoming SIP was submitted to the EPA on May 22, 2008, the EPA commented that the SIP was likely insufficient and requested significant revisions.[2] Several months later, the EPA began discussions with WYDEQ about how the SIP could be improved and resubmitted for approval.[3]

[1] [redacted]

[2] Letter from Callie Videtich at EPA Region 8 to David Finley, WDEQ dated May 29, 2008. "the WRAP recently indicated to us that no further changes would be made to its analysis or the Section 309 milestones in response to our remaining concerns. I am writing to bring these and two additional issues directly to your attention since they may preclude EPA's approval of your State's regional haze State Implementation Plan if not adequately addressed."

[3] Personal correspondence with Ms. Laurel Dygowski, Regional Haze Coordinator at US EPA Region 8, August 2nd, 2012.

In my direct testimony, I provided evidence that the Company had chosen a set of emissions controls long before even BART applications were due in 2007. To reiterate, the Company developed a set of expected emission controls as early as 2002 in response to perceived pressure from the EPA, not in development for regional haze compliance. Planning documents clearly show (a) justification for retrofits based on a [redacted] study from [redacted][4] and (b) the start of investments presupposing Wyoming's BART findings in May 2009.[5]

Finally, once the Company had decided which pollution controls would be part of its portfolio, it fought to ensure that only these controls would be required by regulations. As I noted above, Wyoming submitted its regional haze SIP in 2008 and again in 2011 after EPA suggested that the 2008 SIP regarding the SO_2 trading program might be rejected. However, there were other differences as well – the original BART findings in 2008 required Selective Catalytic Reduction (SCR) on many of PacifiCorp's units. The Company argued rigorously that SCR would be too expensive and pushed for a revision of the BART SIP, promising to install SCRs in later years. An affidavit from WYDEQ tells part of the story:

> During the June or July, 2008 meeting, the Division informed Mr. Lawson [at PacifiCorp] that the preliminary BART determination for the PacifiCorp units was as follows: … Naughton Units 1-3: LNB/OFA/SCR for all units... During the June or July, 2008 meeting and subsequent meetings, I recall PacifiCorp discussing why it was not possible for them to install SCR during the BART period (5 years after EPA approval of SIP). The reasons given were costs, pollution control projects and not enough time to install

[4] For example, from APR 1003744 (N2 LNB 02/09/2010) [redacted]

[5] From APR 10003745. April 22, 2009. [redacted]

> controls. Given these issues and one of the factors in determining BART is cost of compliance, the Division discussed with Mr. Lawson the possibility of not requiring SCR as BART at Jim Bridger Units 1-4 if PacifiCorp would commit to install SCR as part of the long-term strategy…In hindsight, DEQ/AQD should have requested PacifiCorp to put their commitment in writing. [Docket 10-2801. August 6, 2010. Affidavit of Darla Potter, WYDEQ. Sections 13, 15, and 18]

Q You state that it was "disconcerting" that Ms. Woolums indicates that the FGD controls were "installed largely to address nonattainment of the SO_2 NAAQS." Why?

A There are two reasons Ms. Woolums' statement is problematic.

First, Ms. Woolums contradicted almost all other Company documentation that indicates that the FGD controls were installed in anticipation of BART requirements. Sierra Club requested "any analyses… that address the need for any of the Environmental Retrofit Units." [Sierra DR 1.5] Further, Sierra Club requested applications and technical documentation for permits and even correspondence between the Company and Wyoming DEQ regarding these permits. [Sierra DR 1.12] Sierra was provided BART applications, BART permits, PSD permits, and correspondence related to the BART and PSD permits, as well as more recent correspondence to WYDEQ. Intervenors were provided no documentation supporting the contention that the FGD controls were "installed <u>largely</u> to address nonattainment of the SO_2 NAAQS." We have, as of this writing, found no documentation from WYDEQ, EPA, or the company that supports this particular contention, nor has Sierra Club received any SO_2 modeling of Naughton.

Secondly, measured and verified nonattainment caused by an <u>existing source</u> such as Naughton in an area previously in attainment of air quality standards is potentially a serious violation. If it is true, as Ms. Woolums states, that the "results of modeling [in 2006] at Naughton Units 1 and 2 indicated that, when unscrubbed, Naughton Units 1 and 2 individually exceeded the three-hour and 24-hour SO_2 NAAQS in an area near the Kemmerer mine,"[6] then the Company would have knowingly violated air quality standards for nearly six years prior to the installation of the FGD. As of this writing, no such documentation had been provided to interveners or this commission suggesting that such a violation had occurred.

Q So would an FGD have been required even if the Company had modeled a NAAQS violation?

A No. If a violation is modeled during a permit application, the result would have been the rejection of the permit application or modification of permitted conditions.[7] Mrs. Woolums states that:

> If the Company did not act to resolve the SO_2 nonattainment issue at Naughton Units 1 and 2, it would likely have been subject to a regulatory enforcement action or third party action such as a Clean Air Act citizens suit by the Sierra Club. [PAC/1400 Woolums/17 at 20]

Enforcement action have historically required that an actual air monitor, placed in an area of nonattainment, record a violation, a process which unfortunately has taken a number of years to implement and then follow through. The results of an enforcement notice might be the requirement to then install a mitigation measure at the units.

Q So if the FGD was not imminently required for BART and not immediately required by NAAQS, why did the Company move forward with this retrofit so quickly at Naughton?

A An APR document requesting an appropriation for low-NOx burners at Naughton 2 states it most succinctly:

[6] PAC/1400 Woolums/17 at 5-12
[7] Personal correspondence with Mr. Christopher Razzazian at EPA Region 8 on August 8, 2012.

> [redacted] [APR 1003744 – N2 LNB 02/09/2010]

Even if we assume that the Company had good reason to move forward quickly on the FGD at Naughton prior to regulatory certainty, the Company stumbled significantly on the economic justification, as I indicated in my direct testimony. The Company's revised analysis is still flawed, as well.

2. <u>TIMING OF ANALYSIS</u>

Q Mr. Teply states that the analysis supporting the Naughton environmental retrofit was conducted at the appropriate time. Do you agree?

A Presuming the FGD was actually necessary on the timeline put forth by the Company, the Naughton analysis was conducted at <u>one</u> of a number of appropriate milestones. Even using the Company's results from the original present value of revenue requirement differential (PVRR(d)) analysis (provided in OPUC 220-4, "original Naughton analysis"), the Company should have determined that this project was marginal and risky in the very best of circumstances. Had the Company performed the analysis correctly, it would have seen, even at this milestone, that the project was a net liability. This discovery would have triggered a more comprehensive planning process to figure out how the Company would treat this non-economic resource.

Mr. Teply further implies that February 2009 was the last possible moment in which the Company could have reviewed the economics of the Naughton retrofits.

> The Company's financial analysis for Naughton Units 1 and 2 was completed at an appropriate time, February 2009, within the project implementation timeline. Bids had been received, negotiations were ongoing with contractors, permit reviews were ongoing, and the contract was yet to be signed. The contract for the project work was ultimately signed in May 2009 and the contractor was released to begin work. [PAC/1500 Teply/13 at 22]

Given the marginal results of the Naughton analysis and given rapidly falling gas and market prices, the Company should have revisited the economics of this project – even after it had started production – and decided whether it made economic sense to continue investing in Naughton.

Q Staff witness Mr. Erik Colville states that "PVRR(d) analyses updates since the time the decisions were made have been included in the Company's annual business planning and integrated resource planning (IRP), and include proxy costs for CCR and 316b requirements." [Staff/400 Colville/8 at 17] Did the Company update the PVRR(d) analysis from Naughton 1 and 2 at any time after February, 2009?

A No. The Company has verified that the workbooks provided to Staff in OPUC 220-1 through 220-4 represent the workbooks as used in original condition, and that these are the final workbooks used in February, 2009. [Sierra DR 2.2] Further, we received verification that "the Company has not updated the final economic analyses utilized for decision-making since the versions supplied in the Company's responses to OPUC Data Requests 220 and Sierra Club Data Requests 2.3." [Sierra DR 3.1a] The fact that the Company started to look at the economic merit of their coal fleet for the 2011 IRP is immaterial to the decisions made by the Company in 2009. Finally, the Company confirms that they have not updated the PVRR(d) analyses as part of the annual business planning process. [Sierra DR 3.1f]

Q Mr. Colville also states that the "PVRR(d) analyses…have included proxy costs for CCR and 316(b) requirements…the effect of possible CO2 regulatory cost, and variation in fuel and electricity cost." [Staff/400

Colville/13 13-17]. Did the Naughton PVRR(d) analyses include proxy costs for CCR and 316(b) requirements or variation in fuel or electricity cost?

A No. The PVRR(d) analysis for Naughton 3 would have been performed around the time that CCR regulation was first being considered by the EPA,8 but was not included as a monetary risk in the PVRR(d) analysis. The PVRR(d) analysis does not address the potential costs for cooling water intake structures (316(b) requirements), although I would not expect a significant cost implication for this ruling at Naughton. The Naughton PVRR(d) analysis did include a toggle to evaluate high and low market electricity costs at +/-20%, but there is no indication that the results of this toggle were evaluated or made an impact on analytical outcome.

3. <u>REVISED COMPANY NAUGHTON ANALYSIS IS ERRONEOUS</u>

Q Has Mr. Teply changed the Company's analysis in light of material you brought forward in direct testimony?

A Yes. Mr. Teply filed revised workpapers with his reply testimony that concede two points. I will refer to this revised analysis as the "revised Company Naughton analysis". These two points are responsive to a set of critiques I raised in my direct testimony.

First, I pointed out that the execution of the original Naughton analysis, showing that "The model erroneously assumes that a market replacement would occur at the start of the analysis period, in 2009, rather than when a regulation would require either action or retirement, in the 2013-2018 timeframe." (Fisher Direct p39 at 1). The revised Company Naughton analysis reviews the forward-going economics of the Naughton units from 2014 through 2029, instead of 2009 through 2029. This change reduces the net benefit of the Naughton retrofits.

Second, I demonstrated that the timing of the original Naughton analysis, noting that the electricity market prices used in the analysis were out of date by the time

[8] See, for example Bloomburg, December 31, 2008. "Coal-Ash Spill May Cost Utilities Billions in Rules." Alex Nussbaum, Christopher Martin, and Daniel Whitten.

the analysis should have been performed, just prior to having signed the contract to begin work in May 2009. The revised Company Naughton analysis uses March 2009 market prices instead of December 2008 market prices.[9] This change increases the net benefit of the Naughton retrofits.

Q What is the outcome of the revised Company Naughton analysis?

A In a table on page 18 of his rebuttal testimony, Mr. Teply shows that the revised Company Naughton analysis reduces the already marginal benefit, also called the "present value revenue requirement differential" or PVRR(d), of the Naughton 1 unit by about 25% (from [redacted] million[10] to [redacted] million) and reduces the marginal benefit of the Naughton 2 unit by about 33% (from [redacted] million to [redacted] million).

Q In providing the revised Company Naughton analysis, did Mr. Teply sufficiently address your concerns regarding the original Naughton analysis?

A No. I raised several other concerns for which Mr. Teply has provided neither rebuttal nor explanation including: additional capital costs not contemplated in the analysis, the parasitic load of the retrofits, degradation of unit availability, and the use of a low carbon dioxide (CO_2) price forecast.

However, these concerns aside, the revised Company Naughton analysis supported in Mr. Teply's rebuttal testimony contains at least one significant error and two areas of significant disagreement between Mr. Teply's analysis and my own.

- Firstly, the new analysis erroneously shifts the cost of the air initiative costs (FGD and LNB) to the year 2014, rather than leaving them between 2009 and 2012, as incurred.

[9] On page 18 of Mr. Teply's rebuttal testimony, a table erroneously shows the market price date for Naughton 2 as 12/31/2005, rather than 12/31/2008.
[10] This table erroneously lists the values shown as "$ millions". The dollar values shown are in thousands of dollars.

- Secondly, Mr. Teply claims that the Company anticipated a 2013 BART compliance timeframe, instead of the 2015 compliance deadline shown by Sierra Club and CUB.

- Thirdly, the new analysis assumes that the retirement would be a surprise to both the Company and Commission. If the Company were planning for a near-term retirement, it seems likely that they would seek to accelerate depreciation and reduce the level of capital expenditures incurred just prior to the unit's retirement.

Q What is the effect of shifting the cost of the air initiatives to 2014 rather than from 2009 to 2012?

A This time shift makes the retrofits look less expensive from a present value perspective, and thus biases the results towards a favorable outcome for the Naughton units. In addition, the shift reduces the total amount of depreciation expense and taxes incurred on the retrofits, thus also inappropriately lowering the perceived cost in the model.

To fix this error, I simply undid a few formulae put in place in Mr. Teply's revised workbook. I allowed capital air initiative (CAI) costs to be incurred from 2009-2012 as originally modeled, and changed the "in service" date back to 2009 to allow expenses to be capitalized as incurred.

Q To what extent does this timing error impact the outcome of Mr. Teply's revised NPVRR(d) analysis for Naughton?

A Leaving <u>all</u> other questions aside, simply undoing this error erodes the very slight positive PVRR(d) values and turns Naughton 1 into a liability by the Company's own basis. Relative to Mr. Teply's revised workpapers, Naughton 1 shifts from [redacted] million to a liability of [redacted] million, and Naughton 2 shifts from [redacted] million to [redacted] million.

Q **Is Mr. Teply correct that 2013 would have been a reasonable BART compliance timeframe?**

A No. As both Mr. Teply and Mrs. Woolums both state, the Regional Haze Rule requires that "that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." [40 CFR 51.308(e)(1)(iv)] The relevant question here is what date would the unit otherwise have to shut down if it did not choose to install controls? While certainly the Company could push to install controls where clearly economically justified "as expeditiously as practicable", it would not generally be economically sound to rush to shutter a plant years before the first large compliance deadline.

Mr. Teply defines the compliance deadline as the end of 2013:

> Under the Regional Haze Rules, Wyoming's Regional Haze SIP was due in 2008 and EPA was expected to review the Wyoming SIP within a six-month period. If this had occurred, the installation of all control projects would have been required by the end of 2013; within five years of the reasonably expected EPA action. [PAC/1500 Teply/4 at 21]

However, Mr. Teply misstates a reasonable expectation for EPA action. The EPA often takes two or more years to act on state implementation plans (SIPs). In the case of Regional Haze, the EPA has two years to disapprove a SIP and promulgate a federal implementation plan (FIP),[11] as it has now done in Wyoming and Utah. Seven years[12] from Wyoming's first haze SIP submission in May 2008 would require compliance by the Company in 2015. Indeed, in modeling the cost of implementing the haze rule, the EPA assumed that controls and requirements would be in place in 2015. [70 FR 39145]

[11] 64 FedReg 35747
[12] Two years of consideration and five years of implementation.

Q To what extent does the assumed retirement year impact the outcome of Mr. Teply's revised NPVRR(d) analysis for Naughton?

A Leaving Mr. Teply's model structure intact, but shifting CAI investments back to 2009-2012 <u>and</u> moving the assumed replacement date up to January 2016 erodes the PVRR(d) of the retrofits. Relative to Mr. Teply's revised workpapers, Naughton 1 shifts from [redacted] million to a liability of [redacted] million, and Naughton 2 shifts from [redacted] million to [redacted] million.

I show the impact of these corrections on the PVRR(d) values for Naughton 1 & 2 graphically in Figure 1, below.

[redacted]

Figure 1. Present value revenue requirement differential (PVRR(d)) of retrofits at Naughton 1 & 2 in initial analysis ("as filed"), in Teply response testimony, with corrected CAI expenditure timing, and with Jan 2016 replacement date, respectively.

Q Why does the later replacement date appear to slightly <u>increase</u> the PVRR(d) of Naughton 2?

A In the Company's stream of anticipated non-environmental capital expenditures, Naughton 2 has a very high expected capital expenditure of [redacted] million in 2015, the second highest ongoing capital expenditure over the remaining 30 years of life from 2009. By moving the anticipated replacement date from January 2014 to January 2016, we exclude this high cost from the remaining life of the unit, thus decreasing the apparent cost of keeping this unit online relative to retiring the unit in 2016. The net impact is to make a retirement in 2016 look more expensive because of the high cost incurred in the <u>last year</u> of the unit's life.

Q Would you expect the Company to sink significant capital into a unit that would be closed a year later?

A No.

Q How does the revised Company Naughton analysis assume that the retirement would be a "surprise" to both the Company and Commission?

A I expect that if the Company knew that a unit needed to be retired in just a few years, the Company would (a) probably seek some form of accelerated depreciation for new capital investments, such as they are doing for the Carbon plant, anticipated to be retired in April of 2015 [see PAC/1100 Dalley/12 at 6-14] and (b) invest only the bare minimum required to get the optimal amount of energy out of the unit at the lowest price.

The revised Company Naughton analysis starts in full at the year 2014 and compares the cost of ongoing capital expenses, CAI, fuel, and a carbon cost against the cost of market energy. Essentially, this analysis assumes that everything that is incurred prior to 2014 would be no different should the plant continue operation or retire. By ignoring all capital costs incurred from the analysis date in 2009 through 2014, the Company makes an implicit assumption that all capital during that time regardless of whether the unit is retired <u>and</u> that the Company will recover all new capital expenses over a 15-20 year period.

By implementing this assumption, the Company overestimated the expected cost of the retirement scenario by both (a) assigning long-run depreciation and tax expenses to short-term investments <u>and</u> (b) assigning high ongoing capital expenditures to the retiring unit in its last few years of life.

Q Did you correct the Company's assumption that new capital expenses would be subject to accelerated depreciation?

A Yes. In my re-analysis of the Company's initial filing, submitted in my direct testimony, I used an assumption fully consistent with the Company's model. The PVRR(d) model includes a toggle for the end of the depreciable life of the plant.[13] I set up my model differently than Mr. Teply. As I described in my direct testimony, rather than use a single run of the spreadsheet to calculate a PVRR(d) value, I used two versions of the spreadsheet with two different scenarios. [Fisher direct, page 44 at 21 through page 45 at 5] The first scenario ("Run to 2029") simply adds up the total present value revenue requirement (PVRR) of operating a unit from the analysis date (2008) the end of its depreciable life (2029). The second scenario ("Retire in 2015") adds up the total present value cost of operating a unit from the analysis date to the retirement date (2015) plus the cost of replacement market power from 2016 through 2029. To calculate the "differential", I simply take the difference between the total PVRR of the Run to 2029 scenario and the Retire in 2015 scenario.

The mechanism I describe above and in my direct testimony captures the difference between the likely requirement for accelerated depreciation in the Retire in 2015 scenario and the Run to 2029 scenario. My depreciation assumption is fully consistent with the Company's PVRR(d) modeling[14] and request for accelerated depreciation on the Carbon plant. Mr. Teply's rebuttal testimony and the revised Company Naughton analysis are inconsistent with the Company's PVRR(d) modeling framework.

[13] In OPUC 220-4, this toggle is labeled "Plant Calendar End Year" on the "Data" tab (cells L60:61).
[14] The PVRR(d) analyses supplied by the Company effectively require accelerated depreciation for late-stage investments at generators. For example, while an expense incurred at Naughton in 2010 is depreciated over 19 years to the end of the unit's life in 2029, expenses incurred in 2027 are depreciated over two years. Thus, if the unit is to be retired in 2015, we would expect that according to the model, expenses would be depreciated over a shorter span of time.

Q What difference does this accelerated depreciation assumption make in the analysis?

A Overall, under an accelerated depreciation schedule, recovery is front-loaded and higher in near-term years. However, the total PVRR of an accelerated depreciation schedule is slightly lower. When I take into account the March 2009 official forward price curve and slightly lower carbon cost in the revised Company Naughton analysis, the total PVRR(d) value for both Naughton units again declines, now down to [redacted] million for Naughton 1 and [redacted] million for Naughton 2.

The results of this analysis are compared to the other versions of the model in **Figure 2,** below.

[redacted]

Figure 2. Present value revenue requirement differential (PVRR(d)) of retrofits at Naughton 1 & 2 in initial analysis ("as filed"), in Teply response testimony, with corrected CAI expenditure timing, with Jan 2016 replacement date, and results from two-model version of comparison to simulate accelerated depreciation.

Q Did you correct the Company's assumption that high ongoing capital expenses would still be incurred in the last year of life for the Naughton 2 unit?

A No. I have little information regarding the nature of these costs, and thus am unable to provide more realistic values. However, on a purely illustrative basis, if the Company were to only spend $2 million on Naughton 2 in its last year of life (2015) in the replacement scenario instead of [redacted] million, the PVRR(d) would quickly flip from +[redacted] million (as shown in **Figure 2**), above to -[redacted] million.

Q Finally, do any of your analyses include parasitic load, expected coal unit degradation, or the costs of an SCR as anticipated by the Company in 2009?

A No. As I demonstrated in my direct testimony, including a de-rate for parasitic load, the expected degradation of unit availability, and the known costs of SCR and ACI in 2009 decreases the PVRR(d) of maintaining the Naughton coal units. Keeping the March 2009 official forward price curve and lower carbon costs in Mr. Teply's revised model (revised Company Naughton analysis), the results that I produced in direct testimony now look like the values in **Table 1** and **Table 2**, below.

Table 1. Present value revenue requirement difference (PVRR(d)) of the Naughton 1 retrofit relative to market replacement, in thousands of 2009$ (Jan 2016 replacement with March 2009 market prices). The ** marks the most conservative value that the Company should have estimated as the May 2009 contract date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]**	[redacted]	[redacted]

Table 2. Present value revenue requirement difference (PVRR(d)) of the Naughton 2 retrofit relative to market replacement, in thousands of 2009$ (Jan 2016 replacement with March 2009 market prices). The ** marks the most conservative value that the Company should have estimated as the May 2009 contract date.

	Original Generation	FGD De-rate	Derate + degrade
FGD & LNB	[redacted]	[redacted]	[redacted]
FGD, LNB, SCR & ACI	[redacted]**	[redacted]	[redacted]

Q Did Mr. Teply contest the modification of the generation output on the Naughton units to account for parasitic load?

A No.

Q Did Mr. Teply contest the modification of the generation output on the Naughton units to account for unit degradation?

A No. In fact, referencing my critique of the Hunter PVRR(d) analysis, Mr. Teply testified that “Sierra Club’s unit degradation modification is a reasonable consideration, but does not materially impact the overall financial results of the evaluation.” However,the degradation modification does have a significant material impact on the overall financial results of the evaluation here, in the amount of [redacted] million for Naughton 1 and [redacted] million for Naughton 2, very clearly putting both units in negative territory.

Q Did Mr. Teply contest the use of capital costs for SCR and ACI at the Naughton plant in the 2009 analysis?

A Yes. According to Mr. Teply’s testimony, “the Company does not anticipate installing SCRs on Naughton Units 1 or 2 in the future.” [PAC/1500 Teply/14 at 18]

Q Did the Company anticipate installing SCRs on Naughton Units 1 or 2 as of 2009?

A Yes, according to the Company’s 2009 [redacted]

Q Does it matter that the Company currently does not anticipate installing SCRs on Naughton Units 1 or 2?

A No. In this review of the Company’s 2009 actions, we are held to information known or knowable by the Company at the time decisions were made.

Q Did the Company have alternative opportunities to re-evaluate the economics of the Naughton retrofits?

A Yes. Leaving aside the inexplicable rush to install retrofits on this aging plant, the Company could have and should have chosen to re-evaluate the economic implications of the retrofits. It is not credible that as soon as the Company had released contractors to work, that it had no choice but to go all the way through with the project despite all of the indicators that the already marginal economics were rapidly fading. For example, just one month after contracts were signed in May 2009, the Company's long-term outlook on market electricity prices in the replacement period (2015-2029) had fallen by 14% from March 2009. This revised outlook generally stayed about 10-15% below March 2009 forecasts through the next two years, and then dropped to over 20% lower than March 2009 forecasts by 2011.

4. CONCLUSION

Q What would a reasonable company have done in regards to the retrofits at Naughton 1 & 2, given the information presented by the Company?

A First, in 2009, there was no clear mandate requiring the Company to retrofit the Naughton units with flue gas desulfurization (FGD) by the end of 2013 or even 2015. The Company had the opportunity to review requirements, monitor the economic condition of their units, and consider all of the mechanisms at their disposal to meet environmental compliance requirements in a reasonable and reliable timeframe without rushing to retrofit the unit with FGD by 2012.

Second, had the Company determined that there was a real and legitimate reason to move forward on the FGD quickly, the screening analysis should have raised flags for any analyst that the retrofits would result in a net liability at Naughton units 1 and 2. Even if experienced Company analysts failed to notice that the PVRR(d) analysis was constructed incorrectly, was biased in favor of the retrofit, did not account for risk appropriately, and was inconsistent with other Company strategic plans, the outcome of the original analysis should have alerted both analysts and executives that the retrofit was marginal and high risk. Net benefits of about $[redacted] million[15] are not a compelling case for the retrofit investment when considered in the context of the scale of the $[redacted] million investment,[16] the total revenue requirements for the units and the many uncertainties in projecting the future benefits.

[15] Initial Company results from Naughton 1 & 2, combined.
[16] Total CAI investments from 2009-2012 at Naughton 1 & 2, combined. Includes AFUDC.

At best, the concerns raised by the original analysis, or the red flags raised by a correctly executed original analysis should have led to a much more comprehensive effort to evaluate if it was appropriate to retrofit the Naughton units. The Company should have used the System Optimizer model to determine if better build-out options were available, and at what cost. The Company should have explored the range of risk associated with the retrofits. The Company should have deferred the investment to determine if other regulatory risks should further damage the economic condition of Naughton. And of course, the Company should have started reviewing options to retire the Naughton facility as one feasible mechanism of meeting environmental compliance obligations.

Instead, the Company has presented no evidence that either analysts or executives paid particular attention to the construction or outcome of this model in 2009, have continued to confound the issue by attempting to provide retrospective justification for unsupportable actions, and have continued to use this simple model erroneously.

Q Does this conclude your testimony?

A Yes.

PUBLIC UTILITY COMMISSION OF OREGON

UE 246

SIERRA CLUB EXHIBIT 301

Naughton 1&2 Present Value Revenue Requirement Difference Data

REDACTED:
Exhibit included in confidential version of testimony