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September 12, 2012

VIA ELECTRONIC FILING AND FIRST CLASS MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
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Re: Docket UG 221 – Northwest Natural Gas Company Application for a General Rate Revision

Attention Filing Center:

Enclosed for filing in the above captioned docket are an original and five copies of Northwest Natural's Posthearing Brief. A copy of this filing has been served on all parties to this proceeding as indicated on the enclosed Certificate of Service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosure

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UG 221 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UG 221

In the Matter of

NORTHWEST NATURAL GAS COMPANY

Application for a General Rate Revision.

NW NATURAL'S

POSTHEARING BRIEF

September 12, 2012

TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to Administrative Law Judge (ALJ) Lisa Hardie's Ruling on March 12, 2012, Northwest Natural Gas Company ("NW Natural" or the "Company") submits this Posthearing Brief to the Public Utility Commission of Oregon ("Commission"). The Company previously filed a Prehearing Brief that summarized the issues that have been resolved in this case and the parties' positions and supporting evidence on the issues that remain for Commission resolution: return on equity (ROE); Staff's proposed adjustment to cost of capital for an interest rate hedge loss; recovery of costs associated with the Company's environmental remediation activities; recovery of pension costs; prudence of the Mid-Willamette Valley Feeder; and amortization of certain deferred tax balances. This Posthearing Brief provides additional discussion of the issues that remain for Commission resolution based on testimony at the hearing held on August 23, 2012 and the arguments raised in the parties' prehearing briefs.

II. DISCUSSION

A. The Company's Earnings Should Not Serve as a Justification for the Disallowance of Prudently-Incurred Costs.

Throughout this case, the charge of NW Natural overearning became a mantra, repeated in Staff and intervenor testimony, briefs, and at hearing. NW Natural has been accused of "chronically overearning" and of "extensive and obvious over-earning."[1] Indeed, the term "overearning" appears 15 times in CUB's Prehearing Brief *in the first ten pages alone.* In addition to the suggestion that the Company has somehow transgressed the regulatory compact, the Company's overearning was the consistently-echoed justification for why the Company should not recover prudently-incurred costs. For instance:

- Staff and CUB both suggest that the Company should not recover its excess pension contributions because of the strength of its earnings.[2] CUB even goes so far as to state that the Company could have used excess earnings to make

[1] CUB's Prehearing Brief at 8.
[2] *Id.* at 25-26; Staff's Prehearing Brief at18.

pension contributions but instead, just "pocketed the over-earnings."[3] This is a curious accusation given that the Company did, in fact, use investor funds to make the pension contributions.

- Staff and CUB argue that the Company should not be allowed to recover its increase in deferred taxes due to the 2009 state tax change because it was overearning during some of the relevant periods.[4]
- NWIGU and CUB argue that the overearning is a reason why the NW Natural should not be allowed to recover 100 percent of its prudently-incurred environmental expenses.

In order to assess the credibility of these positions, it is first important to establish the extent of the Company's overearning. The relevant calculations are shown on charts found in NWN/1800, Anderson/5, Staff/200, Johnson/4, and discussed in the opening testimony of Staff witness Nick Cimmiyotti at 6. Here are the facts:

NW Natural has eight years of reported earnings since its last rate case—2003 through 2010. Even including weighted average cost of gas (WACOG) gains and losses,[5] in four of those years, the Company under-recovered its authorized ROE. **Again: the Company under-recovered its authorized ROE in four out of the last eight reported years.** In one year, the Company earned **at** its authorized ROE. And in three years, the Company earned **above** its authorized ROE. That is it. Three years. It is hard to square these undisputed facts with the overheated rhetoric offered in this case—particularly that sponsored by CUB.

Second, it is important to establish the impact this overearning has had on the Company's operating income. Including WACOG gains, according to Mr. Cimmiyotti, the Company earned above its authorized ROE by approximately $20 million. Excluding WACOG gains, the Company's earnings above ROE amount to less than $5 million dollars. While those dollars are not insignificant, they are hardly enough to cover the Company's pension contributions, environmental remediation, and increase in deferred taxes all at the same time.

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[3] CUB Prehearing Brief at 26.
[4] *Id.* at 40.
[5] NW Natural believes that it is more appropriate for the Commission to view earnings without WACOG gains and losses. NWN/1800, Anderson/4, lines 8-14.

Moreover, in viewing these facts, it is important to recall that the effects of the Company's excess pension contributions do impact the Company's earnings. So, the earnings do not take into account those significant costs to the Company. Similarly, the earnings do not reflect the Company's very significant environmental remediation expense. In short, while they tell an important part of the Company's financial story, they do not tell the whole story.

NW Natural is not claiming that its earnings have been meager—only that, contrary to the parties' suggestions, they have not been inappropriately high. Claims of extensive and obvious overearning just do not match the facts. More importantly, NW Natural is concerned about the unspoken implication that utilities should be punished for achieving healthy earnings. Achieving authorized earnings demonstrates efficient Company management and accrues to the benefit of utility customers through reduced expenses in the next rate case. For an example of this benefit, the Commission need look no farther than the number of full-time equivalent employees (FTEs) that will be recovered in the case. In 2005, NW Natural employed 1,275 FTEs. In this case, the Company proposed recovery of 1,095 FTEs,[6] and the parties have settled on the issue of FTEs. So while the Company's management between rate cases contributed to its earnings, customers are reaping the benefit now. And, of course, good management translates into lower debt and equity costs for customers as well.[7]

B. The Company's Request of a 10.2 Percent ROE Should Be Granted.

In its testimony and prehearing briefing, NW Natural has established the reasonableness of its requested 10.0 percent ROE. The request is supported by Dr. Hadaway's discounted cash flow (DCF) models and by qualitative factors, including current capital market conditions and NW Natural's unique business risks.

[6] NWN/3400, Sohl/3, lines 6-8.
[7] NWN/1800, Anderson/5, lines 6-18.

1. Considerations of Reasonableness and Comparability Support the Company's ROE Request of 10.0 Percent.

At hearing, the Company offered Exhibit NWN/4322, the Company's testimony in Docket UG 152, where the Commission authorized the Company's current ROE. In that case, the Company requested a conservative ROE, near the bottom of Dr. Hadaway's quantitative range:

> Based on my quantitative analyses, I estimate the fair ROE range at 11.2%-12.1%, with a mid-point of 11.65%. From these quantitative results and my review of the current market, industry and company-specific factors discussed in the remainder of my testimony, I can recommend the point estimate of 11.3% that was selected by the Company from within this range for use in the present case. This estimate is supported by the most conservative of my DCF results, obtained from the two-stage and constant growth version of the DCF model. My recommendation, in the lower part of the DCF range, also gives consideration to the Company's and other parties' efforts to 'narrow the gap' among their ROE recommendations.[8]

The Company interpreted the results of its DCF models through filters of reasonableness, comparability and gradualism, requesting and ultimately accepting through settlement an ROE below that suggested by DCF model results. The final result, an ROE of 10.2 percent, was also well below then-current average allowed ROEs, as Staff notes in its direct testimony.[9]

In this case, the Company has applied these same equitable filters in requesting an ROE that is near the top of Dr. Hadaway's quantitative DCF range and slightly above recent average allowed ROEs for natural gas companies. In Docket UG 152, the Company considered and moderated relatively high DCF model results and average allowed ROE awards in its ROE request; in this case, the Company consistently and symmetrically considered and moderated relatively low DCF model results and average allowed ROE awards in its ROE request.

In contrast, Staff's testimony ignores these considerations and implies that consistency requires the Commission to deviate downward from average allowed ROE results in this case, as it did in Docket UG 152.[10] Staff testifies that a "comparable" ROE in this case would be 79-

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[8] Exhibit NWN/4322 at 3-4.
[9] Staff/1300, Storm/65.
[10] *Id.*

39 basis points below current average allowed ROEs.[11] In this manner, Staff attempts to justify the fact that its ROE recommendation is more than fifty basis points below the 2011 average allowed ROE of 9.92 percent for natural gas utilities.

Under ORS 756.040, the charge of the Commission is to set a reasonable ROE that is commensurate with what an investor could earn in a company with comparable risk. Reasonableness and comparability dictate the balanced approach applied by the Company in this case and in Docket UG 152, and the Company's ROE request of 10.0 percent. These concepts do not support the uniform "deviate downward" approach suggested by Staff in support of its 9.4 percent ROE recommendation.

2. Staff Supports Its Low ROE Recommendation Through Inaccurate Arguments in Its Prehearing Brief.

Staff's prehearing brief in this case submits several inaccurate arguments in support of Staff's low ROE recommendation.

First, Staff argues against any consideration of Dr. Hadaway's constant growth DCF analysis.[12] Citing the Commission's orders in Dockets UE 115 and UE 116, Staff asserts that the Commission has broadly rejected the constant growth DCF model.[13] Staff argues that these cases require the Company to demonstrate the presence of "industry stability" before the Commission will consider this version of the DCF model. Staff then cites to Dr. Hadaway's testimony regarding capital market instability to argue that the Company has failed to make the requisite showing.[14]

There are several serious problems with Staff's analysis. Most notably, the Commission's rejection of the constant growth DCF model in Dockets UE 115 and UE 116 was tied to electric industry restructuring, applied to electric utilities, and referenced the need to

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[11] *Id.*
[12] Staff's Prehearing Brief at 2.
[13] *Id.*
[14] *Id.*

demonstrate electric "industry stability"—considerations which are inapposite to NW Natural, a natural gas utility.[15] In addition, Staff incorrectly characterizes the Company's testimony on capital market instability as testimony on the instability of the natural gas industry. Staff also omits reference to Docket UE 180, where the Commission relied upon an ROE recommendation based on the constant growth DCF model,[16] subsequent to the orders cited by Staff.

Second, Staff alleges that the Company made an "outboard" adjustment of 30 basis points to support its 10.0 percent ROE request, wrongly implying that 9.7 percent is the top of Dr. Hadaway's range of quantitative DCF results.[17] In fact, Dr. Hadaway's constant growth DCF model with GDP growth rates produced a median ROE of 10.3 percent in his direct testimony and 10.1 percent in his surrebuttal update. By pretending that these results do not exist, Staff compounds its error in failing to provide its own constant growth DCF analysis and in completely discounting NW Natural's constant growth DCF results. Staff also fails to give any consideration to Dr. Hadaway's alternative approach to Staff's "P/E Model," which produced a median ROE of 10.6 percent by shortening the time horizon in the model to capture current market conditions.[18]

Third, Staff argues that Dr. Hadaway's DCF growth rate of 5.7 percent is overstated as compared to Staff's own growth rates, ranging from 4.51 percent to 5.14 percent.[19] But, Staff fails to acknowledge that its original ROE recommendation in this case was based upon a GDP growth rate of 5.48 percent.[20] Without explanation, Staff changed the methodology used to determine its long-term growth rate in rebuttal testimony and reduced the rate to 5.14 percent.[21]

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[15] In disregarding the results of the parties' constant growth DCF models in Order Nos. 01-777 and 01-787 in Dockets UE 115 and UE 116, the Commission questioned the model's applicability in light of the ongoing restructuring of the electric industry. The Commission then noted that "[p]arties are free to use the single-stage version of the DCF method in future dockets, but they will be required to show the required industry stability is present."
[16] *In re Portland General Electric*, Docket UE 180, *et al.*, Order No. 07-015 at 46-47 (Jan. 12, 2007).
[17] Staff's Prehearing Brief at 3.
[18] NWN/3200, Hadaway/6, lines 8-23.
[19] Staff's Prehearing Brief at 4, 6-7.
[20] Staff/1300, Storm/64, Table 9.
[21] Staff/2200, Storm/18, Table 3.

While Staff is critical of Dr. Hadaway's 5.7 percent growth rate, this rate is only 22 basis points higher than Staff's original long-term growth rate in this case. Dr. Hadaway's growth rate is also consistent with Value-Line's most recent growth rate of 5.65 percent, the growth rate Mr. Storm applied in the first stage of his DCF models.[22]

C. The Commission Should Reject Staff's Proposed Disallowance Regarding NW Natural's Interest Rate Swap.

In 2007, NW Natural entered into an interest rate swap intended to lock in a target interest rate for an upcoming debt issuance. The Company requested and received approval from the Commission to enter into the interest rate swap, and complied with all of the conditions set by the Commission for the swap. Unfortunately, shortly after NW Natural entered into the swap, the financial crisis hit, disrupting the historical correlation of AA utility bond rates and the swap rate, upon which the hedge was based.

Staff has come up with several theories why it believes that the swap was imprudent and why therefore shareholders should be required to bear a portion of the loss. These reasons shifted and morphed over the course of the case, as Staff revised some of its justifications on cross-examination, and retracted one altogether. In the end, none of Staff's justifications for its proposed disallowance is convincing. On the contrary, it appears that Staff simply wishes to penalize the Company for a loss that could not have been foreseen or prevented. As such, Staff's position is contrary to Commission policy and should be rejected.

1. Staff Agrees with NW Natural as to the Intent of the Swap and the Reason that It Did Not Perform as Intended.

NW Natural has described the workings of the swap in previous testimony and will not repeat that information here.[23] However, several important points were confirmed at hearing on the cross-examination of Staff witness, Matt Muldoon.

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[22] NWN/3200, Hadaway/9-10; Staff/1300, Storm/57.
[23] *See* NWN/2000, Feltz/6, lines 5-22.

- First, Mr. Muldoon agreed with NW Natural that the intent of the interest rate swap is not to make money or to lose money, but rather to lock in a target interest rate for an issuance.[24] Thus, if interest rates go down after the swap is entered, the Company will pay the lower interest rate—but the swap payment *to* the counterparty will bring the total cost to the target rate.[25] Conversely, if interest rates go up after the swap is entered, the Company will pay the lower interest rate on the debt issuance—but its swap payment *from* the counterparty will bring the total cost to the target rate. As such, the point of the swap is to render the Company indifferent as to whether interest rates rise or fall.[26]

- Second, Mr. Muldoon also agreed with NW Natural that the swap's effectiveness relied on a close correlation between the swap rate and the AA bond rate. In other words, had those two rates remained in close correlation, the hedge would have performed as intended and the loss at issue in this case would not have occurred.[27]

- Third, Mr. Muldoon agreed with NW Natural that the swap rate and AA utility bond rates have moved in close correlation since 1991—which is as long as the swap rate has been tracked by market observers.[28] Thus, Mr. Muldoon confirmed Mr. Feltz' testimony in which he explained that the relationship between the AA utility bond rate and the swap rate departed from each other for the first time in history only during the financial crisis.[29]

Thus it became clear at hearing that Staff and NW Natural agree upon the intent of the hedge as well as the reason why the hedge did not operate as intended—that is, the unprecedented "unhooking" of the swap and AA utility rates. Nevertheless, at hearing Mr. Muldoon continued to claim that the hedge was imprudent. However, his answers on cross-0examination and in response to questioning from ALJ Hardie significantly undercut his position.

a. Staff's Criticisms of NW Natural's Analysis of the Hedge Are Unfounded.

The primary reason Staff believes the hedge was imprudent is based upon Mr. Muldoon's opinion that the Company did not perform sufficient analysis prior to entering into the hedge. Throughout this case, Mr. Feltz has provided testimony explaining the research the

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[24] Tr. 77, lines 12-18.
[25] Tr. 163, line 14-Tr. 164, line 1.
[26] Tr. 163, lines 14-20.
[27] Tr. 78, lines 7-16. Mr. Muldoon did qualify his answer by making it clear he believed that the failure of the swap to be effective was also due in part to some deficiencies in the contract with UBS—which are discussed below.
[28] Tr. 82, line 8 to Tr. 83, line 4.
[29] *See* NWN 2000, Feltz/9, lines 11-20.

Company performed to determine the type of hedge best suited for the Company's purposes, and the best timing for the swap.[30] He has also explained how the Company solicited bids to ensure it received the best possible terms.[31] Nevertheless, Staff claims that the Company was imprudent because it did not perform a probabilistic analysis of the risk or a high impact low frequency (HILF) decision tree study.[32]

However, upon questioning at hearing, it became clear that Mr. Muldoon could not credibly claim that *any* analysis would have suggested that the Company acted imprudently in entering the swap. On this point, Mr. Muldoon admitted that Staff has not performed any analysis that would demonstrate that the swap was imprudent, and that when Staff first recommended its disallowance, he did not really know what the outcome of such an analysis might have been.[33] Indeed, the only analysis Mr. Muldoon could point to to support his view was the Monte Carlo analysis performed by the Company during this case.[34] Yet, the Monte Carlo analysis provides no support for Staff's position whatsoever. As explained by Mr. Feltz, the Monte Carlo analysis looks at the risk of interest rates going up or down, and the resulting swap payments that would be made by the NW Natural and the counterparty.[35] Specifically, the Monte Carlo "analysis shows that within a 95 percent confidence band, the variances in the swap rate would have been expected to produce a maximum potential loss on the hedge transaction of $5.6 million, or a maximum potential gain of 7.8 million."[36] Importantly, **"either result would still have been expected to mitigate against any interest rate volatility if the swap rate and the debt issuance rates had remained correlated."**[37]

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[30] *Id.* at 7-8.
[31] *Id.* at 8, lines 16-18.
[32] Staff/2300, Muldoon/9, lines 10-14.
[33] See Tr. 85, line 11-Tr. 88, line 6.
[34] Tr. 87, lines 3-20.
[35] NWN/2000, Feltz/12-13.
[36] *Id.* at 12, line 22-Feltz/13, line 1.
[37] *Id.* at 13, lines 2-3

It is this last point that seems to be the cause of disconnect between the parties' positions. Staff appears to believe that an analysis of interest rates—whether it was a Monte Carlo analysis or a HILF analysis—could have identified the potential for the loss that occurred. This is simply not the case. The only analysis that could have identified the loss that occurred is one that could have predicted the financial crisis and the subsequent unhooking of the swap rate from the AA utility bond rate. And even Mr. Muldoon does not claim that he did or could have predicted these events.

b. Mr. Muldoon Was Forced to Admit that the Company's Accounting for the Hedge Was Not Inconsistent with FASB.

Mr. Muldoon has also charged that the swap was imprudent because the Company's hedging policy calls for less stringent accounting than the Financial Accounting Standards Board (FASB).[38] Mr. Muldoon's responses to questions on this subject were evasive at best, but taken as a whole, his testimony on this subject demonstrates that the Company's accounting for the hedge was required by NW Natural's hedging policies to be consistent with FASB standards, and in fact was consistent with FASB standards.[39]

c. Mr. Muldoon Withdrew His Charge that the Company's Accounting for the Hedge was Not Transparent.

Finally, in his pre-filed testimony Mr. Muldoon stated flatly that the Company was less than transparent and that the hedge loss was not visible to shareholders and customers. In preparing to cross examine Mr. Muldoon on this charge, the Company filed Securities and Exchange Commission reports as exhibits that demonstrate that the Company reported the loss clearly and repeatedly.[40] For this reason, Mr. Muldoon withdrew his testimony on that subject.[41]

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[38] Staff/1200, Muldoon/15, line 21-Muldoon/16, line 2.
[39] *See* Tr. 88, line 6-Tr. 95, line 13.
[40] NWN/4317 at 8; NWN/4318 at 67.68.
[41] Tr. 95, line 14-Tr. 97, line 3.

d. Mr. Muldoon's New Claim that the Company's Hedging Policy Is Imprudent Is Without Support and Should be Disregarded.

Perhaps because his other criticisms of the Company's actions were so significantly undercut on cross-examination, when later questioned by ALJ Hardie and by Commissioner Ackerman, Mr. Muldoon raised for the first time a brand new theory as to why NW Natural's interest rate swap was imprudent. At this late date in the process and for the first time, Mr. Muldoon took the position that the Company's **overall** hedging policy is "[p]ossibly too broad,"[42] and that "the Commission may want to ask the Company to relook at its policy based on what it [has] learned from the process."[43] When the question was directly posed by Chairwoman Ackerman at hearing, Mr. Muldoon confirmed that he was taking the position that the Company's hedging policy is imprudent.[44]

This charge should be disregarded. Mr. Muldoon does not state what the policy is lacking or how it might be improved. And perhaps most significantly, Mr. Muldoon does not state why he never complained about the Company's hedging policy (other than the complaint about the accounting requirements which he later seemed to retract) before the day of hearing. The Company's hedging policy has been previously filed with the Commission and provided to Staff,[45] without question or criticism prior to this case. And even more curiously, prior to hearing Mr. Muldoon filed two rounds of testimony listing the reasons why he believed the interest rate swap to be imprudent, and never said a word about the Company's hedging policy being too broad. Mr. Muldoon's last ditch attempt to provide a basis for his disallowance is too weak to be credited and should be disregarded altogether.

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[42] Tr. 102, lines 16-25.
[43] Tr. 101, lines 16-20.
[44] Tr. 102, lines 23-25.
[45] The Company files its hedging policies each year under the Purchased Gas Adjustment hedging guidelines. *See, e.g.*, the Company's initial filing in Docket UG 239. The Company also provides the policy to Staff during Staff's audit.

D. The Commission Should Find the Company's Environmental Remediation Costs Were Prudently Incurred and Adopt the Company's SRRM.

The Company has proposed the establishment of a "Site Remediation Recovery Mechanism" (SRRM), a mechanism through which the Company will recover expenses associated with environmental remediation related to its historic manufactured gas plants (MGPs). The outstanding issues associated with the SRRM for the Commission's consideration remain: (1) whether shareholders should be required to shoulder the prudently-incurred costs associated with this mandatory remediation; (2) whether the Company should be limited to recovering less than its cost of capital where it is required to invest its funds on behalf of customers to finance these costs; and (3) whether an earnings test should be applied to the SRRM each year in order to limit the amounts that the Company can recover related to these expenses. Based on the record in this proceeding, and sound regulatory policy, the Commission should find that the answer to each of these questions is no.

There is no question that the costs that would be subject to the SRRM were prudent. The Company filed reams of paper and voluminous testimony demonstrating this fact—none of which was contradicted by any party. And there is no question that the Commission precedent requires that prudently-incurred environmental remediation costs be recovered. What seems to be problematic for Staff and intervenors is that the environmental impacts that the Company is remediating in this case are connected to activities that took place decades ago. Accordingly, the parties incorrectly complain that customers do not benefit from these costs and that they cannot control them, and that they therefore should not bear them. However, by focusing on the historic nature of the Company's MGP operations, the parties miss the mark. The facts are that the Company's environmental remediation costs are (a) current costs; (b) flowing from current environmental regulations; and (c) required to keep the Company in compliance with state and federal law. Thus, just as current customers benefit when the Company performs legally-required environmental mitigation when it builds a pipeline, customers also benefit from the costs at issue in this case. Arguments to the contrary are illogical and false.

1. The Commission Should Reject the Parties' Sharing Proposals.

a. Applicable Law

The Commission is empowered to set rates that are "fair and reasonable," meaning that they "provide adequate revenue both for operating expenses of the public utility . . . and for capital costs of the utility."[46] The Commission will include operating expenses in rates to the extent it finds them prudent.[47] In determining whether a company's action was prudent, the Commission reviews "the reasonableness of the action based on the information that was available, or could reasonably have been available, at the time the action was taken. If the action was reasonable, then the expense was prudently incurred."[48] In addition, the Commission also must "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates."[49] Based on this well-established statutory framework, the Commission should allow the Company to recover its prudently-incurred environmental remediation costs.

b. The Parties' Sharing Proposals Would Cause Significant Financial Harm to the Company.

Staff has proposed conditioning approval of the SRRM on applying 90/10 "sharing" to the costs, with customers paying 90 percent and shareholders paying 10 percent.[50] NWIGU-CUB originally argued that the Company should bear 50 percent of costs.[51] It appears now that NWIGU may be arguing that the Company shoulder up to 100 percent of the costs.[52]

There can be no doubt but that these proposals would inflict real damage on the Company. The Company is facing a massive environmental remediation liability, having already

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46 ORS 756.040(1).
47 *See City of Portland v. Portland Gen. Elec. Co.*, Docket UM 1262, Order No. 06-636 at 4 (Nov. 17, 2006).
48 *Re PacifiCorp Application for Approval of Revised Tariffs to Reflect New Net Power Costs*, Dockets UE 134 and UM 1047, Order No. 02-820 at 5 (Nov. 20, 2002).
49 ORS 756.040(1).
50 Staff/200, Johnson/7, lines 16-17.
51 NWIGU-CUB/100, Larkin/52, lines 22-24.
52 *See* NWIGU's Prehearing Brief at 4.

deferred approximately $64.5 million in expenses,[53] while estimating $58 million in future remediation costs.[54] Moreover, it is critical that the Commission keep in mind that the Company's estimate is, in accordance with accounting standards, at the very low end of potential costs. That means that the Company's actual environmental remediation obligations could, and likely will be, much higher. It is also important to note that NW Natural's exposure associated with its environmental remediation liability is unusually high compared with other utilities given the size of NW Natural and the fact that the Gasco plant was one of the largest MGPs in the country.[55]

While Staff's 10 percent sharing proposal may appear on its face to be relatively modest, in reality it is anything but. If adopted, the Company would be required to immediately write off 10 percent of amounts already incurred—about $11 million.[56] Under the NWIGU-CUB proposal, which would deny recovery of 50 percent of these expenditures, the immediate write-off could be as high as $56 million.[57] And of course, NWIGU's new position that the Commission should disallow *all* of the environmental remediation costs would result in an immediate massive write-off. In addition, the parties' proposals would result in continued write offs in future years for amounts not recovered due to sharing.[58] Such write-offs would have devastating effects, would cause long-term harm to the Company's financial profile, and would harm customers as well.

c. The Company's Demonstration of the Prudence of Its Environmental Remediation Actions Is Uncontested.

Over three rounds of testimony, the Company has provided substantial evidence demonstrating that its environmental remediation expenses were prudently incurred to date. At

[53] NWN/1500, Miller/2, lines 11-16. The $64.5 million includes $51.8 million of total expenditures to date plus accrued interest of $18.1 million, partially offset by $5.4 million of environmental costs expensed in prior years.
[54] NWN/1500, Miller/2, line 17-Miller/3, line 1.
[55] *Id.* at 15, lines 3-7; NWN/1600, Middleton/28, lines 20-21.
[56] NWN/1800, Anderson/10, lines 1-3.
[57] *Id.*, lines 3-4.
[58] NWN/1800, Anderson/10, lines 12-13.

the hearing, Ms. Johnson stated that Staff had reviewed the "fairly extensive" documentation,[59] and further agreed that Staff has not raised any question about prudence after reviewing the material.[60] This testimony was consistent with the positions taken by all parties, none of whom questioned the prudence of the Company's actions.

Nevertheless, on cross-examination, Ms. Johnson made the surprising declaration that Staff had *not* in fact conducted a prudence review on the Company's environmental remediation expenses.[61] When questioned, Ms. Johnson explained that Staff typically does not "review for prudency until [the deferral] begins to be amortized,"[62] and that for the $64.5 million already deferred by NW Natural, Staff should "look at that for prudence right now."[63]

To say that the Company is mystified would be an understatement. As Ms. Johnson conceded on the stand, the Company filed several hundreds of pages of documentation demonstrating the prudence of its environmental remediation costs.[64] In his direct testimony, Mr. Miller explicitly requested a "prudence determination for costs deferred through September 30, 2012 in this proceeding."[65] In Mr. Miller's rebuttal testimony he clearly stated that "[t]he Company believes that the evidence it has offered in this proceeding is substantial and more than sufficient to allow the Commission to determine that the Company's costs are prudently incurred and should be recovered through the mechanism the Company has proposed."[66] Moreover, Mr. Miller specifically pointed out that the parties were not contesting the Company's demonstration of prudence, stating: "Staff does not contend that any of the environmental remediation costs NW Natural seeks to recover are imprudent or unreasonable,"[67] and "[l]ike

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[59] Tr. 17, lines 7-19.
[60] Tr. 17, lines 7-16; Tr. 18, lines 2-5.
[61] Tr. 17, line 20-Tr. 18, line 11.
[62] Tr. 18, lines 12-19.
[63] Tr. 37, lines 19-23.
[64] Tr. 17, lines 17-19; NWN/2600, Miller/2, line 19-Miller/3, line 20.
[65] NWN/1500, Miller/11, lines 1-3.
[66] NWN/2600, Miller/4, lines 4-7.
[67] *Id.*, lines 10-11.

Staff, NWIGU-CUB does not challenge the prudence of any costs incurred by NW Natural in its environmental remediation."[68] Based on this record, there was no question that the Company was requesting that the Commission make a finding of prudence in this proceeding.

The Company is now in the position of requesting that the Commission find its costs to be prudent, in the absence of any recommendation from Staff. While this is not where the Company hoped to be, the Company believes that the Commission should make this determination. It is true that Ms. Johnson testified that Staff was not prepared to state whether or not it believed the costs were prudently incurred. On the other hand, Staff *did* review the extensive documentation, and presumably would have commented on any costs it believed were not prudently incurred. Moreover, it can be fairly assumed that the other parties—who presumably noted that the Company was requesting a prudence review—would have pointed out any costs they believed were imprudent. For these reasons, the Company believes that the Commission can and should find that the Company's environmental costs have been prudently incurred.

Moreover, as a matter of law, the Company is entitled to a finding of prudence. As explained by the Commission: "When the parties review the company's filings, they identify the issues with which they are concerned. If a party does not propose a change in a particular item, or if the Commission does not raise the issue, the item is adopted when the Commission issues its final order. In this way, parties can review and challenge the utility's proposed results of operations in a public forum."[69] The Commission has also stated that "once a utility has met the initial burden of presenting evidence to support its request, 'the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue

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[68] *Id.* at 5, lines 16-17.
[69] *Re Portland Gen. Elec. Co.*, Docket UE 47, Order No. 87-1017 (Sept. 30, 1987).

requirement.'"[70] Here, the Company presented substantial evidence supporting a finding of prudence and no party has presented evidence to the contrary.

d. Neither Staff, NWIGU, Nor CUB Present a Reasonable Rationale for Imposing Sharing on Past or Future Amounts.

At hearing, Ms. Johnson provided justification for Staff's sharing proposal, testifying that "sharing helps incentivize the Company to do a really good job on not only holding their costs down when they do a remediation project but to go after partners that should be sharing the cost, which they have done, and to go after aggressively the insurance companies, which they also have done."[71] However, Ms. Johnson's own testimony suggests that the Company already has more than sufficient incentive to manage its costs as responsibly as possible. Ms. Johnson agrees that the Company has been diligently seeking insurance payments and recovery from third parties.[72] Moreover, after reviewing the extensive documentation provided by the Company, Staff has not offered evidence of any imprudent costs. There is therefore no reasonable basis to believe that the sharing mechanisms proposed will provide a needed incremental incentive to control costs, beyond the incentives already placed on NW Natural by the Commission's ongoing prudence reviews, the Company's desire to keep its product competitively priced, and its concern for its customers' rates.

And of course, there is no logical basis for suggesting that Staff's sharing proposal could serve as an incentive regarding the approximately $64.5 million that the Company has already incurred.[73] Ms. Johnson stated that sharing is nonetheless appropriate for these past amounts because "it would serve as an overall incentive to the Company to know that this sharing could

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[70] *Re Portland Gen. Elec. Co. 2012 Annual Power Cost Update Tariff*, Docket UE 228, Order No. 11-432 at 3 (Nov. 2, 2011).
[71] Tr. 40, lines 12-18.
[72] Tr. 40, lines 12-18.
[73] Tr. 48, lines 16-22.

be proposed at any time for that particular purpose."[74] This reasoning is nonsensical, and confirms that Staff's proposal is more akin to a punishment than an incentive.

Ms. Johnson also testified that the Commission has a "long history with NW Natural . . . of sharing costs."[75] But Ms. Johnson did not provide an example of another utility in Oregon sharing environmental remediation or similar costs.[76] And it is clear that utilities do not share costs as a general matter.

In addition to arguing the same incentive point that Staff does, NWIGU and CUB argue that the Company should not recover these costs because NW Natural's investors took the risk of operation, and shareholders received the upside of that risk because the Company incurred no remediation costs in the past.[77] NWIGU and CUB's argument misapplies regulatory principles. Utility rates of return are not set based on the expectation of a loss of a significant amount of prudently-incurred expenses.[78] CUB acknowledges that "a regulated entity has substantially less risk than a competitive company," but that utilities still must face some risk, or else their ROEs would be closer to government bonds.[79]

The Company agrees with CUB on this general point, but disagrees that these extraordinary and unexpected environmental remediation costs were a type of risk any party anticipated when the MGPs were in operation. There is no evidence in the record that this was the case, and the Company has presented evidence in the testimony of Andrew Middleton that during historic MGP operations (1) there was widespread reliance on the manufacturing of gas to provide utility service (in fact, natural gas was not available in the region at the time) and (2) the potential environmental consequences of the operations were not understood.[80] If these

[74] Tr. 48, lines 22-25.
[75] Tr. 22, lines 1-5.
[76] *See* Tr. 22, lines 1-11.
[77] NWIGU's Prehearing Brief at 3; CUB's Prehearing Brief at 33.
[78] Tr. 55, lines 3-9.
[79] CUB's Prehearing Brief at 32-33.
[80] NWN/1600, Middleton/3, 19, 38-39.

costs *had* been expected at the time, they would have been included in rates.[81] Past returns reflected risks expected at that time, and the risk of disallowance of prudently-incurred expenses associated with environmental remediation related to laws that were not even in existence at the time was not a factor.[82]

e. NWIGU and CUB's Intergenerational Equity Argument is not a Basis for Disallowing Prudently-Incurred Expenses.

In their prehearing briefs, NWIGU and CUB continue to argue that customers should not be responsible for the environmental remediation costs because they are not associated with providing natural gas to current customers.[83] NWIGU and CUB are referencing the ratemaking policy of intergenerational equity, through which "the Commission attempts to equitably allocate . . . costs and benefits to customers over time so no one generation of customers receives an inequitable share."[84] Intergenerational equity is a policy consideration in determining the period of time over which costs should be spread—it is not a basis for disallowing prudent costs.

The Commission has a statutory responsibility to ensure that rates are just and reasonable and to balance the interests of utilities and customers.[85] These rates must be "[s]ufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[86] Furthering the policy of intergenerational equity at the expense of the Commission's statutory ratemaking responsibilities is unlawful.

But, even more to the point, NWIGU and CUB's position is at odds with the facts in this case. There is no genuine dispute that the costs that would be flowed through the SRRM are *current* costs, imposed by *current* laws. NW Natural's mechanism actually insures that these costs are collected from ratepayers close to the time at which these costs are incurred,

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[81] Tr. 56, lines 16-24.
[82] Tr. 55, lines 10-15. *See* NWN/1600, Middleton/3, 19, 38-39.
[83] NWIGU's Prehearing Brief at 3; CUB's Prehearing Brief at 31-32.
[84] *Re Application of Portland Gen. Elec. Co. for an Investigation into Least Cost Plan Plant Retirement*, Docket DR 10 *et. al.*, Order No. 08-487 at 66 (Sept. 30, 2008).
[85] ORS 756.040(1).
[86] ORS 756.040(1)(b).

implementing the "matching principle" that is aimed at furthering intergenerational equity. In reality, therefore, NW Natural's proposed SRRM actually furthers the goals of intergenerational equity, and improves upon the status quo, which is a deferral of such current costs for payment by future ratepayers.

f. CUB's Argument that Customers Had No Control over Environmental Remediation Expenses Is Not a Reasonable Basis for Disallowing Costs.

CUB also continues to argue that customers should not pay all environmental remediation expenses because customers "had no knowledge or input into the operation of these facilities. . . [and] were merely consumers of services without any control or knowledge of the possible effects on the environment of the operations taking place on the sites."[87] Under CUB's theory, customers would not pay any expenses because they do not have input into the operation of the utility as a general matter.

In addition, there is no credible evidence in this case that NW Natural was aware of the possible environmental effects or future costs associated with MGP operations at the time of their operation. NWIGU and CUB attempt to smear the Company by providing an utterly unsupported accusation to the contrary. However, NWIGU-CUB's only support for this proposition is a quotation from a claimed MGP expert who is not a witness in the case—**a statement that they claim they do not offer for the truth of the matter asserted therein**.[88] Given the gravity of accusation, and fact that there is not a shred of legitimate evidence to support it, NWIGU-CUB's argument is irresponsible and should be disregarded completely.

[87] CUB's Prehearing Brief at 28.
[88] *Re NW Natural's Request for a General Rate Revision*, Docket UG 221, NWIGU's and CUB's Response to NW Natural's Motion to Strike at 7 (Aug. 8, 2012).

g. The Commission Has Not Previously Imposed Sharing of Environmental Remediation Expenses or Similar Expenses and Should Not Start Now.

Commission precedent indicates that all prudently-incurred remediation costs are recoverable in rates, not a portion of such costs as proposed by the other parties. For instance, decommissioning costs, which generally include substantial costs for environmental remediation—are routinely included in customer rates. In Order No. 07-375, the Commission approved PacifiCorp's request for an accounting order regarding the decommissioning of the Powerdale Hydro Generating Plant.[89] The order allowed PacifiCorp to record decommissioning costs of approximately $6.3 million with provisions for a final true up for actual expenditures.[90] Staff agreed that the accounting order with true up provisions requested by PacifiCorp is the appropriate method to account for decommissioning costs.[91] PacifiCorp amortized the entire deferred amount.[92] Staff did not propose any sharing mechanism.

Similarly, in Docket UE 230, the Commission allowed Portland General Electric Company (PGE) to increase rates in order to include in revenue requirement the increased decommissioning costs resulting from changing the planned Boardman plant closure from the year 2040 to 2020.[93] As of June 2011, PGE had collected $24.1 million from customers to be applied to the decommissioning cost for Boardman and estimated $44.8 million for its share of total decommissioning.[94] Sharing was not an issue in that case.

Finally, in Docket UP 168, the Commission appeared to assume that environmental mitigation costs are recoverable in rates. In that docket, the Commission approved PacifiCorp's sale of the Centralia plant and Centralia coal mine. In assessing whether shareholders should

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[89] *Re PacifiCorp Application for an Accounting Order Regarding Closure of the Powerdale Hydro Generation Plant*, Docket UM 1298, Order No. 07-375 (Aug. 23, 2007).
[90] *Id.*, Appendix A at 2.
[91] *Id.*, Appendix A at 3.
[92] *Re PacifiCorp's Request for a General Rate Revision*, Docket UE 246, PAC/1100, Dalley/34-35 (Mar. 1, 2012).
[93] *Re Portland Gen. Elec. Advice No. 11-07 Schedule 145 Boardman Adjustment Update*, Docket UE 230, Order No. 11-242 (July 5, 2011).
[94] *Id.*, Appendix A at 3.

receive a share of the gain on the sale, the Commission addressed PacifiCorp's argument that it will bear certain future risks associated with the plant and mine.[95] The Commission discounted PacifiCorp's argument, finding that: "[t]he risks associated with the environmental mitigation and mine reclamation are supposedly the risks PacifiCorp is trying to avoid by the sale. The risks associated with replacement power are also risks PacifiCorp is voluntarily opting for by pursuing this sale. In any event, those costs are recoverable in rates."[96]

When facing remediation costs similar to those at issue in this case, the Commission has allowed them into rates without sharing and has indicated that such costs are recoverable in rates. The Commission should adhere to this precedent in this case.

h. Allowing Recovery with No Sharing Is Consistent with the Treatment for Many Utilities Around the Country.

CUB states that several other state commissions have required sharing of environmental remediation costs relative to MGP plants.[97] While this may be true, the Company's review shows that the majority of state public utility commissions allow such costs to be recovered in rates with no sharing.[98] Significantly, the two state supreme courts that have addressed the issue, Minnesota and Illinois, have found that a mechanism with no sharing is appropriate.[99] The Illinois Supreme Court found that the Illinois commission's decision requiring "utilities to share the statutorily imposed costs of coal-tar remediation was 'not supported by substantial evidence based on the entire record of evidence.'"[100] The Illinois commission had allowed full recovery of the remediation expenses, but without interest during amortization, which the court

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95 *Re Application of PacifiCorp for an Order Approving the Sale of its Interest in the Centralia Steam Electric Generating Plant and Related Other Assets*, Docket UP 168, Order No. 00-112 at 9 (Feb. 29, 2000).
96 *Id.* at 9-10
97 CUB's Prehearing Brief at 32.
98 *See* NWN/2600, Miller/15, line 21-16, line 9.
99 *Minn. Dep't of Pub. Serv. v. Minn. Pub. Utils. Comm'n*, 574 N.W.2d 408 (Minn. 1998); *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 166 Ill.2d 111 (1995).
100 *Citizens Util. Bd.*, 166 Ill.2d at 132.

interpreted as sharing.[101] The commission had based its decision in part on the "lack of a relationship between the coal-tar cleanup expenses and current utility service."[102] The court found that this decision "conflicts with the Commission's past treatment of mandatory operating expenses such as taxes, which the Commission has always allowed a utility to recover from its customers, regardless of the relationship of the taxes to the provision of current service."[103]

i. Allowing Recovery of Environmental Remediation Expenses Through an Automatic Adjustment Clause Is Not a Basis for Imposing Sharing.

Staff supports the implementation of an automatic adjustment clause (AAC) as a benefit to customers, because "it allows less interest to accumulate."[104] Additionally, the Company explained in testimony that the reasons it proposes the use of an AAC is to benefit customers, by allowing costs to be spread over a number of years, by allowing insurance recoveries to flow to the benefit of customers, and by reducing the size of deferrals.[105] Nevertheless, Ms. Johnson bases her sharing proposal in part on the fact that the Company was asking for an AAC, stating that an AAC request is different from a request for an accounting order or a request in a general rate case.[106] If Staff is supporting the use of an AAC because it benefits customers, it does not make sense to disallow prudently-incurred costs because the recovery mechanism is an AAC. In addition, Ms. Johnson stated that Staff would be proposing sharing even if recovery was through a mechanism other than an AAC.[107] The Commission should therefore disregard Staff's reliance on the use of an AAC as the basis for sharing.

In conclusion, Company acted prudently every step of the way in this process. All evidence in this case supports the Company's view that Company acted prudently, consistent

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[101] *Id.* at 124-25.
[102] *Id.* at 129.
[103] *Id.*
[104] Tr. 35, lines 5-20.
[105] NWN/1500, Miller/16-17.
[106] Tr. 33, line 23-Tr. 34, line 6.
[107] Tr. 40, lines 9-10.

with current practices in place at the time, when it manufactured gas. And all evidence demonstrates that the Company continues to prudently seek to manage remediation costs—including vigorous pursuit of insurance recoveries. As such, there is no basis in the record to impose sharing.

2. Staff Has Presented No Basis for Applying a Return Lower than Rate of Return on Deferred Amounts Before Amortization.

Staff argues that the deferred amounts in the SRRM should earn at the Modified Blended Treasury Rate (MBTR), rather than applying the Commission's policy of earning at the Company's rate of return (ROR) prior to amortization and at the MBTR during amortization. Staff claims this proposal is because "[t]he risk associated with an automatic adjustment clause is more akin to risk once amortization is approved than the risk related to uncertain recovery in an uncertain and potentially long period of time."[108] However, on cross-examination, Ms. Johnson agreed that the deferred environmental remediation costs would be subject to a prudence review and, for that reason, could be disallowed.[109] Ms. Johnson also agreed that there is a risk that a future Commission may change the AAC, including increasing sharing from what is decided in this case.[110] Therefore, Staff's own testimony in this case indicates that the risk associated with the Company's AAC is higher than the risk for amounts approved amortization.

Furthermore, Staff's argument about the risk associated with recovery ignores the fact that, under the SRRM, NW Natural will in fact be required to finance environmental remediation expenses over a long period of time on behalf of customers. This means that NW Natural will finance these costs with debt and equity, making its cost of capital the appropriate measure of the carrying costs associated with this financing. The Commission has previously found as much in Docket UM 1147, when it found that "deferred accounts represent an investment, to the

[108] Staff's Prehearing Brief at 12.
[109] Tr. 30, lines 13-18.
[110] Tr. 49, lines 1-10.

extent the utility must carry costs that are deferred. We also agree, as we already determined in Order No. 05-1070, that funding of deferred accounts, at least until some amount is amortized, should not be culled out from other utility investments."[111]

Finally, the Commission has already addressed and rejected the argument that Staff espouses in this case in Docket UM 1147. Staff argued in that case that the ROR should not be applied to deferred amounts.[112] The Commission rejected Staff's argument and decided that the utility's ROR should be applied to deferred accounts prior to amortization.[113]

As Ms. Johnson noted at the hearing, under the Commission's UM 1147 policy, a party may request an exception to the general policy of applying MBTR during amortization.[114] However, since the Commission adopted the UM 1147 policy, the only modification to the policy set forth in UM 1147 was to *increase* the interest rate applied to Idaho Power's deferral in amortization.[115] There is not sufficient evidence in this case to support an exception to implement a lower interest rate for SRRM amounts prior to amortization.

3. The SRRM Should Not Be Subject to an Earnings Test.

Staff, CUB, and NWIGU propose that the SRRM be subject to an earnings test. While none of the parties have made their proposed earnings tests clear, one potential proposal is that the Commission deny recovery of prudently-incurred remediation costs in years where their recovery would take the Company over its allowed ROE.[116] At hearing, Mr. Miller explained that under such a mechanism, if the Company overearned by $1 million, $10 million of

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[111] *Re Staff Request to Open an Investigation into Deferred Accounting*, Docket UM 1147, Order No. 06-507 at 6 (Sept. 6, 2006).
[112] *Re Staff Request to Open an Investigation into Deferred Accounting*, Docket UM 1147, Staff Opening Comments re. Issues List at 5 (Oct. 7, 2004).
[113] *Re Staff Request to Open an Investigation into Deferred Accounting*, Docket UM 1147, Order No. 05-1070 at 13-14 (Oct. 5, 2005).
[114] *Re Staff Request to Open an Investigation into Deferred Accounting*, Docket UM 1147, Order No. 08-263 at 16 (May 22, 2008).
[115] Tr. 47, lines 19-Tr. 48, line 4; *Re Staff Request to Open an Investigation into Deferred Accounting*, Docket UM 1147, Order No. 08-477 (Sept. 23, 2008).
[116] Tr. 57, lines 18-22.

environmental expenses could be disallowed.[117] Clearly, an earnings test that would function to disallow prudently-incurred expenses thereby resulting in underearning would be unlawful.[118]

Mr. Miller further explained that even if the parties' proposals would allow the Company to collect environmental remediation expenses up to the Company's authorized ROE, an earnings test would be inappropriate.[119] These expenses will be amortized many years into the future, so the earnings test would function as a cap on earnings.[120] It would be inappropriate to effectively cap earnings at a maximum level for many years, especially when there is no earnings floor.

If the Commission does impose an earnings test, the test should include remediation expenses and other deferred amounts that the Company expended in the years at issue, because the Company paid them even if they were not recognized.[121] Staff argues that NW Natural's proposal is off-base because the objective of an earnings test is "an overall review of earnings, not an account-by-account comparison."[122] Staff misconstrues NW Natural's concern. The issue is that in the years in question, the Company paid deferred amounts and invested in pension contributions for the benefit of customers that are not reflected in the Company's earnings. It would be inappropriate to ignore these significant investments and expenses if the goal is to determine whether the Company could have absorbed the environmental remediation expenses in a given year and remained at its authorized ROE.

Staff argues that under Oregon law, the Commission cannot move previously-deferred accounts into a newly established AAC account without imposing an earnings review.[123] The

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[117] Tr. 58, lines 2-14.
[118] Rates must provide a return that is "(a) Commensurate with the return on investments in other enterprises having corresponding risks; and (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital." ORS 756.040.
[119] Tr. 59, line 25-Tr. 60, line 21.
[120] Tr. 60, lines 4-21.
[121] NWN/2600, Miller/20, lines 1-8; NWN/2200, Feltz/33, lines 1-9.
[122] Staff's Prehearing Brief at 14.
[123] *Id.* at 12.

relevant statute states that "unless subject to an automatic adjustment clause" deferred amounts may be allowed into rates only after a review of the utility's earnings at the time of application to amortize the deferral.[124] Because the amounts to be amortized in this case would be subject to an AAC, this provision does not apply. As far as NW Natural is aware, the Commission has not required an earnings review for the first amortization of an amount subject to an AAC. The plain language of the statute does not support Staff's new construction of the statute.

Finally, as Mr. Miller testified at hearing, it would be almost impossible to rationally apply an earnings test to the environmental remediation amounts at issue. In addition to expenditures, the total amounts deferred include the receipt of insurance proceeds and recovery from other potentially responsible parties.[125] Under the Company's proposal, these amounts would be netted against the environmental remediation expenses to reduce the SRRM amounts included in rates. No party has explained how these amounts would be allocated in the earnings test.

Finally, CUB incorrectly notes in its brief that the Company "already has insurance policies to cover all of these costs but still wants to hold customers on the hook."[126] However, as explained in the responses to Bench Requests, the Company cannot know what amounts it will recover from its insurers, and CUB's point is therefore not helpful or to the point.

4. NWIGU's Proposed Rate Spread Should Be Rejected.

NWIGU argues that the proposed SRRM schedules should not apply to industrial customers, who NWIGU claims are already paying "excessive" margin charges.[127] NW Natural interprets this position as one related to rate spread, rather than as an argument against NW Natural's recovery of prudently-incurred environmental remediation costs. However, NW

[124] ORS 757.259(5).
[125] Tr. 58, lines 19-22.
[126] CUB's Prehearing Brief at 31.
[127] NWIGU's Prehearing Brief at 4.

Natural believes that NWIGU's proposal should be rejected in any event. Because NW Natural's industrial customers also benefitted from the availability of gas from MGP operations, they should be included in the recovery of the costs associated with remediation.

5. CUB's Argument Related to the Gasco Pumping Station Are Off-Base.

CUB argues that the pumping station at Gasco should not be included in rate base on the basis that it is irrelevant to this case because it is yet to be built.[128] Schedule 184 provides that "The pumping station shall be considered in service for rate recovery purposes on the date that the Company submits an attestation to the Commission that the Pumping Station is completed and operational."[129] Therefore, the Gasco pumping station will be included in rates only after it is complete.

The Company proposed Schedule 184 in order to make clear that it was willing to benefit customers by having the costs associated with this facility recovered over a 30-year period, rather than the five years under the SRRM that would otherwise apply. It is for this reason that Schedule 184 provides different treatment for this facility—not an attempt to add amounts to rate base before the project is used and useful as CUB seems to have assumed.

E. The Commission Should Grant the Company's Pension Recovery Proposal.

Through its testimony and briefing to date, the Company has demonstrated the following:

1. As a result of the Pension Protection Act of 2006 (PPA) and the financial crisis of 2008 and 2009, the Company has been obligated to make large pension contributions that it otherwise would not have been forced to make.

2. These pension contributions are in excess of Financial Accounting Standard (FAS) 87 expense, and as such have resulted in a prepaid asset that is currently at approximately $25 million and expected to average approximately $39 million during the Test Year.[130]

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[128] CUB's Prehearing Brief at 27.
[129] NWN/1701, Original Sheet 184-1 (exhibit to Onita King's direct testimony).
[130] Exhibit NWN/2006, Feltz/1.

3. Under the Company's current balancing account, which provides only for the recovery of FAS 87 expense, the Company will never recover this prepaid asset.

For these reasons, the Company has proposed that it be allowed to include in rate base the amount of the prepaid asset (as expected in the Test Year) so that it can recover its return on its investment, and it proposed an amortization of the associated amounts so that it can receive the return of these contributions made on behalf of customers.

All parties have opposed the Company's proposal, offering various legal theories and policy arguments. However, as demonstrated at hearing, no one has contradicted the basic facts expressed above—that the Company has been required by law to make substantial contributions that benefit customers, and that unless the Commission alters its recovery mechanism, NW Natural will never recover its prudently-incurred costs.

NW Natural recognizes that it is asking the Commission to alter a pension recovery policy that served utilities and customers well over many years—and it does not do so lightly. However, with its payments in excess of FAS 87 at nearly $25 million at year end 2011, it is time for the Commission to depart from its use of FAS 87 as a recovery mechanism, and adopt a mechanism that will sustainably serve NW Natural's customers and shareholders into the future.

1. The Parties Agree on the Problem.

In one sense, parties' positions on the pension issue appear to be diametrically opposed. NW Natural has pointed out that its current recovery of pension costs through its FAS 87 balancing account has created significant and growing prepaid pension asset and has therefore requested that the Commission allow the Company to recover a return on its prepaid pension asset by adding that amount to rate base and allowing an eight-year amortization of the balance to allow a return of the contributions. Staff and intervenors argue that the Commission should completely reject NW Natural's proposal and make no changes at all to its current recovery under the FAS 87 balancing account recovery. However, as confirmed through testimony at the hearing, and upon closer review of the testimony, common ground emerges: while the parties do not agree on the solution, they agree quite substantially on the problem.

a. Agreement No. 1: The Company Is Making Pension Contributions Far in Excess of Its FAS 87 Expense, Resulting in a Substantial Prepaid Asset.

The Company's calculation of its prepaid asset is reflected in Exhibit NWN/2006. As of December 31, 2011, the prepaid asset is over $25 million, and with additional contributions is expected to be over $39 million during the Test Year.[131] Moreover, given the expected operation of the Company's FAS 87 balancing account, the Company's actuaries project that by 2021, the prepaid pension asset will total approximately $91 million.[132]

No party has filed testimony disputing the Company's calculation of its current prepaid asset and at hearing, Staff witness Mr. Cimmiyotti confirmed that he has not taken issue with the Company's calculation of its prepaid asset as of that date.[133] Moreover, no party has produced any evidence contradicting the Company's projection that the prepaid asset will total approximately $91 million by 2011. So there appears to be agreement that NW Natural's unrecovered pension costs are substantial and growing.

b. Agreement No. 2: Under the Current FAS 87 Balancing Account, the Company Will Never Recover Its Prepaid Asset.

Under the current FAS 87 balancing account, the Company will eventually recover its actual FAS 87 ***expense*** over time. However, it will never recover the cost of the pension ***contributions*** made in excess of FAS 87 expense. Exhibit NWN/2006 demonstrates the workings of the balancing account—into which the Company is currently deferring excess FAS 87 expense above that recovered in rates. When FAS 87 turns to a negative number, the balancing account will grow smaller, and after it nets to zero, the Company would be expected to begin refunding to customers—thus ensuring that the Company will never recover its prepaid pension asset.

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[131] In his surrebuttal testimony, Mr. Feltz explained that the recent passage of the MAP-21 Act might affect contributions in the Test Year. NWN/3100, Feltz/16, line 17-Feltz/17, line 13. He also proposed a solution for any variance.

[132] NWN/3100, Feltz/22, lines 4-16; Exhibit NWN/2006.

[133] Tr. 116, lines 20-23.

At hearing, Mr. Cimmiyotti agreed with the predicament created for NW Natural by the current recovery mechanism. On cross-examination, he was asked straight out whether he believed that the Company would ever recover its prepaid pension asset under the current FAS 87 balancing account. Mr. Cimmiyotti initially avoided the question; however, when pressed, he had to admit that under the current FAS 87 balancing account treatment, the Company can never recover the prepaid pension asset.[134] No other party has argued to the contrary.[135]

c. Agreement No. 3: The Company's Contributions Have Been Prudently Made for Customers' Benefit.

The Company has explained that it is required to make the contributions under the PPA. No party has questioned this fact, or that the contributions were prudently made.

So, there is general agreement that the Company is contributing millions of dollars to benefit customers, that those contributions are prudently made, and that unless there is a change in its recovery mechanism, it will never recover those contributions. Where the parties differ is their response. The Company is proposing a solution. Staff and intervenors recommend that the Commission do nothing.

2. Staff and Intervenors' Arguments as to Why the Commission Should Not Act to Remedy the Problem Are Without Basis in Law or Policy.

The parties have offered several reasons why they believe that the Commission should not take action to solve the problem. However, at hearing it became quite clear that the reasons offered do not bear scrutiny.

a. NW Natural's Proposal Does Not Violate FAS 87.

First, Staff has argued that to allow the Company to recover excess contributions would somehow constitute a violation of FAS 87.[136] While Mr. Cimmiyotti's reasoning for this position

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[134] Tr. 117 line 11-Tr. 120, line 7.
[135] It is worth noting that in its Prehearing Brief, CUB reiterated the testimony of its expert, Hugh Larkin, who opines that current market conditions requiring the substantial prepayments is temporary. However, neither CUB nor Mr. Larkin go so far as to suggest that the temporary nature of the market conditions means that the Company will ever recover its substantial prepaid assets. CUB's Prehearing Brief at 23.
[136] Staff/900, Cimmiyotti/3, line 17-Cimmiyotti/4, line 2.

is not particularly clear, he seems to believe that because FAS 87 provides a method for *accounting for pension expense*, it somehow controls and limits the way in which pension costs may be recovered by a utility in customer rates. At hearing, Mr. Cimmiyotti continued to take this position, even opining that utilities that recover prepaid pension expenses and pension contributions in rates "would have to be" in violation of FAS 87, and that the state public utility commissions that have approved recovery of pension contributions and prepaid assets were allowing such violations.[137] There is no basis for the idea that FAS 87 restricts the method by which utilities may recover pension costs; this argument should be rejected out of hand.

It is also significant that Mr. Cimmiyotti seemed to resist the idea that other utilities do in fact recover their prepaid pension assets as additions to rate base.[138] There are numerous decisions in other jurisdictions specifically finding that prepaid pension assets should be included in rate base. For example, in 1987, the Missouri Public Service Commission specifically found that "[t]he appropriate amount of prepaid pensions is treated as an asset and made part of the Company's rate base.[139]

In 2003 the Department of Telecommunications and Energy of the Commonwealth of Massachusetts (DTE) issued an order in which it discussed the then-new SFAS Nos. 71, 87, and 106. The DTE specifically found as follows:

> As concerns utility pension and PBOP in particular, the Federal Energy Regulatory Commission and, for example the regulatory agencies of a number of states include prepaid pension in rate base at the full cost of capital. We cite these instances from other jurisdictions to show the unexceptional nature of the issues before us. Cities of Greenwood and Seneca, SC v. Duke Power Company, 77 F.E.R.C. Para 63,017, at item 14 (Initial Decision)(1996).[140]

The Department also stated that:

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[137] Tr. 132, line 1-Tr. 133, line 2.
[138] Tr. 123, line 4-126, line 9.
[139] *Staff of the Mo. Pub. Serv. Comm'n v. Union Elec. Co.*, 90 P.U.R.4th 400 (Dec. 21,1987).
[140] *Id.* at 3, n.2.

> [t]here really is no principled difference between the companies investment in rate base and their investment in pensions and PBOP. Both are long term investments and should be similarly treated.[141]

Thus, there should be no argument that the addition of a utility's prepaid pension asset to rate base is either unusual or a violation of FAS 87.

b. NW Natural's Proposal Does Not Constitute Retroactive Ratemaking.

In addition, Staff argues that the Commission should not allow recovery of the prepaid pension asset given that the Company did not file a deferred accounting application prior to the costs being incurred. Similarly, both CUB and NWIGU argue that recovery of the prepaid pension asset would constitute retroactive ratemaking. However, as demonstrated by Mr. Cimmiyotti's testimony at hearing, these positions ignore the character of pension contributions and are entirely inconsistent with the Commission's statues and policies.

As discussed in NW Natural's Prehearing Brief, the Company's pension contributions are prepaid assets—which are to be included as an addition to rate base. They are not expenses, and therefore not subject to the deferral statute under which utilities may track expenses and revenues.[142] It is worth noting here that, contrary to certain inferences in Staff's and CUB's filings in this case, the Commission *did* authorize the Company to record the prepaid asset as a regulatory asset. In Docket UM 1293, the Commission approved the Company's application for an accounting order to record its Accumulated Other Comprehensive Income (AOCI) related to its pension accounts as an ongoing regulatory liability.[143]

At hearing, Mr. Cimmiyotti agreed, first, that that under FAS 87, pension contributions in excess of FAS 87 expense are prepaid assets.[144] Second, Mr. Cimmiyotti also agreed that in

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[141] *Id* at 40.
[142] *See* ORS 757.259(2)(e).
[143] *Re NW Natural Gas Co. Application for an Accounting Order Regarding Treatment of Accumulated Other Comprehensive Income for Funded Status of Pension and Other Post Retirement Obligations*, Docket UM 1293, Order No. 07-030 (Jan. 29, 2007).
[144] Tr. 133, line 3-Tr. 144, line 11.

accordance with utility accounting authority Robert L. Hahne,[145] a prepaid asset represents an investment of funds *that are generally included in rate base.*[146] Finally, when presented with evidence from PacifiCorp's current rate case, Mr. Cimmiyotti agreed subject to check that at least in that case, PacifiCorp added prepaid assets to rate base, and that Staff had no objection. Thus, at least in theory, Staff agrees that in accordance with standard utility accounting, NW Natural's prepaid pension asset would properly be added to rate base. And if Staff was to be consistent with its position in PacifiCorp's rate case, no deferral of such costs would be necessary or appropriate.

CUB points to a Delaware Public Service Commission (DPSC) for support for its view that NW Natural's proposal would constitute retroactive ratemaking.[147] However, CUB seems to have completely misconstrued the facts and conclusions of that case. In *Delmarva*, the utility, Delmarva Power & Light ("Delmarva") filed a petition with DPSC to create a regulatory asset (also referred to in the order as a "deferral request") representing its pension loss—and to amortize the regulatory asset over a five year period.[148] It is true that the DPSC found that the requested recovery would constitute retroactive ratemaking, and denied the request. However, that finding is not applicable to NW Natural's request in this case.

First, Delmarva was not requesting that a prepaid pension asset be added to rate base. Instead, Delmarva was asking for the deferral of an actuarial loss based on the difference between its actual FAS 87 and the FAS 87 expense recovered in rates.[149] Thus, to begin with, Delmarva was asking to defer an expense as opposed to investor contributions. Indeed, that difference between FAS 87 pension expense and FAS 87 pension expense recovery is

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[145] Mr. Cimmiyotti agreed that Staff routinely relies on Robert L. Hahne's Accounting for Public Utilities as a standard accounting text, and further that the Commission accepts Hahne's book as a standard accounting text. Tr. 134 line 15-Tr. 136, line 12. *See* NWN/4309 at 6-7; NWN/4310 at 8.
[146] Tr. 136, line 23-Tr. 137, line 10; NWN/4311 at 8-9.
[147] CUB Prehearing Brief at 24, citing *Delmarva Power & Light Company*, 2011 WL 3863101, Del. Pub. Serv. Comm'n Docket No. 09-414/09-276T, Order No. 8011 (Aug. 9, 2011).
[148] *Id.* at ¶ 136.
[149] *Id.*

precisely what NW Natural initially sought to defer in Docket UM 1475 and that was ultimately addressed by the current FAS 87 balancing account. This fact supports the point that NW Natural has been attempting to explain: deferrals are necessary to include past expenses in rates and they are not appropriate with respect to shareholder investments.

Second, at the time Delmarva filed the request, the pension expense (loss) was already recorded in the utility's books as an expense, and further, because DPSC did not act by the end of the 2009 year, the expense remained on Delmarva's books as such.[150] Thus, Delmarva was requesting to defer an expense already incurred, and it was therefore appropriate for the Delaware commission to find that the request violated the rule against retroactive ratemaking.[151]

It should also be noted that the DPSC decision seems also to have been motivated by the fact that Delmarva's pension asset was already included in rate base.[152] In other words, at the time it requested its deferral, Delmarva was already recovering FAS 87 expense and its prepaid pension asset. Thus, in the end, the *Delmarva* case supports the Company's view that while a deferral would be necessary in the case of pension expense, it is not necessary or appropriate when adding the prepaid pension asset to rate base. And, of course that case provides yet another example of a utility recovering its prepaid pension asset.

With this point in mind, the Company responds to the Commission's question as to whether the Company can provide examples of utilities recovering their prepaid pension assets in the absence of a deferral order. In researching this question, the Company is cognizant that it is charged with "proving a negative" (*i.e.*, that a deferral was not required)—always a difficult task. That said, in addition to the cases provided in this brief, the Company found many examples of utilities recovering their prepaid pension asset. Most importantly—the Company has found no instance in which the state commission indicated that a deferral application was

[150] *Id.* at ¶ 155.
[151] *Id.*
[152] *Id.* ¶ 156.

required for the treatment. The additional cases are described in Appendix A, along with the relevant excerpts from commission orders and testimony attached.

Finally, at hearing the point was raised that PGE had just the previous day filed a petition for deferral of both excess FAS 87 expense over recoveries and return on its prepaid pension asset.[153] NW Natural agrees that a deferral application is in fact necessary for the excess FAS 87 expense; as discussed in testimony and at hearings, it was a request for a deferral that resulted in the creation of the FAS 87 balancing account in the first instance. Moreover, NW Natural understands why PGE would specifically request the deferral of its return on its excess pension contributions, given the controversy in this case. Indeed, NW Natural recently filed a deferral application relevant to its pension contributions on a going forward basis, simply as a cautionary measure given Staff's position in this case.[154] However, to be clear, NW Natural believes that Oregon law and policy compel the conclusion that prepaid assets—both the return of and return on them—should be recoverable in rates in the regular course and that a deferral application is neither necessary nor appropriate.

c. NW Natural's Ability to Earn its Authorized ROE Should Not Serve as a Reason to Deny Recovery.

Finally, at hearing Mr. Cimmiyotti also discussed another of Staff's reasons for opposing the Company's request to recover excess pension contributions—the fact that in Staff's view the Company's earnings exceeded its authorized return on equity, allowing it to absorb the excess contributions.[155] This is similar to the argument made in Staff's Prehearing Brief that NW Natural's proposal constitutes "cherry picking" of past expenses. In particular, Staff states that "[i]t is not appropriate to choose a single expense category, while ignoring all other categories and argue that because that single item increased, it should be amortized in future rates with a

[153] *See Re Portland Gen. Elec. Co. Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions*, Docket UM 1623, Application (Aug. 22, 2012).
[154] *Re NW Natural Gas Co. Application for Deferral of Costs Relating to Pension Contributions*, Docket UM 1619, Application (July 11, 2012).
[155] Tr. 117, line 11-Tr. 118, line 13.

rate of return, even though at the time the item increased the Company was financially stable and doing well financially overall."[156]

These arguments miss the mark for several reasons. First, NW Natural's excess pension contributions are not out-of-period expenses. As discussed above, they are not expenses at all. They are shareholder investments that are properly added to rate base. The Commission should no more disallow these shareholder investments because of the utility's past ability to recover ROE than it should disallow the recovery of an major new pipeline because of the utility's past ability to earn its ROE. Accordingly, the charge of cherry picking—which might conceivably be appropriate if the Company were asking to recover some increased expense—does not apply. Moreover, because pension contributions are not expenses, the Company's earnings during the relevant period do not reflect the impact of the contributions. Thus to point to strong earnings as a reason the Company should be denied recovery is both illogical and unfair.[157]

d. The Commission Should Not Delay Authorizing NW Natural to Recover its Prepaid Pension Asset.

Finally, in its Prehearing Brief Staff points out that other utilities may be underrecovering pension contributions, and argues that if the Commission is inclined to allow NW Natural recovery of its prepaid pension expense, that it should not do so in a general rate proceeding.[158] While Staff does not explain what type of proceeding would be appropriate, it appears that Staff is suggesting that the Commission open a general investigative docket to reconsider its sole reliance on FAS 87 recovery for pensions.

NW Natural objects to this approach for three practical reasons. First, the record in this case has been fully developed. All in all, the parties have filed five rounds of testimony on NW

[156] Staff Prehearing Brief at 18.
[157] To apply that argument in this instance would be as absurd as saying that major new investments in plant should not be added to rate base because the company over-earned in some past years.
[158] Staff Prehearing Brief at 19.

Natural's proposal, and by the close of this case will have filed three rounds of briefs. To put off a decision in this case would be wasteful and inefficient. Second, and more importantly, since the passage of the PPA, the Company has been required to finance the prepaid pension asset with no recovery—and each year that goes by represents another year of financing costs that the Company will never be allowed to recover. If the Commission decides to put off a decision in NW Natural's case pending the outcome of a generic investigation, the Company will continue to incur unrecoverable costs. For this reason, the Company would ask that, if the Commission decides that it cannot make a decision to allow the Company to recover the return of its prepaid pension asset at this time, that it at least grant the Company return on the prepaid pension asset, pending the outcome of a generic proceeding. Finally, the factual circumstances facing each utility are different. Resolution of this issue in a contested case in which the facts for each utility can be evaluated is necessary to account for these differing circumstances.

F. The Commission Should Find that the Company's Development of the Mid-Willamette Valley Feeder Was Prudent.

The Company has included in revenue requirement costs associated with the Perrydale to Monmouth and Monmouth Reinforcement phases of the MWVF.[159] In its Prehearing Brief, NW Natural addressed the arguments surrounding the MWVF in substantial depth, and so only repeats here and emphasizes certain points.

The Company provided testimony, not contradicted by any party, that both Staff and the Company have had concerns regarding the reliability of service in the Albany-Corvallis area. The Company evaluated its system and determined that the only feasible way to address this concern is to develop a second path to deliver gas to the Albany-Corvallis area. The Company further determined that completing the MWVF, two phases of which had already been

[159] The two phases of the MWVF included in this case do not include bare steel replacement. Tr. 222, lines 8-9.

constructed, would be the most cost effective way to do so, and would provide additional system benefits as well.[160]

Despite these undisputed facts, the parties argue that costs associated with the Perrydale to Monmouth and Monmouth Reinforcement phases of the MWVF should be disallowed because they were not selected for completion by NW Natural's Integrated Resource Plan (IRP),[161] and further, that the Company did not sufficiently analyze the investment.[162] However, as discussed below, these arguments are nothing but red herrings—distractions from the key points that a reliability issue exists that should be remedied, and that there is no more cost effective way to remedy that issue than the one chosen by the Company.

1. Applicable Law

The issue relevant to the MWVF is whether the Company's development of the project was prudent. In reviewing prudence, "the Commission examines the objective reasonableness of a utility's actions at the time the utility acted: 'Prudence is determined by the reasonableness of the actions based on information that was available (or could reasonably have been available) at the time.'"[163] The Commission evaluates whether the "decision was objectively reasonable, taking into account established historical facts and circumstances."[164] If so, "the utility's decision must be upheld as prudent even if the record lacks detail on the utility's actual subjective decision making process."[165]

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[160] NWN/2200, Yoshihara/13-16.
[161] Staff's Prehearing Brief at 21; CUB's Prehearing Brief at 16.
[162] Staff's Prehearing Brief at 21; NWIGU's Prehearing Brief at 6; CUB's Prehearing Brief at 18.
[163] *Re Portland General Electric Co.*, Docket UE 196, Order No. 10-051 at 6 (Feb. 11, 2010).
[164] *Re Application of PacifiCorp for an Accounting Order Regarding Excess Net Power Costs, et* al, Dockets UM 995/UE 121/UC 578, Order No. 02-469 at 5 (July 18, 2002) [hereinafter Order No. 02-469].
[165] *Id.* at 5.

2. **The MWVF Is Needed Now to Address Reliability Concerns in the Albany-Corvallis Area.**

As the Company explained in its Prehearing Brief, the IRP is used to develop long-term resource plans for meeting resource needs on a least-cost, least-risk basis.[166] The IRP is not generally used to model distribution reliability. Mr. Zimmerman's characterizations at hearing of the IRP as being used to model distribution reliability are not consistent with the IRP Guidelines or the Company's acknowledged IRPs.[167]

Staff and the Company agree on two important facts related to the prudence of the MWVF. *First*, the parties agree that a reliability issue exists because the Albany-Corvallis area is served by a single-feed system. Both parties agree that this area is the largest population served by the Company that is susceptible to a single failure on a single source of supply.[168] As explained by Mr. Zimmerman at hearing: "any time a company mentions single-feeder systems . . . or other kinds of problems with pipeline systems, we're always concerned about whether there's going to be disruptions to customers. That's normal."[169] Moreover, Mr. Zimmerman explained that Staff asked the Company to model disruptions in the 2011 IRP, because Albany-Corvallis is served by a single-feed system and Staff wanted to understand the implications of a disruption on the Grants Pass Lateral.[170] *Second*, Staff agrees that building the MWVF will address this reliability concern.

Despite the agreement on these two points, Staff still contends that NW Natural should not recover the costs associated with the MWVF. Staff's position is not that the MWVF will not address the reliability issue, but that it should not have been built until 2019.[171] Staff's position is based on the fact that when a disruption of the Grants Pass Lateral was modeled in the IRP in

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166 NWN/2200, Yoshihara/3, lines 17-19.
167 *See* Tr. 204, lines 2-19.
168 Tr. 216, lines 3-13; Tr. 184, lines 2-Tr. 186, line 21.
169 Tr. 195, line 22-Tr. 196, line 2.
170 Tr. 189, lines 12-15; Tr. 195, line 13-Tr. 196, line 4; Tr. 204, line 24-205, line 8.
171 Staff/1100, Sobhy/10, lines 1-16; Staff's Prehearing Brief at 21.

2020, the MWVF was a resource chosen as the least cost resource to provide additional capacity during the disruption.[172]

Staff's position makes no sense at all. NW Natural has testified, and Staff concedes, that 2020 was randomly selected as the date on which the disruption on the Grants Pass Lateral would be modeled, and the resulting selection of the MWVF for 2019 was because that was the year prior to the year in which the disruption was modeled.[173] If the Company had modeled a disruption on the Grants Pass Lateral in 2012, the MWVF would have been selected for 2011.[174] As such, the 2019 date that forms the basis of the parties' proposal for disallowance is meaningless.

The absurdity of Staff's position on the timing of the MWVF is apparent when one considers what the Commission's response would be if the Company actually waited until 2019 to build the project because of the IRP's modeling of a disruption randomly in 2020. In the event that an outage occurred in 2015 (which is as likely as in 2020 as far as the Company's knowledge goes), the Commission would undoubtedly find NW Natural's justification for delaying the project to be unsatisfactory if all it could offer is that it waited until 2019 because that was the date it randomly chose to address the reliability concern. The Commission should reject the parties' invitation to adhere blindly to a date in the IRP when that date does not stand for the proposition the parties assert it does.

The fact is, no party can predict when a disruption will occur.[175] The only question is whether continuing service of the Albany-Corvallis area on a single-feed system subjected its population to an unacceptable risk of a significant service disruption. Once the Company determined that such was the case, the only prudent response was for the Company to select

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172 Tr. 188, lines 12-24.
173 NWN/2200, Yoshihara/6, lines 9-11.
174 NWN/3300, Yoshihara/4, lines 6-8; Tr. 212, line 10-Tr. 213, line 7.
175 Tr. 195, lines 10-12; Tr. 213, line 24-Tr. 214, line 22.

the most cost effective approach to ensuring reliability—which is precisely what the Company did.

3. The Parties' Claim that the Company's Analysis of the MWVF Was Imprudent Because the Company Did Not Quantify the Need for the Project Is Wrong.

The parties criticize the Company's analysis of the MWVF, arguing that the Company did not perform "financial studies, benefit-cost analysis, and cost-effectiveness analysis" to evaluate the need for the project.[176] But, when pressed, Staff fails to offer any description of a plausible study or action the Company should have taken, but did not.

For example, with respect to the cost-benefit analysis Staff says the Company should have performed, Staff urges that the Company would need to quantify both the amount of investment in the plant (the cost) and the value of the benefits from building the plant.[177] When questioned as to how the Company could quantify the benefit of eliminating the risk of outages that would result from a disruption on the Grants Pass Lateral, Mr. Zimmerman suggested that the Company calculate the cost to the Company of restoring service and calculate the cost that a disruption would impose on customers.[178] Specifically, Mr. Zimmerman testified that the Company should "ask [customers] what they think it's worth for them not having heat. In other words, if they are inconvenienced, . . . what is it worth?"[179]

Staff's proposal is contrary to Oregon law. The Company has an obligation to "furnish adequate and safe service" to its customers.[180] Staff agrees that "safe and reliable operation of NW Natural's natural gas transmission and distribution system is necessary to providing adequate service to natural gas customers."[181] Measuring the benefit that will result from a

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[176] Staff/1100, Sobhy/16, lines 12-18; *See* Tr. 191, lines 3-15; CUB's Prehearing Brief at 18; NWIGU's Prehearing Brief at 6.
[177] Tr. 192, lines 1-9.
[178] Tr. 192, line 22-Tr. 193, line 25.
[179] Tr. 194, lines 5-9.
[180] ORS 757.020.
[181] *Re Application of NW Natural Gas Co. for Deferred Accounting of Safety Program Costs*, Docket UM 1030, Order No. 01-843, Appendix B at 21 (Sept. 28, 2001).

reliability project in terms of dollars is inappropriate given the Company's statutory duty to provide adequate service. In addition, Staff's proposal is unworkable and not a sensible way of evaluating a reliability project.

4. The Company Evaluated Alternatives for Addressing the Reliability Need and Found the MWVF to Be the Most Cost Effective.

Staff claims that the Company did not evaluate alternatives to the MWVF.[182] But that statement is contradicted by Mr. Yoshihara's testimony explaining the alternatives considered by the Company.[183] Specifically, the Company explained that there are no other feasible solutions for meeting increased need for capacity in the area *other than* a pipeline like the MWVF, because satellite storage and expanding the Grants Pass Lateral are not feasible alternatives for meeting the reliability needs the Company had identified.[184] Moreover, the Company found that enhancing the existing pipeline alignment is a more cost effective solution than developing a new pipeline in a new pathway,[185] in part because the MWVF will provide longer-term benefits by helping the Company meet future load increases by transporting low-cost Mist gas to the south.[186] Finally, the Company also explained how it evaluated alternative routes and provided the related feasibility report, prepared by a third party.[187]

In the face of all the evidence produced by NW Natural, Staff still insists that the analysis supporting the MWVF is inadequate. In the end, it appears that Staff is looking for a specific yet undefined quantitative analysis. Staff's approach should be rejected. The Commission has clearly stated that it does not require a utility to perform a specific type of analysis prior to making investments.[188] The Company must show that its actions were reasonable based on information that was available (or could reasonably have been available) at the time, and the

[182] Tr. 196, line 20-Tr. 197, line 6.
[183] NWN/2200, Yoshihara/13-16.
[184] *Id.* at 13, lines 1-8.
[185] *Id.* at 14, lines 13-17.
[186] *Id.* at 14, line 18-Yoshihara/16, line 2.
[187] *Id.* at 16, lines 3-7.
[188] Order No. 02-469 at 5.

Company has met this standard.[189] Disallowing a project because the Company did not do a specific type of analysis would be inappropriate, but would be especially improper considering that the only analysis a party has said is lacking is one that is nonsensical and not standard practice.

Moreover, the IRP disruption modeling supports the Company's choice of the MWVF as the cost-effective option for meeting the reliability need in the Albany-Corvallis area. When a disruption of the Grants Pass Lateral was modeled in the IRP in 2020, the MWVF was a resource chosen as the least cost resource to provide additional capacity during the disruption.[190] And if that disruption had been modeled earlier, the MWVF would have been chosen at that time.[191]

Finally, it is notable that no party has pointed out any reasonable alternative to the MWVF. One option at least mentioned by Ken Zimmerman at the hearing is the Grants Pass Lateral.[192] But increasing capacity on the Grants Pass Lateral would not protect the Albany-Corvallis area from disruptions on that same pipeline.[193] As Mr. Yoshihara explained, the only feasible alternative for addressing the reliability concern in the Albany-Corvallis area is to develop a pipeline to deliver gas to the area, and it was more cost effective to do so using an existing pipeline alignment that already been partially developed.[194]

The evidence shows that the MWVF provides benefits to customers in the near term and in the long term, and that there were no other reasonable alternatives for obtaining these benefits. The Commission should not disallow the project on the basis that the Company did

[189] *Re Public Utility Commission of Oregon Investigation to Consider Adoption of New Federal Standards Contained in the Energy Independence and Security Act of 2007*, Docket UM 1409, Order No. 09-501 at 5 (Dec. 18, 2009).
[190] Tr. 188, lines 12-24.
[191] NWN/3300, Yoshihara/4, lines 6-8.
[192] Tr. 197, lines 2-6.
[193] Tr. 225, lines 13-21.
[194] NWN/2200, Yoshihara/13-14.

not do a particular type of analysis, the parameters of which no party has articulated, when the evidence demonstrates that the Company's analysis was reasonable.

5. CUB's Argument that the Costs of the Perrydale to Monmouth and Monmouth Reinforcement Phases Are Not Known and Measurable Is Moot Given the Partial Stipulation.

CUB argues that the cost of the Perrydale to Monmouth and Monmouth Reinforcement phases should not be included in rates because the Company has not shown the estimates are "known and measurable."[195] CUB's proposal is inconsistent with the Parties' Partial Stipulation. Paragraph 13 of the Stipulation states: "To the extent the Commission finds that [the] projects are prudent, the lower of the forecast or actual costs of such projects, incurred as of the rate effective date, will be added to rate base." The Stipulation also provides for a certification process to establish the known and measurable costs. CUB's argument that the projects should be excluded because their costs are not now "known and measurable" is in conflict with this provision, which specifically provides that the lower of forecast or actual costs will be included in rates if the projects are found to be prudent.

G. The Commission Should Allow Recovery of the Company's Deferred Tax Balances.

The Company included in its revenue requirement in this case the amortization of a regulatory asset related to Oregon state tax rate changes effective with the 2009 tax year that required NW Natural to increase its deferred tax liability by a net of $2.7 million.[196] To recognize the increase, NW Natural booked a regulatory asset of $4.48 million—representing the $2.7 million change in its deferred tax balance, plus an appropriate gross up for taxes.[197]

Staff and NWIGU-CUB propose removing this amount on the basis that it would constitute retroactive ratemaking. However, the regulatory asset at issue relates to deferred taxes, not current taxes that were paid in the past; therefore, the concept of retroactive

[195] CUB's Prehearing Brief at 17, 19.
[196] NWN/1900, Siores/23, lines 10-23.
[197] *Id.* at 24, lines 2-4.

ratemaking is not applicable here. Commission law and precedent, Internal Revenue Service (IRS) guidance, and precedent from other states support the Company's position.

1. Applicable Law

The rule against retroactive ratemaking prohibits utilities from including past profits or losses in future rates.[198] The rule is implicated when the Commission "after determining expected costs and revenues, supplements that determination by employing past profits or losses in setting the future return the utility will be authorized to earn."[199]

2. Amortization of the Deferred Tax Balances Does Not Constitute Retroactive Ratemaking Because Those Balances Will Be Paid in the Future.

The parties continue to argue that it would be retroactive ratemaking for the Company to amortize this regulatory asset. The Company explained in testimony why the parties' retroactive ratemaking argument is off base—namely, that the deferred tax balances reflect taxes that will be paid in the future, not taxes that were paid from the period 2009-2012 or any other prior period.[200] The change in deferred tax balances at issue here represent a change in estimate that is forward-looking, not backward-looking, so by its very nature the change does not implicate retroactive ratemaking.[201]

The Company provided support for this position in the form of Internal Revenue Service guidance, which relied on Federal Energy Regulatory Commission precedent, noting that "Excess deferred taxes have not caused retroactive rate adjustments nor refund orders *but rather have been subject to reconciliation in future ratemaking proceedings.*"[202]

The Company also explained that the one case that the Company is aware of in which this Commission addressed the appropriate rate treatment for deferred tax balances resulting

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[198] Oregon Attorney General Opinion, Opinion Request OP-6076, 1987 WL 278316 at *1 (Mar. 18, 1987).
[199] *Id.*
[200] NWN/1900, Siores/26, lines 18-20.
[201] *Id.* at line 18-Siores/27, line 9.
[202] *Available at* http://www.irs.gov/Businesses/Coordinated-Issue-Utility-Industry-Excess-Deferred-Taxes-and-Section-1341-(Effective-Date:--April-24,-1995) (emphasis added).

from a tax law change prior to a rate case, the Commission allowed the deferred tax balance into rates and approved a stipulation that provided that "[i]n the future, if there is a change in the federal income tax incremental rate . . . that results in the company's deferred tax accounts having been understated or overstated due to the amortization agreed to by the parties [in the stipulation], then the company may apply for, and the OPUC Staff and other parties agree to support, appropriate rate increases or decreases designed to restore its deferred tax balances to the necessary levels."[203] CUB accurately points out that UG 55 was resolved via stipulation.[204] However, regardless of whether the Commission allowed the deferred tax balance into rates via a settlement or a litigated outcome, the fact is that the Commission did not find that allowing the balances into rates would violate retroactive ratemaking.

In addition to this precedent, other states addressing the question of whether including a change in deferred tax balances resulting from a past change in tax rates constitutes retroactive ratemaking have found that it does not. The Court of Appeals of Texas found that the Texas commission appropriately included in rates a one-time adjustment to a utility's deferred tax balance to reflect the fact that the utility's deferred tax balance was too low to pay taxes as they became due.[205] The court stated that "[t]he true effect of the . . . adjustment is to allow the utility to obtain from present and prospective ratepayers its actual current and future tax expenses. Consequently, *this adjustment to the deferred-tax account does not, in any way, constitute retroactive ratemaking.*"[206]

The Vermont Supreme Court similarly found that adjusting a deferred tax balance does not constitute retroactive ratemaking.[207] In that case, the Vermont commission required a utility

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203 *Re. the Investigation into the Effect of the Federal Income Tax Reform Act of 1986 on NW Natural Gas Co.*, Docket UG 55, Order 87-721 (June 29, 1987).
204 CUB's Prehearing Brief at 38.
205 *El Paso v. Pub. Util. Comm'n of Texas*, 839 S.W.2d 895, 930 (Tex. App. 1992) (aff'd in part, rev'd in part not relevant to deferred taxes).
206 *Id.* at 931.
207 *Re Appeal of Investigation into Existing Rates of Shoreham Tel. Co., Inc.*, 915 A.2d 197 (Vt. 2006).

to repay customers amounts the utility had been collecting for deferred taxes on the basis that the utility's "ADIT [accumulated deferred income tax] account represents customer funds that were paid [in the past] for future anticipated income tax obligations."[208] The court agreed with the commission, finding that the action does not amount to retroactive ratemaking because deferred income taxes are collected from customers "to be held for a future tax liability."[209]

The Illinois Supreme Court also found that it is appropriate to adjust the deferred tax balance to account for changes in the tax rate and amortize the difference in rates.[210] The court affirmed the Illinois commission's decision to adjust a utility's deferred tax balance to account for a reduction in the tax rate, which "overstate[d] the amount of taxes the company [would] be required to pay in the future."[211] The court explained that "because the company overestimated the amount of taxes it would pay in future years, the company has charged ratepayers more for *deferred* taxes than the company will actually pay to the Federal government."[212] The court upheld the commission's decision to amortize those excess deferred taxes over three years.[213]

These cases are consistent with NW Natural's position in this case: because the deferred tax balances at issue in this case reflect taxes that will be paid in the future, retroactive ratemaking does not apply. NW Natural is not aware of a state that has found to the contrary.

Staff argues that the Company should not be able to recover these deferred tax balances because "[t]he exception to collecting expenses between rate cases is deferred accounting [and] . . . NW Natural did not file an application for a deferral."[214] Staff's argument is based on a false premise—that the deferred tax balances are related to *past* expenses.

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208 *Id.* at 207.
209 *Id.* at 208.
210 *Bus. And Professional People for the Pub. Interest v. Ill. Commerce Comm'n*, 146 Ill.2d 175, 256-258 (1991).
211 *Id.* at 257.
212 *Id.*
213 *Id.* at 258.
214 Staff's Prehearing Brief at 20.

Staff also argues that at the time the regulatory asset was created, SB 408 was in effect. But Staff never testified that NW Natural's update to its deferred taxes was addressed through SB 408—and in fact it was not. Ms. Garcia simply stated that SB 408 was in effect during the 2009 tax year and that NW Natural's 2009 taxes were reconciled through SB 408.[215] This should not be confused to imply that through SB 408 NW Natural has been made whole on the issue of deferred taxes.

CUB claims that "a utility cannot 'update' a deferred tax balance if it has not filed for a deferral in the first place."[216] CUB appears to be confusing the concept of deferred accounting with the concept of deferred taxes. Under ORS 757.259, the Commission can authorize a utility to defer amounts for later incorporation in rates. Deferred taxes, as explained in the Company's Pre-Hearing Brief, represent future tax liabilities that result from the tax effect of the temporary differences between book income on the Company's books and the taxable income on the Company's tax return (book-tax difference).[217] Although both terms use the word "defer," they are entirely separate concepts.

3. NWIGU's Argument that the Company Has Not Paid the Tax Increase Resulting from the Tax Rate Change Supports the Finding that Changing the Deferred Tax Balance Does Not Constitute Retroactive Ratemaking.

NWIGU continues to offer the inapt argument that the Company "never actually paid any increase in state tax as a result of changes in the tax law."[218] As the Company has explained, NWIGU's argument provides support for the Company's position. The tax rate change resulted in changes to the deferred tax balance, which represents taxes that will be paid in the future, so it is understandable that the Company's tax bills from 2009-2011 were not higher because of this law change.

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[215] Staff/1800, Garcia/13.
[216] CUB's Prehearing Brief at 38.
[217] NWN/3000, Siores/13, lines 6-8.
[218] NWIGU's Prehearing Brief at 5.

The parties have provided no reasonable basis for disallowing amounts necessary to pay future taxes, which would be in conflict with the requirement that income taxes in rates are "fair, just and reasonable if the rates include *current and deferred income taxes* and other related tax items that are based on estimated revenues derived from the regulated operations of the utility."[219] Excluding deferred taxes from rates would contravene this requirement.

III. CONCLUSION

For the reasons set forth in the Company's Prehearing Brief and above, the Company respectfully requests that the Commission: (1) set the Company's ROE at 10.0 percent; (2) reject Staff's proposed adjustment to cost of debt based on the interest rate hedge loss; (3) adopt the Company's environmental remediation cost recovery mechanism with no sharing provision or earnings test, and allowing interest to accrue on deferred amounts consistent with Order No. 06-507; (4) adopt the Company's proposed pension contribution ratemaking methodology; (5) find that the development of the MWVF was prudent and allow into rates the costs associated with the Perrydale to Monmouth and Monmouth Reinforcement phases; and (6) allow the Company to amortize the regulatory asset associated with deferred tax balances.

DATED: September 12, 2012

McDowell Rackner & Gibson PC

Lisa Rackner

Lisa F. Rackner
Amie Jamieson
Of Attorneys for NW Natural

NORTHWEST NATURAL GAS COMPANY
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[219] ORS 757.269(1) (emphasis added).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

NW Natural's Posthearing Brief

Appendix A

September 12, 2012

APPENDIX A

Examples of States Allowing Recovery of Pension Costs Through Additions to Rate Base, and Not Requiring Deferrals or Accounting Orders Before Contributions were Made

State	Utility	Description of Recovery Method	Excerpts Provided for Commission's Reference	Excerpts Found At:	
Arizona	**Arizona Public Service Co.**	APS includes its prepaid pension asset in rate base and also recognizes FAS 87 expense in its revenue requirement. APS, like NW Natural, is a FAS 87 pension expense balancing account. There is no evidence that the commission requires a deferral application or accounting order for the prepaid asset to be added to rate base.	The pension adjustments are shown in Docket No. E-01345A-11-0224 under APS Schedule B-1 (page 1) and C-2 (page 8). It appears that there is no controversy about APS's treatment as the Commission's Decision No. 73183 (issued 5/24/2012) does not address pensions.	Attachment A	
Kansas	**Aquila Networks**	Aquila recognized its pension asset in rate base. The commission's Order in Aquila's 2004 rate case discusses the issue of pension allocations. The appropriateness of the rate base treatment itself, however, was not contested, and the commission does not appear to have ever required a deferral or accounting order related to the pension asset in order for the rate base treatment to have been allowed.	Commission order in Docket 04-AQLE-1065-RTS includes the discussion and adoption of a Staff Adjustment No. 5 (pages 28-29). While pensions are not specifically labeled in rate base, the Staff's adjustment shows that the pension allocation adjustment specifically affects prepaid assets (Schedule A-2).	Attachment B	
Maryland	**Baltimore Gas and Electric**	The Maryland Commission has allowed BGE to put its pension asset in rate base. The Company has not been required to file deferral applications or for accounting orders before including the pension asset in rate base, and no party asserted that the Company should be required to do so. The adjustment to rate base is shown in the referenced workpapers, and was uncontested throughout this case.	The adjustment to rate base to reflect the pension asset is shown in the Exhibit of BGE's Direct Testimony of Castagnera, filed in Case No. 9230. The adjustment is reflected on Company Exhibit RGC-4, line 13, which is included in the referenced attachment.	Attachment C	
Missouri	**AmerenUE**	The Missouri Commission adopted a stipulation that states AmerenUE shall be allowed rate recovery for contributions it makes to pension trust that exceed its FAS 87, (i.e., its prepaid pension asset) through additions to rate base. In the stipulation, various mechanisms were established to track changes in contributions and FAS 87 over time. It does not appear that the Commission required a deferral or any accounting order in order for Ameren to make the adjustment to rate base that the parties agreed to.	Docket ER-2007-0002. See Stipulation pg. 2, item 3.; See Stipulation pg. 2-3, Item 5.	Attachment D	
New Mexico	**Public Service Company of New Mexico**	In 2007, the Commission allowed PSC of New Mexico to adjust its rate base to include its prepaid pension asset. There is no evidence that a deferral application was required for this treatment.	Case No. 07-00077-UT, Final Order, Pages 16-20	Attachment E	
Texas	**AEP Texas Central Company**	AEP's pension prepaid asset is included in rate base. The Commission has not required the filing of deferral applications or accounting orders in order for this treatment to be afforded.	Texas Public Utility Commission Order in Docket No. 33309, pages 5 - 6, provides evidence of the Texas commission's determination that rate base treatment of the pension prepayment asset is appropriate.	Attachment F	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment A
to
Appendix A

September 12, 2012

NEW APPLICATION

ORIGINAL

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

E-01345A-11-0224

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11- APPLICATION

I. INTRODUCTION.

In this Application, Arizona Public Service Company ("APS") seeks a net increase in base rates of $95.5 million, or 3.3%, to become effective on July 1, 2012.[1] The requested increase is required for the Company to continue to meet Arizona's

[1] This Application is filed pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-102 to R14-2-103.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year (a) (A)	Pro Forma (a) (B)	Adjusted Test Year (a) (C)	Unadjusted Test Year (a) (D)	Pro Forma (a) (E)	Adjusted Test Year (a) (F)	Line No.
1.	Gross utility plant in service	$ 13,656,105	$ 972,934	$ 14,629,039	$ 11,522,113	$ 945,501	$ 12,467,614	1.
2.	Less: Accumulated depreciation & amortization	5,219,000	500,580	5,719,580	4,528,867	487,072	5,015,939	2.
3.	Net utility plant in service	8,437,105	472,354	8,909,459	6,993,246	458,429	7,451,675	3.
	Deductions:							
4.	Deferred income taxes	1,931,063	48,834	1,979,897	1,567,902	47,231	1,615,133	4.
5.	Investment tax credits	907	-	907	876	-	876	5.
6.	Customer advances for construction (c)	121,645	-	121,645	121,645	-	121,645	6.
7.	Customer deposits	68,084	-	68,084	68,084	-	68,084	7.
8.	Pension and other postretirement liabilities	711,164	-	711,164	661,518	-	661,518	8.
9.	Liability for asset retirements (c)	328,571	-	328,571	320,592	-	320,592	9.
10.	Other deferred credits	66,842	-	66,842	64,107	-	64,107	10.
11.	Coal mine reclamation (c)	117,243	-	117,243	114,396	-	114,396	11.
12.	Unrecognized tax benefits (c)	65,363	-	65,363	53,961	-	53,961	12.
13.	Regulatory liabilities	260,687	-	260,687	253,750	-	253,750	13.
14.	Total deductions	3,671,569	48,834	3,720,403	3,226,831	47,231	3,274,062	14.
	Additions:							
15.	Regulatory assets	822,177	-	822,177	746,508	-	746,508	15.
16.	Deferred debit income tax receivable (c)	65,498	-	65,498	63,271	-	63,271	16.
17.	Other deferred debits	77,674	-	77,674	72,203	-	72,203	17.
18.	Decommissioning trust accounts (c)	469,886	-	469,886	458,476	-	458,476	18.
19.	Allowance for working capital (d)	233,778	(14,220)	219,558	212,065	(9,859)	202,206	19.
20.	Total additions	1,669,013	(14,220)	1,654,793	1,552,523	(9,859)	1,542,664	20.
21.	Total rate base	$ 6,434,549	$ 409,300	$ 6,843,849	$ 5,318,938	$ 401,339	$ 5,720,277 (e)	21.

Supporting Schedules:
(a) B-2
(b) B-3
(c) E-1
(d) B-5

Recap Schedules:
(e) A-1

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2010
(Thousands of Dollars)

Line No.	Description	(22) Remove PWEC Loan Amortization Total Co. (QQ)	ACC (RR)	(23) Amortize Pension and OPEB Deferral Total Co. (SS)	ACC (TT)	(24) Normalize Pole Attachment Revenues Total Co. (UU)	ACC (VV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(305)	(305)
4.	Total Electric Operating Revenues	-	-	-	-	(305)	(305)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(305)	(305)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	8,740	8,122	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	8,740	8,122	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	2,107	2,035	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total	2,107	2,035	8,740	8,122	-	-
15.	Operating Income Before Income Tax	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(2,107)	(2,035)	(8,740)	(8,122)	(305)	(305)
18.	Current Income Tax Rate - 39.51%	(832)	(804)	(3,453)	(3,209)	(121)	(121)
19.	Operating Income (line 15 minus line 18)	$ (1,275)	$ (1,231)	$ (5,287)	$ (4,913)	$ (184)	$ (184)
	WITNESS:	LA BENZ		LA BENZ		LA BENZ	

(22) Adjustment to Test Year operations to remove PWEC loan amortization and interest authorized in Decision No. 65796 and 67744.

(23) Adjustment to Test Year operations reflect the recovery of the Pension/OPEB deferral authorized in Decision No. 71448 to be amortized over a three year period.

(24) Adjustment to Test Year Other Electric Revenues to reflect change in FCC rules impacting pole attachment fees.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment B
to
Appendix A

September 12, 2012

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners: Brian J. Moline, Chair
Robert E. Krehbiel
Michael C. Moffet

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks – WPK For Approval of the Commission to Make Certain Changes in its Rates for Electric Service.	)	Docket No. 04-AQLE-1065-RTS

ORDER ON APPLICATION

The above matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision upon the rate application filed herein by Aquila, Inc., d/b/a Aquila Networks – WPK (WPK or Applicant). For the reasons discussed below, the Commission sets WPK's overall revenue requirement based upon an operating income of $8,981,416, a rate base of $154,010,018, a return on equity of 10.5 percent, and an overall rate of return of 8.7285 percent. The Commission finds that the net effect on WPK is a revenue requirement increase of $7,408,110 from WPK's current revenue requirement.

I. INTRODUCTION

1. On June 2, 2004, WPK filed its application for changes to its electric service rates pursuant to K.S.A. 66-117 and K.A.R. 82-1-231. WPK is an operating division of Aquila, Inc. (Aquila). For the purposes of this order, references to Aquila shall mean the entire company, and to refer to the exhibits offered by WPK at hearing since that is how the Applicant had them marked. WPK and Applicant shall refer to Aquila's Kansas-regulated electric utility operating division.

U. Pension Contributions and ABO

83. In December, 2002, Aquila contributed $35,000,000 to its qualified pension fund, $7,494,686 of which was directly assigned to WPK. This assignment was based on each business units' unfunded Accumulated Benefits Obligation (ABO) as a percentage of Aquila's total unfunded ABO. Hull Direct, p. 5.

84. However, beginning with the 2003 pension contribution, Aquila allocated pension contribution to each business unit based upon an ABO determined by an independent actuary. Staff adopted Aquila's revised methodology for allocating pension contributions, and derived a different overall amount attributable to WPK. Staff's calculation resulted in a decrease to the WPK prepaid pension thirteen-month average of $4,202,099, and increased the Aquila corporate prepayments allocated to WPK by $215,709.

85. While WPK agreed with Staff's concept, it asserted that Staff failed to take into consideration an order by the Missouri Public Service Commission (MPSC) regarding UtiliCorp United, Inc.'s (UtiliCorp) (Aquila's predecessor) acquisition of the St. Joseph Light and Power Company (SJLP). WPK maintained that the MPSC required Aquila to exclude SJLP's pension assets in allocating the pension contribution. Lowndes Rebuttal, pp. 14-28.

86. The MPSC Order, dated December 14, 2000, in MPSC Case No. EM-2000-292, was entered into the record of this proceeding as Aquila Exhibit No. 105. With regard to the SJLP pension fund, the MPSC stated:

> UtiliCorp agreed that in post-merger cases involving UtiliCorp's SJLP operating division, UtiliCorp will maintain the pre-merger funded status of the SJLP pension fund by accounting for it separately. *UtiliCorp will, however, be allowed to combine the assets.*

MPSC Report and Order, December 14, 2000, p. 14. Emphasis Added.

87. The accounting for SJLP pension funds ordered by the MPSC was designed to protect Missouri ratepayers. The MPSC specifically stated that UtiliCorp would be able to combine the assets for other purposes. Furthermore, this Commission is not bound by another Commission's decision specifically designed to protect the ratepayers within its own jurisdiction. Excluding SJLP results in a greater percentage of the pension contributions being allocable to WPK. The ABO percentage methodology applied to all business units, including the SJLP business unit, reflects a more accurate picture of the existing pension contributions. Therefore, the Commission adopts Staff's Adjustment No. 5 to rate base.

V. Cost Free Capital

88. In its original application, WPK included as cost free capital four items: Accumulated injuries and damages, interest accrued, accrued benefits – comp absences, and other deferred credits. WPK's calculated a total cost free capital amount of $1,643,792. Application, Section 6, Schedule 5.

89. In its Adjustment No. 6 to rate base, Staff eliminated portions of the reserve for general liability, corresponding with adjustments made to the Applicant's proposed injuries and damages expenses, reducing the amount of the rate base relating to cost free capital. Staff also included new accounts, increasing the total cost free capital. Staff included accrued incentives, accrued payroll, and post retirement benefits. The total difference between Staff and WPK's total was $3,450,436 on a pre-jurisdictional basis.

90. In rebuttal, WPK took issue with Staff's inclusion of certain accounts, including the accrued compensated absences in the Applicant's schedule. Lowndes Rebuttal, p. 29. During the hearing, Staff witness Hull acknowledged her uncertainty concerning the inclusion of

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AQUILA, INC
AQUILA NETWORKS - WPK
STAFF ADJUSTMENTS TO APPLICANT ADJUSTED RATE BASE
FOR THE TEST YEAR ENDED DECEMBER 31,2003

DOCKET NO. 04-AQLE-1065-RTS
SCHEDULE A-2
PAGE 1 OF 2

LINE NO.	DESCRIPTION	A APPLICANT ADJ. KANSAS JURISDICTIONAL	B STAFF ADJUSTMENT NO. 1	C STAFF ADJUSTMENT NO. 2	D STAFF ADJUSTMENT NO. 3	E STAFF ADJUSTMENT NO. 4	F STAFF ADJUSTMENT NO. 5	G STAFF ADJUSTMENT NO. 6	H STAFF ADJUSTMENT NO. 7
	ELECTRIC PLANT IN SERVICE:								
1	INTANGIBLE	$47,429							
2	PRODUCTION PLANT	79,722,328							
3	TRANSMISSION PLANT	100,241,352							
4	DISTRIBUTION PLANT	139,592,982							
5	GENERAL	14,967,369							
6	GENERAL - COMMON	18,444,534							(1,685,724)
7	TOTAL ELECTRIC PLANT IN SERVICE	$353,015,994	$0	$0	$0	$0	$0	$0	($1,685,724)
8	PLANT HELD FOR FUTURE USE	0							
9	CONSTRUCTION WORK IN PROGRESS	3,691,850							
10	ACQUISITION ADJUSTMENTS	0							
11	TOTAL UTILITY PLANT	$356,707,844	$0	$0	$0	$0	$0	$0	($1,685,724)
12	LESS: ACCUM. PROV. FOR DEPR. & AMORT.	$173,247,656							
13	LESS: ACCUM PROV. FOR DEPR & AMORT - FUTURE USE	0							
14	LESS: ACCUM PROV. FOR AMORT OF ACQ ADJ	0							
15	TOTAL ACCUM. PROV. FOR DEPR. & AMORT.	$173,247,656	$0	$0	$0	$0	$0	$0	$0
16	NET ELECTRIC PLANT IN SERVICE	$183,460,188	$0	$0	$0	$0	$0	$0	($1,685,724)
	OTHER RATE BASE ITEMS (WORKING CAPITAL):								
17	MATERIALS & SUPPLIES - FUEL	$2,553,290			(914,157)				
18	MATERIALS & SUPPLIES - PLANT	2,412,675							
19	WPK PREPAYMENTS - OTHER	11,775,632				(161,348)	(3,658,734)		
20	WPK'S SHARE OF CORPORATE PREPAYMENTS	962,494					112,494		
21	COST FREE CAPITAL	(1,509,001)						(3,067,093)	
22	CUSTOMER ADVANCES FOR CONSTRUCTION	(21,081)		(22,985)					
23	CASH WORKING CAPITAL	(2,008,136)							
24	ACCUMULATED DEFERRED INCOME TAXES	(26,833,928)							
25	CUSTOMER DEPOSITS	(291,195)	(409,879)						
26	TOTAL OTHER RATE BASE ITEMS (WORKING CAPITAL)	($12,959,250)	($409,879)	($22,985)	($914,157)	($161,348)	($3,546,240)	($3,067,093)	$0
27	TOTAL RATE BASE	$170,500,938	($409,879)	($22,985)	($914,157)	($161,348)	($3,546,240)	($3,067,093)	($1,685,724)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment C
to
Appendix A

September 12, 2012

Before the Maryland Public Service Commission

Case No.______

Prepared Direct Testimony of

Robert G. Castagnera

on Behalf of

Baltimore Gas and Electric Company

May 7, 2010

TABLE OF CONTENTS

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert G. Castagnera and my business address is Baltimore Gas and Electric Company, 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland, 21201.

Q. WHAT IS YOUR POSITION WITH BALTIMORE GAS AND ELECTRIC COMPANY?

A. I am Assistant Controller and Director of Accounting Management of Baltimore Gas and Electric Company (BGE or the Company). My current responsibilities include leading the development and maintenance of the Company's general ledger and oversight as well as compliance for various regulatory filings, including Federal Energy Regulatory Commission (FERC) Form 1 and Securities and Exchange Commission (SEC) Forms 10-K and 10-Q. I am also responsible for conducting accounting research activities, maintaining a robust and compliant financial control environment, structuring cost allocation policies, and evaluating regulatory compliance issues.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been employed by the Company and affiliated entities for almost 34 years, holding various positions in the Finance and Accounting area. I received a Bachelor of Arts Degree in Accounting and a Master of Business Administration Degree from Loyola University in Maryland, and I was awarded a CPA license in Maryland.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before the Commission in Case No. 9036, the Company's most recent gas base rate application, and I have testified before the Commission in an electric fuel rate case. In addition, I have submitted direct testimony in Case No. 9221. However, the hearings for Case No. 9221 have not occurred yet.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am presenting financial data which will demonstrate that, during the test year, our present electric and gas base rates are insufficient to provide the Company a reasonable opportunity to earn the 8.99% rate of return which is supported by the Company in this proceeding. The Company's demonstrated need is based on operating results for the partially projected test year 12 months ended July 31, 2010 and is adjusted for known and measurable changes in expenses and components of rate base. The Company expects to earn a return of 6.19% for electric distribution operations and 6.13% for gas distribution operations on an adjusted basis for the partially projected test year.

Q. MR. CASTAGNERA, COULD YOU PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES ARE SET UNDER TRADITIONAL COST OF SERVICE REGULATION?

A. Certainly. Under traditional cost of service regulation, a regulated company's rates are set so that the company is provided an opportunity to recover its prudently-incurred costs, including taxes and depreciation, plus a fair return on its net investment in utility plant necessary to provide safe and reliable delivery service at fair and reasonable rates. In the instant application, BGE is seeking to revise rates for both electric distribution service and gas distribution service.

III. SUMMARY OF COMPANY EXHIBITS

Q. HAVE YOU PREPARED ANY EXHIBITS AND SUPPORTING SCHEDULES, MR. CASTAGNERA?

A. Yes. I have prepared six exhibits numbered as Company Exhibits RGC-1 through RGC-6 as follows:

- Company Exhibit RGC-1 presents the calculation for electric and gas base rate relief sought by the Company in this proceeding. This request is based on an 8.99% rate of return, supported by the Direct Testimonies of Company witnesses Avera and Hadlock, applied to the adjusted average rate base for the partially projected test period. This calculation produces the total required operating income necessary to provide the Company an opportunity to earn the 8.99% rate of return by the end of the 12-month period following the date new rates go into effect (rate effective year). This total operating income required is then compared to the adjusted operating income for the test year and the difference is the basis for calculating the necessary increase in electric and gas base rates.

  In addition, Company Exhibit RGC-1 presents the calculation of the 5% cap on any electric base rate revenue awarded in this proceeding, which is required by the

D. COMPANY EXHIBIT RGC-4

Q. PLEASE SUMMARIZE COMPANY EXHIBIT RGC-4 WHICH SETS FORTH THE DETAILS OF AVERAGE ELECTRIC AND GAS RATE BASE CALCULATIONS.

A. Company Exhibit RGC-4, entitled "Unadjusted Average Distribution Rate Base," shows each major component of electric and gas distribution rate base consistent with the Commission's previous findings. Rate base represents the amounts financed by investors that are used and useful in providing utility service to our customers. All of the components of unadjusted rate base are 13-month average balances, with the exception of cash working capital which is computed using test year operating expense levels. The cash working capital calculation is presented in Company Exhibit RGC-6.

E. COMPANY EXHIBIT RGC-5

Q. PLEASE SUMMARIZE COMPANY EXHIBIT RGC-5 WHICH LISTS THE ADJUSTMENTS TO AVERAGE RATE BASE THE COMPANY IS PROPOSING FOR RATEMAKING PURPOSES.

A. Company Exhibit RGC-5 lists the six adjustments to average distribution rate base that BGE is proposing. Similar to the Operating Income Adjustments, these adjustments are organized into several broad categories: adjustments specifically authorized in prior rate cases or required under COMAR, annualization of known changes previously approved by the Commission, and other adjustments.

The first rate base adjustment category consists of an adjustment specifically authorized in prior rate cases. This adjustment reflects the unamortized balance of gains on the sale of real estate. This adjustment is consistent with the related operating income

Company Exhibit RGC-4

Baltimore Gas and Electric Company
Unadjusted Average Distribution Rate Base
For the Twelve Months Ended July 31, 2010
(Thousands of Dollars)

Line No.	Electric	Gas	Total
1. Utility plant in service	$ 4,355,188	$ 1,395,520	$5,750,708
2. Construction work in progress	113,570	21,905	135,475
3. Property held for future use	2,796	-	2,796
4. Total utility plant	4,471,554	1,417,425	5,888,979
5. Materials and supplies	26,550	75,124	101,674
6. Unamortized environmental costs	-	4,479	4,479
7. Unamortized deferred conservation program expenditures	26,647	3,588	30,235
8. Cash working capital	38,709	21,862	60,571
9. CN8794/8804 regulatory asset	39,136	-	39,136
10. Deferred employee reduction plans	-	1,518	1,518
11. Accumulated provision for depreciation and amortization	(1,764,993)	(462,673)	(2,227,666)
12. Accumulated deferred income taxes	(570,573)	(222,487)	(793,060)
13. Pension and postemployment benefit costs, net	44,502	19,173	63,675
14. Customer deposits	(54,553)	(28,734)	(83,287)
15. Customer advances for construction	(7,719)	(1,880)	(9,599)
16. Accounts payable financing of capitalized materials and supplies	(499)	(502)	(1,001)
17. Total rate base	$ 2,248,761	$ 826,893	$3,075,654

With the exception of cash working capital, all amounts presented above are 13-month averages.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment D
to
Appendix A

September 12, 2012

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a	)	
AmerenUE's Tariffs Increasing Rates for Electric	)	**Case No. ER-2007-0002**
Service Provided to Customers in the Company's	)	Tariff No. YE-2007-0007
Missouri Service Area	)	

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REPORT AND ORDER

Issue Date: May 22, 2007

Effective Date: June 1, 2007

made a part of the record and may be relied upon by the Commission when making its decision regarding AmerenUE's request for a rate increase. For that reason, attorneys for the various parties are given an opportunity to question witnesses if they desire to do so. A party deciding not to send an attorney to a local public hearing does so at its own risk. Nevertheless, the presence of legal counsel for the parties is not essential to the local public hearing process. Therefore, if a party decides to forego the opportunity to question citizen witnesses by not sending an attorney to a local public hearing, neither the public, nor the Commission's process is harmed. In fact, many parties to this, as well as other rate cases, choose not to send an attorney to local public hearings.

The Commission certainly expects that a utility requesting a rate increase will send representatives to each local public hearing to answer questions from the public, and more importantly, to listen to the concerns and complaints of its ratepayers. AmerenUE had employees present at all of the local public hearing to fulfill that role, even though it did not have an attorney available to enter a formal appearance at some of the hearings.

There is no basis for dismissing AmerenUE from this case, and the Commission will deny Public Counsel's motion.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed three nonunanimous partial stipulations and agreements resolving several issues that would otherwise have been the subject of testimony at the hearing. No party opposed the partial stipulations and agreements. As permitted by its regulations, the Commission treated these unopposed partial stipulations and agreements as unanimous.[5] After considering

[5] 4 CSR 240-2.115(C).

each of the stipulations and agreements, the Commission approved them as a resolution of the issues addressed in those agreements.[6] The issues that were resolved therein will not be further addressed in this report and order.

Overview

AmerenUE is an investor-owned utility providing retail electric service to large portions of eastern and central Missouri, including the St. Louis metropolitan area. It is the largest electric utility in Missouri, serving approximately two million customers. AmerenUE is a subsidiary of Ameren Corporation, which is a holding company that owns electric utilities in Illinois, as well as various other unregulated subsidiaries.

AmerenUE began the rate case process when it filed its tariff on July 7, 2006. In doing so, AmerenUE asserted it was entitled to increase its rates enough to generate an additional $360,709,000 in gross electric revenues per year. AmerenUE set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on July 7. In addition to its filed testimony, AmerenUE provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review AmerenUE's testimony and records to determine whether the requested rate increase was justified.

Obviously, there are a multitude of matters about which the parties could disagree. Fortunately, there was no disagreement about many matters and, as a result, those potential issues were never brought before the Commission. Where the parties disagreed,

[6] An *Order Approving Partial Stipulation and Agreement Concerning Class Cost of Service and Certain Rate Design Issues Filed on March 22, 2007* was issued on April 5, 2007; An *Order Approving Tier I Partial Stipulation and Agreement Filed on March 15, 2007*, and an *Order Approving Tier II Partial Stipulation and Agreement filed on March 26, 2007,* were issued on April 11, 2007.

Schedule 4
Tracker for Pension and Other Post-Employment Benefits

INTENT:

These provisions of the Stipulation and Agreement are intended to accomplish the following:

a. To ensure that the amount collected in rates for pension and other post-employment benefit costs is based on the FAS 87 and FAS 106 costs AmerenUE recognizes for financial reporting purposes; and

b. To ensure AmerenUE recovers in rates certain contributions it makes to its pension and VEBA trusts; and

c. To clarify, for ratemaking purposes, the accounting treatment of future charges AmerenUE would be required to record to equity (e.g., decreases to other comprehensive income) by FAS 87, FAS 106 or any other FASB statement or procedure relative to the recognition of pension and OPEB costs and/or liabilities.

PROCEDURE:

1. The FAS 87 and FAS 106 costs AmerenUE recognizes for financial reporting purposes shall be recognized in rates. The calculation of these costs shall be, unless specifically changed by the issuance of new FASB accounting standards, based on the Market Related Value of Assets that reflects gains and losses over a 4 year period. Unrecognized gains and losses shall be, unless specifically changed by the issuance of new FASB accounting standards, amortized over a 10-year period. This calculation does not employ the corridor approach. AmerenUE will inform the Staff of the Missouri

Public Service Commission and the Office of Public Counsel as soon as it becomes aware of a new FASB accounting standard that would affect the calculation parameters discussed above.

2. Each year AmerenUE shall contribute to its pensions and VEBA trusts the amount of its FAS 87 and FAS 106 costs for that year.

3. AmerenUE shall be allowed rate recovery for contributions it makes to its pension trust that exceed its FAS 87 cost for any of the following reasons: the minimum required contribution is greater than the FAS 87 cost, avoidance of Pension Benefit Guaranty Corporation (PBGC) variable premiums, and avoidance of a charge to other comprehensive income. To track any such excess contributions, a regulatory asset will be established and will be included in rate base.

4. The difference between the level of pension (FAS 87 & FAS 88) costs AmerenUE incurs and the level of those costs built into rates shall be tracked by means of regulatory assets and/or liabilities described in the following paragraphs. Similarly, the difference between the level of other post-employment benefits (OPEBs) shall be tracked by means of regulatory assets and/or liabilities described in the following paragraphs.

5. Regulatory assets or liabilities shall be established on AmerenUE's books to track the difference between the level of FAS 87 and FAS 106 costs AmerenUE incurs during the period between general electric rate cases and the level of FAS 87 and FAS 106 costs built into rates for that period. If the FAS 87, or FAS 106, cost during the period is more than the FAS 87, or FAS 106, cost built into rates for the period, AmerenUE shall establish a regulatory asset which has been reduced by any existing regulatory liability for pensions, or OPEBs, maintained pursuant to the following

paragraph. If the FAS 87, or FAS 106, cost during the period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to the following paragraph, is less than the cost built into rates for the period, AmerenUE shall establish a regulatory liability. Since this is a cash item, the regulatory asset or liability will be included in rate base for purposes of setting new rates in the next rate case, and amortized over 5 years beginning with the effective date of the new rates.

6. If AmerenUE incurs negative FAS 87, or FAS 106, cost, AmerenUE shall set up a regulatory liability to offset the negative cost. The regulatory liability will increase by the amount of negative cost, or decrease by the amount of positive cost, in each subsequent year. Positive cost in such subsequent year will be used to reduce this regulatory liability before being used to establish a regulatory asset pursuant to the preceding paragraph. Any existing regulatory liability related to prior negative FAS 87 or FAS 106 cost will reduce the FAS 87 or FAS 106 included in cost of service in AmerenUE's next rate case. This regulatory liability is a noncash item that AmerenUE shall exclude from its rate base in future rate cases.

7. The parties have designed this agreement so that AmerenUE will receive through rates reimbursement of its FAS 87 and FAS 106 costs. Therefore, AmerenUE shall set up a regulatory asset to offset any charges that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS 87, FAS 106, or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of AmerenUE's Pension or OPEB plans. This regulatory asset shall not be amortized into rates or included in rate base because AmerenUE will recover for the amounts in this regulatory

asset in rates through AmerenUE's FAS 87 or FAS 106 costs in future years. This regulatory asset will increase or decrease each year by the same amount that the equity charge increases or decreases.

8. If AmerenUE has a curtailment, settlement, or special termination cost or credit due to requirements of applicable accounting rules according to FAS 88 and FAS 106, the following procedure will be used to address the cost reimbursement for pension and OPEB costs:

> A. If the special event triggers a charge, then AmerenUE will establish an offsetting regulatory asset. This regulatory asset will not be added to rate base (since it is not a cash item), and it will be amortized over five years beginning when new rates are implemented in AmerenUE's next general electric rate increase or decrease proceeding before the Missouri Public Service Commission. AmerenUE shall make additional contributions to the applicable pension or VEBA trust equal to the amount of the amortization.
>
> B. If the special event triggers a credit, then AmerenUE shall establish an offsetting regulatory liability. This regulatory liability will not be added to rate base (since it is not a cash item), and it will be amortized over five years beginning when new rates are implemented in AmerenUE's next general electric rate increase or decrease proceeding before the Missouri Public Service Commission. Generally, AmerenUE will contribute to the applicable pension or VEBA trust an amount equivalent to its FAS 87/106 costs for the year less the amortization amount, subject to the following condition:
>
> C. If pension cost becomes negative as a result of a FAS 87 and/or FAS 88 credit, the Parties agree AmerenUE shall set up an offsetting regulatory liability. This regulatory liability is a non-cash item which will not require rate base treatment. When FAS 87 costs becomes positive again, the regulatory liability will be amortized over five years, or longer, if necessary to avoid the net of the FAS 87 cost and the offsetting amortized regulatory liability yielding a result which is less than $0 in any year.

9. The parties agree the attached example calculation accurately reflects the intent of this Appendix to the Stipulation and Agreement, and that the testimony Steve Carver and Ken Vogl filed in Case No. ER-2007-0002 provides explanation of the matters addressed in these paragraphs.

APPENDIX A

Ameren Electric Company
Case No. GR-2007-0003

Example of Stipulated Tracking Mechanism for FAS 87 & FAS 88 Pension Cost [1]

Financial & Rate Recognition		Row Reference	1	2	3	Balance End of Yr 3	New Rates 4	5	6	7	8	Total All 8 Years
FAS 87	Rates	(A)	$0.00	$0.00	$0.00	$0.00	$2.00	$2.00	$2.00	$2.00	$2.00	$10.00
FAS 87	Actual		$0.00	$0.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$12.00
FAS 88	Actual		($5.00)			($5.00)						($5.00)
FAS 88 Liability			($5.00)			($5.00)						
FAS 88 Liability - Amortization		(B)					($1.00)	($1.00)	($1.00)	($1.00)	($1.00)	($5.00)
FAS 87 Asset					$2.00	$2.00						
FAS 87 Asset - Amortization		(C)					$0.40	$0.40	$0.40	$0.40	$0.40	$2.00
Net Pension Cost in Rates		(A)+(B)+(C)	$0.00	$0.00	$0.00	$0.00	$1.40	$1.40	$1.40	$1.40	$1.40	$7.00
Net Pension Cost - Actual			($5.00)	$0.00	$2.00	($3.00)	$2.00	$2.00	$2.00	$2.00	$2.00	$7.00
Funding Requirement												
FAS 87	Actual		$0.00	$0.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$12.00
FAS 88 Liability	Amortization						($1.00)	($1.00)	($1.00)	($1.00)	($1.00)	($5.00)
Net Funding Requirement			$0.00	$0.00	$2.00	$2.00	$1.00	$1.00	$1.00	$1.00	$1.00	$7.00

[1] FAS 88 addresses accounting treatment for special events related to pension accounting under FAS 87.
FAS 106 addresses the accounting treatment for other post-employment benefits, including special events.
The example provided above would also reflect the tracking machanism for Other Post-employment Benefits calculated according to FAS 106.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment E
to
Appendix A

September 12, 2012

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATE PURSUANT TO ADVICE NOTICE NO. 334,	)	Case No. 07-00077-UT
PUBLIC SERVICE COMPANY OF NEW MEXICO, Petitioner.	)	

FINAL ORDER PARTIALLY ADOPTING RECOMMENDED DECISION

THIS MATTER comes before the New Mexico Public Regulation Commission ("Commission") on the Recommended Decision of the Hearing Examiner ("RD") issued in this case by James C. Martin on March 6, 2008. Having considered the RD (attached hereto as Attachment 1) and incorporated herein by reference, the exceptions and responses thereto, the oral arguments presented, the record in this case, and being fully informed in the premises,

THE COMMISSION FINDS AND CONCLUDES:

1. The Statement of the Case contained in the RD sets out the history of this case fully up to the time of its issuance and is incorporated herein by reference.

2. Exceptions to the RD were filed on March 17, 2008 by the International Brotherhood of Electrical Workers ("IBEW"), and on March 20, 2008 by PNM, Western Resource Advocates ("WRA") jointly with Coalition for Clean Affordable Energy ("CCAE"), Kroger, Co., and the Board of Regents of the University of New Mexico ("UNM"). Community Action New Mexico and Senior Intervenors' ("CANM/SI") Motion to File Exceptions Late was filed on March 21, 2008. Responses to the

generally agrees with the Cities' incremental cost approach that takes into consideration differences in fuel costs and the ability of the company to make additional sales into the wholesale market from its jurisdictional generating plants during periods that wind energy was serving customer loads. In addition, the company represents it has incurred other incremental costs in absorbing and utilizing the output from the NMWEC, such as for additional regulating capacity. PNM's Response to Third Bench Request.

42. The net incremental cost of the NMWEC PPA, whatever it may be, is now reflected in the base period cost of service.[8] Thus, going forward, PNM will be compensated for these NMWEC-related costs of compliance with the Renewable Energy Act, and there should be no separate rate treatment for these particular RECs. However, in order to comply with the Act, PNM began acquiring wind energy and related RECs in late 2003. If PNM is able to establish that it incurred an actual incremental cost for its compliance efforts over this period, it should be able to recover that cost. Incremental costs for those RECs established by a methodology consistent with this Order may be treated as a regulatory asset by PNM and submitted for rate base treatment and amortization in the company's next rate case.

D. <u>Prepaid Pension Asset</u>

43. As in the PNM Gas Rate case, PNM is requesting an adjustment in this case to its rate base to reflect voluntary pre-payments made to its Deferred Pension Plan. The Commission rejected PNM's proposal in the PNM Gas Rate case on several grounds including: 1) PNM's claim was based on estimates and not on verifiable amounts,

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serve the needs of tits retail customers, it could sell production from San Juan Station at market rates, therefore its cost of serving retail jurisdictional customers is the market rate for power.

[8] The Hearing Examiner, in removing the rate-basing and amortization of RECs from the cost of service, caused $5 MWh for 322,173 MWh of wind energy to be added to purchased power costs. Exhibit A to the RD, line 209.

2) PNM did not establish benefits to ratepayers from additional contributions, 3) the amount claimed is not required to be paid into the fund by the Employee Retirement Income Security Act ("ERISA"), and 4) PNM's proposal has not been approved by the Commission for PNM or any other utility. PNM Gas Case Final Order, pp. 21-26.

44. In both the PNM Gas Rate case and the present case, the claim has been made that the prepaid pension asset amounts to a proposal for retroactive ratemaking. In the prior case, the Commission found that because of the other reasons for rejecting PNM proposal, "that determination is not necessary to the decision in this matter." Id. at 26. The Commission also declined to reach the issue of whether the source of the funds used to pay excess contributions into the fund is determinative of, or relevant to, rate base treatment of the funds.

45. The RD notes that the same problems identified in the Gas Case exist in the present case and the claim should be denied. RD, p. 72-73. Exceptions were filed by PNM claiming that significant differences that exist in the present case were ignored in the RD. First, PNM states that prepayments for pension expenses were allowed for rate base purposes in Case Nos. 2662 and 2262. PNM Ex. 36, Sategna Rebuttal, pp.27-29. Second, PNM contends that it cured the defect of using estimates instead of verifiable amounts in this case by comparing the amounts contributed by PNM with the amount of pension expense calculated pursuant to SFAS-87. PNM asserts that this resulted in a more precise calculation of the amount of the prepaid expense rather than an estimate.

46. PNM claims that denial of recovery for prepaid pension expense would be inconsistent and asymmetrical with the treatment accorded in Case Nos. 2262 and 2662. According to PNM, as a result of a negative prepaid expense due to the difference

between the pension accrual under SFAS 87 and the actual cash contribution, the Commission held in Case No. 2662 that this negative amount should be removed from rate base. In the present case, PNM asserts the amount of the contribution is more than has been collected in rates so by the logic from Case No. 2662, PNM should be allowed to increase rate base by the difference.

47. AG witness Crane testified that the holding in Case No. 2662 related to a cash working capital claim by PNM rather than a pension asset claim. While PNM has calculated the pension asset in the present case as the difference between amounts collected in rates since 1987 and cash contributions made to the fund over some twenty years, AG witness Crane testified concerning PNM's claim in Case No.2662: "It had nothing to do with any comparison between accumulations of FAS 87 expense over any number of years in actual contributions to the plan. It's purely cash working capital, only one year, and just based entirely on the company's FAS 87 expense." Tr. 12/13/08, p. 137. A negative prepaid pension expense should be deducted from rate base when there are any cash working capital implications. AG Ex. 3, Crane Direct, pp. 27-28.

48. In Case No. 2262, PNM modified its original addition of $933, 919 to rate base in its cost of service due to early retirements in 1986 and 1987. PNM reduced its rate base by nearly $5.6 million for prepaid pension in its filed cost of service. PNM Ex. 36, Sategna Rebuttal., p.26. Since the Commission approved the cost of service, PNM asserts that its claimed methodology for treatment of the prepaid pension asset was accepted by the Commission in Case No. 2262.

49. There is no mention of a prepaid pension asset or SFAS 87 in either the Recommended Decision or the Final Order in Case No. 2262. If PNM modified its cost

of service when it filed it with the Commission in that case, it did so by its own choice and the issue of the rate base treatment of a prepaid pension asset was not made an issue in the case. The Commission did not approve PNM's treatment since the matter was removed from consideration by PNM's own actions.

50. PNM asserts that the most significant difference between the facts and circumstances in this case and in the Gas Rate case is the evidence that the Commission had approved similar treatment relating to pension funding in Case No. 2262 and 2662. The Commission disagrees with PNM's assessment of those cases. However, the record in the present case is convincing on two important matters. First, in the PNM Gas case, PNM attempted to measure the difference between the amount contributed by PNM and the amount that was recovered through rates. This led to controversy and was not convincing. In the present case, PNM compared the difference between the amounts it contributed and the amount of pension expense calculated pursuant to SFAS 87. Both amounts can be calculated from audited books and records. The Commission finds that this method produced a more precise calculation of the prepaid pension asset.

51. The second matter involves PNM's showing that there was a substantial benefit to ratepayers that resulted from the early voluntary contribution by PNM to the pension fund. The Commission could not verify such benefits in the Gas Rate case because of the manner in which PNM attempted to calculate the prepaid pension asset. The more precise and verifiable manner in which PNM calculated the asset in this case gives the Commission more confidence that there was a benefit to ratepayers. The record shows that for 2007, the pension cost for PNM's Pension Plan was lower because of the voluntary contributions. PNM Ex. 42, Wickes Direct, p.8. The Commission can

also have confidence in PNM's claim that without that contribution, its annual revenue requirement would be increased by over $1 million. PNM Ex. 34, Sategna Direct, p.31.

52. The Commission finds there is sufficient evidence which was lacking in the PNM Gas Rate case to allow PNM's requested adjustment to its rate base to reflect voluntary pre-payments made to the Deferred Pension Plan. The Commission remains concerned that PNM is contributing a discretionary amount that is in excess of what is required by SFAS 87; i.e., this is not a required investment. Secondly, the benefits of prepayments turn on the company's ability to realize a high rate of return on the additional funds. For these reasons, PNM should continue to bear the burden of proof in future rate cases that any prepayments claimed for rate base treatment result in a lower cost of service than the pay-as-you go approach.

E. Acquisition Adjustments

53. PNM claimed three acquisition adjustments in this case. The request to include an acquisition adjustment for the re-purchase of 60% of the Eastern Interconnect Project ("EIP") was accepted in the RD at page 91. However, the RD disallowed the acquisition adjustments associated with the purchase of transmission facilities from Tri-State G&T and the purchase of a 22% beneficial interest in the PVNGS Unit 1 and 2 leases. RD pp. 89, 93. PNM filed exceptions concerning the recommended denial of those adjustments. Even though there was opposition to the EIP acquisition adjustment before the Hearing Examiner, no exceptions to the RD were filed on that matter.

54. PNM acquired the transmission facilities from Tri-State when Plains G&T Coop. merged into Tri-State. The acquisition of the facilities by PNM was part of a joint proposal by Tri-State and PNM to Plains. PNM claims the RD accepts Staff's position

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 221

Attachment F
to
Appendix A

September 12, 2012

Control Number: 33309

Item Number: 749

Addendum StartPage: 0

PUC DOCKET NO. 33309
SOAH DOCKET NO. 473-07-0833

APPLICATION OF AEP TEXAS	§	**PUBLIC UTILITY COMMISSION**
CENTRAL COMPANY FOR	§	
AUTHORITY TO CHANGE RATES	§	**OF TEXAS**

ORDER

On November 9, 2006, AEP Texas Central Company (TCC) filed an application for authority to change rates pursuant to PURA,[1] Chapter 36, requesting an increase in base rates that would produce an annual base revenue increase of $62,709,174. During the course of this proceeding, TCC reduced this amount to approximately $49,952,000.[2] TCC also seeks to terminate the merger savings and rate reduction riders implemented in Docket No. 19365,[3] further increasing its revenues by $19,988,359 annually. Therefore, the total revenue increase sought by TCC in this proceeding is $69,940,359.

The administrative law judges (ALJs) filed a proposal for decision (PFD) on August 30, 2007. In their PFD, the ALJs recommend that the Commission approve TCC's application, including termination of the merger savings and rate reduction riders, subject to the adjustments recommended in the Proposal for Decision (PFD). The recommendations reduce TCC's adjusted test year total revenue requirements from $581,127,359 to $531,123,478, a reduction of $50,004,479. TCC identified several number-run adjustments required to implement the ALJs' decision.[4] The Commission ordered Commission Staff to incorporate TCC's number-run corrections, which resulted

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[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001 – 64.158 (Vernon Supp. 2007) (PURA).

[2] TCC Ex. 78, RWH-1R.

[3] *See Application of Central and Southwest Corporation and American Electric Power Company, Inc. Regarding Proposed Business Combination,* Docket No. 19365, Integrated Stipulation and Agreement (Nov. 18, 1999).

[4] AEP Central Company's Exceptions to the Proposal for Decision and Request for Number Running Corrections, Attachment E at 87-91(Sept. 20, 2007).

in a revenue requirement of $540,879,671 or a reduction of $40,247,688[5] from TCC's original request. The Commission adopts the PFD issued by the ALJs, including the findings of fact and conclusions of law, with the number run corrections recommended by TCC in its exceptions to the PFD.[6] Finding of Fact No. 42 is modified to reflect Commission Staff's updated number runs.

I. Findings of Fact

Procedural History

1. AEP Texas Central Company (TCC or the Company) is an electric utility operating company and wholly owned subsidiary of American Electric Power Company (AEP), a public utility holding company.

2. TCC has been functionally unbundled, and its costs have been separated for accounting purposes among Transmission, Distribution, and Generation functions since the onset of retail competition in 2002.

3. TCC filed its application with the Public Utility Commission of Texas for authority to increase its transmission and distribution (T&D) rates on November 9, 2006, requesting an overall increase of approximately $62.7 million.

4. As part of its application, TCC gave notice of its intent to terminate approximately $20 million in credits to customers that are provided by separate riders implemented in connection with the Commission's approval of the AEP/CSW merger in *Application of Central and Southwest Corporation and American Electric Power Company, Inc. Regarding Proposed Business Combination*, Docket No. 19265 (Nov. 18, 1999).

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[5] *See generally* Accounting and Depreciation Schedules and Related Workpapers (Nov. 12, 2007).

[6] *See generally* Corrected Page to the Proposal for Decision and Request for Number Running (Sept. 20, 2007).

5. Concurrent with its filing with the Commission, TCC filed a similar petition and statement of intent with each incorporated city in its service area that has original jurisdiction over its retail rates.

6. Notice of TCC's application was published once a week for four consecutive weeks in newspapers having general circulation in each county in TCC's service territory and was completed on December 14, 2006.

7. Individual notice of the TCC's application was provided on November 9, 2006, to the Commission Staff and the Office of Public Utility Counsel (OPC).

8. On October 4, 2006, TCC mailed notice to each municipality in TCC's service area of its intent to change rates charged to retail electric providers (REPs) and certain end-use customers.

9. On November 8, 2006, TCC mailed notice of its petition and statement of intent to each municipality within TCC's service area.

10. Individual notice of the TCC's application was provided and completed by November 9, 2006, to all REPs who have been certified by the Commission and who serve end-use customers in TCC's service area. Notice was provided to all certified REPs.

11. Individual notice of the Application was provided to each party that participated in *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840 (Aug. 15, 2005), TCC's last T&D rate case.

12. The Commission referred this proceeding to the State Office of Administrative Hearings (SOAH) on November 14, 2006. The Commission issued its Preliminary Order setting forth the issues to be addressed in this proceeding on December 19, 2006.

13. The following parties were granted intervention: Alliance for Retail Markets (ARM); Cities served by TCC (Cities); City of Garland; Commercial Customer Group (CCG); CPL Retail Energy, L.P. (CPL); Efficiency Texas; Federal Executive Agencies (Department of the Navy); Occidental Power Marketing, L.P.; OPC; Reliant Energy Retail Services, LLC; South Texas Electric

Cooperative; Sharyland Utilities, L.P.; State of Texas; Texas Cotton Ginners' Association; Texas Industrial Energy Consumers (TIEC); Texas Legal Services Corporation (TLSC); Texas Ratepayers Organization to Save Energy (Texas ROSE); Texas State Association of Electrical Workers; Oncor Electric Delivery Company; TXU Energy, Wholesale and Power Companies; and Wal-Mart Stores Texas, L.P. and Texas Retail Energy LLC (Wal-Mart).

14. TCC timely filed appeals with the Commission of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

15. TCC's application is based on a test year ending June 30, 2006.

16. On January 26, 2007, TCC filed an update to its rate filing that reduced its overall rate increase request by approximately $1.6 million.

17. When TCC filed its rebuttal case, it unilaterally decreased its total requested T&D base rate increase to approximately $50 million, a reduction of approximately $12 million from its initial request. This reduction included the impact of the January 26, 2007 update, as well as other reductions agreed to by the Company as a result of changed circumstances since its initial filing, or based on its review of Commission Staff and intervenor positions.

18. The hearing on the merits commenced on April 12, 2007 and lasted seventeen hearing days, concluding on May 4, 2007.

19. TCC proposed an effective date of December 14, 2006, for the proposed rates. The effective date was suspended for 150 days until May 13, 2007. The Company agreed to further extend the effective date in order to allow the ALJs and the Commission to process the case.

20. On April 17, 2007, TCC filed notice of its intent to put into effect, under bond, the rates set out in attached, filed tariff sheets. The rates will produce an annual base revenue increase of $50,061,000. TCC stated its intent to implement such bonded rates on a system-wide basis on or after May 30, 2007, in order to maintain uniform system-wide rates throughout its service territory.

21. On May 15, 2007, the ALJs issued an interim order finding that a bonded rate is a changed rate under the ISA and PURA § 36.110; therefore, TCC is allowed to terminate the merger savings and the rate reduction riders ordered in Docket No. 19265, upon implementation of bonded rates.

22. On June 27, 2007, the Commission denied an interim appeal of the order identified in the above Finding of Fact No. 21, affirming the ALJs' ruling.

Rate Base

23. TCC's used and useful total transmission plant in service is $944,552,252, and its used and useful transmission plant in service net of accumulated depreciation is $661,911,522.

24. TCC's used and useful total distribution plant in service is $1,719,634,015, and its used and useful distribution plant in service net of accumulated depreciation is $1,135,195,148.

25. TCC included in rate base a pension prepayment asset of $112.4 million.

26. The pension prepayment asset arises under Generally Accepted Accounting Principles (GAAP) in accordance with Statement of Financial Accounting Standards No. 87 (SFAS 87) and represents the amount by which the pension fund exceeds the accumulated pension obligations.

27. Investment income on the pension prepayment asset reduces pension cost calculated under SFAS 87.

28. Accounting in accordance with GAAP requires that both the balance sheet and income statement effects be taken into account.

29. The pension prepayment asset contains $22.799 million included in construction work in progress (CWIP).

30. Only the non-CWIP portion of the income earned on the pension prepayment asset is reflected in the total pension expense and the revenue requirement.

31. The pension prepayment asset should not be included in TCC's rate base to the extent that TCC's pension cost is capitalized to CWIP.

32. The pension prepayment asset of $112.4 million, less the $22.799 million portion included in CWIP, should be included in rate base.

33. All of TCC's operations and maintenance (O&M) and administrative and general (A&G) expenses are included in its cash working capital calculation.

34. The leads and lags in paying these items, which give rise to the amounts recorded in Account 190, have been appropriately included in the calculation of rate base through this process.

35. Accumulated Deferred Federal Income Tax (ADFIT) of $323.9 million is reasonable and should be included in rate base.

36. In arriving at its adjusted test-year-end rate base, TCC reclassified $7.3 million in transmission projects that were classified as CWIP and that had not been closed out to plant-in-service as of June 30, 2006 but which were actually providing service to customers as of that date.

37. TCC also removed from rate base allowance for funds used during construction (AFUDC) of $368,625 related to the transmission projects that were reclassified.

38. The $7.3 million reclassification of these projects to plant-in-service is reasonable and should be adopted.

39. TCC's construction accounts payable were included in TCC's cash working capital calculation. Accordingly, the leads and lags associated with these construction accounts payable are appropriately included in the calculation of rate base.

40. Based on Findings of Fact Nos. 72 through 77, TCC's affiliate capital costs assigned to TCC Distribution should be reduced by $2,454,762, and affiliate capital costs assigned to TCC Transmission should be increased by $211,520.

41. TCC included in rate base $10.2 million in debt restructuring costs related to business separation. TCC also included in cost of service an annual amortization

expense of $914,892 for amortization of these debt restructuring costs over a 15-year period.

42. TCC has a current cash working capital requirement of $2,191,723 for distribution and ($4,532,467) for transmission.

43. TCC's current working capital request reflects a modification of the monthly payment dates from TCC to American Electric Power Service Corporation (AEPSC) from the actual date of payment (usually the second or third working day after receipt) to the thirtieth day after receipt of the bill, as authorized by the TCC-AEPSC Service Agreement.

44. TCC must pay additional AEPSC financing costs for delaying payment of its bill from the second or third day until the thirtieth day after receipt.

45. TCC's own financing costs equal the financing costs charged to it by AEPSC. Thus, TCC will save the same amount of financing costs that AEPSC will charge it for delaying payments to AEPSC, so TCC will not incur any net increase in finance charges by delaying payment to AEPSC.

46. For TCC's cash working capital calculation, it is more appropriate to use the mid-point of the service period than the invoice date in the calculation of third-party expense lead days.

47. Cities' calculation of the third-party payment lead from samples of TCC's third-party invoices is reasonable and should be adopted, resulting in an additional third-party expense lead period of 2.26 days for distribution and an additional third-party expense lead period of 5.63 days for transmission.

48. The additional lead days for third-party expenses reduces TCC's request for cash working capital and rate base by $9,314,603.

49. Beginning with calendar year 2005, TCC was required to implement for financial reporting purposes accounting for legal asset retirement obligations (AROs) associated with the cost of removal of asbestos from buildings in accordance with SFAS 143.