BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 1672-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER OTHER CHANGES EFFECTIVE JULY 18, 2014.	**)**	**PROCEEDING NO. 14AL-0660E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS ARAPAHOE DECOMMISSIONING AND DISMANTLING PLAN.	**)**	**PROCEEDING NO. 14A-0680E**

<u>REBUTTAL TESTIMONY AND ATTACHMENTS OF LISA H. PERKETT</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

December 17, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF REBUTTAL TESTIMONY OF LISA H. PERKETT

Ms. Lisa H. Perkett, Director, Capital Asset Accounting, for Xcel Energy Services Inc., previously submitted Direct Testimony and Attachments in the proceeding. Ms. Perkett sponsors the plant in-service and other plant-related balances for both the 2015 Test Year and the 2013 Historic Test Year and supports the Company's proposals regarding depreciation and amortization expense. The purpose of Ms. Perkett's Rebuttal Testimony is to respond to certain of the positions contained in the answer testimonies of Mr. Jacob Pous for Colorado Energy Consumers ("CEC") and Federal Executive Agencies ("FEA") (jointly, "CEC/FEA"), Mr. Kevin Higgins for CEC, Mr. Stephen Rackers for FEA, Mr. Lane Kollen for Climax Molybdenum Company and CF&I Steel, LP ("Climax"), and Mr. Chris Neil for the Office of Consumer Counsel ("OCC"). In conjunction with the rebuttal testimonies of other Company witnesses, Mr. Jeff Kopp and Mr. Dane Watson, Ms. Perkett responds to arguments directed at the Company's use of removal cost estimates reflected in the Decommissioning Cost Study and other recommendations raised by parties affecting the Company's proposed depreciation rates. Ms. Perkett also provides a comparison of actual plant additions to date to forecasted plant additions for the 2014 bridge year.

In responding generally to the various recommendations made by witnesses in answer testimony regarding depreciation issues, including the use of estimated decommissioning costs for production facilities, Ms. Perkett emphasizes the importance in this rate case of assuring the Company's recovery of its electric utility investments is spread fairly and rationally over the life of the underlying assets. Ms. Perkett highlights the overriding principle of preserving intergenerational customer equity in resolving depreciation issues and observes that, given the comprehensive nature of the Company's proposals concerning depreciation and amortization and the Company's current construction program, this case presents a unique opportunity for the Commission to approve a long-term solution that assures the Company's recovery of its capital costs is fair and equitable to both current and future generations of customers. The Company's comprehensive proposals include: (1) revising depreciation rates for electric and common utility plant, as supported by Mr. Watson's Depreciation Rate Study and considering the Company's depreciation rates have not been changed since its 2006 rate case in Proceeding No. 06S-234EG; (2) incorporating estimated removal costs for production plant based on the results of Mr. Kopp's Decommissioning Cost Study, which follows the principles agreed upon between the Company and the Commission Staff in an effort to resolve disputes arising in the past two electric rate cases concerning the development of estimated dismantling cost studies and the reliability of their results; and (3) amortization of the remaining net book and estimated decommissioning costs associated with the Retired Generating Units (Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 and 2, and Zuni Unit 1) and Retiring Generating Units (Zuni Unit 2, Valmont Unit 5, and Cherokee Unit 3) over a four-year amortization period and including a reallocation of the depreciation reserve to mitigate the rate impacts.

In her Rebuttal Testimony, Ms. Perkett defends the Company's use of the estimated removal costs reflected in the Decommissioning Cost Study in developing depreciation rates, responding to specific criticisms of CEC/FEA witness Mr. Pous. Ms. Perkett also responds to recommendations of Mr. Pous, OCC witness Mr. Neil and Climax witness Mr. Kollen that less than the full cost of removal be included, points out that the Company's proposal is consistent with the FERC Uniform System of Accounts, accepted depreciation accounting principles and reasonably assures that the costs are borne by the generation of customers that caused them to be incurred and benefitted from the service, not by a later generation. Ms. Perkett discusses Xcel Energy's experience in Minnesota, where probability factors are applied to provide for recovery of less than the full estimated cost of removal, a policy that is currently being investigated and seriously questioned in a formal Minnesota Public Utilities Commission proceeding. Lastly, Ms. Perkett responds to the recommendations of Mr. Kollen and Mr. Neil that recovery of the removal costs associated with the Company's production facilities continue to be deferred into the future, emphasizing that such delays exacerbate the intergenerational inequities among customers.

Ms. Perkett also responds to challenges of intervenor witnesses to certain of the Company's proposed depreciation changes, including Mr. Neil's recommendation that no depreciation rate changes be approved in this proceeding. In conjunction with the Rebuttal Testimony of Mr. Watson's, Ms. Perkett addresses Mr. Pous' specific recommendations regarding the appropriate depreciation or amortization rates for Account 303, Intangible Plant and Account 392 Transportation Equipment, including a discussion of the Company's like-kind exchange program and the treatment of trade-in values that occur under such program. Ms. Perkett further explains the Company's change of position regarding the appropriate net salvage ratio for Transportation Equipment, and the impact of this change to annual depreciation expense. Ms. Perkett rebuts Mr. Pous' claims that the Company's proposal regarding reserve differences for general property accounted for under FERC Accounting Release ("AR") 15 amounts to a double-recovery of costs. Ms. Perkett also responds to Mr. Neil's recommendations concerning the amortization of costs associated with Retired and Retiring Generating Units and the proposed reallocation of depreciation reserve.

Finally, Ms. Perkett addresses the concerns raised by CEC witness Mr. Higgins regarding the transparency of the Company's depreciation expense calculations for the 2015 Test Year and the assessment of FEA witness Mr. Rackers regarding the Test Year plant in-service amounts. In support of the Test Year plant in-service balances, Ms. Perkett provides a comparative analysis for the 2014 bridge year between the Company's most recent plant additions amount forecast to the amounts originally filed, which reflects an overall difference of only 0.48 percent.

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REBUTTAL TESTIMONY AND ATTACHMENTS OF LISA H. PERKETT

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LIST OF ATTACHMENTS

Attachment No. LHP-9	Minnesota Department of Commerce's Analysis on the use of Probabilities for Decommissioning Estimates when Determining Depreciation
Attachment No. LHP-10	The Company's Analysis of Actual Plant Additions Compared to Forecast for the 2014 Bridge Year.

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
B&M	Burns & McDonnell Engineering Company, Inc.
CACJA	Clean Air Clean Jobs Act
CEC	Colorado Energy Consumers
CHECC	Colorado Healthcare Energy Coordinating Council
CLIMAX	Climax Molybdenum Company
CPUC, Commission, or Staff	Colorado Public Utilities Commission
DOC	Minnesota Department of Commerce
FEA	Federal Executive Agencies
FERC	Federal Energy Regulatory Commission
FPUA	Fort Pierce Utility Authority
HTY	Historic Test Year
MPUC	Minnesota Public Utilities Commission
NARUC	National Association of Regulatory Utility Commissions
NSPM or NSP-Minnesota	Northern States Power – Minnesota
OCC	Colorado Office of Consumer Counsel
Public Service or the Company	Public Service Company of Colorado
RFP	Request for Proposal
TLG	TLG Services, Inc.

USOA	Uniform System of Accounts

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REBUTTAL TESTIMONY AND ATTACHMENTS OF LISA H. PERKETT

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY, AND RECOMMENDATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lisa H. Perkett. My business address is 414 Nicollet Mall, Minneapolis, MN 55401-1993.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY AND ATTACHMENTS IN THIS PROCEEDING?

A. Yes. I submitted Direct Testimony and Attachments in this case on behalf of Public Service Company of Colorado ("Public Service" or the "Company") as part of the Company's original filing on June 17, 2014.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to some of the positions contained in the Answer Testimonies of Mr. Jacob Pous for Colorado Energy Consumers ("CEC") and Federal Executive Agencies ("FEA") (jointly, "CEC/FEA"), Mr. Kevin Higgins for CEC, Mr. Stephen Rackers for FEA, Mr. Lane Kollen for Climax Molybdenum Company and CF&I Steel, LP ("Climax"), and Mr. Chris Neil for the Office of Consumer Counsel ("OCC"). My testimony responds to arguments directed at the Decommissioning Cost Study, proposed depreciation rates, the recovery of the Retired and Retiring Generating Units,[1] and the comparison of actual plant additions to date to budgeted plant additions for the forecast bridge year.

Two other Company witnesses provide Rebuttal Testimony addressing certain of these issues as well. Mr. Kopp of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") addresses the issues raised that pertain to the cost of removal estimates developed as part of the Decommissioning Cost Study, and Mr. Dane Watson of Alliance Consulting Group addresses challenges raised by intervenors to certain aspects of the depreciation life and net salvage reflected in the Depreciation Study.

[1] For purposes of the Company's Rebuttal Testimony, the terms "Retired Generating Units," "Retiring Generating Units," and the combined "Retired and Retiring Generating Units" have the same meanings as used in my Direct Testimony as set forth in footnotes 1 and 2 therein. In sum, "Retired Generating Units" refers to Cameo Units 1 and 2, Arapahoe Units 1 through 4, Cherokee Units 1 and 2, and Zuni Unit 1 and "Retiring Generating Units" refers to Zuni Unit 2, Valmont Unit 5, and Cherokee Unit 3.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR REBUTTAL TESTIMONY?

A. Yes, I am. I am sponsoring Attachment Nos. LHP-9 and LHP-10.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR REBUTTAL TESTIMONY?

A. I recommend that the Commission reject the recommendations of the various witnesses in Answer Testimony and approve the Company's proposed depreciation and amortization expense, including the proposed amortization of the Retired and Retiring Generating Units and reserve reallocation. In conjunction with this recommendation, I recommend the Commission adopt the proposed depreciation rates recommended by Mr. Watson and set forth in his Depreciation Rate Study, as slightly modified as explained herein, as well as the inclusion of the estimated removal costs for production plant reflected in the Decommissioning Cost Study sponsored by Mr. Kopp. I also recommend the Commission not accept the recommendations of Mr. Rackers regarding the 2015 plant in-service amounts and instead adopt the plant-in service balances underlying the 2015 Test Year revenue requirements.

II. DEPRECIATION AND AMORTIZATION EXPENSE

Q. WHAT IS YOUR GENERAL RESPONSE TO THE POSITIONS OF INTERVENORS WITH REGARD TO THE DEPRECIATION ISSUES IN THIS RATE CASE, INCLUDING THE USE OF ESTIMATED DECOMMISSIONING COSTS FOR PRODUCTION FACILITIES?

A. Given certain of the recommendations regarding the Company's proposals regarding depreciation, estimated removal costs for production plant, and amortization of the Retired and Retiring Generated Units in this proceeding, I am concerned that parties in this proceeding are not grasping the importance of assuring that the Company's recovery of its electric utility investments is spread fairly and rationally over the life of the underlying assets. Considering past treatment of depreciation changes and decommissioning costs in recent electric rate cases, and the current capital construction program spurred by the Company's Electric Resource Plans and the Clean Air-Clean Jobs Act ("CACJA"), there may not be a better opportunity for the Commission to approve a comprehensive solution that assures the Company's recovery of its capital costs is fair and equitable to both current and future generations of customers.

Book depreciation accounting is the process of recognizing in financial statements the consumption of physical assets in the process of providing a service or a product. Generally Accepted Accounting Principles ("GAAP") require the recording of depreciation to be systematic and rational. To be systematic and rational, depreciation should match, to the extent possible, the consumption of the facilities or the revenues generated by the facilities. Accounting theory requires the “matching” of expenses with either consumption or revenues to ensure that financial statements reflect the results of operations and changes in financial position as accurately as possible. Matching is also an essential element of basic regulatory and ratemaking philosophy and, with respect to the spreading of capital costs over many years, it has become known as “intergenerational customer equity.” Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that the charges to customers reflect the actual costs of providing service.

The Company’s depreciation rates have not been changed since the Company’s 2006 rate case in Proceeding No. 06S-234EG. As reflected in the Depreciation Study sponsored by Mr. Watson, an update to the Company’s electric and common utility depreciation rates is warranted, and likely overdue. In its last two rate cases before the Commission in Proceeding Nos. 09AL-299E and 11AL-947E, the Company has proposed to adjust its depreciation rates for production plant to include updated estimates for the cost of removal, but has not succeeded due to fundamental disputes over the appropriate approach to estimating decommissioning costs and the sheer size of these estimated costs. The fundamental disputes raised in these prior rate cases have been largely resolved and these significant costs can no longer be excluded from recovery. Given the substantial new production facilities currently under construction that will be placed in service in the next few years, the amortization necessary to recover the net book and decommissioning costs associated with the Retired and Retiring Generation Units also cannot be postponed any longer.

The Company has proposed measures – a reserve reallocation and a four-year amortization period -- to mitigate the impacts associated with amortizing the costs related to the Retired and Retiring Generating Units. While mitigation of large rate impacts is a worthy objective, the Commission and the parties should not lose sight of the fact that the Company's proposed depreciation rates, including the updated cost of removal, will result in a better matching of depreciation expense to the actual time period over which customers receive the benefit from the production of electricity derived from each generating plant or unit. Both during and after the four-year amortization period, the depreciation rates approved by the Commission in this case must assure that intergenerational inequity is not produced by charging future customers with recovery of costs for assets not recovered efficiently in prior periods due to depreciation periods being misaligned and under-calculated. Avoiding intergenerational subsidies is in the best interest of both current and future Public Service customers and is achieved by adopting the depreciation changes proposed by the Company in this case.

The Commission recently addressed the wisdom of deferring an electric utility's recovery of current and prior period costs to future periods, or postponing consideration of such issues to future rate case proceedings, in the Black Hills/Colorado Electric Utility, LP ("Black Hills") rate case in Proceeding No. 14AL-0393E. In Recommended Decision No. R14-1298, issued October 28, 2014, Administrative Law Judge Robert I. Garvey referred to this approach as "'a bit like kicking the can down the road'" (quoting the testimony of the OCC's witness), and found that "it does not allow for cost recovery in a timely manner." Decision No. R14-1298, p. 78, ¶ 300. The ALJ rejected the OCC's approach, concluding at paragraph 301 that "[t]he ratepayers do not deserve to be misled about reducing rates and then be hit with a huge rate increase after the next Phase I rate case, and Black Hills should be allowed recovery of legitimate expenses in a timely manner." In its deliberations addressing exceptions on December 10, 2014, the Commission announced its ruling denying the OCC's exceptions on this issue. This same misguided approach of "kicking the can down the road" seems to underlie the recommendations of the intervenors in this case to defer consideration of some or all of the Company's proposed changes pertaining to depreciation and amortization expense.

A. __Decommissioning Costs for Generating Units__

Q. WHAT WITNESSES SUBMITTING ANSWER TESTIMONY ADDRESS THE COMPANY'S PROPOSAL TO INCORPORATE THE ESTIMATED COST OF REMOVAL REFLECTED IN THE BURNS & McDONNELL DECOMMISSIONING COST STUDY IN THE CALCULATION OF ITS PROPOSED DEPRECIATION RATES?

A. The witnesses addressing decommissioning cost estimates are CEC/FEA witness Mr. Jacob Pous, OCC witness Mr. Chris Neil, and Climax witness Mr. Lane Kollen.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS THAT HAVE BEEN MADE CONCERNING THE COMPANY'S PROPOSAL TO INCLUDE DECOMMISSIONING COST ESTIMATES RESULTING FROM THE DECOMMISSIONING COST STUDY.

A. CEC/FEA witness Mr. Jacob Pous questions the reliability of the Decommissioning Cost Study, claiming that the results are not adequately supported. Mr. Pous concludes that the results are both excessive and inconsistent with other Burns & McDonnell studies performed for other utilities. Mr. Pous recommends two adjustments addressing indirect costs and contingencies, resulting in a total reduction to depreciation expense of $4.1 million based on plant balances of as of December 31, 2013.

OCC witness Mr. Neil recommends that no new cost of removal estimates be adopted for generating plants in this case because (1) the amount of the costs are "speculative" and (2) the actual terminal retirement dates are uncertain. In making this recommendation, Mr. Neil effectively supports adoption of the cost estimates reflected in the depreciation study submitted in the Company's 2006 rate case that are the basis for the currently approved depreciation rates.

Climax witness Mr. Kollen recommends that the Commission adopt 50 percent of the Company's proposed decommissioning cost estimates reflected in the Decommissioning Cost Study and defer recovery of the remainder of the decommissioning costs until the Commission has reviewed the Company's decommissioning and site restoration plans in a separate proceeding.

Q. ARE ANY OTHER COMPANY WITNESSES SUBMITTING REBUTTAL TESTIMONY IN RESPONSE TO THE ISSUES RAISED REGARDING DECOMMISSIONING COST ESTIMATES?

A. Yes. Company witness Mr. Kopp will address specific criticisms raised directed at the Decommissioning Cost Study and its results. I will address some of these same issues from the Company's point of view, as well as the broader issues concerning the Company's proposal to recover removal costs through its proposed depreciation rates in this proceeding.

Q. IS IT EXPENSIVE TO DEMOLISH GENERATING UNITS?

A. Yes, the removal costs for electric power plants are significant. These are large facilities and proper removal of all the components at the end of their life requires using proper methods to safely remove the equipment and facilities and restoring the land to a state such that the site can be used again for an industrial use. However, the overall cost of decommissioning represents only approximately 8 percent of the total current investment, which is a very reasonable amount considering removal of some of the transmission and distribution equipment is as high as 50 percent of the cost of those particular facilities.

1. Response to CEC/FEA Witness Mr. Pous

Q. FROM PAGE 14, LINE 14 TO PAGE 15, LINE 9 OF HIS ANSWER TESTIMONY, MR. POUS DISCUSSES WHY "BLIND RELIANCE ON THE UNTESTED PRESENTATION OF A COST ESTIMATE FROM AN ENGINEERING COMPANY MAY NOT BE WISE." IS THIS A FAIR CHARACTERIZATION OF WHAT PUBLIC SERVICE DID IN ENLISTING THE

SERVICES OF BURNS & McDONNELL?

A. No it is not. Mr. Pous goes on to reference an instance in Nevada where an engineering firm estimated decommissioning costs for a utility's plant that was actually decommissioned for 25 percent of the estimate. As explained by Mr. Kopp in his Rebuttal Testimony, the cost differential between the engineer's estimate and the actual demolition of the Nevada plant resulted from a difference in decommissioning methodology. It is true the Company is relying on the Burns & McDonnell Study to determine the proper dismantling costs of facilities. However, to characterize this as "blind reliance on an untested presentation" is not reasonable. The use of the Decommissioning Cost Study was a part of a more holistic approach, which combined previous Company experiences related to removal costs with expertise from third-party consultants to develop a reasonable expectation of future decommissioning costs. Reliance on a third-party study is a reasonable basis for establishing dismantling costs estimates. This is especially true here, where the RFP and contractual scope of work incorporated the principles for estimating dismantling costs that were agreed upon between the Company and the Commission Staff.

Q. WHY DOES THE COMPANY BELIEVE ITS RELIANCE ON THE BURNS & McDONNELL DECOMMISSIONING COST STUDY IS REASONABLE?

A. The purpose of engaging a third party engineering firm to provide estimates of dismantling costs is to gain the benefit of that firm's experience and expertise in this area. The Burns & McDonnell study is based on historical data in the sense that it is based on their knowledge of previous dismantling projects, the work that goes into these projects and the costs and salvage credits for these projects. There is also the additional benefit of obtaining a more objective perspective when using an external entity, as opposed to providing estimates internally. This makes reliance on a third party for dismantling estimates preferable to other approaches. Though the Company fully admits the results are estimates that may differ from actual costs, the Decommissioning Cost Study nonetheless represents a good faith effort made by the Company to establish costs deemed likely to occur based on the conditions and requirements currently in place. Furthermore, the use and reliance on experienced third parties for decommissioning study estimates is a well-established practice and is currently the best source of cost information the Company can provide.

Q. HOW DO YOU INTERPRET MR. POUS' STATEMENT AT PAGE 19, LINE 12 OF HIS ANSWER TESTIMONY, WHERE HE CLAIMS THE DECOMMISSIONING COST STUDY REFLECTS A "WORST-CASE DEMOLITION AND SITE RESTORATION SCENARIO"?

A. At page 20, lines 8-12 of his Answer Testimony, Mr. Pous describes a continuum of options when it comes to the treatment of retired generation facilities. At one end is the sale of a facility, which would have positive salvage. At the other end of the spectrum is the complete dismantlement of the facility, which would yield a negative net salvage. The Company's Decommissioning Cost Study assumes the dismantlement of a facility with the inclusion of the scrap value. In Mr. Pous' view, this represents the worst-case scenario, as it would yield the highest cost of removal. However, the lack of a proper level of estimated removal cost in the depreciation rate subjects future customers to the burden of funding the additional cost after retirement, such as is occurring in this case with respect to the Retired and Retiring Generating Units, while also funding replacement facilities at the same time. This creates intergenerational inequities as between current and prior generations of customers.

Q. IS INCLUDING THE FULL COST OF REMOVAL IN THE CALCULATION OF NET SALVAGE IN DEPRECIATION RATES CONSISTENT WITH APPLICABLE ACCOUNTING REGULATIONS?

A. Yes. The Commission has adopted the FERC Uniform System of Accounts for Public Utilities, 18 Code of Federal Regulations Part 101, ("USoA") and requires electric utilities subject to its jurisdiction to maintain their books and records in accordance with the requirements of the USoA. (See Rule 3005(e) of the Commission's Rules Regulating Electric Utilities, 4 Code of Colorado Regulations 723-3-3005(e).) The USoA requires public utilities to develop and implement depreciation rates for electric plant that provide for the recovery of the "the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto." However, the USoA does not allow, as intervenors are advocating in this proceeding, for inclusion of only some or half of the cost of removal. The accounting regulations require depreciation rates be developed based on the full cost of removal.

Q. WHERE IS THIS REQUIREMENT REFLECTED IN THE USoA?

A. The term "cost of removal" is defined in ¶ 10 of the USoA Definitions, as follows:

> 10. *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant,

> including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (*See* General Instruction 25).

Paragraph C of General Instruction No. 22, Depreciation Accounting, provides that "Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the ***service value*** of depreciable property to the service life of the property." [Emphasis supplied.] In turn, "***service value***" is defined as "the difference between original cost and ***net salvage value*** of electric plant" and "***net salvage value***" is defined as "the salvage value of property retired less the ***cost of removal***. (See USoA Definitions ¶¶ 37 and 19; emphasis supplied.)

Q. IS IT REASONABLE TO ASSUME FULL DISMANTLEMENT OF THE FACILITY?

A. Yes, it is. The objective of recovering for cost of removal through depreciation is to collect the expected costs over the useful life of the plant. Without any definitive plan to sell any of its generating plants, the Company has a reasonable expectation that plants listed in the Decommissioning Cost Study will be dismantled fully at the end of their useful life. To assume otherwise would be pure conjecture. Moreover, there is no risk of the Company over-recovering its actual cost of removal for a plant if, at the end of its life, it is not fully dismantled and the actual costs are less than what was previously recovered through depreciation. The USoA and standard depreciation accounting provide for any such decommissioning cost savings to be credited to customers through an adjustment to the Accumulated Provision for Depreciation (FERC Account 108).

In addition, for large retired generating stations, the current procedures adopted by the Commission for utilities to apply for approval of site-specific decommissioning plans and cost recovery effectively prevent the utility from over-recovering the cost of removal.

Q. HAVE THERE BEEN ANY SITUATIONS WHERE XCEL ENERGY HAS FULLY DISMANTLED AND REMOVED A GENERATING FACILITY?

A. Yes. The Company has dismantled and removed the Cameo plant. In addition, Northern States Power Company, our sister electric utility in Minnesota, has dismantled and removed the High Bridge plant.

Q. ON PAGE 11, LINES 16-17, MR. POUS STATES THAT "SOME PROBABILITY EXISTS THAT NOT ALL UNITS WILL BE TOTALLY DEMOLISHED WITHOUT ANY ASSET HAVING A VALUE ABOVE SCRAP VALUE." DO YOU AGREE IT IS POSSIBLE THAT THE COST TO DEMOLISH A PARTICULAR UNIT WILL BE LESS THAN THE SALVAGE VALUE?

A. It is possible, but it is pure speculation to attempt to guess when and where this will occur. Mr. Pous does not define the probability of this situation arising. It has not presented itself for any Public Service facility to date and, thus, one would conclude that the probability is insignificant. Mr. Pous points to two situations at pages 22-23 of his Answer Testimony where equipment was sold, but he does not provide any statistics to support the probability. He claims at page 23, lines 8-10 that the Decommissioning Cost Study ignores the fact that there is an active market for used power plant equipment, but fails to recognize the Company assumed that the equipment at these facilities will have been used to their full potential and, thus, there will not be substantial value left on the equipment that any reuse market would want. Mr. Pous also ignores the fact, as assumed in the Study, that removal cost savings could be realized through demolishing certain components, instead of trying to carefully remove equipment that would not bring in an additional amount of salvage value to justify the additional removal costs. Further, Mr. Pous unjustifiably assumes that the current removal cost for equipment that is to be treated as scrap is the same as would be incurred if the equipment were to be sold on the "active market." There are certainly other ways of taking down power plants, but they are not necessarily less expensive, and Mr. Pous has not provided any evidence that such alternative methods would be applicable for Public Service's generating units.

Q. AT PAGE 11, LINES 18-20, OF HIS ANSWER TESTIMONY, MR. POUS SUGGESTS THAT CURRENT CUSTOMERS WILL BE OVERCHARGED FOR SITE IMPROVEMENT COSTS UNLESS THERE IS AN OFFSET FOR THE SALE OF THE LAND OR REUSE OF THE SITE. DO YOU AGREE?

A. No. The cost estimates reflected in the Decommissioning Cost Study include $74.1 million in scrap value. This is a common argument from Mr. Pous. Based on his discussion at page 24, lines 6-11 of the King Power Plant in Ft. Pierce, Florida, where the winning bid to demolish the plant reflected almost a $1 million benefit (negative cost) to the utility, Mr. Pous apparently assumes the same thing will occur for the demolition of the Company's plants and, thus, the cost estimates should be reduced.

This is an interesting argument in that it nearly the same the argument Mr. Herbert Duane of Duane Corporation made in Xcel Energy's 2008 Texas rate case. There, Mr. Duane suggested that, based upon on the experience at the ongoing demolition at the H.D. King Plant in Fort Pierce, Florida, any fossil electric generating plant demolition would pay for itself. Mr. Duane believed that this sole experience should set the standard that it is not uncommon for the value of salvageable equipment and materials from power plants "to equal or exceed the cost of demolition."[2]

Mr. Seymore, of TLG Services, Inc., who performed the decommissioning cost estimates for Xcel Energy in the Texas case, reviewed the work being done at the King plant and concluded as follows:

> The 24 megawatt combustion turbine at the H. D. King Plant (Mr. Duane's sole example of an actual dismantling experience) may have a potential salvage value between one and four million dollars (with its low usage and short operating history), according to Xcel Energy's Greg Ford (Director of Engineering). The notes of my conversation with Mr. Ford are included in my Attachments FWS-RR-R2. However, according to a representative of the Fort Pierce Utility Authority ("FPUA"), the unit does not meet current U.S. emission regulations. As such, any sale of the unit would have to be to a foreign buyer. As of November 3, 2008, no such buyer has been found (though they have a lead in Kazakhstan), and it would be highly speculative to assume that such a buyer does actually exist in determining the net "worth" of a retired facility.
>
> It should also be noted that the TLG estimates do not include the extra cost to remove items with potential salvage value, transport the items to a safe location, and store the items until such time that a disposition of the items could be

2 *Application of Southwestern Public Service Company for Authority to Change Rates, To Reconcile Fuel and Purchased Power Costs for 2006 and 2007, And to Provide a Credit for Fuel Cost Savings*, Texas PUC Docket No. 35763, Answer Testimony of Herbert Duane on behalf of Texas Industrial Consumers, filed October 13, 2008, p. 17, lns 11-16.

> negotiated. An accurate estimate of such costs would also have to factor in the additional time such removals would add to the demolition project.[3]

I believe the additional information that was provided in our Texas rate case shows that the situation at the H.D. King Plant was not as rosy as it was when demolition started. Furthermore, the experience at the H.D. King Plant is not representative of Public Service's much larger power stations such as Cherokee, Pawnee, or Comanche.

Q. HAS THERE BEEN A SITUATION WHERE THE COMPANY HAS FULLY SOLD A FACILITY OR ONLY PARTIALLY REMOVED A FACILITY?

A. No. This would be an unusual circumstance in the industry. In fact, Mr. Pous has only presented the one experience showing salvage value to be greater than the cost of removal.

Q. IS THERE A RISK TO CUSTOMERS IF TOO LITTLE COST OF REMOVAL IS COLLECTED DURING THE LIFE OF A GENERATING FACILITY?

A. Yes, this is the problem of intergenerational inequities that I mentioned earlier. For example, let's assume the Company used a more optimistic treatment (to use Mr. Pous' terminology) for retired facilities that anticipate only partial removal of a facility. Further assume that five years before shutdown, it was determined that full rather than partial demolition would occur and that this change would result in $100 million in additional removal costs. This means that customers during the last five years of the life of the plant would have to cover an additional

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[3] *Application of Southwestern Public Service Company for Authority to Change Rates, To Reconcile Fuel and Purchased Power Costs for 2006 and 2007, And to Provide a Credit for Fuel Cost Savings*, Texas PUC Docket No. 35763, Rebuttal Testimony of Francis W. Seymore on behalf of Southwestern Public Service Company, filed November 14, 2008, p. 6, lns 18 through p. 7, ln 11.

$20 million per year in depreciation related to removal costs. Such result would unfairly and disproportionately burden this later generation of customers.

Q. HAS A SIMILAR SITUATION HAPPENED TO THE COMPANY BEFORE?

A. Yes. In the 2009 Colorado rate case, Proceeding No. 09AL-299E, the Company proposed an increase in the cost of removal near the end of the life of the Cameo, Arapahoe and Zuni plants. Mr. Eugene Camp for the Commission Staff argued that this request would result in intergenerational inequity because the cost estimate was increased too close to the end of the life of the facility and would result in too large of an increase in depreciation for customers. The Company ultimately withdrew its proposal to change depreciation rates in a comprehensive settlement with Staff. I appreciate Mr. Camp's concern with increasing the recovery for decommissioning costs late in the life of plants and the fact that it tends to put a heavier burden on the customers during these remaining years. However, the tendency in this proceeding and prior ones to shy away from the reality that the estimated site-specific costs are closer to what will actually be incurred is only creating future intergenerational inequity problems that can and should be addressed now.

Q. MR. POUS STATES ON PAGE 21, LINES 3-13, THAT "[T]HE B&M STUDY IS DEFICIENT BECAUSE IT FAILS TO RECOGNIZE ANY SALVAGE VALUE FOR VALUABLE WATER RIGHTS." DO YOU AGREE?

A. No. There are water rights listed separately in the plant accounts for Cherokee and Zuni in Steam Production. The Company does not believe the sale of the water rights would be wise or would offset the cost to decommission these two facilities. For Zuni, the water rights were acquired in 1924 and were originally established for the La Combe power plant. These rights are non-consumptive and are a junior right. Non-consumptive means that the water goes in, is used for cooling, and is then returned to the river after it is cooled. Thus, no water is consumed in the process. A junior right means that we do not have first priority to the water source. To ensure that we have sufficient water for the Zuni plant, we have a contract with the City of Denver and they deliver a contracted amount of water to the plant. As to whether the water sources have saleable value is questionable because of the rights nature being non-consumptive and junior. Also, the Company may be able to extend the contract with the City of Denver to another of its own facilities at the same location, but another entity would have to negotiate a new contract with the City.

For Cherokee, the situation is entirely different. This water right has been established as an interchangeable right, which means that the right to the use of water in the South Platte River Basin can be used at Cherokee, Fort St. Vrain, Pawnee, Rocky Mountain Energy Center, Georgetown, and Cabin Creek. Thus, one could assume that these water rights would remain active as long as Public Service has a generation facility within the South Platte River Basin. The Cherokee water rights have an original value of $112,245 with a depreciation reserve of $4,221 for a net plant value of $108,024. If Public Service sold these rights to offset the cost of demolishing the current four units at Cherokee, the sale value would first have to provide for the undepreciated value and then we would have to purchase new rights at an exorbitant cost to customers. Thus, I see no benefit to selling or even considering the sale of water rights in estimating the cost of decommissioning for the generating facilities.

Q. SHOULD THE COMMISSION ACCEPT MR. POUS' RECOMMENDATION TO REDUCE THE ESTIMATED DECOMMISSIONING COSTS FOR INCLUSION IN DEPRECIATION RATES IN THIS PROCEEDING?

A. No.

Q. AT PAGE 11, LINES 12-20, OF HIS ANSWER TESTIMONY, MR. POUS OFFERS A STANDARD THAT HE SAYS THE COMMISSION SHOULD RELY ON IN ASSESSING DECOMMISSIONING COST ESTIMATES. DO YOU AGREE WITH HIS RECOMMENDED STANDARD?

A. No. Mr. Pous' espoused standard merely restates his arguments and ignores well-established depreciation accounting principles and applicable accounting regulations. The correct standard is establishing depreciation accruals that most reasonably and equitably achieve a systematic and rational allocation of the service value of an asset, including the cost of removal, over the service life of the asset. This includes, as to each asset, the full cost of removal of that asset. The Company's proposal satisfies this standard. Mr. Pous, on the other hand, argues that the Commission should adopt the recommendation that "best represents a fair presentation of what will occur in the future" including recognition of the probability "that not all units will be totally demolished without any asset having a value above scrap value," and that current customers "should also be entitled to a current offsetting benefit expected for the future sale or reuse of the improved site."[4] As explained above, there are many problems with Mr. Pous' suggestions and the negative consequences to future customers do not warrant their adoption under the circumstances in this proceeding.

2. Response to Climax Witness Mr. Kollen

Q. WHAT DOES CLIMAX WITNESS MR. KOLLEN RECOMMEND WITH REGARD TO THE COST OF REMOVAL FOR PRODUCTION PLANT?

A. At pages 45-46 of his Answer Testimony, Mr. Kollen proposes to reduce terminal net salvage for operating plants because of his conclusion that the Company is not generally required to dismantle or decommission a plant and restore the site to industrial use. He recommends the Commission convene a separate proceeding to review options for decommissioning and site restoration and, in the meantime, only allow for recovery of 50 percent of the decommissioning cost estimates set forth in the Decommissioning Cost Study and incorporated in depreciation and amortization expense. He also recommends the Company be put on notice that it may not recover decommissioning costs if it proceeds to decommission a plant before the Commission's review of its plans in a separate proceeding.

Q. IS MR. KOLLEN'S RECOMMENDATION REASONABLE?

A. No. For the reasons I addressed above, Mr. Kollen's recommendation to allow for recovery of only half of the estimated cost of removal for production plant sets a dangerous precedent of creating intergenerational inequity. The process recommended by Mr. Kollen would dampen the recovery of removal costs over

[4] Answer Testimony of Jacob Pous, p. 11, lns. 14-20.

the useful life of the facilities and put off the recovery of a significant portion of the removal cost until it is known. Recovery of the estimated costs to remove a fixed asset is included in the depreciation rate that spreads the cost of recovery for the estimated removal over the useful life of the fixed assets. This allows the generations of customers that are benefiting from the asset to contribute all of the costs associated with the asset. To Mr. Camp's point in the Company's 2009 rate case, waiting too late in the service life of the asset puts an unfair burden on customers late in the asset's life. It is therefore imperative that the Commission approve the correct negative net salvage as part of the depreciation rate in this proceeding.

Q. DO ANY OTHER JURISDICTIONS IN WHICH XCEL ENERGY AFFILIATED UTILITIES OPERATE EMPLOY A SIMILAR CONCEPT OF RECOVERING ONLY A PERCENTAGE OF REMOVAL COSTS?

A. Yes. Northern States Power Company, a Minnesota corporation ("NSP-Minnesota") uses probabilities to account for uncertainty regarding decommissioning costs in the future. NSP-Minnesota was initially ordered to begin recovering 50 percent of the estimated demolition costs of five steam plants by the Minnesota Public Utilities Commission ("MPUC"). This came at the behest of the Minnesota Department of Public Service who wanted to temper the needs of the company to collect removal costs from current customers with the possibility that plants may not need to be fully decommissioned. NSP-Minnesota stuck with using 50 percent of the cost estimates for these five steam plants until 2010, when it proposed a modification to the use of probabilities, one that used length of remaining life as a driver in determining the percentage of decommissioning estimates used to calculate net salvage rates. The criteria approved by the MPUC are as follows:

- If the unit has a remaining life less than ten years, use 100 percent of the cost study's estimate to calculate the net salvage rate.
- If the unit has a remaining life greater than or equal to ten years, but less than twenty years, use 75 percent of the cost study's estimate to calculate the net salvage rate.
- If the unit has a remaining life greater than or equal to twenty years, use 50 percent of the cost study's estimate to calculate the net salvage rate.

Q. HAS ANY CONCERN BEEN RAISED IN MINNESOTA ABOUT NSP-MINNESOTA'S USE OF THESE PROBABILITIES?

A. Yes, the MPUC recently opened a docket at the request of the Minnesota Department of Commerce ("DOC") to investigate the use of probabilities for decommissioning estimates when determining depreciation. Based on their analysis, the DOC argues that only collecting a percentage of expected decommissioning costs through depreciation for a period of time can yield more volatility and cause large increases late in a plant's life, when there is less time to recover any increases in decommissioning cost estimates. A copy of the DOC's analysis is included with my testimony as Attachment No. LHP-9.

Q. IS IT A MATTER OF WELL-ESTABLISHED PRACTICE WITHIN THE UTILITY INDUSTRY TO INCLUDE REMOVAL COST IN THE DEPRECIATION RATE?

A. Yes. I already discussed the basic requirements of the USoA. In addition, the renown, industry-accepted publication, *Public Utility Depreciation Practices*, published by the National Association of Regulatory Utility Commissioners ("NARUC"), 1996 Edition, provides an excellent description of the process:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between the gross salvage that will be realized when the asset is disposed of and the cost of retiring it. Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage. Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.
>
> This treatment of net salvage is in harmony with generally accepted accounting principles and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that current customers pay or receive a fair share of cost associated with the property devoted to their service, even though the costs may be estimated.

The Company's proposal to include the results of the Decommissioning Cost Study in developing depreciation rates in this Proceeding, reasonably implements the above well-established depreciation practices.

Q. DOES THE UNDER-RECOVERY OF TERMINAL REMOVAL COSTS CREATE INTERGENERATIONAL CUSTOMER INEQUITY?

A. Yes. Delaying proper depreciation rate recovery until such time as all retirement facts are certain (*i.e.*, actual shutdown date and specific engineering plans for the actual demolition), as recommended by Mr. Kollen, burdens future customers with a disproportionate share of the removal cost and gives current customers a discount for their share of the costs associated with the unit. For example, waiting until the last five years of the unit's useful life will mean that all necessary removal costs will be allocated across those five short years, instead of over the entire useful life. A hypothetical removal cost estimate of $55 million for a plant having a 55-year useful life will spread $11 million per year of removal cost recovery to customers in the last five years, whereas if earlier customers had provided their fair share of recovery, these same customers would only have to provide $1 million each year.

Q. DO YOU AGREE WITH MR. KOLLEN'S SUGGESTION AT PAGE 44, LINES 4-9, OF HIS ANSWER TESTIMONY THAT DISMANTLEMENT AND SITE RESTORATION MAY BE DELAYED INDEFINITELY?

A. No. Mr. Kollen recommends the Commission consider that units could be mothballed or sit idle after retirement for many years to dampen the cost impact of removal. Although this may delay spending the removal costs, it does not prevent it from occurring. Public Service's Decommissioning Cost Study assumes that the units will eventually have to be removed regardless of how long one delays the activity. Any delayed action will put the removal cost off further into the future (likely increasing the cost as the work has significant labor costs), but it cannot eliminate it. Additionally, such a delay exacerbates intergenerational inequity by pushing the eventual cost further away in time from those customers that benefited from the service provided by the asset.

3. Response to OCC Witness Mr. Neil

Q. PLEASE ADDRESS MR. NEIL'S ARGUMENTS THAT, BECAUSE THE AMOUNT AND TIMING OF DECOMMISSIONING COSTS ARE "SPECULATIVE", THE COMMISSION SHOULD NOT APPROVE ANY CHANGE IN THE DECOMMISSIONING COSTS REFLECTED IN DEPRECIATION RATES APPROVED IN THE 2006 RATE CASE.

A. This is a strange position. As an economic regulator, the Commission deals with estimates all the time. In fact, the process of developing revenue requirements and allocating costs to different classes of customers requires estimations and assumptions. The establishment of rational principles and the exercise of expert judgment reduce the speculative nature of cost recovery in many areas of utility regulation. Providing for recovery of the cost of removal of electric generating facilities is no exception.

Although the actual date of dismantling a plant may not be known with precision, it can be reasonably forecasted. This forecast, coupled with the fact that dismantlement is inevitable, provides enough information to ensure that intergenerational equity is being achieved. Leaving the net salvage for production plant at the rates reflected in the 2006 depreciation study, particularly when subsequent facts indicate a negative percentage closer to 8 percent, promotes intergenerational inequity. If removal costs were not included in rates until the date of dismantlement was certain, the timeframe for recovering those costs would be greatly shortened, thus dramatically increasing costs for future customers. The result may be that removal costs would have to be recovered from customers who never received any benefit from the plant if removal costs are not included in rates for a sufficiently long period of time.

Q. WHAT IS THE BASIS FOR MR. NEIL'S RECOMMENDATION THAT THE COMPANY'S PROPOSED USE OF THE COST OF REMOVAL ESTIMATES FROM THE DECOMMISSIONING COST STUDY BE REJECTED?

A. Mr. Neil cites to the speculative nature of the study as well as the study's lack of certainty as grounds for continuing to use the 2006 study numbers. He makes reference to cost swings between previous dismantling studies for various plants provided in the Company's prior two rate cases to demonstrate the supposed inaccuracy of the process.

Q. DOES THE COMPANY AGREE WITH THESE CRITICISMS?

A. No, the Company believes the most current Decommissioning Cost Study provided should be used to set rates, as it represents the best estimate of dismantling costs to date.

Q. DOES THE COMPANY BELIEVE THAT CHANGES REFLECTED IN THE CURRENT DECOMMISSIONING COST STUDY WHEN COMPARED TO PRIOR STUDIES INDICATE THEY SHOULD NOT BE RELIED UPON?

A. No, a change between the estimates in studies is normal and to be expected as better information becomes available. The very fact that new studies are performed indicates that these changes are expected to occur. To suggest that a change makes the study unreliable effectively eliminates the purpose of the study in the first place. In fact, greater changes are more important to incorporate than smaller ones, provided the estimates have a reasonable basis, as greater changes may translate to a greater disparity between costs incurred at the time of removal and those included in current depreciation rates. Additionally, the longer the Company waits to incorporate current estimates, the more serious the variance becomes since the time frame to implement the change in these expenditures is shortened. As a result, ignoring the best estimates provided by a current decommissioning cost study has the potential to disproportionately burden current and future customers for these expenses as major increases or decreases become necessary closer to the actual time of retirement.

Q. WILL CONTINUED LARGE CHANGES IN DECOMMISSIONING COST STUDY ESTIMATES RESULT IN A LARGE UNDER- OR OVER-RESERVE FOR THESE FUTURE REMOVAL COSTS?

A. No, so long as timely decommissioning cost studies are performed and allowed to be used as a basis for amounts collected there should be a minimal difference between reserve collected and cost incurred for dismantling. As the date of retirement draws nearer, the dismantling estimates should become more accurate because market fluctuations and dismantling plans become less susceptible to change. The interim changes will be spread over the remaining lives of the plant through depreciation rates, and the result will be a smoother flow of depreciation over the life of the plant. The danger of over- or underreserving for these expenses only presents itself when the latest estimates are not allowed to be incorporated as this shortens the period during which estimate changes may be spread and increases the period that old estimates continue in effect.

Q. WHY DOES THE COMPANY BELIEVE IT WOULD BE IMPRUDENT TO CONTINUE USING THE ESTIMATES REFLECTED IN THE 2006 DEPRECIATION STUDY?

A. Using dismantling cost estimates from a depreciation study provided in a 2006 rate case would fail to incorporate years of changes to the economic, regulatory, and labor environments. The current Decommissioning Cost Study is based on the best estimates the Company currently has available, and failing to reflect these changes in the Company's depreciation rates is more likely to produce discrepancies between the removal costs reserved and what the Company must actually spend. There is no reason to believe the depreciation study filed in 2006 was any less affected by necessary estimation processes than the Burns & McDonnell Decommissioning Cost Study and there is no basis to assume otherwise.

Q. WHAT IS MR. NEIL'S POSITION ON THE VALIDITY OF THE RESULTS OF THE DECOMMISSIONING COST STUDY?

A. Mr. Neil disapproves of the current Decommissioning Cost Study. He states that there is a significant disparity between the dismantling costs of various plants, and that the disparity cannot be explained by the generating capacity or quantity of asbestos remaining on site. He suggests this casts doubt on the validity of the study and that, as a result, it should not be used as a basis for changing the amounts recovered through depreciation rates.

Q. DOES THE COMPANY AGREE?

A. No. The Burns & McDonnell Decommissioning Cost Study was performed by experts who have a great deal of experience in estimating dismantling expenses for electric generating plants. While some generic estimates for the dismantling costs are included, Burns & McDonnell has developed site specific estimates of dismantling costs for a number of our plants. These estimates consider the type of equipment that will be dismantled, the order in which the dismantling will be carried out, the tools and processes used in dismantling, as well as certain other cost drivers specific to the various plants. The dismantling process is driven by the requirements of each individual plant and attempting to apply one dismantling rate by generation capacity or the amount of remaining asbestos runs the risk of being overly simplistic. The study performed by Burns & McDonnell provided a more detailed and realistic approach to dismantling than the previous studies, and this is exemplified by the differences in dismantling costs at different plants.

Q. WHAT IS YOUR RESPONSE TO MR. NEIL'S CLAIM ON PAGE 8, LINES 7-9 OF HIS ANSWER TESTIMONY THAT THE DECOMMISSIONING COST STUDY DOES NOT MEET WITH THE PRINCIPLES AGREED TO BETWEEN THE COMPANY AND THE COMMISSION STAFF?

A. Mr. Neil bases this conclusion on his analysis of cost per kW values. Company witness Mr. Kopp addresses the fundamental flaws of Mr. Neil's analysis in his Rebuttal Testimony. Moreover, the fact that the costs calculated on a per kW or

MW basis reflect various ranges by no means shows that the Decommissioning Cost Study was not performed in accordance with the principles agreed to with the Commission Staff.

Q. HAS ANY WITNESS FOR THE COMMISSION STAFF CHALLENGED THE RESULTS OF THE DECOMMISSIONING COST STUDY IN ANSWER TESTIMONY IN THIS PROCEEDING?

A. No, and I find this meaningful. The Commission Staff raised numerous issues in the past two rate cases regarding the appropriateness of the procedures followed in developing estimated decommissioning costs and the results of these studies offered by the Company in those cases. The Company and the Staff spent considerable time negotiating and developing the principles to be applied in future decommissioning cost studies. If the Commission Staff believed that the Decommissioning Cost Study or its results are not reasonably consistent with these principles, we would have expected to hear about it answer testimony in this case.

Q. MR. NEIL CLAIMS AT PAGE 9, LINES 11-23, OF HIS ANSWER TESTIMONY THAT THE DECOMMISSIONING COST ESTIMATE FOR THE HYDRO FACILITIES SHOULD INCLUDE A SALVAGE VALUE FOR THE SALE OF THE WATER RIGHTS. DO YOU AGREE?

A. No. Mr. Neil states that "[s]elling the water rights could offset the decommissioning costs of the hydro units, and customers should not be charged until the sale of water rights are included in the calculation." Mr. Neil inappropriately assumes that the water rights would be fully recovered when they were sold. The salvage received for these assets, if any, should first be applied against any unrecovered value on the books. As I discussed in my response to Mr. Pous' similar argument concerning water rights for the steam production plants, it is important to understand the circumstances of the right. There are six hydro facilities in the Public Service generation fleet. I referenced the Georgetown and Cabin Creek hydro facilities in my earlier discussion because the rights for these two units are interchangeable with the four steam and other production plants.

For the remaining four hydro plants (Ames, Tacoma, Salida, and Shoshone), each of these have non-consumptive, senior rights. A senior right gives the Company first rights to the water. Ames and Tacoma own the reservoirs to which they have water rights. The reservoirs may continue in value after the asset is retired because the Company currently leases storage for consumptive water rights to various communities that are near these reservoirs. Salida has water rights on the south fork of the Arkansas River that are insignificant in amount and, thus, will probably have little value. Finally the water rights for Shoshone are from 1902 and the Company has a dam on the Colorado River. These rights might present a decent salvage value due to having the Front Range above it and the agricultural area below it. However, it is hard to say if the amount received for the rights would be sufficient to cover the removal costs, especially if the FERC were to require removal of any dam facilities once we turned the FERC license back to them when we cease operations.

B. Depreciation Rates

Q. IS MR. NEIL'S RECOMMENDATION THAT THE COMMISSION REJECT ALL OF THE COMPANY'S PROPOSED DEPRECIATION RATE CHANGES REASONABLE?

A. No. Mr. Neil appears to recommend the rejection of all proposed depreciation rates because the final decommissioning costs and retirement dates for Public Service's generation facilities are not certain at this time. On page 13 of his Answer Testimony, Mr. Neil states, "Public Service's core generating units will likely be used indefinitely." This statement is impractical and unsupported by any evidence or study. He also contends the depreciation rates should not be accepted because the study did not factor in unknown future capital additions ("interim additions"). These two viewpoints contradict one another in that Mr. Neil seeks certainty in the final decommissioning costs and retirement dates while asking Public Service to factor in uncertain interim additions.

Additionally, Mr. Neil states on page 20 of his Answer Testimony that

> "the new depreciation rates for the other types of equipment (transmission, distribution, general) could still be implemented, but I do not believe it is worth the effort to try and split out the impact of the production plant from the other categories and implement the new depreciation rates just for the other categories."

Mr. Neil's rejection of all transmission, distribution and general depreciation rates absent specific objections to the Depreciation Study is arbitrary.

Q. WHY IS IT APPROPRIATE TO ESTIMATE THE TERMINAL RETIREMENT DATES OF GENERATING FACILITIES?

A. Analyzing the expected remaining usefulness of a generating unit is based on current information, such as the age, environmental laws and regulations, fuel availability, cost to generate power, and many other factors specific to the generating unit. While the final retirement date cannot be known currently, a reasonable estimate can be justified based on the analysis performed in the Depreciation Study. It would be irresponsible and inappropriate to assume that the generating facilities will continue to operate in perpetuity. The purpose of a depreciation study is to evaluate the current facts and make a recommendation of remaining life based on the most recent information available.

Q. PLEASE EXPLAIN WHY THE DEPRECIATION RATES MAY CHANGE EVEN WHEN THE ESTIMATED RETIREMENT DATE HAS NOT.

A. The goal of a depreciation study is to set depreciation rates such that the estimated remaining net plant balance, plus removal costs net of salvage received, is recovered over the remaining useful life of the underlying assets. For example, a plant with an estimated remaining life of 50 years with negative 10 percent net salvage equates to an annual depreciation rate of 2.2 percent [(100 + 10 net salvage)/(50 years)]. However, if any one of the values for net plant balance, removal costs, salvage received or remaining useful life are adjusted, the 2.2 percent depreciation rate applied will no longer ensure full recovery by the end of the plant's useful life. Public Service routinely performs depreciation studies not less than once every five years to ensure that its depreciation rates are in line with the most current expectations for plant operations. Corresponding adjustments to the depreciation rates in line with these expectations mitigates the risk that customers will be disproportionately burdened through depreciation expense over the life of the assets.

Q. AT PAGE 21 OF HIS ANSWER TESTIMONY, MR. NEIL QUOTES A STATEMENT FROM YOUR DIRECT TESTIMONY THAT CAPITAL ADDITIONS SINCE THE MOST RECENT DEPRECIATION RATE CHANGE IN 2006 ARE A MAIN REASON FOR THE LARGE CHANGE TO DEPRECIATION EXPENSE IN THIS CASE. PLEASE EXPLAIN.

A. Capital additions increase the remaining net plant balance to be recovered by Public Service. As explained above, changes to the remaining net plant balance without a corresponding change to depreciation rates will not ensure full recovery over the useful life of the assets. All capital additions since 2006 have applied the depreciation rates set at that time and, as such, will not be fully recovered by the plant's retirement date without an adjustment to the depreciation rates.

For example, assume a plant balance of $10,000,000 with a remaining life of 10 years with zero percent net salvage, resulting in an annual depreciation rate of 10 percent [(100 + 0 net salvage)/(10 years)]. After five years, the net remaining plant balance is $5,000,000 and the remaining life is five years. Now assume a capital addition of $1,000,000, resulting in a total gross plant balance of $11,000,000 with $6,000,000 unrecovered. At a depreciation rate of 10 percent, the annual depreciation expense of $1,100,000 will result in an unrecovered plant balance of $500,000 at retirement in year 10 ($5,000,000 recovered in years 1-5 and $5,500,000 in years 6-10).

Q. SHOULD INTERIM ADDITIONS BE INCLUDED IN THE DEPRECIATION STUDY AS MR. NEIL SUGGESTS?

A. Inclusion of interim additions could mitigate the need to update depreciation rates as frequently. However, as stated above, additions to remaining net plant balances are simply one of many factors used to set depreciation rates, which is why a depreciation study is performed at least every five years. Mr. Neil recommends the Commission direct Public Service to evaluate interim additions in its next depreciation study. I do not object to this request, but I would recommend that the Commission not accept Mr. Neil's proposal to reject the proposed rates supported by Mr. Watson's current Depreciation Study.

C. <u>Account 303, Intangible Plant</u>

Q. WHAT IS MR. POUS' POSITION ON SOFTWARE?

A. Mr. Pous recommends a reduction of $9,963,173 in annual amortization expense, as detailed in Attachment JP-3 of his Answer Testimony, based on plant as of December 31, 2013. This reduction is due to his recommended extension of software lives from five to six years for routine software and 10 to 15 years for large software systems. Mr. Pous believes the proposed lives are unsubstantiated, artificially short, cause intergenerational inequity to ratepayers and benefit Public Service shareholders inappropriately via additional return on investments that have already been fully accrued.

Q. WHY ARE THE COMPANY'S PROPOSED SOFTWARE LIVES APPROPRIATE?

A. As explained in my Direct Testimony, Public Service assigns software systems amortization periods of three, five, seven or 10 years, depending on the type of system. Large base systems such as Public Service's billing system are assigned the 10-year amortization period while most other software systems are assigned a five-year amortization period. As an intangible asset, Public Service's experience has indicated that the appropriate useful life of its software systems is the period over which vendor support is provided. The amortization periods currently in effect represent the upper end of the vendor servicing time frame.

Q. DO THE AMORTIZATION PERIODS ON SOFTWARE LEAD TO INTERGENERATIONAL INEQUITY?

A. No. Public Service's software assets are amortized over their expected useful lives similar to the Company's group depreciated assets. The intent is to match the useful life of the software with the amortization period billed to ratepayers. Once the software has been fully amortized and its usefulness has been exhausted, Public Service retires the software and capitalizes a replacement software system in a manner consistent with its routine operations on production, transmission and distribution equipment. Periodically, software systems may last longer than the Company anticipates similar to its other property, plant and equipment, but the Company believes the current amortization periods represent the appropriate useful life of the assets on average.

Q. AT PAGE 37, LINE 18, THROUGH PAGE 38, LINE 9, OF HIS ANSWER TESTIMONY, MR. POUS CLAIMS THAT THE COMPANY AND ITS SHAREHOLDERS INAPPROPRIATELY BENEFIT FROM THE SHORT AMORTIZATION PERIODS. WHAT IS WRONG WITH MR. POUS' THEORY?

A. Mr. Pous ignores the negative rebound effect of missing the mark on accurately estimating the amortization periods, and the inherent negative incentive for a utility to do what he claims. Mr. Pous asserts that Public Service artificially shortens its amortization periods to recover its investment as amortization expense in base rates, which, in turn, becomes additional return on investment once the software systems are fully accrued. This comment implies that Public Service actively attempts to manipulate its amortization expense in order to recover its full investment in software systems in advance of their useful lives. While Mr. Pous' oversimplified theory may have some credibility if the Company were able to stay out of rate cases for a long period of time, the Company's premature recovery of the full investment of an asset that remains in service during a rate case test year means that base rates will be set without including any amortization expense or rate base return attributable to that asset. When that asset is subsequently replaced by a new software system, the Company's base rates will not provide adequate compensation, thereby <u>reducing</u> the Company's return on investment. Considering the number of software systems and the many factors that influence the timing of rate cases, Mr. Pous assigns too much credit to the Company in imputing the ability to profit from amortization periods that are artificially short.

D. ***Net Salvage Ratio for Account 392, Transportation Equipment***

Q. WHAT ISSUE DOES MR. POUS RAISE RELATED TO DEPRECIATION FOR TRANSPORTATION EQUIPMENT?

A. At pages 85-90 of his Answer Testimony, Mr. Pous contends that the Company's proposal to decrease the net salvage rate for transportation equipment is inappropriate and instead recommends a net salvage rate of positive 25 percent.

Q. WHAT IS MR. POUS' BASIS FOR DISPUTING THE COMPANY'S PROPOSED NET SALVAGE RATE FOR TRANSPORTATION EQUIPMENT?

A. Mr. Pous disagrees with the Company's usage of a like-kind exchange program and the treatment of trade-in values that occur in that type of program. Mr. Pous argues that this treatment of trade-in value is a violation of the USoA. In addition, he states that he is concerned that applying trade-in value to the capitalized value of a replacement vehicle would create intergenerational inequities and would be "a gross distortion of the net salvage process."[5]

Q. DOES THE COMPANY'S TREATMENT OF TRADE-IN VALUE UNDER ITS LIKE-KIND EXCHANGE PROGRAM VIOLATE THE USoA?

A. No it does not. The specific portion of the USOA relied upon by Mr. Pous to support his conclusion that like-kind exchange program transactions do not constitute salvage, but rather a reduction in the replacement investment, is in Electric Plant Instruction No. 2.D. This Instruction provides as follows:

> The electric plant accounts shall not include the cost or other value of electric plant contributed to the company. Contributions in the form of money or its equivalent toward the construction of electric plant shall be credited to

[5] Answer Testimony of Jacob Pous, page 86, line 4

> accounts charged with the cost of such construction. Plant constructed from contributions of cash or its equivalent shall be shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledgers of accounts. The accumulated gross costs of plant accumulated in the work order shall be recorded as a debit in the plant ledger accounts along with the related amounts of contributions concurrently recorded as a credit.

Following this rule, when an old vehicle is traded in and the value of that trade-in is applied to lower the purchase price of a new vehicle, then the value capitalized is the lowered purchase price. Despite Mr. Pous' claims, placing the full value of a new asset in the plant accounts before the trade-in credit is actually inconsistent with the USoA. The Company's treatment of like-kind exchanges is both prudent and follows the USoA.

Q. MR. POUS ALSO ARGUES AT PAGES 87-88 OF HIS ANSWER TESTIMONY THAT THIS TREATMENT CREATES INTERGENERATIONAL INEQUITY. IS THIS TRUE?

A. No. The currently approved depreciation rate for Account 392 includes a net salvage percentage of 10 percent. To continue with the vehicle example, based on this, customers' rates would include depreciation expense for 90 percent of the original cost of a vehicle. Under the current process, a $10,000 vehicle would generate depreciation expense of $9,000 over the life of the asset, with $1,000 of gross salvage being credited to accumulated depreciation. At the end of the useful life, the plant and reserve balance for the vehicle would be $10,000. Under our like-kind exchange program, all salvage proceeds from previous vehicles are applied to the original cost of newly purchased vehicles. If we were to receive a trade-in value of $1,000 on a retired vehicle and this credit were applied to a $10,000 vehicle, the customers would end up paying $9,000 in depreciation expense over the life of the vehicle. Under either scenario, customers pay gross plant less net salvage over the life of the asset. Thus, contrary to Mr. Pous' claim, no intergenerational inequity issues exist.

Q. DO YOU AGREE WITH MR. POUS' PROPOSAL TO CHANGE THE NET SALVAGE RATE TO A POSITIVE 25 PERCENT FOR TRANSPORTATION EQUIPMENT?

A. No. Mr. Pous' recommended net salvage rate was based on a hypothetical calculation of the salvage value of one brand of personal-use truck, a Ford F-150, and is not a representative net salvage rate for the Company's transportation equipment. Company witness Dane Watson provides a more detailed breakdown of why Mr. Pous' recommended net salvage rate is not reasonable.

Q. SHOULD THE COMMISSION ADOPT MR. POUS' RECOMMENDATION TO REDUCE THE 2013 DEPRECIATION FOR TRANSPORTATION EQUIPMENT?

A. No, it should not. The Company's like-kind exchange program follows the USoA and does not create intergenerational inequity, despite Mr. Pous' assertion to the contrary.

Q. IS THE COMPANY PROPOSING TO MAKE A CHANGE TO ITS PROPOSED DEPRECIATION RATE FOR TRANSPORTATION EQUIPMENT AS PART OF ITS REBUTTAL CASE IN THIS PROCEEDING?

A. Yes. After this case was filed, the Company decided it would not continue using the like-kind exchange program for our fleet of transportation equipment. The switch was made because the continuation of accelerated depreciation tax benefits eliminated the benefits of like-kind exchanges for the Company. The Company is in a positive tax status (i.e., not owing income taxes) and anticipates being in this situation for the near future, which eliminates any tax benefits that a like-kind exchange program may provide. Due to this change, the Company would like to withdraw its previous request to change the net salvage rate for transportation equipment to zero percent. Since the Company is no longer accounting for salvage proceeds on the front end of the capitalization of assets, a proper net salvage rate needs to be built into its depreciation rates.

Q. WHAT DOES THE COMPANY BELIEVE IS A REASONABLE NET SALVAGE RATE FOR TRANSPORTATION EQUIPMENT?

A. The Company recommends that the previously approved net salvage rate of positive ten percent for transportation equipment continue to be used going forward. Based on the Company's experiences related to the salvage value of recently sold equipment, along with market data on the resale value of equipment, the Company is confident that ten percent is a more reasonable net salvage rate than the rate proposed by Mr. Pous. Mr. Watson provides more detail showing the reasonableness of a positive ten percent net salvage rate. This is a change from our initial proposal in this case. For purposes of this rate case, the annual impact of changing from the originally proposed zero percent net salvage rate to the modified proposal of 10 percent is only about $740,832, based on plant balances as of December 31, 2013. The corresponding decrease in depreciation expense for the 2015 Test Year, after allocation of common plant, is $740,149.

Q. IS THE COMPANY UPDATING ITS PROPOSED DEPRECIATION RATES AND TEST YEAR DEPRECIATION EXPENSE TO REFLECT THIS CHANGE IN POSITION?

A. Not at this time. Given that parties in this proceeding have recommended other changes which, if approved, would result in further modifications to depreciation rates, I have not revised the Company's proposed depreciation rates, as originally set forth in my Attachment No. LHP-4, or the proposed Test Year depreciation expense, as originally set forth in my Attachment No. LHP-5. I would propose to update these two attachments at a later point in this proceeding, and to file them with the Commission, to reflect the final depreciation rates and annual depreciation expense resulting from the Commission's rulings on the depreciation issues in this proceeding.

Q. BECAUSE THE COMPANY HAS SWITCHED HOW IT IS ACCOUNTING FOR TRANSPORTATION EQUIPMENT SALVAGE PROCEEDS, IS THERE ANY CHANGE THAT NEEDS TO BE MADE TO THE DEPRECIATION GROUPS FOR TRANSPORTATION EQUIPMENT?

A. Yes. Assets that were purchased during the like-kind exchange program have been capitalized at a value lower than they otherwise would have been due to the application of salvage proceeds from a previous vehicle to the purchase price of the new vehicle. For example, if the Company purchased a vehicle with a sticker price of $10,000 and received trade-in value from a retired vehicle of

$1,000, the vehicle would have been capitalized at $9,000. Essentially, the net salvage for this vehicle, if you assume a net salvage rate of positive ten percent, has already been credited to the value, and has lowered the total depreciation that will be needed on this vehicle. If you then were to apply a positive net salvage of 10 percent to this lowered value, then the Company would only receive $8,100 of depreciation for a vehicle even though the recoverable service value (original cost less net salvage value) is $9,000. Under this scenario, net salvage credits would essentially have been applied to this vehicle twice.

Q. WHAT IS YOUR RECOMMENDATION TO SOLVE THIS PROBLEM?

A. The Company recommends that a new transportation group be established for all assets purchased under the like-kind exchange program. This transportation group would use a net salvage rate of zero percent to acknowledge that the vehicles in the group have already received net salvage proceeds on the front end of their capitalization. This would allow the Company to recover the full value of the vehicle, net of salvage proceeds, through depreciation.

E. <u>Amortization Reserve Differences</u>

Q. AT PAGES 90-94 OF HIS ANSWER TESTIMONY, MR. POUS ASSERTS THAT THE COMPANY IS ATTEMPTING TO RECOVER ITS INVESTMENT IN CERTAIN GENERAL PROPERTY TWICE. DO YOU AGREE?

A. No. Mr. Pous recommends a $2,405,110 annual reduction in depreciation expense for General Plant based on December 31, 2013 plant balances. This recommendation is based on Mr. Pous' belief that the previously approved rates should have fully compensated the Company for its investment in AR-15 general property. In other words, the Company should have set its remaining net recoverable amount to ensure full recovery of its investment based on the lives and rates approved by the Commission at adoption of AR-15. Such practice would have required an inappropriate transfer of reserve from Public Service's other functional classes against FERC rules. Company witness Mr. Watson responds to Mr. Pous' arguments in more detail in his Rebuttal Testimony.

Q. IS THE COMPANY SEEKING TO RECOVER ITS INVESTMENT IN GENERAL PROPERTY TWICE?

A. No. Mr. Pous contends that the Company is attempting to recover its investment in general property twice via an actual to theoretical reserve deficiency. The Company has excluded its fully accrued assets from this calculation and will only charge depreciation expense on general property to the extent it provides for recovery of 100 percent of the investment plus any net salvage. The $2,405,110 referenced by Mr. Pous is the annual depreciation expense related to the life-to-date under-recovered portion of the Company's AR-15 property and is not an attempt to recover the asset value a second time. As it does in its production, transmission and distribution property, Public Service is recommending that the deficiency be recovered over the expected life of the underlying assets.

F. <u>Transparency in the Company's 2015 Test Year Depreciation Expense Calculations</u>

Q. WHAT IS MR. HIGGINS' ISSUE WITH CALCULATING DEPRECIATION FOR THE 2015 TEST YEAR?

A. At pages 35-38 of his Answer Testimony, Mr. Higgins complains at length that he was unable to replicate the Company's depreciation expense calculations for the FTY. Instead, Mr. Higgins brings in the recommended depreciation rates and expense from Mr. Pous' analysis and provides a rough estimate of the 2015 Test Year impact. His rough estimate of the jurisdictional revenue requirement adjustment for depreciation expense is a decrease of $18,701,209. He claims that, because the Company used its PowerPlant system to calculate the 2015 Test Year change in depreciation expense, the best that CEC could do is guess at what the impact would be using their recommended rates.

Q. WAS IT POSSIBLE FOR MR. POUS OR MR. HIGGINS TO FORECAST THE 2015 TEST YEAR DEPRECIATION FROM THE INFORMATION PROVIDED?

A. Yes. The Company provided a very detailed worksheet when CEC claimed it could not calculate the 2015 Test Year depreciation on the information available. This file documented the process that the Company uses for forecasted depreciation.

Q. HOW DOES THE COMPANY CALCULATE FORECASTED DEPRECIATION?

A. We calculate the forecast depreciation at a higher level than we do for the actuals. The depreciation rates used in the forecast system are a composite of the rates approved for the individual FERC accounts. For example, there are six actual FERC accounts that are combined into the transmission line forecast group. The Company composites the individual depreciation rates from these six accounts to get the forecast depreciation rate. The composite is based on the actual plant balances at the start of the forecast process, basically a dollar weighted average.

Q. DID YOU RUN CEC'S PROPOSED DEPRECIATION RATES THROUGH THE POWERPLANT SYSTEM?

A. Yes and we provided our calculation using the proposed depreciation rates in our responses to Discovery Request No. CEC24-1. Our calculation came out surprisingly similar to what was provided by CEC. Thus, their guess was not that far off. Using our information provided to do the calculation, CEC was able to replicate the calculation with their proposed depreciation rates. Accordingly, CEC was not prejudiced by any difficulty in replicating the Company's 2015 Test year calculations.

III. RETIRED AND RETIRING GENERATING UNITS

Q. WHAT IS OCC WITNESS MR. NEIL'S POSITION ON THE COMPANY'S PROPOSED RECOVERY OF COSTS ASSOCIATED WITH THE RETIRED AND RETIRING GENERATING UNITS?

A. Mr. Neil disagrees with Public Service's proposal to amortize the $133 million of retirement costs of these units (Arapahoe 1-4, Cameo 1-2, Cherokee 1-2, Zuni 1, Cherokee 3, Zuni 2 and Valmont 5) over four years, as well as the reserve reallocation.

Q. WHAT DOES MR. NEIL RECOMMEND?

A. With respect to the Retiring Generating Units, Mr. Neil recommends that no change in recovery be approved in this rate case, but rather the Commission deal with these units in future rate cases after the units have actually been retired. With respect to the Retired Generating Units, Mr. Neil recommends an alternative cost recovery method that would recover retirement costs over five years, resulting in an increase in amortization expense of $2.9 million in 2015, and no reserve reallocation.

Q. WHAT IS YOUR RESPONSE TO MR. NEIL'S RECOMMENDATIONS?

A. Mr. Neil's recommendations are not well-supported and are not well-conceived.

Q. DO YOU AGREE WITH MR. NEIL'S STATEMENT ON PAGE 28, LINES 16-17, OF HIS ANSWER TESTIMONY THAT "THE PROPOSED RESERVE REALLOCATION IS LIKE PUBLIC SERVICE ADDING A NEW $131 MILLION POWER PLANT TO ITS RATE BASE."?

A. No. The entire depreciation reserve is already reflected in rate base. The reserve reallocation proposed by Public Service just moves the reserve that is already in rate base to another part of rate base.

Q. MR. NEIL STATES ON PAGE 29, LINE 8 AND 9, OF HIS ANSWER TESTIMONY THAT HE HAS "ELIMINATED THE RESERVE REALLOCATION IN THIS PROCEEDING FOR THE RETIRED UNITS." WHAT IS YOUR RESPONSE?

A. Mr. Neil does not state how he accounted for the reserve reallocation he eliminated for the retired generating units, so it is unclear where it went. Mr. Neil has harmed the customers by not including the $81.7 million reserve reallocation in the calculation of depreciation. The $81.7 million of reserve has been recovered from the customers and should be utilized to reduce depreciation expense of current unrecovered plant assets or regulatory assets.

Q. BASED ON MR. NEIL'S TABLE CN-6 ON PAGE 30 OF HIS ANSWER TESTIMONY, WILL ALL OF THE UNRECOVERED COSTS FOR THE RETIRED GENERATED UNITS BE RECOVERED BY THE END OF 2019?

A. No. Mr. Neil has proposed that $80.6 million in costs be recovered in years 2015-2019. Per Attachment No. LHP-7, unrecovered costs relating to the Retired Generating Units at the end of 2014 is $94.1 million.

Net Regulatory Asset at 12/31/2014 (LHP-7, page 6 of 8)	$45,841,103
Arapahoe Decommissioning Costs	$34,781,000
Cherokee Unit 1 and Unit 2 Decommissioning Costs	$2,935,800
Zuni Unit 1 Decommissioning Costs	$10,579,000
Total Unrecovered Retiring Generating Units at 12/31/2014	$94,136,903

Mr. Neil recommended a five-year amortization period to be used for Retired Generating Units. Therefore, the unrecovered costs of $94.1 million would be amortized over 5 years resulting in expense of $18.8 million annually for years 2015-2019. This is an increase of $5.9 million over the current rates of $12.9 million for the Retired Generating Units.

Q. WHAT IS THE EFFECT OF MR. NEIL'S RECOMMENDATION FOR THE RECOVERY OF RETIRING GENERATING UNITS?

A. Mr. Neil has recommended that the Retiring Generating Units that have not yet been retired should be addressed in future rate cases. Mr. Neil has proposed to use the current rates for the Retiring Generating Units. At the current rates, it would take another 14 years, or until 2028, to fully amortize the unrecovered plant and decommissioning costs of the Retiring Generating Units. The unrecovered balance attributable to the Retiring Generating Units as of 12/31/2018 per Attachment No. LHP-8, page 6 of 8, is $86.8 million. Based on the continuing annual expense allowance in 2018 of $8.9 million, it will take an additional 9.8 years to fully amortize the Retiring Generating Units. Therefore, the Retiring Generating Units would be fully amortized in 2028 based on the current rates.

Rate Base at 12/31/2018 (LHP-8, page 6 of 8)	$32,817,906
Cherokee Unit 3 Decommissioning Costs	$12,044,550
Valmont Unit 5 Decommissioning Costs	$30,630,000
Zuni Unit 2 Decommissioning Costs	$11,297,000
Total Unrecovered Retiring Generating Units at 12/31/2018	$86,789,456

Q. IS HIS RECOMMENDATION CONSISTENT WITH OTHER RECOMMENDATIONS IN MR. NEIL'S TESTIMONY?

A. No. Mr. Neil opposed the reserve reallocation, stating that it is an expensive way to mitigate these costs and results in the retirement costs being recovered over a long period of time instead of four years.

Q. WHAT IS PUBLIC SERVICE'S RECOMMENDATION RELATED TO THE RESERVE REALLOCATION?

A. Reserve reallocation is typically done in a depreciation study within the functional class within FERC Account 108. However, the balances associated with the Retired Generating Units currently reside in FERC Account 182.2. We are proposing that the reserve reallocation performed within the Depreciation Rate Study for Steam Production include the operating units and the Retired Generating Units as one group. If approved, Public Service will move $81.7 million in associated accumulated depreciation from FERC Account 108 to Account 182.2 at the time the rates go into effect.

Q. WILL THIS CREATE INTERGENERATIONAL INEQUITY?

A. For intergenerational inequity to have been eliminated, the costs for the Retired Generation Units should have been recovered while the stations were operating. The costs for the Retiring Generating Units would need to be recovered before the plants retire on their terminal retirement dates during 2015 through 2017. Under these circumstances, it is not feasible to eliminate generational inequities without substantially large rate impacts. Public Service's proposal to utilize the reserve reallocation to reduce depreciation expense spreads the cost over the life of the remaining assets from which the customers are receiving service benefits. While the Company proposed new depreciation rates in the last two rate case filings, the Commission chose not to approve the new depreciation rates which would have reduced the intergenerational inequities.

IV. <u>2015 TEST YEAR PLANT IN SERVICE BALANCES</u>

Q. AT PAGE 12, LINES 13-23 OF HIS ANSWER TESTIMONY, FEA WITNESS STEPHEN M. RACKERS SUGGESTS REDUCING FORECASTED PLANT IN-SERVICE AMOUNTS TO REFLECT QUARTERLY FERC REPORTING OF PLANT IN SERVICE. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. His assessment includes analysis of 2014 budget data through June and applies a percentage reduction to the 2015 Test Year forecast data. It is more appropriate to consider a budget to actual variance analysis and the affect it would have on the 13 month average plant balances of the Test Year. When evaluating the Test Year data, the analysis should include review of the 2014 data and then concentrate on reviewing whether the capital additions are representative of what will occur. The test is whether the Test Year is fairly close to expectations. Overall, the data provided in the Test Year is a better representation of where the rate base will be when the rates take effect, even given the variable nature of forecasting. Even if the actual additions through the end of September are lagging behind where they were forecasted to be, this would at most suggest an adjustment to the Test Year. When evaluating whether a forecast is reliable, one must look at the entire forecast period and not just an instant in time. Mr. Rackers uses June 30, 2014 as the instant in time to draw his conclusion. However, there are several facts that need to be understood as to how the Company forecasts rate base. In order to present a Test Year, the Company needs to start with the last available book numbers and roll the plant and plant-related balances forward month-by-month based on anticipated construction schedules and in service dates. The period chosen in this case was 2015 with general rates going into effect in February 2015. The 2015 roll-forward was created using December 2013 actuals combined with a monthly forecast continuing through 2015. Also, the Company used a 13-month average for 2015 rate base. This places more weight to additions occurring earlier in the year than to additions occurring later in the year.

To evaluate the appropriateness of this roll-forward, one should review not only the projects included in the test year, but the general trend of spend levels and plant additions. If rate base is trending up given the forecast, the analysis should look at the reasonableness of the increase (*e.g.*, is it following past trends, is it based on cost increases or changes in government requirements, or is it based on several large projects). If the roll-forward has projected spend levels and plant additions based on reasonably anticipated spend level and plant addition trends, the roll-forward should be accepted.

Q. HAVE YOU UPDATED DATA PROVIDED FOR DISCOVERY TO REFLECT AN UPDATE TO ANTICPATED TEST YEAR PLANT IN-SERVICE ACTIVITY?

A. Yes, my Attachment No. LHP-10 is an analysis based on actual plant additions through September 2014 with updated forecasted amounts through the end of the year as compared to the 2014 forecast data used in this case. As the attachment indicates, the net effect on the 2015 13-month average test year is an increase of $4.2 million. Attachment No. LHP-10 is an update to the Company's response to Discovery Request CHECC2-223.

Q. WHAT IS THE IMPACT OF THE DIFFERENCE BETWEEN BUDGETED AND UPDATED FORECASTED CLOSINGS FOR CALENDAR YEAR 2014?

A. As shown on Attachment No. LHP-10, the total difference between original and updated forecasted closings to plant in-service for 2014 is ($5.3) million. To understand the impact that such a difference might have on the Test Year, one must analyze the difference to determine what portion of the total is due to a shift of in-service dates, a variance in total spend, or other reasons. Such analysis is reflected in Attachment No. LHP-10, which indicates that the effect on the Test Year is approximately $4.2 million, or a .48% percent *increase* to Plant Rate Base. Thus, overall it is a very small impact because the additions eventually do become part of rate base.

Q. CAN YOU PROVIDE FURTHER DETAIL ON HOW THE COMPARISON IS DONE?

A. Yes. All projects were evaluated to determine the difference from what was originally forecasted. The differences in closings were reviewed to determine whether the difference is due to timing within the current year, timing between 2014 with 2015, or a change in the estimated project cost. Several projects were originally forecasted to be completed in 2014, but as construction commenced, the timeline shifted. If a project was in this category, the effect on the rate base was factored in by subtracting $1/13^{th}$ for every month the project in-service date was later than originally forecast. In contrast, those projects coming in earlier than forecast were assigned full value to the rate base rather than partial value.

Lastly, if the spend originally forecasted was greater or less than current actuals or expectations, these changes were factored into the analysis as well.

Q. HOW CAN A ($5.3) MILLION DIFFERENCE HAVE A TEST YEAR EFFECT OF $4.2 MILLION?

A. Major differences comprising the ($5.3) million discrepancy in closings to plant in-service were selected for analysis. The major differences that were evaluated in this attachment total ($6.8) million, or 128 percent, of the ($5.3) million. Of the ($6.8) million, $25 million was due to a differential between forecasted capital expenditures and actual spend. Dollars associated with a spend differential have a 100 percent effect on the test year. The net of projects shifting in-service dates between years total ($33) million. This shift in in-service has a ($22) million effect on rate base. If the project was delayed and its new estimated in service date is March 2015, it would have a $9/13^{th}$ effect on the 2015 Test Year. The net impact is an increase to rate base of $4.2 million. The individual differences are not as important as evaluating whether the rate base forecast will be achieved within the year. Attachment No. LHP-10 shows that the Company ~~will~~ is expected to achieve the rate base as originally forecasted in 2015.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

MINNESOTA DEPARTMENT OF COMMERCE

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October 10, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota, 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E,G999/CI-13-626

Dear Dr. Haar:

On May 16, 2014, the Minnesota Public Utilities Commission (Commission) issued its second *Notice of Comment Period on Decommissioning Cost Investigation*. Attached are the Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in this matter.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ CRAIG ADDONIZIO
Financial Analyst

CA/ja
Attachment

MINNESOTA DEPARTMENT OF COMMERCE

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E,G999/CI-13-626

I. INTRODUCTION AND BACKGROUND

In its July 31, 2013 Order on Minnesota Power's 2012 Remaining Lives Depreciation Petition, the Minnesota Public Utilities Commission (Commission) opened the instant Docket to review decommissioning policies related to depreciation expense, including the calculation of the salvage portion of depreciation expense.

On March 6, 2014, the Commission issued a *Notice of Comment Period on Decommissioning Cost Investigation* in which it requested that utility companies provide explanations of their respective decommissioning practices in Minnesota and other jurisdictions, as well as justifications for the use of decommissioning probabilities. The Commission's Notice also allowed for comments on the utilities' submissions.

On April 7, 2014, several utilities filed Comments in response to the Commission's Notice.

On May 7, 2014, the Minnesota Department of Commerce (the Department) filed Comments (Initial Comments) that attempted to summarize and analyze the utilities' Comments. As discussed further below, in its Initial Comments, the Department concluded that there are two main sources of uncertainty with respect to decommissioning costs: timing and amount. Because the lives of generating plants are frequently extended, it is often unclear whether a plant with a long remaining life will be decommissioned at the end of its current remaining life. The Department's analysis in its Initial Comments demonstrated that if a plant's decommissioning cost is known and certain (regardless of the timing of decommissioning), then uncertainty in the timing of decommissioning could justify some use of a decommissioning probability. However, decommissioning costs are not known and certain in advance. Given the uncertainties of both the timing and amount of decommissioning costs, the Department requested that utilities provide more information about changes in decommissioning costs over time to assess further how decommissioning probabilities should be used in depreciation petitions.

Specifically, the Department requested that utilities provide additional data in order to determine if there is a predictable pattern in changes to decommissioning cost estimates over time. More specifically, the Department requested that utilities explain whether they adjust their decommissioning cost estimates to account for expected inflation, and provide historical decommissioning cost estimates, decommissioning accruals, and decommissioning probabilities. The following four utilities provided the requested data:

- Minnesota Power (MP)
- Xcel Energy (Xcel)
- Otter Tail Power Company (Otter Tail)
- Interstate Power & Light (IPL)

The Department's analysis of the utilities' data is provided below.

II. DEPARTMENT ANALYSIS

The Department's analysis in its Initial Comments indicated that when decommissioning costs are certain, but timing is uncertain, the use of a decommissioning probability can be justified. The Department considered an example of a hypothetical plant with 30-year remaining life, and a 10 percent chance of receiving no life extension, a 40 percent chance of receiving a 15-year life extension and a 50 percent chance of receiving a 30-year life extension, with a known decommissioning cost of $10 million. [1] Table 1 below, which is a reproduction of Table 1 from the Department's Initial Comments, uses these life-extension probabilities to calculate a decommissioning probability that would best spread estimated decommissioning costs evenly over time.

[1] The Department notes that some of the figures in the text of the Department's initial comments were not accurate; these figures are corrected in the text above.

Table 1
Reproduction of Table 1 from Initial Comments
Example 1
Uncertain Timing of Decommissioning with
Certain Decommissioning Costs
($000s)

Scenario	Life Extension	Decomm. Cost	Plant Whole Life	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]
1	0	$ 10,000	30	0	$ 10,000	10%	$ 1,000
2	15	10,000	45	15	6,667	40%	2,667
3	30	10,000	60	30	5,000	50%	2,500
						100%	6,167
Weighted 30-year Removal Cost "Target"							6,167
Estimated Decommissioning Cost							$ 10,000
Decommissioning Probability							61.7%

The Department notes that, if decommissioning costs are known (certain), then the more likely life extensions are considered to be, the lower is the appropriate decommissioning probability. For example, given a 10 percent chance of no life extensions, a 20 percent chance of a 15-year life extension, and a 70 percent chance of a 30-year life extension in the above example, the appropriate decommissioning probability would be 58.3 percent (as opposed to 61.7 percent, as calculated in Table 1).

However, because decommissioning costs are not known and certain, especially at the beginning of a plant's life, the Department attempted to add uncertainty to its decommissioning cost estimate, as shown in Table 2 below, which is a reproduction of Table 3 from the Department's Initial Comments.

Table 2
Reproduction of Table 3 from Initial Comments
Example 3
Uncertain Timing of Decommissioning with
Uncertain Decommissioning Costs and Weighted Cost Outcomes

Scenario	Life Extension	Decomm. Cost	Plant Whole Life	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Probability of Life Extension	Probability of Decomm. Cost	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]=[g]x[h]	[j]=[f]x[i]
1a	0	$ 5,000	30	0	$ 5,000	10.00%	10.00%	1.00%	$ 50
1b	0	10,000	30	0	10,000	10.00%	50.00%	5.00%	500
1c	0	15,000	30	0	15,000	10.00%	40.00%	4.00%	600
Subtotal								10.00%	1,150
2a	15	5,000	45	15	3,333	40.00%	10.00%	4.00%	133
2b	15	10,000	45	15	6,667	40.00%	50.00%	20.00%	1,333
2c	15	15,000	45	15	10,000	40.00%	40.00%	16.00%	1,600
Subtotal								40.00%	3,067
3a	30	5,000	60	30	2,500	50.00%	10.00%	5.00%	125
3b	30	10,000	60	30	5,000	50.00%	50.00%	25.00%	1,250
3c	30	15,000	60	30	7,500	50.00%	40.00%	20.00%	1,500
Subtotal								50.00%	2,875
Total								100.00%	7,092

Weighted 30-year Removal Cost "Target"	7,092
Estimated Decommissioning Cost	$ 10,000
Decommissioning Probability	70.9%

Notes:
[f] = ([c] / 30) * $1,000,000

For each possible life extension, the Department considered three possible cost outcomes, and weighted the two highest cost outcomes more heavily than the lowest cost outcome. Table 2 demonstrates that when the uncertainty in decommissioning costs is accounted for, and cost increases are considered to be more likely than cost decreases, the appropriate decommissioning probability for a plant with an initial 30-year remaining life rises relative to the appropriate decommissioning probability when costs are treated as certain (referring to the 70.9 percent figure, rather than the 61.7 percent figure in Table 1 above).

Based on this analysis, the Department concluded that in order to evaluate whether the use of decommissioning probabilities is reasonable, it needed to analyze how decommissioning cost estimates change over time. For this reason, the Department requested that the utilities provide historical decommissioning estimates, accruals, and probabilities reaching as far back in time as practicable. Xcel, Otter Tail, and MP provided this data going back to 1983, 1980, 2008, respectively. IPL provided decommissioning accruals back to 2006, but provided only its current salvage estimates. Thus, the Department is unable to analyze the trend in IPL's decommissioning estimates.

Additionally, as described in the Department's Initial Comments, Otter Tail adjusts its decommissioning estimates for inflation. In other words, Otter Tail develops a decommissioning cost estimate for each of its plants measured in present-day dollars, and then uses an assumed inflation rate to inflate those estimates to the retirement dates of their respective plants. Thus, it is difficult to analyze the trends in Otter Tail's decommissioning estimates over time without knowing the uninflated estimates and the assumed inflation rates and the remaining lives used to calculate the inflated estimates. The Department was able to gather this data from eDockets back to 1998 from Otter Tail's five-year depreciation studies.

The Department's analysis of this data is described in greater detail in Attachments 1, 2, and 3 to these Comments. In summary, however, despite some limitations in the data, there appears to be a clear upward trend in the decommissioning estimates. Xcel has several plants which have had decommissioning costs built into depreciation since 1983, and the decommissioning cost estimates for these plants have grown by 2.8 percent to 6.0 percent per year over that time, including inflation. The average annual rate of growth in the decommissioning estimates for Otter Tail's plants over the period 1998-2013 has been 7.9 percent to 10.1 percent, including inflation. While growth rates this high are not sustainable over long periods of time, based on these trends, the Department revisited its examples from its Initial Comments, and attempted to reflect growth rates of two to four percent, based on expected inflation.

In Table 2 above, the Department attempted to represent uncertainty in decommissioning costs by creating three cost scenarios, which were assumed to be applicable to all of the timing scenarios. In other words, the high cost was assumed to be the same regardless of whether it was incurred in year 30, year 45, or year 60. Based on the Department's analysis in Attachments 1, 2, and 3, the Department now recognizes that decommissioning cost and timing are correlated, as the longer a plant is in service, the higher its decommissioning cost is likely to be, due to effects of inflation and other factors. The Department therefore revised Example 3 to reflect this correlation. In Table 3 below, instead of assuming fixed low, medium and high cost scenarios, the Department applied four growth rates to the initial decommissioning cost estimate. Thus, the final estimate of decommissioning cost (shown in column [f]) is a function of the growth rate and the plant's whole life.

Table 3
Revised Example 3
Uncertain Timing of Decommissioning with Uncertain Decommissioning Costs and Weighted Cost Outcomes

Scenario	Life Extension	Initial Decomm. Cost Estimate	Decomm. Cost Growth Rate	Plant Whole Life	Final Decomm. Cost Estimate	Remaining Life at the End of Year 30	Accumulated Decomm. Cost at End of Year 30	Probability of Life Extension	Probability of Decomm. Cost	Scenario Probability	Accumulated Decomm. Cost Multiplied by Scenario Probability
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]=[i]x[j]	[l]=[h]x[k]
1a	0	$ 10,000	0%	30	$ 10,000	0	$ 10,000	10.00%	10.00%	1.00%	$ 100
1b	0	10,000	2%	30	17,758	0	17,758	10.00%	40.00%	4.00%	710
1c	0	10,000	3%	30	23,566	0	23,566	10.00%	40.00%	4.00%	943
1d	0	10,000	4%	30	31,187	0	31,187	10.00%	10.00%	1.00%	312
Subtotal										10.00%	2,065
2a	15	10,000	0%	45	10,000	15	6,667	40.00%	10.00%	4.00%	267
2b	15	10,000	2%	45	23,901	15	15,934	40.00%	40.00%	16.00%	2,549
2c	15	10,000	3%	45	36,715	15	24,476	40.00%	40.00%	16.00%	3,916
2d	15	10,000	4%	45	56,165	15	37,443	40.00%	10.00%	4.00%	1,498
Subtotal										40.00%	6,732
3a	30	10,000	0%	60	10,000	30	5,000	50.00%	10.00%	5.00%	250
3b	30	10,000	2%	60	32,167	30	16,083	50.00%	40.00%	20.00%	3,217
3c	30	10,000	3%	60	57,200	30	28,600	50.00%	40.00%	20.00%	5,720
3d	30	10,000	4%	60	101,150	30	50,575	50.00%	10.00%	5.00%	2,529
Subtotal										50.00%	9,187
Total										100.00%	17,984

Weighted 30-year Removal Cost "Target"	17,984
Estimated Decommissioning Cost	$ 10,000
Decommissioning Probability	179.8%

Notes:
[f]=[c]x(1+[d])^([e]-1)
[h]= ([f] / 30) * $10,000

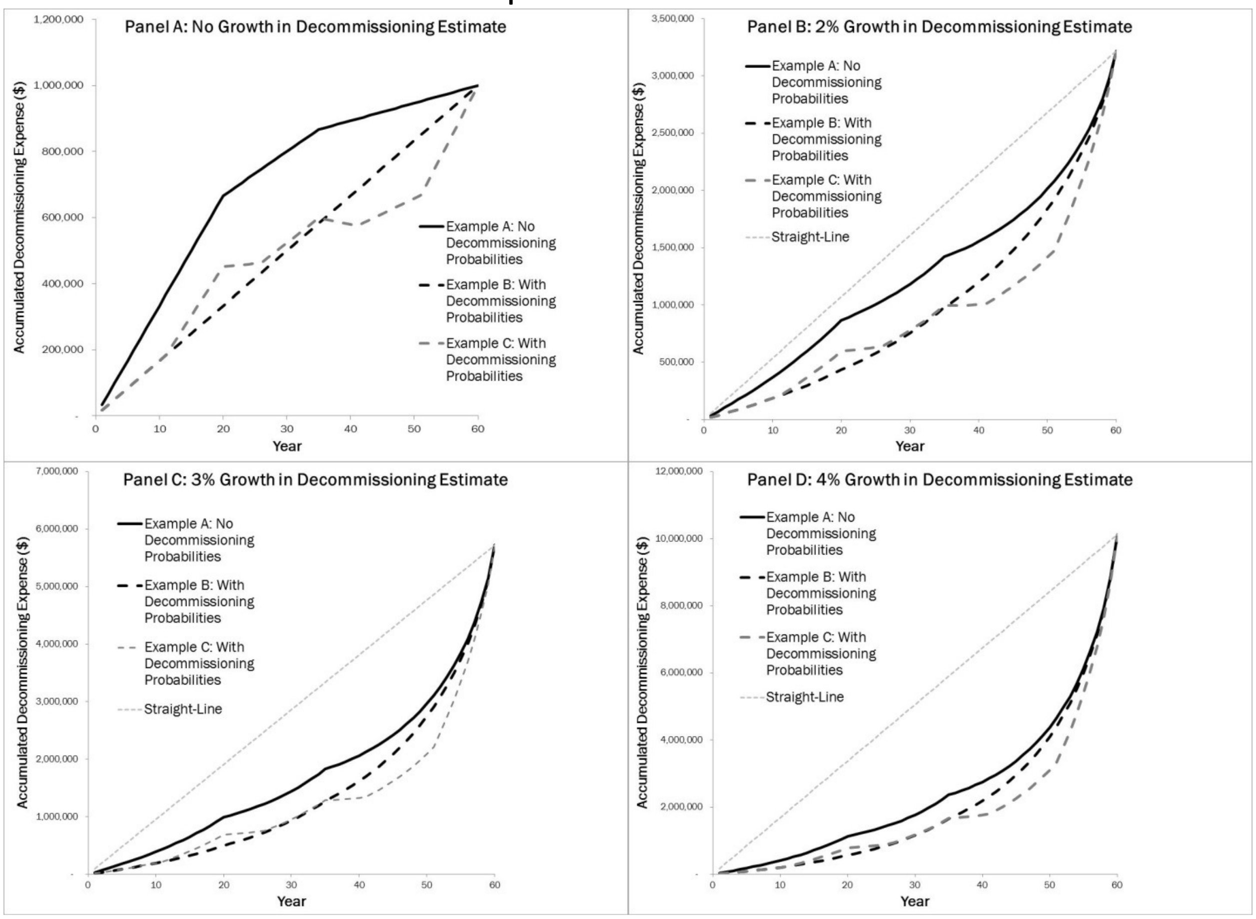
As shown, the introduction of even modest growth in decommissioning costs more than eliminates the need for a decommissioning probability to adjust the current decommissioning cost estimate. In fact, this example shows that it may be appropriate to inflate a plant's current decommissioning estimate (measured in current dollars) in order to achieve straight-line accruals in the face of potential growth. This approach would be, in effect, equivalent to Otter Tail's practice of adjusting its decommissioning estimates upwards to account for expected inflation.

The Department is hesitant to advocate for this position, however. The Department notes that the final decommissioning cost estimates in column [f] are inflated into future dollars. In other words, if the initial decommissioning cost estimates are measured in 2014 dollars, then the final cost estimate in scenario 3d of $101,150 is measured in 2074 dollars. The rest of the calculations in scenario 3d assume that this $101,150 is expensed in equal installments every year from 2014 to 2074. This means that ratepayers in 2014 will pay the same nominal amount as ratepayers in 2074, but much more in real terms. While this result may comply with the letter of the Commission's rule requiring straight-line depreciation, it is clearly not the desired effect of that rule.

This issue highlights an important difference between plant depreciation, which is the expensing over time of a known historical cost, and the amortization of estimated decommissioning costs, which is the expensing over time of an unknown future cost. A $100 plant with a ten year life would incur depreciation expense of $10 per year. Thus, ratepayers in year one will pay more for that plant in real terms than ratepayers in year 10, even though both sets of ratepayers will pay the same amount in nominal terms. However, plant additions, which are measured in current dollars, increase depreciation expense and counterbalance much of this real/nominal difference. No such natural counterbalance exists for decommissioning expense.

Figure 1 below demonstrates the effects of various assumptions about the growth of decommissioning costs on accumulated decommissioning expense over time, and is based on the example in Attachment 1 to the Department's Initial Comments. The data in Panel A are taken directly from that example (Panel A is a reproduction of Figure 2 from the Department's Initial Comments). Example A assumes that decommissioning expense is calculated with no decommissioning probabilities, and Examples B and C assume the use of decommissioning probabilities with different rules regarding when to change or update the probabilities. Example B was designed to produce a perfect straight-line accrual over time, while in Example C, decommissioning probabilities are governed by the rules Xcel uses to set its actual decommissioning probabilities (see page 5 of Xcel's April 7, 2014 Comments). Example A appears to over-accumulate decommissioning expense during the first half of the plant's life, and then under-accumulate it during the second half. Thus, Panel A demonstrates that when growth in estimated decommissioning costs is assumed to be zero, decommissioning probabilities are justified.

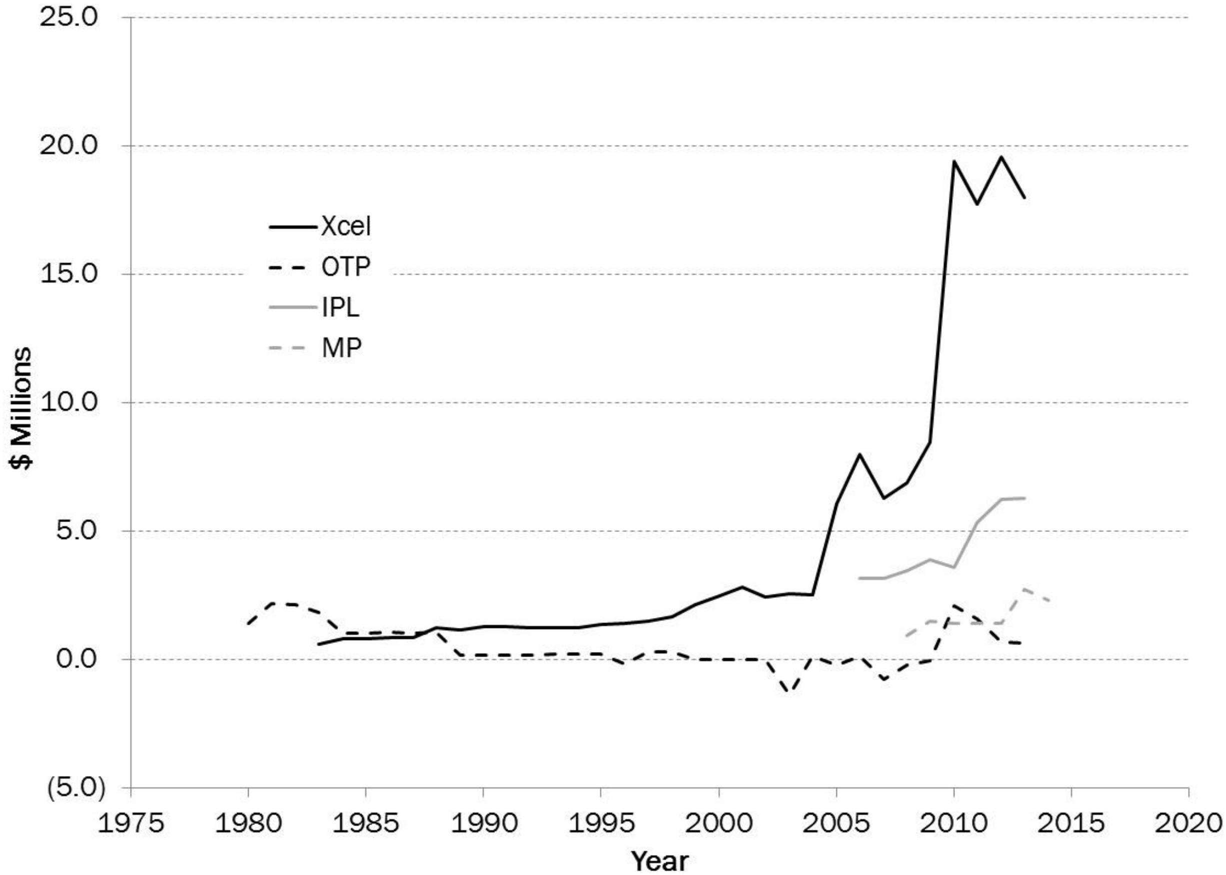
Figure 1
Accumulated Decommissioning Expense
Using Various Decommissioning Probability
Assumptions and Growth Rates



Panels B, C, and D, however, demonstrate that when growth in costs of decommissioning a plant is considered, all three methods tend to under-accrue decommissioning expense early and over-expense it late in order to catch up. However, as described above, some degree of under-accrual may be desirable to ensure that current ratepayers do not pay significantly more in real terms than future ratepayers. Perhaps more importantly, Panels B, C, and D demonstrate that the effects of decommissioning probabilities are largely overwhelmed by the effects of growth in decommissioning cost estimates.

In its initial Comments, the Department stated its desire to analyze the actual historical decommissioning accruals of utilities to determine whether the annual accruals of utilities that use decommissioning probabilities are less volatile than the accruals of those that do. The Department attempted to complete this analysis with the data provided by the utilities in response to the Commission's May 16, 2014 Notice of Comment Period. Figure 2 plots the data provided by utilities.

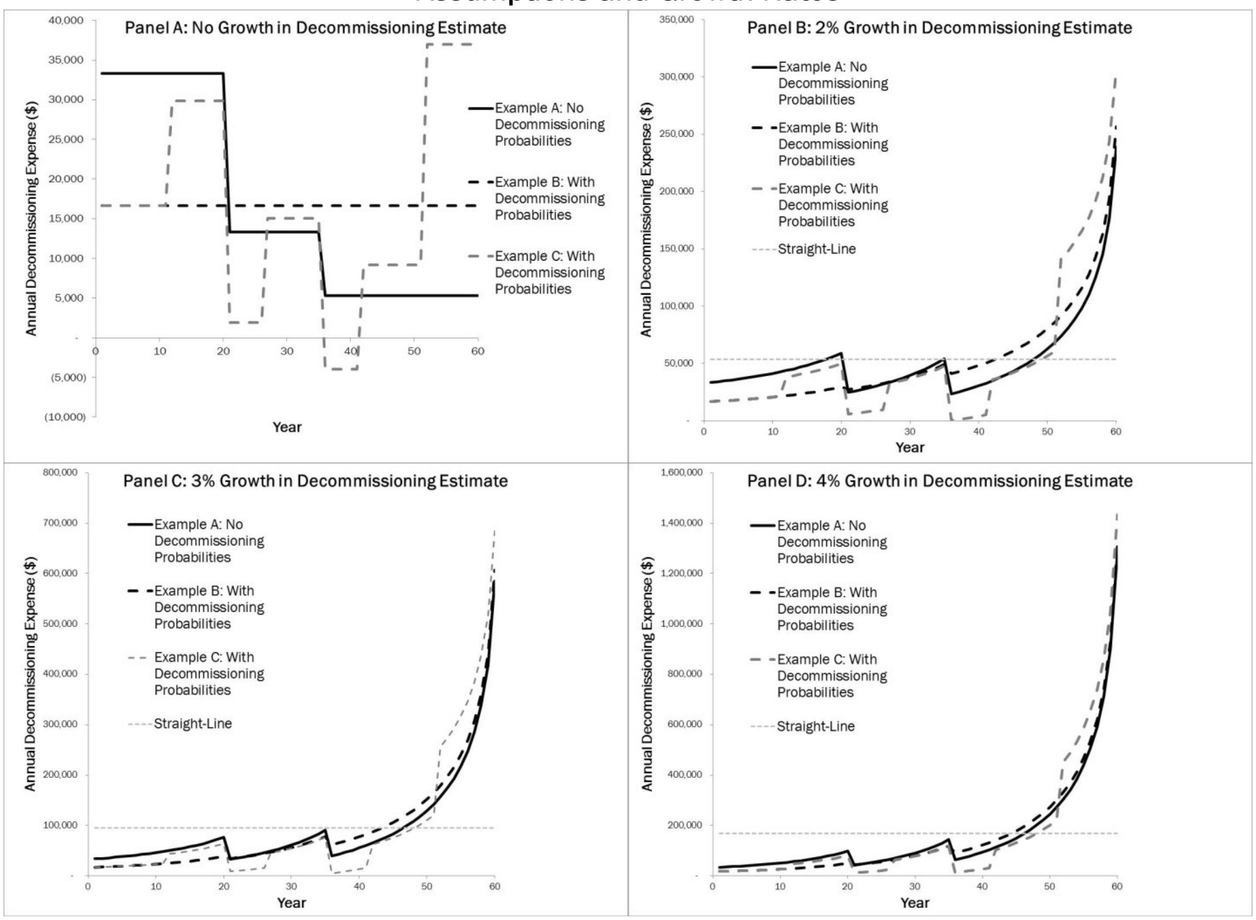
Figure 2
Actual Historical Decommissioning Accruals



As discussed above, MP and IPL provided only seven and eight years of data, respectively, which is not sufficient to draw any meaningful conclusions. Xcel and Otter Tail provided data covering much longer periods than the data MP and IPL provided. Both appear to have relatively smooth accruals until the mid-2000s, at which point Otter Tail's data begins to show some increase in volatility, while Xcel's data indicate significant increases in decommissioning costs. The Department notes that Xcel established decommissioning estimates for many of its plants in 1983, and did not revisit those estimates until 2005. Since 2005, Xcel has been updating its decommissioning estimates regularly, which has resulted in the observed growth. Therefore, Xcel's decommissioning accruals over the period 1983-2005 are not indicative of Xcel's current decommissioning practices, and the increases since 2005 are due more to changes in decommissioning cost estimates than decommissioning probabilities.

The Department therefore reviewed the annual accruals in the examples in Figure 2 above to determine how the introduction of growth rates interacts with decommissioning probabilities to affect accruals. Figure 3 below compares the annual accruals from the examples in Figure 1.

Figure 3
Accumulated Decommissioning Expense
Using Various Decommissioning Probability
Assumptions and Growth Rates



As shown, the effects of growth in the decommissioning cost estimates tend to overwhelm the differences between the examples. However, in Panels B, C, and D, Example A (without decommissioning probabilities) exhibits less volatility in the early years than Example C, and Example A expenses are a slightly smaller portion of total decommissioning cost in the last ten years or so than Examples B and C.

III. CONCLUSION

As described in the Department's Initial Comments, the intent of decommissioning probabilities is to is recognize and account for uncertainty in decommissioning costs when calculating depreciation expense, and smooth the expensing (and recovery) of decommissioning costs over the life of a plant. Based on the Department's analysis, it is not clear that decommissioning probabilities accomplish this goal, and in fact may have the opposite effect. The Department's example, which uses Xcel's rules for managing decommissioning probabilities, indicates that decommissioning expense appears to be more volatile, and results in larger increases late in a plant's life, than the example that does not use decommissioning probabilities. Thus, when growth in decommissioning costs over time is reflected, the Department sees little or no support for the continued use of decommissioning probabilities.

Therefore, the Department recommends that the Commission require utilities to cease using decommissioning probabilities, on a going-forward basis.

If the Commission agrees with this recommendation, it may wish to consider the financial impact this change will have on MP and Xcel in determining whether to require the utilities to make this change before their next rate cases. The Department notes that MP has provided estimates of the impact that elimination of decommissioning probabilities would have on its annual depreciation expense in recent depreciation filings. In Docket No. E015/D-14-318, MP estimated that it would increase depreciation expense by $2.2 million, or roughly 3.5 percent. The Department did not estimate the effect that eliminating decommissioning probabilities would have on Xcel, but notes that, in 2010, Xcel set many of its decommissioning probabilities to 100 percent, and thus only a small number of its plants would be affected by such a change.

/ja

Minnesota Power's Decommissioning Cost Estimates

MP's Decommissioning Cost Estimates and Growth Rates 2008-2014

Year	Boswell Energy Center Unit 1	Boswell Energy Center Unit 2	Boswell Energy Center Unit 3	Boswell Energy Center Unit 4	Boswell Energy Center Common	Laskin Energy Center	Taconite Harbor Energy Center	Total - All Plants	Total - Excluding Tac. Harbor
1999	1,112,314	1,067,535	15,240,693	22,503,732	5,032,654	5,036,724	n/a	n/a	49,993,652
2008	1,173,877	1,130,974	16,083,051	19,242,310	4,427,706	7,382,216	6,634,859	56,074,993	49,440,134
2009	1,659,770	1,599,590	22,616,338	27,071,100	6,219,344	8,574,264	6,634,859	74,375,265	67,740,406
2010	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2011	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2012	1,659,770	1,599,590	25,144,338	27,071,100	6,219,344	8,574,264	6,634,859	76,903,265	70,268,406
2013	6,314,600	6,443,000	29,575,200	34,394,480	10,131,451	11,444,000	10,896,000	109,198,731	98,302,731
2014	5,685,255	5,685,255	27,013,141	32,798,976	7,407,312	11,568,000	8,039,000	98,196,939	90,157,939
Annualized Growth Rate									
1999-2014	11.5%	11.8%	3.9%	2.5%	2.6%	5.7%	n/a	n/a	4.0%
2008-2014	30.1%	30.9%	9.0%	9.3%	9.0%	7.8%	3.3%	9.8%	10.5%

The table above contains MP's decommissioning estimates for the years 2008-2014, as reported in MP's July 30, 2014 Comments. The Department also added data for 1999 as filed in Docket No. E015/D-99-502 (MP's 1999 Depreciation Petition, its oldest five-year study available on eDockets). The Department calculated the annualized rate of growth in the decommissioning estimate for each plant, as well as the sum of MP's decommissioning estimates across all plants for the periods 1999-2014 and 2008-2014. The decommissioning estimates for all plants are positive, but are sensitive to the start date. As shown, the growth rates for the period 2008-2014 are significantly higher than they are for the period 1999-2014. Over the fifteen year period 1999-2014, MP's decommissioning growth rates range from 2.5 percent to 11.8 percent, and average 4.0 percent across all plants.

Otter Tail's Decommissioning Cost Estimates

Otter Tail's Decommissioning Cost Estimates and Growth Rates 1998-2013

Plant	1998	2003	2008	2013	Annualized Growth Rate
Inflated Dismantlement Estimates					
Hoot Lake Plant Unit 1		265,302			
Hoot Lake Plant Units 2&3		4,301,561	4,618,000	6,707,000	4.5%
Hoot Lake Plant	3,033,881				
Big Stone Plant	6,628,217	4,330,110	8,375,993	8,179,325	1.4%
Coyote Station	4,633,561	2,040,016	4,561,690	7,521,605	3.3%
Uninflated Dismantlement Estimates					
Hoot Lake Plant Unit 1		250,000			
Hoot Lake Plant Units 2&3		2,999,000	4,618,000	7,858,319	10.1%
Hoot Lake Plant	2,526,191				
Big Stone Plant	5,136,864	3,031,767	11,498,443	16,037,006	7.9%
Coyote Station	3,347,315	1,293,388	6,914,000	13,357,202	9.7%

The table above contains Otter Tail's inflated and uninflated decommissioning estimates from various depreciation petitions filed with the Commission. The table reports both the uninflated and inflated decommissioning estimates, and shows that the uninflated cost estimates (i.e. the estimates measured in current dollars) for Big Stone and Coyote Station have been growing by approximately 8-10 percent over the last 15 years.

The Department notes that in 1998, the decommissioning cost estimate for "Hoot Lake Plant" reflects units 1, 2, and 3. In 2003, Otter Tail separated the estimate for unit 1 from the estimate for units 2 and 3, and unit 1 was retired in 2005. Thus, for Hoot Lake, the Department calculated the growth rate only for units 2 and 3, over the period 2003-2013.

Xcel's Decommissioning Cost Estimates

Pages 3 and 4 of this Attachment contains Xcel's decommissioning cost estimates for the years 1983-2013, as reported in Xcel's July 30, 2014 Comments. The Department calculated annualized rates of growth in the decommissioning estimates for each plant. Xcel's data was complicated by several additions to existing plants, as well as fuel conversions at certain plants. Below, the Department explains how it accounted for changes at selected plants.

High Bridge and Riverside

Xcel's High Bridge and Riverside plants were original built in the early 1900s as coal-powered generating stations. Both were replaced with natural gas facilities in the mid-2000s. In Xcel's data, the plants are reclassified from Steam Production to Other Production in the year the new natural gas facilities began operation. The Department calculated growth rates which treat the old and new facilities as the same plant. However, as a result of the refueling, there may be important differences between the plant needing to be decommissioned in 2013 and the plant needing to be decommissioned in 1983. For this reason, the Department also calculated the growth rate for the Steam Production facilities for the period beginning in 1983, and ending in the last year each facility was classified under Steam Production.

Sherco

For the years 1983-1987, Xcel's data includes a Steam Production plant labeled "Sherco." Beginning in 1988, when Unit 3 was added, Xcel's data includes two separate line items labeled "Sherco Units 1&2" and "Sherco Unit 3." The Department treats "Sherco" and "Sherco Units 1&2" as the same plant in calculating an annualized growth rate.

Angus Anson

Xcel's data for 2005 includes a line-item labeled "Angus Anson." Beginning in 2006, the plant was separated into two line-items labeled "Angus Anson Units 2&3" and "Angus Anson Unit 4." During the years 2006-2009, Xcel states that the decommissioning estimate attributed to "Angus Anson Units 2&3" is the estimate for the whole facility. Therefore, the Department sums the two Angus Anson line-items in calculating Angus Anson's growth rate.

Summary

As shown in the table below, except for Xcel's Hydro and Gas Production facilities, the growth rates in the decommissioning estimates for Xcel's plants are positive, ranging from 2.8 percent to 30.9 percent. The Department notes that for a number of plants, the decommissioning estimates cover only the period 2005-2013, and that all of the plant with growth rates greater than ten percent fall in this category. Given the limited amount of data available for these plants, it is difficult to draw strong conclusions.

Xcel's Decommissioning Cost Estimates and Growth Rates
($)

Plant	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Steam Production/Black Dog	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	6,372,000	N/A	N/A
Other Production/Black Dog Unit 5																		
Steam Production/High Bridge	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	N/A	N/A
Other Production/High Bridge																		
Subtotal	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	4,084,000	N/A	N/A
Steam Production/Allen S King	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000	6,647,000
Steam Production/Minnesota Valley	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Pathfinder	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Red Wing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Steam Production/Riverside	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	N/A	N/A
Other Production/Riverside																		
Subtotal	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	5,589,000	N/A	N/A
Steam Production/Sherco	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000													
Steam Production/Sherco Units 1&2						14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	N/A	N/A
Subtotal	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	14,297,000	N/A	N/A
Steam Production/Sherco Unit 3						-	-	-	-	-	-	-	-	-	-	-	N/A	N/A
Steam Production/Wilmarth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other Production/Alliant Tech																		
Other Production/Angus Anson																		
Other Production/Angus Anson Units 2&3																		
Other Production/Angus Anson Unit 4																		
Subtotal																		
Other Production/Blue Lake																		
Other Production/Blue Lake Units 1 thru 4																		
Other Production/Blue Lake Units 7&8																		
Other Production/Granite City																		
Other Production/Inver Hills																		
Other Production/Key City																		
Other Production/United Health																		
Other Production/United Hospital																		
Other Production/West Faribault																		
Other Production/Grand Meadow																		
Other Production/Wind Storage																		
Other Production/Nobles																		
Hydro Production/Hennepin Island											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/Lower Dam											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/Upper Dam											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Hydro Production/St. Croix Falls											N/A	N/A						
Gas Production/6" Pipe											N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Gas Production/Maplewood											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Sibley											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Wescott											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Storage/Wescott											N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas Production/Grand Forks																		N/A

Note: Annualized Growth Rates are calculated over the longest possible period for which data is available. For example, the growth rate for Steam Production/Allen King is calculated for the period 1983-2013, while the rate for Steam Production/Sherco Unit 3 is calculated for the period 2005-2013.

Xcel's Decommissioning Cost Estimates and Growth Rates
($)

Plant	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Annualized Growth Rate
Steam Production/Black Dog	N/A	N/A	N/A	N/A	17,830,000	17,830,000	17,830,000	17,830,000	17,830,000	23,786,570	23,786,570	23,786,570	23,786,570	4.5%
Other Production/Black Dog Unit 5					2,610,000	2,610,000	2,610,000	2,610,000	2,610,000	13,493,635	13,493,635	13,493,635	13,493,635	22.8%
Steam Production/High Bridge	N/A	N/A	N/A	N/A	20,000,000	20,000,000	20,000,000	20,000,000						6.6%
Other Production/High Bridge								-	-	11,536,000	11,536,000	11,536,000	11,536,000	0.0%
Subtotal	N/A	N/A	N/A	N/A	20,000,000	20,000,000	20,000,000	20,000,000	N/A	11,536,000	11,536,000	11,536,000	11,536,000	3.5%
Steam Production/Allen S King	6,647,000	6,647,000	6,647,000	6,647,000	18,140,000	18,140,000	18,140,000	18,140,000	18,140,000	33,401,000	33,401,000	33,401,000	33,401,000	5.5%
Steam Production/Minnesota Valley	N/A	N/A	N/A	N/A	10,130,000	10,130,000	10,130,000	10,130,000	10,130,000	13,875,000	13,875,000	13,875,000	N/A	4.6%
Steam Production/Pathfinder	N/A	N/A												
Steam Production/Red Wing	N/A	N/A	N/A	N/A	3,400,000	3,400,000	3,400,000	3,400,000	3,400,000	10,392,000	10,392,000	10,392,000	10,392,000	15.0%
Steam Production/Riverside	N/A	N/A	N/A	N/A	30,650,300	30,650,300	30,650,300	30,650,300	30,650,300					6.8%
Other Production/Riverside									-	32,501,168	32,501,168	32,501,168	32,501,168	
Subtotal	N/A	N/A	N/A	N/A	30,650,300	30,650,300	30,650,300	30,650,300	30,650,300	32,501,168	32,501,168	32,501,168	32,501,168	6.0%
Steam Production/Sherco														
Steam Production/Sherco Units 1&2	N/A	N/A	N/A	N/A	43,320,000	43,320,000	43,320,000	43,320,000	43,320,000	36,236,953	36,236,953	36,236,953	36,236,953	
Subtotal	N/A	N/A	N/A	N/A	43,320,000	43,320,000	43,320,000	43,320,000	43,320,000	36,236,953	36,236,953	36,236,953	36,236,953	3.1%
Steam Production/Sherco Unit 3	N/A	N/A	N/A	N/A	38,340,000	38,340,000	38,340,000	38,340,000	38,340,000	47,856,384	47,856,384	47,856,384	47,856,384	2.8%
Steam Production/Wilmarth	N/A	N/A	N/A	N/A	3,250,000	3,250,000	3,250,000	3,250,000	3,250,000	9,373,000	9,373,000	9,373,000	9,373,000	14.2%
Other Production/Alliant Tech					-	-	-	-	-	-	-	-		
Other Production/Angus Anson					1,280,000									
Other Production/Angus Anson Units 2&3						1,280,000	1,280,000	1,280,000	1,280,000	3,249,262	3,249,262	3,249,262	3,249,262	
Other Production/Angus Anson Unit 4					-	-	-	-	-	1,989,208	1,989,208	1,989,208	1,989,208	
Subtotal					1,280,000	1,280,000	1,280,000	1,280,000	1,280,000	5,238,470	5,238,470	5,238,470	5,238,470	19.3%
Other Production/Blue Lake					820,000									
Other Production/Blue Lake Units 1 thru 4						820,000	820,000	820,000	820,000	2,882,769	2,882,769	2,882,769	2,882,769	19.7%
Other Production/Blue Lake Units 7&8					820,000	820,000	820,000	820,000	820,000	2,882,769	2,882,769	2,882,769	2,882,769	17.0%
Other Production/Granite City					1,590,000	1,590,000	1,590,000	1,590,000	1,590,000	3,319,000	3,319,000	3,319,000	3,319,000	9.6%
Other Production/Inver Hills					920,000	920,000	920,000	920,000	920,000	7,944,000	7,944,000	7,944,000	7,944,000	30.9%
Other Production/Key City					1,590,000	1,590,000	1,590,000	1,590,000	1,590,000	3,319,000	3,319,000	3,319,000	3,319,000	9.6%
Other Production/United Health					-	-	-							
Other Production/United Hospital					-	-	-	-	-	-	-	-	-	
Other Production/West Faribault					1,590,000	1,590,000	1,590,000	1,590,000						
Other Production/Grand Meadow								-	-	17,146,000	17,146,000	17,146,000	17,146,000	
Other Production/Wind Storage									1,590,000	-	-	-	-	
Other Production/Nobles										-	-	-	-	
Hydro Production/Hennepin Island	N/A	N/A	N/A	N/A	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	11,820,000	0.0%
Hydro Production/Lower Dam	N/A	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	
Hydro Production/Upper Dam	N/A	N/A	N/A	N/A	-	-	-	-	-	-	-	-	-	
Hydro Production/St. Croix Falls														
Gas Production/6" Pipe														
Gas Production/Maplewood	N/A	N/A	N/A	N/A	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	(121,000)	0.0%
Gas Production/Sibley	N/A	N/A	N/A	N/A	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	(239,500)	0.0%
Gas Production/Wescott	N/A	N/A	N/A	N/A	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	(23,000)	0.0%
Gas Storage/Wescott	N/A	N/A	N/A	N/A	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	(227,000)	0.0%
Gas Production/Grand Forks	N/A		N/A	N/A	2,000	2,000	2,000	2,000	2,000	2,000	2,000			0.0%

Note: Annualized Growth Rates are calculated over the longest possible period for which data is available. For example, the growth rate for Steam Production/Allen King is calculated for the period 1983-2013, while the rate for Steam Production/Sherco Unit 3 is calculated for the period 2005-2013.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Reply Comments

Docket No. **E,G999/CI-13-626**

Dated this 10th day of October 2014

/s/Sharon Ferguson

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Public Service Company of Colorado
Analysis Comparing Updated Forecast Data to Roll Forward Data for 2014

	Forecasted Additions - Original Jan - Dec	Forecasted Additions - Updated Jan - Dec	Difference Jan - Dec	Representative Effect on Plant In-service (2015 TY)	Percent of Total Difference
Electric Intangible	9,248,402	6,661,832	(2,586,570)	-	48.54%
Electric Steam Production	380,825,556	373,431,223	(7,394,332)	(10,012,121)	138.77%
Electric Hydro	5,675,222	6,985,437	1,310,215	-	-24.59%
Electric Other	13,438,313	15,957,414	2,519,101	-	-47.27%
Electric Transmission	137,343,833	121,041,370	(16,302,463)	(6,712,241)	305.94%
Electric Distribution	223,942,318	232,960,221	9,017,904	12,891,936	-169.23%
Electric General	20,332,819	20,921,165	588,346	-	-11.04%
Common Intangible	39,456,434	49,847,137	10,390,704	8,076,989	-195.00%
Common General	51,795,781	48,924,240	(2,871,541)	-	53.89%
	882,058,678	876,730,041	(5,328,637)	4,244,562	100.00%
			Effect on Plant as a % of Budgeted Additions	0.48%	
			Effect on Plant as a % of Rate Base		

Analysis of Major Differences / Timing Effect on 2015 Rate Base	Difference (A-B)	Effect on Rate Base	Business Area
Shift within 2014			
Electric Steam Production			
11418711 PAW1C - Pawnee SCR and Scrubbe	(6,884,207)	(6,884,207)	Lower addition due to earlier in service date
Shift within 2014		**(6,884,207)**	
Shift from 2014 to 2015			
Electric Transmission			
11894929 2014 PSCo Spare Auto 230kV-115kV, S	(2,602,426)	(1,000,933)	Shift in Date, revised estimated in-service date is May 2015
11492309 Malta 230/115 kV xfmr #2,Sub	(13,676,932)	(7,364,502)	Shift in Date,revised estimated in-service date is Jul 2015.
11519732 Reserve 345/230 Auto Xfmr Comanche,	(2,168,369)	(166,798)	Delay by manufacturer in shipment and delivery of the transformer (Oct to Dec 2014). Final assembly, dress-out, oil fill, testing and commissioning delayed to January 2015 due to crew availability.
11634803 Breckenridge Breaker addition, Sub	(2,065,612)	(2,065,612)	In-service date extended from 9/30/15 to 9/30/16 due to system outage constraints, limited construction window, scope changes and design refinement.
Electric Distribution			
11142530 Ptarmigan Sub Construction	(14,704,474)	(13,573,360)	Delayed in-service of substation due to technical issues with facility components. Revised in-service date December 2015.
Common Intangible			
11727527 Identity and Access Mgmt SW PS	(1,394,737)	(1,394,737)	Increase in project scope; deferred ISD to 2015
Shift from 2014 to 2015		**(25,565,942)**	
Shift into 2014			
Electric Steam Production			
10362021 VAL04006 Ash disposal Cell Con	1,681,484	1,681,484	Project was put in-service earlier than planned. Was forecasted for 2017 in-service date.
Electric Transmission			
11707132 Waterton 345kV Reactor, Sub	1,326,437	1,326,437	Project was put in-service earlier than planned. Was forecasted for March 2015 in-service date.
Common Intangible			
11709161 Xcel Corporate Network SW PSCO	952,010	952,010	Project extension from original 2013 ISD into 2014
11438101 Regulatory Process Standard SW	4,155,191	4,155,191	Project in-servicing accelerated from early 2015 to late 2014
11685117 GRC Compliance SW PSCO	2,310,328	2,310,328	Project was broken into pieces of scope and a portion was put in-service earlier than planned. Was forecasted for May 2015 in-service date.
Shift into 2014		**10,425,450**	

Public Service Company of Colorado
Analysis Comparing Updated Forecast Data to Roll Forward Data for 2014

Spend Different than Forecast

Electric Steam Production				
11500294	COM2C REP U2 CIRC WATER TOWER	(5,194,089)	(5,194,089)	Insurance Proceeds not in February Forecast
10623195	PAW1C - Repl Furnace SH Div Wa	(1,077,945)	(1,077,945)	Change in Scope
10924165	PAW0C - Replace Wet Pipe Fire	(4,474,966)	(4,474,966)	Change in Scope
11662986	COMOC Emergent work	4,310,234	4,310,234	Emergent Work
11827420	COM3C REP ACC FAN BLADES	1,627,367	1,627,367	Change in Scope
Electric Transmission				
11230663	PSCo Line Capacity, Line	(1,636,846)	(1,636,846)	Change in Scope
11901556	Ridge Auto Restoration - Ridge Sub	(1,368,730)	(1,368,730)	Difference in Spend
11492109	CACJA-Cherokee 115kV Bus Term, Sub	1,288,391	1,288,391	Difference in Spend
11793217	CACJA-Cherokee 5,6,7 Customer Funde	4,276,352	4,276,352	Difference in Spend
Electric Distribution				
10130058	Psco - Dist. Trfs	10,405,381	10,405,381	Accelerated transformer purchases due to increase in new business
10130202	1912 - Southeast Metro -Ug Ext	2,119,691	2,119,691	New subdivsions resulted in a increase in new extension growth
10333868	PSCO-Accelerated URD Cable Rep	10,931,912	10,931,912	Increase in funding for the proactive effort to improve reliability on URD cable replacement
10229490	Psco-Fdr Cable Replacement-Pro	3,008,312	3,008,312	Changed the work plan to increase cable replacement work needed
Common Intangible				
11218046	BS-Fcst-BD-SW-CM-P	(1,043,357)	(1,043,357)	Emergent Demand account; funds redistributed to other projects via Governance and prioritization processes
11491871	Windows 7 OS Migration SW PSCO	1,086,774	1,086,774	Project complexity resulted in additional costs and later ISD
11619867	Budget System Upgrade SW PSCO	817,110	817,110	Project complexity resulted in additional costs and later ISD
		Spend Different than Budget	**25,075,591**	

Added Project

Common Intangible				
12008629	CPC Phase II SW PSCO	1,193,670	1,193,670	Project not in Forecast
		Added Project	**1,193,670**	