BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority To Change its Depreciation Rates Effective January 1, 2008	))))	DOCKET NO. 07-035-13 DPU CWK Exhibit No. 2.0

DIRECT TESTIMONY AND EXHIBITS

OF

CHARLES W. KING

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES

UTAH DEPARTMENT OF COMMERCE

OCTOBER 15, 2007

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DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 37-year history, members of the firm have participated in over a thousand proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Division of Public Utilities of the Utah Department of Commerce.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to recommend depreciation rates for the Utah jurisdictional electric plant of the Rocky Mountain Power Company ("RMP" or "the Company"). In the process, I will review and critique the depreciation study submitted by Donald S. Roff on behalf of RMP.

Q. PLEASE DESCRIBE THE PROCESS YOU USED IN PREPARING THIS TESTIMONY.

A. I began by requesting the Company to provide me with the same data that it had provided its consultant, Mr. Roff. Having reviewed the data, I then input it into our Company's depreciation analysis software to test the validity of Mr. Roff's results. I also prepared a number of data requests and carefully read the Company's responses. Independently, I evaluated the approach used by Mr. Roff to the treatment of salvage and retirement costs, and I developed the alternatives that I shall discuss in my testimony. I then prepared the schedules found in my Exhibit DPU CWK-2.1. The calculations underlying these schedules are found in my workpapers. The workpapers were prepared and the calculations performed either by me or under my direction.

SUMMARY OF RECOMMENDATIONS

Q. WHAT DEPRECIATION RATES DO YOU RECOMMEND?

A. My recommended depreciation rates are set forth in Schedule 1 of Exhibit CPU CWK-2.1. A summary comparison of my recommended rates accruals with the existing accruals is a follows:

Description	12/31/2006 Balance	DPU Recommended Rate	DPU Recommended Accrual	Present Rates Rate	Present Rates Amount	Increase or (Decrease)
Total Company						
Steam Production	4,687,335,913	1.90	88,860,487	3.14	146,994,980	(68,094,359)
Hydraulic Production	507,940,786	2.11	10,728,868	2.42	12,314,551	826,111
Other Production	804,775,343	2.99	24,032,529	3.35	26,931,998	(3,353,038)
Transmission	2,652,005,379	1.59	42,167,175	2.12	56,313,992	(17,840,706)
Utah Jurisdiction						
Distribution	1,904,102,727	2.16	41,096,941	2.55	48,603,233	(13,796,396)
General	252,988,167	4.34	10,970,750	4.38	11,075,195	(202,441)
Miining	196,152,876	3.51	6,878,564	5.87	11,510,180	(4,684,741)

A summary comparison of my recommended rates and accruals with those proposed by RMP witness Roff is as follows:

Description	12/31/2006 Balance	DPU Recommended Rate	DPU Recommended Accrual	RMP Proposed Rate	RMP Proposed Accrual	Increase or (Decrease)
Total Company	$	%	$	%	$	$
Steam Production	4,687,335,913	1.90	88,860,487	2.01	94,177,049	(5,316,563)
Hydraulic Production	507,940,786	2.11	10,728,868	2.67	13,562,441	(2,833,573)
Other Production	804,775,343	2.99	24,032,529	3.56	28,039,681	(4,007,152)
Transmission	2,652,005,379	1.59	42,167,175	2.23	59,126,660	(16,959,485)
Utah Jurisdiction						
Distribution	1,904,102,727	2.16	41,096,941	3.11	59,213,906	(18,116,965)
General	252,988,167	4.34	10,970,750	4.54	27,964,406	(16,993,656)
Miining	196,152,876	3.51	6,878,564	3.52	6,905,799	(27,235)

Q. HOW DO YOUR RECOMMENDED DEPRECIATION RATES DIFFER FROM THOSE PROPOSED BY MR. ROFF?

A. My recommended depreciation rates differ from those proposed by Mr. Roff in four respects:

- I recommend that the combustion and combined cycle turbine plant life spans be set at the mid-point between the Company's proposed life spans and the 45 years that our studies show these units to be surviving at the national level.
- I have removed the five-year forecast of interim additions from the production plant accounts.
- I have lengthened the forecast service lives of two transmission and two distribution plant accounts to accord with the life indications found by both Mr. Roff and myself.
- I recommend accruals for net removal costs that reflect the present value of those costs, while Mr. Roff proposes to charge ratepayers for future removal costs at their undiscounted nominal value.

DEPRECIATION- GENERAL

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for net salvage, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. CAN DEPRECIATION BE CALCULATED WITH PRECISION?

[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q. HOW DOES THIS JUDGMENTAL CHARACTERISTIC OF DEPRECIATION INFLUENCE THE COMMISSION'S APPROACH TO THE SUBJECT?

A. The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. This is why, in this proceeding, the Commission must choose among depreciation rates that yield widely differing annual depreciation accruals.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

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[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1*.

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. As traditionally applied, it is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered. With a few exceptions (e.g. vehicles, work equipment) most gas utility plant has a higher removal cost than its salvage value, so that recognition of net salvage adds to the amount to be recovered.

Finally, virtually all major utilities, including RMP, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1 -.05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700{,}000}{10 \text{ years}} = \$70{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70{,}000}{\$1{,}000{,}000} = 7.0\%$$

The foregoing illustrates the traditional formulation of depreciation rates. As I shall discuss later in this testimony, I am recommending a modification that independently derives an annual allowance for the present value of net removal costs. Assume that this calculation yields an annual allowance of $5,000. In that case, the depreciation rate would be calculated as:

$$\frac{\$70{,}000 + \$5{,}000}{\$1{,}000{,}000} = 7.5\%$$

TRANSMISSION, DISTRIBUTION AND GENERAL PLANT SERVICE LIFE ESTIMATION

Q. WHAT INFORMATION DID YOU RECEIVE FROM RMP TO ASSIST YOU IN YOUR STUDY OF THE COMPANY'S TRANSMISSION, DISTRIBUTION AND GENERAL PLANT ACCOUNT SERVICE LIVES?

A. I received the record of plant additions, retirements, transfers, adjustments, and balances for each transmission, distribution and general plant account each year as far back as the initiation of the account, which in some cases was 1898. This information I refer to as "vintage data." For the transmission and two of the distribution accounts, I also received a record of plant retirements by year of placement. I refer to this information as "actuarial data."

Q. WHAT LIFE STUDIES DID YOU PERFORM?

A. I performed three types of life studies for each account for which there were sufficient data, Simulated Plant Record ("SPR") studies, actuarial studies and Geometric Mean Turnover ("GMT") analyses.

Q. PLEASE DESCRIBE THE SPR STUDIES.

The SPR study procedure is a trial and error mechanism whereby a computer program fits alternative Iowa Curves and average service life combinations to the record of plant additions, retirements and balances.

The SPR – Balances program measures the degree to which various combinations of Iowa curves and service lives applied to the plant additions each year yield the plant balances in subsequent years. The degree of fit is measured by sum of the squared differences between the predicted plant balances and the actual balances. When the square root of those differences is divided into the average of the actual balances, the result is a “conformance index.” The reciprocal of the conformance index is called the “index of variation.” The lower that index, the better the fit.

Another test of SPR results is the “retirements experience index,” which measures the maturity of the account under each curve-life combination. A retirements experience index of 100 indicates that the account has experienced a full life cycle, that is, all of the plant placed in the oldest vintage is now retired. An index of 50 suggests that the account is only half way through its life cycle. In general, SPR results with retirements experience indexes less than 50 are considered to have little value, while those over 75 are considered of significant value.

Q. PLEASE DESCRIBE THE ACTUARIAL STUDIES.

A. Actuarial studies are far more precise than SPRs, but they require considerably more data and, to be effective, the data must be fairly "thick," that is, they must reflect a fairly large number of retirements. Actuarial studies use the record of retirements by date of placement, which means that the age of each retirement must be known. With this knowledge, it is possible to compute the history of retirements at each age, and from that record, to fit Iowa curve and service life combinations that reproduce that history.

The actuarial data cover all of RMP's transmission plant but only two accounts within the Utah distribution functional category.

Q. PLEASE DESCRIBE THE GEOMETRIC MEAN TURNOVER METHOD.

A. The Geometric Mean Turnover Method ("GMT") is one of several turnover methods of life analyses. "Turnover" means the period of time that it takes for the plant in an account to retire fully. The advantage of turnover methods is that they study retirements in relation to plant balances irrespective of the age of the property retired.[3] The GMT method is based on ratios of annual additions and retirements to plant balances. The life estimate is the reciprocal of the geometric mean of the additions and retirements ratios averaged over a period of years.[4] The GMT method is very useful in detecting service lives and service life trends. Turnover methods assume a uniform retirement dispersion, in other words the

[3] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Depreciation Manual"), p. 81.

results of turnover analyses focus on the fundamental life statistic, unencumbered by 31 possible Iowa curve retirement dispersion estimates.

Q. IS THERE A SOURCE WHERE THE COMMISSION COULD FIND DETAILED EXPLANATIONS OF THESE STUDY METHODOLOGIES?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") has published a manual titled, "Public Utility Depreciation Practices," the latest edition of which is dated August 1996. This manual provides a full description of the theories behind depreciation, the procedures for studying it, the application of depreciation, and its effect on a utility's financial performance.

Q. DID THESE STUDIES YIELD PRECISE INDICATIONS OF SERVICE LIFE?

A. No. In many cases, the best fits were associated with curve and life combinations that had inadequate retirement experience indices.

Q. WHAT WERE THE RESULTS OF YOUR SERVICE LIFE ANALYSES OF RMP'S TRANSMISSION AND UTAH DISTIRUBTION AND GENERAL PLANT?

[4] Id., p. 91.

A. The results of my service life analyses of RMP's Utah plant are set forth on Schedule 2 of Exhibit DPU CWK-2.1. In this schedule, I have presented the RMP study life and curve shape parameters which can be compared with my results. I should hasten to add that the results shown for my tests are only the "best fit" of a number of different runs of data covering varying time spans. The time spans that are shown on Table 2 are presented in the column titled "band." Other bands of data yielded different results, but generally they are in the same range as those shown in Schedule 2.

Q. HOW DO YOUR RESULTS COMPARE WITH THOSE OF MR. ROFF

A. My results conform generally with the selected life and Iowa curves selected by Mr. Roff, with some notable exceptions.

Among the transmission accounts, I show a life indication of 94 years for the transmission Rights of Way account to Mr. Roff's 70 years. I show 57 years for the Supervisory Equipment account, to Mr. Roff's 25 years. I show 80 years for the underground conduit account to Mr. Roff's 60 years.

Among the Utah distribution accounts, I show 75 years for the Structures & Improvements account, but other indications using other bands of data support Mr. Roff's 60 years. For the Underground Conduit account, I show life indications of 83 and 72 years to Mr. Roff's proposed 60 year life. For the

Underground Conductors & Devices account, I show life indications of 61 and 84 years to Mr. Roff's selection of 50 years.

Q. WHAT LIFE ESTIMATES DO YOU RECOMMEND FOR RMP'S UTAH JURISDICTIONAL TRANSMISSION AND DISTRIBUTION PLANT?

A. Given the general correspondence of my results with those of Mr. Roff, and considering the desirability of limiting the areas of controversy, I recommend accepting Mr. Roff's life and curve shape parameters for all of the transmission, distribution and general plant accounts, with four exceptions. In each of those four cases, both my life studies and those of Mr. Roff confirm that Mr. Roff's life selection is too short.

Exhibit CWK-2 contains both my workpapers and those of Mr. Roff for the following accounts:

<u>Account 353.7 Transmission Supervisory Equipment</u>, where the life indications support a service life of 55 years with an SO.5 Iowa curve.

<u>Account 357 Transmission Underground Conduit</u>, where the life indications support a service life of 80 year and a R1.5 Iowa curve.

<u>Account 366 Distribution Underground Cable</u>, where the life indication support a service life of 80 years and a R1.5 Iowa Curve.

<u>Account 367 Distribution Underground Conductors & Devices</u>, where the life indications support a service life of 60 years and a R2.5 Iowa curve.

I recommend that the life and curve shape indications shown by our studies be adopted in lieu of Mr. Roff's selections for these four accounts.

<u>PRODUCTION PLANT LIFE SPANS</u>

Q. WHAT DO YOU MEAN BY "LIFE SPANS?"

A. The transmission, distribution and general plant accounts are known as "mass property" accounts because they consist of many individual items of plant that are continually being added and retired. As a result, there is no fixed terminal retirement date for the plant in these accounts. The forecast retirements range over virtually all the years in the foreseeable future.

That is not the case with production plants. They experience retirements and additions of piece parts during their service lives, but most of the plant is retired when the generating unit is finally taken out of service. Much of this "terminal retirement" plant is in service from the date the plant first starts up to the date it finishes generating electricity. That time between these two dates is the life span of the production plant.

In computing his depreciation rates for production plant, Mr. Roff calculates the weighted average of the estimated remaining life of the terminal retirement plant and the remaining life of the plant that will retire in the interim prior to terminal retirement.

Q. HOW DID THE COMPANY ESTIMATE THE LIFE SPANS OF ITS PRODUCTION PLANTS?

A. At page 4 of his testimony Company witness Mark Mansfield testifies that the life spans were estimated by PacifiCorp Energy's engineering staff under his direction.

Q. WHAT LIFE SPANS DOES THE COMPANY RECOMMEND FOR ITS PRODUCTION PLANTS?

A. The life spans now recommended by the Company are presented in Mr. Mansfield's Exhibit (MCM-1). They are based on a standard expected service life for steam production plants of 64 years.

Q. WERE THESE LIFE SPANS ORIGINALLY RECOMMENDED BY PACIFICORPS ENERGY'S ENGINEERING STAFF?

A. No. In an earlier study, based on March 31, 2006 plant, the PacifiCorp Energy engineering staff recommended much shorter lives for all but one of the Company's steam plants. Schedule 3 of my Exhibit DPU CWK-2.1 compares the two sets of service life estimates. Between the March 31, 2006 study and the

December 31, 2006 study now in evidence, Mr. Mansfield overruled his engineering staff and increased the estimated plant lives.

Q. WAS IT APPROPRIATE TO OVERRULE THE ENGINEERING STAFF'S LIFE SPAN ESTIMATES?

A. Yes. Exhibit DPU CWK-2.3 is a study that my firm prepared in 2000 of all of the steam plants that had been retired to date nationally. In that study we found that the average service life of retired plants was 60 years. Seven years have transpired since that study, and very few steam plants have been retired. This suggests to me that Mr. Mansfield's 64 year life estimate is much more appropriate than the shorter service lives initially estimated by PacifiCorp Energy's engineering staff.

Q. HOW DID THE COMPANY ESTIMATE THE LIFE SPANS OF ITS HYDROELECTRIC PRODUCTION PLANTS?

A. As Mr. Mansfield explains, the terminal retirement date of the hydro plants is assumed to be either the expiration of the existing FERC license or that of a 30-license extension that the Company has either filed with FERC or plans to file. Some projects are exempt from licensing, and their remaining lives are based on engineering evaluations of the critical elements of the plants. Additionally, there are a number of small plants that are scheduled to be retired.

Q. WHAT IS YOUR ASSESSMENT OF THESE LIFE SPAN ESTIMATES?

A. These are no doubt the minimum life spans of these projects. In some cases – possibly many – the ultimate life spans may be much longer, at least for the basic structures. That is because the FERC usually grants license renewals to hydro plants provided they continue to be economical to operate and do not present unacceptable environmental problems. However, because further life extensions beyond those estimated by the Company would be based on pure speculation, I recommend that the Company's hydro plant life spans be accepted.

Q. ARE THERE ANY OTHER PRODUCTION PLANTS FOR WHICH THE COMPANY HAS ESTMATED SERVICE LIFE SPANS?

A. Yes. There is the so-called "other production" plant category. These are gas-fired plants and renewable energy facilities. Most of the gas-fired plants are either combustion turbines or combined cycle combustion turbines with steam units that run on the recaptured heat. The plants in this category are RMP's newest generating facilities.

Q. HOW DID RMP ESTIMATE THE SERVICE LIFE SPANS OF THESE OTHER PRODUCTION PLANTS?

A. There are six gas-fired production plants, of which four are fairly new. For these new plants, the Company estimated the life spans based on the original design life of the respective installations. Those life spans are either 25 or 35 years. The Gadsby plant, which dates from the 1950s, is evaluated based on its current condition and the likely capital expenditures. The 14 MW Little Mountain plant is assumed to retire when the current contract expires two years hence.

The lives of the five geo-thermal, wind and cogeneration plants are based on the terms of their governing contracts with RMP.

Q. WHAT IS YOUR ASSESSMENT OF THESE LIFE SPAN ESTIMATES?

A. I accept the life estimates for the Gadsby and Little Mountain plants, and for the renewable resource plants. I cannot accept the life span estimates for the four new combustion turbine ("CT") and combined cycle combustion turbine ("CCCT") plants.

Q. WHY CAN'T YOU ACCEPT THE SERVICE LIFE SPANS OF THE CT'S AND THE CCCT'S?

A. The experience with steam plants is that they last much longer than the design life of the original equipment. Those lives, which typically were about 40 years, proved to be gross under-estimates of the actual life span of plants in which piece-part replacements are regulatory installed. The design life apparently assumes that the original equipment will survive until the terminal retirement of the total plant. The practice of replacing parts that wear out has resulted in steam plants lasting, on average, 60 to 65 years. The same is apparently true of combustion turbine generators.

The basis of this statement is Exhibit DPU CWK-2.3, which is my firm's study of combustion turbine service lives. That study, which covered all retirements between 1899 and 1996, indicates that these plants have survived on average 46.5 years and that this average has increased in recent years to 56.5 years.

Q. WHAT DO YOU RECOMMEND AS THE LIFE SPANS OF RMP'S CT AND CCCT UNITS?

A. I am not comfortable in totally disregarding the Company's life span estimates for these plants. For this reason, I recommend plant lives that are mid-way between the Company's estimates and the 46-year average service life found in our firm's national study. These service lives is presented in Schedule 4 of my Exhibit DPU CWK-2.1. For comparison purposes, I also show the life spans proposed by the Company. These revised life spans are reflected in columns C and G of Schedule 1 of Exhibit DPU CWK-2.1, which show the average service life and the remaining life, respectively, of each account in each generating unit.

<u>INTERIM ADDITIONS</u>

Q. WHAT ARE INTERIM ADDITIONS?

A. Interim additions are items of plant that are placed in production facilities during their service lives. They are mostly replacements of piece parts that wear out prior to the final retirement of the plant.

Q. WHAT IS THE ISSUE WITH RESPECT TO INTERIM ADDITIONS?

A. Mr. Roff proposes to include the next five years' interim additions in his calculation of production plant depreciation rates. Since these additions have a shorter life span than the existing plant, the effect of this inclusion is to inflate the depreciation rates.

Q. IS THIS ADJUSTMENT APPROPRIATE?

A. No. It is an established principle of utility ratemaking that ratepayers are responsible only for the costs of plant that is used and useful in the provision of their utility service. Mr. Roff's inclusion of future interim additions would charge 2008 ratepayers for plant that will not be put into service until 2011. This amounts to an out-of-test period ratemaking adjustment. It should therefore be disallowed.

<u>REMOVAL COST ALLOWANCES</u>

Q. WHAT DO YOU MEAN BY "REMOVAL COSTS?"

A. Removal costs are any costs that are required to retire a unit of plant. They include dismantlement, physical removal and restoration of the site to a permanent, stable condition.

Q. DOES RMP INCUR REMOVAL COSTS?

A. Yes. RMP expects to incur removal costs for all of its production plants and all of its transmission and distribution plant accounts other than land and rights of way. It also forecasts removal costs for its general plant structures account no. 390.

Q. HOW DOES RMP'S DEPRECIATION WITNESS, MR. ROFF, TREAT REMOVAL COSTS?

A. Mr. Roff adds his forecasts of removal costs, net of positive salvage, to the total amount of money to be recovered in depreciation rates. In this manner, he produces depreciation rates that recover both the original investment and the expected net cost to remove the plant represented by that investment.

Q. HOW DOES MR. ROFF FORECAST HIS REMOVAL COSTS?

A. Mr. Roff uses two procedures depending upon the type of removal costs. For "mass property" accounts, which include all transmission and distribution accounts and the "interim retirements" from the production plant accounts, he produces a ratio of removal costs to total plant. He nets this ratio against a ratio of positive salvage (if any) to derive a "net salvage" factor which he uses to inflate the amount to be recovered in depreciation.

Mr. Roff derives these net salvage ratios by computing ratios of the recorded removal costs and salvage of recently retired plant with the original cost of that plant. Because of the very great year-to-year variability of these costs, he averages these ratios for varying periods and selects what he deems a representative relationship of net removal costs to retirements. That relationship is then used to inflate each plant account so as to accrue for future removal costs.

Mr. Roff does not use historical data to estimate the costs to dismantle production plants at the end of their service lives. Rather, he uses special studies of dismantlement costs to develop plant-specific forecasts of these terminal retirement costs. The most specific study is that performed recently by the engineering firm of Black & Veatch of three of RMP's generating plants. That study estimated that it would cost approximately $22 million in current dollars to dismantle the 175 MW Carbon plant, $56.3 million to dismantle the 772 MW Dave Johnston plant, and $64.3 million to dismantle the 1,108 MW Hunter plant. These estimates work out to $125, $60, and $58 per kW, respectively.

Separately, Mr. Roff has compiled a list of dismantlement studies in other jurisdictions, which he has presented as his Exhibit DSR-4. That exhibit shows a wide range of results, ranging from $20 per kW to $575 per kW. Mr. Roff computes a simple average of $69.70 per kW.

Based on these inputs, Mr. Roff uses an estimate of $50 per kW as the basis for the terminal dismantlement cost of each of RMP's steam and other production plants. Separately, the Company has provided Mr. Roff with site-specific dismantlement costs for four hydroelectric plants.

Q. HOW LARGE ARE THE REMOVAL COST RATIOS RECOMMENDED BY MR. ROFF?

A. They are very large. Mr. Roff's removal cost ratios are presented in Schedule 2 of his depreciation study. There, he shows both salvage and removal cost ratios, the net of these being the "net salvage" that is added to, or subtracted from the amount to be recovered through depreciation. The net removal cost ratios proposed by Mr. Roff range as high as 105 percent for Utah distribution plant. A 105 percent removal cost ratio means that for every dollar of depreciation recovered, another $1.05 is accrued against future removal costs.

Q. CAN YOU QUANTIFY ANNUAL REMOVAL COST ACCRUAL THAT MR ROFF PROPOSES BE CHARGED TO UTAH RATEPAYERS FOR RMP'S DISTRIBUTION PLANT IN THAT STATE?

A. Yes. Schedule 5 in Exhibit DPU CWK-2.1 shows the accruals that Mr. Roff proposes based on December 31, 2006 plant in service. The accrual rates in column D are taken from Schedule 2 in Mr. Roff's Depreciation Study. The accruals are presented in column I of my Schedule 5. For transmission plant, they amount to $9,328,602 company-wide. Utah ratepayers would pay $12,958,682 for distribution plant removal costs in their state.

Q. HOW LARGE ARE THE ACTUAL REMOVAL COSTS THAT RMP HAS EXPERIENCED?

A. The actual annual removal cost expenditures, net of salvage, for the years 2002 through 2006 are shown in column J of Schedule 4 of Exhibit DPU CWK-2.1. The average removal cost expenditure for these five years has been $1,615,971 for transmission plant and $6,344,280 for Utah distribution plant.

Q. HOW DO MR. ROFF'S PROPOSED REMOVAL COST ACCRUALS COMPARE WITH THE ACTUAL REMOVAL COST EXPERIENCE?

A. In the final column of Schedule 4, I show that the excess of Mr. Roff’s proposed removal cost accruals over average removal cost expenditures is $7,712,630 for transmission plant and $6,344,280 for Utah distribution plant. Mr. Roff would collect removal cost accruals that are 5.8 times actual removal expenditures for transmission plant and twice the actual removal cost expenditures for distribution plant.

Q. HOW DOES MR. ROFF DERIVE SUCH LARGE REMOVAL COST ACCRUALS WHEN THE ACTUAL EXPERIENCED REMOVAL COSTS ARE SO MUCH LESS?

A. Mr. Roff uses a procedure that I call the Traditional Inflated Future Cost Approach (“TIFCA”). For each account, he compares the original cost of retirements during recent years with the experienced costs of removal during those same years. The ratio of the removal costs to plant retirements becomes the removal cost ratio. As Mr. Roff’s report indicates, this ratio can be as high as 110 percent. These ratios are used to develop annual removal cost rates. When those rates are applied to all plant in service as of the December 31, 2006, the result is the annual accruals shown in Schedule 5.

The reason for these very high removal cost ratios is that Mr. Roff is comparing dollars of very different values. The numerator of the removal cost ratio is recently incurred removal costs covering the years since about 2001. The denominator is the original cost of the plant retired. Those costs can be quite old. The average service life of a pole, for example, is 40 years. If a 40 year-old pole is retired in 2006, its original cost is expressed in 1976 dollars. In 1976, the dollar was worth 3.5 times its present value.[5]

With many low-valued dollars in the numerator and a few high-valued dollars in the denominator, the removal cost ratio is very high. As noted, these high ratios result in proposed removal cost accruals at least twice actual removal cost expenditures.

Q. WHAT IS THE RATIONALE BEHIND TIFCA?

A. The rationale underlying TIFCA is set forth on page 157 of Public Utility Depreciation Practices, published by the National Association of Regulatory Utility Commissioners in August 1996:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning are the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life. (emphasis supplied.)

[5] The Consumer Price Index in 1976 was 56.9; in 2006, it was 201.6. stats.bls.gov/cpi/home

The TIFCA procedure purports to forecast the future cost of removal associated with plant currently in service, and it charges that cost to the ratepayers that use that plant.

Q. IS THIS RATIONALE VALID?

A. The rationale would be valid if the TIFCA procedure recognized the present value of future costs. It does not.

Q. WHY DO YOU SAY THAT TIFCA FAILS TO RECOGNIZE THE PRESENT VALUE OF FUTURE COSTS?

A. The TIFCA procedure charges ratepayers now for the nominal dollar cost of removing plant at the time of its retirement. Under Mr. Roff's proposal, when RMP installs a pole in 2008, it would add a removal cost allowance of $1.05 to each dollar of construction cost recovered. Yet that $1.05 will not be spent, on average, for another 40 years, or until the year 2048. A dollar spent in 2048 is worth far less than a dollar collected in 2008. Not only will inflation erode the value of the 2048 dollar, but the holder of the dollar has the benefit of its earning (or spending) value in the intervening 40 years.

The TIFCA procedure simply ignores this relationship between present and future dollars. It assumes that a dollar collected now has exactly the same value as a dollar spent 40 years from now. Mr. Roff would have RMP collect these 2048 dollars from ratepayers starting next year.

Q. YOUR DISCUSSION HAS FOCUSED ON REMOVAL COSTS FOR MASS PROPERTY TRANSMISSION AND DISTRIBUTION ACCOUNTS. DOES THIS SAME FAILURE TO RECOGNIZE THE PRESENT VALUE OF FUTURE COSTS APPLY TO THE PRODUCTION PLANT REMOVAL COSTS AS WELL?

A. Yes. Mr. Roff uses the same TIFCA procedure to estimate the removal costs associated with interim production plant retirements. The terminal dismantlement costs are estimated differently, but the same issue applies. Terminal dismantlement costs are estimated in 2006 dollars, not future dollars, as are mass property removal costs. Yet, just as with distribution plant removal costs, the terminal dismantlement costs will not be incurred for years to come. RMP's Cholla 4 unit, for example, is not expected to retire until 2045; the Colstrip units are forecast for retirement in 2049. It is not appropriate to collect undiscounted dollars in 2008 for a cost that will not be incurred until 2049.

Q. WHAT IS THE SOLUTION TO THIS FAILURE TO RECOGNIZE THE PRESENT VALUE OF FUTURE COSTS?

A. The solution to the failure of TIFCA to recognize the present value of future costs is found in Statement of Financial Accounting Standards No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations*, issued by the Financial Accounting Standards Board in June 2001.

Q PLEASE DESCRIBE SFAS 143.

A. SFAS 143 addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."[6] A good example of such an obligation is the requirement to dismantle, entomb or decontaminate a nuclear generating plant.

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the "fair value" of that cost, defined as the cost of a contract with an independent party to retire the asset, negotiated when the asset is installed. In effect, this fair value is the present value of the future cost, using as the discount factor the risk-adjusted interest rate when the liability was recognized. The company also adds a value corresponding to that liability to the asset being booked. The initial fair value estimate is considered to

[6] SFAS 143, ¶2

be part of the original cost of the asset, which in turn is depreciated over the asset's life.

The annual expense associated with this liability consists of two parts. One is the depreciation of the liability, which is the present value of the liability divided by the life of the asset. The second expense is the annual accretion in the present value of the liability, similar to interest expense.

Q. CAN YOU DESCRIBE HOW THIS PROCESS WORKS?

A. Assume that RMP installs a pole that it expects to last for 40 years. Assume further that RMP is legally obligated to remove that pole when it retires. The estimated removal cost at the time of the pole's retirement is $1,000. RMP would record an asset and book a liability for this retirement cost, not at $1,000, but at $1,000 discounted at the risk-adjusted interest rate. If the risk-adjusted interest rate over 40 years is 5 percent, then the asset and the liability would be booked as $142.05 ($\$1,000/1.05^{40}$)

Each year, RMP would show two items of expense. The first would be the depreciation of the asset, $142.05/ 40 years = $3.55. The second expense would be the annual accretion in the present value of the liability. In this instance, it would be $1,000 times $1/1.05^{39} – 1/1.05^{40}$. This is $1,000 x (0.149148 - 0.142046

=.00710) or \$7.10. Total expense in the first year of operation would be \$3.55 + \$7.10 = \$10.65**.**

The first expense item, the depreciation of the initial Asset Retirement Obligation ("ARO"), stays the same each year throughout the asset's life. The second item, the annual accretion in the liability, increases as the present value factors increase.

Q. DO RMP'S REMOVAL COSTS QUALIFY AS LEGAL RETIREMENT OBLIGATIONS?

A. Some of RMP's removal costs are legal obligations, particularly where there is potential environmental degradation when the assets are retired. Most removal costs, however, have not been declared "Asset Retirement Obligations" subject to SFAS 143.

Q. DOES THIS MEAN THAT SFAS 143 IS IRRELEVANT TO THE ISSUES IN THIS PROCEEDING?

A. No. To the contrary, the principle embodied in SFAS 143 applies as much to non-legal removal costs as to legal removal costs. That principle is that any current recognition of future removal costs must reflect the time value of money while still ensuring that the utility ultimately accrues the full amount of the removal costs over the life of the plant.

Q. CAN SFAS 143 PROCEDURES BE APPLIED TO RMP'S NON-LEGAL REMOVAL COSTS?

A. Yes. The same procedures can be applied to non-legal removal cost obligations as to legal obligations.

Q. HAVE YOU IMPLEMENTED THE SFAS 143 PROCEDURES FOR RMP'S MASS PROPERTY REMOVAL COSTS?

A. Yes. Schedule 6 in my Exhibit DPU CWK-2.1 is a sample worksheet on which I have implemented the SFAS 143 procedures for the Utah plant in Account 364 – Poles, Towers and Fixtures. Because this is a mass property account, I must apply these procedures separately to each vintage (year of placement) of plant. I have accepted Mr. Roff's net removal cost ratios and have applied them to each vintage of plant to derive the estimated future removal cost amount. Then, I have discounted these costs back to the year of placement, using RMP's most recently approved cost of capital as the discount factor. I divide this value by the average service life of the account to derive the current year's depreciation – the first of the two components of the SFAS 143 expense.

I next determine the average remaining years for each vintage and calculate the accretion in the present value of that vintage's removal costs from the current year to the next year. In the column q of Schedule 6, I present each vintage's SFAS 143 expense. The sum of these expenses is the appropriate removal cost allowance for the account. This amount is transferred to column I "Cost of Removal Allowance," on Schedule 1 of Exhibit DPU CWK-2.1.

Q. HAVE YOU APPLIED THE SFAS 143 PROCEDURES TO THE TERMINAL DISMANTLEMENT COSTS OF RMP'S PRODUCTION PLANTS?

A. Yes. The procedures are the same for terminal dismantlement costs, with two notable differences. First, the dismantlement costs proposed by Mr. Roff are expressed in 2006 dollars, and the SFAS 143 procedures call for them to be inflated to an estimate of the actual cost at time of retirement. I have performed this inflation using the remaining life of the plants and an inflation factor derived from the average annual increases in the Handy Whitman cost indexes during the last five years. I then discount this forecast future cost back to the year of the plant's installation.

The other difference is that, unlike the mass property accounts with continuous additions and retirements, the production plants will each retire in a specific year. For this reason, the SFAS 143 removal cost allowance will increase each year as the plant retirement year approaches. I have assumed that the depreciation rates set in this case will be applied during the coming five years, so I have used the plant remaining lives as of the mid-point of the coming five-year period, which is the year 2010. Schedule 7 in Exhibit DPU CWK-2.1 is a sample worksheet for this calculation.

Q. ASIDE FROM REFLECTING THE PRESENT VALUE OF FUTURE COSTS, IS THERE ANY OTHER REASON TO DISCOUNT RMP'S REMOVAL COST ESTIMATES?

A. Yes. These removal cost estimates are very, very uncertain. Indeed, the only certainty is that they will be incorrect. The mass property removal costs are based on a very shaky and unstable assumed relationship between retirements and removal costs. The production plant dismantlement costs are based on equally shaky assumptions as regards the nature and timing of dismantlement.

Q. WHY DO YOU SAY THAT THE MASS PROPERTY REMOVAL COSTS ARE BASED ON A SHAKEY AND UNSTABLE ASSUMED RELATIONSHIP BETWEEN RETIREMENTS AND REMOVAL COSTS?

A. Since retirements cause removal costs, one would think that there would be a close correlation between the value of retirements from year to year and the amount of removal costs incurred. Unfortunately, that correlation does not always show up in the actual data. Schedule 8 in Exhibit DPU CWK-2.1 compares the annual retirements with the annual removal costs in the five Utah distribution accounts that show the highest levels of removal costs. At the bottom of each set of columns, I present the R^2, or index of determination for each series. The R^2 indicates the extent to which one variable – retirements, in this case – can be used to predict the other variable – removal costs. Of the five accounts studied, only two show an R^2 greater than .70. The other three accounts show R^2 values of .007, .040 and .318, suggesting a very low level of confidence that retirements can be used to predict removal costs. Yet just such a prediction is embedded into Mr. Roff's removal cost ratios.

The reason for this lack of correlation has to do with measurement, not causality. Retirements are valued at their original cost, and that cost varies radically over time. In any given year, the age of retired plant will differ from the age during the previous and the subsequent years. Even over a period of, say, five years, one cannot assume that the retired plant represents a normal dispersion of retirement values around some representative average.

Then, there is the fact that neither retirements nor removal costs are homogeneous. Many plant accounts consist of a variety of items having different unit costs. The mix of these items retired each year will differ from previous and future years. The same is true of removal costs. Because the mix of plant retired differs each year, the mix of removal activities also differs. The result of these variations is an extremely unstable relationship between retirements and removal costs. When that relationship is used to forecast future removal costs, the result is a very uncertain forecast.

Q. WHY DO YOU SAY THAT THE DISMANTLEMENT COST ESTIMATES REFLECT A SHAKY ASSUMPTION ABOUT THE NATURE AND TIMING OF DISMANTLEMENT?

A. The implicit assumption of the Black & Veatch dismantlement studies, and I suspect most of the studies in Mr. Roff's survey, is that the plants will be dismantled and the site cleared when the existing generating units are retired. I question this assumption. The best use for any power plant site where the generating units have worn out is as a site for new generating units. Not only are many of the basic structures still usable, but the common facilities for fuel handling and storage, water movement and treatment, and transportation remain in place. Perhaps more important, the site is already connected into the transmission grid and bears the requisite environmental and zoning approvals.

Given the advantages of existing sites, it would be economically irrational for the RMP to totally dismantle every one of its retired generating plants and clear the site. Yet this is the implicit assumption of the Company's dismantlement allowances. Presumably, the capacity represented by RMP's retiring units must be replaced, and the best site for the replacement units is an existing power plant.

This is the probable use of most of RMP's generating plants following the retirement of the existing generating units.

Furthermore, not all plants are retired. Many are sold instead. Since 1991, RMP has removed seven generating plants from its production fleet. Of these, only two have been decommissioned; the remaining five sold.[7] RMP has incurred no decommissioning costs for these five plants.

Q. DO YOU HAVE ANY OBJECTIVE EVIDENCE TO SUPPORT THESE OPINIONS?

A. Yes. In 1998, our firm surveyed the disposition of all steam units over 50 MW retired in the United States during the previous decade. There were 67 of these units at 37 different locations. Fifty of them, retired in 25 separate locations, were in plants where other steam units continued in operation. Most of these retired units had not been dismantled, and all of the plants, including their basic structures, continued in use. Another 6 units in 5 locations were in plants where combustion turbines, combined cycle units or internal combustion units continued to operate. Only 11 units in 7 locations were fully retired. Among these retired plants, we were able to identify only two, containing five units, that had been fully dismantled. Yet even here, the dismantled was not necessarily to "greenfield" status. In one case the stack and some of the buildings were integrated into a local development project.

I have not been able to update this survey because the U.S. Energy Information Agency no longer collects this information for all generating plants. Nonetheless, the evidence as of a few years ago indicated that there is an important distinction between retiring a unit and retiring a plant, and between retiring a plant and dismantling the plant. Units may retire, but most of the plants in which they are located continue on. Even after the plant is retired, many of the structures and facilities are not dismantled.

Q. HOW DOES THE UNCERTAINTY OF RMP'S REMOVAL COST ESTIMATES AFFECT THE CALCULATION OF REMOVAL COST ALLOWANCES?

A. Four years following the issuance of SFAS 143, the Financial Accounting Standards Board issued FASB Interpretation No. 47, intended to clarify SFAS 143 in cases where the entity is uncertain as to the timing or method of meeting its retirement obligation. This interpretation states as follows:

> Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists.[8]

[7] Response to DPU D.R. 1.53.

[8] Financial Accounting Standards Board, FASB Interpretation No. 47 *Accounting for Conditional Asset Retirement Obligations*, March 2005, Summary.

It appears from this directive that even disregarding the issue of the present value of future cost, the uncertainty of RMP's removal cost estimates would justify a substantial discounting of their value.

Q. ARE THERE ANY OTHER JURISDICTIONS THAT HAVE ADOPTED THE PRESENT VALUE APPROACH YOU HAVE RECOMMENDED FOR TREATING REMOVAL COSTS?

A. Yes. In July of this year, the Maryland Public Service Commission adopted the present value approach in two decisions involving the Potomac Electric Power Company[9] and the Delmarva Light & Power Company.[10] In June, the Michigan Public Service Commission imposed a requirement that each utility compute both discounted and undiscounted removal costs when developing its depreciation rates.[11]

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

[9] Maryland P.S.C. Order No. 81517, Case No. 9092, July 19, 2007.
[10] Maryland P.S.C. Order No. 81518, Case No. 9093, July 19, 2007.
[11] Michigan P.S.C. Case No. U-14292, Opinion and Order, June 26, 2007.