

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NOS. UE-072300 and UG-072301

DIRECT TESTIMONY OF CHARLES W. KING (CWK-1T)

ON BEHALF OF

PUBLIC COUNSEL

MAY 30, 2008

DIRECT TESTIMONY OF CHARLES W. KING (CWK-1T)
DOCKET NOS. UE-072300 AND UG-072301

TABLE OF CONTENTS	<u>PAGE</u>
I. INTRODUCTION / SUMMARY	1
II. SUMMARY OF RECOMMENDATIONS	2
III. DEPRECIATION—GENERAL	4
IV. COLSTRIP LIFE SPANS	8
V. OTHER PRODUCTION PLANT LIVES	12
VI. ACCOUNT 365 – OVERHEAD CONDUCTORS & DEVICES	14
VII. REMOVAL COSTS	15
VIII. CONCLUSION	33

TABLES AND GRAPHS	<u>PAGE</u>
Table 1. Comparison of Accruals on 12/31/06 Plant	3

EXHIBIT LIST

Exhibit No. ___ (CWK-2)	Education and Employment History
Exhibit No. ___ (CWK-3)	Appearances as an Expert Witness
Exhibit No. ___ (CWK-4)	Electric Depreciation Schedules
Exhibit No. ___ (CWK-5)	Natural Gas Depreciation Schedules
Exhibit No. ___ (CWK-6)	PSE Response to Public Counsel Data Request No. 642
Exhibit No. ___ (CWK-7)	PSE Response to Public Counsel Data Request No. 646

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Exhibit No. ___ (CWK-8) National Study of Other Production Unit Lives—Steam Plant
Production Units

Exhibit No. ___ (CWK-9) National Study of Other Production Unit Lives—Combustion
Turbine Service Lives

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I. INTRODUCTION / SUMMARY

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 Snavelly King Majoros O'Connor & Lee, Inc. (Snavelly King). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q: Please describe Snavelly King.

A: Snavelly King, formerly Snavelly, 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 38-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. Exhibit No. ___ (CWK-2) is a summary of my qualifications and experience.

Q: Have you previously submitted testimony in regulatory proceedings?

A: Yes. Exhibit No. ___ (CWK-3) is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

1 **Q: For whom are you appearing in this proceeding?**

2 A: I am appearing on behalf of the Public Counsel Section of the Office of the
3 Attorney General (Public Counsel).

4 **Q: What is the objective of your testimony?**

5 A: The objective of my testimony is to recommend depreciation rates for the electric
6 and gas plant of the Puget Sound Energy Company (PSE or the Company). In the
7 process, I will review and critique the depreciation study submitted by C. Richard
8 Clarke on behalf of PSE.

9 **Q: Please describe the process you used in preparing this testimony.**

10 A: I began by reviewing the depreciation study submitted by Mr. Clarke. Based on
11 that review, I prepared a number of data requests and carefully read the Company's
12 responses. Independently, I evaluated the approach used by Mr. Clarke to the
13 treatment of production plant lives and salvage and retirement costs, and I
14 developed the alternatives that I shall discuss in my testimony. I then prepared the
15 schedules found in my exhibits. The exhibits were prepared and the calculations
16 performed either by me or under my direction.

17 **II. SUMMARY OF RECOMMENDATIONS**

18 **Q: What depreciation rates do you recommend?**

19 A: My recommended electric and gas plant depreciation rates are set forth in Schedules
20 1 of Exhibit No. ___ (CWK-4) and ___ (CWK-5), respectively. Schedules 1 of
21 those exhibits also provide an account-by-account comparison of my recommended

1 accruals with the existing accruals and those proposed by the Company. The
 2 accruals are all based on plant in service as of December 31, 2006. A summary
 3 comparison of my recommended rates accruals with the existing and Company
 4 proposed accruals are as follows:

Comparison of Accruals on 12/31/06 Plant

<u>Electric Plant</u>	<u>Present</u>	<u>PSE Proposed</u>	<u>PC Recommended</u>
Steam Production	\$ 22,870,109	\$ 26,011,990	\$ 12,400,711
Hydro Production	11,348,270	4,774,697	3,133,568
Other Production	24,950,161	26,500,160	23,626,912
Transmission	7,796,779	6,803,170	5,847,870
Distribution	76,995,670	79,589,144	70,988,011
General	6,788,743	11,774,595	11,676,487
Total Electric	\$ 150,749,732	\$ 155,453,756	\$ 127,673,559
<u>Gas Plant</u>			
Production	\$ 334,834	\$ 61,946	\$ 46,164
Storage	766,758	460,795	393,050
LNG	432,970	400,147	382,346
Transmission	1,097,674	-	-
Distribution	64,942,654	72,845,223	53,366,786
General	2,518,382	10,239,164	5,402,942
Total Gas	\$ 70,093,272	\$ 84,007,275	\$ 59,591,289

5

6 **Q: How do your recommended depreciation rates differ from those proposed by**
 7 **Mr. Clarke?**

8 **A:** My recommended depreciation rates differ from those proposed by Mr. Clarke in
 9 the following respects:

- 10 ▪ I increase the life spans for the Colstrip units to 60 years.
- 11 ▪ I increase life spans of the “other production” gas turbines to 45 years.

- 1 ▪ I increase the average service life of account 365 – Overhead Conductors
- 2 and Devices – from 40 to 45 years.
- 3 ▪ I set removal cost accruals based on either the present value of the future
- 4 costs or the net removal cost experience of the last five years, whichever is
- 5 higher.

6 III. DEPRECIATION—GENERAL

7 **Q: What is depreciation?**

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

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

18
19 The second commonly cited definition of depreciation is that of the American
20 Institute of Certified Public Accountants:

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

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

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

1
2 If depreciation can be defined in a single sentence, I would say that it is the
3 process of recovering the initial investment in tangible capital assets,
4 adjusted for net salvage, in a systematic fashion over the useful service life
5 of the plant, recognizing that a utility plant is typically a group of
6 investments.

7 **Q: Does calculation of depreciation involve the exercise of judgment?**

8 A: Yes. Depreciation calculations are similar in this sense to setting the required rate
9 of return to equity investors. Both are developed from analyses that, while based on
10 quantitative values, require considerable application of judgment. In the case of
11 rate of return, that judgment pertains to the earnings expectations of investors as
12 indicated by the stock market and corporate financial data. In the case of
13 depreciation, the judgment pertains to the estimation of the future surviving life of
14 plant as indicated by past patterns of retirements.

15 **Q: How does this judgmental characteristic of depreciation influence the**
16 **Commission's approach to the subject?**

17 A: The Commission must recognize that the development of depreciation rates is not a
18 refined science subject to mathematical precision. Because depreciation analysts
19 use judgment in their estimation of depreciation, the Commission must necessarily
20 exercise its own judgment in assessing the rationale and data that underlie
21 alternative depreciation rates. In this proceeding, the Commission must choose
22 among depreciation rates that yield widely differing annual depreciation accruals.
23

1 **Q: What are the basic parameters required to develop a depreciation rate?**

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

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

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

21 Finally, virtually all major utilities, including PSE, employ what is known as
22 “remaining life depreciation.” This procedure computes the depreciation rate by

1 dividing the unrecovered net investment, adjusted for net salvage, by the estimated
2 remaining years of the asset (or group of assets). It effectively ensures that any past
3 under- or over-accruals of depreciation are recovered during the remaining life of
4 the asset.

5 **Q: Please illustrate how the parameters you have just described are used to**
6 **develop depreciation rates?**

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

9
$$1/20 = 5\%$$

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

12
$$\frac{1 - .05}{20} = \frac{.95}{20} = 4.75\%$$

13
14
15 Assume next that the cost of removing this asset amounts to 15 percent of its
16 value. The depreciation rate increases:

17
$$\frac{1 - .05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

18
19
20 This is called a "whole life" rate because it is based on the whole life of 20 years.

21 To develop the remaining life rate, we must identify some additional items of data:
22 the original investment, the depreciation reserve (the amount of depreciation that
23 has already been recovered), and the remaining life of the asset.

24 In this illustration, let us assume that the asset originally cost \$1 million and
25 that past depreciation charges have recovered \$400,000. This means that we have

1 yet to recover \$600,000 in original cost, plus a negative net salvage (i.e. net cost of
2 removal) amounting to 10 percent of the original cost, or \$100,000. The total
3 amount yet to be recovered is thus \$700,000. Let us further assume that the asset is
4 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the
5 unrecovered amount is divided by the remaining life years:

6
$$\frac{\$700,000}{10 \text{ years}} = \$70,000 \text{ required annual accrual}$$

7
8
9 The depreciation rate is then calculated by dividing the annual amount to be
10 recovered by the gross investment, in this case:

11
$$\frac{\$70,000}{\$1,000,000} = 7.0\%$$

12
13
14 The foregoing illustrates the traditional formulation of depreciation rates. As I
15 shall discuss later in this testimony, I am recommending a modification that
16 independently derives an annual allowance for the present value of net removal
17 costs. Assume that this calculation yields an annual allowance of \$5,000. In that
18 case, the depreciation rate would be calculated as:

19
$$\frac{\$70,000 + \$5,000}{\$1,000,000} = 7.5\%$$

20
21
22 **IV. COLSTRIP LIFE SPANS**

23
24 **Q: Have you identified depreciation issues with Colstrip plant in this case?**

25 **A:** Yes. The Colstrip life spans, proposed by PSE, are unreasonably short because
26 they are inconsistent with: (1) the Company's own Integrated Resource Plan, (2)

1 the life spans approved for PacifiCorp, co-owners of Colstrip Unit 4, for the same
2 plant, and (3) the service lives of steam plants nationwide.

3 **Q: What do you mean by “life spans?”**

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

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

15 **Q: How does Mr. Clarke calculate depreciation for production plant?**

16 A: In computing his depreciation rates for production plant, Mr. Clarke calculates the
17 weighted average of the estimated remaining life of the terminal retirement plant
18 and the remaining life of the plant that will retire in the interim prior to terminal
19 retirement.

20

1 **Q: How did the company estimate the life spans of its Colstrip steam production**
2 **plants?**

3 A: It is my understanding that these plant lives are based on the expiration of the
4 contracts for coal deliveries to these plants.

5 **Q: What life spans does the company recommend for its Colstrip plants?**

6 A: The life spans now recommended by the Company are presented in Schedule 2 of
7 Exhibit No. ____ (CWK-4). They range from 40 to 44 years.

8 **Q: Why did the Company use the coal contracts as the basis for the Colstrip life**
9 **spans?**

10 A: In a conference call with the Company's personnel, I was told that the mine mouth
11 coal at the Colstrip location will exhaust as these contracts expire.

12 **Q: Have you since confirmed this information?**

13 A: No. I inquired as to the exhaustion of the coal used by the Colstrip plant. The
14 response is attached as Exhibit No. ____ (CWK-6). In PSE's response to Public
15 Counsel Data Request No. 642, PSE states that there is no impending exhaustion of
16 coal from the Rosebud Mine and that the reserves are sufficient to support
17 operations through the end of 2019 *and beyond*.

18 **Q: You have identified three reasons why you believe the Colstrip life spans are**
19 **too short, the first of which is that they are inconsistent with the Company's**
20 **own Integrated Resource Plan. What is the basis for this contention?**

21 A: The basis for this contention is PSE's response to Public Counsel Data Request No.
22 646, which I have attached as Exhibit No. ____ (CWK-7). On page 38 of Mr.

1 Clarke's Revised Exhibit No. ____ (CRC-3), he lists the retirement dates of the four
2 Colstrip units. According to Mr. Clarke, Units 1 and 2 are to be retired in 2019,
3 Unit 3 is to be retired in 2024, and Unit 4 is to be retired in 2025. All of these
4 retirements are within a 20-year horizon of 2007, the year the latest Integrated
5 Resource Plan (IRP) was filed. Yet, according to Exhibit No. ____ (CWK-7), the
6 2007 IRP includes all four Colstrip units in PSE's resources throughout the 20-year
7 planning horizon.

8 **Q: The second reason you cited for stating that the life spans of the Colstrip units**
9 **are too short is that they are inconsistent with the life span of the very same**
10 **plant that has been approved for PacifiCorp, a co-owner of Colstrip Unit 4.**

11 **What is the basis for this contention?**

12 A: In Docket No. UE-071795³, the Commission approved a multi-state settlement of
13 the depreciation rates of PacifiCorp. That settlement included a 60-year life for the
14 Colstrip plant.

15 **Q: Your third reason for stating that the Company's life spans for the Colstrip**
16 **units is that they are inconsistent with the lives of steam plants nationwide.**

17 **What is the basis for this contention?**

18 A: The basis for this contention is an actuarial study that my firm has conducted of all
19 steam plant retirements since 1900. The study, described in Exhibit No. ____
20 (CWK-8), is based on the installation and retirement dates of these steam
21 production units. The study reveals that the average life span of these plants was 59

1 years. The source of the data for this study is the Energy Information Service of the
2 U.S. Department of Energy.

3 **Q: What life span do you recommend for the Colstrip plants.**

4 A: I recommend a life span of 60 years for the Colstrip units. The Company-proposed
5 and my recommended retirement dates are presented in Schedule 2 of Exhibit
6 No. ____ (CWK-4).

7 **Q: Have you calculated depreciation rates that reflect a 60-year life for the**
8 **Colstrip units?**

9 A: Yes. The remaining lives in Column D of Schedule 1 of Exhibit No. ____ (CWK-4)
10 are a composite of the remaining portion of each unit's 60-year life span and the
11 remaining lives of the units of plant that are forecast to retire in the interim between
12 now and the terminal retirement dates. In computing the remaining lives for these
13 interim retirements, I have accepted the life and survivor curve parameters that are
14 shown in Column 2 of Table 1 of Mr. Clarke's Revised Exhibit No. ____ (CRC-3).

15
16

V. OTHER PRODUCTION PLANT LIVES

17 **Q: What is meant by "other production?"**

18 A: The term "other production" refers to the combustion turbine units that PSE uses to
19 meet peak load conditions. There are six of these plants, and they are listed at the
20 bottom of Schedule 2 of Exhibit No. ____ (CWK-4). The term also applies to the two

³ *In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power, For An Accounting Order Authorizing a Revision to Depreciation Rates, Docket No. UE-071795, Order No. 1, (April 10, 2008).*

1 wind farms the Company has recently installed. Since I am not challenging the life
2 parameters of the wind farms, I have not listed them on Schedule 2.

3 **Q: What life spans does the company assume for these plants?**

4 A: Schedule 2 of Exhibit No. ____ (CWK-4) also shows the installation year, the
5 Company's forecast retirement year, and the assumed life spans of each of the
6 plants. These numbers are abstracted from the table on page 38 of Mr. Clarke's
7 Revised Exhibit No. ____ (CRC-3).

8 **Q: What is your assessment of the company's life span estimates?**

9 A: The life spans of all the units other than Crystal Mountain are between 29 and 35
10 years. These estimates are unreasonably short. A far more appropriate estimate of
11 the life span of a combustion turbine is 45 years.

12 **Q: What is the basis for your assertion that 45 years is a more appropriate life
13 span for combustion turbines?**

14 A: The basis of this statement can be found in Exhibit No. ____ (CWK-9), which is my
15 firm's study of combustion turbine service lives. That study, which covered all
16 retirements of combustion turbines since 1899, indicates that these plants have
17 survived on average 46.5 years and that this average has increased in recent years to
18 56.5 years.

19 **Q: Have you calculated depreciation rates reflective of your 45-year life span
20 estimate?**

21 A: Yes. The remaining lives in Column D of Schedule 1 of Exhibit No. ____ (CWK-4)
22 opposite the respective "other production" plant accounts, reflect my estimate of

1 45-year life spans. Like the steam plant remaining lives, these lives are a composite
2 of the remaining life span of components that are forecast to survive to the plants'
3 retirement and the interim retirements that will occur before that time. Again, I
4 have accepted Mr. Clarke's life and survivor curve parameters for the interim
5 retirements.

6 **VI. ACCOUNT 365 – OVERHEAD CONDUCTORS & DEVICES**

7 **Q: What life and survivor curve does PSE propose to use for Account 365 –**
8 **Overhead Conductors and Devices?**

9 A: The Company is proposing a 40 year average service life with an R1 survivor curve.

10 **Q: Do you agree with this life estimate?**

11 A: No, I do not. While the Company's historical life studies justify a 40 year life,
12 these are retrospective analyses that cannot anticipate future developments. In this
13 case, the Company is proposing a considerable increase in its tree trimming
14 expenditures. If the tree trimming program is enhanced, the probable effect will be
15 less retirements from the Overhead Conductors account, leading to a longer average
16 service life. This will continue the trend noted by Mr. Clarke in his write-up on
17 Account 265 in the "Account by Account Summary" of his report.

18 **Q: What service life to you recommend?**

19 A: I cannot predict the precise effect of the enhanced tree trimming program, so I am
20 proposing a modest 5-year increase in the average service life of plant in this
21 account. The result is an average service life of 45 years.

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VII. REMOVAL COSTS

Q: Does PSE incur removal costs?

A: Yes. PSE expects to incur removal costs for all of its steam and hydro production plants and most of its transmission and distribution plant accounts other than easements and structures. It also forecasts removal costs for the common plant structures account.

Q: How does PSE's depreciation witness, Mr. Clarke, treat removal costs?

A: For each of the affected plant accounts, Mr. Clarke adds his forecast 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. Clarke forecast his removal costs?

A: Mr. Clarke uses two procedures depending upon the type of removal costs, one for "mass property" accounts, which include all transmission and distribution accounts, the other for "life span" accounts, which include all of the production plant accounts.

Mr. Clarke does not describe his procedure for deriving removal costs for the mass property accounts, but it appears that he has employed what I call the Traditional Inflated Future Cost Approach that is used by virtually all

1 utility-sponsored depreciation analysts. It begins with an examination of the
2 history of retirements, removal costs and salvage proceeds. Mr. Clarke then
3 subtracts each year's salvage receipts from that year's removal costs to derive an
4 annual amount of "net salvage." Except for the transportation and power-operated
5 equipment general plant accounts, the removal costs are always much more than the
6 salvage proceeds, so the result is "negative net salvage." These amounts would
7 better be expressed as "positive net removal costs," or just "removal costs." I shall
8 use this term in the remainder of my testimony.

9 Mr. Clarke then compares the annual net removal costs to the annual amount
10 of plant retired to derive a "net salvage ratio." The numerator is net salvage (net
11 removal costs) and the denominator is retired plant. Because of the very great year-
12 to-year variability of these ratios, he averages them for varying periods and selects
13 what he deems a representative relationship of net removal costs to retirements.
14 That relationship is then applied to the total value of plant in the account to derive
15 the amount of net removal costs that must be recovered in depreciation rates.

16 Mr. Clarke does not use historical data for the "life span" production plants
17 accounts. In these cases, it is necessary to estimate the costs to dismantle plants at
18 the end of their service lives. While there have been no decommissioning studies,
19 Mr. Clarke proposes to allow an amount in the net salvage rate for final dismantling
20 until site-specific studies are performed. For this reason, he retains the existing
21

1 removal cost ratios, as follows:

2	Acct. 311 Steam Plant Structures & Improvements	-5%
3	Acct. 312 Boiler Plant Equipment	-10%
4	Acct. 314 Steam Turbo Generator Equipment	-10%
5	Acct. 331 Hydro Structures & Improvements	-25%
6	Acct. 332 Reservoirs, Dams and Waterways	-25%

7 **Q: How large are the removal cost ratios recommended by Mr. Clarke?**

8 A: They are very large, at least for gas plant. Mr. Clarke's removal cost ratios are
9 presented in Column 3 of Tables 1 and 2 of his depreciation study. The net removal
10 cost ratios proposed by Mr. Clarke range as high as 75 percent for Account 380 –
11 Gas Services. A 75 percent removal cost ratio means that for every dollar of
12 depreciation recovered, another \$0.75 is accrued against future removal costs.

13 **Q: Can you quantify the annual removal cost accrual that Mr. Clarke proposes be**
14 **charged to ratepayers for PSE's electric and gas distribution plant in this**
15 **state?**

16 A: Yes. Schedule 3 in Exhibit No. ____ (CWK-4) shows the accruals that Mr. Clarke
17 proposes for electric transmission and distribution plant based on December 31,
18 2006, plant in service. For the electric plant, the annual removal cost accruals come
19 to \$6,185,797. Schedule 2 in Exhibit No. ____ (CWK-5) shows that the Company's
20 proposed removal cost accruals for gas distribution plant amount to \$15,989,716.
21 These are the annual amounts that ratepayers would pay for removal costs each year
22 based on year-end 2006 plant.

1 **Q: How large are the actual removal costs that PSE has experienced?**

2 A: The actual annual removal cost expenditures, net of salvage, for the years 2002
3 through 2006 are shown in the same schedules. For electric plant, actual removal
4 cost expenditures for transmission and distribution plant came to \$7,254,333. The
5 average annual removal cost expenditure for gas distribution plant was \$3,659,559
6 for all gas distribution plant.

7 **Q: How do Mr. Clarke's proposed removal cost accruals compare with the actual
8 removal cost experience?**

9 A: The final columns of both schedule 3 in Exhibit No. ____ (CWK-4) and Schedule 2
10 in Exhibit No. ____ (CWK-5) show the difference between Mr. Clarke's proposed
11 removal cost accruals and the average removal cost expenditures. For electric
12 plant, the average removal cost expenditures exceed Mr. Clarke's proposed accruals
13 by \$1,068,536. For gas plant, Mr. Clarke's accruals exceed actual average
14 expenditures by \$12,330,157—over three times actual removal expenditures.

15 **Q: How does Mr. Clarke derive such large removal cost accruals for gas plant
16 when the actual experienced removal costs are so much less?**

17 A: As discussed earlier, Mr. Clarke develops his removal cost allowances by
18 comparing the original cost of retirements during recent years with the experienced
19 costs of removal during those same years. The ratio of the removal costs to plant
20 retirements becomes the removal cost ratio. As Mr. Clarke's report indicates, this
21 ratio can be as high as 75 percent. These ratios are used to develop annual removal

1 cost rates. When those rates are applied to all plant in service as of the December
2 31, 2006, the result is the annual accruals shown in Schedule 2 of Exhibit
3 No. ____ (CWK-5).

4 The reason for these very high removal cost ratios is that Mr. Clarke is
5 comparing dollars of very different values. The numerator of the removal cost ratio
6 is recently incurred removal costs covering the years since about 2001. The
7 denominator is the original cost of the plant retired. Those costs can be quite old.
8 The average service life of a section of gas main is 50 years. If a 50 year-old gas
9 main is retired in 2006, its original cost is expressed in 1966 dollars. According to
10 Handy-Whitman, the construction cost index in 1966 for plastic gas mains was 76.
11 By 2006, that index had increased to 434, or 5.7 times.⁴

12 With many low-valued dollars in the numerator and a few high-valued dollars
13 in the denominator, the removal cost ratio is very high. As noted, these high ratios
14 result in proposed removal cost accruals well over three times the actual removal
15 cost expenditures. This is why I refer to Mr. Clarke's procedure as the Traditional
16 Inflated Future Cost Approach, or TIFCA.

⁴ *Handy-Whitman Bulletin No. 165*, p. G-6-6 and G-6-8, Whitman Requardt & Associates, LLP,
Baltimore, MD.

1 **Q: What is the rationale behind TIFCA?**

2 A: The rationale underlying TIFCA is set forth in *Public Utility Depreciation*
3 *Practices*, published by the National Association of Regulatory Utility
4 Commissioners⁵:

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

17
18 The TIFCA procedure purports to forecast the future cost of removal associated
19 with plant currently in service, and it charges that cost to the ratepayers that use that
20 plant.

21 **Q: Is this rationale valid?**

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

24 **Q: Why do you say that TIFCA fails to recognize the present value of future**
25 **costs?**

26 A: The TIFCA procedure charges ratepayers now for the nominal dollar cost of
27 removing plant at the time of its retirement. Under Mr. Clarke's proposal, when

⁵ National Association of Regulatory Utility Commissioners (NARUC), *Public Utility Depreciation Practices*, (August 1996), p. 157.

1 PSE installs a gas service in 2008, it would add a removal cost allowance of \$0.75
2 to each dollar of construction cost recovered. Yet that \$0.75 will not be spent, on
3 average, for another 40 years, or until the year 2048. A dollar spent in 2048 is
4 worth far less than a dollar collected in 2008. Not only will inflation erode the
5 value of the 2048 dollar, but the holder of the dollar has the benefit of its earning
6 (or spending) value in the intervening 40 years.

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

11 **Q: Your discussion has focused on removal costs for mass property transmission**
12 **and distribution accounts. Does PSE fail to recognize that the present value of**
13 **future costs applies to the production plant removal costs as well?**

14 A: Yes. The terminal dismantlement costs are estimated differently, but the same issue
15 applies. Terminal dismantlement costs of steam and hydro production plant are
16 estimated in 2006 dollars, not future dollars, as are mass property removal costs.
17 Yet, just as with distribution plant removal costs, the terminal dismantlement costs
18 will not be incurred for years to come. I am forecasting that the Colstrip plants will
19 be retired between 2035 and 2045. It is not appropriate to collect undiscounted
20 dollars in 2008 for a cost that will not be incurred until 2035.

1 **Q: Doesn't the fact that removal cost accruals are included in the depreciation**
2 **reserve that is subtracted from rate base adequately recognize the time value**
3 **of those accruals?**

4 A: No, it does not, for two reasons. First, the TIFCA front loads the accrual of future
5 removal costs, and second, because the time value of money is much higher for
6 ratepayers, particularly residential ratepayers, than it is for PSE.

7 **Q: Why do you say that TIFCA front-loads the accrual of future removal costs?**

8 A: If all of the vintages of plant (i.e. plant added each year) had the same dollar value
9 and the same service life, then the subtraction of removal cost accruals from rate
10 base would adequately account for the time value of money to ratepayers. But the
11 reality is that, for almost all accounts, the dollar value of the vintages (new plant
12 added each year) increases. That occurs because PSE's system is growing, and
13 even if it were not, the continuous process of inflation would mean that just to
14 replace the same plant as it is being retired, more dollars must be added each year.

15 As a result, in every account there are always more dollars of new plant than
16 dollars of old plant. To illustrate, the average service life of the Gas Services
17 Account No. 380 is 40 years. The remaining life of this plant is 28.8 years, which
18 means that the average age of the dollars in this account is on the order of 11 years,
19 or only about a third of the average service life.

20 The TIFCA procedure accrues removal costs for each vintage in even nominal
21 dollar amounts each year, seemingly a straight-line recovery of those costs. But in
22 “real” dollars, that is, dollars of equal value in terms of both inflation and time

1 value, it is very much front-loaded; it recovers much more in the early years of a
2 vintage's life than in the later years. Because all of the accounts have more money
3 in newer than older vintages, the Company is always ahead, and ratepayers are
4 always behind under TIFCA – even acknowledging the rate base subtraction – than
5 if the accruals were expressed in dollars of equal time value.

6 **Q: Why do you say that the time value of money is greater for ratepayers than for**
7 **PSE?**

8 A: If the time value of money to PSE is the same as it is to ratepayers, then ratepayers
9 should be indifferent as to whether they pay more dollars now and receive the
10 benefit of a rate base deduction, or whether they defer the rate base deduction and
11 pay later.

12 But the time value of money is not the same. The time value of money to PSE
13 is the interest rate that PSE pays for short-term debt. That rate varies month to
14 month depending on the capital markets, but for most electric utilities, it is in the
15 range of five to six percent.

16 The time value of money to PSE's ratepayers depends on the category of
17 ratepayers. For some large industrial and commercial customers, the time value of
18 money is likely to be about the same as that for PSE – the short-term borrowing
19 rate. Those customers will be indifferent to whether removal costs are accrued
20 sooner or later.

21 Smaller commercial customers probably have a higher short-term capital costs
22 than PSE. "Mom and Pop" businesses usually pay a premium over the banks'

1 prime rate owing to their lower credit ratings. Some marginal businesses may not
2 have access to bank credit at all, in which case the time value of their money is
3 measured by the late charges and penalties assessed by their creditors.

4 Of the three major categories of customers, residential customers have the
5 highest time value of money. To begin with, only residential ratepayers have to pay
6 their electric bills with after-tax dollars. If the marginal tax rate for a middle-class
7 ratepayer is 35 percent, then the ratepayer must earn \$1.54 ($1/(1-.35)$) for each
8 dollar he pays in electric bill. Setting aside the tax effect, the overwhelming
9 majority of residential customers are net debtors, if only because most home-
10 owners have outstanding home mortgages. The Federal Reserve reports that the
11 average April rate for new conventional 30-year mortgages was 5.92 percent,⁶
12 probably about the same as PSE's cost of short-term borrowing. But that is the rate
13 for "prime" mortgages. Other, more risky "balloon" and "interest only" mortgages
14 bear higher interest rates.

15 At the margin, however, the cost of money to residential customers is
16 considerably higher. Second trust mortgages bear somewhat higher interest rates
17 than first trust mortgages. Higher still is the cost of credit card debt, ranging up to
18 22.4 percent.⁷ Highest of all is the cost of money to residential customers who
19 simply cannot pay any more than their incomes will allow. For them, the cost of

⁶ Federal Reserve Statistical Release, *H.15 Select Interest Rates (Weekly)*, (May 5, 2008),
Available at: www.federalreserve.gov/releases/h15/20080505.

⁷ Available at: www.capitalone.com/creditcards/products.

1 money is the burden imposed by doing without critical life necessities: food,
2 clothing and shelter.

3 It is clear from the foregoing that ratepayers are not adequately compensated
4 for the time value of their money when the nominal, undiscounted value of future
5 removal costs is subtracted from the rate base. That is because the TIFCA
6 procedure front-loads those accruals and because the time value in money is much
7 higher for ratepayers than it is for PSE.

8 **Q: What is the solution to this failure to recognize the present value of future**
9 **costs?**

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

14 **Q: Do PSE's removal costs qualify as legal retirement obligations?**

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

19 **Q: Does this mean that SFAS 143 is irrelevant to the issues in this proceeding?**

20 A: No. To the contrary, the principle embodied in SFAS 143 applies as much to non-
21 legal removal costs as to legal removal costs. That principle is that any current
22 recognition of future removal costs must reflect the time value of money while still

1 ensuring that the utility ultimately accrues the full amount of the removal costs over
2 the life of the plant.

3 **Q: Can SFAS 143 procedures be applied to PSE's non-legal removal costs?**

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

6 **Q: Have you implemented the SFAS 143 procedures for PSE's mass property
7 removal costs?**

8 A: Yes. Schedule 3 in my Exhibit No. ____ (CWK-5) is a sample worksheet on which I
9 have implemented the SFAS 143 procedures for the plant in Account 380 – Gas
10 Services. Because this is a mass property account, I must apply these procedures
11 separately to each vintage (year of placement) of plant. I have accepted Mr.
12 Clarke's 75 percent net removal cost ratio and have applied it to each vintage of
13 plant to derive the estimated future removal cost amount. Then, I have discounted
14 these costs back to the year of placement, using PSE's most recently approved cost
15 of capital as the discount factor. I divide this value by the average service life of the
16 account to derive the current year's depreciation – the first of the two components
17 of the SFAS 143 expense.

18 I next determine the average remaining years for each vintage and calculate
19 the accretion in the present value of that vintage's removal costs from the current
20 year to the next year. In Column Q of Schedule 3, I present each vintage's SFAS
21 143 expense. The sum of these expenses is the appropriate removal cost allowance
22 for the account. I then divide that amount by the December 31, 2006 plant balance

1 to derive the increment in the depreciation rate for removal costs. This value is
2 transferred to Column G "Removal Cost Accrual Rate," on Schedule 1 of Exhibit
3 No. ____ (CWK-5).

4 **Q: Have you applied the SFAS 143 procedures to the terminal dismantlement**
5 **costs of PSE's production plant accounts?**

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

14 The other difference is that, unlike the mass property accounts with
15 continuous additions and retirements, the production plants will each retire in a
16 specific year. For this reason, the SFAS 143 removal cost allowance will increase
17 each year as the plant retirement year approaches. I have assumed that the
18 depreciation rates set in this case will be applied during the next five years, so I
19 have used the plant remaining lives as of the mid-point of the next five-year period,
20 which is the year 2010. Schedule 4 in Exhibit No. ____ (CWK-4) is the worksheet
21 for this calculation.

1 **Q: Aside from reflecting the present value of future costs, is there any other**
2 **reason to discount PSE's removal cost estimates?**

3 A: Yes. These removal cost estimates are very, very uncertain. Indeed, the only
4 certainty is that they will be incorrect. The mass property removal costs are based
5 on a very shaky and unstable assumed relationship between retirements and
6 removal costs. The production plant dismantlement costs are even less reliable, for
7 two reasons. First, there has been no formal study of dismantlement costs. Second,
8 they are based on shaky assumptions as regards the nature and timing of
9 dismantlement.

10 Mass property ratios are shaky due to measurement, not causality.
11 Retirements are valued at their original cost, and that cost varies radically over time.
12 In any given year, the age of retired plant will differ from the age during the
13 previous and the subsequent years. For example, even over a period of five years,
14 one cannot assume that the retired plant represents a normal dispersion of
15 retirement values around some representative average.

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

1 costs. When that relationship is used to forecast future removal costs, the result is a
2 very uncertain forecast.

3 **Q: Why do you say that the dismantlement cost estimates reflect shaky**
4 **assumptions about the nature and timing of dismantlement?**

5 A: Mr. Clarke's report concedes that there are no studies of the cost to dismantle its
6 production and hydro plants.⁸ He therefore simply adopts the existing
7 dismantlement ratios. There is no evidence in the record of this case (or any other,
8 to judge from PSE's responses to data requests⁹) to support these ratios.
9 Additionally, the implicit assumption of Mr. Clarke's ratios is that the plants will be
10 dismantled and the site cleared when the existing generating units are retired. I
11 question this assumption. The best use for any steam production plant site where
12 the generating units have worn out is as a site for new generating units. Not only
13 are many of the basic structures still usable, but the common facilities for fuel
14 handling and storage, water movement and treatment, and transportation remain in
15 place. Perhaps more important, the site is already connected into the transmission
16 grid and bears the requisite environmental and zoning approvals.

17 The same condition applies to the hydro plants. The service lives of the hydro
18 plants are based on the remaining lives of their FERC licenses. These licenses can
19 be renewed, so that the basic structures, dams and waterways will continue in
20 operation, even if the generating equipment is replaced. However, Mr. Clarke's 25

⁸ See PSE Response to WUTC Staff Data Request No. 20, Attachment A.

⁹ See PSE Response to Public Counsel Data Request No. 179 and to WUTC Staff Data Request No. 020.

1 percent removal cost ratios apply to the structures, dams, reservoirs, and waterways
2 accounts.

3 Given the advantages of existing sites, it would be economically irrational for
4 the PSE to totally dismantle every one of its retired generating plants and clear the
5 site.

6 **Q: Do you have any objective evidence to support these opinions?**

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

19 **Q: How does the uncertainty of PSE’s removal cost estimates affect the**
20 **calculation of removal cost allowances?**

21 A: Four years following the issuance of SFAS 143, the Financial Accounting
22 Standards Board issued FASB Interpretation No. 47, intended to clarify SFAS 143

1 in cases where the entity is uncertain as to the timing or method of meeting its
2 retirement obligation. This interpretation states as follows:

3 Uncertainty about the timing and (or) method of settlement of a
4 conditional asset retirement obligation should be factored into the
5 measurement of the liability when sufficient information exists.¹⁰
6

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

10 **Q: Are there any other jurisdictions that have adopted the present value approach**
11 **you have recommended for treating removal costs?**

12 A: Yes. In July of last year, the Maryland Public Service Commission adopted the
13 present value approach in two decisions involving the Potomac Electric Power
14 Company¹¹ and the Delmarva Light & Power Company.¹² In June, the Michigan
15 Public Service Commission imposed a requirement that each utility compute both
16 discounted and undiscounted removal costs when developing its depreciation
17 rates.¹³

18 **Q: What removal cost ratios do you recommend?**

19 A: I am concerned that the heavy discounting of future removal costs may fail to
20 generate sufficient allowances to cover the current cost of removing plant. This is
21 particularly true of mass property electric accounts, where PSE's removal cost

¹⁰ Financial Accounting Standards Board, FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, (March 2005), Summary.

¹¹ Maryland P.S.C. Order No. 81517, Case No. 9092, (July 19, 2007).

¹² Maryland P.S.C. Order No. 81518, Case No. 9093, (July 19, 2007).

¹³ Michigan P.S.C. Case No. U-14292, Opinion and Order, (June 26, 2007).

1 ratios are relatively low compared to the TIFCA-based removal cost ratios that I
2 have observed in analyzing other electric utility company depreciation studies.

3 Accordingly, I have compared the removal allowances that result from the
4 application of the present value technique with the Company's actual average
5 annual removal costs during the last five years (2002-2006). This comparison is
6 presented in Schedule 5 of Exhibit No. ____ (CWK-4) for electric plant and in
7 Schedule 4 of Exhibit No. ____ (CWK-5) for gas plant. I find that all of the present
8 value allowances for gas plant and electric transmission plant recover as much or
9 more revenue than actual 2002-2006 removal cost experience. However, for all but
10 two of the electric distribution accounts, actual removal costs during the 2002-2006
11 period exceeded the allowances that would be derived from the application of the
12 present value procedure. For these accounts, I recommend that removal cost
13 allowances be based on the average experience of the last five years.

14 **Q: Is there any precedent for using the last five years' average removal cost**
15 **experience as the basis for removal cost allowances?**

16 //
17 ///
18 ////
19 /////

20

1 A: Yes. This procedure is used for all utilities in Pennsylvania¹⁴ and for electric
2 utilities in New Jersey¹⁵, Delaware¹⁶ and Georgia.¹⁷

3
4 **VIII. CONCLUSION**

4 **Q: Can you please summarize the results of your findings?**

5 A: Schedule 5 of Exhibit ____ (CWK-4) applies the depreciation rates identified in
6 Schedule 1 to the test year plant balances. It reveals that, based on my review of
7 Mr. Clarke's depreciation study and my independent analysis of proper
8 depreciation treatment for production plant lives and salvage and retirement costs,
9 I conclude that PSE's depreciation expense is overstated by \$19,811,503 for
10 electric plant. Schedule 4 of Exhibit ____ (CWK-5) shows that test year
11 depreciation for gas plant is overstated by \$20,380,520. I have asked Mr.
12 Majoros to include these adjustments in his calculation of PSE's revenue
13 requirements.

14 **Q: Does this complete your testimony?**

15 A: Yes, it does.

¹⁴ *Penn Sheraton, et.al. v. Pennsylvania Public Utilities Commission*, 198 Pa.Super. 618, 184 A.2d 324, (1962).

¹⁵ I/M/O Rockland Electric Company, BPU Docket Nos. ER02080614 and ER02100724, Initial Decision, June 10, 2003 and Summary Order, (July 31, 2003). I/M/O Atlantic City Electric Company, BPU Docket Nos. ER03020110, ER04060423, EO03020091 and EM02090633, Decision and Order Adopting Initial Decision and Stipulation of Settlement, (May 26, 2005). I/M/O Jersey Central Power & Light Company, BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173, Summary Order, (August 1, 2003). I/M/O Public Service Electric and Gas Company, BPU Docket No. GR05100845, Decision and Order Adopting Initial Decision and Stipulation of Settlement, (November 11, 2006), p. 4.

¹⁶ Delaware PSC Order No. 6930, Case No. 05-304, signed June 6, 2006, ¶ 174.

¹⁷ Georgia PSC Docket No. 4007-U, (1991).