

**EXHIBIT NO. ___(JAP-1T)
DOCKETS UE-17___/UG-17___
2017 PSE GENERAL RATE CASE
WITNESS: JON A. PILIARIS**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

**Docket UE-17___
Docket UG-17___**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

JON A. PILIARIS

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 13, 2017

PUGET SOUND ENERGY
PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
JON A. PILIARIS

CONTENTS

I.	INTRODUCTION	1
II.	PRO FORMA REVENUE FROM ELECTRIC AND NATURAL GAS OPERATIONS.....	10
	A. Pro Forma Revenue Electric Operations.....	10
	B. Pro Forma Revenue from Natural Gas Operations	14
III.	COST OF SERVICE OVERVIEW	18
IV.	ELECTRIC COST OF SERVICE	23
	A. Previous Cost of Service Studies	23
	B. Overview of PSE’s Electric Cost of Service Study	24
	C. Classification of Production Costs.....	26
	D. Classification of Transmission Costs.....	29
	E. Classification of Distribution Costs	30
	F. Allocation of Production and Transmission Demand Costs.....	30
	G. Allocation of Distribution Costs	31
	1. Distribution Substations and Feeder Costs	31
	2. Distribution Line Transformer Costs	32
	3. Service Line and Meter Costs	34
	H. Administrative, General and Other Cost Allocation Factors	34
V.	PSE’S NATURAL GAS COST OF SERVICE STUDY	35
	A. Previous Cost of Service Studies	35

B.	Overview of PSE’s Proposed Gas Cost of Service Study.....	35
C.	Peak and Energy Gas Allocation Factors.....	37
D.	Allocation of Gas Plant Costs and Operating Expenses	41
E.	Classification and Allocation of Distribution Main Costs	43
F.	Results of the Distribution Cost of Service Study	48
G.	Classification and Allocation of Purchased Gas Related Costs.....	49
VI.	ELECTRIC RATE SPREAD AND RATE DESIGN.....	52
A.	Proposed Rate Spread	52
B.	Electric Rate Design Guidelines and Overview.....	55
C.	Proposed Residential Electric Rate Design.....	57
D.	Proposed General Service Rate Design	67
E.	Proposed Campus Rate Design.....	69
F.	Proposed High Voltage Rate Design	73
G.	Retail Wheeling Rate Design.....	74
H.	Summary of Proposed Rate Impacts.....	75
VII.	ELECTRIC LIGHTING RATE DESIGN	78
A.	Expanded LED Wattage Ranges.....	78
B.	Lighting Study	81
C.	Other Administrative Changes.....	88
VIII.	GAS RATE SPREAD AND RATE DESIGN	88
A.	Rate Spread	88
B.	Rate Design.....	89
1.	Residential Gas Rate Design.....	91
2.	Non-Residential Gas Rate Design	94

i.	Non-Residential Gas Demand Charges	94
ii.	Non-Residential Firm Sales Procurement Charge	96
C.	Bill Impacts	98
D.	Other Tariff Changes	100
1.	Schedule 41 and 41T Maximum Volumes.....	101
2.	Schedule 85 and 85T Annual Minimum Load Charge	104
3.	Schedule 85 and 85T Demand Charge for Firm Service	105
IX.	REVIEW OF AND PROPOSED CHANGES TO PSE’S ELECTRIC AND GAS DECOUPLING MECHANISMS.....	106
A.	Overview of Existing Mechanisms.....	106
B.	Review of Operation of the Decoupling Mechanisms	114
1.	Rate Test Challenges.....	115
2.	Earnings Test Challenges.....	116
3.	Opportunities to Improve Rate Groupings.....	117
4.	Third Party Review of Decoupling Mechanisms.....	121
5.	Other Lessons Learned About Existing Decoupling Mechanisms	125
C.	Proposed Changes to Mechanisms.....	125
1.	Move Fixed Power Costs into the Electric Decoupling Mechanism.....	127
2.	Reorganize Non-Residential Decoupling Rate Groups	129
3.	Modify the Calculation of the Decoupling Rate Tests.....	133
4.	Modify the Calculation of the Decoupling Earnings Tests.....	138
5.	Other Proposed Changes to the Decoupling Calculations	139
D.	Approval of the Modified Decoupling Mechanisms is in the Public Interest.....	140

X.	ELECTRIC COST RECOVERY MECHANISM	147
XI.	SCHEDULE 451.....	151
XII.	COMPLIANCE FILING	156
XIII.	CONCLUSION.....	159

EXHIBIT LIST

- 1. Prefiled Direct Testimony (Nonconfidential) of Jon A. Piliaris**
- 2. Professional Qualifications of Jon A. Piliaris**
- 3. Pro forma Revenue from Electric Operations**
- 4. Pro forma Revenue from Natural Gas Operations**
- 5. Exhibit No. ___(JAP-04) in Docket UE-141368**
- 6. Updated Results of Peak Credit Methodology**
- 7. Summary of Electric Cost of Service Results**
- 8. Summary of Gas Cost of Service Results Excluding Gas Costs**
- 9. Summary of Gas Cost of Service Results Including Gas Costs**
- 10. Summary of Gas COS Class Allocated Costs**
- 11. Summary of Gas COS Classifications**
- 12. Summary of Gas COS Allocation Factors**
- 13. Diagram of Peak and Average Method Used to Allocate Gas Mains**
- 14. PGA Gas Cost Allocation**
- 15. Electric Rate Spread and Rate Design Proposal**
- 16. Proposed Electric Tariff Schedule Revisions**
- 17. Residential Electric Basic Charge Survey**
- 18. Schedule 40 Coincidence Factors**
- 19. Estimated Electric Bill Impacts from Proposed Base and Rider Rates**
- 20. Classification of Electric Lighting Costs**
- 21. Development of Electric Lighting Allocation Factors**

- 22. Development of Electric Lighting Rates**
- 23. Electric Lighting Results**
- 24. Gas Rate Spread and Proposed Gas Rates**
- 25. Proposed Gas Tariff Schedule Revisions**
- 26. Residential Gas Basic Charge Survey**
- 27. Development of Gas Procurement Charge**
- 28. Estimated Gas Bill Impacts from Proposed Base and Rider Rates**
- 29. 3rd Party Review of PSE's Electric and Gas Decoupling Mechanisms**
- 30. Electric Decoupling Mechanism Calculations**
- 31. Gas Decoupling Mechanism Calculations**
- 32. Development of Electric CRM Rates**
- 33. Electric Decoupling Allowed Revenue Per Customer Without
Microsoft Schedule 40 Load**

1 **PUGET SOUND ENERGY**

2 **PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**
3 **JON A. PILIARIS**

4 **I. INTRODUCTION**

5 **Q. Please state your name and business address.**

6 A. My name is Jon A. Piliaris. I am employed as Manager of Pricing and Cost of
7 Service with Puget Sound Energy ("PSE" or the "Company"). My business
8 address is 10885 NE Fourth Street, Bellevue, WA 98009-9734.

9 **Q. Have you prepared an exhibit describing your education, relevant**
10 **employment experience and other professional qualifications?**

11 A. Yes, I have. It is Exhibit No. ____ (JAP-2).

12 **Q. What is the purpose of your testimony?**

13 A. My testimony presents the following:

- 14 1. PSE's pro forma revenue from electric and natural gas operations,
15 2. PSE's electric cost of service study and PSE's proposed rate spread and rate
16 design for electric service,
17 3. A rate design study specific to PSE's electric lighting schedules,
18 4. PSE's gas cost of service study and PSE's proposed rate spread and rate
19 design for gas service,
20 5. The evaluation of PSE's electric and gas decoupling mechanisms, along with

1 proposed changes to these mechanisms,

- 2 6. The proposed cost allocation and rate design for PSE's Electric Cost Recovery
3 Mechanism ("ECRM"),
- 4 7. Issues that must be addressed in this filing related to PSE's proposed Schedule
5 451 that is concurrently being litigated in Docket UE-161123, and
- 6 8. A summary of the list of tariff sheets that will potentially be filed as part of
7 the compliance for this case and their overall rate impacts.

8 **Q. Please summarize your testimony.**

9 A. I would summarize my testimony as follows:

10 *Pro forma Revenue*

- 11 • The total pro forma electric revenue at current base rates is estimated to be
12 \$1.964 billion based on 22.82 billion kWh in electric sales.
- 13 • The total pro forma natural gas revenue at current margin rates is estimated
14 to be \$441.5 million based on 1.14 billion therms in gas sales. The total pro
15 forma base revenue, including gas costs, is estimated to be \$815.8 million.

16 *Electric Cost of Service, Rate Spread and Rate Design*

- 17 • The electric cost of service results show a needed increase of 7.57 percent to
18 the existing base rates of state-jurisdictional customers, or approximately
19 \$148.7 million.
- 20 • The estimated parity ratios and proposed rate increases to base rates

1 resulting from the electric cost of service study are as follows:

2 **Table 1- Proposed Electric Base Parity Percentages and Rate Changes**

3

4

Customer Class	Rate Schedule	Parity Percentage	Proposed Base Rate Increase
Residential	7	95 %	8.32 %
General Service, < 51 kW	8/24	109 %	6.24 %
General Service, 51 - 350 kW	11/25/7A/29	108 %	6.24 %
General Service, >350 kW	12/26	108 %	6.24 %
Primary Service, Gen & Irr.	10/31/35	109 %	6.24 %
Primary Service, Schools	43	104 %	8.32 %
Campus Rate*	40	95 %	13.28 %
High Voltage	46/49	109 %	6.24 %
Lighting Service	50 – 59	97 %	8.32 %
Choice/Retail Wheeling	448/449	65 %	6.07 %
Total Jurisdictional Retail Sales	n/a	n/a	7.57 %
Firm Resale	5	47 %	128.35 %**
System Total/Average		100%	7.59 %

*Campus Rate increase proposal reflects customer-specific distribution rates according to agreement.

**Reflects the rate increase necessary to move non-jurisdictional rates to parity.

5 *Electric Lighting Study*

- 6
- 7
- 8
- 9
- 10
- PSE performed its first full cost of service study specific for lighting service in at least 16 years.
 - Between individual lighting schedules, the proposed change in base rates varied greatly. These variations are primarily the result of a more refined cost allocation methodology, where less of the costs are allocated simply on

1 estimated energy usage. Instead, more of the costs were allocated on
 2 contributions to capital costs, operating and maintenance costs, and
 3 contributions to peak demand.

4 Gas Cost of Service, Rate Spread and Rate Design

- 5 • The gas cost of service results show a needed increase of 5.3 percent to
 6 existing base margin rates, or approximately \$23.0 million.
- 7 • The estimated parity ratios and proposed rate increases to base rates, with
 8 and without gas costs, based on the gas cost of service study are below:

9 **Table 2 - Proposed Gas Base Parity Percentages and Rate Changes**

Customer Class	Rate Schedule	Parity Percentage	Proposed Base Rate Increase*	Proposed Margin Increase
Residential	16/23/53	108%	2.7%	4.8%
Commercial & Industrial	31/31T/61	79%	3.5%	7.3%
Large Volume	41/41T	95%	1.8%	4.8%
Interruptible	85/85T	102%	2.3%	4.8%
Limited Interruptible	86/86T	121%	0.9%	2.4%
Non-exclusive Interruptible	87/87T	76%	2.5%	7.3%
Special Contracts		59%	5.9%	6.3%
Rentals	71/72/74	186%	0.0%	0.0%
Total/System Average		100%	2.8%	5.3%

* Includes gas costs

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18

Electric and Gas Decoupling Mechanisms

- Overall, the mechanisms performed well over their first three years, producing modest rate impacts and removing PSE’s throughput incentive associated with the recovery of its delivery system costs.

- Incorporating the lessons learned over the first three years of the mechanisms implementation, PSE proposes to make the following changes to its current decoupling mechanisms:¹
 - Increase the trigger for the Rate Test as it is applied to natural gas residential customers and all electric customers in the decoupling mechanism from three percent to five percent,

 - Modify the Earnings Test so that, for revenue sharing purposes, all normalizing adjustments to actual results are excluded and all conforming adjustments are retained for calculating operating income.

 - Per a previously approved settlement, move fixed power costs into the electric decoupling mechanism.

 - Disaggregate the non-residential rate groups in these mechanisms to

¹ In addition to the changes listed below, there are a number of other minor changes proposed to the mechanisms, as discussed later in this testimony. These will have very little impact, if any, on customer rates and are primarily intended to improve the administrative efficiency associated with these mechanisms.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

create more homogeneity, with smaller customers separated from larger ones.

Electric Cost Recovery Mechanism

- PSE proposes to allocate the revenue requirement associated with its proposed ECRM in a manner that is consistent with the way like facilities are allocated in PSE’s overall electric cost of service study, where costs are allocated to the customer classes in proportion to their loads on the replaced facilities.
- The estimated first-year rate impact on PSE’s electric customers is expected to be 0.50 percent overall, ranging from 1.06 percent for Schedule 43 (Electric Schools) to 0.07 percent for Schedule 31 (Primary General Service). The residential impact is projected to be 0.75 percent, or approximately \$0.72 per month for a typical customer using 900 kWh.

Schedule 451 Proposal

- Service taken under PSE’s proposed Schedule 451 will have an impact on PSE’s ability to recover its power costs.
- PSE proposes alternative allowed fixed power costs per customers and Power Cost Adjustment (“PCA”) baseline rates to address its ability to recover production-related expenses if and when customers begin to take service under the proposed Schedule 451.

1 Compliance Filing and Overall Rate Impacts

2 • The rates in a number of PSE’s adjusting price schedules will need to be
3 reset simultaneously with the proposed changes to base rates in this
4 general rate case. While electric and gas Schedule 142 and gas Schedule
5 149 will not be filed as part of this case,² they will be included among the
6 tariff sheets filed as part of the final compliance filing. The full list of
7 adjusting price schedules that will be included in the final compliance
8 filing are as follows:³

- 9 ○ Electric Schedule 95 (Power Cost Adjustment Clause)
- 10 ○ Electric Schedule 141 (Expedited Rate Filing Rate Adjustment)
- 11 ○ Electric Schedule 142 (Revenue Decoupling Adjustment
12 Mechanism)
- 13 ○ Electric Schedule 149 (Electric Cost Recovery Mechanism)
- 14 ○ Gas Schedule 141 (Expedited Rate Filing Rate Adjustment)
- 15 ○ Gas Schedule 142 (Revenue Decoupling Adjustment Mechanism)
- 16 ○ Gas Schedule 149 (Cost Recovery Mechanism for Pipeline
17 Replacement)

² Sample tariff sheets for electric and gas Schedule 142 are provided in Exhibit No. ___(JAP-16) and Exhibit No. ___(JAP-25).

³ As discussed later in this testimony, other rate schedules will need to be updated shortly after the conclusion of this case.

- The net impact on PSE’s electric customer rates associated with these rate updates, plus the proposed changes to base rates, is an overall increase of 4.1 percent for state-jurisdictional customers, or approximately \$86.7 million. The impact on the monthly bill of PSE’s typical residential electric customer using 900 kWh is an increase of \$3.73, or 3.9 percent over current levels.
- Including the overall impacts by customer class of the proposed changes to base rates, Schedule 95 (Power Cost Adjustment Clause), Schedule 141 (Expedited Rate Filing Rate Adjustment), Schedule 142 (Revenue Decoupling Adjustment Mechanism) and proposed Schedule 149 (Electric Cost Recovery Mechanism) are shown below.

Table 3 - Estimated Overall Impacts of Proposed Electric Rates

Customer Class	Rate Schedule	Overall Impact*
Residential	7	4.0 %
General Service, < 51 kW	8/24	2.8 %
General Service, 51 - 350 kW	11/25/29	4.8 %
General Service, >350 kW	12/26	4.3 %
Primary Service, Gen & Irr.	10/31/35	4.2 %
Primary Service, Schools	43	6.7 %
Campus Rate	40	12.1 %
High Voltage	46/49	4.6 %
Lighting Service	50 - 59	(3.4) %
Choice/Retail Wheeling	448/449	0.6 %
Total Jurisdictional Retail Sales	n/a	4.1 %

* Includes base rates, as well as Schedules 95, 141, 142 and 149.

- The net impact on PSE’s gas customer rates associated with these rate updates, plus the proposed changes to base margin rates, is an overall decrease of 2.4 percent, or approximately \$22.3 million. The impact on the monthly bill of PSE’s typical residential gas customer using 64 therms is a decrease of \$2.01, or 2.9 percent over current levels.
- Based on the parity ratios resulting from the gas cost of service study, the proposed increases to base rates, including gas costs, and proposed changes to gas Schedule 141 (Expedited Rate Filing Rate Adjustment), Schedule 142 (Revenue Decoupling Adjustment Mechanism) and Schedule 149 (Cost Recovery Mechanism for Pipeline Replacement), the estimated overall impacts by customer class are as follows:

Table 4 - Estimated Overall Impacts of Proposed Gas Rates

Customer Class	Rate Schedule	Overall Impact*
Residential	16/23/53	-2.9%
Commercial & Industrial	31/31T/61	-1.0%
Large Volume	41/41T	-0.9%
Interruptible	85/85T	-2.7%
Limited Interruptible	86/86T	-1.5%
Non-exclusive Interruptible	87/87T	-2.3%
Special Contracts		0.7%
Rentals	71/72/74	-9.6%
Total/System Average		-2.4%

* Includes base schedules, as well as Schedule 101, 141, 142 and 149.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22

**II. PRO FORMA REVENUE FROM
ELECTRIC AND NATURAL GAS OPERATIONS**

A. Pro Forma Revenue Electric Operations

Q. What is pro forma revenue?

A. Pro forma revenue is an estimate of test year revenue based on test year billing determinants (*e.g.*, energy sales, billed demand, number of bills) and the rates that are in place at the time of filing for a rate change. It is developed to ensure that the test year revenue used in calculating the revenue deficiency: (1) reflects only those rate schedules that are being considered in the present case, (2) encompasses any rate changes that have taken place during or since the test year, and (3) is consistent with the normalized test year revenue requirement and loads. The billing determinants used to produce pro forma revenue are also used to estimate the revenue from proposed rates.

Q. Have you prepared an exhibit that demonstrates PSE's development of its pro forma revenue from electric operations?

A. Yes, I have. It is the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ____ (JAP-3).

Q. Please explain page one of Exhibit No. ____ (JAP-3), Pro Forma Delivered Sales.

A. Pro forma revenue is based on test year billing determinants, which is primarily based on energy sales. Therefore, a key step in developing pro forma revenue involves making normalizing adjustments to test year energy sales. PSE's

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

adjustments to test year electricity sales for this case are summarized on page one of Exhibit No. ___(JAP-3).

Column d of page one shows the billed electricity sales for the test year in this proceeding, which is the twelve months ending September 2016.

Column e includes an adjustment for unbilled electricity sales. This column adjusts for the fact that customers' bills are issued throughout the month and do not correspond to calendar months. The unbilled sales in column e, which underlies PSE's income statement, removes the portion of sales that was consumed in the previous month, and adds an estimate of sales that occurred during the calendar month but were not yet billed.

The Schedule 40 migration adjustment in column f reflects estimated movement of customers and sales between Schedules 24, 25, 26 and 31 and Schedule 40 for two new "campus" locations and one existing location that will be removed from Schedule 40. These customer migrations are discussed further in the context of Schedule 40 rate design later in this testimony.

The Schedule 46 adjustment in column g reflects the correction for a multi-year metering error that was discovered late in the test year in this case. The related revenue corrections were pro formed into the months in which the use would have occurred.

The temperature adjustment to electricity sales presented in column h adjusts for the effect of non-normal temperatures from test year loads, so that test year loads

1 and revenues are more reflective of normal operating conditions. This adjustment
2 is described in the Prefiled Direct Testimony of Dr. Chun K. Chang, Exhibit
3 No.__(CKC-1T).

4 Pro forma electricity sales that reflects all of these adjustments is totaled in
5 column c. Total pro forma electricity sales are used for calculating the pro forma
6 revenue that is presented in column i on page one of Exhibit No. __(JAP-3).

7 **Q. Please explain page two of Exhibit No. __(JAP-3), Pro Forma Revenue**
8 **Summary.**

9 A. Page two of Exhibit No. __(JAP-3) presents explanations of the differences
10 between test year revenue, as presented in PSE's income statement, and pro forma
11 revenue, as calculated based on billing determinants and rates. The revenue
12 included in the test year income statement is presented in row 1 of page two, and
13 pro forma revenue based on billing determinants and current rates is in row 32.
14 The items presented in rows 4 through 30 are explanations of the differences
15 between the income statement and pro forma revenue. These items are related to:

- 16 1. removal of revenue from municipal taxes and adjusting
17 price schedules (rows 4-16);
- 18 2. the previously-discussed restating adjustment changes in
19 unbilled revenue adjustment (row 24);
- 20 3. a schedule migration adjustment that reflects customer
21 movement from Schedules 24, 25, 26 and 31 to Schedule
22 40 (row 26);
- 23 4. adjustments for out of period billing adjustments and the
24 billing correction for Schedule 46 noted above (row 27),
25 and
- 26 5. an adjustment to revenue to reflect the temperature

1 normalization adjustment to electricity sales (row 30).

2 **Q. Will rates in any of the adjusting electricity price schedules in rows 4**
3 **through 16 change as a result of this filing?**

4 A. Yes. Certain adjusting electricity price schedules will be reset
5 contemporaneously with the approval of new base rates in this proceeding.

6 First, as has commonly been required in past rate cases, rates within Schedule 95
7 (Power Cost Adjustment Clause) will be set to zero, as power costs will be fully
8 recovered through the base rates approved in this case.

9 Next, electric Schedule 141, Expedited Rate Filing Rate Adjustment (“ERF”),⁴
10 was intended as a one-time increase to base rates set in PSE’s 2011 general rate
11 case (“GRC”).⁵ As these revenues will now be collected through the base rates
12 approved in this case, the rates in this schedule will be set to zero.

13 Finally, and as discussed more fully in Section IX later in my testimony, rates
14 and allowed revenue per customer within electric Schedule 142, Revenue
15 Decoupling Adjustment Mechanism, will be reset to align with the new base rates
16 approved in this case.

17 **Q. What are PSE’s resulting pro forma electricity sales and revenue?**

18 A. The total pro forma electricity sales for the test year is 22.82 billion kWh, and is

⁴ Dockets UE-130137 and UG-130138, consolidated.

⁵ Dockets UE-111048 and UG-111049, consolidated.

1 presented in column c of page one of Exhibit No. ____ (JAP-3). The total pro
2 forma revenue is \$1.964 billion and is presented in column b of page two.

3 **B. Pro Forma Revenue from Natural Gas Operations**

4 **Q. Have you prepared an exhibit that demonstrates PSE's development of its**
5 **pro forma revenue from natural gas operations?**

6 A. Yes, I have. It is the Third Exhibit to my Prefiled Direct Testimony,
7 Exhibit No. ____ (JAP-4).

8 **Q. Please explain page one of Exhibit No. ____ (JAP-4), Adjustments to Volume**
9 **(Therms) by Rate Schedule.**

10 A. As mentioned above, pro forma revenue is based on test year billing determinants,
11 which is largely based on normalized energy sales. PSE's adjustments to test year
12 natural gas throughput for this case are summarized on page one of Exhibit
13 No. ____ (JAP-4). This begins with column B of page one, which shows the
14 volume of sales and transportation for the twelve months ending September 2016.
15 The restating adjustments in column C include an out-of-period adjustment and an
16 unbilled volume adjustment. The out-of-period adjustment corrects usage
17 associated with billing corrections by moving the consumption from the period in
18 which it was corrected into the period in which it should have been billed. As
19 discussed earlier, the unbilled volume adjustment adjusts for the fact that
20 customers' bills are issued throughout the month and do not correspond to
21 calendar months. As with the sales of electricity, the gas volume in column B

1 removes the portion of that volume that was consumed in the previous month, and
2 adds an estimate of sales that occurred during the calendar month but were not yet
3 billed. In the adjustment to unbilled volume included in column C, this estimate
4 of the unbilled portion of sales was updated to reflect sales that actually took
5 place during each calendar month, by rate schedule, after the whole month's
6 consumption was actually billed.

7 The Schedule 41 migration adjustment in column D moves a portion of the load
8 that was served in the test year within Schedule 41 and Schedule 41T to Schedule
9 85 and Schedule 85T, respectively. The movement of load between these
10 schedules is related to the proposal discussed later in this testimony to set a
11 maximum usage threshold for service under Schedule 41 and Schedule 41T
12 whereby load that exceeds this threshold would be placed onto Schedule 85 or
13 Schedule 85T, respectively. The adjustments in column D reflect the load served
14 under Schedule 41 or Schedule 41T in the test year that exceeded the proposed
15 maximum usage threshold. This load was moved to the corresponding Schedule
16 85 or Schedule 85T.

17 The weather normalization adjustment to gas volume presented in column E
18 removes the effect of non-normal temperatures from test year loads, so that test
19 year loads and revenues are more reflective of normal operating conditions. This
20 adjustment is described in the Prefiled Direct Testimony of Dr. Chun K. Chang,
21 Exhibit No. ____ (CKC-1T).

22 Pro forma volume that reflects all of these adjustments is totaled in column F and

1 is used for calculating pro forma revenue as presented in column G on page one
2 of Exhibit No. ____ (JAP-4).

3 **Q. Please explain page two of Exhibit No. ____ (JAP-4), Reconciliation of Revenue**
4 **by Rate Schedule.**

5 A. Page two of Exhibit No. ____ (JAP-4) presents explanations of the differences
6 between test year revenue, as presented in PSE's income statement, and pro forma
7 revenue, as calculated based on billing determinants and rates. The revenue
8 included in the test year income statement is presented in column B of page two,
9 and pro forma revenue based on billing determinants and current rates is in
10 column O. The items presented in columns C through N are explanations of the
11 differences between the income statement and pro forma revenue. These items
12 are related to:

- 13 1. removal of revenue from municipal taxes and adjusting
14 price schedules (columns C-H);
- 15 2. other restating adjustments that correspond to the
16 previously-discussed restating volume adjustments,
17 specifically the billing corrections and the change in
18 unbilled revenue adjustment (column I);
- 19 3. adjusting for price changes that took place during or after
20 the test year, specifically the 2015 and 2016 purchased gas
21 adjustment ("PGA") (column J);
- 22 4. a schedule migration adjustment discussed earlier that
23 reflects customer movement from Schedules 41 and 41T to
24 Schedules 85 and 85T (column K);
- 25 5. an adjustment to revenue to reflect the weather adjustment
26 to volume (column L); and
- 27 6. an adjustment to revenue to reflect an updated rate for
28 PSE's revenue adjustment factor (column M).

1 **Q. Please explain further the schedule migration adjustment.**

2 A. The Schedule 41/41T migration adjustment reflects estimated movement away
3 from Schedule 41, Large Volume High Load Factor Gas Service, and Schedule
4 41T, Distribution System Transportation Service (Firm-Large Volume High Load
5 Factor). As described later in my testimony, PSE proposes to require customers
6 with volume requirement of 150,000 therms or more per year to migrate from
7 Schedules 41 and 41T to Schedules 85 and 85T as part of proposed changes to the
8 latter schedules in this proceeding. This will require that 92 customers on
9 Schedule 41 and 41T to move to Schedules 85 or 85T when the volume
10 requirement is implemented, and the migration adjustment is the test year
11 adjustment to revenue that results from this migration.

12 **Q. Will rates in any of the adjusting gas price schedules in Columns D through**
13 **H on page 2 of Exhibit No. ___(JAP-4) change as a result of this filing?**

14 A. Yes. As with the electric schedules, certain adjusting gas price schedules will be
15 reset contemporaneously with the approval of new base rates in this proceeding.
16 First, rates within gas Schedule 141 will be set to zero, since this revenue will
17 now be collected through the base rates approved in this case. Next, and as
18 discussed more fully in Section IX later in my testimony, rates and allowed
19 revenue per customer within gas Schedule 142 will be reset to align with the new
20 base rates approved in this case. Finally, rates within Schedule 149 (Cost
21 Recovery Mechanism for Pipeline Replacement or “Gas CRM”), will be reset to
22 reflect the transfer of Gas CRM program revenue from gas Schedule 149 to base

1 natural gas rates, as discussed in the Prefiled Direct Testimony of Susan E. Free,
2 Exhibit No.__(SEF-1T).

3 **Q. What are PSE’s resulting pro forma natural gas volume and revenue?**

4 A. The total pro forma natural gas volume for the test year is 1.14 billion therms, and
5 is presented in column G of page one of Exhibit No. __(JAP-4). The total pro
6 forma revenue is \$815.8 million and is presented in row 19 of column O on page
7 two. The revenue associated with gas cost included in this amount is \$374.2
8 million, and is presented in line 20 of column O on page two.

9 **III. COST OF SERVICE OVERVIEW**

10 **Q. Please summarize the purpose of a cost of service study.**

11 A. A cost of service study identifies the costs that are incurred to serve a particular
12 customer class. Identifying the cost responsibility of each class requires an
13 analysis of PSE’s costs and then an allocation of those costs to each customer
14 class. This allocation is accomplished by first directly assigning to a customer
15 class any costs determined to be caused by that class alone. Joint costs that are
16 shared by multiple customer classes are then allocated to those classes on a pro
17 rata basis, based on factors appropriate to the costs being allocated.

18 The ultimate objective of the cost allocation process is to create a just, fair,
19 reasonable and sufficient allocation of costs to different customer classes. This
20 cost of service information is then used to allocate the revenue requirement to the
21 different customer classes.

1 **Q. How are cost of service study results generally used for ratemaking**
2 **purposes?**

3 A. Historically, the Commission has treated cost of service studies as a guidepost for
4 the allocation of the revenue requirement and has eschewed a mechanical
5 application of these studies, particularly given the widely varying perspectives
6 among rate case participants as to the “true” cost of providing service to any given
7 class of customers. Therefore, while such studies may be representative of the
8 overall level of costs that should be recovered from any particular class, the
9 Commission routinely exercises its broad discretion in how strictly to apply the
10 results of such analyses.

11 **Q. Please summarize the process for preparing the cost of service study.**

12 A. A cost of service study starts with the revenue requirement. The electric cost of
13 service study in this case starts with the electric revenue requirement that is set
14 forth in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit
15 No. ___(KJB-1T) and associated exhibits, which represents PSE’s costs to
16 provide service to its electric customers. The associated natural gas revenue
17 requirement in this case is set forth in the Prefiled Direct Testimony of Susan E.
18 Free, Exhibit No. ___(SEF-1T) and associated exhibits.

19 The first step of this study is to separate these revenue requirements into the major
20 utility functions. This process is referred to as the functionalization of costs.

21 The second step is to further divide the costs associated with each of the major

1 functions into customer, demand and energy components (which are explained
2 below). This process is referred to as the classification of costs.

3 The third step is to allocate each of the cost components to the individual
4 customer classes.

5 **Q. Please describe the first step in a cost of service study, functionalization.**

6 A. Functionalization separates plant and expenses into categories based on the major
7 functions of the utility. For PSE's electric service, these functions include
8 generation, transmission, and distribution. For PSE's natural gas service, these
9 functions have traditionally been the production, storage and distribution of
10 natural gas.

11 **Q. Please describe the second step in a cost of service study, classification.**

12 A. Classification further separates costs into categories based on the utility operation
13 for which the plant is constructed and expenses are incurred. PSE's utility
14 systems are designed to perform the following three primary tasks: (1) stand
15 ready to provide services to *customers* served by the system; (2) to serve peak
16 *demands* of all customers; and (3) to supply or deliver the *energy* sold to or
17 transported for its customers. There are costs associated with each of these
18 services and the cost of service study categorizes them according to customer,
19 demand, or commodity.

20 Given these three primary functions of PSE's utility systems, classification
21 answers the question: "Why was the cost incurred – to serve the customer, to

1 meet peak demand, or to provide the energy?" Another way to ask this is, "Does
2 the cost vary with the number of customers, the peak demand for which the
3 system was designed, or the amount of energy sold or transported over the
4 system?"

5 **Q. Please describe customer-related costs.**

6 A. Customer-related costs are those costs that would be needed to serve customers
7 regardless of their level of energy usage. These costs include, at a minimum, the
8 costs of the service line and meter, meter reading and billing, and maintaining the
9 customer accounting system. In the case of PSE's electric system, they may also
10 include costs associated with line transformers. Customer costs vary with the
11 number of customers on the utility system, regardless of how much energy those
12 customers consume.

13 **Q. Please describe demand-related costs.**

14 A. Demand, or capacity, costs are those costs associated with designing, installing,
15 and operating the system to meet peak demands. The system must be sized to
16 meet peak requirements, even though average loads are below peak levels;
17 otherwise the system would not have adequate capacity to serve customers'
18 demand during the times of greatest energy consumption. Demand costs vary
19 with the size of the peak demand for which the system was designed. Demand
20 costs are incurred whether all the capacity is used or not.

1 **Q. Please describe energy costs.**

2 A. Energy costs vary with the amount of energy supplied or delivered over PSE's
3 system. This includes both the energy sold to customers and the energy
4 transported for customers who purchase their energy supply from providers other
5 than PSE. Over a one-year period, the average energy delivered through PSE's
6 utility systems is considerably less than that delivered on a peak day. Generally
7 speaking, energy-related costs are more associated with the supply of energy
8 rather than its delivery.

9 **Q. Is it always clear whether costs are demand, energy or customer related?**

10 A. No. One of the challenges of classifying costs between demand, energy, and
11 customer categories is that some utility equipment is commonly considered to
12 serve multiple functions. For example, electric generation equipment is widely
13 recognized as jointly providing capacity (demand) and energy. While there are a
14 number of generally accepted methods for apportioning these joint costs between
15 demand and energy, even these methods are the subject of considerable debate.

16 **Q. Please describe the third step in a cost of service study, allocation.**

17 A. Allocation is the final step in the assignment of costs to customer classes. Unless
18 a cost is unique to a specific customer class and can be directly assigned to that
19 customer class, it is allocated based on an allocation factor that is related to that
20 type of cost. In general, (1) customer-related costs are allocated based on the
21 number of customers, (2) demand-related costs are allocated based on peak

1 demand, and (3) energy-related costs are allocated to customer classes based on
2 energy sales. There are many variations of these allocation factors based on the
3 specific costs and plant items being allocated, and some costs may be allocated
4 based on a combination of allocation factors.

5 IV. ELECTRIC COST OF SERVICE

6 A. Previous Cost of Service Studies

7 **Q. Please identify all electric cost of service studies conducted by PSE in the last**
8 **five years.**

9 A. Prior to the electric cost of service study conducted in this case, PSE last
10 conducted a fully allocated embedded cost of service study to support its 2011
11 GRC.

12 **Q. Please describe the methodology used in the 2011 study.**

13 A. The 2011 electric cost of service study used the same basic approach to
14 functionalizing, classifying and allocating costs as is presented in the study
15 supporting this 2017 filing with a few minor differences.

16 **Q. Please explain these differences.**

17 A. The first difference relates to the functionalization of certain facilities. In PSE's
18 2011 GRC, its 55 kV-115 kV electric facilities were considered to be distribution-
19 related. On September 16, 2011, PSE filed with the Washington Utilities and
20 Transportation Commission ("Commission") a petition for a declaratory order and

1 for an accounting order approving PSE's proposed reclassification of its 55 kV-
2 115 kV distribution facilities as transmission facilities and authorizing the
3 Company to apply such reclassification in PSE's accounts and reports to the
4 Commission.⁶ PSE received approval for this reclassification on December 14,
5 2011.⁷ While the functionalization of these facilities changed during the course of
6 the 2011 GRC, there was no change to the method used to classify or allocate the
7 cost of these facilities. These costs were already classified and allocated using the
8 Company's peak credit methodology explained later in this testimony.

9 **Q. Are there any other notable differences?**

10 A. Yes, in accordance with a settlement approved by the Commission and discussed
11 in more detail later in this testimony, PSE's demand-related production and
12 transmission costs were allocated in this case on the basis of each class's
13 contribution to coincident system peaks ("CP") in the months of November and
14 December 2015 and January and February 2016. This is referred to as the "4-CP"
15 allocation factor. This is a change from the previous allocation factor used for
16 these costs in PSE's 2011 GRC, which used each class's contribution to the top
17 75 hours of load during the test year.

18 **B. Overview of PSE's Electric Cost of Service Study**

19 **Q. Please explain the methodology for classification and allocation of electric**

⁶ Docket U-111701.

⁷ *Id.*, Order 01.

1 **costs that PSE used in this proceeding.**

2 A. With the few changes noted above, the electric cost of service study in this case
3 utilizes the same methodology as PSE used in its last GRC. This methodology is
4 discussed in more detail in Sections C through H, below.

5 **Q. What are the results of PSE’s electric cost of service study?**

6 A. The parity percentages by customer class that result from the electric cost of
7 service study are shown in Table 5, below. Parity reflects the relative relationship
8 between normalized revenue currently recovered in rates to the revenue required
9 based upon the cost of service analysis. A parity percentage over 100 percent
10 indicates that the customer class is currently paying more than its allocated costs
11 (once all classes are adjusted for system-level over or under recovery).

12 **Table 5 - Results of Company's Electric Cost of Service Study**

Customer Class	Rate Schedule	Parity Percentage
Residential	7	95 %
General Service, < 51 kW	8/24	109 %
General Service, 51 – 350 kW	11/25/7A/29	108 %
General Service, >350 kW	12/26	108 %
Primary Service, Gen & Irr.	10/31/35	109 %
Primary Service, Schools	43	104 %
Campus Rate	40	95 %
High Voltage	46/49	109 %
Lighting Service	50 - 59	97 %
Choice/Retail Wheeling	448/449	65 %
Firm Resale	5	47 %
System Total / Average		100 %

1 **Q. Was the model used to develop the cost of service study the same model used**
2 **in PSE's most recent general rate case?**

3 A. Yes. The model used for this study is the same model used in the last general rate
4 case. This model was originally developed for PSE by Navigant Consulting, Inc.
5 for its 2006 GRC.

6 **C. Classification of Production Costs**

7 **Q. Please describe how production costs were classified into energy and demand**
8 **components in PSE's electric cost of service study.**

9 A. The Company utilized the "peak credit" methodology to divide production costs
10 into demand and energy components. The peak credit method classifies PSE's
11 electric production costs, regardless of the type of generating resource, as either
12 energy-related or demand-related, based on the ratio of the cost of a proxy
13 peaking generating resource to the cost of a proxy baseload generating resource.
14 The numerator and denominator of the ratio are expressed in \$ per kW-year.

15 **Q. Was PSE constrained in how it performed its peak credit analysis in this**
16 **case?**

17 A. Yes. As part of a Settlement Stipulation in Dockets UE-130583, UE-130617, UE-
18 131009, and UE-131230, the parties agreed to initiate a pair of collaborative
19 processes to address issues surrounding (1) PSE's power cost adjustment and
20 power cost only rate case and (2) electric cost of service, rate spread and rate
21 design. Since the parties did not reach agreement on issues related to electric cost

1 of service, rate spread and rate design in this collaborative process, PSE filed
2 testimony and exhibits to update its peak credit methodology. This filing initiated
3 Docket UE-141368. On October 21, 2014, the parties filed a Settlement
4 Stipulation (the “Rate Design Settlement”) settling that case. This settlement,
5 among other things, specified how the peak credit methodology would be
6 performed in PSE’s next general rate case. The Rate Design Settlement was
7 approved on January 29, 2015.⁸

8 **Q. Was the peak credit analysis in this rate case performed in accordance with**
9 **the Rate Design Settlement approved by the Commission in Docket UE-**
10 **141368?**

11 A. Yes. Consistent with the Rate Design Settlement, PSE has classified 25 percent
12 of production costs as demand and 75 percent as energy in this rate case. These
13 results follow from the analysis performed as part of my testimony in Docket UE-
14 141368. This analysis is provided in Exhibit No.__(JAP-5C).

15 **Q. Does the analysis in Exhibit No.__(JAP-5C) contain the most currently**
16 **available data?**

17 A. No. While PSE has filed with the Commission its 2015 Integrated Resource Plan
18 (“IRP”), has continued to refine many of the underlying assumptions in the
19 development of its 2017 IRP and proposed a new rate of return in this case, the

⁸ Docket UE-141368, Order 03.

1 peak credit analysis used to support this rate case does not reflect this updated
2 information.

3 **Q. Why don't the proposed peak credit results in this case reflect this updated**
4 **information?**

5 A. Paragraph 10 in the Rate Design Settlement states that "PSE will adjust
6 demand/energy cost allocation percentages to 25% demand and 75% energy."
7 PSE is interpreting this language as preventing any other outcome.

8 **Q. Would it be appropriate to update the analysis in Exhibit No.__(JAP-5C) to**
9 **reflect more current data?**

10 A. Yes. While PSE is willing to stand by this strict interpretation of the Rate Design
11 Settlement, I believe it would be more appropriate to update the peak credit
12 analysis for purposes of this rate case to reflect more current information than was
13 used in Exhibit No.__(JAP-5C). Doing so would be consistent with sound
14 ratemaking practices, which are supportive of more current and accurate electric
15 price signals. It would also be consistent with the intent behind this portion of the
16 Rate Design Settlement, which was to update the data used to perform PSE's peak
17 credit analysis to a period more current than was used in PSE's 2011 GRC.⁹

18 **Q. What would be the result of the PSE's peak credit calculation using more**
19 **current data than provided in Exhibit No.__(JAP-5C)?**

⁹ Dockets UE-111049 and UG-111049.

1 A. Updating the calculations presented in Exhibit No. ____ (JAP-5C) to be consistent
2 with the underlying assumptions being used in the development of PSE's 2017
3 IRP and the proposed rate of return in this rate case, the percent of production cost
4 classified as demand would be 18 percent, with 82 percent classified as energy.
5 The derivation of these percentages is provided in Exhibit No. ____ (JAP-6C).

6 **D. Classification of Transmission Costs**

7 **Q. How are transmission costs classified in PSE's electric cost of service study?**

8 A. PSE uses the peak credit method, described above, to classify transmission costs.
9 The peak credit percentages are applied to transmission costs under the theory that
10 transmission lines are constructed to deliver the energy and capacity provided by
11 generating plant, and in the same proportion as it is being provided.

12 Using the peak credit results discussed above, 25 percent of transmission costs are
13 classified as demand and 75 percent are classified as energy. PSE also separately
14 identifies transmission related to generation-integration and other transmission
15 before allocating costs to customer classes.

16 **Q. Why does PSE distinguish between generation-integration transmission and
17 other transmission?**

18 A. Generation-integration transmission brings PSE's remote generation to its
19 integrated transmission system. PSE segregates the costs of generation-
20 integration transmission from other transmission because customers in the
21 Choice/Retail Wheeling class do not use PSE's remote generation resources.

1 Thus, it is appropriate to exclude these customers from the allocation of costs for
2 transmission lines used for integration of remote resources. However, this class
3 continues to receive an allocation of PSE's other transmission costs.

4 **E. Classification of Distribution Costs**

5 **Q. How are distribution costs classified in PSE's electric cost of service study?**

6 A. With three exceptions, all electric distribution costs are classified as demand-
7 related. The three exceptions are the costs of meters, service lines and distribution
8 line transformers. These are classified as customer-related, as discussed in
9 Sections G(2) and G(3).

10 **F. Allocation of Production and Transmission Demand Costs**

11 **Q. How are production and transmission demand costs allocated in PSE's
12 electric cost of service study?**

13 A. As noted earlier, PSE has changed the way it allocates demand-related production
14 and transmission costs in this case. In accordance with the Commission-approved
15 Rate Design Settlement discussed earlier, PSE allocated these costs using a 4-CP
16 allocator. This was a change from PSE's previous approach, which allocated
17 costs based on an average of hourly class loads that occurred coincident with the
18 top 75 system hourly loads during the test year.

19 **Q. Did the Commission endorse the use of this new allocation methodology
20 beyond this rate case?**

21 A. No. The Commission only approved this allocation methodology for PSE's

1 current rate case, with the expectation that this subject would be explored more
2 thoroughly in the near future.

3 **G. Allocation of Distribution Costs**

4 **1. Distribution Substations and Feeder Costs**

5 **Q. How does PSE allocate distribution substations and feeder costs in its cost of**
6 **service study?**

7 A. Consistent with PSE's past four general rate cases, PSE assigns the cost of
8 distribution underground circuits, overhead circuits, and substations based upon
9 allocation factors constructed from each class's contribution to feeder and
10 substation peak loads and the length of the distribution circuit. These allocation
11 factors are constructed from monthly energy and load factors for the twelve-
12 month period ending September 2016.

13 **Q. Would you please describe specifically how substation costs are allocated?**

14 A. For each month, each customer class's contribution to the peaks of individual
15 distribution substations, as a percent of those peaks, is calculated using the
16 average hourly consumption of each class's load on the substation, divided by the
17 non-coincident peak ("NCP") load factor of that class in that month. Each class's
18 contribution to the peak load on each individual substation is then averaged across
19 the months of the year. This average monthly contribution to each substation's
20 peak load is then multiplied by the booked cost of the individual substation in
21 2016 dollars to derive the allocated cost of each substation. These allocated

1 substation costs are then summed by customer class and compared with PSE's
2 total substation investment in 2016 dollars to develop the substation cost
3 allocations for Federal Energy Regulatory Commission ("FERC") Accounts 360-
4 362.

5 **Q. How does PSE allocate distribution line costs?**

6 A. PSE uses customer information system ("CIS") and geographic information
7 system ("GIS") to associate each customer with a feeder. Monthly NCP load
8 factors are then used for each customer class to determine each class's
9 contribution to each feeder's monthly NCP as a percent of each month's peak on
10 the feeder. Each class's contribution to monthly peak load on the feeder is
11 multiplied by the number of overhead and underground miles on the feeder.
12 These load-weighted line miles are then added across all the feeders to develop
13 the total load-weighted overhead and underground distribution line miles
14 allocated to each class. Allocation factors for overhead and underground lines are
15 then developed by dividing the total load-weighted line miles attributable to each
16 class by the total load-weighted line miles for all classes. The overhead allocators
17 are applied to FERC Accounts 364 and 365, and the underground allocators are
18 applied to FERC Accounts 366 and 367.

19 **2. Distribution Line Transformer Costs**

20 **Q. How does PSE classify line transformer costs in its cost of service analysis in**
21 **this case?**

1 A. As in PSE's previous four general rate cases, line transformer costs are classified
2 as being customer-related.

3 **Q. Why does PSE classify line transformer costs as a customer-related cost?**

4 A. PSE classifies line transformer costs as a customer-related cost because (1)
5 transformer sizes are standardized, (2) line transformers are installed and sized
6 specifically to serve a particular customer or group of customers, and (3)
7 transformers are rarely re-sized for a particular customer or a group of customers.
8 Therefore, transformer costs are appropriately characterized as customer-related
9 costs.

10 **Q. Please describe how the line transformer cost allocation factor is developed.**

11 A. The Company uses its CIS and GIS to associate each line transformer with the
12 customers using the transformer. This results in allocating approximately 330,550
13 transformers to PSE's different customer classes by type and size. The majority of
14 line transformers are used by a single class and thus are directly assigned. The
15 remaining transformers are allocated to each class based upon the class's relative
16 contribution to the transformer's load. The transformers are priced at current
17 costs, including installation, to determine each class's contribution to embedded
18 line transformer costs (FERC Account 368). The embedded line transformer
19 costs in the FERC account reflect PSE's line extension policy and are reduced for
20 customer contributions.

21

1 **3. Service Line and Meter Costs**

2 **Q. How are service line and meter costs allocated in PSE’s cost study?**

3 A. Service line costs are allocated based on the number of customers taking service
4 at secondary voltage. Costs of all underground service lines are assigned to the
5 residential class because non-residential secondary voltage customers own their
6 underground services. Costs of overhead service lines are allocated based on the
7 number of secondary voltage overhead service customers in each class. Meters
8 are allocated based on the current cost of electric meters assigned to customers in
9 each class relative to the current cost of all electric meters.

10 **H. Administrative, General and Other Cost Allocation Factors**

11 **Q. How does PSE allocate administrative and general costs in its electric cost of**
12 **service study?**

13 A. The majority of administrative and general costs are assigned based upon
14 production, transmission, distribution, and customer costs. Property insurance
15 allocations are based upon allocated plant, and pensions and employee insurance
16 follow the allocation of salary and wages.

17 **Q. What other cost allocations does PSE use in its electric cost of service study?**

18 A. PSE reviews historical experience with late payments and assigns the costs to
19 each class. Other miscellaneous revenues associated with non-sufficient fund
20 checks and reconnects are allocated to each class based upon a historical analysis
21 of revenues received from these sources.

1 **Q. Has PSE provided a summary of its electric cost of service study in this**
2 **proceeding?**

3 A. Yes. PSE's proposed electric cost of service study is summarized in Exhibit
4 No. ___(JAP-7).

5 **V. PSE'S NATURAL GAS COST OF SERVICE STUDY**

6 **A. Previous Cost of Service Studies**

7 **Q. Please identify all gas cost of service studies conducted by PSE in the last five**
8 **years.**

9 A. Prior to the gas cost of service study conducted in this case, PSE last conducted a
10 fully allocated embedded cost of service study to support its 2011 GRC.¹⁰

11 **Q. Please describe the methodology used in the 2011 gas cost of service study.**

12 A. The 2011 gas cost of service study used the same basic approach to
13 functionalizing, classifying and allocating costs as is presented in the study
14 supporting this 2017 filing.

15 **B. Overview of PSE's Proposed Gas Cost of Service Study**

16 **Q. Why did PSE conduct its gas cost of service analysis both including and**
17 **excluding gas commodity costs?**

¹⁰In Docket UG-151663, PSE also presented an updated gas cost allocation study using methods similar to those employed in its 2011 GRC, but with updated cost and load information, to illustrate the impact of a proposed liquefied natural gas facility on customer rates. However, no rates were set as a result of this analysis. It was provided purely for illustrative purposes.

1 A. PSE conducted the analysis both including and excluding gas commodity costs to
2 ensure that the gas cost of service study is consistent with the total gas revenue
3 requirement including gas costs presented in the testimony of Susan E. Free,
4 Exhibit No. ____ (SEF-1T), and to be consistent with past cases. The study that
5 includes gas costs is informational only in this filing, because PSE's PGA
6 mechanism addresses changes in commodity costs. However, the gas demand cost
7 allocation factors from this study will be used in the 2018 PGA filing. This
8 proceeding addresses the gas revenue requirement deficiency that is caused by
9 changes in costs *other than* gas commodity costs. Unless otherwise noted, I will
10 refer to the gas cost of service analysis that excludes gas costs throughout the
11 remainder of my testimony.

12 **Q. Have you prepared exhibits that present PSE's gas cost of service study for**
13 **its natural gas service in this proceeding?**

14 A. Yes. Exhibit No. ____ (JAP-8) presents the summary results proposed in this
15 proceeding, excluding gas costs. Exhibit No. ____ (JAP-9), presents the summary
16 results proposed in this proceeding, including gas costs. Exhibit Nos. ____ (JAP-
17 10, 11 and 12), present supporting details of PSE's proposed gas cost of service
18 study, including gas costs.

19 **Q. What model did PSE use for its gas cost of service study?**

20 A. PSE used the same model that it used in its 2011 GRC. This model was originally
21 developed for PSE by Navigant Consulting, Inc. for its 2006 GRC.

1 **C. Peak and Energy Gas Allocation Factors**

2 **Q. What was the basis for allocating gas commodity costs?**

3 A. PSE used weather-normalized natural gas volume for the test year, which was
4 developed for the calculation of pro forma gas revenue and is discussed earlier in
5 my testimony.

6 **Q. How did PSE develop the peak demand allocator for demand-related gas
7 costs?**

8 A. PSE used the system design day to develop its peak demand allocator. The gas
9 system design day is based on 52 heating degree days ("HDD"), as explained in
10 PSE's 2015 Integrated Resource Plan.¹¹ In broad terms, peak gas requirements
11 include the firm loads of sales and transportation customers. To estimate the total
12 gas peak demand of customers on firm sales schedules, PSE's Load Forecasting
13 Group developed regression equations to characterize the relationship between
14 firm peak loads and monthly firm gas volume considering the difference between
15 peak and monthly temperatures. The total peak gas demand of customers on firm
16 sales schedules was then estimated using the estimated regression coefficients, the
17 system design day of 52 HDD and weather normalized throughput for the test
18 period. The transportation and interruptible sales customers' peak was equal to
19 either those customers' contract demands (for Schedules 85, 85T, 86, 86T, 87,
20 87T, and contracts), which represent the firm gas demand PSE is obligated to

¹¹ See PSE's 2015 Integrated Resource Plan, Appendix E: Demand Forecasting Models, page E-14, on file with the Commission and publicly available at www.pse.com.

1 serve, or their fixed demand (for Schedule 41T), which is established annually
2 and billed every month. The total gas system peak was the sum of the peak
3 demand of gas customers on firm schedules and the contract or fixed demands of
4 customers on transportation or interruptible sales schedules.

5 **Q. How was the gas peak allocation factor for firm sales schedules developed at**
6 **the customer class level?**

7 A. The firm sales component of the gas peak demand allocation factor described
8 above was allocated to gas Schedules 16, 23, 31, 53, and 41 based on a
9 combination of fixed demands and consumption in the peak month of the test
10 year. Gas Schedule 41 customers have fixed demands that are established
11 annually, based on the customers' usage in the system peak month, and billed
12 every month. These fixed demands were used to estimate Schedule 41 customers'
13 contribution to the system peak. Of the total gas peak of firm sales schedules, the
14 portion not assigned to Schedule 41 based on those customers' fixed demands was
15 allocated between Schedules 16, 23 and 53 (Residential and Propane) and
16 Schedule 31 (Commercial and Industrial), based on those schedules' actual
17 volume during the peak month in the test year.

18 **Q. Why did PSE use only the contract demands of interruptible customers?**

19 A. PSE's interruptible gas rate schedules currently allow customers to take firm
20 service under the same schedule. Contract demands represent those customers'
21 firm load on these interruptible schedules, and any use in excess of their contract
22 demand is interruptible. PSE's system is designed to serve firm load. Capacity

1 projects are undertaken for the purpose of serving firm loads, not interruptible
2 loads, so allocating gas peak-related costs to interruptible customers based on
3 interruptible loads would not be consistent with the way gas costs are incurred by
4 PSE. PSE's gas system capacity planning relies on design day weather
5 conditions, when all interruptible gas loads of transportation and sales customers
6 are assumed to be curtailed, to ensure that PSE is able to serve its firm load.
7 Many interruptible gas customers have both firm and interruptible components to
8 their loads, and during design day weather conditions the only service to
9 interruptible customers is assumed to be their firm component. Because the
10 contract demand represents the firm portion of their loads, it is the best estimate
11 of their contribution to the costs of meeting the gas system peak.

12 **Q. Why did PSE use its design day peak demand to allocate demand-related gas**
13 **costs instead of using a peak based on actual weather data from a recent**
14 **historical period?**

15 A. There are two primary reasons design day peak is a better choice than historical
16 peak for gas cost allocation:

- 17 1. Design day peak is a better indicator of gas cost causation than
18 historical peak demands.
- 19 2. Design day provides a more stable estimate of gas peak than
20 historical peaks provide, and provides more stable gas cost of
21 service results over time.

1 **Q. Why does design day peak better reflect the gas costs that are incurred than**
2 **a historical peak does?**

3 A. Cost causation is the primary consideration in cost of service analysis, and PSE
4 designs its gas system to meet a design day peak demand, which is based on cold
5 weather conditions. Regardless of how often those design day conditions occur,
6 PSE incurs the capacity costs associated with being able to provide natural gas
7 service on a design day. PSE uses the design day standard in its gas capacity
8 investment decisions and builds capacity to meet that standard. If PSE built its
9 gas system based on a peak that occurred in a given historical period, the capacity
10 might not be sufficient to serve customer needs in extreme weather. The gas
11 design day standard was developed in PSE's IRP process and has been accepted
12 by the Commission. An estimated peak based on historical weather conditions
13 during a particular period would not necessarily reflect PSE's costs associated
14 with meeting its peak demand.

15 **Q. Why does design day peak provide a more stable estimate of peak than a**
16 **peak based on historical temperatures?**

17 A. Weather, gas volumes and peak gas demands change from year to year, yet the
18 costs of designing and building PSE's gas system do not. If historical data were
19 used, cost allocation would depend on weather conditions that happened to prevail
20 during the period considered rather than the conditions for which the system was
21 designed, which do not vary considerably from one year to the next the way
22 weather does. The historical gas peak might also include some interruptible

1 loads, which would vary over time based on both weather conditions and the
2 amount of excess capacity in the gas distribution system available to serve those
3 loads. These factors could result in greater volatility of cost assignments from
4 one gas cost of service study to the next. The design day standard is a more stable
5 determinant of planned gas capacity.

6 With respect to stability over time, use of design day is consistent with the use of
7 weather normalized volume in cost allocation. If actual gas volume were used,
8 allocation of gas costs among the classes would change from year to year based
9 on the weather because some customer classes exhibit greater weather sensitivity
10 than other classes. Use of weather-normalized volume avoids these swings in
11 cost allocation from one rate case to the next. Similarly, design day is a more
12 stable basis for cost allocation because it does not depend on the weather that
13 actually occurred during a recent period.

14 **D. Allocation of Gas Plant Costs and Operating Expenses**

15 **Q. Were gas facilities identified that could be directly assigned to specific**
16 **customer groups?**

17 A. Yes. PSE conducted an analysis to identify the cost of services in FERC Account
18 380 that are dedicated to customers on gas Schedules 85, 85T, 87, 87T and special
19 contracts. This portion of plant in FERC Account 380 was directly assigned to
20 these customer classes, and the remainder was allocated to all other gas customer
21 classes based on weighting factors. Different customer classes require different
22 sizes and types of services, which vary in cost. The number of gas customers was

1 weighted based on cost data for various sizes and types of services, and these
2 weighted customer counts were used to allocate gas costs across customer classes.
3 The use of weighting factors takes these cost differences into account when
4 assigning costs to the customer classes.

5 **Q. How were other customer-related gas costs allocated to classes?**

6 A. Meters and meter installations (Accounts 381 and 382), house regulators and
7 installations (Accounts 383 and 384), and industrial measuring and regulating
8 station equipment (Account 385) were allocated based on the actual types of
9 meters used to serve gas customers in different customer classes and the current
10 costs of those meters and their installation.

11 **Q. How were distribution-related gas operation and maintenance ("O&M")
12 expenses allocated?**

13 A. Other than directly-assigned expenses, these expenses follow the cost allocation
14 of the corresponding plant accounts.

15 **Q. How were administrative and general ("A&G") expenses and taxes allocated
16 to each gas customer class?**

17 A. A&G expenses were allocated on an account-by-account basis. Items related to
18 labor costs, such as employee pensions and benefits, were allocated based on
19 O&M labor costs. Items related to plant, such as maintenance of general plant
20 and property taxes, were allocated based on plant. Items related to revenue, such
21 as regulatory commission expenses, were allocated based on revenue. All other

1 A&G costs were allocated based on operation and maintenance expenses.

2 **E. Classification and Allocation of Distribution Main Costs**

3 **Q. Please describe how investment in gas distribution mains was classified and**
4 **allocated.**

5 A. Following a long-standing practice, dating back to PSE's 2007 GRC,¹² PSE used
6 the peak and average methodology for allocating gas distribution main costs.
7 This methodology allocates gas demand costs based on a combination of peak
8 demand and average demand (or average throughput). PSE used an estimate of
9 the gas system load factor to determine how much of these demand-related gas
10 costs would be allocated based on average gas demand and how much would be
11 allocated based on peak gas demand. The gas system load factor was calculated
12 based on weather-normalized throughput and design day peak demand, which
13 were discussed earlier in my testimony. Multiplying this load factor by the gas
14 plant investment provides an estimate of costs that can be attributed to average
15 use, with the remainder being assigned to peak use.

16 **Q. What is the resulting classification of gas distribution mains?**

17 A. PSE's gas system design day load factor is 33 percent. So, based on the peak and
18 average methodology, PSE's demand-related gas distribution mains were
19 allocated 33 percent on average demand and 67 percent on design day peak
20 demand.

¹² Dockets UE-072300 and UG-072301, consolidated.

1 **Q. Is this approach to classifying and allocating gas distribution mains**
2 **reasonable?**

3 A. Yes. The peak and average methodology's use of system load factor provides a
4 reasonable basis for classifying and allocating these costs. This peak and average
5 approach reflects a balance between the way the gas system is designed (to meet
6 peak demand) and the way it is utilized on an annual basis (throughput based on
7 gas usage that occurs during all conditions, not only peak conditions). It also
8 acknowledges previous Commission guidance that some portion of gas demand
9 costs should be allocated based on energy use.

10 **Q. How was the peak and average method of cost allocation applied to gas**
11 **distribution mains?**

12 A. A diagram of the allocation of gas distribution mains is presented on page one of
13 Exhibit No. ___(JAP-13). The cost of mains was allocated in the following steps:
14 First, the total gas distribution mains plant was divided into the portion to be
15 allocated based on peak demand and the portion to be allocated based on average
16 demand using the gas system load factor described above. This resulted in \$547
17 million (33 percent) of gas plant to be allocated based on average gas demand and
18 \$1,165 million (67 percent) to be allocated based on peak gas demand.
19 Second, the 67 percent to be allocated based on peak gas demand was allocated to
20 all gas customer classes based on their estimated contributions to the gas system
21 design day peak demand.

1 Third, the 33 percent based on average gas demand was split into three groups: 1)
2 large distribution main (greater than or equal to four inches in diameter); 2)
3 medium distribution main (two to three inches in diameter); and 3) small
4 distribution main (less than two inches in diameter). Large main was allocated to
5 all gas customer classes based on annual weather normalized gas throughput, and
6 small main was allocated to all gas classes except Schedules 85, 85T, 87, 87T and
7 contracts based on annual weather normalized throughput. Medium main was
8 allocated 33 percent to all classes and 67 percent to all gas classes except 87, 87T
9 and contracts, based on annual weather normalized throughput.

10 **Q. Why were small distribution mains, those less than two inches, not allocated**
11 **to all gas customer classes?**

12 A. The smallest main is in isolated locations on PSE's gas distribution system and is
13 unlikely to provide benefits to the large gas commercial and industrial loads
14 served on Schedules 85, 85T, 87, 87T and contracts.

15 **Q. Why were medium distribution mains, those two to three inches in diameter,**
16 **split into two groups?**

17 A. Parties in PSE's 2007 GRC raised different concerns regarding the allocation of
18 gas distribution mains. In general, two different ways of looking at the benefits to
19 customers were presented in discussions about the allocation of gas distribution
20 mains costs, and these two viewpoints are diametrically opposed. One view is
21 founded on a belief that gas customers only benefit from pipe through which gas

1 molecules flow, or might flow, to reach their locations, and thus should only be
2 allocated a share of the cost of those specific pipes, nothing more. The other view
3 is that the gas distribution network provides an integrated system that benefits all
4 gas customers, regardless of the customers' locations on that system and
5 regardless of the actual (or modeled) flow of molecules. Giving the largest gas
6 interruptible customers a full allocation of costs emphasizes system benefits, and
7 exempting them from the cost of medium main emphasizes customers' physical
8 connections and the flow of gas. PSE's use of both of these approaches for
9 medium gas distribution mains balances the two perspectives.

10 **Q. Why did PSE choose the one-third, two-thirds split, with one-third of**
11 **medium main allocated to all gas customers and two-thirds of medium main**
12 **allocated to all gas customers except Schedules 87, 87T and Contracts?**

13 A. PSE considered the historical treatment of Schedules 87, 87T and contracts
14 customers and the benefits associated with being part of the gas distribution
15 system. Historically, these customers had some assignment of costs related to
16 medium main, but that assignment was small. Prior to PSE's 2004 GRC,¹³ when
17 PSE introduced the use of SynerGEE into its gas cost of service study, the only
18 assignment of medium gas distribution main given to those largest gas customers
19 was based on a direct assignment. The two-thirds weighting of the exemption of
20 these gas customers is an acknowledgement that, in the past, the Commission

¹³ Dockets UE-040640 and UG-040641, consolidated.

1 approved very limited cost assignments to this group of customers. The one-third
2 weighting of assigning the cost of medium gas distribution main to all gas
3 customers acknowledges the benefits to all gas customers of being part of a
4 distribution system. So while their cost assignment of medium main should be
5 small, it should not be zero. This methodology is consistent with the approach
6 taken since PSE's 2009 GRC.¹⁴

7 **Q. Why did PSE choose two inches as the point for exempting large gas**
8 **customers?**

9 A. Large gas distribution main (four inches and greater) is the backbone of the
10 system, and medium to small main (three inches and smaller) is used to deliver
11 gas to most customers. Main smaller than two inches is located mostly in isolated
12 locations on PSE's gas distribution system and is unlikely to provide benefits to
13 large gas commercial and industrial loads, whereas medium main is ubiquitous
14 throughout the distribution system. Three-inch main is grouped with two-inch
15 main, but there is very little three-inch main in the system.

16 **Q. Please summarize the benefits of PSE's approach to allocating gas**
17 **distribution mains.**

18 A. There are five benefits to PSE's approach. First, this method recognizes that all
19 customers benefit from the gas distribution system of medium to large mains as a
20 whole, not only from the stretch of main through which gas flows to reach the

¹⁴ Dockets UE-090704 and UG-090705, consolidated.

1 individual customer. PSE's gas distribution system is a network of pipes that
2 provides benefits to customers in addition to providing the stretch of pipe through
3 which molecules flow to reach the individual customer. Second, in previous
4 general rate cases some parties have opposed the use of a customer's physical
5 location on the system to determine the costs that should be assigned to that
6 customer. The proposed method avoids this practice. Third, by exempting large
7 gas customers from the cost of the smallest diameter main (less than two inches),
8 this approach acknowledges the fact that the smallest main is in isolated locations
9 on the system and is unlikely to benefit large commercial and industrial
10 customers. Fourth, PSE's approach addresses concerns regarding cost
11 responsibility for two-inch main by allocating a portion of it to all customers and
12 excluding the largest interruptible customers from a portion of it. Fifth, PSE's
13 approach is relatively transparent and easy to understand.

14 **F. Results of the Distribution Cost of Service Study**

15 **Q. Please summarize the results of the gas cost of service study conducted by**
16 **PSE.**

17 A. The parity percentages under current rates, excluding gas costs, are summarized
18 in Table 6 below. The parity percentage indicates what portion of the cost of
19 service customers pay under current rates, relative to other customer classes.
20 These results are also provided in the summary of results from the cost of service
21 study on page one, line 36, of Exhibit No. ____ (JAP-8).

1

Table 6 – Results of Gas Cost of Service Study

Customer Class	Schedule	Parity Percentage
Residential	16/23/53	108%
Commercial & Industrial	31/31T	79%
Large Volume	41/41T	95%
Interruptible	85/85T	102%
Limited Interruptible	86/86T	121%
Non-exclusive Interruptible	87/87T	76%
Special Contracts		59%
Rentals	71/72/74	186%
Total/System Average		100%

2

3

G. Classification and Allocation of Purchased Gas Related Costs

4

Q. Are PSE’s purchased gas cost rates being set in this case?

5

A. No. These rates are set in PSE’s Purchased Gas Adjustment (“PGA”) filings that occur each fall. However, the historic practice in these PGA filings is to rely on the classification and allocation results from PSE’s GRCs to allocate costs in these filings.

6

7

Q. When was the last time PSE reviewed in a GRC the classification and allocation factors used in its PGA filings?

8

9

A. PSE last reviewed the classification and allocation factors used in its PGA filings in its 2007 GRC.¹⁵ These factors were developed in Washington Natural Gas’s

10

11

12

¹⁵ Dockets UE-072300 and UG-072301, consolidated.

1 1994 rate restructuring case. With significant changes in the resource mix
2 between these two cases, PSE determined that it was necessary to update its
3 allocation factors. With the passing of another 10 years, PSE is again evaluating
4 the development of these factors for their continued appropriateness.

5 **Q. How did PSE classify and allocate its purchased gas expenses in its 2007**
6 **GRC?**

7 A. PSE classified purchased gas costs into two components: demand and variable.
8 Variable costs included interstate pipeline transportation variable costs, gas
9 supply contract commodity, spot market gas costs, the net cost of gas injected into
10 and withdrawn from storage, and the associated volumetric-based fees for these
11 services. Demand-related costs included interstate pipeline demand charges,
12 underground storage service contracts (Clay Basin and Jackson Prairie) demand
13 charges, and fixed charges related to gas supply contracts.

14 The various demand and variable cost components of the gas supply portfolio
15 were allocated to the Company's customer classes according to annual sales
16 volumes, winter sales volumes, and design peak demand allocation factors, as
17 well as the composite allocation factors composed of design peak demands,
18 winter season sales and annual sales as discussed above.

19 The components of the Company's gas costs and the allocation factors used to
20 allocate those costs are provided in Exhibit No. ___(JAP-12).

1 **Q. Please describe the methods PSE used to allocate fixed demand-related gas**
2 **supply costs.**

3 A. The reservation charges associated with winter firm and peaking supply contracts
4 were classified as demand costs and allocated on a winter season and peak day
5 basis, respectively. Interstate pipeline transportation demand costs (TF-1-year-
6 round) were allocated on the basis of a composite allocation factor that represents
7 the proportionate year-round, winter season and system design peak requirements
8 served by the underlying pipeline capacity. The Company used the annual, winter
9 and design peak pipeline capacity percentage requirements derived by weighting
10 the applicable customer usage characteristics. Specifically PSE used the class-by-
11 class contributions to annual sales, winter season sales, and the system design
12 peak day, and applied the result to the various pipeline demand charges in the
13 Company's supply portfolio. Clay Basin storage costs and related pipeline
14 transportation (TF-1-year-round) were allocated based on winter sales volumes.
15 The portion of Jackson Prairie storage costs and related pipeline transportation
16 (TF-2 and TF-1-winter only) demand charges not related to balancing (80
17 percent) were allocated on a weighted winter season and design day peak basis.
18 Finally, the portion of Jackson Prairie demand charges related to its balancing
19 function (20 percent) was allocated to all classes on a system average throughput
20 basis.

21 **Q. How were the variable gas supply costs allocated?**

22 A. All variable gas supply costs were classified as commodity costs. Peaking

1 supply-related charges were allocated on a design peak day basis. Pipeline
2 variable costs related to Jackson Prairie storage delivery (TF-2 and TF-1-winter
3 only) were allocated using a composite allocator consistent with the allocation of
4 fixed costs related to Jackson Prairie. Storage withdrawal and injection costs
5 were allocated on the basis of winter sales. The rest of the variable costs related
6 to purchased gas supplies or pipeline fuel use charges were allocated on the basis
7 of annual gas sales, with the exception of those costs related to Jackson Prairie
8 balancing, which were allocated on system average throughput (including
9 transportation volumes).

10 **Q. Is PSE proposing to further update its approach to classifying or allocating**
11 **its gas supply costs in this case?**

12 A. Not at this time. The existing methods for classifying and allocating gas supply
13 costs continue to be appropriate given PSE's current mix of gas supply resources.

14 **Q. Based on the forgoing, what is the resulting allocation of PGA-related costs**
15 **in this case?**

16 A. The resulting allocation is provided in Exhibit No. ___(JAP-14). PSE intends to
17 propose gas demand rates in its 2018 PGA filing that reflect these results.

18 VI. ELECTRIC RATE SPREAD AND RATE DESIGN

19 A. **Proposed Rate Spread**

20 **Q. Would you briefly describe rate spread and its relationship to cost of service?**

21 A. Rate spread is the process of determining what portion of the total revenue

1 requirement should be allocated to each customer class for recovery in that class's
2 rates. Rate spread is guided by the results of the cost of service study.

3 **Q. What rate spread policy factors does PSE consider in developing its rate**
4 **spread recommendation?**

5 A. The Company's proposal emphasizes two factors: the customer class relationship
6 to parity and customer impacts. The Company's proposal is guided by the results
7 of the cost of service study and continues movement towards parity. PSE also
8 considers the relative impact on different classes of customers.

9 **Q. Would you please summarize PSE's proposed electric rate spread?**

10 A. Based upon the parity percentages shown in PSE's electric cost of service study
11 and the desire to move towards full parity (a parity percentage of 100 percent) in a
12 gradual manner, PSE proposes to 1) apply, with three exceptions, an adjusted
13 average rate increase to retail classes within five percent of full parity; and 2)
14 apply a rate increase that is 75 percent of the adjusted average to the retail classes
15 that are more than five percent above full parity.

16 As in PSE's last rate case, rates in Schedule 40 (Large Demand General Service
17 Greater than 3 aMW) are tied to rates in the High Voltage Schedules, such that the
18 rate increase for Schedule 40 is not independently determined. The Schedule 40
19 production and transmission charges are linked to those found in the High Voltage
20 Schedules and distribution charges are based on customer-specific information.

21 This results in a calculated rate spread amount for this class, rather than a rate

1
2
3
4
5
6
7
8
9
10
11
12
13

spread based on a class-specific cost of service and rate spread analysis.

The Firm Resale class is allocated an amount that would move it to full parity so that there is not a cross-jurisdictional subsidy.

The adjusted average electric rate increase is the average electric rate increase after accounting for the effect of above-average or below-average increases to certain classes. Since the customer class receiving a below-average increase generates greater revenue for PSE than the retail class receiving the above-average increase, the adjusted average retail electric increase of 8.32 percent is greater than PSE average retail electric increase of 7.59 percent.

A summary of PSE's proposed electric rate spread is provided in Table 7. Please also see the Exhibit No. ___(JAP-15) for a detailed worksheet of PSE's rate spread proposal.

Table 7 - Proposed Electric Base Rate Spread

Customer Class	Rate Schedule	Parity Percentage	Proposed Base Rate Increase
Residential	7	95 %	8.32 %
General Service, < 51 kW	8/24	109 %	6.24 %
General Service, 51 - 350 kW	11/25/7A/29	108 %	6.24 %
General Service, >350 kW	12/26	108 %	6.24 %
Primary Service, Gen & Irr.	10/31/35	109 %	6.24 %
Primary Service, Schools	43	104 %	8.32 %
Campus Rate*	40	95 %	13.28 %
High Voltage	46/49	109 %	6.24 %
Lighting Service	50 – 59	97 %	8.32 %
Choice/Retail Wheeling	448/449	65 %	6.07 %
Total Jurisdictional Retail Sales	n/a	n/a	7.57 %
Firm Resale	5	47 %	128.35 %**
System Total/Average		100%	7.59 %

*Campus Rate increase proposal reflects customer-specific distribution rates according to agreement.

**Reflects the rate increase necessary to move non-jurisdictional rates to parity.

B. Electric Rate Design Guidelines and Overview

Q. What are the guidelines used by PSE in designing customer rate development?

A. Rates should (1) provide for recovery of the total revenue requirement, (2) provide revenue stability and predictability to the utility, (3) provide rate stability and predictability to the customer, (4) reflect the cost of providing service, (5) be

1 fair, (6) send proper price signals; and (7) be simple and understandable. These
2 principles are consistent with those presented in "Principles of Public Utility
3 Rates," by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen,
4 2nd Edition, 1988.

5 **Q. Please summarize the changes PSE proposes to make to electric rate design.**

6 A. The Company is proposing limited changes in this case to the design of existing
7 rates. With only a few exceptions, all rates in a customer class will be increased
8 by the class average percentage increase.

9 The exceptions include:

- 10 1. Schedule 7, where the monthly basic charge is proposed to increase to \$9
11 and the blocked energy charges are increased by the same percentage to
12 recover the revenues assigned to this class;
- 13 2. Schedule 26, where the demand and energy rates are tied to Schedule 31;
- 14 3. Schedule 40, where customer specific distribution rates are charged and
15 the loss-adjusted energy and demand charges are set equal Schedule 49;
- 16 4. Schedules 50-59, where individual charges within and among these
17 lighting schedules were first calculated based on a new lighting cost study
18 (discussed later in this testimony) and where these cost-based rates were
19 scaled to generate the revenue proposed for this group of customers; and
- 20 5. Schedules 448/449, where PSE is proposing to eliminate the kVA charge
21 and instead collect all state-jurisdictional costs from the proposed

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

customer charges.

Q. Has PSE prepared new base electric tariff schedules based upon the electric cost of service study results and consistent with its rate design proposals in this case?

A. Yes, the proposed electric tariff schedules are presented in Exhibit No. ____ (JAP-16).

C. Proposed Residential Electric Rate Design

Q. Please summarize PSE’s current residential electric rate design.

A. The current rate is a two-block energy rate with a monthly basic charge (single-phase) of \$7.49, a first-block energy rate of 8.5578 cents per kilowatt hour (“kWh”), and a second-block energy rate of 10.4157 cents per kWh. The first block energy rate applies to usage up to 600 kWh per month, with all monthly usage above that level charged the second-block rate.

Q. Is PSE proposing to change the design of its electric residential rate design in this case?

A. No, not in its filed tariff sheets. However, as another part of the Rate Design Settlement in Docket UE-141368, PSE agreed to propose rates based on the assumption that the new electric rate design would include an inverted three-block rate structure with the first block including monthly usage up to 800 kWh, the second block including usage between 800 kWh and 1,800 kWh and the third block including usage above 1,800 kWh. While PSE has developed rates under

1 this three-block rate structure, as presented and discussed more fully below, we do
2 not believe that the results are in line with the expectations of parties when this
3 agreement was originally made. Specifically, the rate PSE has calculated for the
4 third-block is lower than the rate for the first and second block, and would not
5 send the desired price signals to customers. As a result, PSE elected to
6 specifically file proposed residential electric rates using the existing two-block
7 structure rather than the three-block rate structure.

8 **Q. By not filing residential electric rates reflecting a three-block energy rate**
9 **structure, should one conclude that PSE is opposed to this rate structure?**

10 A. No. To be clear, PSE is not opposed to a three-block rate structure for its
11 residential electric customers, but continues to believe that these rates should
12 reflect appropriate cost-based price signals. If other parties can develop and wish
13 to propose alternative rates that meet this objective, PSE is willing to consider
14 those alternatives.

15 **Q. Is PSE sponsoring testimony explicitly supporting the addition of a third**
16 **block to its electric residential rates?**

17 A. No. PSE is deferring to the advocates of this three-block rate structure in the Rate
18 Design Settlement to support this part of the proposal in their prefiled testimony.

19 **Q. Please summarize PSE's proposed residential rate design under the filed two-**
20 **block and unfiled three-block rate design.**

21 A. PSE's proposed rates are summarized in Table 8 below.

Table 8 - Proposed Electric Residential Rates Under Three-Block and Two-Block Energy Rate Structure

Rate Component	Three-Block Rate Structure	Two-Block Rate Structure
Monthly Basic Charge	\$9.00	\$9.00
Energy Rates (¢/kWh):		
- First Block	9.6377	9.1770
- Second Block	11.7300	11.1693
- Third Block	8.9742	

Q. How has PSE calculated residential electric rates under the alternative three-block rate structure?

A. PSE first priced the tail block residential electric rate, for usage above 1,800 kWh per month, at its estimated long-run avoided cost of power and delivery. PSE then proportionally adjusted the price of the other two rate blocks to a level sufficient, when added to the revenue recovered at the proposed tail-block rates and from the proposed monthly basic charge, to recover the revenue requirement spread to electric residential customers, as discussed above. As a result the differential between the first and second block residential rates continues to reflect the existing differential of approximately two cents per kWh.

Q. Why should the tail-block residential electric rate be priced at PSE’s estimated long-run avoided cost of power and delivery?

A. One of the primary goals of utility rate making, as discussed above, is to give customers the proper price signal. To that end, the price signal received by PSE’s residential electric customers using over 1,800 kWh should generally be reflective of the utility’s long-run avoided costs. To do so will allow these customers to

1 make their own resource decisions using a price signal that is more consistent
2 with the avoided costs measures used to support the cost-effectiveness of PSE's
3 supply and demand side resource acquisition.

4 **Q. What specific measure of avoided cost did PSE use to calculate the potential**
5 **third-block residential rate?**

6 A. PSE used an estimate of the long-run avoided cost for serving residential load that
7 is calculated based on many of the assumptions currently being used to support
8 the development of the Company's 2017 IRP and filed avoided costs rates¹⁶ and
9 the analytical framework used to support cost-effectiveness of its acquisition of
10 demand-side resources. Specifically, this calculation derives the 20-year
11 levelized avoided cost of generation, transmission and distribution capacity;
12 energy costs; line losses; and the statutorily directed ten percent adder for
13 conservation benefits.¹⁷ Figure 1 below summarizes the results of this analysis
14 and shows the 20-year levelized avoided cost of residential load to be 8.9742
15 cents per kWh.

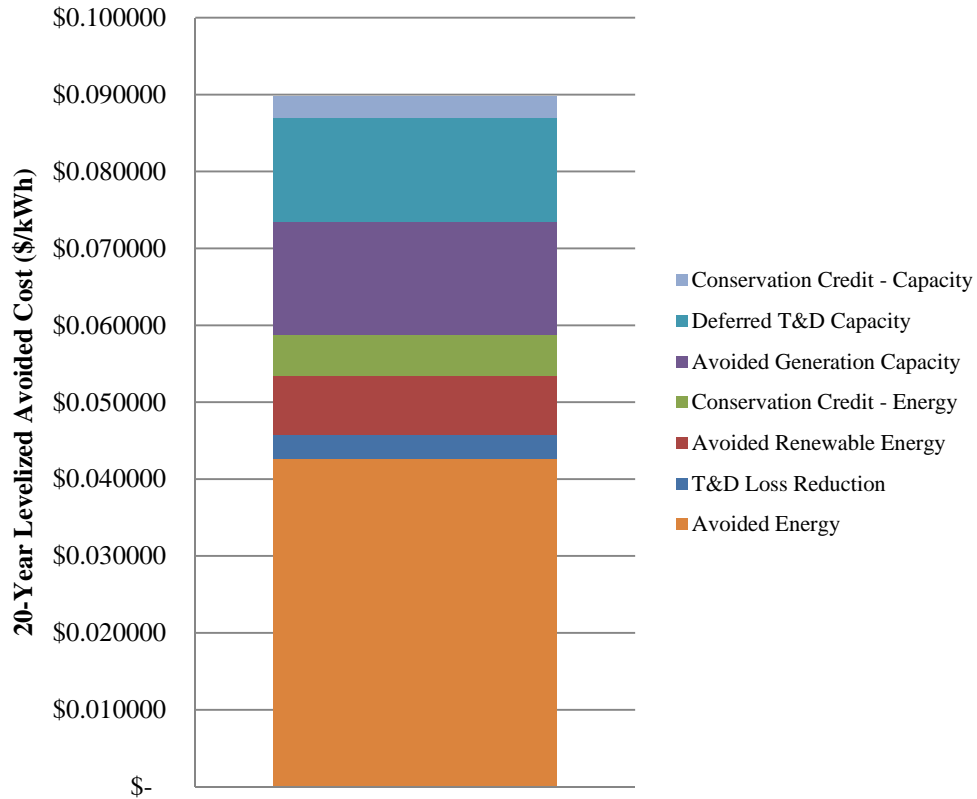
¹⁶ For example, see the avoided costs filed in PSE's Schedule 91 (Cogeneration and Small Power Production).

¹⁷ See Northwest Power Act, §3(4)(D), 94 Stat. 2699 for the statutory language supporting the 10 percent increment.

1

Figure 1

**Long-Run Avoided Cost - Residential
(\$0.089742/kWh)**



2

3

Q. Why is PSE proposing to use this measure of avoided cost in the pricing of a third-block residential electric rate?

4

5

A. PSE expects that this price signal will be more relevant to the evaluation of resource choices facing our customers. The most prevalent resource decisions PSE customers make today relates to their investments in energy efficiency.

6

7

8

Therefore, the proposed tail-block rate would put PSE and its customers on more even footing in terms of the avoided costs being used to make their respective resource decisions.

9

10

1 **Q. Why is the 20-year levelized cost appropriate in this context?**

2 A. The period of analysis should be reasonably commensurate to the period over
3 which the resource choices made in response to these price signals would be
4 evaluated. While PSE's generating resources require an analysis over a longer
5 period of time, as they are generally more long-lived assets, the majority of the
6 Company's resource acquisition over the near term will be from demand-side
7 resources, which typically have a much shorter life. From PSE's customers'
8 perspective, there too, the majority of emphasis should be placed on the
9 acquisition of demand-side resources, as this will likely be the most relevant
10 resource decision for the vast majority of PSE's residential customers. Using
11 PSE's residential electric conservation program as an indication, the average
12 measure life in its program for the 2016-2017 biennium is less than 15 years.
13 Therefore, a 20-year period of analysis is generous.¹⁸

14 **Q. Why is PSE proposing to retain the existing price differential for the first two**
15 **blocks of the residential electric rate?**

16 A. This rate differential continues to provide an appropriate price signal, while also
17 maintaining a certain degree of rate stability for customers using less than 1,800
18 kWh per month. One potential basis for this rate differential is the average
19 difference in prices between on-peak and off-peak hours, which is reflective of
20 relative differences in short-run marginal costs. In reviewing the price differential

¹⁸ Using a shorter period would result in an even lower levelized avoided cost.

1 experienced at the Mid-Columbia trading hub over the past five years, on-peak
2 prices have been approximately 30 percent higher than off-peak prices. Applying
3 this 30 percent differential to PSE's roughly six cent per kWh embedded cost of
4 power is a little less than two cents per kWh. This is reasonably consistent with
5 existing rate differential between PSE's first two residential rate blocks at current
6 rates. Preserving the same general rate differential will help to minimize the
7 impacts of the redesigned residential rates, since less than eight percent of the
8 class monthly usage is expected to be in excess of 1,800 kWh. Based on this, PSE
9 proposes to retain the existing relative rate differentials between the first two
10 electric residential rate blocks when these rates are scaled to the levels required to
11 recover their allocated costs.

12 **Q. Is a three block rate structure the best way to convey a cost-based price**
13 **signal to PSE's residential electric customers?**

14 A. I don't believe so. While the use of block rates has been used in the industry for
15 some time and continues to have its advocates, primarily for the conservation
16 incentive it provides, other approaches may be better suited to provide PSE's
17 residential electric customers with an appropriate price signal. Specifically, rate
18 designs that reflect the time-dependent value of the energy may be a better
19 solution. The most common example of this would be through the use of so-
20 called time-of-use ("TOU") rates, where these rates are differentiated by the time
21 of day in which the power is consumed (or, in the case of a net metered customer,
22 when it is generated). Other popular examples include critical peak pricing and

1 peak time rebates, which focus primarily on the periods of the highest annual peak
2 loads.

3 **Q. Are time-based rates for residential customers supported elsewhere?**

4 A. Yes. Time-based rate structures are commonly endorsed by electric utility
5 industry thought leaders. It is endorsed by the Regulatory Assistance Project
6 (“RAP”) in its July 2015 “Smart Rate Design For a Smart Future.”¹⁹ It is also
7 discussed by the National Renewable Energy Laboratory (“NREL”) in its
8 November 2013 “Regulatory Considerations Associated with the Expanded
9 Adoption of Distributed Solar”²⁰ as a viable approach to addressing cost recovery
10 from net metered customers.

11 **Q. If it would be a better way to address this issue, why isn’t PSE proposing**
12 **TOU rates in this case?**

13 A. The implementation of TOU rates requires the use of energy measurements for
14 defined periods within the day. While the vast majority of PSE’s residential
15 electric customers have meters capable of reading energy usage with the required
16 level of granularity, the network used to communicate this usage to the utility is
17 not currently robust enough to reliably transmit the data when it is required.

¹⁹ See pages 61-62, for example. This report can be found on RAP’s website at www.raponline.org/document/download/id/7680.

²⁰ See pages 39-41, for example. This report can be found on NREL’s website at <http://www.nrel.gov/docs/fy14osti/60613.pdf>.

1 While PSE's existing network could be enhanced, it would likely come at
2 considerable additional cost and, perhaps more importantly, divert the Company's
3 focus from the work currently being conducted to transition PSE to advanced
4 meter infrastructure ("AMI"), which will allow for TOU rates and produce
5 additional benefits that cannot be achieved through PSE's AMR system. As a
6 result, PSE is unwilling to propose TOU rates at this time.

7 **Q. Is PSE also proposing to change the residential electric basic charge?**

8 A. Yes, PSE is proposing to increase its basic charge for single-phase electric service
9 to \$9 per month to reflect the current level of costs traditionally recovered through
10 its residential electric basic charges, including customer service, customer
11 accounting, meter reading, billing and line transformation. This is a \$1.51 per
12 month increase over current rates.

13 **Q. Is the proposed increase to the residential electric basic charge reasonable?**

14 A. Yes, the proposed increase is reasonable for several reasons.

15 First, it is important to note that while PSE is proposing to increase the residential
16 monthly basic charge by \$1.51 per month for single-phase service, \$0.38 per
17 month of that amount is already being paid by residential customers through
18 Schedule 141 (Expedited Rate Filing). Since the rates within Schedule 141 will be
19 set to zero coincident with the new base rates going into effect at the end of this
20 rate case, the net impact on the residential electric monthly basic charge is a lower
21 increase of \$1.13 per month.

1 Second, the current overall residential basic monthly charge of \$7.87 per month,
2 inclusive of Schedule 141, is based on a test year ending June 2012. So, it is
3 reasonable to expect there would have been cost growth in the intervening time.

4 Third, and in support of that argument, PSE's electric cost of service study in this
5 filing supports a basic charge over \$2 per month higher than being proposed in
6 this filing.

7 Fourth, PSE has had a rate plan in effect since July 1, 2013 that provided for three
8 percent annual increases to allowed delivery revenue for electric service, where
9 this revenue is intended to cover both the cost of delivery and customer-related
10 costs that is normally recovered through monthly basic charges. However, as a
11 compromise in the development of its decoupling mechanism, PSE has recovered
12 100 percent of these annual revenue increases through volumetric charges rather
13 than being spread across all rate components, including the monthly basic charge.
14 Had the three percent increases been applied to monthly basic charges, the basic
15 charge that will be in effect in 2017 would have been \$9.12 per month.

16 All that said, in deference to the issues routinely raised by low-income and
17 environmental advocates that argue for restraint on increases to the monthly basic
18 residential charge, PSE is proposing a more modest increase.

19 **Q. How does PSE's proposed residential electric basic charge compare with**
20 **basic charges of other electric utilities?**

21 A. I reviewed the basic charges of national and local investor-owned electric utilities

1 and government and customer-owned utilities in Washington state that are closer
2 to PSE's service territory. The 107 basic charges of the national electric utilities
3 surveyed average \$9.17 per month. Of the 42 other Washington state electric
4 utilities surveyed, 28 have residential basic charges that are greater than or equal
5 to \$15.30 per month, or at least 70 percent per month more than \$9.00 per month
6 amount proposed in this filing. The average basic charge for all 44 of the utilities
7 surveyed in Washington State (including PSE) is \$17.76, or almost double the
8 basic charge being proposed by PSE in this filing. These basic charge surveys are
9 provided in Exhibit No. ____ (JAP-17).

10 **D. Proposed General Service Rate Design**

11 **Q. Please summarize the proposed rate design for the General Service rate class.**

12 A. The General Service (Rate Schedule 24) class has a monthly basic charge and a
13 single-block energy rate that varies by season. This rate schedule does not have a
14 demand charge. The Company's proposal is to increase all rate components,
15 including the basic charge, by the class average increase.

16 **Q. Please summarize the proposed rate design for Small Demand General
17 Service.**

18 A. The Small Demand General Service (Rate Schedule 25) class has a basic charge
19 rate, two-block seasonal energy rates and a two-block seasonal demand rate. The
20 first 50 kW block of billing demand has no demand charge and the demand-
21 related costs are recovered in the first block of the energy rate. Under PSE's

1 proposal, all Schedule 25 rates are increased by the class average increase.

2 **Q. Please summarize the proposed rate design for large general service**
3 **customers.**

4 A. These customers are served under two principle schedules: Large Demand
5 General Service (Rate Schedule 26) and Primary General Service (Rate Schedule
6 31). Both schedules have basic charges, a single-block energy charge and
7 seasonally-differentiated demand charges. The demand and energy rates of the
8 two schedules are linked such that the lower rates for Schedule 31 reflect the
9 lower voltage transformation costs and associated lower energy losses.

10 **Q. Why does PSE link the demand rates of the two schedules?**

11 A. Since the loads and load factors for these schedules are comparable, PSE's intent
12 is to provide a cost-based differential between the two rates schedules that create
13 an end-point where customer motivation to take primary service will be based
14 upon customer needs (i.e., whether to take service at primary vs. secondary
15 voltage) rather than a desire to qualify for the schedule with the lower rate.

16 **Q. Please describe the proposed Schedule 26 and Schedule 31 rate designs.**

17 A. PSE increased all Schedule 31 and Schedule 26 rate components by the class
18 average increase, which is 75 percent of the adjusted average for all classes. The
19 reactive power charge for each schedule was increased by the applicable class
20 average increase. The Schedule 26 demand charges were then set equal to the
21 Schedule 31 demand charges on a loss-adjusted basis. PSE then increased the

1 Schedule 26 energy rate by an amount that will recover the remainder of the rate
2 responsibility of the Schedule 26 rate class.

3 **E. Proposed Campus Rate Design**

4 **Q. Please describe the purpose of Schedule 40.**

5 A. Rate Schedule 40 (Large Demand General Service Greater than 3 aMW) was
6 developed in PSE's 2004 GRC to serve customers with large loads that are either
7 typically in a campus configuration or share a distribution feeder with other
8 customers. The rate first became effective on March 17, 2005 and was voluntary
9 until the GRC following the third anniversary of that date. This rate is now
10 mandatory for those customers that qualify. The rate requires a cost study to be
11 performed by PSE to establish a customer-specific distribution charge, and new
12 customers can only be added or removed in a GRC.²¹

13 **Q. Has PSE identified any customers that should be added to Schedule 40 in this**
14 **case?**

15 A. Yes. As noted above, Schedule 40 is now mandatory once a qualifying customer
16 has been identified and approved for Schedule 40 service in a general rate case.
17 There are two additional customers who now qualify for this rate. These
18 customers have been included in Schedule 40.

²¹ Customers with loads currently served under Schedule 40 that add new meters to the same feeder between GRCs take service under Schedule 40 at those new locations under the interim rate.

1 **Q. Has PSE identified any customers that should be removed from Schedule 40**
2 **in this case?**

3 A. Yes. There is one customer who no longer qualifies for this rate. This customer
4 has been pro formed out of the calculation of Schedule 40 rates in this case and
5 pro formed into the appropriate alternative rate schedules.

6 **Q. Is PSE proposing to change any of the eligibility standards for qualifying**
7 **under this tariff?**

8 A. Yes. PSE is proposing to grandfather locations already served under Schedule 40
9 from losing their eligibility in future GRCs when these locations would have
10 otherwise qualified for service under Schedule 40 but for the fact that electric
11 service at this location was subsequently provided from a different substation.

12 **Q. What prompted this proposal?**

13 A. PSE is attempting to address a situation where a decision made solely by the
14 Company to maintain reliable service to its customers unintentionally results in
15 the removal of a customer location from its existing service under Schedule 40.
16 Without the proposed language change, one customer location currently served
17 under Schedule 40 will no longer qualify for service under this schedule solely as
18 a result of PSE's decision to reroute their service from a different substation. PSE
19 believes that such an outcome is contrary to the underlying purpose of this
20 schedule (i.e., to serve "campus" loads) and, as a result, is proposing tariff
21 language changes to address these relatively narrow and rare circumstances.

1 **Q. Please summarize the rate design for Schedule 40.**

2 A. Rates for Schedule 40 are calculated using the same general rate methodology
3 used since the inception of this rate schedule. Schedule 40 has customer-specific
4 distribution rates and a bundled energy and transmission rate that is based upon
5 Schedule 49 after an adjustment for losses. The distribution rate is designed to
6 recover customer-specific distribution costs on a levelized basis. The bundled
7 production and transmission energy and demand rates are linked to the parity-
8 adjusted high voltage rates because the aggregated load of each of these
9 customers is comparable to the load of high voltage customers.

10 The Company reviewed the distribution rates of the customers and adjusted their
11 distribution costs, transformer costs, and substation costs based on plant additions
12 and retirements that have occurred since PSE's 2011 GRC.

13 **Q. Is PSE proposing any other changes?**

14 A. Yes, PSE is proposing some minor modifications to the O&M factors used to
15 develop Schedule 40 rates. First, PSE is proposing to calculate the Substation
16 O&M factor, which is used to estimate O&M costs associated with assigned
17 substations, as a percent of net substation plant. Currently, the factor is calculated
18 as the relationship between system-level distribution O&M to *gross* distribution
19 plant and then applied to *net* substation plant. Since this factor is being applied to
20 net substation plant, calculating the factor as a percentage of net plant is more
21 appropriate.

1 Second, PSE is proposing to create a new O&M factor for the calculation of
2 O&M for overhead distribution feeders. Currently, there is a single distribution
3 feeder O&M factor that is applied to the estimated distribution feeder plant
4 serving each Schedule 40 location, regardless of whether the feeder is overhead or
5 underground. However, this O&M factor is based exclusively on the relationship
6 between system-level O&M and plant for underground feeders. In other words,
7 an O&M factor developed on the system-level relationship between O&M and
8 plant for underground feeders is currently being applied to the estimated plant
9 cost for overhead feeders to estimate the associated overhead feeder O&M under
10 Schedule 40. PSE is instead proposing to apply a new O&M factor based on the
11 relationship between system-level O&M and plant for overhead feeders to the net
12 plant value of overhead feeders serving each Schedule 40 location.

13 **Q. Is PSE proposing any other changes to the rate calculations within Schedule**
14 **40?**

15 A. Yes. As part of the Rate Design Settlement discussed earlier in this testimony,
16 PSE agreed to perform a study of the coincidence factors used to calculate each
17 customer's Schedule 40 rates. The proposed Schedule 40 rates in this case reflect
18 the results of this study, which compiled the hourly load profiles of nearly all
19 locations served under Schedule 40 and calculated the relationship between the
20 average monthly peak load for each "campus" and the sum of the monthly non-

1 coincident peaks of each location within the campus.²² The intent of this
2 calculation is to produce a “coincidence” factor to be applied to Schedule 40
3 monthly metered demands to estimate what those metered demands would have
4 been if the entire campus were metered as one location (i.e., looking more like a
5 Schedule 49 customer). The coincident demands for the Schedule 40 customers
6 are then applied to the production and transmission rates in Schedule 49 as if it
7 were a high-voltage customer served under this schedule. A summary of the
8 resulting coincident factors for each campus, including new campuses that will
9 begin taking service under Schedule 40 upon the effective date of rates in this
10 GRC, is provided in Exhibit No.____(JAP-18).

11 **F. Proposed High Voltage Rate Design**

12 **Q. Please summarize the high voltage rate design.**

13 A. These customers are served under two schedules: High Voltage General Service
14 (Schedule 49) and High Voltage Interruptible Service (Schedule 46). Both
15 schedules have demand charges and a single-block energy charge. The energy
16 rates for these schedules are tied together, only the demand charge differs. Each
17 rate component for Schedule 49 and Schedule 46 was increased by the class
18 average increase.

19

²² Due to unforeseen metering challenges, some locations served under Schedule 40 are missing data for some or all of the period analyzed. PSE used all available data in the estimation of each campus’s average monthly coincidence factor.

1 **G. Retail Wheeling Rate Design**

2 **Q. Please summarize the retail wheeling rate design.**

3 A. PSE proposes to significantly simplify pricing for Power Supplier Choice and
4 Retail Wheeling Service (Schedules 448 and 449) by setting the basic charge at its
5 cost of service and eliminating the existing per kVA charges.

6 **Q. Why is PSE proposing to eliminate the kVA charges for Schedules 448 and
7 449?**

8 A. PSE is proposing to eliminate the kVA charges under Schedules 448 and 449
9 since they are not necessary for PSE to recover its cost of serving customers under
10 these schedules. There are three primary categories of costs incurred by PSE in
11 providing service to these customers: customer-related costs, distribution costs
12 and transmission costs. Customer-related costs are recovered through the basic
13 charges within these schedules. Distribution costs, for those retail wheeling
14 customers that take service at distribution voltages, are currently recovered under
15 PSE's Schedule 62 (Substation and Related Equipment Capacity). Transmission
16 costs are recovered from these customers through PSE's FERC-jurisdictional
17 OATT. Since there are no further costs for PSE to recover from these customers,
18 the kVA charges are unnecessary.

19 **Q. If PSE is recovering its costs from these customers through its basic charges,
20 Schedule 62 and OATT, why is there such a difference between their
21 allocated costs and proposed revenue?**

22 A. These differences are tied to the recovery of distribution and transmission costs.

1 First, as noted earlier, distribution costs are recovered from these customers
2 through Schedule 62. Schedule 62 recovers PSE's distribution costs through a
3 lease-type arrangement where these payments are levelized over a 10-year period.
4 As a consequence, there may be timing differences between the incurrence and
5 recovery of costs under this schedule. However, over the term of the lease, these
6 costs are intended to be fully recovered from these customers.

7 Second, as also noted earlier, transmission costs are recovered through PSE's
8 OATT. PSE recovers a substantial majority of its transmission costs through a
9 formula rate approved by FERC, which allocates costs and prices transmission
10 service based on a methodology approved by FERC. These methodologies differ
11 from those approved by the WUTC for state-jurisdictional transmission service.
12 The cost of service study provided with this filing allocates transmission costs
13 using PSE's "peak credit" methodology discussed earlier in testimony, which
14 allocates a substantial portion of transmission costs on energy consumption.
15 However, the offsetting transmission revenue for these customers is based on a
16 FERC-approved method for allocating these transmission costs, which are largely
17 allocated on customers' contribution to the average monthly coincident demand
18 on PSE's transmission system (i.e., "12 CP").

19 **H. Summary of Proposed Rate Impacts**

20 **Q. What are the impacts of PSE's proposed electric rates in this case?**

21 A. This calculation is slightly more complicated than in previous rate cases. It is
22 important to note that several electric rider schedules will be reset concurrent with

1
2
3
4
5
6
7
8
9
10
11
12
13
14

the effective date of new base rates resulting from this rate case. Therefore, to properly understand the bill impacts of PSE’s proposed rates, all of the relevant rate changes must be viewed in aggregate. Specifically, the impacts of the base rate changes must be added to the impacts of rate changes associated with the concurrent changes to PSE’s Schedule 95 (Power Cost Adjustment Clause), Schedule 141 (Expedited Rate Filing) and Schedule 142 (Revenue Decoupling Adjustment Mechanism). The combined impact of these changes, based on rates currently in effect, is presented below in Table 9. Exhibit No.__(JAP-19) presents the contributions made by each of the base and rider rate changes to the overall bill impact. Note, however, that it is expected that rates within Schedule 142 will be updated on May 1, 2016. So, the ultimate impacts to customer bills at the time of the compliance filing for this case will be different than those shown below.

1 **Table 9 – Estimated Electric Bill Impacts from Proposed Base and Rider Rates**

2

3 Customer Class	Rate Schedule	Overall Impact*
4 Residential	7	4.0 %
5 General Service, < 51 kW	8/24	2.8 %
6 General Service, 51 - 350 kW	11/25/29	4.8 %
7 General Service, >350 kW	12/26	4.3 %
8 Primary Service, Gen & Irr.	10/31/35	4.2 %
9 Primary Service, Schools	43	6.7 %
10 Campus Rate	40	12.1 %
11 High Voltage	46/49	4.6 %
12 Lighting Service	50 - 59	(3.4) %
13 Choice/Retail Wheeling	448/449	0.6 %
14 Total Jurisdictional Retail Sales	n/a	4.1 %

* Includes changes to base rates, as well as Schedules 95, 141, 142 and 149.

15 **Q. Please summarize the impacts shown above.**

16 A. Based on the information provided in Table 9, most customers will see rate
17 increases less than 5.0 percent, inclusive of the rate changes that will occur for
18 Schedules 95 (Power Cost Adjustment Clause), Schedule 141 (Expedited Rate
19 Filing) and Schedule 142 (Revenue Decoupling Adjustment Mechanism)
concurrent with the effective date of rates in this filing. The notable exception in
the results above is for Campus Rate customers served under Schedule 40, who
will experience a wide range of impacts depending on their individual distribution
rates. It is also noteworthy that the impacts estimated in Table 9 are based on
rates (and allowed revenue) in effect at the time of this filing. During the

1 pendency of this general rate case, rates under Schedule 142 are expected to
2 change, effective May 1, 2017. This will affect the rate impacts estimated above.

3 **VII. ELECTRIC LIGHTING RATE DESIGN**

4 **Q. Is PSE proposing any changes to its electric Lighting tariffs in this case?**

5 A. Yes, PSE is proposing three changes. It proposes to:

- 6 1. Expand the wattage range for each Light Emitting Diode (“LED”) rate,
- 7 2. Update overall lighting rates to better reflect cost causation with a more
8 detailed and current cost analysis, and
- 9 3. Remove the “Wattage Including Driver” column in tariffs with LEDs.

10 **A. Expanded LED Wattage Ranges**

11 **Q. Why is PSE expanding the wattage range applicable for each LED rate?**

12 A. In the past, LED rates have been placed on the various lighting schedules on an ad
13 hoc basis as new lighting wattages and types were offered to customers. The
14 result has been the creation of many “gaps” in between LED lighting options,
15 requiring many one-off tariff filings to add a new LED rate for each new offering.
16 From a ratemaking and tariff administration perspective, PSE has found this to be
17 an inefficient approach to expanding its lighting offerings. Therefore, as part of
18 its proposal, PSE is proposing a continuous range of rates (i.e., without gaps) that
19 can accommodate new LED offerings as they become available.

20 Moreover, this historic ad hoc approach has created a proliferation of unique LED

1 rates, as many as 54 on an individual lighting schedule. These numerous rates
2 subsequently lead to the need for just as many additional rates for many of the
3 applicable adjusting price schedules. PSE's proposal here is meant to address this
4 proliferation of LED rates in its electric tariff. Under the proposed wattage
5 ranges, to which individual rates would apply, customers only have to choose
6 from nine options. This simplifies customer choice and billing, removes the rate
7 gaps and need for multiple one-off rate filings with the Commission to offer new
8 LEDs, better enables PSE's rate structure to offer customers the lamps they want
9 amid rapid advancement in LED technology, and considerably reduces
10 administrative workload on the part of the Company, interested stakeholders and
11 the Commission.

12 **Q. Please describe the ranges of LED lamp wattages in PSE's existing lighting**
13 **schedules.**

14 A. On existing lighting schedules, LED lamps are priced in five watt ranges. On
15 Schedules 51, 53, and 54, these offered ranges start at 30 – 35 watts and end at
16 295.01 – 300 watts. On Schedules 55 and 56, the offered ranged start at 30 – 35
17 watts and end at 95.01 – 100 watts. On Schedules 58 and 59, the offered ranges
18 start at 50.00 – 55 watts and end with 875.01 – 880 watts and many gaps exist
19 between offered ranges. LEDs are not offered under Schedules 50, 52, and 57.

20 **Q. Please explain how PSE proposes to expand the LED lamp wattage ranges.**

21 A. PSE proposes that the LED wattage ranges be expanded to 30 watt ranges instead
22 of five watt ranges. To establish a consistent offering across schedules, all lighting

1 schedules that previously offered LEDs are proposed to offer LED wattage ranges
2 beginning with 30 – 60 watts and ending with 270.01 – 300 watts. Finally, to
3 accommodate schedule specific customer needs, additional ranges were added to
4 Schedules 58 and 59. These additional ranges cover 100 watts beginning with
5 300.01 – 400.00 watts and ending with 800.01 – 900.00 watts.

6 **Q. What are some of the consequences of expanding the wattage ranges for**
7 **LEDs?**

8 A. Expanding the ranges for LED rates may cause a small amount of cross
9 subsidization to occur when a broader range of LED wattages are charged a single
10 rate. Within each 30 watt range, lamp rates are calculated with the assumption
11 that lamps in that range have wattage at the middle of the range (e.g., for the
12 range of 30 watt – 60 watt, the prices are calculated at 45 watt). Consequently,
13 low wattage lamps would be charged slightly above what it may otherwise be
14 charged if the existing wattage ranges were preserved and vice versa for higher
15 wattage lamps.

16 **Q. Is PSE concerned about the potential for some increased cross-subsidies**
17 **among effected customers?**

18 A. While, all other things being equal, PSE would prefer to limit cross-subsidies
19 among its customers, in this particular instance PSE believes the benefits of
20 expanding the ranges outweigh the negative consequences of these potential
21 cross-subsides. Moreover, relative to PSE's many other rate schedules that
22 charge a single rate or set of rates for all customers served under that schedule, the

1 proposed LED ranges continue to provide a large degree of protection against
2 cross-subsidies. Finally, many of the most popular lamp sizes continue to be in
3 separate wattage ranges or are so close in wattage to one another that the cross-
4 subsidies are relatively minor.

5 **B. Lighting Study**

6 **Q. Why is PSE performing a more detailed electric lighting analysis for this**
7 **filing?**

8 A. Through a more detailed electric lighting analysis, PSE can provide its lighting
9 customers rates that are fairer and more reflective of current costs. It has been at
10 least 16 years since PSE has conducted a detailed electric lighting analysis. In
11 that time, lighting rates have been adjusted proportionally in each general rate
12 case with the general cost of service for all lighting schedules. As a result, and as
13 reflected by the differential in rate impacts discussed later, many of the individual
14 lighting rates within each schedule have drifted from the current cost of service.
15 The purpose of this detailed analysis is to bring the rates more in line with current
16 costs, which in turn will provide customers with more fair rates.

17 **Q. Please provide an overview of how this lighting analysis was performed.**

18 A. The methodology employed in this analysis was designed to develop rates for
19 lighting schedules more in line with current costs. The five step process used to
20 conduct this analysis was as follows:

- 21 1. Identify the revenue required from the lighting customer class.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19

- 2. Classify lighting costs based on relevant cost drivers.
- 3. Identify the contribution each kind of lamp and pole offered on lighting schedules towards these cost drivers.
- 4. Allocate the classified costs based on each lamp size/type and pole's contribution to these cost drivers.
- 5. Develop lighting and pole rates from the allocated costs.

Through this process, the lighting revenue requirement is allocated directly to each lamp size/type or pole based on the characteristics of that lamp or pole and the schedule under which the customer takes service. This provides continuity in rates across all lighting schedules and sets rates proportional to the estimated cost of service for each lamp size/type or pole.

Q. How did PSE determine the revenue required from the lighting customer class in step one?

A. The revenue required from lighting schedules is based on the rate spread and rate design provided in Exhibit No. ___(JAP-15). Column j, line 15 of page 26 of this exhibit shows the lighting class is responsible for approximately \$19.2 million in billed revenue, which is the basis for this lighting analysis.²³

Q. How did you classify the lighting revenue requirement?

A. The revenue requirement is classified into five different categories in Exhibit _____

²³ Note that the assignment of unbilled revenue for lighting customers is addressed in Exhibit No.__(JAP-15).

1 No.__(JAP-20). Each category represents a cost driver that is responsible for a
2 portion of the revenue requirement. The five cost categories and their definitions
3 are listed below.

- 4 • Capital: Costs related to capital investments for lighting schedules. This is
5 subdivided into Capital (Lamps) and Capital (poles).
- 6 • Distribution O&M Expense: O&M expense for lighting schedules.
- 7 • Administrative & General (“A&G”) Expense: A&G expense for lighting
8 schedules were classified as being driven by demand, energy, and customer
9 uses.
- 10 • Production / Transmission Components (Demand-Related): Costs to meet the
11 demand-related power needs for lighting schedules.
- 12 • Production / Transmission Components (Energy-Related): Costs related to
13 meeting the energy commodity needs for lighting schedules.

14 The revenue requirement was classified into these five categories so that it could
15 be recovered from rates in proportion to each lamp or pole’s contribution to these
16 cost drivers.

17 **Q. How did you identify the contribution made by each kind of lamp and pole to**
18 **the lighting cost drivers?**

19 A. These contributions were driven by specific service characteristics related to the
20 lamps or poles. The characteristics are specific to each kind of lamp and pole and
21 include:

- 1 • Lamp/Pole Type: The specific type of lamp or pole. The lamp types include
2 LEDs, high pressure sodium (“HPS”), mercury vapor (“MV”) and compact
3 fluorescent (“CFL”). The pole types include new and old poles. These
4 characteristics are relevant to the subsequent allocation of capital costs, as
5 well as the energy costs in the case of lamps, that are assigned to the lighting
6 schedules.
- 7 • Wattage: The peak power demand of a lamp. This characteristic helps to
8 allocate both demand-related and energy-related production and transmission
9 expenses assigned to the lighting schedules.
- 10 • O&M: If PSE incurs O&M expense associated with the lamp or pole, as
11 determined by the schedule under which the customer receives service. This
12 helps to assign cost responsibility for distribution O&M expenses assigned to
13 the lighting schedules.
- 14 • Financier: Either the Company or customer depending on who pays for the
15 installed cost of the lamp or pole. This helps to determine which lamps or
16 poles will be allocated the overall capital costs assigned to the lighting
17 schedules.
- 18 • Installed Cost: The estimated cost of installing a lamp or pole including all
19 parts and labor. This, again, helps to allocate the capital costs assigned to the
20 lighting schedules.

21 These influencing characteristics are identified in Exhibit No.____ (JAP-21) and

1 are used in developing unitized costs (used to allocate costs) and in subsequently
2 calculating the proposed rate for each lamp wattage range or pole size/type on
3 each lighting schedule.²⁴

4 **Q. How did you develop unitized costs in order to allocate revenue recovery to**
5 **the lighting schedules?**

6 A. The unitized costs are designed to spread the lighting revenue requirement across
7 the lighting schedules based on their characteristics that influence each cost
8 driver.

9 Broadly, the unitized costs fall into these categories:

- 10 • Capital Components: Used to allocate lighting capital costs.
- 11 • Distribution O&M: Used to allocate O&M expense.
- 12 • Customer-Related Overhead: Used to allocate customer-related and A&G
13 expense.
- 14 • Demand Components: Used to allocate demand-related power costs.
- 15 • Commodity Components: Allocate energy-related power costs.

16 Each of these unitized costs, calculated in Exhibit No. ___(JAP-21), represents
17 the amount of revenue that should be recovered from a lamp or pole based on the
18 characteristics of that lamp or pole. For example, line 13 on
19 Exhibit No. ___(JAP-21) shows that the estimated monthly cost per dollar of

²⁴ Or, in the case of Schedule 57, the rate for each connected watt.

1 capital investment in the listed schedules is \$0.00796. So, if the capital
2 investment for a particular lamp size was \$100, the associated monthly costs
3 would be approximately \$0.80 per month.

4 **Q. How were customer-related costs allocated?**

5 A. Customer-related costs were allocated based on kWh. PSE also considered
6 allocating on either the number of customers served or the number of lamps or
7 poles. However, when exploring these options, it quickly became apparent that
8 doing so would create significant and potentially cost-prohibitive rate impacts for
9 certain lighting offerings versus simply spreading these costs on energy, as has
10 been done in the past. Allocating on customers shifts more costs to schedules
11 with relatively fewer lamps per customer (e.g., Schedules 55 and 58), while
12 allocating on lamps shifts more costs to those with lower wattage, creating a
13 potential disincentive for the use of lower wattage lamps. Taking this all into
14 consideration, the Company chose to allocate the customer-related costs on a per
15 kWh basis as it may better promote more energy efficient lighting selections by
16 customers.

17 **Q. How did you use the unitized costs to allocate each category of cost?**

18 A. The costs were allocated by applying the unitized costs to each lamp or pole based
19 on its characteristics. This process was performed for capital costs, O&M costs,
20 customer costs, demand-related costs, and energy-related costs. These allocated
21 costs are then summed to find the total monthly charge for each lamp type, pole

1 type, or (in the case of Schedule 57) connected watt. These total monthly charges,
2 and each of their components, are illustrated in Exhibit No.__(JAP-22).

3 **Q. Has PSE presented the impacts associated with the proposed rates for each**
4 **lighting schedule?**

5 A. Yes, rate impacts for each lighting schedule are presented in Exhibit No.__(JAP-
6 23). Rate impacts are presented as changes in revenue and are shown in two
7 ways, relative to existing base rates and relative to base rates plus adjusting price
8 Schedules 95, 141 and 142, since the lighting rates within these adjusting price
9 schedules will be set to zero as part of the compliance filing in this case.

10 Proposed base rate revenue for lighting schedules in Exhibit No.__(JAP-23) are
11 shown to be 8.34 percent higher than current base rate revenue.²⁵ However, when
12 rate impacts for lighting schedules are presented relative to base rates plus
13 adjusting price Schedules 95, 141 and 142 to zero, the net impact on overall
14 lighting revenue is a 2.91 percent decrease.

15 Between individual schedules, the change in revenue varies greatly, with base rate
16 impacts ranging from a 17.68 percent decrease for Schedule 52 to a 206.28
17 percent increase in the facilities charge for old poles on Schedules 55 & 56.

18 These variations are primarily the result of a more refined cost allocation
19 methodology, where the new methodology allocates more costs based on

²⁵ The small difference in rate impact between this exhibit and Exhibit No.__(JAP-15) is due to rate rounding.

1 contributions to capital, O&M, and demand-related costs. Previously, many of
2 these costs were simply allocated on energy consumption, and as a result of this
3 prior allocation, schedules with very low energy usage now face relatively higher
4 rate increases while schedules with high energy usage face rate decreases.

5 **C. Other Administrative Changes**

6 **Q. Why is PSE removing the “Wattage Including Driver” column from LED**
7 **portions of the lighting schedules?**

8 A. The “Wattage Including Driver” column on Schedules 51, 53, 54, 55 & 56, and 58
9 & 59 contains information that is not informative, nor relevant to customer
10 choice. Consequently, PSE has deemed it superfluous and proposes removing it.

11 **VIII. GAS RATE SPREAD AND RATE DESIGN**

12 **A. Rate Spread**

13 **Q. Please summarize PSE’s gas rate spread proposal.**

14 A. Based on the parity percentages shown in Table 10 and the desire to move toward
15 full parity over time, PSE proposes to: 1) apply the system average increase to
16 those classes with parity percentages between 90 percent and 110 percent
17 (Schedules 23, 16, 53, 41, 41T, 85 and 85T); 2) apply 50 percent of the average
18 increase to those classes between 110 and 150 percent of parity (Schedules 86 and
19 86T); 3) apply no increase to those above 150 percent of parity (Schedules 71, 72
20 and 74); and 4) apply 150 percent of the average increase to those below 90
21 percent of parity (Schedules 31, 31T, 87 and 87T). The proposed revenue

1 allocation by rate class of the proposed \$22.993 million increase is presented on
 2 page one of Exhibit No. ___(JAP-24), and the resulting increases are summarized
 3 in Table 10.

4 **Table 10 - Proposed Gas Base Rate Changes**

Customer Class	Rate Schedule	Proposed Base Rate Changes*	Proposed Margin Changes
Residential	16/23/53	2.7%	4.8%
Commercial & Industrial	31/31T	3.6%	7.3%
Large Volume	41/41T	2.0%	4.8%
Interruptible	85/85T	2.5%	4.8%
Limited Interruptible	86/86T	0.9%	2.4%
Non-exclusive Interruptible	87/87T	2.6%	7.3%
Special Contracts		6.3%	6.3%
Rentals	71/72/74	0.0%	0.0%
Total/System Average		2.8%	5.3%

* Includes gas costs

5 **B. Rate Design**

6 **Q. Please describe PSE's current rate structure for distribution service.**

7 A. The Residential (Schedule 23) and General Service Commercial/Industrial
 8 (Schedules 31, 31T) schedules have only the basic charge and single-block
 9 delivery charges, whereas the Large Volume Commercial/Industrial schedule
 10 (Schedules 41, 41T) and the interruptible schedules (Schedules 85, 85T, 86, 86T,
 11 87 and 87T) have demand charges and multiple block delivery charges in addition
 12 to basic charges. Interruptible sales schedules also have a single-block,

1 volumetric procurement charge.

2 **Q. Please describe the proposed changes to PSE’s natural gas tariff schedules.**

3 A. For each schedule that receives an increase, PSE proposes to increase all charges
4 related to distribution services by an equal percentage. For example, for Schedule
5 31, Commercial and Industrial General Service, the basic charge and delivery
6 charge would increase by the same percentage.²⁶ The primary exceptions to this
7 rule are for demand charges associated with Schedules 41, 85, 86, 87, 41T, 85T,
8 86T and 87T. As discussed further below, PSE is proposing to move each pair of
9 sales and corresponding transportation schedules’ demand charge closer to their
10 cost of service. PSE is also proposing to make cost-based changes to the
11 procurement charges, which are generally very small. Changes to the remaining
12 rate components may vary slightly to achieve the assigned revenue. The proposed
13 rates from basic, demand and volumetric charges are provided in pages 3 through
14 13 of Exhibit No. ____ (JAP-24).

15 **Q. Has PSE prepared new gas tariff schedules based upon the gas cost of service
16 study results and consistent with its rate design proposals in this case?**

17 A. Yes, the proposed gas base tariff schedules are presented in Exhibit No. ____ (JAP-
18 25).

19

²⁶ There may be very small differences due to rounding of rates.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21

1. Residential Gas Rate Design

Q. Please describe the residential natural gas basic charge.

A. The residential natural gas basic charge is applied to customer bills each month. The residential basic charge for gas service of \$10.34 is currently set below the \$15.62 cost of providing this service.

Q. What costs are identified as customer-related in PSE’s gas cost of service study?

A. PSE’s gas cost of service study includes the costs of service lines, meters and regulators and related installation, a portion of general plant, operating and maintenance costs associated with these plant items, customer accounts expenses, a portion of administrative and general costs, and related taxes.

Q. Do these customer-related costs include all fixed gas delivery costs?

A. No. They only include those delivery costs that have been identified as customer-related in the gas cost of service study. Most other delivery costs have been identified as demand-related, which means they vary with the capacity of the distribution system, although most of these costs will continue to be recovered through volumetric rates under PSE’s proposal. These costs are also fixed, but they are not included in the \$15.62 per month of customer-related costs. If all fixed gas distribution costs were included in a monthly basic charge the rate would be considerably higher.

1 **Q. What changes does PSE propose to the residential gas basic charge?**

2 A. Applying the proposed equal percentage increase to the residential class will
3 increase the monthly basic charge to \$11.00 from its current rate of \$10.34, or
4 \$10.29 including the Schedule 141 rate decrease for natural gas.

5 **Q. Is this proposed increase reasonable?**

6 A. Yes, this increase is reasonable for many of the same reasons the proposed
7 increase to the residential electric basic charge is reasonable.

8 First, the current overall residential basic monthly charge of \$10.29 per month,
9 inclusive of Schedule 141, is based on a test year ending June 2012. So, as with
10 the electric basic charge, it is reasonable to expect there would have been cost
11 growth in the intervening time.

12 Second, as noted earlier, PSE's gas cost of service study in this filing supports a
13 basic charge over \$5 per month higher than the basic charge proposed in this
14 filing.

15 Third, PSE has had a rate plan in effect since July 1, 2013 that provided for 2.2
16 percent annual increases to allowed delivery revenue for gas service. However, as
17 a compromise in the development of its decoupling mechanism, PSE has
18 recovered 100 percent of these annual revenue increases through volumetric
19 charges rather than being spread across all rate components, including the basic
20 charge. Had the 2.2 percent increases been applied to the basic charge, the basic
21 charge that will be in effect in 2017 would have been \$11.47 per month.

1 Again, as in the case of the electric basic charge, in deference to the issues
2 routinely raised by low-income and environmental advocates that argue for
3 restraint on increases to the monthly basic residential charge, PSE is proposing a
4 more modest increase than the increase that is supported by the gas cost of service
5 study and the other factors discussed above.

6 **Q. How do PSE's residential gas basic charges compare to the minimum**
7 **monthly charges for residential customers of other utilities?**

8 A. Exhibit No. ___(JAP-26) contains a comparison of the monthly minimum charges
9 and percentile rankings for residential service from 92 natural gas distribution
10 utilities throughout the country. This data was compiled by the American Gas
11 Association for its member utilities. These utilities represent all areas of the
12 contiguous United States and are a comprehensive group for comparison
13 purposes. The average gas residential basic charge is \$15.07 per month. By
14 comparison, PSE's current residential basic charge of \$10.29 per month is in the
15 25th percentile of the 92 companies. In other words, 75 percent of the other
16 surveyed gas distribution companies have residential basic charges higher than
17 PSE's charge. PSE's proposed residential basic charge of \$11.00 per month
18 would only put PSE in the 27th percentile, with 73 percent of the other utilities
19 still having higher basic charges.

20 **Q. What are the proposed rates for residential gas Schedule 23?**

21 A. PSE proposes to increase the residential basic charge from \$10.34 to \$11.00 per
22 month and the delivery charge from \$0.36492 per therm to \$0.38012 per therm.

1 **2. Non-Residential Gas Rate Design**

2 **Q. Does PSE propose any changes to its non-residential gas rate design?**

3 A. Yes. PSE is proposing two changes to its non-residential gas rate design. First,
4 PSE proposes to better align demand charges for non-residential customers with
5 the underlying demand related costs that they are intended to recover. Second,
6 PSE proposes to update and realign its procurement charges to better reflect the
7 recovery of these costs of supply

8 **i. Non-Residential Gas Demand Charges**

9 **Q. What are the current demand rates charged by PSE to non-residential gas**
10 **customers?**

11 A. Non-residential gas customers that have a demand charge on their bill all face the
12 same base demand rate of \$1.15 per therm per month. Depending on the
13 schedule, the billing determinant is based on either (a) their highest daily usage in
14 therms per day from the most recent November 1 through March 31 winter
15 period, or (b) the maximum daily delivery of firm use gas as set forth in the
16 customer’s service agreement.

17 **Q. What are PSE’s proposed demand rate charges for these customers?**

18 A. PSE is proposing to charge different demand charges for different pairs of non-
19 residential gas rate schedules. These proposed rates are summarized in Table 11
20 below.

1

Table 11 - Proposed Non-Residential Gas Demand Charges

Customer Class	Rate Schedule	Current Demand Charge	Proposed Demand Charge
Large Volume	41/41T	\$1.15	\$1.17
Interruptible	85/85T	\$1.15	\$1.20
Limited Interruptible	86/86T	\$1.15	\$1.21
Non-exclusive Interruptible	87/87T	\$1.15	\$1.38
Special Contracts		Per contract	Per Contract

2

3

Q. Why is PSE proposing to differentiate the demand charges for non-residential gas customers?

4

5

A. Beyond the fact that demand charges are generally too low overall, the demand-related costs vary between these rate schedules. PSE is proposing to move each customer class's demand charges closer to recovering their demand-related costs.

6

7

8

Q. Is PSE proposing to move each customer class's demand charge fully to its cost of service?

9

10

A. No. There is a significant variation in demand-related costs for each customer class, with certain classes having much higher demand-related costs than others depending largely on the level of firm use present in the schedule. However, given these significant variations, PSE is proposing to move demand rates incrementally closer to demand costs. Specifically, in the interest of gradualism, PSE is proposing to move the demand charges for all customers 25 percent closer to their full demand-related costs. The one exception is for the Special Contract

11

12

13

14

15

16

1 class whose demand charges are set contractually.

2 **Q. What are the impacts of the proposed changes to the demand charges on**
3 **PSE’s non-residential gas customers?**

4 A. Generally speaking, customers with better load factors or that use less firm
5 service will benefit. The proposed changes may also provide an incentive for
6 more interruptible use, which may benefit all gas customers by potentially
7 deferring new capacity investments

8 **ii. Non-Residential Firm Sales Procurement Charge**

9 **Q. What is the purpose of PSE’s Gas Procurement Charge?**

10 A. This charge is intended to recover the cost associated with procuring and
11 managing gas supply for sales customers. It is also intended to recover the cost
12 associated with PSE’s storage facilities used to manage gas supply for its sales
13 customers.

14 **Q. To whom does this charge currently apply?**

15 A. This charge currently applies to non-residential gas customers served under gas
16 Schedules 85, 86 and 87. This charge was first implemented in 2005 as part of
17 PSE’s 2004 GRC. Prior to that time, these costs were recovered from all
18 customers through base rates.

19

20

1 **Q. What change is PSE proposing with regard to this charge?**

2 A. PSE proposes to extend the application of this charge to non-residential customers
3 served under Schedules 31 and 41. Simultaneously, PSE proposes to eliminate
4 the Gas Procurement Credit for customers served under Schedule 31T and 41T.
5 PSE also proposes to update the Gas Procurement Charge to reflect current costs
6 for each schedule to which it applies.

7 **Q. Why is PSE proposing these changes?**

8 A. PSE is proposing to add this charge to the bills of Schedule 31 and 41 to align
9 better with the rate structure of the interruptible sales schedules that have a similar
10 charge. As currently applied, it is confusing to explain why firm transportation
11 customers get a credit for these procurement costs while interruptible sales
12 customers receive a charge. When this charge was originally proposed in PSE's
13 2004 GRC, it was intended to recover the associated supply-related costs only
14 from sales customers so that these costs were not borne by transportation
15 customers who did not receive the services associated with these costs.

16 When PSE's then-current transportation Schedule 57 was reorganized in its 2007
17 GRC into the current set of parallel rate schedules (i.e., Schedules 31T, 41T, 85T,
18 86T and 87T), PSE's cost of service studies retained the pairing of sales and
19 transportation customers (e.g., Schedule 85 and 85T) to maintain consistent
20 delivery rates for each pairing of parallel schedules. To ensure that the new
21 Schedules 85T, 86T and 87T did not bear the supply-related costs associated with
22 the procurement charge, they were only recovered from their parallel Schedules

1 85, 86 and 87. However, two other transportation schedules were also created in
2 the 2007 GRC (i.e., Schedules 31T and 41T) that did not receive the same
3 treatment. The result has been that, since that time, Schedules 31T and 41T have
4 been absorbing these costs in their delivery charges.²⁷ The current proposal
5 simply corrects this oversight by extending the procurement charge to Schedules
6 31 and 41 so that the procurement-related costs that are allocated to their
7 respective cost of service classes are not absorbed into the shared delivery charges
8 of their paired transportation schedules.

9 **Q. How is the proposed storage charge being calculated?**

10 A. PSE is extending the current methodology for calculating this charge to customers
11 served under Schedules 31 and 41. In simple terms, these rates are calculated by
12 first identifying the allocated gas supply and storage costs allocated to each rate
13 group, subtracting certain cost associated with gas balancing and dividing the total
14 by the group's pro forma sales therms. These calculations are summarized in
15 Exhibit No. ___(JAP-27).

16 **C. Bill Impacts**

17 **Q. What are the impacts of PSE's proposed gas rates in this case?**

18 A. As with the electric bill impacts, this calculation is slightly more complicated than
19 in previous rate cases. As with electric rates, several gas rider schedules will be

²⁷ Service taken under these transportation schedules has grown greatly since they were first created, which has raised the importance of addressing this issue.

1 reset concurrent with the effective date of new base gas rates resulting from this
 2 rate case. Specifically, the impacts of the base gas rate changes must be added to
 3 the impacts of gas rate changes associated with the concurrent changes to PSE's
 4 Schedule 141 (Expedited Rate Filing), Schedule 142 (Revenue Decoupling
 5 Adjustment Mechanism) and Schedule 149 (Cost Recovery Mechanism). The
 6 combined impact of these changes, based on rates currently in effect, is presented
 7 below in Table 12. Exhibit No.__(JAP-28) presents the contributions made by
 8 each of the base and rider rate changes to the overall bill impact. Note, however,
 9 that it is expected that rates within Schedule 142 will be updated on May 1, 2017
 10 and rates within Schedule 149 will be updated on November 1, 2017. So, the
 11 ultimate impacts to customer bills at the time of the compliance filing for this case
 12 will be different than those shown below.

13 **Table 12 – Estimated Gas Bill Impacts from Proposed Base and Rider Rates**

Customer Class	Rate Schedule	Overall Impact
Residential	16/23/53	-2.9%
Commercial & Industrial	31/31T	-1.0%
Large Volume	41/41T	-0.9%
Interruptible	85/85T	-2.7%
Limited Interruptible	86/86T	-1.5%
Non-exclusive Interruptible	87/87T	-2.3%
Special Contracts		0.7%
Rentals	71/72/74	-9.6%
Total/System Average		-2.4%

1 **Q. Please summarize the impacts shown above.**

2 A. The results above show an overall estimated rate decrease of 2.4 percent based on
3 the schedules proposed to be updated as part of this general rate case. Most
4 customer classes will experience rate decreases between one and three percent.
5 The two exceptions are Special Contracts, that would experience a 0.7 percent
6 increase and Rentals, which would experience a 9.6 percent decrease.

7 **D. Other Tariff Changes**

8 **Q. Does PSE propose any other changes to its base natural gas tariffs for non-
9 residential gas customers?**

10 A. Yes. PSE is proposing three changes to its base natural gas tariffs for non-
11 residential gas customers. First, PSE proposes to implement annual maximum
12 volume limitations on Schedules 41 and 41T, effectively requiring customers
13 exceeding these volume limits to take service on Schedule 85 or 85T. Second,
14 and related to the first, PSE proposes to eliminate the existing annual minimum
15 load charge on Schedules 85 and 85T. Third, to ease the transition of customers
16 from Schedules 41 or 41T to Schedules 85 or 85T, PSE proposes to charge fully-
17 firm customers on Schedules 85 and 85T based on their actual demands and to
18 relieve gas sales customers receiving fully-firm service of the obligation to sign a
19 separate customer agreement for service under these schedules.

20

21

1 **1. Schedule 41 and 41T Maximum Volumes**

2 **Q. What are the current eligibility standards for service under Schedules 41 and**
3 **41T?**

4 A. Customers served under these schedules must have either had a minimum of
5 12,000 therms of use over the previous 12-consecutive month period or, if the
6 customer is new to PSE, the eligibility standard requires that this customer be
7 expected to use 12,000 therms over the initial 12-consecutive month period.
8 There is no maximum usage threshold for service under this schedule.

9 **Q. Why is PSE now proposing to add a maximum usage threshold for service**
10 **under this schedule?**

11 A. Customers currently served under Schedule 41 and 41T that exceed the minimum
12 threshold for eligibility under Schedule 85 or 85T are paying rates that are
13 different for firm service than they would pay under Schedules 85 or 85T. There
14 is no sound policy reason for customers on different schedules that are receiving
15 substantially the same service (i.e., fully firm gas delivery service) to pay
16 different rates. In fact, state law prohibits such discriminatory pricing.

17 **Q. How many customers currently served under Schedules 41 or 41T are**
18 **eligible for service under Schedules 85 or 85T?**

19 A. Based on test year usage and customer statistics, 92 customers served under
20 Schedules 41 or 41T are also eligible for service under Schedules 85 and 85T.

1 **Q. If their rates would be lower, why aren't these eligible PSE customers**
2 **requesting to switch from Schedules 41 and 41 to Schedules 85 or 85T?**

3 A. This isn't clear. One issue may be the annual minimum load charge that is
4 currently assessed under Schedules 85 and 85T. However, it appears that the
5 minimum load charge would only impact a small subset of eligible customers. It
6 may also be related to the fact that moving to Schedule 85 or 85T requires a
7 separate customer agreement and a specified level of contract demand, whereas
8 service under Schedule 41 or 41T requires no such customer agreement and
9 customers are only charged for what they use under these firm schedules, not for
10 the capacity that they have reserved. Whatever the reason, they are making
11 choices that don't appear to be financially advantageous.

12 **Q. Should it be PSE's responsibility to make these choices for its non-residential**
13 **gas customers?**

14 A. Yes. While choices about whether to take sales or transportation service and
15 whether to take firm or interruptible service should be completely left to the
16 customer, once those choices are made it is better rate policy to not promote rate
17 structures that create winners or losers among otherwise identical customers
18 simply because of the particular tariff under which they take service. It has been
19 our experience in talking with customers that, for all but a handful of the largest
20 and most sophisticated customers, they simply don't have the time or expertise to
21 choose between schedules that offer essentially the same service. PSE's proposal

1 relieves our customers of this burden in this particular instance.²⁸

2 **Q. How would PSE’s proposal to set a maximum usage threshold on Schedules**
3 **41 and 41T work in practice?**

4 A. It would operate very much like the non-residential electric schedules operate,
5 where customers often must fall within minimum and maximum usage thresholds
6 to qualify for the schedule under which they are served. In practice, the
7 customer’s usage would be evaluated on a rolling 12-month basis to determine
8 ongoing eligibility and customers would be automatically moved to the
9 appropriate schedules when they are no longer eligible.²⁹ For customers that are
10 moved from Schedule 41 to 85, no service agreement will be required and they
11 will continue to be billed on actual usage, rather than contract demand. The only
12 difference they will see is the Schedule 85 rates. Similarly, for customers that are
13 moved from Schedule 41T to 85T, their existing service agreements will be rolled
14 over to service under Schedule 85T and, as with the sales customers, they will
15 continue to be billed on actual usage, rather than contract demand.

16 **Q. Is the proposed migration of Schedule 41 and 41T customers to Schedules 85**
17 **and 85T reflected in PSE’s pro forma revenues?**

18 A. Yes, as discussed in the section on gas pro forma revenue, this is one of the

²⁸ Decisions as to whether to take firm or interruptible service, or sales or transportation service will continue to be the customers’ responsibility, not PSE’s.

²⁹ Movement between schedules will continue to be limited to no more than once per 12 month period, per PSE’s Rule 4.

1 adjustments made to pro forma revenue.

2 **2. Schedule 85 and 85T Annual Minimum Load Charge**

3 **Q. How is the Annual Minimum Load Charge currently calculated for**
4 **Schedules 85 and 85T?**

5 A. The Annual Minimum Load Charge is calculated as the positive difference
6 between the Minimum Annual Therms less actual total annual therms delivered
7 multiplied by the initial block of the total interruptible delivery service charge or
8 total transportation service commodity charge. This calculation is performed on
9 each anniversary of the effective date of the customer's service agreement under
10 this schedule. The Minimum Annual Therms is currently set at 180,000 therms
11 per year.

12 **Q. What change is PSE proposing to this calculation?**

13 A. PSE is proposing to eliminate the Minimum Annual Therms used to calculate the
14 Annual Minimum Load Charge.

15 **Q. Why is PSE proposing to eliminate this charge?**

16 A. With PSE's proposal that customers maintain at least 150,000 therms of annual
17 usage to qualify for service under Schedules 85 or 85T, there is no longer a need
18 to charge them for usage under this level. Originally, this minimum charge was
19 meant as an economic incentive for customers to only elect service under these
20 schedules when they were sufficiently large enough for the lower rates on this
21 schedule to outweigh their potential minimum charges. As discussed above, PSE

1 has found evidence that non-economic choices continue to be made. Moreover,
2 implementing this charge would seem unnecessarily punitive when customers are
3 already being removed from service under the schedule. So, in concert with its
4 proposal to require a minimum level of usage to be eligible for service under these
5 schedules, PSE is also proposing to remove this unneeded charge.

6 **Q. How many customers are expected to be impacted by this change?**

7 A. For the test year, only nine customers were impacted, and the total bill impact was
8 \$66,190 combined for all customers.

9 **Q. Has PSE reflected the impact of this change in its pro forma revenues?**

10 A. No. Given this very small amount of potential revenue, no specific adjustments
11 were made to pro forma revenue for this proposed change.

12 **3. Schedule 85 and 85T Demand Charge for Firm Service**

13 **Q. Is PSE proposing any other changes to Schedules 85 and 85T to**
14 **accommodate its proposed changes to Schedules 41 and 41T?**

15 A. Yes, Schedules 85 and 85T will both have a proposed provision in the pricing
16 section of these tariffs to allow for the billing of demand charges for fully firm
17 customers based on actual demands³⁰ rather than contract demands. These
18 proposed changes have been included as part of the proposed tariff revisions in

³⁰ Here, “actual demands” are defined to be the customer’s highest daily usage in therms per day from the month in which occurs the Company’s coincident peak day from the most recent November 1 through March 31 winter period.

1 Exhibit No. ____ (JAP-25).

2 **Q. Why is PSE making this proposal?**

3 A. The intent of this proposal is to facilitate transitions between Schedules 41 or 41T
4 to Schedules 85 or 85T, both from the customer and Company perspective. From
5 the customer perspective, fully firm customers will continue to be charged for
6 monthly demands on the same basis regardless of the schedules. From the
7 customer's and Company's perspective, allowing fully firm gas sales customers to
8 be charged for monthly demands based on actual demands, rather than contract
9 demands, eliminates the need for a service agreement, reducing the potential
10 administrative complexity to both parties of providing service to these customers
11 under Schedule 85.

12 **IX. REVIEW OF AND PROPOSED CHANGES TO PSE'S**
13 **ELECTRIC AND GAS DECOUPLING MECHANISMS**

14 **A. Overview of Existing Mechanisms**

15 **Q. What is a revenue decoupling mechanism and what is its purpose?**

16 A. As described in the Commission's *Report and Policy Statement on Regulatory*
17 *Mechanisms, Including Decoupling, To Encourage Utilities To Meet Or Exceed*
18 *Their Conservation Targets*³¹ ("Decoupling Policy Statement"), decoupling is "a
19 means to separate a utility's recovery of costs and return from the amount of

³¹ Docket U-100522 (November 4, 2010).

1 energy it sells.”³² As the Commission noted in its order originally approving
2 PSE’s mechanisms, decoupling “removes the so-called throughput incentive, thus
3 promoting PSE’s more aggressive pursuit of cost-effective conservation.”³³

4 **Q. How do PSE’s revenue decoupling mechanisms generally operate?**

5 A. Like many decoupling mechanisms approved for other utilities, PSE’s mechanism
6 links its allowed revenue to the number of customers it serves. It also currently
7 pertains only to PSE’s delivery system costs, not the cost of supply. Specifically,
8 PSE’s mechanisms calculate the Company’s allowed delivery revenue as the
9 product of its monthly allowed delivery revenue per customer multiplied by the
10 number of customers served in each month and for each decoupling rate group.
11 Each month and for each decoupling rate group, PSE defers the difference
12 between its allowed delivery revenue and actual delivery revenue, including
13 effects of weather, and trues up this amount in the following year in the
14 Company’s annual Schedule 142 rate filing. Allowed delivery revenue per
15 customer is shaped by month to, ideally, minimize fluctuations in the monthly
16 deferrals. Also noteworthy is that PSE’s allowed delivery revenue per customer
17 has grown annually by a “K-factor” (3.0 percent for electric customers and 2.2
18 percent for gas customers).

19 **Q. What rate classes are in each of the decoupling mechanisms’ rate groups?**

³² *Id.* at ¶ 7.

³³ Dockets UE-121697 and UG-121705, Consolidated (“the Decoupling Case”), Order 7, Synopsis.

1 A. For the electric decoupling mechanism, there are currently four rate groups: (i)
2 Residential, (ii) Schedules 12 and 26, (iii) Schedules 10 and 31, and (iv) a group
3 comprised of Schedules 8, 11, 24, 25, 29, 40, 43, 46 and 49. As discussed in
4 more detail below, it is worth noting that Schedules 10, 12, 26 and 31 were
5 originally included in the same rate group as the other non-residential customers.
6 However, as part of a settlement related to petitions for reconsideration of the
7 Commission's original approval of the decoupling mechanisms, the new rate
8 groups were formed and certain concurrent rate design changes were approved
9 and went into effect beginning January 1, 2014.³⁴ The rate design changes
10 increased demand charges for these customers so that the decoupling mechanism
11 could use demand charge revenue as the basis for determining their actual
12 delivery revenue used in the decoupling deferral calculation.³⁵

13 For PSE's gas decoupling mechanism there are currently two rate groups:
14 Residential and Non-Residential, which currently include customers served under
15 Schedules 31, 31T, 41, 41T, 86 and 86T. As also discussed further below,
16 customers in Schedules 85, 85T, 87 and 87T were included in the gas decoupling
17 mechanism for the first six month of its operation and, as a result of the settlement
18 of the petitions for reconsideration of the original order approving PSE's
19 decoupling mechanism, were excluded from the gas decoupling mechanism

³⁴ Decoupling Case, Order 9.

³⁵ *Id.*

1 effective January 1, 2014.³⁶

2 **Q. Are there any customer protections in place with PSE's decoupling**
3 **mechanisms?**

4 A. Yes. As part of the approval of its decoupling mechanisms, PSE proposed and the
5 Commission approved (with minor modification) an Earnings Test, a Rate Test,
6 increased funding for low-income customers and a condition to conduct a third-
7 party review of these mechanisms on or before the filing of the Company's next
8 GRC. The Earnings Test shares 50 percent of the amount PSE earns in excess of
9 its authorized 7.77 percent rate of return.³⁷ The Rate Test ensures that customers
10 will not experience more than a three percent increase in rates each year as a
11 result of the decoupling mechanism.³⁸ Low-income customers received a \$1
12 million increase in annual bill assistance, as well as an additional \$500,000 in
13 annual low-income weatherization funding and an additional \$100,000 per year of
14 shareholder funding for these weatherization programs. Finally, PSE committed
15 to conducting a third-party review of its decoupling mechanism to review its

³⁶ *Id.* Note also that a portion of the decoupling deferrals that accrued in 2013 were allocated to these departing customers. So, from May 1, 2014 through April 30, 2015, these customers were only subject to the payment of their allocated decoupling deferral balances, but no new deferrals were accumulated for these customers.

³⁷ PSE originally proposed a 50 basis point deadband before sharing earnings with customers. In Order 7 of the Decoupling Case, the Commission eliminated this deadband, reasoning in paragraph 25 that the Company's authorized return was already "at the high end of what we presently perceive to be within the range of reasonableness."

³⁸ The Rate Test operates as a "soft cap," where amounts not recovered due to the limitations on rate increases are allowed to be recovered in a subsequent rate period.

1 operation, impacts on bills and conservation achievement and to potentially
2 identify any unintended consequences associated with either decoupling
3 mechanism. This review is discussed later in this testimony.

4 **Q. What other benefits have customers received as a result of PSE's decoupling**
5 **mechanisms?**

6 A. PSE customers received additional benefit from the approval of the Company's
7 decoupling mechanisms through more conservation. Specifically, PSE committed
8 to achieving five percent more conservation than required by RCW 19.285 in
9 each two-year reporting biennium. In addition, PSE committed to participate in a
10 gas market transformation study that was proposed by the Northwest Energy
11 Efficiency Alliance ("NEEA").

12 **Q. Did PSE follow through on these conservation-related commitments?**

13 A. Yes. In the amended decoupling petition, PSE committed to exceed its statutory
14 electric conservation achievement by five percent. As reported in its 2014-2015
15 Biennial Conservation Report, PSE exceeded this statutory requirement by over
16 eight percent. PSE has also built its five percent commitment into its 2016-17
17 Biennial Conservation Plan. This will result in an additional 27,993 MWh of
18 conservation savings over this biennial period.³⁹ In addition, PSE fulfilled its
19 natural gas commitment to participate in NEEA's recent gas market

³⁹ See Table 1c: Building the 2017-2017 Electric Target in the Executive Summary of PSE's 2016-2017 Biennial Conservation Plan.

1 transformation efforts.

2 **Q. Please explain more about how PSE fulfilled its commitment regarding the**
3 **NEEA gas market transformation effort.**

4 A. PSE is actively involved in this effort. For example, it is a major funder of this
5 initiative, committing to contribute \$7.6 million or (41 percent) of the initiative
6 costs. PSE also helped develop the related business plan, committee governance
7 and measure selection for this initiative. It also participates on NEEA's Natural
8 Gas Advisory Committee.

9 **Q. Has there been any tangible results from this effort?**

10 A. Yes. The business plan is well into the implementation phase and the committee
11 selected five measures that it believes to have the best chance of impacting the
12 market over the next few years. These include gas-fired heat pump water heaters;
13 hearth products, combination space/water heating systems; rooftop heating,
14 ventilation and air conditioning ("HVAC") systems; and gas clothes dryers.

15 **Q. Can you please summarize again the several changes that were made to**
16 **PSE's decoupling mechanisms since they were originally approved in 2013?**

17 A. Yes, as mentioned above, the current mechanisms have already evolved
18 somewhat since their original approval in 2013. Schedules 10, 12, 26 and 31
19 were moved into separate electric decoupling rate groups. Schedules 85/85T and
20 87/87T were removed from the gas decoupling mechanism. In addition, the
21 calculation of "actual" margin revenue was corrected to remove revenue

1 associated with the amortization of prior year deferrals.⁴⁰

2 **Q. Why were Schedules 26 and 31 moved to separate electric decoupling rate**
3 **groups?**

4 A. In their petition for reconsideration of Order 7 in the Decoupling Case, advocates
5 for customers served under these schedules called for a rate design alternative to
6 decoupling. Specifically, they called for higher demand charges (with revenue
7 neutral reductions in energy charges) to address PSE's fixed cost recovery
8 challenges, theorizing that these charges produced more fixed revenue. PSE
9 argued that demand charges, while producing more stable revenues than energy
10 charges, were still subject to variation and, importantly, the impacts of
11 conservation. The approved change was a compromise, where demand charges
12 were increased and the decoupling deferrals were calculated based on actual
13 delivery revenue recovered from demand charges rather than energy sales. To the
14 extent that advocates for these customers were correct in their claims that demand
15 charge revenues were "fixed," there would be little or no decoupling deferrals
16 and, hence, no material impact from their inclusion in standalone decoupling rate
17 groups. However, these decoupling rate groups still generated revenue deferrals
18 due to lower billed demands per customer.⁴¹ As such, and as discussed below,

⁴⁰ Decoupling Case, Order 14.

⁴¹ Since the start of the decoupling mechanism through November 2016, PSE has deferred approximately \$1.8 million for Schedules 12 and 26, and \$1.9 million for Schedules 10 and 31 in each of these decoupling rate groups.

1 PSE proposes that these customers continue to be included in the electric
2 decoupling mechanism.

3 **Q. Why were the sales and transportation customers served under Schedules 85**
4 **and 87 removed from the gas decoupling mechanism?**

5 A. As discussed in Order 9 in the Decoupling Case, the marginal volumetric revenue
6 associated with these customers is so low that variations in their average use per
7 customer do not generate significant deviations in revenue.⁴² With only a very
8 modest throughput incentive, PSE agreed to propose, and the Commission
9 subsequently approved, that they be excluded from the gas decoupling
10 mechanism.

11 **Q. Please explain the correction made to the original calculation of actual**
12 **margin revenue.**

13 A. In the original construction of PSE's decoupling mechanisms, the derivation of
14 actual delivery revenue included both the actual revenue required to recover its
15 delivery costs, but also the revenue required to amortize past differences between
16 allowed and actual delivery revenue. This calculation created a problem of
17 circularity where current year deferrals were impacted by the amortization of
18 prior year deferrals. Since PSE's decoupling mechanisms initially had no deferral
19 to true-up, this problem of circularity went undetected when originally approved.

⁴² Decoupling Case, Order 9, ¶¶ 41-44.

1 However, as PSE began work on its decoupling true-up filing in early 2015, this
2 issue was discovered. On March 31, 2015, PSE filed in the decoupling docket to
3 correct this issue, removing the amortization of prior year deferrals in the
4 calculation of current year deferrals, and it was approved by the Commission in
5 Order 14 on April 22, 2015. The net effect of this correction reduced the rates to
6 customers that became effective May 1, 2015; the corrected rates were \$12
7 million lower than they would have been without this correction.

8 **B. Review of Operation of the Decoupling Mechanisms**

9 **Q. How have the electric and gas decoupling mechanisms generally performed?**

10 A. With the exception of the correction to the calculation of actual delivery revenue
11 above, the mechanisms have generally performed consistent with expectations.
12 However, given the particularly unusual weather experienced in PSE's service
13 area since approval of these mechanisms, there have been a few lessons learned
14 along the way.

15 **Q. What lessons have you learned in PSE's three and a half years of experience
16 with these mechanisms?**

17 A. As expected when piloting new rate mechanisms, there are bound to be a few
18 lessons learned along the way. Some of the most noteworthy include the
19 following.

20 (1) Rate Test: With sustained warm winter weather, deferrals can grow rapidly,
21 triggering the three percent Rate Test and leading to lower current year

1 revenue.

2 (2) Earnings Test: PSE's Earnings Test has been returning revenue to customers
3 even though the Company has not generally been exceeding its authorized
4 ROE.

5 (3) Rate Groupings: Certain decoupling rate groups that are currently aggregated
6 could reasonably be disaggregated to address some potential cost shifting that
7 may be occurring between rate schedules within the decoupling mechanisms.

8 These three issues are discussed in more detail below. I also make
9 recommendations for changes to the decoupling mechanism based on these, and
10 other, factors later in my testimony.

11 **1. Rate Test Challenges**

12 **Q. Please explain more about the challenges created by the three percent Rate**
13 **Test.**

14 A. The intent of the Rate Test was to mitigate potential rate volatility associated with
15 PSE's decoupling mechanisms. In operation, to the extent that decoupling-related
16 rate adjustments would exceed three percent, PSE limits the amortization of prior
17 year deferrals to limit the rate increase to three percent and recovers any
18 unrecovered amounts in subsequent rate periods. The challenge created by this
19 approach to mitigating rate volatility arises when the Rate Test is triggered and
20 deferrals are left on the balance sheet increasing the likelihood that they will not
21 be recovered within a 24 month period.

1 **Q. Why is this a problem?**

2 A. Generally accepted accounting practice (“GAAP”) requires revenue to be
3 recovered within 24 months of the time they are accrued to be recognized as
4 current year revenue. Due to this requirement, and given the significant deferred
5 balances that have accumulated for certain decoupling rate groups, PSE could not
6 recognize \$10.0 million as revenue for calendar year 2015 even though the
7 revenue was “allowed” for recovery by the Commission through the allowed
8 revenue per customer. By extension, not being able to recognize these revenues
9 in 2015 also reduced recognized earnings for the utility. These unrecognized
10 earnings were not foreseen when PSE’s decoupling mechanisms were originally
11 proposed and this outcome runs counter to addressing the Company’s throughput
12 incentive. Indeed, under this scenario, PSE would welcome higher loads to
13 absorb the decoupling deferrals that the Company cannot recognize as current
14 year revenue under GAAP rules.

15 **2. Earnings Test Challenges**

16 **Q. Has PSE experienced other issues with the application of this Earnings Test?**

17 A. Yes, these are discussed in the Prefiled Direct Testimony of Daniel A. Doyle,
18 Exhibit No. ___(DAD-1T). However, they have been referenced here for the sake
19 of increased clarity as to PSE’s proposed changes to its decoupling mechanisms.
20 As noted in Mr. Doyle’s testimony, PSE proposes to continue to the use of an
21 Earnings Test, but recommends that, for revenue sharing purposes, all
22 normalizing adjustments to actual results be excluded and all conforming

1 adjustments be retained for calculating operating income.⁴³

2 **3. Opportunities to Improve Rate Groupings**

3 **Q. Please explain how the decoupling rate groups could be rearranged to**
4 **reasonably reduce potential cost shifting.**

5 A. As discussed earlier, a certain amount of rearranging of the decoupling rate
6 groups has already occurred since the inception of these mechanisms. However,
7 recognizing that it may also slightly increase the potential for greater decoupling-
8 related rate volatility, a few additional changes may be warranted to reduce
9 potential cost shifting.

10 First, advocates for customers served under electric Schedules 40, 46 and 49
11 vigorously fought against their inclusion in PSE's electric decoupling mechanism
12 when originally proposed. They were unwilling to discuss the potential for
13 separate rate group treatment at a time when other customer groups proposed and
14 were granted such treatment (e.g., for customers served under Schedules 26 and
15 31). The unfortunate outcome was that very large electric customers were
16 combined into a single rate group with the smallest non-residential customers.
17 Given the very significant operational and usage characteristic differences of
18 PSE's largest and smallest non-residential customer groups, it is apparent that
19 these groups, at a minimum, should be disaggregated.

20 Second, even among the smaller non-commercial customer groups, those that are

⁴³ Exhibit No. ___(DAD-1T), Section IV.

1
2
3
4
5
6
7
8
9
10

served under PSE’s small commercial electric and gas rate schedules, electric Schedule 24 and gas Schedule 31, respectively, tend to dominate the results for the rest of the customers in their decoupling rate groups. For that reason, and the fact that the sheer size of these customer groups is large enough to justify a separate decoupling rate group, these two small commercial classes could reasonably be separated from other non-residential customers in the decoupling rate groups.

Q. Do you have any analysis to support the rearrangement of the decoupling rate groups?

A. Yes, this is provided below in Table 13.

1
2

Table 13 – Change in Use Per Customer by Rate Schedule from ERF Test Year Levels

	ERF Test Year				% Difference from ERF		
	July 2011 - June 2012	July 2013 - June 2014	July 2014 - June 2015	July 2015 - June 2016	July 2013 - June 2014	July 2014 - June 2015	July 2015 - June 2016
Electric (kWh)							
<u>Residential Group:</u>							
Schedule 7	11,220	11,084	10,419	10,500	-1.2%	-7.1%	-6.4%
<u>Non-Residential Group:</u>							
Schedules 8 & 24	23,085	23,285	23,194	23,510	0.9%	0.5%	1.8%
Schedules 11 & 25	406,765	410,356	404,345	401,071	0.9%	-0.6%	-1.4%
Schedule 29	22,415	23,509	27,933	26,625	4.9%	24.6%	18.8%
Schedule 35	4,067,400	4,493,400	5,326,800	4,809,000	10.5%	31.0%	18.2%
Schedule 40	6,314,895	5,333,950	5,051,183	4,896,400	-15.5%	-20.0%	-22.5%
Schedule 43	795,123	793,230	704,084	731,942	-0.2%	-11.4%	-7.9%
Schedule 46 & 49	30,449,562	25,513,322	26,297,965	24,928,979	-16.2%	-13.6%	-18.1%
<u>Schedule 12 & 26 Group:</u>							
Schedules 12 & 26*	5,839	-	5,894	5,898		0.9%	1.0%
<u>Schedule 10 & 31 Group:</u>							
Schedules 10 & 31*	6,722	-	6,735	6,858		0.2%	2.0%
Gas (Therms)							
<u>Residential Group:</u>							
Schedules 23 & 53	795	787	649	697	-1.0%	-18.4%	-12.4%
<u>Non-Residential Group:</u>							
Schedule 31	3,752	3,846	3,294	3,538	2.5%	-12.2%	-5.7%
Schedule 31T		18,895	23,253	9,856			
Schedule 41	40,184	50,299	44,635	46,920	25.2%	11.1%	16.8%
Schedule 41T	176,110	174,966	171,572	177,443	-0.6%	-2.6%	0.8%
Schedule 86	40,232	36,198	31,324	35,050	-10.0%	-22.1%	-12.9%
Schedule 86T	26,572	86,501	103,223	116,433	225.5%	288.5%	338.2%

* Volumes are KW

3

4

Q. What do the results in Table 13 show?

5

A. Note that the need for decoupling is largely driven by changes in use per customer from test year levels and, as noted earlier, it is appropriate to group customers with relatively similar use per customer to mitigate potential cost shifting. Table 13 details the change in actual annual use per customer for the years ending June 2014, 2015 and 2016 compared to the ERF test year that set the baseline for the

6

7

8

9

1 decoupling mechanisms.

2 For electric non-residential customers, actual use per customer for Schedules 8,
3 24, 29 and 35 have actually risen slightly from test year levels. Actual use per
4 customer for Schedules 11 and 25 has been relatively close to test year levels with
5 usage in the first year slightly over test year levels and usage during the next two
6 years slightly below test year levels. Lastly, actual use per customer for Schedule
7 43 has been below test year levels, while use per customer for Schedules 40, 46
8 and 49 has declined significantly. The results from the last three years support the
9 argument that, not only should they remain in the decoupling mechanism,
10 customers served under Schedules 40, 46 and 49 should be in their own rate group
11 to reduce cost shifting to other customer groups.

12 For gas non-residential customers, actual use per customer for Schedules 41 and
13 86T was significantly higher than test year levels for the first three years of the
14 decoupling mechanism. For Schedule 31, use per customer was higher for the
15 first year but lower than test year levels for the next two years. For Schedule 41T,
16 use per customer has been relatively close to test year levels with slightly lower
17 use in the first two years and slightly higher in the last year. Actual use per
18 customer for Schedule 86 has been significantly lower than test year levels. As
19 discussed above, since Schedules 31 and 31T tend to dominate the results in the
20 current non-residential gas decoupling group, the use per customer results indicate
21 that putting these schedules into their own rate group would help minimize
22 potential cost shifting.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17

4. Third Party Review of Decoupling Mechanisms

Q. Were there any other lessons learned as a result of PSE’s obligation to have a third-party review of its decoupling mechanisms?

A. Yes, a copy of this report is provided in Exhibit No.__(JAP-29). The lead author was H. Gil Peach & Associates LLC, with assistance from Forefront Economics, Inc. and Joseph Associates, Inc. Hereafter this will be referred to as the Gil Peach Report.

Q. What period was covered by this report?

A. The Gil Peach Report covered the three-year period between July 1, 2013, when the mechanisms were originally approved, and June 30, 2016.⁴⁴

Q. What issues did the Gil Peach Report address?

- A. The Gil Peach Report addressed the following seven basic issues:
- i) Were the decoupling deferrals and rates calculated in accordance with the Commission Order?
 - ii) What were the impacts of the decoupling tariff tracker adjustments?
 - iii) What were the impacts of the decoupling mechanisms on low-income residential customers?

⁴⁴ Note that, at the request of stakeholders, a report covering the first two years of the mechanism was filed in Dockets UE-121697 and UG-121705 on June 6, 2017.

1 iv) Were there any conclusive trends in conservation program performance
2 associated with the decoupling mechanisms?

3 v) Were there any adverse impacts associated with decoupling?

4 vi) Given the growth in deferred revenue for residential natural gas service, when
5 are these likely to be recovered in rates and what are the likely impacts?

6 vii) Were there any impacts on the conservation achievement for customers served
7 under electric Schedules 26 and 31?

8 **Q. According to the Gil Peach Report, were PSE's decoupling deferrals and**
9 **rates calculated in accordance with Commission Orders?**

10 A. Yes. The Gil Peach Report confirms that PSE calculated its decoupling rates and
11 deferrals in accordance with Commission orders.

12 **Q. According to the Gil Peach Report, what were the overall impacts of the**
13 **decoupling tariff tracker adjustments?**

14 A. The Gil Peach Report finds that the overall impacts so far have been small for
15 electric customers and most natural gas customers, with rate increases generally
16 below the three percent cap associated with the Rate Test.⁴⁵ However, the report
17 notes that the three percent cap associated with the Rate Test was exceeded three
18 times over the three-year evaluation, once for electric Schedules 10 & 31 and

⁴⁵ The Rate Test ensures that any annual decoupling-related rate adjustment does not exceed three percent. Any unrecovered amounts continue to be deferred for later recovery.

1 twice for gas residential Schedule 23. By limiting the rate increases to three
2 percent for residential customers in these instances, the deferred balances for gas
3 residential customers have reached such a level, due to the unusually warm
4 winters experienced over the evaluation period, that the report recommends that
5 the Rate Test for gas residential customers be increased from the current three
6 percent cap to a five percent cap. This would allow for a more accelerated
7 amortization of their accumulated deferred revenue balances.

8 **Q. What did the Gil Peach Report conclude regarding the impact of the**
9 **decoupling mechanisms on low-income customers?**

10 A. As with the overall impacts, the report finds the decoupling mechanisms to have a
11 very small impact on low-income customers, where these customers were defined
12 to be those customers that received bill assistance from PSE during the evaluation
13 period. However, during the evaluation period, the report also concluded that
14 low-income customers saw changes to their conservation funding, with
15 significantly more funding for electric conservation and less for gas conservation
16 (largely due to the diminished cost-effectiveness of natural gas conservation
17 programs given the continued downward trends in natural gas prices).

18 **Q. Did the Gil Peach Report find any conclusive trends in conservation program**
19 **performance during the evaluation period?**

20 A. It did not. Rather, it found overall stable performance of PSE's conservation
21 programs during the evaluation period and views the removal of the throughput

1 incentive as a positive step in removing barriers to energy efficiency performance.

2 **Q. Did the Gil Peach Report find any adverse impacts associated with PSE's**
3 **decoupling mechanism?**

4 A. The report did not identify any adverse impacts, although it acknowledged that
5 this may be a matter of perspective. The report noted concerns over the growing
6 deferred balances for gas residential customers, but then goes on to note that the
7 mechanism is operating as planned. It also found PSE's overall service quality
8 metrics to be satisfactory, while also noting that certain metrics were out of range
9 for 2015. The report interpreted those events as being due to weather events, but
10 suggested that they be watched for 2016 and 2017 to be sure they were in-fact
11 one-time events. Finally, the report called out improved attitudes of executive
12 management towards exceeding its conservation targets and slowing growth in
13 O&M costs as possible beneficial impacts associated with the decoupling
14 mechanism and rate plan.

15 **Q. What did the Gil Peach Report conclude about the growing balance of**
16 **deferred revenues for residential natural gas service?**

17 A. The report suggests that these growing balances may be a potential problem for
18 both the customers in this rate group and for PSE and recommends adjusting the
19 Rate Test upward from a three percent cap to a five percent cap. This will allow
20 the decoupling mechanism to clear balances in most years while still protecting
21 customers from extreme rate changes. It will also better align incurred costs and

1 revenue collection.

2 **Q. Did the Gil Peach Report find any impact on conservation achievement for**
3 **customers served under electric Schedules 26 or 31?**

4 A. No. The report concluded that conservation for these customers proceeded as
5 business as usual.

6 **5. Other Lessons Learned About Existing Decoupling**
7 **Mechanisms**

8 **Q. Were there other lessons learned by PSE over the course of its experience**
9 **with its decoupling mechanisms?**

10 A. Yes. As illustrated in Table 13 above, PSE has observed that the customers
11 whose revenues are decoupled from kW demands, rather than kWh sales,⁴⁶ have
12 still experienced changes in kW demands per customer from test year levels over
13 the course of the electric decoupling mechanism. This suggests that a throughput
14 incentive would still exist in the absence of decoupling and, therefore, continuing
15 to include these customers within the electric decoupling mechanism is
16 appropriate.

17 **C. Proposed Changes to Mechanisms**

18 **Q. Is PSE proposing to continue its electric and gas decoupling mechanisms?**

19 A. Yes, it is. Despite some of the challenges noted above, the mechanisms have

⁴⁶ This includes electric Schedules 10, 12, 26 and 31.

1 generally performed well. Mitigating PSE's throughput incentive, particularly in a
2 time of continued stagnant load growth, continues to be in the public interest, and
3 PSE proposes to continue the decoupling mechanisms.

4 **Q. Has PSE prepared exhibits illustrating the proposed calculations for the new**
5 **electric and gas decoupling mechanisms?**

6 A. Yes. Calculations associated with PSE's electric decoupling mechanism are
7 provided in Exhibit No.__(JAP-30). Calculations associated with PSE's gas
8 decoupling mechanism are provided in Exhibit No.__(JAP-31).

9 **Q. Given all that PSE has learned and observed since the decoupling**
10 **mechanisms were approved, what changes is PSE proposing to its decoupling**
11 **mechanisms?**

12 A. There are four significant changes being proposed to the decoupling mechanisms.
13 First, PSE proposes to move its fixed power costs into the electric decoupling
14 mechanism. Second, PSE proposes to realign its non-residential electric and
15 natural gas decoupling rate groups. Third, PSE proposes to change the operation
16 of the decoupling Rate Tests. Fourth, PSE proposes to modify the operation of
17 the decoupling Earnings Tests. The remainder of the proposed changes to the
18 decoupling mechanisms are essentially housekeeping changes intended to
19 improve the operation of these mechanisms with little or no impact on customers
20 or their rates.

1 **1. Move Fixed Power Costs into the Electric Decoupling**
2 **Mechanism**

3 **Q. Why is PSE proposing to move fixed power costs into its electric decoupling**
4 **mechanism?**

5 A. This proposal is the result of the PCA settlement stipulation approved in Docket
6 UE-130617, in which the parties agreed that if PSE's electric decoupling
7 mechanism continues after its review in this general rate case that the mechanism
8 would include the recovery of fixed power costs in addition to delivery costs.
9 Including fixed power costs in the electric decoupling mechanism further
10 eliminates PSE's throughput incentive for electric service. As PSE is proposing to
11 continue its electric decoupling mechanism in this case, it is also proposing to
12 move fixed power costs into the mechanisms in accordance with the settlement
13 stipulation.

14 **Q. When does the settlement stipulation approved in Docket UE-130617 require**
15 **PSE to remove fixed power costs from the PCA mechanism?**

16 A. Item 4 of page 7 of the settlement stipulation requires PSE to remove fixed power
17 costs from the PCA mechanism on January 1, 2017 and allowed PSE to file an
18 accounting petition to request deferral of revenue variances associated with the
19 recovery of fixed power costs to bridge the period between implementation of the
20 changes to the PCA mechanism on January 1, 2017 and the start of the rate year
21 for PSE's next general rate case.

1 **Q. Did PSE file for an accounting petition to defer revenues associated with the**
2 **recovery of fixed power costs?**

3 A. Yes, on September 30, 2016 PSE filed an accounting petition to defer revenue
4 variances associated with fixed power costs. On November 10, 2016 the
5 Commission approved the petition which allows PSE to defer these revenues until
6 December 31, 2017 when rates from this GRC go into effect.

7 **Q. How does PSE propose to allocate these amounts deferred for calendar year**
8 **2017 to the decoupling groups if the decoupling of fixed power costs is**
9 **approved in this case?**

10 A. Consistent with the way power costs are normally allocated in its general rate
11 cases, PSE proposes to allocate the total deferred amount as of December 31,
12 2017 or whenever rates from this GRC go into effect to the decoupling groups
13 using their relative contributions to the “peak credit” allocation factor in effect
14 during the year. This factor is the one approved by the Commission in Docket
15 UE-141368. It is reflected in Exhibit No.__(JAP-5C).

16 **Q. How does PSE propose to add fixed power costs to its proposed electric**
17 **decoupling mechanism?**

18 A. PSE’s fixed power costs have been included in the proposed electric decoupling
19 mechanism in this case, but have been kept as a distinct cost category from the
20 delivery costs in the calculation of Allowed Revenue per Customer. This
21 calculation is illustrated on page one of Exhibit No.__(JAP-30)

1 **Q. Why did PSE propose to calculate a separate allowed revenue per customer**
2 **for production costs in its electric decoupling mechanism?**

3 A. PSE will continue to have the ability to file power cost only rate cases
4 (“PCORCs”) in the future. Keeping the portion of allowed revenue tied to
5 production costs separate from those tied to delivery costs allows PSE’s electric
6 decoupling mechanism to be transparently updated at the time of a compliance
7 filing in a PCORC.

8 **Q. Is moving fixed power costs into PSE’s electric decoupling mechanism in the**
9 **public interest?**

10 A. Yes. PSE continues to have a throughput incentive associated with the recovery
11 of fixed power costs. Placing the recovery of these costs in the electric
12 decoupling mechanism removes this significant throughput incentive for PSE.

13 **2. Reorganize Non-Residential Decoupling Rate Groups**

14 **Q. What changes are you proposing to the electric decoupling rate groups?**

15 A. PSE proposes to further disaggregate its non-residential electric decoupling rate
16 groups to improve their homogeneity. As noted earlier, the non-residential electric
17 rate groups include one for customers served under Schedules 12 and 26, another
18 for customers served under Schedules 10 and 31 and a third that combines the

1 remaining non-residential rate schedules into one group.⁴⁷ PSE proposes to
2 separate this last rate group into three groups: one that would include customers
3 served under Schedules 8 and 24; another that includes customers served under
4 Schedules 40, 46 and 49; and another that includes all the remaining non-
5 residential rate schedules that are currently in PSE's electric decoupling
6 mechanism.

7 **Q. How do these proposed non-residential rate groups improve the functioning**
8 **of PSE's electric decoupling mechanism?**

9 A. The increased homogeneity of the groups mitigates some of the cross subsidies
10 discussed earlier in my testimony.⁴⁸ At a minimum, Schedules 40, 46 and 49
11 should be treated as a separate rate group, given their significantly different load
12 and service characteristics. PSE proposes to separate customers in Schedules 8
13 and 24 due to their far smaller use per customer and because these customers are
14 so great in number and aggregate load that they tend to dominate the overall
15 results for the existing non-residential group.

16 **Q. Are there any other reasons why Schedules 40, 46 and 49 should continue to**

⁴⁷ This group excludes the Lighting and Retail Wheeling Schedules.

⁴⁸ This improved homogeneity can be seen by simply comparing the proposed allowed delivery revenue per customer for these new groups to their existing allowed delivery revenue per customer in the current mechanism. The current annual allowed delivery revenue per customer for these customers is approximately \$1,475. As shown on page 2 of Exhibit No. ___(JAP-29), the annual allowed delivery revenue per customer is just under \$700 for Schedules 8 and 24, almost \$174,000 for Schedules 40, 46 and 49 and almost \$12,000 for the remaining non-residential customers.

1 **be in PSE's electric decoupling mechanism?**

2 A. These schedules have been experiencing significant declines in electric use per
3 customer. This can be seen in Table 13 above, where customers served under
4 Schedule 40 are shown to have over 22 percent lower use per customer in the
5 third year of the decoupling mechanism (i.e., July 2015 through June 2016)
6 relative to the use per customer that was present in the test year used to set the
7 baseline decoupling allowed delivery revenue per customer (i.e., July 2011
8 through June 2012). Similarly, this table shows that average use per customer
9 was approximately 18 percent lower over the same period for customers served
10 under Schedules 46 and 49. Therefore, keeping these customers within the
11 electric decoupling mechanism would address the continued revenue erosion
12 created by this declining use per customer and the associated throughput incentive
13 that exists for PSE in providing service to these customers.

14 **Q. If separating these rate schedules into their own rate groups mitigates cross**
15 **subsidies between schedules, why not simply create a separate rate group for**
16 **each non-residential rate schedule?**

17 A. Doing so could create the potential for stronger swings in decoupling deferrals
18 and, therefore, stronger swings in the associated annual rate true-ups. PSE's
19 proposal strikes a balance between the competing objectives of minimizing cross
20 subsidies and minimizing rate volatility, both of which are important ratemaking
21 considerations.

1 **Q. What changes are you proposing to the gas decoupling rate groups?**

2 A. PSE is proposing to create a separate non-residential decoupling rate group
3 composed of customers served under Schedules 31 and 31T. All the remaining
4 non-residential gas customers that are currently in the decoupling mechanism will
5 remain in the same decoupling rate group.⁴⁹

6 **Q. Why are you proposing to create these new non-residential decoupling rate**
7 **groups?**

8 A. Like the electric proposal, this proposal is intended to balance the competing
9 objectives of minimizing cross subsidies while also mitigating rate volatility.
10 Also similar to the electric proposal, the large number of small commercial
11 customers served under Schedules 31 and 31T tend to dominate the results for the
12 rest of their existing decoupling rate group. The remaining customers in the non-
13 residential decoupling rate group also have a use and revenue per customer more
14 similar to one another than to customers served under Schedules 31 and 31T.

15 **Q. How will the decoupling deferrals accumulated under the existing decoupling**
16 **mechanism be treated for customer groups that are being reorganized?**

17 A. It will work much like it did when non-residential electric and gas decoupling rate
18 groups were reorganized in 2014. PSE proposes to allocate the decoupling
19 deferrals, interest and amortization balances accumulated in the existing rate

⁴⁹ This includes customers served under Schedules 41, 41T, 86 and 86T.

1 groups to the new rate groups in proportion to the relative weather-normalized
2 volumetric delivery revenue for each group. Since the final amount to allocate
3 will not be known at the time of the compliance filing in this case (or even at its
4 conclusion), the amounts accrued in calendar year 2017 will be transferred to new
5 deferral accounts associated with the new decoupling rate groups and
6 incorporated into new Schedule 142 rates at the time of PSE's next regularly
7 scheduled filing for rates effective May 1, 2018.

8 **Q. How will any earnings sharing for calendar year 2017 be allocated to the**
9 **reorganized customer groups?**

10 A. In the event there are any earnings sharing for calendar year 2017, an additional
11 step will be necessary to allocate any sharing to the reorganized customer groups.
12 The first step will be to allocate any sharing to the current decoupling groups
13 using the current methodology that has been used in past annual filings (i.e., based
14 on each group's relative contribution to Allowed Revenue). The second step will
15 be to allocate any excess earnings allocated to the non-residential electric and gas
16 customer groups (i.e., in the first step) to the new non-residential groups in
17 proportion to the relative weather-normalized volumetric delivery revenue for
18 each rate schedule in the new groups. If there are any earnings sharing for
19 calendar year 2017 this allocation would take place in the annual Schedule 142
20 rate filing for rates effective May 1, 2018.

21 **3. Modify the Calculation of the Decoupling Rate Tests**

22 **Q. Please explain PSE's proposed changes to the operation of the Rate Test.**

1 A. PSE proposes two primary changes to the operation of the Rate Test. First, PSE
2 proposes to calculate the Rate Test using a baseline where “current” revenue (i.e.,
3 the basis for determining the percentage change in rates) is calculated as the
4 product of current rates⁵⁰ and the weather-normalized billing determinants in the
5 prior calendar year. This is very similar to the way PSE develops its pro forma
6 revenue in each rate case and presents its bill impacts in its various annual rate
7 filings. Second, PSE proposes to increase the Rate Test trigger for the residential
8 gas customers in the gas decoupling mechanism and for all customers in the
9 electric decoupling mechanism from three percent to five percent.

10 **Q. Please explain why PSE is proposing to change the way it calculates current**
11 **revenue in the Rate Test.**

12 A. PSE’s proposed change will make the Rate Test more transparent and easier to
13 calculate. PSE currently uses normalized revenue from its Commission Basis
14 Report (“CBR”) as the basis for determining the Rate Test. These revenues are
15 not decomposed at the schedule level that is required to conduct the Rate Test for
16 each decoupling rate group and doing so requires considerable effort. Schedule
17 142 revenue embedded in these results must also be removed and replaced with a
18 pro formed level of revenues at current Schedule 142 revenue for each schedule.
19 Rather than perform these multiple steps, a more straight-forward and transparent
20 approach is simply to multiply the weather-normalized billing determinants from

⁵⁰ Where current rates are calculated as pro forma revenue divided by pro forma energy sales for the base and adjusting price schedules applicable to customer bills.

1 the CBR by the current rates, similar to the way that pro forma revenue is
2 calculated.⁵¹

3 **Q. Why does PSE believe a higher Rate Test trigger for gas residential**
4 **customers is appropriate?**

5 A. To date, gas residential customers have experienced very high levels of
6 unamortized deferred revenues and setting a higher Rate Trigger will better align
7 cost causation and cost recovery, and improve intergenerational equity. The
8 longer the deferred balances remain on the balance sheet, the less likely the
9 customers who benefited from the deferred recovery of costs will be the
10 customers that pay for those costs. In addition it is reasonable to believe that, the
11 longer the period between cost causation and cost recovery, the more likely it will
12 create customer confusion and dissatisfaction regarding why rates continue to be
13 elevated for costs incurred in the past. PSE's proposal is also supported by the
14 recommendations in the Gil Peach Report and analysis the Company has
15 performed, which show that amortization rates could have been proposed to clear
16 all of the decoupling-related gas residential deferrals in the 2015 and 2016 annual
17 filings if a five percent cap on rate increases had been in place.

18 **Q. Why does PSE believe a higher Rate Test trigger for all customers within the**
19 **electric decoupling mechanism is appropriate?**

⁵¹ PSE understands that this is the way Avista currently performs this calculation for its decoupling mechanism.

1 A. While there has not been a significant historic problem with significant
2 unamortized deferred revenue for customers within PSE's electric decoupling
3 mechanism, the addition of fixed power cost recovery to this mechanism may
4 create the potential for future problems. As will be discussed in more detail later
5 in this testimony, adding fixed power costs to the electric decoupling mechanism
6 will almost double the allowed revenue recovered through the electric
7 mechanism. This means that any variations in electric customer use will have
8 almost double the impact on potential rate impacts in the future. For example, in
9 May of 2015, the rate impacts to the Residential and Non-Residential Rate
10 Groups in the electric decoupling mechanism were 2.9 percent and 2.4 percent,
11 respectively. It therefore stands to reason that, if fixed power costs were also
12 included at that time, the impacts would have roughly doubled (using the rough
13 proportionality of the proposal in this case). While it is true that the Rate Plan
14 also contributed to a portion of the historic rate increases and a similar plan will
15 not be present in the proposed mechanisms in this case, the Rate Plan likely
16 contributed to approximately one percent of the historic increase. In summary,
17 rather than wait until there is a problem, PSE proposes that the Commission heed
18 the example experienced for gas residential customers and consider a more liberal
19 rate cap to help ameliorate similar concerns for electric customers in the future.

20 **Q. Is PSE proposing a minimum rate trigger for its Rate Test in order to**
21 **amortize its deferred revenues?**

22 A. No. While PSE is aware that PacifiCorp's recently approved decoupling

1 mechanism requires a minimum 2.5 percent rate trigger based on allowed revenue
2 in order to begin amortizing deferrals in its annual rate filings, PSE is not
3 proposing a similar minimum rate trigger percentage in order to amortize its
4 decoupling deferrals. PSE's proposal will credit or surcharge the year end
5 decoupling balances regardless of the size, but still subject to the Rate Test cap.

6 **Q. Why is PSE not proposing a minimum rate trigger percentage to amortize**
7 **deferred revenue?**

8 A. There are three main reasons why a minimum rate trigger percent is not
9 appropriate for PSE.

10 The first reason is the GAAP requirement mentioned earlier in my testimony that
11 requires PSE to amortize accruals within 24 months from when they are recorded
12 in order to classify the accruals as revenue in the current period. Such a minimum
13 rate trigger percent requirement will lead to more problems with this issue, with
14 balances staying on PSE balance sheet longer and revenues being more likely to
15 be recorded in periods other than when the deferrals took place.

16 The second reason it is not appropriate is due to the intergenerational equity
17 issues and potential customer confusion that it creates. The longer the deferred
18 balances remain on PSE's balance sheet, the less likely the customers who
19 benefited from the deferred recovery of costs will be the customers that pay for
20 those costs. Moreover, the longer cost recovery is separated from cost incurrence,
21 the more difficult it is for the average utility customer to relate their current bill to
22 current (or simply recent) use, which is generally what they expect.

1 Finally, if the interest in setting a minimum rate test trigger is to minimize rate
2 changes for PSE customers, such a proposal would not make a material
3 difference. PSE has two other schedules, conservation and property tax that
4 change rates annually on May 1st, which is the same date that its decoupling rates
5 change. Since rates are very likely to change on the same day, it should make
6 little difference to customers that yet another component of their bill is changing
7 at the time.

8 **4. Modify the Calculation of the Decoupling Earnings Tests**

9 **Q. What is PSE proposing to change about the decoupling Earnings Test?**

10 A. PSE proposes that, for revenue sharing purposes, all normalizing adjustments to
11 actual results be excluded and all conforming adjustments be retained for
12 calculating operating income. Please see the Direct Prefiled Testimony of Daniel
13 A. Doyle, Exhibit No.__(DAD-1T) for a more detailed discussion of this issue
14 and PSE's proposed changes to the Earnings Test.⁵²

15 **Q. Is PSE proposing any other change to the application of its Earnings Test?**

16 A. Yes. When the Earnings Test triggers under the new decoupling mechanisms,
17 PSE is proposing to allocate the amount returned to customers in relation to their
18 allowed revenue rather than based on their volumetric revenue.

19 **Q. Why is PSE proposing this change?**

⁵² Exhibit No.__(DAD-1T), Section IV.

1 A. PSE's earnings in the year the Earnings Test triggers are a direct result of the
2 allowed revenue that it books, rather than the level of volumetric revenue that it
3 receives. As a result, using allowed revenues to allocate Earnings Test refunds to
4 customers will produce a result that is more aligned to their contributions to the
5 revenues producing the overearnings.

6 **5. Other Proposed Changes to the Decoupling Calculations**

7 **Q. Please discuss the other "housekeeping" changes that PSE is proposing to**
8 **make for the gas decoupling mechanism.**

9 A. The other changes PSE proposes for the decoupling mechanisms generally relate
10 to the calculation of actual margin revenue for the new non-residential gas rate
11 group.

12 **Q. How does PSE currently calculate actual margin for non-residential gas**
13 **customers in its decoupling mechanisms?**

14 A. Currently, PSE uses a blended average margin rate to determine the actual
15 revenues upon which it calculates its decoupling deferrals for these customers.
16 The blended rate is multiplied by actual therm volumes to calculate actual
17 revenues.

18 **Q. How is PSE proposing to change the calculation of actual margin for these**
19 **non-residential gas customers in the decoupling mechanism?**

20 A. PSE is proposing to use the actual margin revenue for non-residential gas
21 customers. This would be accomplished by multiplying the actual base rates for

1 both volumetric and demand charges by the appropriate billing determinants.

2 **Q. Why is PSE proposing this change?**

3 A. Doing so will produce more accurate results for these customers, since the actual
4 margin collected will be used to calculate deferrals. The blended rate currently
5 used to determine actual margin is calculated using the results from PSE's last
6 GRC and any changes in customers' usage and demand charge patterns since the
7 last GRC could produce results that deviate from the actual margin recovered
8 since then. For the amortization revenue calculations for these customers, PSE is
9 already using this more granular calculation, so making this change would be
10 consistent with how amortization amounts are calculated.

11 **D. Approval of the Modified Decoupling Mechanisms is in the Public**
12 **Interest**

13 **Q. Do the proposed modified decoupling mechanisms still meet the goals**
14 **outlined in the Commissions Decoupling Policy Statement?**

15 A. Yes. Note first that the Gil Peach Report found that the mechanisms are operating
16 as intended and have produced no material adverse impacts. Second, PSE has
17 only made minor modification to its existing decoupling mechanisms. These
18 modifications should improve the operation of the decoupling mechanisms and
19 therefore further weigh in favor of being in the public interest for the reasons
20 outlined earlier in this testimony.

21 **Q. Please describe the basic requirements and criteria the Commission has used**
22 **to evaluate decoupling mechanisms for their approval.**

1 A. These requirements were outlined in the Commission's Decoupling Policy
2 Statement and can be summarized as follows:

- 3 1. A description of the decoupling mechanism;
- 4 2. The impact of the mechanism on rate of return;
- 5 3. The earnings test proposed in association with the mechanism;
- 6 4. The accounting of off-system sales and avoided costs in
7 association with the mechanism;
- 8 5. The applicability of the mechanism to customer classes;
- 9 6. The effects of weather in the mechanism;
- 10 7. Evidence of incremental conservation associated with the
11 mechanism;
- 12 8. Effect of mechanism on low-income customers;
- 13 9. The proposed duration of the mechanism;
- 14 10. An evaluation report on the mechanism; and
- 15 11. Other factors impacting the public interest.

16 **Q. Has your testimony already described the proposed modifications to the**
17 **existing decoupling mechanisms?**

18 A. Yes. In general, the proposed mechanisms will operate in much the same fashion
19 as the existing mechanisms where allowed and actual revenue will be compared
20 on a monthly basis, with the deferrals accumulated each calendar year trued up
21 beginning May of the following year. The most significant differences will be the
22 inclusion of fixed power costs in the electric decoupling mechanism and a modest
23 rearrangement of non-residential customers in the decoupling rate groups.

1 **Q. Has the Company evaluated the impact of the proposed mechanism on its**
2 **rate of return?**

3 A. No. This issue was discussed extensively in the remand of the Commission's
4 approval of PSE's amended petition to approve its original decoupling
5 mechanisms. In Order 15, the Final Order on Remand, in the Decoupling Case,
6 the Commission devoted 16 pages to the evaluation of this issue. With regard to
7 the impact of decoupling on a utility's return on equity, the Commission
8 determined:

9 We believe it is correct that cost of capital analysis cannot be
10 expected to produce results that support measurement of
11 decrements to ROE ostensibly due to approval of one risk
12 mitigation mechanism or another. Nor would cost of capital
13 analysis be adequate to the task of identifying increments to ROE
14 that might be considered due to some measure of additional risk a
15 company takes on at some point in time. The Commission has
16 never tried to account separately in its ROE determinations for
17 specific risks or risk mitigating factors, nor should it.
18 Circumstances in the industry today and modern regulatory
19 practice that have led to a proliferation of risk reducing
20 mechanisms being in place for utilities throughout the United
21 States make it particularly inappropriate and unnecessary to
22 consider such an undertaking.⁵³

23 The Commission concluded:

24 In sum, we find persuasive the expert opinions of Dr. Morin and
25 Mr. Gorman and find that the risk reducing effect of decoupling is
26 reflected adequately in the data derived from the companies in
27 their respective proxy groups. We reject the idea of a separate
28 decrement to ROE to account for the same risk reduction. We also
29 find persuasive the point that cost of capital analysis cannot
30 achieve the level of granularity necessary to support a discrete

⁵³ Decoupling Case, Order 15, ¶155.

1 adjustment to ROE to account for particularized risks—up or
2 down.⁵⁴

3 **Q. Does the new proxy group used by PSE in this filing to determine its ROE**
4 **adequately reflect the risk reducing effects of decoupling and other risk**
5 **mitigation mechanisms?**

6 A. Yes. For further information, please see the Prefiled Direct Testimony of Dr.
7 Roger E. Morin, Exhibit No.__(REM-1T) and the Prefiled Direct Testimony of Mr.
8 Daniel A. Doyle, Exhibit No.__(DAD-1T).

9 **Q. Is there a proposed earnings test associated with the proposed decoupling**
10 **mechanisms?**

11 A. Yes. PSE has proposed an earnings test, albeit somewhat modified from the
12 current test. For further information, please see the Prefiled Direct Testimony of
13 Mr. Daniel A. Doyle, Exhibit No.__(DAD-1T).

14 **Q. Do the proposed decoupling mechanisms explicitly account for off-system**
15 **sales and the associated avoided cost of wholesale power and gas supply?**

16 A. As was the case with the existing mechanisms, these issues are already
17 sufficiently addressed in the Company's PGA and PCA mechanisms. PSE's
18 proposed modifications to the existing decoupling mechanisms do nothing to
19 change this.

⁵⁴ *Id.* ¶ 156.

1 **Q. Has your testimony already discussed which customers are affected by the**
2 **decoupling proposals?**

3 A. Yes, this was discussed earlier in this section of my testimony. Noteworthy in
4 this context, PSE is proposing to modestly rearrange the grouping of the non-
5 residential customers in both mechanisms to reduce the potential for cross-
6 subsidization between rate schedules while balancing the common interest to
7 moderate the volatility in decoupling deferrals and the associated rates required to
8 amortize them. As such, the proposed modifications to these rate groups are
9 improvements over the groupings in current mechanisms.

10 **Q. How are the effects of weather incorporated in the proposed decoupling**
11 **mechanisms?**

12 A. As with the existing mechanisms, actual revenue used to determine the
13 decoupling deferrals in the proposed mechanisms will not be adjusted for the
14 effects of weather.

15 **Q. Will the proposed decoupling mechanisms produce additional conservation**
16 **achievement on the part of the Company?**

17 A. As with the existing mechanisms, PSE proposes to continue its commitment to
18 accelerate its conservation achievement five percent above the levels approved by
19 the Commission for PSE's biennial conservation target and submit itself to
20 penalties equivalent to those outlined in RCW 19.285 for failure to achieve these
21 incremental savings.

1 Also, as with the existing mechanism, given PSE's continued commitment to
2 voluntarily accelerate its conservation achievement beyond its Commission-
3 approved biennial conservation target, no further test of conservation achievement
4 is being offered beyond its commitment to exceed these targets.

5 **Q. Is the Company making any further commitments regarding natural gas**
6 **conservation achievement as part of its current decoupling proposal?**

7 A. PSE will commit to achieving five percent more natural gas conservation than
8 required to meet guidance from the PSE Integrated Resource Plan over the same
9 two-year reporting biennium as is used to determine compliance with the
10 electrical conservation requirements in RCW 19.285

11 **Q. What would happen if PSE does not meet these decoupling-related gas**
12 **conservation commitments?**

13 A. PSE proposes to pay \$20,000 for meeting between 4.5 percent and 5.0 percent of
14 its incremental gas conservation commitment, \$50,000 for meeting between 3.75
15 percent and 4.5 percent of its incremental commitment, and \$75,000 for less than
16 3.75 percent of its incremental commitment. These penalties are structured after
17 the existing penalties for gas conservation performance, as outlined in the 2001
18 Stipulation Agreement in Docket UG-011571, but with penalty amounts that are
19 10 percent of the corresponding levels that apply when it fails to meet its
20 minimum requirements.

21 **Q. How will low-income customers be impacted by the decoupling proposals?**

1 A. As already noted in the Gil Peach Report, the bill impacts to customers receiving
2 bill assistance from PSE have been minor. In addition, PSE agreed to increase its
3 funding for low-income weatherization by \$500,000 per year as part of the
4 original decoupling mechanisms. PSE proposes to continue this higher funding
5 level for the proposed mechanisms in this filing.

6 **Q. What is the proposed duration of the new decoupling mechanisms proposed**
7 **in this filing?**

8 A. PSE proposes that these decoupling mechanisms become permanent and continue
9 until such time PSE proposes, and the Commission approves, to have them
10 discontinued or modified. With the significant growth in the use of decoupling
11 mechanisms around the country, as well as in this state, and the lack of evidence
12 that there are significant adverse impacts associated with these mechanisms, there
13 is very little risk in the Commission approving the indefinite continuation of
14 PSE's decoupling mechanisms.

15 **Q. Is PSE proposing another third-party evaluation of the newly proposed**
16 **decoupling mechanisms?**

17 A. No. PSE does not believe that yet another third-party evaluation would materially
18 influence the growing body of evidence that decoupling mechanisms are working
19 as intended to remove utilities' throughput incentive and their associated financial
20 disincentives to support their customers' conservation efforts. Interested

1 stakeholders can perform their own evaluations of these mechanisms from their
2 unique perspectives as the mechanisms continue to be updated in the future.

3 **Q. Are there any other factors to consider regarding the proposed decoupling**
4 **mechanisms that weigh on whether their approval is in the public interest?**

5 A. Other than the factors discussed earlier in my testimony and the factors discussed
6 by the Commission in Order 07, PSE is not aware of other factors impacting the
7 public interest.

8 **X. ELECTRIC COST RECOVERY MECHANISM**

9 **Q. Why is PSE proposing an Electric Cost Recovery Mechanism?**

10 A. As discussed in the Prefiled Direct Testimonies of Ms. Booga Gilbertson, Exhibit
11 No.__(BKG-1T) and Ms. Catherine A. Koch, Exhibit No.__(CAK-1T), PSE is
12 requesting an Electric Cost Recovery Mechanism (“ECRM”) in order to
13 accelerate the replacement of targeted reliability improvements intended to reduce
14 the number and length of outages.

15 **Q. What is the estimated revenue requirement associated with the ECRM in the**
16 **first year it is requested to go into effect?**

17 A. As presented in Exhibit No.__(KJB-9) and further discussed in the Prefiled
18 Direct Testimony of Katherine J. Barnard, Exhibit No.__(KJB-1T), the
19 estimated revenue requirement associated with the ECRM in the first year is
20 approximately \$10.5 million.

1 **Q. How does PSE propose to allocate this revenue requirement among its**
2 **electric customers?**

3 A. PSE proposes a two-step process to allocate these costs to its electric customers.
4 In the first step, the overall revenue requirement will be allocated between
5 overhead and underground investments based on the relative capital investment in
6 these two cost categories. Next, the overhead and underground-related CRM
7 revenue requirement are each allocated to electric customers based on the load-
8 weighted line miles associated with each type of distribution feeder.

9 **Q. How does PSE propose to develop rates from these allocated costs?**

10 A. PSE proposes to simply unitize the allocated costs based on test year loads and,
11 much like most of its other adjusting price schedules, charge customers a single
12 schedule-specific rate per kWh that would be applicable on all energy sales within
13 the applicable rate schedules.

14 **Q. Has PSE developed an exhibit to show these calculations?**

15 A. Yes, it is provided in Exhibit No. ____ (JAP-32).

16 **Q. Please describe the calculations in Exhibit No. ____ (JAP-32).**

17 A. As noted, the first step in the rate calculation is to allocate the revenue
18 requirement between overhead and underground investment. As shown in this
19 exhibit, the proposed revenue requirement is predicated on approximately \$28.6
20 million in overhead investment and \$47.8 million in underground investment. So,
21 the associated revenue requirement was proportionally split between overhead

1 and underground investment, roughly \$3.92 million to overhead and \$6.56 million
2 to underground.

3 The overhead and underground revenue requirements were allocated based on
4 load-weighted line miles of facilities being replaced. These allocation factors
5 were developed using the same programs used to allocate these facilities in PSE's
6 electric cost of service (see Section IV.G.1 above for more discussion), but
7 limiting the focus to only those circuits included in the replacement program and
8 excluding the rest. As a result, Exhibit No. ___(JAP-32) shows weighted line
9 miles just over 1,000 miles for underground and overhead facilities versus the
10 system level totals for each of over 10,000 miles.

11 The last step is to create the ECRM rates. These rates were calculated by first
12 summing the overhead and underground ECRM-related revenue requirement
13 allocated for each class and then dividing by the test year energy sales for that
14 class. The resulting system average ECRM rate is \$0.000541 per kWh, with wide
15 variations among the classes ranging from \$0.001010 per kWh for Schedule 43 to
16 \$0.000062 per kWh for Schedule 31.

17 **Q. What are the rate impacts from these estimated Electric CRM rates?**

18 A. These impacts are summarized in the table below. For a typical electric
19 residential customer using 900 kWh, the estimated impact is \$0.72 per month.

1
2

Table 14 - Estimated Rate Impact of Electric CRM

Customer Class	Rate Schedule	Estimated Rate Increase
Residential	7	0.75 %
General Service, < 51 kW	8/24	0.39 %
General Service, 51 - 350 kW*	11/25	0.21 %
General Service, >350 kW	12/26	0.11 %
Primary Service, Gen & Irr.*	10/31	0.07 %
Primary Service, Schools	43	1.06 %
Campus Rate	40	0.00 %
High Voltage	46/49	0.00 %
Lighting Service**	50 – 59	0.00 %
Choice/Retail Wheeling	448/449	0.00 %
Total Jurisdictional Retail Sales		0.50 %

* Schedules 7A, 29, and 35 will not see rate increases as part of this initial ECRM proposal.

** As discussed below, PSE proposes not to implement ECRM rates for lighting.

3
4
5
6
7
8
9
10
11

Q. Please explain why there is such a wide variation in proposed Electric CRM rates.

A. This is largely a function of where the investments are being made and the customers served on those particular circuits. The higher the load concentration of a particular customer class on the replaced circuits, the higher the allocated costs and, therefore, the higher the rate. Generally speaking, since many of these circuits tend to be in more rural areas, it is not surprising that rates tend to be higher for customer groups more likely to be served in those areas.

Q. Why did PSE choose to use this particular method to allocate these costs?

1 A. This method allows for a more seamless transition when these investments are
2 later transferred into base rates, as the allocation of these costs will be unchanged.
3 To do otherwise, would create a mismatch between the way these costs are
4 allocated in the ECRM and the way they would subsequently be allocated when
5 rolled into base rates.

6 **Q. Is PSE proposing to apply the ECRM rates to its lighting customers?**

7 A. No. As shown in Exhibit No.____(JAP-32), the allocated costs to this group are
8 just over \$5,000. Even if this amount were multiples higher than this level, given
9 the way lighting rates are almost always rounded to the nearest cent per month,
10 the majority of these rates would be rounded to zero. So, rather than increasing
11 the administrative burden of applying these rates to lighting customers, PSE is
12 proposing to forgo the accelerated recovery of these costs within the ECRM.
13 When these allocated investments are eventually rolled into PSE’s base rates, then
14 lighting customers will begin to pay for these investments through their base
15 rates.

16 **XI. SCHEDULE 451**

17 **Q. Does PSE have any other filings pending before the Commission that may**
18 **impact the rate design for Schedule 40 in this case?**

19 A. Yes, on October 7, 2016, PSE filed a proposed new Large Customer Retail
20 Wheeling service (Schedule 451) under Docket UE-161123 (the “Retail Wheeling
21 Docket”). This filing is intended to implement a new retail wheeling service for

1 large non-core customers. If approved, service taken under this schedule will
2 necessarily impact PSE's recovery of power costs and, therefore, have ratemaking
3 implications in this proceeding.

4 **Q. When is a decision expected in the Retail Wheeling Docket?**

5 A. An order is expected shortly before the September 7, 2017 suspension date for
6 that tariff filing. PSE expects that this should provide sufficient time to
7 implement contingent mechanisms in this general rate case to reflect the decision
8 in the Retail Wheeling Docket.

9 **Q. What contingent mechanisms will be required in this case to accommodate**
10 **the potential for service taken under PSE's proposed Schedule 451?**

11 A. At least two contingencies will need to be accommodated in this general rate case
12 to reflect the potential for service in the Retail Wheeling Docket. First, PSE will
13 need to file two PCA baseline rates, one reflecting no service taken under the
14 proposed Schedule 451 and another reflecting service taken by Microsoft under
15 Schedule 451. Second, PSE will need to file two sets of allowed delivery and
16 fixed power cost revenue per customer and two sets of volumetric delivery and
17 fixed power cost revenue per unit rates in its electric decoupling mechanism
18 (discussed earlier in testimony) to, again, reflect whether service is being taken by
19 Microsoft under the proposed Schedule 451. While described here, these
20 contingent calculations for the PCA baseline rate will not be provided until power
21 costs are updated later in this case.

1 **Q. Why do these contingent calculations need to be made?**

2 A. As mentioned earlier, whether or not Microsoft takes service under the Schedule
3 451 will have an implication on the recovery of PSE's power costs. Indeed, this is
4 the focus of the discussion around the proposed Power Supply Stranded Cost
5 Charge in the Retail Wheeling Docket. The purpose of this charge is to
6 compensate for the power costs that will be stranded if and when Microsoft
7 begins to take service under Schedule 451. PSE has proposed in the Retail
8 Wheeling Docket that the remaining PSE customers receive 100 percent of the
9 benefits of this charge with the expectation that these customers will also absorb
10 100 percent of the stranded power costs that served as the justification for this
11 charge.

12 **Q. What is the implication if the contingent calculations are not allowed to go**
13 **into effect if or when Microsoft begins to take service under the proposed**
14 **Schedule 451?**

15 A. If no allowance is made in this proceeding to simultaneously reflect the stranded
16 power costs in this rate proceeding with the timing of Microsoft beginning to take
17 service under the proposed Schedule 451, then PSE will propose that a portion of
18 the Power Supply Stranded Cost Charge be retained by PSE shareholders to
19 compensate for the recovery of stranded costs that are not being borne by
20 remaining PSE customers.

21 **Q. Please briefly described how these contingent calculations will be performed.**

1 A. The calculations will be relatively simple. For PSE’s Power Cost Adjustment
2 (“PCA”) mechanism, the PCA baseline rate will be calculated once including
3 Microsoft’s load as being served under Schedule 40 (i.e., the status quo) and
4 alternatively reflecting this load being served under the proposed Schedule 451
5 (i.e., where Microsoft no longer pays PSE for power supply). These calculations
6 will be explained in more detail when power costs are updated during the course
7 of this case.

8 Similarly, for PSE’s electric decoupling mechanism, the allowed delivery and
9 fixed power cost revenue per customer used to calculate allowed revenue and the
10 volumetric delivery and fixed power cost revenue per units rates used to calculate
11 actual revenue will be alternatively calculated with Microsoft’s load alternatively
12 assumed to be served under Schedule 40 or the proposed Schedule 451. These
13 decoupling calculations are explained in greater detail later in this testimony.

14 **Q. Has PSE calculated the electric decoupling allowed revenue per customer**
15 **with Microsoft’s load removed from Schedule 40?**

16 A. Yes, this analysis is provided in Exhibit No.____(JAP-33C). This exhibit mirrors
17 the analysis in Exhibit No.__(JAP-30), but without the Microsoft load. As
18 expected, the results on page 2 of Exhibit No.__(JAP-33C) show that the
19 allowed “Fixed Power Cost Revenue Per Customers” increases for all the
20 remaining customers as the stranded costs are shifted to these customers.

21

1 **Q. When does PSE propose that the allowed revenue in Exhibit No. ___(JAP-**
2 **33C) take effect?**

3 A. PSE proposes that the allowed revenue per customer calculated in this exhibit take
4 effect as part of a compliance filing at the time Microsoft begins taking service
5 under Schedule 451. The effective date for these new allowed revenues would be
6 contemporaneous with the date on which PSE's alternate PCA baseline rate
7 (discussed above) and stranded cost rate credit to remaining customers through
8 Schedule 137 take effect. Setting all of these rates to go into effect at the same
9 time allows customers to receive their credit associated with Microsoft's stranded
10 cost payment at the same time they absorb into their rates the underlying increase
11 in power cost that result from Microsoft taking service under Schedule 451.

12 **Q. When will this compliance filing occur?**

13 A. It will occur shortly after Microsoft is ready, willing and able to begin taking
14 service under Schedule 451, which of course will first require approval of this
15 tariff schedule by the Commission. It will also require certain necessary
16 operational conditions to be met (e.g., for Microsoft to secure an alternative
17 power supply arrangement, obtain transmission service, install required metering,
18 etc.). It is unclear at this time when all of these necessary conditions will be met

19 **Q. Why shouldn't the Commission simply wait for those other conditions to be**
20 **met before addressing the required changes to PSE's PCA baseline rate and**
21 **decoupling allowed revenue?**

1 A. Doing so will unnecessarily lengthen the time at which Microsoft can begin
2 taking service under Schedule 451 or, as mentioned above, result in PSE's
3 shareholders unfairly incurring stranded costs for which no compensation would
4 be made. PSE's recovery of power costs will be materially impacted by the loss
5 of Microsoft's load. So, it is imperative that this factor be addressed immediately
6 in PSE's rates upon Microsoft's initiation of service under Schedule 451.
7 Moreover, since the data is already available to make these rate determinations in
8 this case, there is nothing preventing the Commission from approving these rates
9 contingent upon Microsoft taking service under Schedule 451 at some point after
10 the conclusion of this case.

11 **Q. PSE is proposing a new electric adjusting price Schedule 149 (Electric Cost**
12 **Recovery Mechanism) in this case. Will this schedule apply to Schedule 451?**

13 A. Yes, if both electric Schedule 451 and Schedule 149 are approved by this
14 Commission, PSE proposes that customers served under Schedule 451 also be
15 include among the applicable schedules within Schedule 149. To the extent that
16 costs recovered through Schedule 149 benefit customers served under Schedule
17 451, it is appropriate that these customers also contribute towards the underlying
18 costs recovered through this schedule.

19 **XII. COMPLIANCE FILING**

20 **Q. Please summarize all of the rates that PSE intends to update in its**
21 **compliance filing for this case.**

1 A. The compliance filing in this case will include updates to all PSE base electric and
2 natural gas rate schedules, as well as a host of adjusting price schedules. These
3 adjusting price schedules that will be included in the compliance filing are as
4 following:

- 5 • Electric Schedule 95 (Power Cost Adjustment Clause)
- 6 • Electric Schedule 141 (Expedited Rate Filing Rate Adjustment)
- 7 • Electric Schedule 142 (Revenue Decoupling Adjustment Mechanism)
- 8 • Electric Schedule 149 (Electric Cost Recovery Mechanism)
- 9 • Gas Schedule 141 (Expedited Rate Filing Rate Adjustment)
- 10 • Gas Schedule 142 (Revenue Decoupling Adjustment Mechanism)
- 11 • Gas Schedule 149 (Cost Recovery Mechanism for Pipeline Replacement)

12 **Q. Have the proposed tariff sheets for these adjusting price schedules been**
13 **included in this filing?**

14 A. The proposed changes to the electric tariff sheets for the adjusting price schedules
15 are included in Exhibit No.__(JAP-16). The proposed changes to the natural gas
16 tariff sheets for the adjusting price schedules are included in Exhibit No.__(JAP-
17 25), except for gas Schedule 149. Since PSE is not proposing any structural
18 changes to gas Schedule 149 and will only be updating the rates on this schedule
19 based on the outcomes of its normal update next November 1 and the subsequent
20 outcome of this general rate case, this schedule is not included among the tariff

1 sheets in Exhibit No. ____ (JAP-25).

2 **Q. Have all of these tariff sheets been formally filed as part of this case?**

3 A. No. Proposed changes to the electric and gas decoupling adjusting price Schedule
4 142 have not been filed as part of this case and are only included in the above
5 noted exhibits. These schedules are on an annual filing schedule, for rates
6 effective May 1 of each year. So, it is administratively easier to present the
7 changes in this case as exhibits to this testimony to avoid complications with the
8 annual update filings that will occur later this year.

9 For similar reasons, gas Schedule 149 also has not been filed as part of this case.

10 It is normally updated each year for rates effective November 1.

11 **Q. Are there any other tariff schedules that will be impacted by the outcome of**
12 **this general rate case?**

13 A. Yes. There are several tariff sheets that rely on the results of the most current rate
14 case. These include the following:

- 15 • Electric Schedule 62 (Substation and Related Equipment Capacity),
- 16 • Electric Schedule 85 (Line Extensions & Service Lines),
- 17 • Electric Schedule 87 (Income Tax Rider)
- 18 • Electric Schedule 139 (Voluntary Long-Term Renewable Energy Purchase
19 Rider), and

1
2
3
4
5
6
7

- Gas Rule 6 (Extension of Distribution Facilities).⁵⁵

Q. When will these tariff revisions be filed with the Commission?

A. PSE intends to file these tariff revisions within 30 days of the effective date of new base rates resulting from this general rate case.

XIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

⁵⁵ Rule 6 is expected to be approved in Docket UG-161268 just prior to the filing of this case, replacing Rule 7.