EXH. JAP-1T
DOCKETS UE-18___/UG-18___
2018 PSE EXPEDITED RATE FILING
WITNESS: JON A. PILIARIS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of: **PUGET SOUND ENERGY** **Expedited Rate Filing**	**Docket UE-18____** **Docket UG-18____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

JON A. PILIARIS

ON BEHALF OF PUGET SOUND ENERGY

NOVEMBER 7, 2018

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JON A. PILIARIS

CONTENTS

LIST OF EXHIBITS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JON A. PILIARIS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jon A. Piliaris. I am employed as Director, Regulatory Affairs, with Puget Sound Energy ("PSE" or the "Company"). My business address is 10885 NE Fourth Street, Bellevue, WA 98009-9734.

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

A. Yes, I have. It is Exh. JAP-2.

Q. What is the purpose of your testimony?

A. My testimony presents the following:

i) PSE's calculation of the revenues at present rates used to derive the electric and natural gas revenue deficiencies in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, using weather-normalized billing determinants for the test year ending June 30, 2018;

ii) PSE's proposed rate spread and rate design for the recovery of the $18.9 million electric revenue deficiency presented in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, through electric Schedule 141;

iii) PSE's proposed rate spread and rate design for the recovery of $21.7 million of the $37.5 million natural gas revenue deficiency presented in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, through natural gas Schedule 141;

iv) the resulting updates to electric Monthly Allowed Delivery Revenue Per Customer and Monthly Allowed Fixed Power Cost Revenue and the associated Delivery Revenue Per Unit and Fixed Power Cost Revenue Per Unit in electric Schedule 142; and

v) the resulting updates to natural gas Monthly Allowed Delivery Revenue Per Customer and the associated Delivery Revenue Per Unit in natural gas Schedule 142.

Q. Please summarize your testimony.

A. Consistent with the methodology used to develop rates in Dockets UE-170033 and UG-170034 ("2017 general rate case") and PSE's subsequent tariff revision filings that reflected the effects of the lower federal income tax rates associated with the Tax Cuts and Jobs Act of 2017, Dockets UE-180282 and UG-180283 ("2018 Tax Reform Filing"), PSE has spread its electric revenue deficiency based on this rate spread allocation and based its rate design on a consistent

methodology. PSE has spread the gas revenue deficiency on an equal percent of margin and equally across all margin rate components. These approaches are consistent with the Multiparty Settlement Stipulation and Agreement ("2017 Settlement Agreement") in PSE's 2017 general rate case.[1]

The tariff increases requested in electric Schedule 141 will result in a 0.9 percent average rate increase for electric customers. The tariff increases requested in natural gas Schedule 141 will result in a 2.7 percent average rate increase for natural gas customers. PSE has proposed corresponding updates to its decoupling mechanisms in electric and natural gas Schedule 142 to align with the rates being proposed in electric and natural gas Schedule 141.

II. DEVELOPMENT OF RATE SPREAD

Q. How did PSE assign its revenue deficiencies to customer classes in this Expedited Rate Filing ("ERF")?

A. PSE used the electric rate spread and rate design incorporated in its compliance filing in the 2017 general rate case, as updated in PSE's 2018 Tax Reform filing, as the basis for spreading the electric revenue deficiency. PSE has spread gas revenue deficiency on an equal percent of margin and equally across all margin rate components. These approaches are consistent with the 2017 Settlement

[1] Exhibit I to the Multiparty Settlement Stipulation and Agreement in Dockets UE-170033 and UG-170034 states that "[t]he ERF will not include changes to rate spread or rate design from the most recently filed general rate case."

Agreement.

Q. Please summarize how PSE spreads the electric revenue deficiency.

A. Based upon the 2017 general rate case, PSE proposes:

- an adjusted average rate increase to Schedule 7 (Residential Service), Schedule 43 (Interruptible All Electric Schools) and Schedules 50-59 (Lighting Service);

- a rate increase that is 75 percent of the average to Schedules 8/24 (General Secondary Service);

- a rate increase that is 65 percent of the average to Schedule 7A (Master Metered Residential Service), Schedules 11/25 (Small Demand General Service), Schedule 12/26 (Large Demand General Service), Schedule 29 (Seasonal Irrigation and Drainage Pumping Service), Schedules 10/31 (Primary General Service), Schedule 46 (High Voltage Interruptible Service) and Schedule 49 (High Voltage General Service);

- a rate increase that is 150 percent of the average to Schedule 35 (Seasonal Primary Irrigation and Drainage Pumping Service);

- rates in Schedule 40 (Large Demand General Service Greater than 3 aMW) are tied to rates in the High Voltage Schedules, such that the rate increase for Schedule 40 is not independently determined. The Schedule 40 production and transmission charges are linked to those found in the High Voltage Schedules

and distribution charges are based on customer-specific information. This results in a calculated rate spread amount for this class, rather than a rate spread based on a class-specific cost of service and rate spread analysis.

Q. Are there rate classes that are treated differently from the 2017 general rate case rate spread?

A. Yes, PSE proposes that the Firm Resale class and Schedules 449/459 should receive average rate increases to all or a portion of their annualized revenues.

Q. Why are these rate classes treated differently?

A. In the 2017 general rate case, the Firm Resale class was allocated an increase equal to an amount that would move it to full parity so that there is not a cross-jurisdictional subsidy. Since this full parity was just recently completed, in this ERF rate spread, PSE proposes to apply an average increase to its proforma revenues.

In the 2017 general rate case, Schedules 449/459 (Retail Wheeling Class) were allocated an increase equal to state-jurisdictional costs through their customer charges. PSE proposes to apply an average increase to the monthly customer charge, as the state-jurisdictional costs are already reflected in this charge.

Q. What is the difference between an average increase and an adjusted average increase?

A. 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 less revenue for PSE than the retail class receiving the above-average increase, the adjusted average retail electric increase of 1.09 percent is greater than PSE's average retail electric increase of 0.93 percent.

Q. Please summarize how PSE spread the natural gas revenue deficiency.

A. PSE's natural gas rates already unbundle delivery from gas supply; therefore, the natural gas revenue deficiency was simply allocated on relative weather-normalized test year delivery rate revenue for natural gas customers.[2]

Q. Please summarize the results of the natural gas ERF allocation factor calculation.

A. This summary is provided in the table below. Additional detail supporting and explaining the derivation of these figures is discussed in the next section of this testimony.

[2] Delivery revenue is also commonly referred to as "base" or "margin" revenue for natural gas service.

Table 1 – Natural Gas ERF Allocation Factor Results

Customer Class	Rate Schedules	ERF Revenue ($millions)	Allocation Factor
Residential	16/23/53	$311.3	70.2%
Commercial & Industrial	31/31T/61	$91.6	20.6%
Large Volume	41/41T	$18.5	4.2%
Interruptible	85/85T	$8.6	1.9%
Limited Interruptible	86/86T	$2.0	0.5%
Non-exclusive Interruptible	87/87T	$4.7	1.0%
Special Contracts		$1.7	0.4%
Rentals	71/72/74	$5.4	1.2%
System Total / Average		$443.8	**100.0%**

III. ERF TEST PERIOD REVENUE

Q. Please describe how PSE determined the electric and gas weather-normalized sales volumes during the test year ending June 30, 2018.

A. PSE used the most current (2018) electric and gas weather sensitivity model coefficients and 30-year normal weather values. The 2018 model coefficients and normal weather values are based on the sales and weather histories ending December 2017.

Q. Please describe how PSE determined the annualized electric revenue associated with weather-normalized sales made during the test-year ending June 30, 2018.

A. PSE multiplied electric rates approved in Docket UE-180282 by the weather-normalized billing determinants for the period ending June 30, 2018. The

resulting electric revenue for this period was determined to be $2,026.4 million. These calculations are shown in Exh. JAP-4. This level of revenue was used to determine the electric deficiency in the Prefiled Direct Testimony of Susan E. Free, SEF-1T.

Q. Please describe how PSE determined the Commission Basis Report electric adjustment for the normalization to load for temperature during the test year ending June 30, 2018.

A. PSE multiplied the variable power cost portion of electric rates that were in effect during the test period by the adjustment to weather-normalized load for the period ending June 30, 2018. This adjustment to revenue is included in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T.

Q. Please describe how PSE determined the Commission Basis Report natural gas adjustment for the normalization to load for temperature during the test year ended June 30, 2018.

A. PSE multiplied the natural gas margin rates in effect during the test year by the adjustment to weather-normalized load for non-decoupled rate schedules for the period ending June 30, 2018. This adjustment to revenue is included in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T.

Q. Please describe how PSE determined the annualized natural gas ERF-related revenue associated with weather-normalized sales made during the test year ending June 30, 2018.

A. PSE multiplied natural gas rates approved in Docket UG-180283 by the weather-normalized billing determinants for the period ending June 30, 2018. The resulting ERF-related natural gas margin revenue for this period was determined to be $448.9 million. These calculations are shown in Exh. JAP-3. This level of revenue was used to determine the natural gas revenue deficiency in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T.

IV. RATE DESIGN

Q. Please describe the rate design methodology used to recover the electric ERF revenue deficiency.

A. For the most part, the revenues associated with the class allocated revenue deficiency were allocated to the basic, energy, demand, reactive or lamp charges as performed in the 2017 general rate case. Exceptions to the 2017 general rate case rate design were used for the following customer classes: Schedule 49 (High Voltage General Service), Schedules 449-459 (Retail Wheeling), and Lighting Schedules 50-59. These deficiencies are recovered through the electric adjusting rate schedule, Schedule 141.

Q. How did PSE design electric Residential ERF rates?

A. Residential customers (Schedule 7) did not receive an increase to the monthly basic charge, as that was determined by Commission order to be $7.49 in the 2017 general rate case. The Block 1 and Block 2 energy relationships were retained, and the class average increase was applied to each component, adjusting the first block for residual rounding.

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

A. PSE proposes to increase all rate components of General Service (Schedule 24), including the basic charge, by the class average increase. This is consistent with the rate design in the 2017 general rate case.

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

A. Except for the tailblock energy charge, which received no rate increase, the Small Demand General Service (Schedule 25) class rate components are each increased by the class average increase. This is consistent with the rate design in the 2017 general rate case.

Q. Please summarize the proposed rate design for Seasonal Irrigation and Drainage Pumping Service.

A. The Seasonal Irrigation and Drainage Pumping Service (Schedule 29) class rate

components are each increased by the class average increase. This is consistent with the rate design in the 2017 general rate case.

Q. Please describe the proposed rate design for Schedule 26 and Schedule 31.

A. PSE increased all Schedule 26 and Schedule 31 rate components by their class average increase. The reactive power charge for each schedule was increased by the applicable class average increase. The Schedule 26 demand charges were then set equal to the Schedule 31 demand charges on a loss-adjusted basis. PSE then increased the Schedule 26 energy rate by an amount that will recover the remainder of the rate responsibility of the Schedule 26 rate class. This is consistent with the rate design in the 2017 general rate case.

Q. Please summarize the proposed rate design for Seasonal Primary Irrigation and Drainage Pumping Service and Interruptible Primary Service for Total-Electric Schools.

A. The Seasonal Primary Irrigation and Drainage Pumping Service (Schedule 35) and Interruptible Primary Service for Total-Electric Schools (Schedule 43) basic charges are set equal to the Schedule 31 basic charge. The energy, demand and reactive power rate components are each increased by the remaining class average increase. This is consistent with the rate design in the 2017 general rate case.

Q. Please summarize the rate design for Schedule 40.

A. Rates for Schedule 40 are calculated using the same general rate methodology

used since the inception of this rate schedule. Schedule 40 has customer-specific distribution rates and a bundled energy and transmission rate that is based upon Schedule 49 after an adjustment for losses. There was no change made to the distribution rate as it is designed to recover customer-specific distribution costs on a levelized basis, as approved in the 2017 general rate case. The bundled production and transmission energy and demand rates are linked to the parity-adjusted high voltage rates because the aggregated load of each of these customers is comparable to the load of high voltage customers.

Q. Please summarize the proposed rate design for High Voltage Interruptible Service.

A. The High Voltage Interruptible Service (Schedule 46) energy charge was set equal to the Schedule 49 energy charge. The demand charge was set to collect the remaining amount of the class average increase. This is consistent with the rate design in the 2017 general rate case.

Q. Please summarize the proposed rate design for High Voltage General Service.

A. In the 2017 general rate case rate design, the High Voltage General Service (Schedule 49) demand charge was increased by 48 percent. Increasing this demand charge another 48 percent again is not necessary to keep this class within a reasonable parity ratio. So, PSE proposes to increase both the demand and energy charge by the class average increase.

Q. Please summarize the retail wheeling rate design.

A. In the 2017 general rate case rate design, PSE proposed to simplify pricing for Power Supplier Choice and Retail Wheeling Service (Schedules 448 and 449) by setting the basic charge at its cost of service and eliminating the existing per kVA charges. PSE proposes to increase the customer charge by the overall system average increase of 0.93 percent.

Q. Please summarize the lighting rate design.

A. The increases for lighting customers served on Schedules 50-59 were allocated proportionally with a portion of the rates approved in Dockets UE-180282 and UE-180382, for rates effective May 1, 2018 and June 1, 2018. In the 2017 general rate case, lamp charges were segregated into five cost categories for lighting schedules: (i) capital costs related to capital investments, (ii) distribution operations and maintenance ("O&M") expense, (iii) administrative and general ("A&G") expense, (iv) production/transmission costs (demand related), and (v) production/transmission costs (energy related). The revenue requirement was classified into these five categories so that it could be recovered from rates in proportion to each lamp or pole's contribution to these cost drivers. For purposes of the calculations of the ERF-related rates, only the capital, O&M and A&G costs were used to allocate the ERF revenue deficiency to lamp type and size. Lamp charges inclusive of the proposed increases in this filing, are provided in Exh. JAP-4. Column C of Exh. JAP-4 at pages 9 through 16 shows the derivation

of proposed Schedule 141 rates that recover only the calculated ERF electric revenue deficiency.

Q. Is this the same approach taken for electric rate design in PSE's previous ERF filing in Docket UE-130137?

A. No, it is not. However, this approach is consistent with the 2017 Settlement Agreement in which the parties agreed to not include changes to rate spread and rate design from the 2017 general rate case.[3]

Q. Can you summarize the impacts of PSE's electric ERF proposal for each class?

A. Yes. The allocated electric ERF-related deficiency and associated average rate impacts are presented below. Additional detail supporting these figures is provided in Exh. JAP-4 at page 1.

[3] *See* Dockets UE-170033 & UG-170034, 2017 Settlement Agreement, ¶ 115 and Exh. I.

Table 2 – Summary of Electric ERF-Related Revenue and Rate Impacts

Customer Class	Rate Schedule	Allocated ERF Deficiency ($M)	Average Rate Impact
Residential	7	$12.1	1.1%
General Service, < 51 kW	8/24	$2.2	0.8%
General Service, 51 – 350 kW	7A/11/25/29	$1.9	0.7%
General Service, >350 kW	12/26/26P	$1.1	0.7%
Primary Service	10/31/35/43	$0.9	0.7%
Campus Rate	40	$0.2	0.5%
High Voltage	46/49	$0.3	0.7%
Lighting Service	50 - 59	$0.2	1.1%
Choice/Retail Wheeling	448/449	$0.0	0.1%
Firm Resale/Special Contract	5	$0.0	0.9%
System Total / Average		$18.9	0.9%

Q. Has PSE prepared electric rates based upon the rate spread and rate design approach you describe above?

A. Yes, the proposed rates are calculated in Exh. JAP-4, and proposed sheets for electric tariff Schedule 141 are presented in Exh. JAP-5.

Q. How did PSE design natural gas ERF rates?

A. For each rate schedule, all elements of rates (basic, energy, demand and procurement charge) were increased by an equal percentage to recover the ERF increase. The calculations of the ERF-related natural gas rates, inclusive of the proposed increases in this filing, are provided in Exh. JAP-6.

Q. Has PSE prepared natural gas tariff sheets to recover its natural gas ERF deficiency?

A. Yes, the proposed natural gas tariff sheets for Schedule 141 are presented in Exh. JAP-7.

Q. Please summarize the impacts of PSE's natural gas ERF proposal for each class.

A. The allocated natural gas ERF-related deficiency and associated average rate impacts are summarized below. More detailed rate impact calculations can be found in Exh. JAP-8.

Table 3 – Summary of Natural Gas ERF-Related Revenue, Rate Spread and Rate Impacts

Customer Class	Rate Schedule	Allocated ERF Deficiency ($M)	Base Rate Impact[4]	Overall Rate Impact[5]
Residential	16/23/53	$ 14.8	2.9 %	2.7 %
Commercial & Industrial	31/31T/61	$ 4.8	2.9 %	2.9 %
Large Volume	41/41T	$ 1.1	2.9 %	2.9 %
Interruptible	85/85T	$ 0.4	2.9 %	2.9 %
Limited Interruptible	86/86T	$ 0.1	2.9 %	3.0 %
Non-exclusive Interruptible	87/87T	$ 0.3	2.9 %	3.0 %
Special Contracts		$ 0.05	2.9 %	2.6 %
Rentals	71/72/74	$ 0.2	2.9 %	2.8 %
System Total / Average		$ 21.7	2.9 %	2.7 %

Q. Why doesn't the overall natural gas revenue deficiency presented above match the amount presented in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T?

A. The overall increase associated with the deficiency presented in Ms. Free's testimony would exceed the three percent limit in rate impacts set forth in WAC 480-07-505(1)(a). Therefore, consistent with the process and procedures used in

[4] *See* Exh. JAP-6, Page 1, Column L. This represents increases relative to the sum of margin and gas cost rates (i.e., excluding other adjusting price schedules).

[5] *See* Exh. JAP-8, Page 1, Column T. These impacts are relative to all revenue, including other adjusting price schedules.

Docket UG-130138, PSE is limiting natural gas rate increases in this proceeding to 2.9 percent of current base rate revenue, inclusive of gas costs.

Q. What are the impacts to residential customers associated with PSE's ERF proposal?

A. The typical impact to PSE's residential electric customers using 900 kWh per month would be $1.00 per month, or a 1.1 percent increase over current rates. The typical impact to PSE's residential natural gas customers using 64 therms per month would be $1.58 per month, or a 2.7 percent increase over current rates.

V. DECOUPLING MECHANISM UPDATES

Q. Do the proposed ERF rates necessitate changes to PSE's decoupling mechanism?

A. Yes. PSE's decoupling mechanisms allow the Company to recognize electric and natural gas delivery revenue that is collected volumetrically on a per-customer basis for certain classes of customers. The electric decoupling mechanism also allows the Company to recognize electric fixed power cost revenue that is collected volumetrically on a set amount per month basis for certain classes of customers. The proposed ERF rates will change PSE's volumetric delivery and fixed power cost rates for electric service and volumetric delivery rates for natural gas service. Due to this change in rates, the allowed delivery revenue per customer and fixed power cost per month for each electric decoupling rate group and

allowed delivery revenue per customer for each natural gas decoupling rate group within Schedule 142 must be contemporaneously updated to consistently recognize the additional revenues being authorized as part of the ERF rate increases in Schedule 141. Similarly, in the tracking of variances between volumetric and allowed revenue, the delivery revenue per unit and fixed power cost per unit for each electric decoupling rate group and delivery revenue per unit for each natural gas decoupling rate group must also be updated to reflect the increase in volumetric ERF rates.

Q. Has PSE calculated the updated allowed revenue, delivery revenue per unit and fixed power cost per unit associated with the proposed ERF rate increases?

A. Yes. PSE has calculated updated allowed revenue, delivery revenue per unit and fixed power cost per unit associated with the proposed ERF rate increases for each decoupling rate group. The derivation of the electric decoupling allowed delivery revenue and delivery revenue per unit are presented in Exh. JAP-9. The derivation of the electric decoupling allowed fixed power cost revenue and fixed power cost revenue per unit are presented in Exh. JAP-10. Calculations for PSE's natural gas decoupling mechanisms are presented in Exh. JAP-11.

Q. Has PSE prepared updated decoupling tariff sheets to reflect these updated allowed revenue and delivery revenue per unit?

A. Yes. Proposed tariff sheets for the electric decoupling mechanism are presented in Exh. JAP-12. Proposed tariff sheets for the natural gas decoupling mechanism are presented in Exh. JAP-13.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.